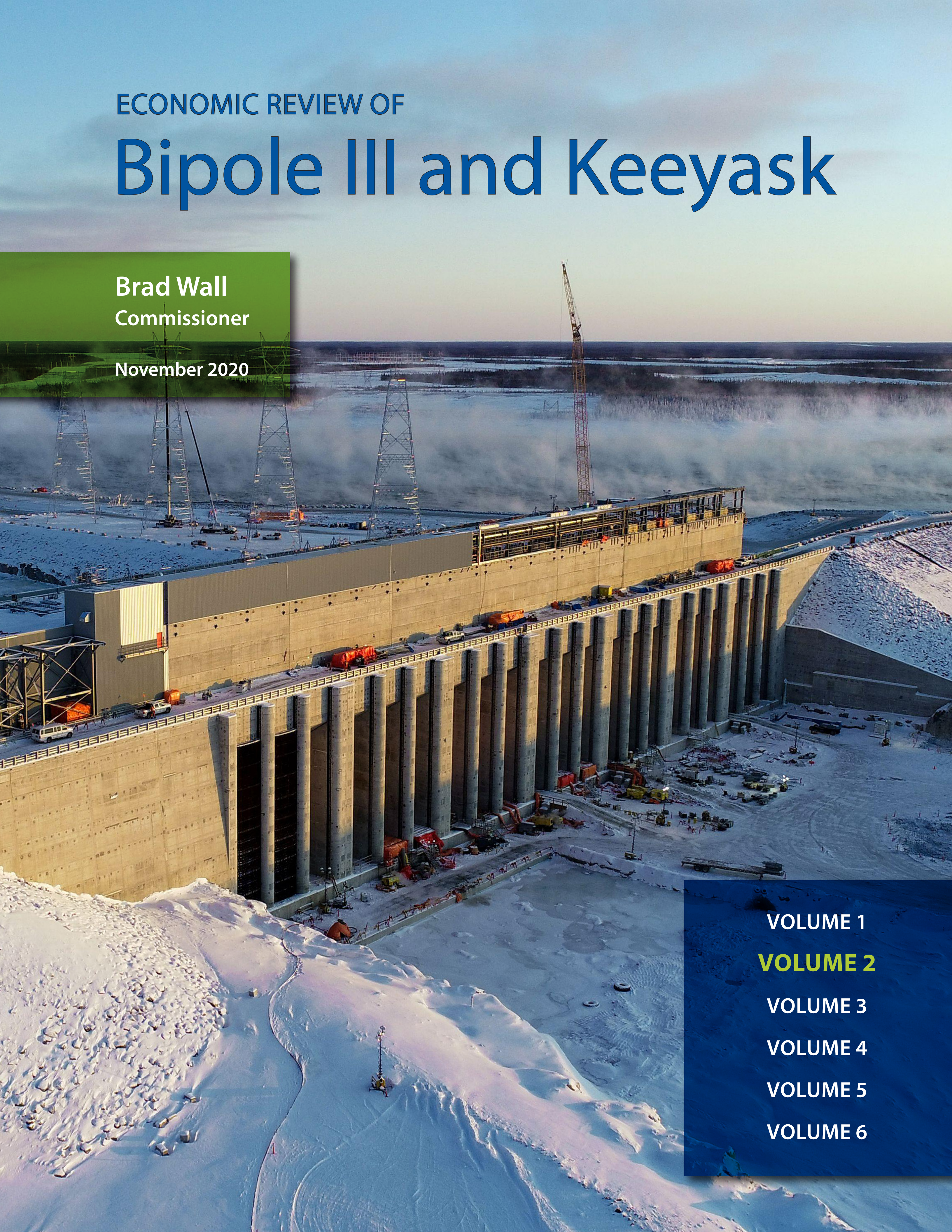
ECONOMIC REVIEW OF

Bipole III and Keeyask

Brad Wall
Commissioner

November 2020



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Tab 1

Dam-nation: Why Man. plan is too costly

By Graham Lane

Reading Time: 3 minutes

Published: June 28, 2013
Opinion

Many Manitoba residents are aware of the provincial government's planned massive expansion of Manitoba Hydro's northern hydroelectric generation and transmission facilities, but few understand the negative implications for their own pocketbooks.

The government's plans for Hydro were developed before 2008, when the economic environment was different. At that time, premier Gary Doer said: "Hydroelectricity is Manitoba's oil".

Hydro and government expected:

- Natural gas prices would stay high and increase. Not $4 per gigajoule but $10 or more.
- There would be a price on carbon, providing for a premium price for hydro power.
- Rather than industrial closures, new and expanded industry would develop to drive demand growth.
- Higher spot and fixed export prices would develop, rather than the less than three cents for spot sales of recent years.
- Construction costs to increase with inflation. The initial forecasts are now recognized as being far too low.
- An eastern route for BiPole III would save $1 billion and reduce troublesome engineering concerns.
- A lower Canadian dollar.
- A much higher rate would be in place for new or expanded energy intensive industry.

The global credit crisis and recession has since led to an industrial slow down, with the Americans focusing on their economy rather than on climate change.

As well, Americans began using more renewable energy by subsidizing wind and solar power, while new technology reduced the cost of wind and solar power. Americans also moved to generate jobs in the United States.

New production technology un-locked a torrent of shale gas, which drove natural gas prices much lower, providing increased use of gas turbine generating stations.

The Canadian dollar is at or near par, construction costs have skyrocketed, the model first dam, Wuskwatim, has proved an economic disaster, and the government forces a western BiPole III route while ignoring opportunities to diversify supply.

The strategy that is unfolding involves spending a considerable amount of money ahead of final approval of the projects, which will force up rates to keep Hydro's bo om line in the black.…

BiPole III will require either new net revenue or a 30 percent rate hike when it comes into service.

So, regardless of the weakness of Hydro's new revenue forecast, it counts on more export revenue to justify the building of the Keeyask and Conawapa dams while also planning to rebuild Pointe de Bois, "doubling down" the bet.

To assist these plans, the government has allowed Hydro to withhold critical information from the Public Utilities Board as the costs and risks of its development plan grows.

In essence, the strategy appears to be one hiding the real rate cost to consumers by gradually increasing rates.

We are already seeing the plan unfold: rates are climbing and forecasts of further rate increases are gradually being accepted while costs incurred are being deferred, allowing for the "feathering in" of the rate increases to consumers.

Who backstops the risk for Hydro blunders? Only ratepayers. Who protects ratepayers? Not Hydro, not the Public Utilities Board, not the auditor general and certainly not the provincial government.…

The development bus needs to slow down. The party that is truly at risk is required to be brought to a full understanding of the merits and risks of the present plans.

Reviews and audits need to be undertaken, options need to be examined and risks need to be adequately addressed.

Proceeding without a truly adequate dialogue represents an unnecessary and foolhardy process, one that could well bring economic and social pain to a province that lacks the financial base to gamble.

This article is excerpted from a Frontier Public Policy paper entitled DamNation: Rolling the Dice on Manitoba's Future by Graham Lane. The full report can be found at www.fcpp.org/files/5/PS153_DamNation_JN04F2.pdf. Lane is a retired chartered accountant and former chair of the Public Utilities Board.

Tab 2

Selinger: 'Hydro Power is Manitoba's Oil'

September 29, 2011 11:28 AM | News

Manitoba Votes 2011

NDP leader **Greg Selinger** spoke to a business crowd Thursday morning, where he outlined the importance Manitoba Hydro plays to the province's economy.

"Hydro power is Manitoba's oil," Selinger told the Manitoba Chambers of Commerce. "The main economic question in this election is do we build Hydro or not? The differences between myself and Mr. McFadyen on this are clear as day."

Greg Selinger (CHRISD.CA FILE)

Selinger went on to outline Hydro's contribution of $500 million to the economy each year through export sales, and noted it's poised to invest as much as $15 billion in new dams and transmission lines.

Selinger again went on to criticize his main opponent, Progressive Conservative Party leader **Hugh McFadyen**, saying the PCs would be "reckless" with their plans for Bipole III, a controversial high-voltage Manitoba Hydro transmission line taking power to northern Manitoba via the west side of the province. McFadyen has continually said his government would reroute the line on the east side of Lake Winnipeg — making for a shorter, more cost-effective alternative.

"The Liberals want to put the Bipole under water," Selinger added. "Different parties, different positions, but both would lead to the same sorry results: letting jobs and opportunities die on the vine."

The Green Party has gone on record to say the project wouldn't be necessary at all.

← Previous: Jets Chalk Up Home Ice Win Over Carolina Hurricanes

Next: Bachman & Turner to Headline NHL Face-Off Party →

Tags: Greg Selinger | Manitoba Hydro | NDP | Provincial Election 2011

Tab 3

ENVIRONMENT

MARCH 24, 2013 / 6:10 AM / UPDATED 8 YEARS AGO

Analysis: Obama's climate agenda may face setbacks in federal court

By Valerie Volcovici

WASHINGTON (Reuters) - President Barack Obama's plan to use federal agencies, and the Environmental Protection Agency in particular, to drive his second-term climate change agenda might be in peril if he cannot fill vacant seats on the federal court that has jurisdiction over major national regulations, legal experts say.

U.S. President Barack Obama waves as he boards Air Force One at the airport in Amman March 23, 2013. REUTERS/Majed Jaber

Obama is the first full-term president in more than a half century not to have appointed a single judge to the powerful U.S. Court of Appeals for the District of Columbia Circuit.

The court, considered the second most important in the nation, decides cases challenging agency regulations such as those involving the EPA's Clean Air Act and often serves as a feeder to the Supreme Court.

New York attorney Caitlin Halligan, Obama's first nominee to fill one of four vacant seats on the 11-judge bench, announced her withdrawal on Friday after Republicans twice blocked her nomination over concerns about a 2001 case in which she represented New York state and argued that gun manufacturers had created a "public nuisance" under state law.

Obama said in a statement on Friday that he was "deeply disappointed" that a minority of senators continued to block an up-or-down vote on her nomination after two and a half years.

Meanwhile, Obama's second pick, former corporate lawyer Sri Srinivasan, will have a Senate Judiciary Committee hearing in the next few weeks after being delayed in 2012 by Republican requests for more information about his role in the settlement of a housing act case as a U.S. deputy solicitor general.

While some fault Republicans for slow-walking the appointment of judges that would shift the balance of the court to Democrat-appointed judges, others fault Obama for not taking advantage of the now-four open seats and making judicial appointments a political priority. Two of the four vacant seats have been open since Obama came into office in January 2009. The seat Halligan was nominated for has been vacant since 2005.

Some legal experts warn that under the status quo - four Republican appointees and three Democratic appointees among active judges - Obama's plan to bypass a deeply partisan Congress to address climate change using existing authorities will not be easy.

"There is really no moving forward with regulation without going to the DC Circuit and the decision of the court could really have major consequences," said Michael Livermore, executive director of the Institute for Policy Integrity at New York University's law school.

The court hears all challenges to government agency regulations.

And regardless of the political balance, some warn the short-staffed court will have a hard time handling a growing case load of challenges to increasingly complex EPA regulations.

"There is a reason why there are 11 judges on that court of appeals," said John Cruden, director of the Environmental Law Institute. "They (cases) will take longer to resolve than they are right now because they are more complicated and they require and demand a lot of attention."

A former D.C. circuit judge on the court from 1979 to 1999 last month termed the ongoing vacancies a cause of "extreme concern" because the court lacks the manpower to carry out its "weighty mandate," which includes cases ranging from environmental protection to civil rights to national security.

Patricia Wald, who was an appointee of Democratic President Jimmy Carter, wrote in a February 28 op-ed in the Washington Post that the number of pending cases per judge has grown to 188 today from 119 in 2005.

Although the court's six senior status judges can hear cases, they cannot participate in re-hearings. Five of those six judges are Republican appointees.

AUTOMATIC CHALLENGE

Obama said in his February State of the Union address that he would direct his cabinet to take steps to curb carbon emissions if lawmakers fail to enact legislation - a likely outcome in the deeply divided Congress.

The EPA is expected to be at the center of Obama's climate efforts. It is due this year to finalize emissions standards for new power plants and industrial facilities. After that, it will set a standard for the country's power plants and industrial sources that account for nearly 40 percent of domestic emissions.

The proposed regulations will almost certainly be challenged by industry, including electric utility companies and manufacturers, who argue the agency is wrongly interpreting the Clean Air Act to write its standards.

“He (Obama) can lean as heavily as he wants on the EPA and its all for nothing if he gets the wrong panel reviewing what they do,” said Tom McGarity, a law professor at the University of Texas law school in Austin, who specializes in environmental and administrative law.

Three-judge panels are assigned randomly to resolve cases brought to the court. With just seven active judges, many of the same judges will deliberate similar EPA challenges.

Some analysts say the court has become more polarized on these issues, making the outcome largely dependent on the panel that gets selected - a roll of the dice.

Some also expect delays or revisions to the EPA’s proposed standard for new power plants beyond an April 13 deadline as the agency anticipates inevitable challenges in the DC circuit and uncertainty about how the judges will rule.

“It’s certainly possible that the EPA has recognized that it needs to be a little less aggressive in its interpretation and implementation of its authority,” said Jonathan Adler, a law professor at Case Western Reserve University.

Recent setbacks in the DC circuit might have reminded EPA that its technical and legal analysis needs to be bullet proof.

One such loss was the court’s 2-1 decision in August to strike down an EPA rule to curb sulfur dioxide and nitrogen oxide emissions from power plants that cause acid rain and smog across state lines. The decision called on the agency to rewrite the rules, a process that could take years.

Two of the three judges ruling on the case said the EPA exceeded its “jurisdictional limits” in interpreting the Clean Air Act. The EPA asked for a full-court hearing in January but it was denied.

The court ruled more favorably for the EPA in June, though, when it upheld agency rules on greenhouse gas emissions, including the scientific justification to regulate them because they endanger public health.

But new standards for power plants, mercury and hazardous materials, ozone rules and other controversial regulations will face uncertain fates in the court if the status quo continues.

NYU’s Livermore said that, while recent decisions on the EPA’s interpretation of the Clean Air Act have been mixed, the court has clearly demonstrated it is not afraid to strike down rules and send the agency back to the drawing board.

“This is not a court that is afraid to act and use its powers. There is no getting around these guys. It is small, so one or two judges can make a big difference in the ultimate decision,” he said.

Observers say Obama needs to make more nominations for the court or broker a deal with Republicans to get at least some of his judicial picks confirmed, or he will risk missing out on a chance to leave his mark on the court.

“If we continue on the current path of invalidating critically important rules, the DC circuit will be the graveyard for all programs, initiatives that are being pushed by the Obama administration and will affect all of us,” said Nan Aron, president of the judicial rights group Alliance for Justice.

“The DC circuit has that much power.”

Reporting By Valerie Volcovici.; Editing by Ros Krasny and Andre Grenon

Tab 4

The New York Times | https://nyti.ms/1KDWFkJ

Supreme Court Deals Blow to Obama’s Efforts to Regulate Coal Emissions

By Adam Liptak and Coral Davenport

Feb. 9, 2016

WASHINGTON — In a major setback for President Obama’s climate change agenda, the Supreme Court on Tuesday temporarily blocked the administration’s effort to combat global warming by regulating emissions from coal-fired power plants.

The brief order was not the last word on the case, which is most likely to return to the Supreme Court after an appeals court considers an expedited challenge from 29 states and dozens of corporations and industry groups.

But the Supreme Court’s willingness to issue a stay while the case proceeds was an early hint that the program could face a skeptical reception from the justices.

The 5-to-4 vote, with the court’s four liberal members dissenting, was unprecedented — the Supreme Court had never before granted a request to halt a regulation before review by a federal appeals court.

“It’s a stunning development,” Jody Freeman, a Harvard law professor and former environmental legal counsel to the Obama administration, said in an email. She added that “the order certainly indicates a high degree of initial judicial skepticism from five justices on the court,” and that the ruling would raise serious questions from nations that signed on to the landmark Paris climate change pact in December.

In negotiating that deal, which requires every country to enact policies to lower emissions, Mr. Obama pointed to the power plant rule as evidence that the United States would take ambitious action, and that other countries should follow.

The White House said in a statement that it disagreed with the court’s decision and remained confident that it would ultimately prevail. “The administration will continue to take aggressive steps to make forward progress to reduce carbon emissions,” it said.

Opponents of Mr. Obama’s climate policy called the court’s action historic.

“We are thrilled that the Supreme Court realized the rule’s immediate impact and froze its implementation, protecting workers and saving countless dollars as our fight against its legality continues,” said Patrick Morrisey, the attorney general of West Virginia, which has led the 29-state legal challenge.

"There's a lot of people who are celebrating," said Jeff Holmstead, a lawyer with Bracewell & Giuliani, a firm representing energy companies, which are party to the lawsuit. "It sends a pretty strong signal that ultimately it's pretty likely to be invalidated."

The challenged regulation, which was issued last summer by the Environmental Protection Agency, requires states to make major cuts to greenhouse gas pollution created by electric power plants, the nation's largest source of such emissions. The plan could transform the nation's electricity system, cutting emissions from existing power plants by a third by 2030, from a 2005 baseline, by closing hundreds of heavily polluting coal-fired plants and increasing production of wind and solar power.

"Climate change is the most significant environmental challenge of our day, and it is already affecting national public health, welfare and the environment," Solicitor General Donald B. Verrilli Jr. wrote in a brief urging the Supreme Court to reject a request for a stay while the case moves forward.

The regulation calls for states to submit compliance plans by September, though they may seek a two-year extension. The first deadline for power plants to reduce their emissions is in 2022, with full compliance not required until 2030.

The states challenging the regulation, led mostly by Republicans and many with economies that rely on coal mining or coal-fired power, sued to stop what they called "the most far-reaching and burdensome rule the E.P.A. has ever forced onto the states."

A three-judge panel of the United States Court of Appeals for the District of Columbia Circuit in January unanimously refused to grant a stay.

The court did expedite the case and will hear arguments on June 2, which is fast by the standards of complex litigation.

The states urged the Supreme Court to take immediate action to block what they called a "power grab" under which "the federal environmental regulator seeks to reorganize the energy grids in nearly every state in the nation." Though the first emission reduction obligations do not take effect until 2022, the states said they had already started to spend money and shift resources.

Eighteen states, mostly led by Democrats, opposed the request for a stay, saying they were "continuing to experience climate-change harms firsthand — including increased flooding, more severe storms, wildfires and droughts." Those harms are "lasting and irreversible," they said, and "any stay that results in further delay in emissions reductions would compound the harms."

In a second filing seeking a stay, coal companies and trade associations represented by Laurence H. Tribe, a law professor at Harvard, said the court should act to stop a "targeted attack on the coal industry" that will "artificially eliminate buyers of coal, forcing the coal industry to curtail production, idle operations, lay off workers and close mines."

The E.P.A., represented by Mr. Verrilli, called the requests for a stay "extraordinary and unprecedented." The states challenging the administration's plan, he said, could point to no case in which the Supreme Court had "granted a stay of a generally applicable regulation pending initial judicial review in the court of appeals." In a later brief, the states conceded that point.

Mr. Verrilli said judicial review of the plan, including by the Supreme Court, will be complete before the first deadline for emissions reductions in 2022.

"There is no reason to suppose that states' duties under the rule will be especially onerous," Mr. Verrilli wrote. "A state can elect not to prepare a plan at all, but instead may allow E.P.A. to develop and implement a federal plan for sources in that state."

The two sides differed about whether current declines in coal mining and coal-fired power generation are attributable to the administration's plan. "Some of the nation's largest coal companies have declared bankruptcy, due in no small part to the rule," a group of utilities told the justices.

A coalition of environmental groups and companies that produce and rely on wind and solar power said other factors were to blame for coal's decline.

"These changes include the abundant supply of relatively inexpensive natural gas, the increasing cost-competitiveness of electricity from renewable generation sources such as solar and wind power, the deployment of low-cost energy efficiency and other demand-side measures, and increasing consumer demand for advanced energy," they wrote.

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A version of this article appears in print on , Section A, Page 1 of the New York edition with the headline: Justices Deal Blow to Obama Effort on Emissions

Tab 5

Fourth Session - Thirty-Eighth Legislature

of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
(Hansard)

Published under the
authority of
The Honourable George Hickes
Speaker

Vol. LVII No. 55 - 1:30 p.m., Tuesday, April 25, 2006

MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Eighth Legislature

Member	Constituency	Political Affiliation
AGLUGUB, Cris	The Maples	N.D.P.
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ALTEMEYER, Rob	Wolseley	N.D.P.
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JHA, Bidhu	Radisson	N.D.P.
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LAMOUREUX, Kevin	Inkster	Lib.
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STRUTHERS, Stan, Hon.	Dauphin-Roblin	N.D.P.
SWAN, Andrew	Minto	N.D.P.
TAILLIEU, Mavis	Morris	P.C.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

LEGISLATIVE ASSEMBLY OF MANITOBA

Tuesday, April 25, 2006

The House met at 1:30 p.m.

PRAYER

Speaker's Statement

Mr. Speaker: I have some information for the House.

The Honourable Jobie Nutarak was a wonderful and very caring man. He was the Speaker of Nunavut Territory, and I am sad to announce that he passed away on the weekend due to a hunting accident. I am informing the House that I passed along sympathies and condolences to his family on behalf of all members, and also on behalf of everyone that is associated with the Manitoba Legislative Assembly.

ROUTINE PROCEEDINGS

PETITIONS

Funding for New Cancer Drugs

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, thank you for that message, and our condolences to your colleague.

I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

Cancer is one of the leading causes of death of Manitobans.

Families are often forced to watch their loved ones suffer the devastating consequences of this disease for long periods of time.

New drugs such as Erbitux, Avastin, Zevalin, Rituxan, Herceptin and Eloxatin have been found to work well and offer new hope to those suffering from various forms of cancer.

Unfortunately, these innovative new treatments are often costly and remain unfunded under Manitoba's provincial health care system.

Consequently, patients and their families are often forced to make the difficult choice between paying for the treatment themselves or going without.

CancerCare Manitoba has asked for an additional $12 million for its budget to help provide these leading-edge treatments and drugs for all Manitobans.

Several other provinces have already approved these drugs and are providing them to their residents at the present time.

We petition the Legislative Assembly of Manitoba as follows:

To request the Premier (Mr. Doer) of Manitoba and the Minister of Health (Mr. Sale) to consider providing CancerCare Manitoba with the appropriate funding necessary so they may provide leading-edge care for patients in the same manner as other provinces.

To request the Premier of Manitoba and the Minister of Health to consider accelerating the process by which new cancer treatment drugs are approved so that more Manitobans are able to be treated in the most effective manner possible.

This petition is signed by S. Holden, D. Jeanson, G. Peck and many, many others.

Mr. Speaker: In accordance with our Rule 132(6), when petitions are read they are deemed to be received by the House.

***** (13:35)

Point of Order

Mr. Leonard Derkach (Official Opposition House Leader): On a point of order, Mr. Speaker.

Mr. Speaker: The honourable Member for Russell, on a point of order.

Mr. Derkach: Well, Mr. Speaker, for the last two weeks in this House, we have been reading petitions, and, basically, the petitions urge the Premier (Mr. Doer) and the government.

Mr. Speaker, the Premier has said quite out loud in this Chamber that petitions are a waste of time. I am wondering whether we could encourage that the reading of petitions should not begin until the Premier is present since they are, in fact, directed at him and his government.

Mr. Speaker: The honourable Minister of Energy, Science and Technology, on the same point of order?

Hon. Dave Chomiak (Minister of Energy, Science and Technology): Yes, thank you, Mr. Speaker. I just want to make two points to the House. Firstly, we changed the order of petitions in order to allow petitions to be read in this Chamber. So the order was changed by agreement of all parties of which I think the member opposite signed on.

Secondly, Mr. Speaker, I think the member misappropriated what the Premier said. He said the bell ringing was a waste of time.

And, thirdly, Mr. Speaker, the Premier was just returning on behalf of the Province of Manitoba– *[interjection]*

Mr. Speaker: Order.

Mr. Chomiak: The Premier was just returning from speaking on behalf of the Province of Manitoba at the Holocaust Memorial ceremony that just took place, Mr. Speaker. *[interjection]*

Mr. Speaker: On the point of order raised by the Official Opposition House Leader, all members are aware that mentioning the presence or absences of members is not allowed in our rules. The honourable member does not have a point of order.

*** * ***

Mr. Speaker: But we will continue on with petitions.

Mr. Cliff Cullen (Turtle Mountain): Mr. Speaker, I ask for leave to present the petition on behalf of the Member for Tuxedo (Mrs. Stefanson).

Mr. Speaker: Does the honourable member have leave? *[Agreed]*

Mr. Cullen: Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

Cancer is one of the leading causes of death of Manitobans.

Families are often forced to watch their loved ones suffer the devastating consequences of this disease for long periods of time.

New drugs such as Erbitux, Avastin, Zevalin, Rituxan, Herceptin and Eloxatin have been found to work very well and offer new hope to those suffering from various forms of cancer.

Unfortunately, these innovative new treatments are often costly and remain unfunded under Manitoba's provincial health care system.

Consequently, patients and their families are often forced to make the difficult choice between paying for the treatment themselves or going without.

CancerCare Manitoba has asked for an additional $12 million for its budget to help provide these leading-edge treatments and drugs for Manitobans.

Several other provinces have already approved these drugs and are providing them to their residents at present time.

We petition the Legislative Assembly of Manitoba as follows:

To request the Premier (Mr. Doer) of Manitoba and the Minister of Health (Mr. Sale) to consider providing CancerCare Manitoba with the appropriate funding necessary so they may provide leading-edge care for patients in the same manner as other provinces.

To request the Premier of Manitoba and the Minister of Health to consider accelerating the process by which new cancer treatment drugs are approved so that more Manitobans are able to be treated in the most effective manner possible.

This petition is signed by Graham Hnatiuk, Leanne Peixob, Kristjana Wood and many, many others.

***** (13:40)

Grandparents' Access to Grandchildren

Mr. Ralph Eichler (Lakeside): Mr. Speaker, I wish to present the following petition.

These are the reasons for this petition:

It is important to recognize and respect the special relationship that exists between grandparents and grandchildren.

Maintaining an existing, healthy relationship between a grandparent and a grandchild is in the best interest of the child. Grandparents play a critical role in the social and emotional development of their grandchildren. This relationship is vital to promote the intergenerational exchange of culture and heritage, fostering a well-rounded self-identity for the child.

In the event of divorce, death of a parent or other life-changing incident, a relationship can be severed without consent of the grandparent or the grandchild. It should be a priority of the provincial government to provide grandparents with the means to obtain reasonable access to their grandchildren.

We petition the Manitoba Legislative Assembly as follows:

To urge the Minister of Family Services and Housing (Ms. Melnick) and the Premier (Mr. Doer) to consider amending legislation to improve the process by which grandparents can obtain reasonable access to their grandchildren.

Submitted on behalf of A.C. Anderson, Liz Anderson, Chris Mazur and many, many others.

Crocus Investment Fund

Mr. Denis Rocan (Carman): I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

The Auditor General's *Examination of the Crocus Investment Fund* indicated that as early as 2001, the government was made aware of red flags at the Crocus Investment Fund.

In 2001, Industry, Economic Development and Mines officials stated long-term plans at the Crocus Investment Fund requiring policy changes by the government were cleared by someone in "higher authority," indicating political interference at the highest level.

In 2002, an official from the Department of Finance suggested that Crocus Investment Fund's continuing requests for legislative amendments may be a sign of management issues and that an independent review of Crocus Investment Fund's operations may be in order.

Industry, Economic Development and Mines officials indicated that several requests had been made for a copy of Crocus Investment Fund's business plan, but that Crocus Investment Fund never complied with the requests.

Manitoba's Auditor General stated, "We believe the department was aware of red flags at Crocus and failed to follow up on those in a timely way."

As a direct result of the government ignoring the red flags, more than 33,000 Crocus investors have lost more than $60 million.

The relationship between some union leaders, the Premier (Mr. Doer) and the NDP seems to be the primary reason as for why the government ignored the red flags.

The people of Manitoba want to know what occurred within the NDP government regarding Crocus, who is responsible and what needs to be done so this does not happen again.

We petition the Legislative Assembly of Manitoba as follows:

To strongly urge the Premier to consider calling an independent public inquiry into the Crocus Investment Fund scandal.

Signed Jeff MacDonald, Bob Gass, Craig MacDonald and there are many, many others.

Mr. Larry Maguire (Arthur-Virden): Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

The Auditor General's *Examination of the Crocus Investment Fund* indicated that as early as 2001, the government was made aware of red flags at the Crocus Investment Fund.

In 2001, Industry, Economic Development and Mines officials stated long-term plans at the Crocus Investment Fund requiring policy changes by the government were cleared by someone in "higher authority," indicating political interference at the highest level.

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As a direct result of the government ignoring the red flags, more than 33,000 Crocus investors have lost more than $60 million.

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The people of Manitoba want to know what occurred within the NDP government regarding Crocus, who is responsible and what needs to be done so this does not happen again.

We petition the Legislative Assembly of Manitoba as follows:

To strongly urge the Premier to consider calling an independent public inquiry into the Crocus Investment Fund scandal.

This petition is signed by Eric Dickson, Brad Rowat, Marion Kostuik and many, many others.

***** (13:45)

Civil Service Employees–Neepawa

Mr. Glen Cummings (Ste. Rose): Mr. Speaker, I wish to present the following petition to the Legislative Assembly.

These are the reasons for this petition:

Eleven immediate positions with Manitoba Conservation Lands Branch, the Crown Lands and Property Special Operating Agency, are now being moved out of Neepawa.

Removal of these positions will severely impact the local economy with potentially 33 adults and children leaving the community.

Removal of these positions will be detrimental to revitalizing the rural and surrounding communities of Neepawa.

We petition the Legislative Assembly of Manitoba as follows:

To request the provincial government to consider stopping the removal of these positions from our community and to consider utilizing current technology, as Land Management Services existing satellite sub-office in Dauphin does, in order to maintain these positions in their existing location.

Signed by Jim Beaumont, David Beaumont and Barnie Provost.

Crocus Investment Fund

Mr. Kevin Lamoureux (Inkster): Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

The background to this petition is as follows:

The Manitoba government was made aware of serious problems involving the Crocus Fund back in 2001.

Manitoba's provincial auditor stated "We believe the department was aware of red flags at Crocus and failed to follow up on those in a timely way."

As a direct result of the government not acting on what it knew, over 33,000 Crocus investors have lost tens of millions of dollars.

The relationship between some union leaders, the Premier (Mr. Doer) and the NDP seems to be the primary reason as for why the government ignored the red flags.

We petition the Legislative Assembly of Manitoba as follows:

To request the Legislative Assembly of Manitoba to consider the need to seek clarification on why the government did not act on fixing the Crocus Fund back in 2001.

To urge the Premier and his government to co-operate in making public what really happened.

Signed by M. Singh, J. Rapose, E. Rapose and many, many others.

MINISTERIAL STATEMENTS

Holocaust Memorial Day

Hon. Nancy Allan (Minister responsible for Multiculturalism): Yes, Mr. Speaker, I have a ministerial statement for the House.

On May 1, 2000, Manitoba's Legislative Assembly voted unanimously to pass Bill 19, an act to proclaim Holocaust Memorial Day or Yom Hashoah in Manitoba.

On this day, we in Canada and all over the world stand in solidarity with our Jewish brothers and sisters to remember the atrocities committed by the Nazi regime towards the Jewish community in Europe, which culminated in the death of 6 million Jewish men, women, children and others. Today we must remember that the Holocaust was not only a tragedy for the Jewish people but also a human tragedy. We owe nothing less than awe to the strength and determination of the survivors. In these people we see the power of the human spirit, the triumph of hope over loss and the victory of courage over fear.

This morning I was honoured to participate in the "unto every person there is a name" ceremony here at the Legislature. I was joined by many of my colleagues as well as the Maples Collegiate Unity Group who were awarded the International Peace Medal in 2003, as well as the Manitoba Human Rights Award in 2005 for their efforts to promote human rights, anti-racism and social justice issues. I congratulate the Maples Collegiate Unity Group for their efforts to combat racism and promote human rights, as well as a better understanding and respect for cultural diversity.

The attitudes and values of young people will shape Canadian society, and the future will depend on their involvement and engagement. Today we not only look to our youth for hope, but also look to our leaders for inspiration.

Earlier today, as I recited the names of the Holocaust victims who are inscribed on the Holocaust monument on the Legislative grounds, I was reminded that it is important for all of us to stand together in unity and say: Never again. Let us remember that, while the tragedies of history cannot be undone, we must envision the future with courage and determination, and never let the errors of the past be repeated.

Mr. Speaker, after my colleagues have spoken, I would ask that all members observe a moment of silence as we reflect on those whose silence we will remember forever.

***** (13:50)

Mr. Stuart Murray (Leader of the Official Opposition): Mr. Speaker, I wish to join the minister on her reflection and on the reflection of all members in this Chamber for what was, I believe, a very important bill that was passed unanimously to proclaim Holocaust Memorial Day or Yom Hashoah in Manitoba.

I know that those of us who had the opportunity to participate in "unto every person there is a name" this morning, it just sends an incredible, powerful message to all of us that we stand before people to recite names of family members' loved ones that were so taken away for something that to this day, I do not think anybody can understand why it happened.

I know that my wife and I were joined with a number of Manitobans on a solidarity mission. I know the Premier (Mr. Doer) and the Minister of Energy, Science and Technology (Mr. Chomiak) have also been over to Israel, along with others, to understand and try to get a sense of why it is that we are in a situation that we have to deal with issues such as remembering the Holocaust. Anybody who has a chance to travel to Israel will see a people who were put onto a desert, and unto their determination and spirit they have created a society that, I think, we all can stand back and learn from.

So, today, Mr. Speaker, I say to all members of the Legislature and to all Manitobans, we join the minister in citing that we all must, in our own way, every single day of our lives, ensure that atrocities, as happened to the Jewish people who suffered in the Holocaust, and all of those people who were affected, that all of us ensure that it will never, ever happen again. That is something that we, as this side of the House, that side of the House, all members of this Legislature, I think, stand united. We always must take time to never forget. Thank you very much.

Hon. Jon Gerrard (River Heights): I ask leave to speak to the minister's statement.

Mr. Speaker: Does the honourable member have leave? *[Agreed]*

Mr. Gerrard: Mr. Speaker, I would like to join my colleagues today, Holocaust Memorial Day, in remembering the tragedy of the Holocaust, the 6 million people who died, the 1.5 million children, and in joining others in the resolve to do everything in our power here and elsewhere to prevent such tragedies in the future.

This Holocaust Memorial Day has a special meaning to me this year because I was in Jerusalem in February and had a chance to visit the Holocaust Museum. What an incredible experience going through and seeing the many stories.

After I read at the memorial, "unto every person there is a name," after I had read some of the names this morning, I had a chance to talk with one of the survivors who has lived here in Winnipeg now for many years. It was very moving, both on the one hand to hear her speak of the pain that is there every day for her even now, so many years later from the many people whom she knew and she lost in the terrible tragedy that was the Holocaust. But, Mr. Speaker, in spite of that pain being there every day, she has contributed in Manitoba in many, many ways, including working with children at the Children's Hospital for many years.

***** (13:55)

I think it is an important opportunity to salute those who have come through this terrible experience and, yet, have been able to contribute in one way or another so much here in Manitoba and others, of course, around the world.

This is a real opportunity to remember and to recommit ourselves to preventing this sort of thing from ever happening again. Thank you.

Mr. Speaker: Do members wish to rise for a moment of silence? *[Agreed]* We will rise for a moment of silence.

A moment of silence was observed.

Introduction of Guests

Mr. Speaker: Prior to Oral Questions, I would like to draw the attention of honourable members to the public gallery where we have with us from Isaac Brock School 10 Grade 9 students under the direction of Mr. Larry Beaudoin and Mr. Paul Doerksen. This school is located in the constituency of the honourable Member for Minto (Mr. Swan).

On behalf of all honourable members, I welcome you here today.

ORAL QUESTIONS

Manitoba Hydro
East Side Transmission Line

Mr. Stuart Murray (Leader of the Official Opposition): Mr. Speaker, currently, 70 percent of the power from northern Manitoba comes down two high voltage transmission lines, Bipole I and Bipole II. Both lines are located on the west side of Lake Winnipeg.

Manitoba Hydro will eventually need Bipole III, a third high voltage line to bring down power from the North. A route going down the west side of Lake Winnipeg will be $400 million to $550 million more expensive than a line going down the east side of Lake Winnipeg. A west side route will also be 400 kilometres longer and result in additional line losses of some 70 megawatts.

Mr. Speaker, to put this into perspective, the proposed $1.2 billion Wuskwatim Dam is a 200-megawatt project, meaning a west side line will result in the losses of more than a third of the output of the Wuskwatim Dam. This NDP government has vetoed an east side route.

I ask the Premier: Why is his NDP government choosing an alternative that is more expensive and results in greater line loss than an east side route?

Hon. Gary Doer (Premier): Mr. Speaker, there are a number of options that Hydro is looking at. Part of those options that are being discussed is the cost not only of the direct transmission line, which the member reports, but also the cost of potential settlements and the cost of delay. So the members opposite do not cite the costs of communities that may be in favour of it, and many other communities on the east side are not in favour of it. That is different than a straight-line engineering calculation, and, of course, Hydro has to consider making decisions not only of the straight-line transmission costs but the costs of not being able to build the line and the cost of not being able to have appropriate agreements with people who actually live in the area.

I am pleased that members opposite, the mothball party of Manitoba, have a new interest in hydro development, but I would point out that it was the NDP government who built the direct current line which is one of the most efficient in all of the world, Mr. Speaker. I would point out that Manitoba's profit last year was $400 million after we built Limestone, and it is going to be comparable this year.

* (14:00)

Mr. Murray: Well, I do not want to get into the millions and millions and millions of dollars that they raided out of Hydro, but I digress, Mr. Speaker.

Mr. Speaker, events such as the Québec ice storm of 1998 and the northeastern brownout of 2003 remind us of how vulnerable we are to power interruptions. It is important that we prepare ourselves for a power outage, particularly during Manitoba's minus 40 degree Celsius temperatures. A winter power outage would threaten Manitobans who heat their homes with electricity and natural gas users whose furnace fans are powered by electricity. Instead of building a transmission line down the east side of Lake Winnipeg and increasing the reliability of power to Manitobans, this government is proposing to not build a second but a third transmission line down the western corridor. An east side route would help to protect the province from natural disasters and terrorist attacks.

Nowhere else do we see the arrogance that this government exhibits. We are a province, Mr. Speaker, with an opportunity to increase the reliability of our electricity supply. Instead of embracing these opportunities, this NDP government is squandering the opportunity. An east side transmission line would provide greater reliability for all Manitobans.

I would like to ask the Premier: Why has his NDP government vetoed the possibility of a route that would provide increased reliability for Manitobans?

Mr. Doer: Mr. Speaker, I do not know whether the member opposite has been on the east side meeting with people in the community, but we have had over 30 community meetings on the east side. We actually respect when people live in an area, there may be a diverse few, but if people are opposed to it those are not even factored into Hydro calculations, and if the line is never built the delay and the cost of delay is also not factored in.

I would point out, Mr. Speaker, everybody is talking about east and west. We may be talking because we are not just dealing with reliability. This government is not only looking at reliability, it is also looking at increased sales. Those increased sales may go to the east across the north and may go to the west across the north. So there is more than one option on the table.

They are the mothball party that cancelled Limestone. They cancelled Conawapa. The NDP will build Hydro for the future, Mr. Speaker.

Mr. Murray: Mr. Speaker, this is a very important issue for the future of Hydro and the future of all Manitobans, clearly.

Mr. Speaker, what we see from the member opposite, the Premier, is that the NDP government apparently is prepared to take their advice from Bobby Kennedy, Jr. We believe all Manitobans should be involved in this discussion. Every Manitoban can gain from this, not just Bobby Kennedy, Jr. We think that Manitoba officials from Hydro believe that a Bipole III line is necessary. We believe that discussions should take place, including all Manitobans, to ensure what is right for the province of Manitoba. What we do not want is a veto.

Mr. Speaker, this government is to veto the option of building a transmission line down the east side of Lake Winnipeg and is ignoring the needs of residents along the east side. Many of the east side residents see this development of an east side corridor as an opportunity to construct an all-season road that would provide them with access to goods, access to services year-round, including–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Murray: Well, thank you, Mr. Speaker. An all-year access road would provide them with goods and services year-round and improve their quality of life. Each year, a winter road is constructed to provide access to the east side residents and to transport goods into the community. Weather permitting, the winter road is open for a small window each year. During the rest of the year, east side residents are isolated from the markets and from critical services such as health care.

Mr. Speaker, I would like to ask this Premier: How long does he expect the east side residents of Lake Winnipeg to live as second-class citizens?

Mr. Doer: Mr. Speaker, as one who was in the Cabinet that extended the transmission line into the Island Lake area and had consultations beforehand with the people in the communities, we respect and we respect greatly the people in the communities and their views. The people in the communities have a right to have a say and, they do have a say, not somebody else. I think it is Robert Kennedy, Jr. you are talking about, unfortunately, a different person the member was mentioning.

Mr. Speaker, secondly, the issue of the road, the road costs between $350 million and $400 million. We do believe in more access. We are working on plans to extend the road up the east side and extend the road, like we did with the winter road from Norway House into the Island Lake area which we did this year, to get goods and services there.

But to say Hydro, on the one hand, should not be raided and, on the other hand, if you build the transmission line for the road, getting $400 million from Hydro is just creating a false choice, it is not true. People should not say it and journalists should not say it because it is just not true.

When we have meetings with Aboriginal people, we tell the truth. We do not say you are going to get a free road if a transmission line comes in. Part of the debate should be truth, Mr. Speaker.

Finally, Mr. Speaker, the only raid that has taken place in this province is the Tories selling one Manitoba Telephone System against the consent of the people of this province.

Lake Winnipeg
Eastern Access Road

Mr. Larry Maguire (Arthur-Virden): Well, Mr. Speaker, Manitobans are not interested in ancient history. There are–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. The honourable Member for Arthur-Virden has the floor.

Mr. Maguire: Mr. Speaker, there are tens of thousands of stranded Manitobans on the east side of Lake Winnipeg. Winter roads are becoming less reliable and more costly. Air lifting is extremely expensive. Fuel costs continue to skyrocket.

Can the Minister of Transportation and Government Services tell Manitobans why he has not promoted the development of an east side access route in conjunction with a proposed new transmission line needed to deliver more electric power for Manitobans or for export?

Hon. Ron Lemieux (Minister of Transportation and Government Services): Mr. Speaker, how hypocritical. You have the member opposite who criticizes us for putting money into winter roads; we have doubled the winter roads' budget. He criticizes that, criticizes any initiative we have; $29 million more into the current budget. He criticizes that, yet will not have the courage to debate the budget on these monies to be forwarded to Manitobans.

I can tell you we are committed to northern Manitobans, eastern Manitobans, western Manitobans, members from all over Manitoba. They know we are committed to transportation, that we put in many dollars over the last number of years to Manitobans.

Mr. Maguire: Mr. Speaker, the only thing we are criticizing here is the minister's responsibility in acting in this regard in a responsible manner. These tens of thousands of isolated Manitobans need road access for many reasons; better health care facilities, economic development, access to family members and friends in neighbouring communities and access to more competitively priced food products, to name a few.

Can the minister tell Manitobans, particularly those isolated on the east side of Lake Winnipeg, what discussions his government has had with Manitoba Hydro regarding the construction of an eastern access road?

Hon. Gary Doer (Premier): Mr. Speaker, let the record show that nobody is perfect, but you put more money in 11 years into the road to Oak Hammock Marsh than you put in all northern Manitoba. How dare you raise these questions today.

Mr. Maguire: Well, Mr. Speaker, I am sure that that is no solace to the people on the east side of Lake Manitoba who remain isolated. The minister talks of having good roads as an economic driver in our economy, yet his government had to add over 400 kilometres to this winter roads system to deliver basic essentials so these eastern citizens have access to what other Manitobans take for granted.

Can the minister explain why he continues to isolate the tens of thousands of eastern Manitobans by denying health care access, competitive food products and better economic opportunities that an eastern access road would provide?

***** (14:10)

Mr. Lemieux: We put millions of dollars into repairing airports in northern communities providing access. We have also provided millions of dollars with regard to winter roads. Also, we have taken many, many kilometres off of the ice and off of the river system in order to provide safety for northern Manitobans.

Mr. Speaker, members opposite continually criticize us every time we talk about putting money into northern Manitoba. Here on this side they are trying to provide a wedge between northern Manitobans and southern Manitobans, but we as a government care for all Manitobans in transportation throughout this province.

Crocus Investment Fund
Co-investment Risk Analysis

Mr. Glen Cummings (Ste. Rose): Mr. Speaker, the state of the roads in this province, I would not be bragging about it if I was–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Cummings: Yesterday, Mr. Speaker, the Minister of Finance refused to answer whether he had received any information about Crocus Investment Fund status while receiving reports from Treasury Board analysis or any other risk and exposure the government might have had. Again he proved that he must have something to hide or he would be willing to answer some questions.

Mr. Speaker, I will give him a chance again today to answer the question. As head of Treasury Board, who should be the most knowledgeable minister on that side of the House regarding financial affairs, did he receive information about the Crocus Fund in 2001, about his performance through Treasury Board or any other risk assessment?

Hon. Greg Selinger (Minister of Finance): Mr. Speaker, yesterday I read into the record how the fund was set up by the former government, and it was very clear at the time that the members opposite wanted it to be a community-driven institution, driven by the private sector, driven by business leaders and independent from government. No private organization reports to Treasury Board. The member sat on Treasury Board, he should know that.

Mr. Cummings: Mr. Speaker, again this minister has proven why we need an inquiry into what happened at Crocus. There is no limit to his evasive answers it would appear. I remind him that at some point he is going to have to swear under oath and provide answers that are truthful in public.

Did he or his officials meet with Sherman Kreiner?

Mr. Selinger: All the relevant events, in terms of meetings, are reported in the Auditor General's report. The member has full access to it in terms of all the meetings that occurred. He simply has to take the time to read the report. If he really wants to go fishing, Mr. Speaker, I suggest he go fishing in some of the excellent lakes we have in Manitoba where he might catch something.

Public Inquiry

Mr. Glen Cummings (Ste. Rose): If that was my seven-year-old son, I would assume that the answer was yes, from that type of an answer, but they expect better from the Minister of Finance.

If he has nothing to hide, why will he not answer the simplest of questions? He is right and, in fact, I was on Treasury Board for a number of years. I believe that this minister would have or should have received reports that would have had implications with information about co-investments where there was risk associated with Crocus. If he did not know, he was asleep at the switch, Mr. Speaker.

Will he now join this side of the House in agreeing that we need a public inquiry into what happened at Crocus?

Hon. Greg Selinger (Minister of Finance): Well, Mr. Speaker, just because the member opposite mistreats his seven-year-old son does not mean he can mistreat the people of Manitoba.

The evidence of all the meetings is in the Auditor General's report. The member should take the time to read it. When he came to Public Accounts, ministers were ready to answer his questions. When he was confronted with the evidence, he folded his tent, went home and cancelled the meeting.

Now the member, in addition, has asked about MIOP loans. They are all reported in the Public Accounts. All he has to do is read the Public Accounts and he will see that all the loans that went bad were loans that the members opposite made when they were in government. They lost money. If they really want to know the facts, all they have to do is read all the information disclosed on the public record instead of going fishing in the Legislature, instead of fishing in the excellent lakes that we have in Manitoba.

Teachers' Retirement Allowance Fund Board Member Removal

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, Jon Singleton, the Auditor General, has criticized the Minister of Education for his inaction on Tom Ulrich's letter.

On page 13 of Tom Ulrich's letter to the Minister of Education, he stated that, and I quote, "I was surprised to discover that the citizen representative, Bob Malazdrewich, had been replaced. I contacted him to express my surprise and thank him for his service and support and he informed me that it was not his choice to leave. Never in the history of TRAF had a citizen representative been removed from the TRAF board except by resignation."

I would like to ask this Minister of Education: Why was Bob Malazdrewich, who had been appointed by Order-in-Council, removed from the board?

Hon. Peter Bjornson (Minister of Education, Citizenship and Youth): Mr. Speaker, with respect to the TRAF board, I should point out for the member opposite, who has been asking about the chair, that currently we are, as I said yesterday, in the process of dealing with the chair and appointment of the chair.

Mr. Speaker, I would also like to point out with regard to the allegations that had been received from Mr. Ulrich, when we received those allegations we immediately followed up with the TRAF board. I also contacted the office of the Auditor General, because the letter had been copied to the office of the Auditor General and the Auditor General's office is the office that does the audit on TRAF. So we had followed up with the allegations.

Mrs. Driedger: Well, Mr. Speaker, he certainly totally avoided answering that question. It is interesting the letter that Mr. Ulrich wrote and the concerns he wrote were sent back to the people he was raising concerns about. Mr. Ulrich also went on to say, and I quote, "It led me to wonder whether Bob's outspoken support of me and his questioning the advisability of some local investment proposals had affected his reappointment."

So I would like to ask the Minister of Education: Did he remove Bob Malazdrewich from the teachers' fund board because he spoke out against the $10-million pension money investment into the Manitoba Property Fund?

Mr. Bjornson: No, I did not.

Investment Practices

Mrs. Myrna Driedger (Charleswood): Bob Malazdrewich was replaced on the board by Lea Baturin, who was also on the Crocus board. As Crocus was pushing the Manitoba Property Fund, the NDP board appointee, Alfred Black, on TRAF, was pushing the Manitoba Property Fund on TRAF.

I would like to ask the Minister of Education: Was Lea Baturin put on the teachers' pension board to help Mr. Alfred Black push the Manitoba Property Fund on TRAF?

***** (14:20)

Hon. Peter Bjornson (Minister of Education, Citizenship and Youth): Mr. Speaker, that is not the case, and with respect to the Property Fund that the member has been talking about–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Bjornson: With respect to the Property Fund that the member is talking about, I have repeatedly told the member that this Property Fund has performed at or above the industry benchmarks for the rate of return. The member is also inaccurate in talking about the figure of $10 million, Mr. Speaker. TRAF has not invested $10 million in the Property Fund as the member has repeatedly put on the record.

I wish the member would do some research. There are three letters, Mr. Speaker–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Bjornson: Thank you, Mr. Speaker. I have provided the member opposite with three letters that I have tabled in this House from the stakeholders in TRAF that have said if the member has some concerns to contact the CEO, and she will get accurate information with regard to her concerns.

Child Welfare System
Case Reviews

Mrs. Mavis Taillieu (Morris): Mr. Speaker, the four authorities who deliver child welfare on their own initiative are conducting face-to-face interviews with all the children in care and those whose files were closed within 30 days.

Now, at the halfway mark of the review, can the Minister of Family Services say how many children are still to be accounted for, how many have had face-to-face meetings and how many children are not accounted for because their whereabouts are not known?

Hon. Christine Melnick (Minister of Family Services and Housing): Mr. Speaker, we worked with the four authorities to put together a plan for them to make sure that they were having face-to-face meetings with the children, that the front-line workers were meeting with the children. I think it is important to note that these people are professionals and that they know that it is very important to have these independent meetings.

I also think it is important for the House to know that in 1999-2000, there were some 440 front-line workers, social workers; in 2006-07, there are 553. Mr. Speaker, that is an increase of 112 front-line social workers, an increase of over 25 percent.

Mrs. Taillieu: Mr. Speaker, I am afraid that was not an answer to the question.

We have been told by front-line social workers that in past they have been directed to close files when they could not physically locate the child. Manitobans want to be assured that no more children slip through the cracks and die like Phoenix Sinclair, whose file was closed three months before she died.

Is the minister satisfied all children whose files were closed are not at risk? What directive has the minister given to account for children whose files were closed because they could not find the child?

Ms. Melnick: Again, Mr. Speaker, we are working with the four authorities. They have put together a work plan with their front-line workers. They have brought in extra staff to make sure that the deadlines can be met. They are meeting with children. They are working with families. They are professionals who are working on the front lines in some very difficult situations. I think it is important that this House support the work of the four authorities, that they support the work of the front-line workers and that we all work together in the best interests of the children of Manitoba.

Mrs. Taillieu: Well, Mr. Speaker, we certainly recognize the good work that social workers do, but we also recognize the minister places impossible time limits on social workers and this continues to put children at risk. The minister does not give answers to my questions either because she has no good news, has something to hide, or she just has not bothered to find out how many children are not accounted for.

What information has the minister received from the authorities to date? Will she make it public today, and will she promise to make public the authorities' findings once the 30-day review is finished on May 5?

Ms. Melnick: Mr. Speaker, the 30-day review was not something that was imposed. It is something that was agreed upon with the consensus of all four authorities. It was something that was agreed upon by myself with the four authorities. These people are working on the front lines. They are working with the children. They are working with the families.

Again, it is very important, rather than fearmonger and place doubt in the minds of all Manitobans around a very important service for very vulnerable families and children in this province, that we support the work of the front-line workers, that we support the work of the authorities and that, mostly, we support the work to take care of the vulnerable children of Manitoba.

Devils Lake Outlet
Filtration System–Negotiations

Mr. Stuart Murray (Leader of the Official Opposition): Mr. Speaker, yesterday, I challenged the Premier to describe what efforts he made to address the concerns related to the opening of the Devils Lake outlet. Although he indicated he had, indeed, spoken with the U.S. Council on Environmental Quality, the Premier refused to elaborate on what was discussed or whether an agreement would be reached in time. We are now six days away from the scheduled opening of the Devils Lake outlet, and the clock continues to run down.

We have heard today in the *Winnipeg Free Press*, Mr. Speaker, that the federal government, and I quote, has come to a meeting of the minds, end quote, on this issue.

Mr. Speaker, will the Premier please describe to this House whether his mind was at that meeting and what the outcome of the latest rounds of negotiations was?

Hon. Gary Doer (Premier): Well, Mr. Speaker, I will be speaking later with a federal minister who was at the meeting. Today, the CEQ secretary that reports to President Bush committed United States to the design which they have already completed and which they are consulting with Canada on and the filter construction which we think is a positive step. I will be discussing today with the federal minister the latest developments, and I provide to the House what I can in terms of what is available to be made public.

But what I said yesterday is very consistent. What I said last week was what was announced this morning. There still remain difficulties for Manitoba, as I have said before.

Mr. Murray: Well, thank you, Mr. Speaker. The Premier has so far refused to verify whether an actual risk to Lake Winnipeg exists from the release of water from Devils Lake. As we get closer and closer to the opening of the outlet, there remains a continuing lack of scientific data.

The Premier has claimed repeatedly that there were species in Devils Lake that were a threat to Lake Winnipeg. He has argued that there is scientific evidence to support this claim.

To quote directly from an interview that the Premier gave to the CBC, on August 8, 2005, and I quote the Premier: Twenty biologists have been on the lake for the last three weeks, and we have a lot of test results. However, these results, Mr. Speaker, have yet to have been tabled in the House.

Mr. Speaker, the only scientific information that was made available is a very limited survey of Devils Lake that was not the work of 20 biologists over three weeks. Nevertheless, the Premier maintained that the evidence was clear that there was a risk to Lake Winnipeg from Devils Lake.

Mr. Speaker, the limited study released by the government last fall called for further study on Devils Lake.

I ask the Premier: Has there been any further study conducted, and can he provide information in light of recent negotiations at the federal level?

Mr. Doer: Mr. Speaker, we just had the U.S. government confirm that they have designed and are going to construct a multimillion dollar filter. They are not doing it because they do not believe that there are any issues for Manitoba's water. They are doing it because we know from the tests–the good news was that 13–*[interjection]*

Mr. Speaker: Order.

Mr. Doer: I have read the report.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

***** (14:30)

Mr. Doer: The fear we had about the unknowns on Devils Lake, because it was an isolated lake for 1,000 years, it had been stocked artificially by North Dakota from outside sources. The fear we had is alien species from the Missouri River may have gotten into Devils Lake. Those tests have concluded that 13 of the species that were most at risk for Lake Manitoba, invasive species which we are also concerned about with NAWS, why we went to court, and with the North Dakota state water act, those species do not exist in Devils Lake. What does exist there are parasites and some algae that are not specific to Lake Winnipeg.

Mr. Speaker, we feel, therefore, that a filter should be built; designed, which it has been; built, which has been committed to and implemented before the water flows.

Mr. Murray: Mr. Speaker, in light of what the Premier has just said, I would very simply ask him, because he knows that through all of the political rhetoric he has spun in Manitoba, with less than a week to go, that water scheduled to flow, and it will flow in thousands of cubic feet per second through the Devils Lake outlet. I would just ask this Premier: Can he stand today and ensure all Manitobans that no water will flow through the Devils Lake outlet on May 1 unless a filter is put in place? Will he ensure that not one drop of water will flow on May 1 unless a filter is put in place?

Mr. Doer: Mr. Speaker, the thousands of cfs, I really would caution the member opposite. I will get the exact number from last year's projections, but it is quite a bit less. Having said that–*[interjection]* No, it is just important to get the facts right.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Doer: Well, Mr. Speaker, I hear members talking about it. You know, when Governor Schafer was going to build an inlet from the Missouri River to Devils Lake, there was no agreement not to build that. Now, in Manitoba, for the first time ever, we have an agreement that there will be no inlet from the Missouri River to Devils Lake, something members opposite sat on for three years, including the member who was in Cabinet at the time.

Now having said that, Mr. Speaker, we believe the filter is very simple. We are glad the United States has agreed to design the filter, which they have done. We are glad they have agreed to pay for it, which they have done. We are glad they agreed to construct it, which they are going to do. We believe the construction and implementation of the filter should take place before the water flows. That is the position of the Prime Minister, that is the position of the Foreign Affairs Minister and that is the position of the Government of Manitoba.

Why can we not get the opposition on side? I know the Member for Emerson (Mr. Penner) does not believe that there is any risk in Devils Lake. He gave me a lot of flack for going to court on Devils Lake. He said that is the reason why the border was closing for cattle. Let us get some straight answers in this House, Mr. Speaker.

Clean Environment Commission Hog Production Sustainability Study

Hon. Jon Gerrard (River Heights): Mr. Speaker, my question is to the Premier. Yesterday, in response to my question, the Premier emphasized the integrity of the Clean Environment Commission in relationship to the Maple Leaf Foods review. The review the Premier referred to recommended that Manitoba Conservation oversee a study to examine the sustainability of hog production with a full report due by December 2005. It is now May 2006.

Why has this report not been completed? Indeed, has the study even been started?

Hon. Gary Doer (Premier): Well, there were a number of conditions that the Clean Environment Commission placed on the licensing of a second shift at Maple Leaf. One was a review of the Assiniboine River Watershed, not the whole province, just in terms of that recommendation. Secondly was a recommendation that the nutrient levels coming out of Maple Leaf would have to be of greater quality for water quality before a licence was granted.

The work on the Assiniboine River Watershed is completed. The Department of Conservation is releasing it, even though Maple Leaf is not proceeding with a second shift because, Mr. Speaker, the conditions of the licence for the increased improvement on water quality is not in place in the water treatment plant that was approved by members opposite. As a condition precedent of the second shift going forward, both the study and the nutrient levels have to be met. The study has been completed. The nutrient levels, the water treatment plant, is not in place. Therefore the licence, second shift is not approved by this government.

Mr. Gerrard: Mr. Speaker, we have not seen the report. We did not know that there were public hearings that we could present to. What kind of a behind-the-scenes effort was this?

My supplementary to the Premier: The issue here is the integrity of the Premier's government. The issue here is the commitment of the government to follow through on the Clean Environment Commission recommendations. The Clean Environment Commission said 2005. It did not say 2006. It did not say 2007. It did not say 2008. Where is this report? Why was it not ready in 2005? Why did the Premier fail to meet the commitment? Why did the Premier not act with integrity in following through with the Clean Environment Commission recommendations?

Mr. Doer: Well, Mr. Speaker, I need no lectures from the member opposite on integrity. We know he sat around the Cabinet table when the sponsorship scandal was developed in 1996 and '97.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Point of Order

Mr. Speaker: The honourable Member for River Heights, on a point of order?

Mr. Gerrard: Mr. Speaker, the issue here is the study on hogs in the province of Manitoba and the Assiniboine basin. It is not some thing that is going on in Ottawa some time ago. What is the matter with the Premier? Does he not understand what hogs are and the Assiniboine basin? Where is this study? Why is it not tabled?

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. The honourable First Minister, on the same point of order?

Mr. Doer: Yes. Mr. Speaker, I would caution members to be holier than thou. When they are, they should be prepared for the rebuttal.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. The honourable Official Opposition House Leader, on the same point of order?

Mr. Leonard Derkach (Official Opposition House Leader): Well, on the same point of order, Mr. Speaker, the Member for River Heights did raise an issue. It is a serious issue. The issue has to do with a situation in Manitoba, and he is correct about that. He was seeking information from the Premier. Now, for the Premier to treat it so lightly and to give his flippant responses, even on a point of order, is not within the character of the First Minister of our province. I think he should be cautioned to answer a question that has been posed seriously.

Mr. Speaker: On the point of order raised by the honourable Member for River Heights, we do allow leaders' latitude, and the First Minister still has the floor.

* * *

Mr. Doer: Mr. Speaker, we have never in government, never, overturned a recommendation of the Clean Environment Commission. The second shift for Maple Leaf has not proceeded with even though, obviously, the economics of that, of a plant that is already built, are good for the government. But what we are not going to do is sacrifice the water quality recommendations of the Clean Environment Commission. We have stood on that recommendation for two years. The member opposite talks about public hearings. There were public hearings into the Maple Leaf licensing process. He should have been there.

***** (14:40)

Crocus Investment Fund Conflict of Interest

Mr. Kevin Lamoureux (Inkster): Mr. Speaker, when the wheels fell off the Crocus Fund back in December of 2004, within two weeks MLAs were sent a letter, and I will table a copy of that letter, suggesting how we really need to come together and support the Crocus Fund. Some would even suggest strong-armed. Who was the author of that letter? Well, no one else but the Premier's good buddies and friends, Mr. Alfred Black and Peter Olfert.

Here we have that special relationship that goes beyond just having a special relationship. We are also talking about–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Lamoureux: Mr. Speaker, we are not only talking about a special relationship to the Premier; these are individuals who contribute to the New Democratic Party.

I believe that this is a conflict of interest and my question to the Premier is: Can the Premier indicate how many of those board members and other people closely tied to the Crocus fiasco have donated to his political party, and what is the total amount–we know it is into the thousands, Mr. Speaker–in 2004? Will the Premier tell this House?

Hon. Gary Doer (Premier): Well, Mr. Speaker, I would point out that one of the individuals mentioned was appointed to the board of directors of Crocus by the previous government, not by our government. Secondly,–*[interjection]*

If I could please–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. The honourable First Minister has the floor.

Mr. Doer: We passed legislation, Mr. Speaker, that Mr. Harper is now passing, Prime Minister Harper, to allow the Auditor General to follow the money no matter where it goes. We passed that in 2001. I am glad Parliament, to clean up the Liberal mess, is passing similar legislation in 2006. I hope our federal party supports it.

Finally, Mr. Speaker, when the Auditor General was being potentially stopped by the same individuals mentioned by the member opposite, we backed up the Auditor General to follow the money wherever it was, including with the individuals mentioned by the members opposite.

Mr. Speaker: Order. Time for Oral Questions has expired.

Speaker's Ruling

Mr. Speaker: I have a ruling for the House.

Following Members' Statements on April 11, 2006, the honourable Official Opposition House Leader (Mr. Derkach) raised a point of order regarding the Standing Committee on Agriculture and Food and noted that the committee had not been called to transact business since May 9, 2001. He concluded his advice to the Chair by recommending that the Government House Leader (Mr. Mackintosh) be instructed to call a committee for the purpose of undertaking a review on the state of agriculture in the province, hear witnesses and travel throughout the province and report back to the House by December 1, 2006. The honourable Government House Leader, the honourable Member for Inkster (Mr. Lamoureux) and the honourable Member for Lakeside (Mr. Eichler) also offered advice to the Chair on the point of order. I took the matter under advisement in order to consult the procedural authorities.

I would note for the House that there is no requirement in our rules which dictates how often committees meet and that, by practice, the Government House Leader schedules meetings of standing committees often in consultation with other members such as House leaders or critics. Also, Speaker Rocan ruled in 1989, 1993 and 1994 that the opinion of the Speaker cannot be sought in the House about matters arising in committee and that it is not competent for the Speaker to exercise procedural control over committees.

After considering the submissions of members and also considering the advice of procedural authorities, I would rule that there is no point of order. What has been raised is an issue of negotiation and scheduling between the House leaders, which should not be raised as a point of order in the House. I would encourage the House leaders to discuss the issue, and if they so wish, take the appropriate steps after their negotiations.

MEMBERS' STATEMENTS

Pembina Trails Voices

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, I rise today to pay tribute to the Pembina

Trails Voices, an internationally acclaimed choir from the Pembina Trails School Division.

Pembina Trails Voices returned recently from the Young Prague International Festival of Choirs. This international musical festival has made it its aim to help promising young artists who are starting their career in classical music, such as instrumentalists, choirs, conductors, as well as composers.

The festival this year was under the patronage of Ms. Anna Curdova, the Member of Parliament of the Czech Republic. The festival, now in its 12th year, brought talented young musicians and singers to the Czech capital from around the world from March 23 to 26.

Prague is a magical city, one of music, theatre, dance and opera. Many countries were represented at this spectacular event. There was a high level of competition, a parade through the city centre and joint performances of all festival musicians and singers on the beautiful Old Town Square.

The Pembina Trails Voices returned with gold and silver medals: the girls' choir directed by Ruth Wiwchar won a silver medal; the boys' choir directed by Michael Proudfoot won a gold medal; the mixed choir directed by Ruth Wiwchar won a silver medal; the best conductor performance was Ruth Wiwchar in the mixed choir category.

This was the experience of a lifetime for these young singers, and I would like to extend congratulations to the performers, conductors and volunteers of Pembina Trails Voices who worked so hard to make their participation in this event possible. Thank you, Mr. Speaker.

Holocaust Remembrance Day

Mr. Doug Martindale (Burrows): Mr. Speaker, April 25 is Yom Hashoah or Holocaust Remembrance Day. On this day, Manitobans join people all over the world to pause and remember the six million Jews who were put to death by Nazi Germany.

From their ascension to their dying days, Hitler's Nazis persecuted, murdered and attempted to annihilate Europe's Jews with an incomprehensible zeal and fervour. Over six million Jews lost their lives in the Holocaust. This day of remembrance marks this terrible event, an indelible stain on human history.

But it is also important on this day, Mr. Speaker, that we remember all the victims of fascism: Gypsies and Poles, Catholics and Communists, Slavs and the disabled, gays and lesbians, partisans and pacifists. These millions all died by the Nazis' hands. All had their lives cut brutally short.

The enormity of these numbers, their sheer size, must not blind us, however, to the individuals who all died their own death. By remembering the names of the millions and bearing witness to their constant humanity, each and every one of them can continue to live in us and through us still.

Today, there was a ceremony on the legislative grounds at the Holocaust monument marking the Day of Remembrance for Manitobans. This ceremony allows all Manitobans to join together in grieving the Jewish community's loss. It also serves as a reminder of the ever-present dangers of religious discrimination and racism and a call to staunchly confront these insidious elements wherever they lurk.

Devils Lake Outlet

Mr. Ralph Eichler (Lakeside): Mr. Speaker, this NDP government has indicated time and time again that there were serious environmental concerns with water flowing from Devils Lake. They have touted themselves as Manitoba's protectors, but now the Premier (Mr. Doer) is saying that it is the responsibility of the federal government. This NDP government has passed the buck to Ottawa and Washington.

Where is this Premier's conviction and his promises to fight for Manitoba now? Where is the update through scientific evidence to back up his claims? If Manitoba's waterways, including Lake Winnipeg, are truly under threat, then this Premier should have ensured that an effective filtration was in place.

The Premier has admitted that this so-called signed agreement did not exist. With the May 1 deadline fast approaching to open the Devils Lake outlet, why has this NDP government not reached out to the state of North Dakota to build a partnership to find real and timely solutions?

Instead of working for a solution, this NDP government exposed our province to lawsuits. Mr. Speaker, the Premier's mistrust, accusation and misleading ways are serious injustices against our province. The Premier should apologize to Manitobans for misleading them as to the existence of a signed agreement potentially exposing an already flooded southern Manitoba to more water.

Wanda Koop

Mr. Rob Altemeyer (Wolseley): Mr. Speaker, I am pleased to announce that Wanda Koop, famous artist and long-time resident of the Wolseley constituency, was recently awarded the Order of Canada.

***** (14:50)

Wanda Koop is a very deserving recipient of our nation's highest honour for lifetime achievement. She is an internationally renowned artist whose work spans three decades. She is a visual artist who works primarily in paint and video, and her art often depicts scenes of urbanization, industrialization and war. Her work challenges us to reflect upon powerful ubiquitous cultural images that confront us daily through broadcast media. Her work has been featured in over 50 solo showings in locations around the world.

Mr. Speaker, Wanda Koop is also a very deserving recipient of this honour for the work she has done in the West Broadway area. She is the founder of Art City, a storefront art centre on Broadway that provides inner city youth with a safe environment to have fun and express themselves creatively.

Art City has had a tremendously positive impact on the community. It has beautified buildings through murals and turned empty storefront windows into colourful displays and art installations. Art City also now has two annual events which are at the heart of West Broadway during the summer parade and also during their annual Halloween Howl and Haunted House. Art City has changed the lives of many neighbourhood youth who have developed new skills and confidence there, and we have Wanda, above all else, to thank for it.

Mr. Speaker, on behalf of all members, I congratulate Wanda Koop on an outstanding career as an artist and a citizen. I look forward to seeing her receive this deserved honour from Governor General Michaëlle Jean at a ceremony later this year. Thank you very much.

Devils Lake Outlet

Mr. Jack Penner (Emerson): Mr. Speaker, the Premier (Mr. Doer) has stated repeatedly that there was a signed agreement between Canada and the United States to have a filter installed to protect Manitoba waterways from biota in water from Devils Lake. We now know that there is no such signed agreement.

The Premier has stated that there were 20 scientists on, in and under the lake for 20 days, 24 hours a day, studying the water for harmful organisms, biota and fish species. We now know that there were only two Manitoba people on one boat for the better part of three days in North Dakota on Devils Lake.

Findings in the report from the Department of Water Stewardship state that, and I quote: "None of the targeted 12 known species of concern were found in this survey of Devils Lake." Despite this, the Premier has repeatedly stated that Manitoba waters and fisheries would be threatened by the water from Devils Lake.

Mr. Speaker, it would appear that there have been mixed messages and misdirection coming from the Premier about Devils Lake. I would suggest that the Premier is so convinced that the water from Devils Lake would cause severe harm to lakes and fisheries in Manitoba, he should go to North Dakota, sit down with the governor and offer to build a filter immediately and determine who would pay for it later to ensure our lakes and waterways would be protected from Devils Lake water flows into Manitoba again.

We are serious about protecting the fish, the fishery in Lake Manitoba. We are serious about protecting the waterways in Manitoba, and if what the Premier has been telling Manitobans is true, then, Mr. Speaker, it is imperative that the Premier go to North Dakota now and enter into an agreement to build a filter.

MATTER OF URGENT PUBLIC IMPORTANCE

Mr. Stuart Murray (Leader of the Official Opposition): Mr. Speaker, in accordance with Rule 36(1), I move, seconded by the Member for Emerson (Mr. Penner), that the regular scheduled business of the House be set aside to discuss a matter of urgent public importance, namely the issue of the Devils Lake outlet, set to open on May 1, 2006, and this Premier's ongoing fearmongering over the presumed risk that the water from Devils Lake possesses to Lake Winnipeg ecosystems and the Province's multimillion-dollar fishery, and his assertion that an agreement existed at the federal level to construct an advanced filtration system, an agreement that has been proven fictitious, additionally the Premier's comments of yesterday when he indicated that the United States government was working with the

Canadian federal government on a proposal to install a permanent filter at Devils Lake.

Mr. Speaker: Order. Before recognizing the honourable Leader of the Official Opposition, I believe I should remind all members that under Rule 36(2), the mover of a motion on a matter of urgent public importance and one member from the other parties in the House are allowed not more than 10 minutes to explain the urgency of debating the matter immediately.

As stated in *Beauchesne's* Citation 390, "urgency" in this context means the urgency of immediate debate, not of the subject matter of the motion. In their remarks members should focus exclusively on whether or not there is urgency of debate and whether or not the ordinary opportunities for debate will enable the House to consider the matter early enough to ensure that the public interests will not suffer.

Mr. Murray: Mr. Speaker, I thank you for reminding me of those requirements because this is a very important issue facing all of Manitobans.

Mr. Speaker, there are two conditions that must be satisfied for this matter to proceed. The first requirement was to file this motion with the Speaker's office at least 90 minutes prior to Routine Proceedings. I believe that that requirement has been made. The second condition is that the matter is an urgent nature.

Mr. Speaker, the Devils Lake outlet is set to begin releasing thousands of cubic feet per second of water that will then make its way into the Red River and Lake Winnipeg. The outlet will be opened on May 1, 2006, which is six days from now. To date there has been no effort to construct an advanced filtration system to protect Lake Winnipeg from potentially invasive species entering Manitoba's waterways, jeopardizing the health of the lake's indigenous species. Limited scientific study of Devils Lake has proven inconclusive in establishing whether there is actual risk to Lake Winnipeg that exists in terms of foreign biota.

However, the Premier (Mr. Doer) and his ministers continue to maintain that there is a risk. To quote the Premier directly from a March 24, 2000, news release, Manitoba's water resources, and I quote: "could be jeopardized if foreign life forms and other harmful substances that we know are in Devils Lake are transferred" to the Red River system.

Mr. Speaker, how can the Premier be so certain that there is a risk to Lake Winnipeg's ecosystem, when in-depth research into the biota of Devils Lake has not taken place? The Premier has argued for months now that, unless a filtration system is installed in the Devils Lake outlet, the water should not flow. Well, the outlet is scheduled to open in six days, regardless of what this Premier's assertions are. He has long argued that it was the federal government's responsibility to ensure the filter was put in place and that his government was not to blame for the fact that the outlet would be opened with or without a filter.

On April 18, 2006, the Premier stood up in this very House and stated that, and I quote the Premier: The document that was signed was signed between Canada and the United States last summer. That is August 2005.

Prior to that on April 13, 2006, the Premier assured this House that he would "get a copy of the agreement," and that "it was released to the public."

Well, Mr. Speaker, the Premier did not provide a copy of that agreement, because the only physical documentation that exists regarding this agreement was a press release, a press release that was issued by the federal government signifying its willingness to work with the United States on determining the need for a filter, and that they would be interested in co-operating on its construction.

Mr. Speaker, after generating public fear and anxiety over the supposed existence of harmful organisms in Devils Lake, the Premier pinned all of his hopes and all of Manitoba's hopes on a federal agreement to build a filter to protect this province. Well, that agreement has proven to be nothing more than the actual press release, unsigned, and not legally binding.

***** (15:00)

When I spoke with the U.S. Consul to Manitoba, Mr. Todd Schwartz, about the existence of this so-called alleged agreement that this Premier talked about, the U.S. Consul specifically stated that there was no signed agreement that he was aware of. The Premier had no choice but to acknowledge this fact.

Mr. Speaker, to recap, we now have claims by this NDP government that there are potentially invasive species that pose a risk to the health of Lake Winnipeg based only on an extremely limited scientific study. Nevertheless, they have argued that the only way to protect our lake is with the construction of a filtration system in the Devils Lake outlet.

Rather than negotiate its construction, this NDP government has chosen to rely on a non-existent federal government agreement to build. With six days left, until this outlet is set to open, there is yet no filter and Manitobans are left to wait and to worry. In the eleventh hour of this situation, the Premier is still looking to assure all Manitobans that he is continuing lobbying for a resolution to this issue.

When pressed for details in this House, the Premier continues to defer to the U.S. Council on Environmental Quality, the American organization in charge of dealing with the Devils Lake outlet. To date, the CEQ has offered nothing to reassure Manitobans that the Devils Lake water is safe.

Mr. Speaker, time is running out. It is crucial that the concerns of Manitobans be addressed on this issue. The Premier has indicated that Manitoba should stand by as negotiations continue. However, they need to know what the Premier is doing to address the concerns he himself has generated. We need to know that and we need to know that today. We, the people of Manitoba, are not content to rely on NDP press releases stating the government's level of concern. We must have results.

If the water starts to flow on May 1, then it is too late to do the proper work to be done in resolving this matter. I, therefore, argue in favour of proceeding with this MUPI today so that the duly elected representatives of the people of Manitoba, all of us in this Chamber who have serious concerns about what is going to happen on May 1, may be fully established on what course of action is to be taken on this very urgent matter. Thank you, Mr. Speaker.

Hon. Steve Ashton (Minister of Water Stewardship): Mr. Speaker, well, let us start with one very clear and evident fact. Members opposite, if they are so concerned about Devils Lake, if they are so concerned with the fact that we have right now the fifth greatest flood of the century, the fifth most significant, if they are concerned about any of the important issues of the day, they can debate them in about 10 minutes or so by allowing us to get into Orders of the Day and discuss the budget, in which case each and every member of the Legislature will get an opportunity to speak, not for 10 minutes but for 30 minutes. That is the first point I want to make.

The second point I want to make, Mr. Speaker, is this opposition has shown the lowest level of petty partisanship you could ever imagine on as significant an issue as Devils Lake. Let us not only go from the comments made by the Member for Emerson (Mr. Penner), who, at various different times, has said there is no problem with the water, that the filtration is not needed or that there is a problem and we do need the filtration but Manitoba should build it, or that we should build it and collect it back from the various different levels of government. Well, I do not know from day to day whose side the Member for Emerson is on, but it sure is not Manitoba's.

I want to go one step further because– *[interjection]*

An Honourable Member: Mr. Speaker, on a point of order.

Mr. Speaker: Order.

Point of Order

Mr. Speaker: The honourable Member for Emerson, on a point of order?

Mr. Jack Penner (Emerson): Mr. Speaker, on a point of order. The minister just put on the record that I had indicated I was in favour of allowing Devils Lake waters to flow to the Sheyenne River and to the Red River, and, in other words, Lake Winnipeg, without it being treated. I have never said that. What I have said is, constantly, that if we can believe what the Premier (Mr. Doer) has been telling the people of Manitoba that there was a signed agreement and that there was danger of that water to our waters, then we wanted this government to take action and build a filter. That is what I have said.

Mr. Speaker: Order. I remind members that points of order are supposed to be raised to point out to the Speaker a breach of the rule of the House. Points of order should never be used for means of debate.

The honourable Member for Emerson does not have a point of order. It is a dispute over the facts.

* * *

Mr. Speaker: The honourable Minister of Water Stewardship has the floor.

Mr. Ashton: Thank you, Mr. Speaker. You know, all throughout this and shown again today by the Leader of the Opposition (Mr. Murray), there is a clear indication of just how little members opposite are concerned about any issues related to the environment. I know that the Member for Emerson has stated on the public record that water in Manitoba is in better shape today than it was 30 years ago. He is about the only person in the province that believes that, a charter member I am sure of the Flat Earth Society, which, I am sure, has membership in all the members opposite.

But, Mr. Speaker, what I think is appalling is the degree to which this member and the Leader of the Opposition understand nothing about issues related to foreign biota. I tell you, Joe Belford is a person I respect. He is from Devils Lake in North Dakota. I expect him to be making the kind of arguments that I have heard him make over the last number of years. But I expect better from the Leader of the Opposition and the Water Stewardship critic who do not understand that the No. 1 issue with foreign biota is that if there is any chance of a transfer of foreign biota, you have to be concerned. What you do is you have a proper environmental assessment and you have mitigation. That is why we went and argued that it should be referred to the IJC. I point out the members opposite, at that time, claimed to support going to the IJC.

Mr. Speaker: Order. I remind members that this is the point in time where trying to convince the Speaker of their urgency of dealing with this matter. This is not the time to be getting into debate.

Mr. Ashton: Mr. Speaker, what they do, take for example the survey work that was done last year, and they belittled it. It came out of an agreement of about 20 scientists from all the jurisdictions, and it was put on the record. It was released as public information, a report. It was tabled in this House. It has been on the Web site since October. There are four algae species and three fish parasites that are not known to be in Lake Winnipeg, a number of which had not been previously identified. The basic principle when it comes to foreign biota is that you err on the side of protection.

I would expect the members opposite, if they cared about Manitoba, not to be undercutting the evidence that is clearly there, accepted by this province, the State of Minnesota, the Government of Canada and the CEQ.

You know, Mr. Speaker, what a bunch. I realize they have a leadership convention up this weekend. I am surprised they have anybody willing to lead that group over there. Their latest is to attack the CEQ. They call it an organization. It is the Commission on Environmental Quality. It is the White House. It is George W. Bush. It is the federal U.S. government that is committing to the filtration for Devils Lake.

Mr. Speaker: Order.

Point of Order

Mr. Speaker: The honourable Official Opposition House Leader, on a point of order?

Mr. Leonard Derkach (Official Opposition House Leader): Yes, thank you, Mr. Speaker, on a point of order.

Mr. Speaker, the Leader of the Opposition (Mr. Murray) rose in his place today and argued for a matter of urgent public importance to be debated in the House. In doing that, there is going to be a response from the government. I would expect that they would want to argue either in favour of the matter of urgent public importance to proceed or argue why it should not be proceeded with.

***** (15:10)

The Minister of Water Stewardship has embroiled himself in the debate. Now, I am assuming that the debate must be going ahead because the Minister of Water Stewardship is now into the body of a debate.

So, Mr. Speaker, if that is the case, then I say let us proceed, and the speaking order then should be one party to another. But, if we have agreed already and we are proceeding with the debate on this matter, I am encouraged by it.

Mr. Speaker: On the point of order raised by the honourable Official Opposition House Leader, he does have a point of order because our rules are very clear at this point in time. I do allow a certain amount of leeway, but our rules are very clear that this is the time to convince the Speaker that there is an urgency to debate this matter immediately.

So the honourable member does have a point of order.

* * *

Mr. Ashton: Indeed, I apologize, Mr. Speaker, if I was responding to the Leader of the Opposition.

But I do want to make the point that on a day in which the CEQ has made a clear commitment, Mr. Speaker, the head of the CEQ in a press conference with Rona Ambrose, Minister of the Environment– who, by the way, commended not only the Prime Minister and the President of the U.S. but also the Premier of Manitoba for the efforts to get to the point of having the filtration–I would expect the Leader of the Opposition, the Water Stewardship critic, all members on that side of the House to be saying let us have a united stand. Instead, they want to move and suggest we have a debate, to what? To divide this province more.

I say no, Mr. Speaker. If they want to debate this issue, they can do this on the budget. But I would suggest one thing, and I should maybe be generous to the Leader of the Opposition who will soon be retired from the most difficult job in Manitoba. It is not actually being the Leader of the Opposition; it is being Leader of the Conservative Party.

You know, Mr. Speaker, after I see what has happened on issues like Devils Lake, I can understand why the Leader of the Opposition is smiling, because, quite frankly, you are faced with issues like this and you have a caucus and a party that is out of touch with the year 2006, that does not get that when you have had a commitment from the U.S. federal government, you do not belittle that; you say that it is good.

But let us get that filtration in place before the water flows. Let us have a united front. If I could, I want to suggest, Mr. Speaker, you have two choices. You play the kind of petty politics we are seeing again on this proposed matter of urgent public importance, or you stand up for Manitoba. The NDP, in fact, 99 percent of Manitobans are prepared to stand up for Manitoba. Which side are the Tories on?

Mr. Speaker: The honourable Member for River Heights, if he is up to speak to this matter of urgent public importance, would require leave.

Hon. Jon Gerrard (River Heights): I would ask for leave to speak to this matter of urgent public importance.

Mr. Speaker: Does the honourable member have leave?

Some Honourable Members: Leave.

Mr. Speaker: Yes, leave has been granted.

Mr. Gerrard: Thank you, Mr. Speaker. We have had a debate back and forth, it would appear, over whether our waters are cleaner now than they were 30 years ago or not. Although the Member for Emerson (Mr. Penner) may be right that there are a few streams or lakes that may be cleaner, most of them have, in fact, had more problems. That is particularly true of Lake Winnipeg where the levels of phosphorus are higher. The problems with algae are higher. The problems at our beaches are worse in terms of people going out and swimming because of the E. coli levels.

The fact of the matter is that it is worse now than it was 30 years ago which is a reflection of the fact that the Conservative and NDP governments which have been in power over the last 30 years have not done their job properly.

What we need to be debating is the situation with Devils Lake. That is my understanding of what the Leader of the Opposition (Mr. Murray) was putting forward. It was emphasizing the need to have a debate on Devils Lake.

Clearly, Mr. Speaker, this is timely because the deadline is May 1, as we understand it now, for the water to flow. From what I hear we are in agreement in this House that the water should not flow until the filter is there. So it would be important that we have this discussion. I would suggest that since there seems to be unanimity here among all parties of the importance of not having the water flow until the filter is there that there is an opportunity to build consensus and go forward with the debate which will emphasize what is critically needed. That is that the water should not flow until the filter is in place and has been tested and shown to be working. That is what we need.

We can talk about all the problems, all the way along the way from where we are now. I know that a number of years ago there was an opportunity to have this go to the IJC which the government turned down. But we are now where we are and we have to deal with this situation. There is an opportunity to get everybody here in the Legislature on the same page, and that same page being that the water should not flow out of Devils Lake until the filter is in place and has been properly tested to know that it is working.

That is our position on the Liberal Party. That is the position that we would like to advance together with the other members of the Legislature as part of this effort. So that, Mr. Speaker, is why we need this debate today. Thank you.

Mr. Speaker: Order. I thank the honourable members for their advice to the Chair on whether the motion proposed by the honourable Leader of the Official Opposition should be debated today. The notice required by Rule 36(1) was provided under our rules and practices. The subject matter requiring urgent consideration must be so pressing that the public interest will suffer if the matter is not given immediate attention. There must also be no other reasonable opportunities to raise the matter.

I do not doubt that this matter is one that is of serious concern to members as water is an essential resource, and clean and safe water is important to all of us. I have listened very carefully to the arguments put forward. However, I was not persuaded that the ordinary business of the House should be set aside to deal with this issue today.

Additionally, I would like to note that there are other avenues for members to raise this issue including questions in Question Period, raising the item under Members' Statements, and raising the issue during budget debate.

Therefore, with the greatest of respect, I rule the motion out of order as a matter of urgent public importance.

Mr. Derkach: Mr. Speaker, with the greatest of respect, I am disagreeing with you. But you are telling me I cannot challenge the ruling, is that correct?

Mr. Speaker: Order. Our Manitoba rules state that matters of urgent public importance, the decision of the Speaker is final. There is no challenge to the rulings.

Point of Order

Mr. Speaker: The honourable Official Opposition House Leader, on a point of order or a matter of privilege?

Mr. Derkach: On a point of order, Mr. Speaker.

Mr. Speaker: On a point of order.

Mr. Derkach: Mr. Speaker, it is a sad day because we are six days from the water flowing from Devils Lake into Manitoba. It is sad that the government does not want to allow debate on this very important matter.

***** (15:20)

But, Mr. Speaker, I have another point of order. This point of order has to do with a very simple matter, but one that is fairly serious. When the House rose on December 8, the Hansard number was 27A and B. When the House returned on March 6, the Hansard number was 32. The issue for me is how did that happen. *[interjection]* Well, the Minister of Energy, Science and Technology (Mr. Chomiak) says it was the Julian calendar.

Maybe it was, but, Mr. Speaker, I just simply do not have an answer for it, and so therefore I raise this issue as a point of order because I would like to know whether we have lost five days or whether in fact I misunderstand the way that Hansard is numbered.

I raise this as a point of order, so perhaps you, as Mr. Speaker, may want to take this under advisement and come back with a clarification for my purposes, or perhaps we can get to the bottom of it in some way, shape or form. I thank you for that.

Mr. Speaker: For the explanation for the honourable member, the reason that you have noticed a difference in days is because there were some intersessional committee meetings, and the agreement of the House at that time was that the intersessional committee meetings would be included as sitting days of the House. That was agreed to by all parties, and that is why you noticed the difference of that day to when you came back.

Mr. Derkach: I thank the Speaker for that information, and I just wanted to confirm that there were in fact five sitting days of intersessional committees between December 8 and March 6. If that is the case, I accept that as an explanation.

Mr. Speaker, I have another point of order. *[interjection]* Yes, that is not a problem. I do not want to belabour it.

Mr. Speaker: If the honourable official opposition would not mind, I can get those dates for you and bring the information back to the House, so that way we can move ahead.

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You had indicated you had a new point of order?

An Honourable Member: Yes, I did.

Mr. Speaker: The honourable Official Opposition House Leader, on a new point of order.

Mr. Derkach: Mr. Speaker, I appreciate the fact that this information will be forthcoming and there is no rush for it at all, but before I start on my point of order, I do want to make a comment regarding your announcement today with respect to the Speaker of Nunavut if I may take a minute.

Mr. Speaker, on behalf of our party, I do extend our heartfelt sympathies to the people of Nunavut in losing the Speaker of their Legislature. I met Jobie Nutarak when I was with you in Nunavut, and I also met him on one previous occasion when we were still in government at a time when we visited Nunavut just at the time Nunavut received its own government.

What struck me about Jobie was that he was a very kind and gentle-hearted person and, Mr. Speaker, after speaking to him for a little while, his very calm nature and his very kind demeanour left one with a very positive and a very warm impression of this individual. I know that the people of Nunavut will miss this individual because he indeed was one who attracted people to himself because of his nature.

Mr. Speaker, if I just could conclude, not only from myself personally but indeed from members of this side of the House, we extend our heartfelt sympathies to his family and to the government of Nunavut and all of the people in the territory of Nunavut.

Mr. Speaker: I thank the honourable member very much for that comment, and I will ensure that the comment will appear in Hansard. I will send it up to the Legislature so they can share it with the people of the territory.

Point of Order

Mr. Speaker: The honourable Official Opposition House Leader, on a point of order.

Mr. Derkach: Yes, Mr. Speaker, I am on a point of order now with regard to comments made by the Government House Leader (Mr. Mackintosh) in Saturday's *Winnipeg Free Press* column. The Government House Leader said, and I quote: "There is a sessional order . . . that is now in peril."

Mr. Speaker, this is a serious question because what is happening now is the House Leader went on to say: "There is now a serious question as to what the Speaker will do on June 13" with regard to the budget votes.

Well, Mr. Speaker, the reason this is a serious issue is because it now is reflecting upon the Speaker. If we go to *Beauchesne*, 6th Edition, section 71(1), where it states very clearly, and I will quote from *Beauchesne*, that "the Speaker should be protected against reflections on his or her actions." Secondly–this is on page 21, Citation 71(1): "The Speaker should be protected against reflections on his or her actions."

Mr. Speaker, our rules, Rule 41 states: "Questions not to be revived or anticipated. No member shall revive a debate already concluded during the session or anticipate a matter appointed for consideration of which notice has been given."

Mr. Speaker, the House made a decision concerning the proceedings of the session on June 9, 2005, as found on pages 373 to 375 of *Journals*. The Government House Leader is now indicating that somehow the House order is in peril, or is anticipating that you will be taking some action concerning this matter. If that is the case, we on this side of the House would like to know what the government has in mind concerning the House order. If the Government House Leader is so willing to speak to the media about this, and others outside of the House, he should have the courage to rise in his place to speak on the matter or have the courage to call me, as the Opposition House Leader, to see who we would like to see as leading the commission of inquiry related to Crocus so then we can get on with the business of the House.

So he has some choices to make, Mr. Speaker. But he has chosen not to do this. Instead, he is trying or attempting to reflect on your responsibilities as they relate to an order that was passed in this House. Now, the order, as it was passed in this House, was very clear. The order stated that, regardless of what happens with regard to debate, if the criteria that were set out in the order are proceeded with, then the Speaker has no choice but to call for a vote on the budgetary bills, and they are listed in the order. The Speaker will, it says on June 12 and 13, deal with these matters in an appropriate way, which means he will call a vote on them. It is spelled out in the order.

In my view, Mr. Speaker, the Government House Leader has erred in his comments in the paper. He has again, like his leader, like the Premier (Mr. Doer), misled Manitobans to believing that somehow the budget will not pass on the 13th of June, which is not the case. Our hands are tied, whether we are in opposition or in government, with regard to what happens on June 12 and 13, because the order spells it out very clearly. Unless the government chooses not to vote for its own budget, I can see no other action but that the budget will pass because you, as Mr. Speaker, have no choice but to call those supply motions, those motions that have been identified through the order on the 12th and 13th of June.

Now, Mr. Speaker, with regard to the legislation, there are some deadlines that have to be met. We have passed one of those deadlines. We are approaching another deadline. Then there is as yet a third deadline that has to be met prior to June 12 and 13.

***** (15:30)

It is up to the government to conduct the business of the House. They can do it in several ways. The opposition have drawn a line in the sand. The opposition in this House have said that the Premier has to call a public inquiry because, otherwise, we will continue not to debate the budget. If you listen to the media, the media have called upon the government to call a public inquiry. They have not relented from that position, Mr. Speaker. Just this morning, Mr. Speaker, on CJOB, it was very clear that we are on the right track, that the government needs to call a public inquiry.

Mr. Speaker, if we look at the *Free Press* editorial of just a day or two ago, it was very clear that the government has a responsibility to be accountable to Manitobans and call a public inquiry. That is what we are demanding of the government. Let there be no mistake; let there be no mistake. It is a public inquiry that we and the Liberal Party are calling for. It is very clear, unmistakable.

Mr. Speaker, if the government calls the public inquiry, we will get on with the business of the people, the business of the House. The government can then start the process of going into Estimates, calling bills, and the normal processes of this House can take place. But, without calling the public inquiry, I am afraid the government finds itself in a pickle, and that pickle is this: the deadlines are approaching; there are some pieces of legislations that could be in peril. It is at the hands now of the opposition, I think, that we will–

An Honourable Member: Wear it.

Mr. Derkach: Yes, we will wear it, Mr. Speaker. As a matter of fact, we will trumpet it. What we will trumpet is the fact that this government has not got the courage to call a public inquiry because it is culpable, because it has implicated itself in the whole scandal. This, to Manitoba, is like Gomery is to Canada. On a per capita basis, it is probably even worse.

Now, Mr. Speaker, Manitobans, whether they live in Thompson, in Russell, in Binscarth, in Winnipeg, in Brandon, in Winkler, wherever, are calling for a public inquiry. How long will the government resist?

Now, I say, Mr. Speaker, the Government House Leader (Mr. Mackintosh) erred. He said that the order is in peril. I think he needs to retract that statement or he needs to correct it, because the order is not in peril. The order of the House stands, simple as that. It was passed. Unless the Government House Leader needs to have an explanation given to him about what he signed, I see no other way, unless there is unanimous consent in the House, that the order will be proceeded with.

Now, I look at my colleagues in the Liberal Party, and I do not think they are about to try to renege on the order. Certainly, the opposition is not about to renege on the order. Now, I do not know whether the government wants to renege. By the looks of it, they would like to renege on the order. Then, of course, by virtue of reneging on the order, they would simply blame the opposition for not being able to do anything in the House. Oh my goodness. Have you ever seen a situation where a government has a majority of 15 members–

Mr. Speaker: Order. We are getting into debate here. I would like to remind the honourable member that when up on a point of order, it is to advise the Chair of a breach of a rule or a departure of Manitoba practice.

Mr. Derkach: Thank you, Mr. Speaker, and this is a breach of a rule that is quite clearly stated in *Beauchesne's*, Edition No. 6, Citation 71(1), where in fact it states that "the Speaker should be protected against reflections on his or her actions."

Well, the action here,–and I apologize for taking a little bit of latitude there, but I thought I was allowed some, given the speech we had from the Minister of Water Stewardship (Mr. Ashton). But, nevertheless, on this citation it says the Speaker should be protected against reflections, and clearly, the Government House Leader's comments were a reflection of a ruling, an action of the House, and you as Mr. Speaker, because the House Leader said, and I quote: "There is a sessional order . . . that is now in peril." Now how could that be, Mr. Speaker? How could that be? Is the government somehow going to use its majority to try and persuade you as Mr. Speaker and us as a Legislature, that we should change the order. Well, it can do that, but I do not see how the order itself is now in peril. It is not in peril. The order will be proceeded with.

Mr. Speaker, we have talked to the media about the order as well. It is clear. So, when the House Leader of the government says that the order is in peril, he is clearly mistaken. So I think that the House Leader needs to correct the record, needs to apologize for misleading Manitobans and misleading this Chamber, and, more importantly, he has an obligation to apologize to you for reflecting on you as the Speaker of this Chamber who has taken an action on behalf of the Chamber and accepted the order that was agreed to by the government and by the opposition, along with the Liberal Party. That is an order, in my view, that is solid and cannot be tampered with. Thank you.

Hon. Dave Chomiak (Minister of Energy, Science and Technology): Mr. Speaker, as has been a pattern in this House ever since the opposition began its campaign of stalling the Legislature and failing to deal with the day-to-day business, either because of a leadership convention, because of internal issues or whatever issues are on the table of members opposite, they are failing to deal with the day-to-day business of the Legislature.

Because an article appeared in one of the newspapers being critical of the opposition for wasting the time of the Legislature and costing the people of Manitoba resources and because the House Leader made a comment outside of the House in reflection to questions regarding the obstinacy of the members opposite, the fact that members opposite are coming here every day raising points of order, challenging every one of your rulings, Mr. Speaker, every one of your rulings on a daily basis, because members opposite are in that kind of a situation, they are now seeing that they have to try to wiggle their way out, wiggle their way out of the jam that they have gotten themselves into by virtue of raising frivolous points of order that are not even (a) points of order, (b) on the record.

Mr. Speaker, we have before this House a budget that sets the spending of the Province of Manitoba over the next year, and members opposite are either afraid or unwilling to debate the budget. Day after day they ring the bells rather than have the courage to debate the budget. Now, I know that members opposite are involved in events perhaps somewhat removed from activities in the day-to-day Chamber. Maybe there are various campaigns going on. Maybe people are out visiting various groups and individuals. That is possible. I do not know, but I know what happens in here every day. We come in here wanting to pass the budget and pass legislation that is important to the people of Manitoba, and members opposite ring the bells consistently, raise points of order, rebut every single one of your rulings.

There have been more actions with respect to not just appealing the ruling of the Chair but the order that deals with personal–*[interjection]* Matters of privilege. There have been more matters of privilege in this session than I recall during my entire career in opposition. That is from 1990 to 1999. There have been more privileges by members opposite in this session than we raised during those entire nine years. What does that tell you, Mr. Speaker? That tells you there is a little bit of difficulty with members opposite. They are afraid or unwilling to debate the budget and all of the bills that are on the Order Paper, that we have put on the Order Paper for the benefit of Manitobans, which include matters dealing with crystal meth, which include matters dealing with health, which include matters dealing with natural resources.

Mr. Speaker, it is very simple for members opposite. They need a way out. We are offering them a way out. The way out is to debate the budget, debate the bills, get on to doing what the people of Manitoba have sent us here to do, not ring the bell hour after hour after hour in an attempt to–in contravention of what we are elected to do, and that is to make the laws of the Province of Manitoba, debate the laws of the Province of Manitoba, and, most importantly, let the public have a say in the bills that are before this Chamber.

***** (15:40)

Their actions disallow the public from having an opportunity to have a say in what we are debating in this Legislature, and the record will show, and history will show, the consequences of the actions taken by members opposite, just as history has shown that the consequences of members opposite in ramming through the MTS bill have rained upon them and have ramifications upon them to this very day in terms of their credibility amongst the general public of Manitoba.

The public remembers, Mr. Speaker. The public knows what is going on. They know what members opposite are doing, and I suggest to members opposite that we get on with debating the budget and the bills that are important for the people of Manitoba.

Mr. Speaker: Is the honourable Member for Inkster (Mr. Lamoureux) rising to give the Speaker some procedural advice on this point of order?

Mr. Kevin Lamoureux (Inkster): Yes, Mr. Speaker, in addition to that to respond–

Mr. Speaker: Okay, the honourable Member for Inkster.

Mr. Lamoureux: Yes, Mr. Speaker. But, of course, and I listened very patiently, as you did, as the government representative tried to give us a lesson on a number of things. One of the things that I thought was most interesting is he was talking about a way out, and there is a way out of this situation that we currently have. You have had both oppositions in a very strong way encourage the government to use that way. You have had independent media outlets encourage this government to do what is right. You have had Crocus shareholders, individual Manitobans, even former NDP Premier Ed Schreyer tell this government to do, or show them the way out, and the way out, of course, is to call for a public inquiry regarding the Crocus fiasco.

Mr. Speaker, if we look at *Beauchesne's* as the Opposition House Leader (Mr. Derkach) has so eloquently pointed out, *Beauchesne's* 71, I think that there is merit for us to deal with what the government–and it is the Government House Leader (Mr. Mackintosh) that we are talking about, who is putting not only, I would argue, you, but he is also reflecting on all members inside this Chamber, and I am concerned that there is indeed a serious attempt by this government to put a political spin around this whole budget and possibly some legislation in terms of not being able to pass.

Mr. Speaker, the Member for Russell (Mr. Derkach) points out about an agreement, and the government is fully aware of that agreement. Yes, there are some decisions that do need to be made, but I would like to read in particular one portion of that agreement where it states, and I do this so that the Member for Kildonan (Mr. Chomiak) and other government members would be familiar with what that agreement actually states, and it is item 7:

"By the usual adjournment hour on Monday, June 12, 2006, the business of supply for the 2006-07 fiscal year must be concluded as follows: (a) by 4:00 p.m. on that day (i) the consideration of departmental estimates in the Committee of Supply must be concluded, and (ii) both the concurrence motion in the Committee of Supply and the concurrence motion in the House must be put; and (b) by the usual adjournment hour on that day, all stages for the passage (including all related motions and all three readings) of the following bills must be completed: The Appropriation Act, 2006, The Loan Act, 2006, The Budget Implementation and Tax Statues Amendment Act, 2006.

"If the Committee of Supply, the Committee of the Whole, or the House has not concluded any item or stage described above by the required hour, the Committee Chairperson or the Speaker, as the case may be, must interrupt the proceedings at the usual adjournment hour on that day and, without seeing the clock, put all questions necessary to dispose of the required items without further debate or recorded vote."

Mr. Speaker, so the Member for Russell is right on when he talks about what it is that the Government House Leader (Mr. Mackintosh) has done in making statements. Ultimately, he might have compromised the very chair in which you sit in and, in fact, all members of this Legislature. I do not believe the Premier (Mr. Doer) is, nor is the Government House Leader, doing a service to Manitobans by trying to give the impression that the budget will not pass, and you know what? It is possible in one way. It is possible in one way, and that is if not enough government members support the budget, then, yes, the budget will not pass, but I can appreciate that there might be some members, whether it is Transcona, Radisson, Fort Whyte–or Fort Garry, I should say–that might be a little nervous about that.

Mr. Speaker: Order. We are getting into debate. A point of order is to point out to the Speaker a breach of a rule, not to be used for means of debate.

Mr. Lamoureux: In short, in listening to what the Member for Russell has brought to our attention, Mr. Speaker, I do believe that we need to look at the consequences of those statements, because indeed it is a reflection on something that has taken place where there was full agreement, and that full agreement was from everyone inside this Chamber. I believe it was June 9 of 2005 when that agreement was put into place, and, as the Speaker of this Legislature, you have the responsibility to ensure that that agreement is adhered to.

Now, Mr. Speaker, I can appreciate the government, particularly the Premier, might have some concerns, as Manitobans do have some concerns. They like to see proper and due course given and attention and debate and public meetings and discussions in committees, in fact, addressing all the wide variety of things that we have to deal with, whether it is a budget or legislation that is before this

Chamber. But this is something which the Premier is going to have to sleep on, and the Premier is going to have to realize what his ways are in order to be able to address both the need for a public inquiry regarding the Crocus fiasco and the legislative and budget agenda of this government.

It is not appropriate for the Government House Leader (Mr. Mackintosh) to be reflecting to the degree in which he has as to what you are going to be facing come June 12, unless it is an attempt by the government to apply pressure on your Chair, and I hope that that is not the case. I trust that the government is going to be more careful with the way that they are reflecting on what is taking place and be more transparent with Manitobans on this issue.

As the Minister of Energy, Science and Technology (Mr. Chomiak) has pointed out, Mr. Speaker, there is a need for a way out, and the one who has the responsibility to get that way out is going to be the Premier of the province and the Government House Leader. I would suggest that they start looking at that way, and the way to start it off would be to call a public inquiry regarding the Crocus fiasco.

Mr. Speaker: Well, that is one of the longest points of order that I have heard previously, because points of order are usually dealt with in a few comments and then a rule is pointed out and we vote on it. We have spent over 20-some minutes on this, so I will hear the honourable Member for River East, briefly.

Mrs. Bonnie Mitchelson (River East): Thank you very much, Mr. Speaker, and I will be very brief, but as my colleague did point out in *Beauchesne* Citation 71(1) on page 21, it is very clear that the Government House Leader (Mr. Mackintosh) has gone beyond what he should be saying publicly and has put into question your ability to make the right decisions based on the rules that have been set out and, I think, have been fairly clearly articulated here in the Legislature this afternoon.

***** (15:50)

I listened very carefully to the Member for Kildonan (Mr. Chomiak), the Minister of Energy, Science and Technology, when he spoke and talked about how the opposition now, somehow, was trying to wiggle their way out of some circumstance that we have gotten into in the House. Well, I would submit that the only people who are trying to wiggle their way out of an uncomfortable situation is the government who refuse to call a public inquiry into the Crocus scandal.

You know, I also heard the minister, in his response to this point of order, indicate that we do not have the courage to debate the budget. Well, I would submit to you, Mr. Speaker, that the only people that do not have courage in this Legislature are the government members who do not have the courage to call a public inquiry.

Mr. Speaker, what are they hiding? I would venture to guess that if, in fact, they could tie the whole Crocus scandal to the former government, they would have called an inquiry the very first opportunity they had. But they did not, and why are they not calling a public inquiry? Are they afraid to put their hands on the Bible and swear that they are not tied directly to the scandal through their union brothers and sisters that have controlled and manipulated the Crocus Fund to a point where nothing that this government says in the House can now be believed?

Mr. Speaker, we would ask and submit that the way we could end this dispute in the Legislature and move on with the business of the House would be to have the government call the inquiry, agree to put their hands on the Bible and to swear and tell the truth because we are not getting the answers that we should be getting to very serious questions in this Legislature.

Mr. Speaker, then their reflecting on your office and your ability to manage the affairs of the House, as set out in the rules, is extremely serious and is very misleading to the general public out there. I think you should take this issue and this point of order very seriously and, possibly, censure the Government House Leader (Mr. Mackintosh) for his comments that he made publicly to try to deflect away from their inability to tell the truth and the inability of Manitobans to get to the bottom of the issue, the Crocus scandal, that is facing our province and will, very definitely, leave a black mark for years to come. So I would hope that you would take this point of order very seriously and rule that the Government House Leader stepped beyond his authority by making those comments publicly and has done a disservice to the working of this Legislature. Thank you.

Mr. Speaker: On the point of order raised by the honourable Official Opposition House Leader (Mr. Derkach), I am going to take this matter under advisement so I can check all resources available to me, and I will be consulting with the procedural authorities. I will be returning to the House with the ruling.

* * *

Mr. Speaker: But I have some further information for the first point of order that was raised by the honourable Official Opposition House Leader. Due to recent rule changes respecting intersessional standing or special committees, the volume numbering for the daily Hansard has been adjusted to reflect this change.

The sitting dates that were sitting intersessionally were Friday, December 9, 2005, at 9:30 a.m., and it was dealing with Public Accounts, and the second day was January 26, 2006, at 1 p.m. dealing with the Committee on Justice. The other, third day, was February 2, 2006, dealing with Public Accounts at 9:30 a.m., and Wednesday, March 1, 2006, at 6 p.m., dealing with the Justice Committee.

I hope that is the information that the member was seeking. So that would account for the days that the member thought were missing from one Hansard to the next Hansard. If you need further information, I welcome you to go on to the Internet. The information is all there on the Internet.

* * *

Mr. Speaker: The honourable Official Opposition House Leader, on a new point of order or a matter of privilege?

Mr. Derkach: Mr. Speaker, I move that the House do now adjourn.

Mr. Speaker: Order. A motion cannot be moved until we get to Orders of the Day, and we have not reached that stage yet, so the motion is totally out of order.

The honourable Official Opposition House Leader, on either a point of order or a matter of privilege.

Mr. Derkach: Mr. Speaker, with the greatest of respect, I challenge your ruling.

Mr. Speaker: The ruling of the Chair has been challenged.

Voice Vote

Mr. Speaker: All those in favour of sustaining the ruling of the Chair, say yea.

Some Honourable Members: Yea.

Mr. Speaker: All those opposed to sustaining the ruling of the Chair, say nay.

Some Honourable Members: Nay.

Mr. Speaker: In my opinion, the Yeas have it.

Formal Vote

Mr. Derkach: A recorded vote, Mr. Speaker.

Mr. Speaker: A recorded vote having been requested, call in the members.

Order. Sixty minutes have expired. Please turn the bells off.

The question before the House is shall the ruling of the Chair be sustained.

Division

***A RECORDED VOTE** was taken, the result being as follows:*

Yeas

Allan, Altemeyer, Ashton, Bjornson, Brick, Caldwell, Chomiak, Dewar, Doer, Irvin-Ross, Jennissen, Jha, Korzeniowski, Lathlin, Lemieux, Mackintosh, Maloway, Martindale, McGifford, Melnick, Nevakshonoff, Oswald, Reid, Robinson, Rondeau, Sale, Santos, Schellenberg, Selinger, Smith, Struthers, Swan, Wowchuk.

Nays

Cullen, Cummings, Derkach, Driedger, Dyck, Eichler, Faurschou, Goertzen, Hawranik, Lamoureux, Maguire, Mitchelson, Reimer, Taillieu.

Madam Clerk (Patricia Chaychuk): Yeas 33, Nays 14.

Mr. Speaker: The ruling of the Chair has been sustained.

* * *

Mr. Derkach: Mr. Speaker, I see it is about a minute to five. Do we want to call it five o'clock?

Mr. Speaker: Is it the will of the House to call it five o'clock?

Some Honourable Members: No.

Mr. Speaker: No? Okay.

Point of Order

Mr. Speaker: The honourable Official Opposition House Leader, on a point of order or a matter of privilege?

Mr. Derkach: Well, Mr. Speaker–

Mr. Speaker: On a point of order or a matter of privilege?

Mr. Derkach: On a point of order, Mr. Speaker.

Mr. Speaker: Okay, the honourable Official Opposition House Leader, on a point of order.

Mr. Derkach: Mr. Speaker, on a point of order, earlier today in Question Period the Minister of Education (Mr. Bjornson) was asked some fairly serious questions by the Member for Charleswood (Mrs. Driedger). Instead of dealing with the matter raised, the minister decided to bring in some extraneous areas which made no sense whatsoever, misleading the House, misleading Manitobans and not dealing with the matter raised.

***** (17:00)

Now, Mr. Speaker, *Beauchesne* 417 is very clear and, although we do not use it during Question Period because we allow the latitude for a minister to be able to respond to preamble that a member puts forward, or a questioner to respond in her preamble to the question to what the minister may want to put on record, the issue is that 417–

Mr. Speaker: Order.

The hour being 5 p.m., we will adjourn and this point of order will continue as first order of business tomorrow.

The hour being 5 p.m., this House is adjourned and stands adjourned until 1:30 p.m. tomorrow (Wednesday).

LEGISLATIVE ASSEMBLY OF MANITOBA

Tuesday, April 25, 2006

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of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
(Hansard)

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http://www.gov.mb.ca/legislature/hansard/index.html

MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Ninth Legislature

Member	Constituency	Political Affiliation
ALLAN, Nancy, Hon.	St. Vital	N.D.P.
ALTEMEYER, Rob	Wolseley	N.D.P.
ASHTON, Steve, Hon.	Thompson	N.D.P.
BJORNSON, Peter, Hon.	Gimli	N.D.P.
BLADY, Sharon	Kirkfield Park	N.D.P.
BOROTSIK, Rick	Brandon West	P.C.
BRAUN, Erna	Rossmere	N.D.P.
BRICK, Marilyn	St. Norbert	N.D.P.
BRIESE, Stuart	Ste. Rose	P.C.
CALDWELL, Drew	Brandon East	N.D.P.
CHOMIAK, Dave, Hon.	Kildonan	N.D.P.
CULLEN, Cliff	Turtle Mountain	P.C.
DERKACH, Leonard	Russell	P.C.
DEWAR, Gregory	Selkirk	N.D.P.
DOER, Gary, Hon.	Concordia	N.D.P.
DRIEDGER, Myrna	Charleswood	P.C.
DYCK, Peter	Pembina	P.C.
EICHLER, Ralph	Lakeside	P.C.
FAURSCHOU, David	Portage la Prairie	P.C.
GERRARD, Jon, Hon.	River Heights	Lib.
GOERTZEN, Kelvin	Steinbach	P.C.
GRAYDON, Cliff	Emerson	P.C.
HAWRANIK, Gerald	Lac du Bonnet	P.C.
HICKES, George, Hon.	Point Douglas	N.D.P.
HOWARD, Jennifer	Fort Rouge	N.D.P.
IRVIN-ROSS, Kerri, Hon.	Fort Garry	N.D.P.
JENNISSEN, Gerard	Flin Flon	N.D.P.
JHA, Bidhu	Radisson	N.D.P.
KORZENIOWSKI, Bonnie	St. James	N.D.P.
LAMOUREUX, Kevin	Inkster	Lib.
LATHLIN, Oscar, Hon.	The Pas	N.D.P.
LEMIEUX, Ron, Hon.	La Verendrye	N.D.P.
MACKINTOSH, Gord, Hon.	St. Johns	N.D.P.
MAGUIRE, Larry	Arthur-Virden	P.C.
MALOWAY, Jim	Elmwood	N.D.P.
MARCELINO, Flor	Wellington	N.D.P.
MARTINDALE, Doug	Burrows	N.D.P.
McFADYEN, Hugh	Fort Whyte	P.C.
McGIFFORD, Diane, Hon.	Lord Roberts	N.D.P.
MELNICK, Christine, Hon.	Riel	N.D.P.
MITCHELSON, Bonnie	River East	P.C.
NEVAKSHONOFF, Tom	Interlake	N.D.P.
OSWALD, Theresa, Hon.	Seine River	N.D.P.
PEDERSEN, Blaine	Carman	P.C.
REID, Daryl	Transcona	N.D.P.
ROBINSON, Eric, Hon.	Rupertsland	N.D.P.
RONDEAU, Jim, Hon.	Assiniboia	N.D.P.
ROWAT, Leanne	Minnedosa	P.C.
SARAN, Mohinder	The Maples	N.D.P.
SCHULER, Ron	Springfield	P.C.
SELBY, Erin	Southdale	N.D.P.
SELINGER, Greg, Hon.	St. Boniface	N.D.P.
STEFANSON, Heather	Tuxedo	P.C.
STRUTHERS, Stan, Hon.	Dauphin-Roblin	N.D.P.
SWAN, Andrew	Minto	N.D.P.
TAILLIEU, Mavis	Morris	P.C.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

LEGISLATIVE ASSEMBLY OF MANITOBA

Wednesday, September 26, 2007

The House met at 1:30 p.m.

PRAYER

ROUTINE PROCEEDINGS

INTRODUCTION OF BILLS

Bill 18–The Forest Health Protection Act

Hon. Stan Struthers (Minister of Conservation): I move, seconded by the Minister of Health (Ms. Oswald), that Bill 18, The Forest Health Protection Act; Loi sur la protection de la santé des forêts, be now read a first time.

Motion presented.

Mr. Struthers: Mr. Speaker, The Forest Health Protection Act will give us the tools to protect the health of all trees and forests in Manitoba by enabling the Province to monitor and respond quickly with effective preventative measures to control forest pests in the event of an outbreak. Thank you.

Mr. Speaker: Is it the pleasure of the House to adopt the motion? *[Agreed]*

Bill 19–The Fair Registration Practices in Regulated Professions Act

Hon. Nancy Allan (Minister of Labour and Immigration): Mr. Speaker, I move, also seconded by the Minister of Health (Ms. Oswald), that Bill 19, The Fair Registration Practices in Regulated Professions Act; Loi sur les pratiques d'inscription équitables dans les professions réglementées, be now read a first time.

Motion presented.

Ms. Allan: Mr. Speaker, this bill will provide that regulated professions and individuals applying for registration in Manitoba are governed by registration practices that are transparent, objective, impartial and fair.

In particular, fair registration practices will assist in breaking down the qualifications recognition barriers for internationally educated or out-of-town or out-of province individuals seeking work in their fields of expertise.

Thank you.

Mr. Speaker: Is it the pleasure of the House to adopt the motion? *[Agreed]*

PETITIONS

Provincial Trunk Highway 2–Glenboro

Mr. Cliff Cullen (Turtle Mountain): Mr. Speaker, I wish to present the following petition to the Legislative Assembly.

These are the reasons for this petition:

As a result of high traffic volumes in the region, there have been numerous accidents and near misses along Provincial Trunk Highway 2 near the village of Glenboro, leading to serious safety concerns for motorists.

The provincial government has refused to construct turning lanes off Provincial Trunk Highway 2 into the village of Glenboro and onto Golf Course Drive, despite the fact that a number of businesses along Provincial Trunk Highway 2 have increased greatly in recent years.

We petition the Manitoba Legislative Assembly as follows:

To urge the Minister of Infrastructure and Transportation (Mr. Lemieux) to consider implementing a speed zone on Provincial Trunk Highway 2 adjacent to the village of Glenboro.

This petition is signed by Jill Nowazek, Henry Thornborough, Ron Book and many, many others.

Mr. Speaker: In accordance with our rule 132(6), when petitions are read they are deemed to be received by the House.

Provincial Trunk Highway 10–Brandon Hills Estates

Mrs. Leanne Rowat (Minnedosa): I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

Provincial Trunk Highway 10 serves as a route for an ever-increasing volume of traffic including heavy trucks, farm vehicles, working commuters, tour buses, campers and the transport of dangerous goods.

Provincial Highway 10 access travelling south to Brandon Hills Estates is not only unsafe for school students who must cross the busy highway, but also for the turning vehicles who must cross a solid line to enter the park community.

Traffic levels are expected to escalate further due to projected industrial expansions.

Highway upgrades of Provincial Highway 10 are occurring within a short distance of this site. Priority should be given to this community, based on the dangerous access to highways for residents.

We petition the Legislative Assembly of Manitoba as follows:

To urge the Minister of Infrastructure and Transportation (Mr. Lemieux) to act on the situation by considering construction of turning lanes that would reduce the danger posed in traffic access to Brandon Hills Estates, which is home to 85 residents.

This petition signed by Judy Stuckel, Larry Stuckel, Hazel Asham and many, many others.

Cree Nation Child and Family Caring Agency

Mrs. Mavis Taillieu (Morris): I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition.

Cree Nation Child and Family Caring Agency is a provincially mandated First Nation child protection and welfare agency. Operated under authority of the Provincial Ministry of Family Services and Housing, the mission is to keep children, families and communities safe and secure, and promote healthy citizen development and well-being.

Lynn Lake is located 321 kilometres northwest of Thompson, Manitoba on PR #391. There is no social worker living and working in the community. The goals of the ministry are implemented from a distance and supplemented with infrequent and short visits from a social worker located in Thompson.

The Lynn Lake Friendship Centre is a designated safe house and receiving home providing accommodations, services and care to children and families experiencing difficulties in a safe environment. The designated safe house and receiving home are forced closed at this time due to outstanding accounts payable due from Cree Nation Child and Family Caring Agency.

Failure to have a social worker based in Lynn Lake providing immediate and sustained services and forcing the receiving home and designated safe house to close, children and families experiencing difficulties in Lynn Lake and area have their health and safety placed in great jeopardy.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Family Services and Housing (Mr. Mackintosh) to consider re-staffing the social worker position in Lynn Lake in order to provide needed services to northwestern Manitoba in a timely manner.

To request the Minister of Family Services and Housing to consider mediating outstanding accounts payable due to Lynn Lake Friendship Centre and Cree Nation Child and Family Caring Agency in order to allow the designated safe house and receiving home to resume regular operations and services and continued utilization of these operations and services.

This is signed by Minnie Carberry, Mary Bighetty, Tom McCann, and many more concerned Manitobans.

***** (13:40)

Provincial Slogan

Mr. Kevin Lamoureux (Inkster): Mr. Speaker, I wish to present today the following petition to the Legislative Assembly of Manitoba.

The background to this petition is as follows:

That the NDP have authorized the spending of hundreds of thousands of tax dollars to promote the new slogan, Spirited Energy.

That Friendly Manitoba is a better description of our province.

We petition the Legislative Assembly of Manitoba as follows:

To request the Legislative Assembly of Manitoba to consider supporting the slogan, Friendly Manitoba over Spirited Energy.

To urge the Premier and his NDP caucus to make public the total cost in creating and promoting the new slogan, Spirited Energy.

Signed by Eric Miranda, Nellie Miranda, Jeric Miranda, and many, many other fine Manitobans.

TABLING OF REPORTS

Mr. Speaker: I am pleased to table in the House the Reports of Members' Expenses for the year ended March 31, 2007, in compliance with section 4 of the Indemnities, Allowances, and Retirement Benefits regulations.

Hon. Greg Selinger (Minister of Finance): I would like to table the following, the *Manitoba Finance, Supplementary Information for Legislative Review: 2007-2008 Departmental Expenditure Estimates*.

Hon. Diane McGifford (Minister of Advanced Education and Literacy): I'm pleased to table the 2007-2008 Departmental Estimates for Advanced Education and Literacy.

Hon. Oscar Lathlin (Minister of Aboriginal and Northern Affairs): I'm pleased to table the 2007-2008 Departmental Estimates for Aboriginal and Northern Affairs and the *Annual Report of the Communities Economic Development Fund*.

MINISTERIAL STATEMENTS

National Forest Week

Hon. Stan Struthers (Minister of Conservation): I have a statement for the House.

This white spruce tree seedling is presented to you in celebration of National Forest Week, September 23-29, 2007, by Manitoba Conservation and the Manitoba Forestry Association (MFA). The white spruce is, of course, Manitoba's provincial tree, and these seedlings are locally grown at Pineland Forest Nursery in Hadashville.

In Manitoba, the Manitoba Forestry Association, or MFA, has marked this annual occasion by providing white spruce seedlings to my honourable colleagues. I commend the MFA for their ongoing efforts to celebrate and create awareness of our valuable forest resources and to provide forestry education to Manitobans of all ages.

Mr. Speaker, sustaining Manitoba's forests for environmental, social, and economic benefits is a priority for Manitoba Conservation. Thank you.

Mrs. Heather Stefanson (Tuxedo): I thank the minister for his statement today. On behalf of members of this side of the House, Mr. Speaker, we want to say how happy we are to celebrate this week, National Forest Week.

It should also be noted that today is Maple Leaf Day, a day when Canadians are asked to reflect on the link between our lives, our Canadian heritage, and our symbol, which is historical and economic environmental link between these and the trees, Mr. Speaker.

I want to just take this moment, this opportunity, to quote a former colleague of mine, which I'm sure is familiar to many members in this House, one Harry Enns, the former member for Lakeside, who made a comment each year when he got up to thank members opposite for the trees. He said, and I quote: The trees seem to get smaller each year, Mr. Speaker. Obviously this government is truly conserving.

Mr. Speaker, I think, and I do have to say that at this time–

Mr. Speaker: Order. Just for information of the House, responses to Ministerial Statements should not take longer than the response of the ministers unless–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. If a person wanted to put more on record, they would have to have unanimous consent of the House by leave. That's just information for the House.

Hon. Jon Gerrard (River Heights): I ask for leave to speak to the minister's statement.

Mr. Speaker: Does the honourable Member for River Heights have leave? *[Agreed]*

Mr. Gerrard: Mr. Speaker, I rise to salute the importance of the forest industry and to speak out on behalf of trees and forests in Manitoba because of what they contribute, not only to Manitoba. Forests have often been called the lungs of the planet because they contribute so much to the well-being of our environment. Certainly from a perspective of global warming, forests can play a very important role and we need to acknowledge that. So I join with other colleagues in paying attention to trees and forests and make sure that we continue to do so. Thank you.

Introduction of Guests

Mr. Speaker: Prior to Oral Questions, I'd like to draw the attention of honourable members to the public gallery where we have with us today 47 retired teachers.

On behalf of all honourable members, I welcome you here today.

ORAL QUESTIONS

Bipole Power Line West Side of Manitoba

Mr. Hugh McFadyen (Leader of the Official Opposition): Mr. Speaker, I would like to just pick up on what the Member for Tuxedo (Mrs. Stefanson) was saying. I want to just say that on this side of the House, all trees are equal. We don't discriminate between east-side trees and west-side trees. They all deserve equal treatment when it comes to their future.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. McFadyen: Mr. Speaker, yesterday we witnessed a situation, a shameful situation, where perhaps the most significant policy decision to be made by this government in the term of this mandate or any other mandate was made by the CEO of a Crown corporation under the cover of another government announcement relating to a public statutory holiday.

Now, this decision to build the next bipole power line down the west side of the province of Manitoba, Mr. Speaker, is going to cost future generations of Manitobans upwards of $500 million, a legacy of debt of half a billion dollars for future generations of Manitobans. That's not to mention the lost potential for sales arising from the line loss arising from an extra 230 kilometres of line that's going to be required, much of it through forest in the northern and western part of Manitoba.

Mr. Speaker, the Premier has admitted that no environmental study has been done to justify the environmental arguments that have been made. The CEO of Hydro says it's going to cost between $300 million and $400 million for the line alone, plus lost sales, plus other lost opportunities for Manitobans.

Now I know the Premier is concerned about symbolism. He's concerned about political legacies. He said yesterday in Estimates, he doesn't want to be accused of flip-flopping.

I'd like to ask the Premier today if he would set aside the short-term, personal political considerations and do what's right for the future of Manitobans. Don't leave them a legacy of debt, environmental destruction and despair for the residents of the east side of Lake Winnipeg.

***** (13:50)

Hon. Gary Doer (Premier): Unlike members opposite, we do believe that all people are equal and that's why, Mr. Speaker, I thought it was passing strange in the questions and points the members opposite were making in my Estimates that they did not deal with the starting point of First Nations people that reside and live and have lived for generations, in fact thousands of years on the east side of Lake Winnipeg.

In speaking in terms of trees are equal, Mr. Speaker, there is, I believe, some 800 kilometres of trees on the east side. There is much less than that on the west side. I believe the number is about 550 kilometres. Thirdly, it is clear that the east side is less developed than the west side in terms of other right-of-way areas for Hydro and, of course, other rights-of-way that have developed in mining, hydro-electricity, other developments on the west side.

Mr. Speaker, we made our feelings and preference known during the election campaign. When members talk about the timing of an announcement, the timing–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. The honourable First Minister has the floor.

Mr. Doer: The timing of the specific announcement was that of Hydro. The issue of the debate on the Tory vision, Mr. Speaker, which has been before their Cabinet in the early '90s and not proceeded with, our vision was well debated in the election campaign. We fully admitted that the cost of doing the west side transmission line was higher from a straight, straight-line basis. It's obviously cheaper to build a straight line than it is to have a more circuitous route. We admitted that during the campaign. And if you go to that logic, you would proceed with the line down the Interlake route because it is an absolute straighter line with already the right-of-way fully obtained. But that is not the most reliable route.

So there are issues of reliability, cost, ecology, First Nations, sustainability. I would also point out that there is the issue of long-term markets for the sale of hydro-electric power, and that's why we stated our preference in the election campaign. The member opposite stated his preference, and that was fully debated in the election campaign. The member opposite put his position out in the campaign. It was debated in every constituency, at least where we were contesting the election. We were proud to put our position forward because it is the long-term visionary position for Manitoba, Mr. Speaker.

Mr. McFadyen: The Premier is wrong on so many counts in that answer, Mr. Speaker. I'm going to have to take full advantage of leader's latitude to go through it because he is absolutely wrong on every count, and he talks about debates and political campaigns. He was the one who was ducking live debates because he didn't want to have to justify his positions, and he didn't want to have to defend himself and respond to questions related to this very misguided decision which is going to have a long-term impact on generations to come of Manitobans.

We know there is no environmental study. The Premier talks about the equality of all people in Manitoba. There's been no consultation with people on the west side. He talks about consultation on the east side. He hasn't consulted with people on the west side who are going to be impacted by the development on that side of the province.

We have a quote, this morning in the media, from Elijah Harper representing people, Aboriginal people, First Nations people who have lived for thousands of years on the east side of Lake Winnipeg and he says, and I quote: We were devastated by today's announcement.

This is Elijah Harper. A movie has been made about Elijah Harper. He is a legend. He is a person who is trusted by First Nations throughout our province. He calls this decision devastating for his people. So the environmental case has not been made. The people who are concerned are speaking up and saying that it's wrong. They've done so much damage to Hydro in the past through their raids on its reserve, Mr. Speaker, that this decision makes the MTX fiasco of the Howard Pawley years look like child play. There's absolutely no comparison when you look at the comparison. He turns up the volume and shouts but if you look up the responses, they just don't stand up.

Bob Brennan, the CEO of Hydro, yesterday said that there was a case to be made in terms of reliability whether you went down the east side of the lake or on the route that has been selected. The reliability argument doesn't stand up, and he's contradicted by his own Hydro CEO, Bob Brennan, whose word I will take 10 times out of 10 when it's put up against the words of the member opposite.

So, Mr. Speaker, we've got a situation now where by Hydro's estimates there will be 78 megawatts of line loss running through the Interlake. That line loss will be increased by more than 78. It'll be more than 78 megawatts. We've got 99 megawatts of power coming from wind power. It'll wipe out in one move, wipe out the entire capacity of wind power in Manitoba, completely undo everything that's been done in wind power in Manitoba today.

Will the Premier admit he has made a mistake, back away from this terrible decision before it's too late and send a clear message that he's prepared to show leadership, admit a mistake, end the political hoax and do what is right for future generations of Manitobans?

Mr. Doer: Mr. Speaker, the member opposite did not listen to my answer. I said the most direct route was the Interlake route between the two lakes. That's the Interlake route. The east side is the east side of Lake Winnipeg. The west side is west of Lake Winnipegosis. The Interlake route is between Lake Manitoba and Lake Winnipeg.

So when I said that the issue of reliability–the line was shorter in the existing and the right-of-ways were better on the Interlake route. That was the issue of reliability. So the argument you're making is on the wrong route. I already answered that. Secondly–

Some Honourable Members: Oh. Oh.

Mr. Speaker: Order.

Mr. Doer: Mr. Speaker, that presumes that there will be no sale of hydro-electric power to Saskatchewan and Alberta, and I can assure the House that we are in negotiations with different provinces on the west side. We've just received a number of reports about the absolute demand on the west side, and it also presumes that the east-side line can be built.

There are serious licensing issues on the east side. The reviews of the east-side option raise serious image and market potential and liabilities in markets that we already export, i.e., places like Minnesota where there will be huge international opposition to the destruction or tampering with parts of the boreal forest.

I would also point out that we do know that on the east side there are two heritage rivers affected. On the west side there is one heritage river affected. Again, that's part of the analysis that's taken place.

But certainly Hydro has done a review. We've done our review. We've stated our preference, and we absolutely believe that the reliability issues dictate that the west side is the preferred option. That will go to public hearings with the licensing by the Clean Environment Commission. There will be lots of debate. Hydro will be required to scope the route that has been chosen by the Hydro board. It's certainly consistent with our view and we believe that the–*[interjection]*

The member who dropped his paper yesterday is now chattering at the back of the room, Mr. Speaker.

Some Honourable Members: Oh. Oh.

Mr. Speaker: Order.

***** (14:00)

Mr. Doer: Mr. Speaker, there is significant opposition to the east side. There is significant opposition not just in Manitoba but in places where we sell power. We always have to work on securing any power sale we have in international markets. So, we would argue that if you can't build the line on the east side, if you're denied a licence on the east side for all the reasons I've indicated, or if the east side becomes an issue for external and international markets or other markets in western Canada or eastern Canada, then the economics have to be adjusted accordingly.

This is a serious challenge for Manitoba to be dealing with international markets in Minnesota with the opposition that would be outlined by those people. They are able to put commercial pressure on Manitoba Hydro. The commercial pressure can exert different decisions with different agencies in United States, and those factors also have to be considered when looking at the two routes. I personally believe, Mr. Speaker, that the former government had a recommendation to proceed on the east side in 1992-1993. They didn't go ahead. Why?

Mr. McFadyen: The fact is that the Premier hasn't even made the effort to make the case to potential buyers based on facts rather than spin, in order to deal with the issues and opposition that might exist. He hasn't even attempted to take that proposal through the licensing process, Mr. Speaker, because, for reasons that are not entirely clear–presumably because of some political whim–he has landed on a decision that he now can't back out of and has decided to proceed full speed ahead against the evidence, contrary to the facts, and with the outcome that future generations of Manitobans will be left with hundreds of millions of dollars in debt, added environmental degradation, and a loss of hope for people on the east side.

Mr. Speaker, I have confidence that potential buyers, such as Minnesota Power and others, will look at the facts. They won't be taken in by rhetoric when it comes to any proposal that's made by Manitoba. As an example, if the Premier was making the argument to Minnesota, he might want to point out that running the line down the east side, rather than the proposal that he's adopted for all the wrong reasons, would save, could save, in the range of 100 megawatts of line loss. That's half the capacity of the Taconite Harbor Energy Center coal-fired plant in Minnesota. He could shut down half the capacity of a coal-fired plant in Minnesota if he made the right decision. He doesn't care about coal-fired plants operating in Minnesota and the chance to displace that power. He doesn't care about the fact that with the added 200-plus kilometres of line, the trees are going to have to be cut. It's all about spin; it's all about rhetoric; it's all about a political hoax; and the result is that he is going to leave a triple-D legacy: a legacy of debt, despair, and environmental destruction.

I would call on the Premier at this point to take a step back, put this decision on hold, look at the facts, and make the right decision for future generations of Manitobans.

Mr. Doer: Mr. Speaker, the debt-for-debt ratios have gone down under our administration. The 86 percent we inherited from the Conservatives has been reduced consistently.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Doer: Thank you, Mr. Speaker.

The issue of the coal-fired plant. I would point out that we closed down the coal plant in Selkirk that was operating with one of the highest emission records anywhere in Manitoba. Members opposite were belching out smoke into their own constituents' backyards. We had the courage to close it down and we're proud we did.

We are also proceeding on a strategy to close down the plant in Brandon with redeployment of employees from that area and, Mr. Speaker, we have developed over 300 megawatts of renewable energy in Manitoba. A lot more than just a hundred megawatts of wind power. Over 300 megawatts have been developed by our government by going from ninth place under the Conservatives in energy renewability to first place in Canada.

Mr. Speaker, there is an extremely active lobby in the state of Minnesota against hydro-electric development and sales. It is an important lobby to pay attention to. It is very important that we proceed in the most environmentally sound way with the majority of First Nations people on our side to develop export sales.

Members opposite have no experience in developing export sales. The only thing they developed was mothballing projects that we had brought forward. They're the mothball party of Manitoba. We are the only ones capable of developing export sales to take advantage of the transmission line that we are going to build on the west side of Manitoba, but we will do so in full awareness of the proximity to the west side, to Saskatchewan and Alberta where the demand for energy and renewable energy is going up every day. We will also do so with an eye to the south of Manitoba where environmental stewardship, the protection of the Boreal Forest and relationships with First Nations people will be paramount for the regulatory bodies to approve future hydro development sales. That's why we'll get it done, Mr. Speaker.

Child Welfare System
Government's Response to Problems

Mr. Stuart Briese (Ste. Rose): Mr. Speaker, the child welfare system in Manitoba is in chaos. Children have been lost in the system, social workers are in very short supply and priorities have been misguided and misplaced. Children are being put at risk. The proof is in the growing list of children who have died tragically while in the care of a system that was supposed to protect them. In short, the minister has grossly mismanaged child and family services.

Mr. Speaker, will the minister take responsibility for his role in creating the chaos and confusion within the child welfare system?

Hon. Gord Mackintosh (Minister of Family Services and Housing): First, Mr. Speaker, I congratulate the member for his first question. I still remember my first question. I also reflect we were able in previous capacities to work together to solve issues for rural Manitobans, and I anticipate that we will look for opportunities to work together to better serve the needs of Manitoba families in our current capacities.

Mr. Speaker, Manitoba, not unlike other jurisdictions, has for too long suffered serious shortcomings in the child welfare system. We know that, not just from too many tragedies, but also from the independent eyes of what has been an historical analysis by both the Advocate and the Ombudsman. The recommendations that were made challenges Manitoba to become a leader in child welfare. To meet that challenge we've introduced changes for children. It was introduced in October initially with a $42-million investment.

Mr. Briese: Mr. Speaker, Gage Guimond, aged two, died while in the care of Child and Family Services. He died after CFS decided he should be removed from a loving foster home and placed with relatives. His best interests were not protected.

Mr. Speaker, the minister has failed to establish clear priorities for our child welfare system. Children are paying the price of this government's mismanagement. Will the minister take action today and issue a written directive to all child welfare authorities that in every instance a child's safety and well-being outweigh all other considerations?

Mr. Mackintosh: Mr. Speaker, I remind members that Manitoba has launched the most significant aggressive overhaul, if not transformation, of the child welfare system as a result of the Changes for Children initiative that began in October. We are not yet one-third of the way into this overhaul, but it holds out great promise for significant strengthening of the child welfare system.

The loss of Gage Guimond has weighed heavily on the hearts of, not only myself certainly, all Manitobans, I trust. When we have a loss like this, a tragic loss, it's important that we learn what went wrong and that we make changes accordingly. That, Mr. Speaker, we are committed to doing.

***** (14:10)

Mr. Briese: Mr. Speaker, the minister refuses to acknowledge that in practice the child's best interests are always being put first. He refuses to acknowledge that under his watch, other priorities are put first.

His mismanagement of the child welfare system is failing Manitoba children. I will ask the minister again: Will he do whatever it takes today to make it clear to all Child and Family Services staff that the child's safety and well-being comes before everything else?

Mr. Mackintosh: Mr. Speaker, the Changes for Children initiative devolution is built on the essential component of the child protection system of Manitoba, which is child safety. That is the foundation of the child protection system. It is found throughout the legislation, and indeed, when the authorities legislation was introduced into this House and agreed to unanimously, it began with the important WHEREAS that the safety, security and well-being of children and families is of paramount concern of the people of Manitoba.

Mr. Speaker, when members opposite introduced changes to the legislation to recognize that aboriginal children be placed with family and extended family, even then there was no trumping of safety. Safety is job one, always has been, always will be.

Addiction Treatment
Availability of Programs

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, in July the *Canadian Journal of Psychiatry* released a study indicating that 13.5 percent of Manitobans were dealing with substance abuse issues. Not only is this higher than the Canadian average, but it's twice that of the rate of Toronto. Workers with the Addictions Foundation of Manitoba are saying that the NDP government is cutting funding, closing treatment programs during the summer and reducing workers to treat addiction.

Mr. Speaker, why is it that when the province's addiction problem is getting worse, this government is doing less?

Hon. Kerri Irvin-Ross (Minister of Healthy Living): Mr. Speaker, our government has been committed to supporting individuals with addictions since being elected in 1999. Our support has increased over the years. The Addictions Foundation of Manitoba in 1999 when we took office received $9 million. This year it is now $14 million.

We've also continued to support the whole network, ensuring that Manitobans have a whole spectrum of services that are available for them from the point of prevention and awareness to recovery services.

Mr. Goertzen: Mr. Speaker, the minister's comments defy not what I'm saying but what the Addictions Foundation of Manitoba is saying. In fact, Barry Rudd, a prevention and education consultant with the very same Addictions Foundation of Manitoba, said that while more youth are indicating that they are taking illegal drugs, treatment programs in Manitoba often have limited availability.

In fact, his comments are bang on: two months wait for a female to access the River House treatment programs; three and a half months wait to get into the impaired driving programs; a month wait for drug treatment at Gimli. It's a month wait for drug treatment in the community of Steinbach.

Mr. Speaker, a day is a lifetime for a drug addict. A month or two can mean death for those who are dealing with addiction. Why is it that this minister hasn't made this a priority for her government and those that are dealing with addiction in our province?

Ms. Irvin-Ross: Mr. Speaker, I'm proud to say that this has been a priority for our government. We continue to provide the services that are necessary. We have provided in-patient services as well as day program services to all Manitobans to ensure that they have the services that they need. The amount of money–$17 million has been invested in the last two years for addiction services across the province of Manitoba to ensure that we are providing a continuum of services for all Manitobans.

Mr. Goertzen: Mr. Speaker, the minister refuses to adhere to what the experts are saying, the Addictions Foundation of Manitoba, when they say that there are long waiting times backed up by the fact that her own department provides. The City of Winnipeg recently said–the police department–that 80 percent of crimes somehow relates back to drugs or drug addiction, yet this government is not making it a priority to ensure that there's addiction treatment in our communities, on the streets or even in our prisons.

Mr. Speaker, when addicts finally open their minds to getting treatment, they shouldn't have to find a closed door at the treatment centre. When an addict shows up at that door, they should find help and not be given a number and told to wait their turn for a month or two. Why won't this government finally make it a priority and commit to when they show up at the door, they'll get the treatment they need.

Ms. Irvin-Ross: Mr. Speaker, the resources are being provided to all Manitobans. We've increased the budget by 50 percent. We continue to ensure that there is a whole spectrum of services for people that have addictions. People that are needing addiction services need to have in-patient programs as well as day programs, as well as recovery programs. We make sure that that spectrum of service is available to all Manitobans. We take this very seriously, and we will continue to work with all of our community partners to ensure that services are available for everyone. Thank you.

Hollow Water First Nation Cottage Barricade

Mr. Gerald Hawranik (Lac du Bonnet): Mr. Speaker, last week the Premier (Mr. Doer) and the Justice Minister trotted off to Ottawa to ask the federal government to add more criminal laws. Also last week Hollow Water First Nation unlawfully set up a barricade on a public road to protest this government's mismanagement of the cottage lot draw system. It's now 12 days since that public road was blocked. No action from the NDP, no consequences for that unlawful act.

So I ask the Minister of Justice: Why would he ask for more criminal laws at the time when he isn't prepared to enforce the laws that he already has?

Hon. Dave Chomiak (Minister of Justice and Attorney General): Mr. Speaker, I want to remind the member that I was very proud to be part of a delegation that included the leader of his own party, the leader of the third party in the Legislature, the police chief of Winnipeg and Brandon, the mayor of Winnipeg and Brandon, and Chief Dennis Meeches of Sioux Valley, and a victim, who all unanimously agreed with the position that we have taken in Manitoba. The Minister of Justice, the Canadian Minister of Justice said how pleased he was that we could come together in Manitoba to work together to deal with crime and that he would carry our message forward to Parliament, which is responsible for making the laws that we are involved with enforcing.

Mr. Hawranik: Mr. Speaker, he's asking for more laws and at the same time he isn't even enforcing the laws he already has.

A week ago RCMP Sergeant Doug Ashton stated that blocking a roadway is illegal according to The Highway Traffic Act, and yesterday on CJOB the Minister of Conservation (Mr. Struthers) stated that the barricades are illegal and he wasn't going to stand on a barricade that shouldn't be there. Those were his words.

So I ask the Minister of Justice: Since the barricades are illegal and shouldn't be there, why has he failed to enforce the law?

Mr. Chomiak: I think that one of the most moving speeches that I've ever heard last week was said by Chief Meeches before the parliamentarians that youth have choices now: The gangs or the clan? I think that was the most moving moment that we all had in terms of the opportunities that we must provide young people.

Mr. Speaker, I do not direct the police. The police undertake these matters, and I rely on the police to determine their course of action in these matters. I suspect that there's no Solicitor General nor a Justice Minister in the country who would want to be in the position of say–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Hawranik: Mr. Speaker, the RCMP and the Minister of Conservation (Mr. Struthers) are clearly on the record stating that the barricades are illegal. However, the Minister of Culture, Heritage and Tourism (Mr. Robinson) is on the record this week as well, indicating that Hollow Water should be respected for their attempts to protect their traditional land. In effect, what he's saying is that Manitobans should respect an illegal barricade on a public road.

So I ask the Minister of Justice: Is he prepared to respect an illegal act or will he do his duty as Minister of Justice in this province and enforce that law?

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

***** (14:20)

Mr. Chomiak: Mr. Speaker, the function and role of the police, I think members indicated yesterday in their speeches that the role and function of police– and now I understand why members voted against our increases to police. Now I understand why they voted against the Prosecutions' increase. They want us to step into the position of police officers. They want us to step into the position of prosecutors and do their jobs.

Our job, Mr. Speaker, is to provide them with the resources and the direction; their job is to do their work. I would not want to be in the position of the former Premier of Ontario–

Mr. Speaker: Order.

Mr. Chomiak: I don't want to be in the position of the former Conservative Premier of Ontario, Mr. Speaker, who put on his police hat and went running out–that is not the position. In fact, if I were to cross that boundary, I would be in dereliction of my duty.

School Review Process
School Board's Authority

Mr. Ron Schuler (Springfield): Mr. Speaker, yesterday evening, parents attended a public meeting where the process was outlined that would be followed in the viability review of Westview School, a process put in place by the provincial government that should apply equally to all schools.

I ask the Minister of Education whether his department school review policy is still, in fact, a 20-month process and whether school boards still have the authority to decide the viability of the school?

Hon. Peter Bjornson (Minister of Education, Citizenship and Youth): Certainly when school divisions are faced with issues such as declining enrolments, they do have difficult decisions to make with respect to the viability of the facilities, and we are currently reviewing the school closure policies and guidelines, Mr. Speaker.

It's rather interesting that members opposite would be raising this when you consider their election promise where they didn't see it necessary to increase any funding to the Education budget because of declining enrolment, Mr. Speaker. But we continue to support schools. We have small school grants; we have declining-enrolment grants. We know how important they are to the community, and school divisions have difficult decisions to make when it comes to school closures.

Mr. Schuler: What's funny, Mr. Speaker, is the Premier (Mr. Doer) said he would live up to the COLA for retired teachers. He never did, and they are sitting in the gallery right now.

Mr. Speaker, what's problematic about this issue is a senior member of this NDP government, the legislative assistant to the Premier, rose yesterday at the public meeting and said to the parents and members of the community that, and I quote: 2009 doesn't have to be *Apocalypse Now*. If we need more time, let us have more time. In other words, the process can be changed, assuming by him.

I would like to ask this Minister of Education whether the Member for Radisson's (Mr. Jha) comments reflect a change in policy, and has he neglected to inform parents and elected trustees of this change?

Mr. Bjornson: Mr. Speaker, we have committed to review the closure policies based on a request by the Manitoba Association of School Trustees and we're certainly going to do that. As I said, the viability of schools is an issue that many school divisions wrestle with because of declining enrolment. There is declining enrolment. We have committed to review the policies. We will review the policies. But we continue to fund education at unprecedented levels, and that's what allows schools to remain viable in the communities and remain an important focal part of that community.

Mr. Schuler: Mr. Speaker, the problem is that the process of a school viability review needs stability. The Member for Radisson stands up and grandstands, saying the 20-month minimum is no *Apocalypse Now*, or, in other words, it can be changed. The Minister of Education must send a clear message to students, parents and the community on his school review policy, and while he's at it, will he please admonish the Member for Radisson on the irresponsible comments made last night at the community meeting.

Mr. Bjornson: Mr. Speaker, as I said, we continue to increase funding to support programming, to support the viability of schools. Talk about grandstanding, I've heard the member refer to the teachers' pension where they continue to masquerade as advocates on behalf of teachers. They did nothing to the pension during the 1990s. They cut 252 teachers because of a lack of funding in 1995. How did that impact the pension? They made a promise during the election to fund two-thirds COLA, and the numbers that they have thrown out are absolutely false with respect to how they could achieve that.

The member opposite should not lecture me about grandstanding, Mr. Speaker. We're the government that supports education. We support teachers; we support small schools in the province.

Spirited Energy Campaign
Involvement of Former NDP Staff Member

Mrs. Leanne Rowat (Minnedosa): Mr. Speaker, yesterday the Premier (Mr. Doer) confirmed that Pat Britton, whose name is on a majority of the Spirited Energy invoices, is the same Pat Britton who was the former executive director for the NDP. I would like to table a sampling of these invoices, Mr. Speaker.

It seems pretty hypocritical for the government to say Spirited Energy isn't simply a partisan paint job when their former executive director is holding the purse strings.

Mr. Speaker, I would like to ask the Minister of Competitiveness (Mr. Rondeau): Why was the former executive director of the NDP so closely involved with the Spirited Energy campaign?

Hon. Gary Doer (Premier): Mr. Speaker, the individual in question did have another position in between the time she was working for government. *[interjection]* I just want to be factual.

I'll pass on her gratuitous comments about the Spirited Energy campaign that were made yesterday in the House and again today in the House. I'll pass that on to all the volunteer business people that have been involved. I'll pass it on to the Chamber of Commerce. I'll pass it on to Mr. Silver that is also spearheading this move. I'll pass it on to Mr. Starmer. I'll pass it on to the mayor of Brandon that endorsed the Spirited Energy campaign. I've got a whole list of business people that I'll pass it on to. I don't think they'll appreciate her gratuitous advice. If we have to take advice on a campaign, we'll take it from people like Bob Silver, not from the member opposite, Mr. Speaker.

Expense Claims

Mrs. Leanne Rowat (Minnedosa): Mr. Speaker, yesterday in this House I asked the minister about beer and wine that was approved as a taxpayer expense for the Spirited Energy campaign. In light of the confirmation of Pat Britton's role in the campaign, I would like to know, and I'd like to ask the minister if the former NDP executive director's decision was to approve the expenses of taxpayer dollars for the beer and wine consumed for the development of the Spirited Energy campaign.

Hon. Jim Rondeau (Minister of Competitive Training and Trade): I'm pleased to provide some information on the Spirited Energy campaign which is led by the business community. May I remind the people that it is not a partisan committee. The PEAC organization is led by Bob Silver, the president of Western Glove Works. We have Jim August who's the CEO of the North Portage, and all these people have provided their expertise, their guidance. Dave Angus. We have Irene Merie. We have all these people, a whole page of people who work on this campaign, and they do it because they want to promote Manitoba in a non-partisan, positive way.

And when we talk about the expense on beer and wine, we're talking about $68. A lot of times we have people who are spending lots of time volunteering, they're spending their own time, efforts–

Mr. Speaker: Order.

Time for Oral Questions has expired.

Some Honourable Members: Oh, oh.

Point of Order

Mr. Speaker: Order. The honourable Member for River Heights, on a point of order?

Hon. Jon Gerrard (River Heights): Mr. Speaker, on a point of order. I am asking for leave to ask my question and two supplementaries which I should be able to do in this Chamber when it's operating fairly.

Mr. Speaker: The honourable member has requested the unanimous consent of the House to pose his question and two supplementary questions. Is there leave of the House? *[Agreed]*

I will now recognize the honourable Member for River Heights to pose his question.

Power Line Development Agreement with Ontario

Hon. Jon Gerrard (River Heights): Mr. Speaker, I remember before and during the election that when the Premier (Mr. Doer) was asked about power transmission lines, he said: I like the option of a power transmission line going straight from Conawapa to Ontario, Sudbury or somewhere like that. I presume that line was predicated on agreement with Ontario, power sales to Ontario, support from the national government.

What happened, Mr. Premier, to the option of a line through Ontario, to the agreements with Ontario, to the national support?

***** (14:30)

Hon. Gary Doer (Premier): Mr. Speaker, there are two issues here. One is the issue of export sales and future export sales, and the other issue is an ongoing issue that would include both sales and reliability. The issue of reliability has been before the previous government from 1992 on. There is a view and advice that reliability must be enhanced. We are attempting to do that with enhancing sales at the same time. Future developments in northern Manitoba, there's a potential of a number of dams on the Nelson River. Over time, if there was a sale to Ontario, it could necessitate or allow for that route.

So it's not an either/or. There's one potential for reliability, which is, as I say, been before governments since 1992. Obviously, Hydro has reviewed the three options north and south, but there was other potential east and west. Certainly that's a site that is not being approved by the board of Hydro last week.

Mr. Gerrard: It seems to me, Mr. Speaker, that the Premier is essentially saying that the line to Ontario is essentially dead because Ontario is not a very reliable partner, Ontario is not coming to the table by buying sales, that there wasn't a reliable national government who was ready to support a trans-Canada transition line.

What is the problem with reliability here of a third line going to Ontario as an alternative to a line in western Manitoba?

Mr. Doer: Well, I don't want to be involved in partisan politics in Ontario, but just to talk about the federal government. I would mention that the Ontario latest energy report and the one before that and the one before that, and I'm sure the members opposite have read it, have referred to Manitoba and the potential of Manitoba. We are attempting to sell power south, which we believe is extremely positive and an extremely sensitive market. We are selling power to Ontario now, and we plan to sell more power to them if it's the right price. We are in discussions with Saskatchewan and the western provinces have already agreed to a grid.

In terms of funding for a grid, Mr. Speaker, there is more money from the existing federal government for partial funding of east-west connections than there was with the previous government. So I don't want to get involved in the back and forth between the Liberals and the Conservatives. I just want to state the facts.

Placement in Manitoba

Hon. Jon Gerrard (River Heights): My question to the Premier: I know that Manitoba Hydro is planning an alternative to the Dorsey substation, which is a Riel substation east of Winnipeg. I would ask: If the Premier is so confident that there may be sales to Saskatchewan or Alberta, why is he not putting that substation in western Manitoba where it would be much more convenient for serving people west instead of east?

Hon. Gary Doer (Premier): Well, Mr. Speaker, the Hydro is recommending–the chief executive officer is recommending, over time, two of them for reliability. That, of course, makes up almost half of the issue of transmission.

I would point out in the election campaign we had clear positions. Our position was to support the option of the west side, with the additional costs and being up front because we thought that was the only viable option. The members opposite had a position for the east side, which was the position recommended to them back in 1992. The Liberals had no position. They were on the one hand and on the other hand. They liked to protect the boreal forests and they want the cheaper line. What's your position, sir?

Mr. Speaker: Order. That will now conclude oral questions and we'll move on to members' statements.

MEMBERS' STATEMENTS

Anola Centennial

Mr. Ron Schuler (Springfield): Mr. Speaker, it gives me great pleasure to congratulate the village of Anola on celebrating its centennial in 2007. Anola is located in the rural municipality of Springfield at the highway intersection known locally as "Twelve and Fifteen."

One-time and well-known residents of Anola include a baseball player, Corey Koskie, and entertainer, Al Simmons. The friendly and welcoming nature of all residents of this community has always impressed me. I was pleased to receive a copy of *Anola Past and Present*, a book written to celebrate and document the village's history. I would like to recognize the efforts of everyone involved in this project and centennial celebrations throughout the year.

The village was originally named Free Port by American businessmen from Freeport, Illinois, in 1912. The name was changed to Anola. Agriculture has been an economic and cultural mainstay in Anola, supported by the many family farms in the area.

Close-knit and hardworking families have benefited from local businesses, recreational sports and social clubs over the last century. Fond memories were formed at businesses like the small, one-room Bugyik's store started in 1915 to the more recent Anola Village Inn. Generations have shared many laughs and countless cups of coffee together. A popular social club is the still active Anola and District Over 50 Club. Anola has been blessed with dedicated congregations that still gather to serve in worship at beautiful churches.

Anola is also home to the Selo Ukrainian Dancers and Mohutnity Ukrainian Dance Ensemble. These dance troupes have provided breathtaking entertainment for many and demonstrate how proud residents are of their cultural heritage.

The Anola and District Museum has done a tremendous job honouring Anola's history. Officially opened in 1975, it has continued to preserve the area's heritage with the dedicated assistance of volunteers. The museum features a pioneer house, chapel, school, blacksmith shop, and the RM of Springfield's first fire truck.

In closing, I would like to congratulate all past and present residents of Anola as they celebrate their historic centennial. Thank you, Mr. Speaker.

Cranberry Portage Community Events

Mr. Gerard Jennissen (Flin Flon): Mr. Speaker, apart from the large urban centre known as the city of Flin Flon, there are many unique, smaller communities in what constitutes the huge Flin Flon constituency. Cranberry Portage is one of those unique communities which, in 1928, mushroomed out of the northern soil almost overnight. This August, Cranberry Portage was able to showcase its talents and skills as the village hosted the sixth Annual National Aboriginal Arts Administrators and Funders gathering in conjunction with the second Annual Summer Arts Festival. Various colourful events were held in the park in front of beautiful Lake Athapapuskow. The big attraction was the world's largest canvas teepee.

I am pleased to announce that the former teepee height record was shattered. The world's largest canvas teepee now stands a proud 22.6 metres high and has a diameter of 21.6 metres. The opening ceremony was able to accommodate not only the delegates but numerous visitors, dignitaries, and the media.

Although the main teepee was the centrepiece of the gathering, there were 20 other smaller teepees, including my own. Each teepee was painted by a creative northern Manitoba artist. The event was an excellent way to have northern artists network and share ideas about how to increase their exposure and access to vital grants.

This gathering was also a wonderful way for the whole community to get involved. The artists offered sessions and teachings in their craft. For example, residents participated in painting classes, sweat lodges, elders' teepee, and learned the use of natural products in art creation, among many other offerings.

Cam McLean showcased his beautifully restored Bombardiers. After all, Mr. Speaker, Cranberry Portage unofficially is the Bombardier capital of Canada.

The delicious community feast involved 538 people and was another great way for residents, delegates, and artists alike to share their experiences. In fact, some delegates commented that the town's hospitality made them feel regal. Northern hospitality is indeed special. Mr. Speaker, the event was so well received and organized that every artist in attendance has registered for the third annual arts festival next year.

Congratulations to the main organizers Lisa Gamblin and Irvin Head, the Cranberry Aboriginal Arts Committee, and the many volunteers that made this event a great success. They have shown that the people of Cranberry Portage, when they work together, can accomplish wonderful things. I call on all honourable members to join me in congratulating the whole community of Cranberry Portage. By hosting this important national conference, they've put a small village on the map with the world's largest canvas teepee.

Stubble Burning Ban

Mrs. Mavis Taillieu (Morris): Mr. Speaker, in late August, an inadvertent stubble fire caused dark smoke to drift across the highway just east of Elie in my constituency and, unfortunately, an accident ensued.

The knee-jerk reaction of this government was to slap a ban on burning instead of investigating and determining that this was an isolated incident. A week later, they lifted the ban, and what happened? Pent-up need for burning resulted in many burns, more smoke and, unfortunately, another accident.

I blame the mismanagement of the NDP government for this mess. If they'd investigated the first fire, found it to be an isolated incident, no ban would have been necessary, and the producers could have continued with the controlled regime adhered to in years past.

Burning of stubble is controversial, but we need to balance the need of those whose health is aggravated by the smoke and those who need to do it for their livelihood, Mr. Speaker. Producers have done a good job of managing their fields, which has resulted in less and less burning over the years. Permits to burn issued on certain days have also been successful.

Mr. Speaker, this government's knee-jerk reaction to this situation is just another example of the mismanagement, lack of vision and leadership that they constantly exhibit. Thank you.

***** (14:40)

Bishop Grandin Greenway

Ms. Erin Selby (Southdale): Mr. Speaker, the residents of south Winnipeg are able to breathe a little easier thanks to the Bishop Grandin Greenway. This greenway stretches from Royalwood to the Red River. The path encourages people to exercise and travel in an environmentally friendly way, and also provides a natural prairie habitat for Manitoba wildlife.

A dedicated group of volunteers have been working to enhance, maintain and connect the greenway to other trails. What better way to combat climate change, Mr. Speaker, than to encourage people to leave their cars at home. Over a thousand trees have been planted on this path alone, with more to come next year. There are plans for a community garden that will be home to Manitoba butterfly species and this path is an exciting addition to our community.

With support from Community Places, this dream was realized, and this initiative is an excellent example of how our government helps communities reach their goals. It is truly a pleasure to see the excitement this greenway has created with residents in the neighbourhood, as well as cycling and outdoors enthusiasts from all over Winnipeg. But the celebration is not yet over. There are plans to expand the path to Fort Whyte Alive and to Lagimodiere Boulevard, and I look forward to working with the volunteers to bring this next phase of their plan to life.

I would ask that all honourable members join me in congratulating the forward-thinking organizers and hardworking volunteers of the Bishop Grandin Greenway for their outstanding efforts in making this greenway a reality. Thank you, Mr. Speaker.

Hecla Island Causeway

Hon. Jon Gerrard (River Heights): Mr. Speaker, I want to acknowledge the efforts of Halli Jonasson, of Riverton, in bringing forward his long-time concerns about the major impacts of the causeway to Hecla Island. The causeway was constructed in about 1970 and blocked much of the flow through the Grassy Narrows, the channel between Hecla Island and the mainland on the west side of Lake Winnipeg.

Halli Jonasson has lived, trapped and fished in the Grassy Narrows area for many, many years and he's very knowledgeable of the situation, both before the causeway was constructed and since. Al Kristofferson, who is the managing director of the Lake Winnipeg Research Consortium, has said of Halli Jonasson: "I think (Jonasson) has his head screwed on straight and has a lot of good information."

Mr. Jonasson has observed dramatic declines in the numbers of muskrats, minks, ducks, geese and jackfish in the marshes in the Grassy Narrows channel. Before the causeway was constructed, Jonasson observed that the marshes served to trap and filter out significant quantities of algal blooms. Today, because of the causeway and changes to the adjacent marsh, this is not happening. Mr. Jonasson has furthermore observed that the water flow both north and south in Lake Winnipeg has been significantly altered as a result of the Hecla Island causeway and this may have had an impact on the erosion along the shores of Lake Winnipeg.

Clearly, scientific work by the Lake Winnipeg consortium, and perhaps by others, is needed to investigate the impact of the Hecla Island causeway before further action is taken. But I think it's important to report today that, at a meeting last Saturday in Riverton, I found considerable support for the ideas that Halli Jonasson is putting forward. I understand that the MLA for Gimli (Mr. Bjornson) has been approached on this issue starting some time ago, several years ago but has declined so far to show any real interest. I would hope that the MLA for Gimli and his government would start paying more attention to the needs of Lake Winnipeg.

ORDERS OF THE DAY

GOVERNMENT BUSINESS

House Business

Hon. Dave Chomiak (Government House Leader): Mr. Speaker, I wonder if I might have leave of the House to change the hours for the Estimates committees in all three locations for Wednesday and Thursday. I wonder if I might have leave of the House to change those hours to extend from 5 p.m. until 6:30 p.m. in all three sites today and Thursday.

Mr. Speaker: Is there leave for the Estimates to continue between 5 p.m. to 6:30 p.m. in all three committee rooms for the Estimates? Is there leave? Is there agreement? *[Agreed]*

Mr. Chomiak: Mr. Speaker, I wonder, also, if I might have leave of the House, with respect to these hours, to have the Friday rules apply to those sittings between 5 p.m. and 6:30 p.m. on Thursday and Friday and, presumably, the House will adjourn at 6:30 on Thursday.

Mr. Speaker: Is there agreement of the House for Wednesday and Thursday, between 5 p.m. and 6:30 p.m. to apply the Friday rules to those two days, which is no quorum and no votes. Agreed? *[Agreed]*

Mr. Chomiak: I wonder if I might have leave to change the order of the Estimates on the Estimate order sheet that was tabled in the Chamber yesterday, that I might have leave to move Education, Citizenship and Youth in the Chamber to be after Labour and Immigration but before Science, Technology and Energy, and that only for today, in Room 255, at 5 p.m. Conservation will take the place of Agriculture, Food and Rural Initiatives from 5 to 6:30, and tomorrow in Room 255, Agriculture, Food and Rural Initiatives will continue in Room 255 as per the schedule.

Mr. Speaker: For clarification for the House, the honourable Government House Leader, when you were proposing the sittings extend from 5 to 6:30 on Wednesday and Thursday, did you also include no sitting on Friday? Okay.

So for clarification of the House, there will be no Estimates sitting for this Friday. We ask for a clarification of the House.

Okay, for the information of the House, today from 5 to 6:30 p.m., there will be a change in the Estimates from Agriculture and Food to Conservation for today only. Also, to change permanently on the Estimates order, that Education, Citizenship and Youth will now follow Labour and Immigration, and that's a permanent change. Okay?

Mr. Chomiak: Mr. Speaker, I thank all members of the House for their co-operation and the Clerks and yourself for working a way through this.

I wonder if the Chamber might dissolve into Committee of Supply or resolve itself into Committee of Supply or dissipate into Committee of Supply. Thank you, Mr. Speaker.

Mr. Speaker: The House will now resolve into Committee of Supply.

Deputy Speaker and the Chairs, please proceed to the respective rooms that you will be chairing.

COMMITTEE OF SUPPLY (Concurrent Sections)

INFRASTRUCTURE AND TRANSPORTATION

***** (15:00)

Madam Chairperson (Marilyn Brick): Will the Committee of Supply please come to order. This section of the Committee of Supply will now resume consideration of the Estimates for the Department of Infrastructure and Transportation. As had been previously agreed, questioning for this department will proceed in a global manner.

The floor is now open for questions.

Mr. Larry Maguire (Arthur-Virden): I want to welcome others that have come in for the day on water resources and water services–

Madam Chairperson: I'm sorry to interrupt you. I think all the individuals who were at the table are still the same.

Is there someone additional? Okay.

Just prior to that then, what I will ask is if the minister, just for a review of the members who are here from yesterday an introduction of any new members who have joined us at the table. That would be excellent. Thank you.

Hon. Ron Lemieux (Minister of Infrastructure and Transportation): We have the general manager of Water Services, if I am using the correct title, and that's Mr. Dick Menon.

Floor Comment: An engineer?

Mr. Maguire: I would like to welcome Mr. Menon as well.

Before we get to some of the questions, there was one that I got in just before the bell yesterday in regard to an upgrade or an update, I guess if you would, from the minister on, I believe it was the No. 10 bridge, No. 10 highway, bridge work that was done in the summer. I just wondered if he could indicate to us what was done, the final results, when it was opened again. I know it is open, I was over it the other day. Just an update on it.

Mr. Lemieux: Two things: One, I'll comment on the bridge shortly, on No. 10 south of Brandon, but there was an outstanding question related to staff and the amount of people that the department has hired in '06-07. We hired 388 people in '06-07, and to date in '07-08, the department has hired 161 people.

With regard to the bridge, we replaced two sections of failed concrete on the bridge. The Member for Arthur-Virden is correct. It is now open and being used.

Mr. Maguire: Just for a little more clarification, when the concrete block fails like that, can the minister elaborate on just whether that's in the rebar that's in the bridge or just what structural defect becomes obvious or becomes aware or how do they become aware of those kinds of defects? Can he elaborate a little more on what they mean by failed concrete?

Mr. Lemieux: A point of clarification. Is that the bridge we're talking about on No. 10 or this just any bridge in the province?

Mr. Maguire: Mainly on this particular bridge. I suppose it's the same–well, actually, it's probably different in each case, but if you could give me an indication on this one.

Mr. Lemieux: In the case of this particular bridge, a hole was punched through the deck and the concrete piece or section failed and that piece had to be replaced. This is not always the case, but in aging bridges and other structures, this happens from time to time. That was spotted, and of course action was taken as soon as possible to rectify it.

Mr. Maguire: I was just wondered if the minister could comment on rebar failure or that sort of thing. Sometimes the concrete falls off with these issues, off the surfaces. Were there rebar failures?

Mr. Lemieux: Well, I've been advised that this was a case of just the concrete itself punching through. I can clarify that with staff, but there are various reasons why bridges are repaired. I'm sure the member appreciates this. I'm not in engineering with regard to the specifics or the technicalities related to bridge failures or deck failures, but I will enquire with staff to find out in this particular case was it more than just concrete or was it also rebar? I've been advised it was just concrete that was punched through, but I'll clarify it while the member is asking his follow-up question.

Mr. Maguire: Yes, I'd just like to take a moment to let the minister get the answer. I would just say that, as I said earlier, there are likely differences in the reasons that there are failures in bridges every time something like this comes up, and if he could just confirm that for me. I would assume this is different than some of the other bridges that have failed around the province.

Mr. Lemieux: Well, I thank the member for the question. I've consulted with staff and they've said in this particular case it wasn't a matter of traditional rebar corroding, for example, the traditional rebar that's been used in our bridges, whereas the rebar and the concrete punched through as a result of a truck or another vehicle going over this particular section. In this particular case, I've been advised that it is the concrete that was just punched through.

Just to add to bridges, I'm not sure if the member is aware that today we made an announcement over the next four years of adding $125 million that would be added to the Infrastructure funding. That $125 million is added to bridges to improve inspections, to improve bridges, whether it's rehab or other work that needs to take place. I know he has an appreciation for bridges by virtue of raising this as one of his first questions today and how important he feels bridges are.

The major focus of our restructuring of the Department of Infrastructure and Transportation is renewal. Renewal is what we feel is very, very important to our system, and I know that the priority is evident in today's announcement that allocates funds specifically to maintain and support Manitoba's bridges. This will lead, of course, to more inspections and more regular maintenance and more repairs overall as needed.

This is a huge amount of money because we're talking about, not only the $400 million, $2 billion, five-year plan, we're talking about an additional approximately $30 million being added per year, so it's approximately $430 million per year now that will be part of Infrastructure and Transportation's budget.

It's a large announcement. We feel that it's a proactive way to address our structures in the province of Manitoba. Again, with today's announcement, it'll mark a first in Manitoba's history, a total investment average of about

$430 million per year. During this time, we will see that average of $30 million invested in preserving, maintaining, and inspecting our bridges, but it's a 40-percent increase over current levels. Investment in Manitoba's bridges is possible because of an aggressive $4-billion multi-year highway plan that we put forward.

I know that all key stakeholders, including the Heavy Construction Association, Association of Manitoba Municipalities, and others are all working together just based on the 2002, 2020 Vision consultation process. We've moved forward since then, not as a result of recent incidents that have taken place in the province but as a result of consultations that took place in 2002. We realize that we have an aging infrastructure as do the other provinces in Canada, as does the states in the United States, with regard to not only bridges but our highways. So, with that answer, I look forward to the member's question.

Mr. Maguire: I absolutely knew that sometime this afternoon the minister would have a chance of remaking his announcement. I appreciate that announcement, and I think all Manitobans will in regard to the kinds of dollars that are being made available. I may have a few more questions in that area later.

But yesterday I had indicated that I wanted to have a few questions and some time on the Water Services Board, and so, with the minister's indulgence, I would try to go to some of those questions just a little bit on that department.

I appreciate Mr. Menon taking time to be here today as well as the lead staffperson in that area. I note with interest in this department that there are a great many projects. There're always more requests for projects than there are funds to go around on these issues, and as our aging infrastructure continues to age, there will be more need for, I believe, the kinds of waterfication that we're seeing in some areas of Manitoba and the kinds of sewer and water needs that we have, never mind the over a billion dollars that we need in the city of Winnipeg alone to take care of some of the needs there.

As I've stated publicly a number of times, we can have the best roads in the world leading to all of our communities, including Winnipeg, but if we don't have good water and sewer facilities in those communities, then it's very unlikely you're going to attract new citizens, retirees, or businesses to those regions. So I think it's doubly important that we have, I guess, a sound plan on how to develop and proceed with the development of water and sewer needs that we have throughout the province of Manitoba. I know that those are some of the major projects that this area of the minister's department deals with.

First of all, I wondered if the minister could just provide me with the number of projects that perhaps Water Services is presently dealing with across the province of Manitoba.

***** (15:10)

Mr. Lemieux: Well, let me just say first of all, before I answer the member's question, I just want to thank him very much for allowing us to ask Mr. Menon to come in from Brandon, and that's important, but even though we're willing to go global, you know, to give us a heads-up as to who we would need some assistance from to help us with the answers. That was important because Mr. Menon would be able to plan his day and so on. So I thank the Member for Arthur-Virden (Mr. Maguire) for that heads-up as I am sure Mr. Menon does.

There are a lot of projects, a huge amount of projects, and as a provincial government, I would agree in total with the comments made about how important water is and sewerage issues are and water treatment is to the province of Manitoba. We've taken many initiatives, whether we're dealing with phosphorus or nitrogen into our great lakes or whether or not we're talking about sewer and water projects in each community. We know that if we're asking people to retire and stay in their communities–whether it's in rural Manitoba, northern Manitoba or indeed, Winnipeg–we would, and they expect to, receive services dealing with water and water treatment and sewage treatment.

Just to directly mention some of the projects, and when I say they're almost too numerous to go through all of them, I will try to go through some and maybe highlight some.

The sewer and water projects again, these are currently being worked on: the one in Gimli we're talking about, waste water treatment, the phase 2 completion as well as waste water treatment phase 3 start-up; and we're also talking about Grandview, Manitoba, a new waste water treatment plant; also looking at Lansdowne and Arden, a water and sewer system. Also, we're looking at MacGregor, a regional water supply; Melita, which the member will be familiar with in the corner of the province that he is, resides, new waste water treatment plant and reservoir as well. Also, we're looking at the park in San Clara, a lagoon; the city of Portage, a waste treatment plant upgrading; also, in the R.M. of Portage la Prairie, water and sewer system at Peony Farm; St. François Xavier, water and sewerage system extension.

Also, we're looking at Springfield and Anola, which is, I understand, the community celebrating an anniversary. This is related specifically to a boil-water order that took place in that particular community and that's being addressed. Also, Springfield regional waste water treatment system and the community of Whitemouth is also receiving a water supply booster station, and there are water development issues related to regional water lines and this is very, very important in Westbourne and Wallace and Stanley and Portage and Grey, Yellowhead region as well. There are other miscellaneous water development and regional water line supplies as well.

New projects, Gimli phase 4 we're currently looking at, Minnedosa as well as Flin Flon, and the projects that I've just mentioned are very important to these communities. We take a look at the community of Roblin, for example, a water treatment plant upgrade; Shoal Lake, Manitoba; The Pas; Plum Coulee; Lac du Bonnet; Franklin; Dominion City. A lot of these projects are truly important to these communities, and we know that the communities, generally the ones that need more work, this program is oversubscribed. It always is, no different than community places grants or other programs that we have in place in government.

We talk about aging bridges, aging infra-structure, overall aging transportation networks, but we also have a system that's aging, that many people do not see and that could be sewer lines under the ground. People don't see that. They might see a bridge that is having some difficulty and is in stress, but you don't see the sewer lines and water lines that are running under the ground that have corroded over years of time and of use. It's something that's very important to us as a government and we know that a program like this is oversubscribed. Yet I know that Mr. Menon and people in Water Services branch as well as the Water Services Board are trying to make long-range capital plans as well as taking a look at the short-term issues they need to address. They need to be thanked, and I'll publicly thank them now for all the hard work they've done with managing a budget that is often oversubscribed by many, many times the amount they have.

Water has become an important issue. I would argue not just recently but over the last numbers of years, and we as a government are not only interested in taking care of the roads and highways and bridges in our province, but also feel that water lines and sewer lines and treatment are also equally as important to the citizens of its province. They expect us to be investing. I use the word investment because it's not cost; it's an investment that we place in the future of our province and with young people in our province. Thank you.

Mr. Maguire: Madam Chairperson, I know I didn't expect the minister to go through a plethora of the listing of them, but I would ask him if he could provide me with a list of the present projects that might be on the go in Manitoba from his department. That would be helpful to help follow as well.

Mr. Lemieux: I would just like to make sure I give the member an updated list, and we'll try to get that to you in the next number of days just to make sure the list is updated and everything is correct.

Mr. Maguire: I know there are particular projects that I and some of my colleagues may want to ask a few questions on this afternoon. I wonder if we could do that for both the waterfication projects that are on the go in Manitoba as well as some of the sewer projects and lagoon work that's being done as well.

Mr. Lemieux: Certainly, Madam Chairperson, anything that's part of the public record. I'll be pleased to do so.

Mr. Maguire: Which raises some concern by the minister stating that it's anything that would be available to me from a public perspective, does that mean that there are–could he just qualify that? I mean I'm assuming that there are projects on the go that they're in negotiations with. Is that what he means, that those aren't available?

Mr. Lemieux: Well, there are communities that have come forward. I've mentioned the program, as he has, that it's oversubscribed. There are many communities that are coming forward all the time, you know, raising issues related to water or sewer, or sewage treatment that are really in a state of discussions. I mean there is no–you know, I mean they've either applied and have not been approved or indeed they may be actually looking for a bump-up in infrastructure because costs have gone up, whether it's dealing with steel or concrete or asphalt. All costs have gone up and these costs have also–you know, people have been challenged with these costs of their projects going up.

So there are a lot of discussions going on. That's all I meant by that. I mean, we're going to provide the member with everything that we have.

Mr. Maguire: Can the minister indicate to me whether there's a set sharing program that he has with municipalities and the federal government on the costs of these projects in regard to the sharing of the cost of the projects? Is there a formula that's used in the sharing of those? Are they all a third, a third, a third with rural municipalities and the federal government, or are they negotiated.

Mr. Lemieux: Well I understand the sharing is on rural pipelines, for example. There is that kind of sharing. That's my understanding, the one-third, one-third, one-third.

***** (15:20)

Mr. Maguire: I just wanted to clarify that, Madam Chairperson, as well.

Can the minister indicate to me with all of the projects that are coming forward what sort of mechanism he or his department uses in regards to which ones would go forward, which ones would wait? Is it a first come, first served on the list, or is there a–I know there will be emergencies and priorities that might come into that sort of thing, and so can he just indicate to me the pecking order, I guess, that's used in regards to how you determine which ones will be done first?

Mr. Lemieux: Well, thank you for the question. I think it's good for the citizens of Manitoba to know that there is a point system that's used. How the point system really works is that there are issues related to public health, environmental issues. For example: documented problems and water shortages; boil water; septic breakouts; septic breakouts, as I mentioned, in different emergencies. Also, there are first-time services for some, potential concerns and problems to meet legal requirements. There are also economic benefits; there's also a point system related to applications; benefit to the province, for example; benefit to the municipality; water conservation measures; innovation wetlands and effluent irrigation. That's another area.

There's another category which talks about meeting certain standards. Also, water and sewer maintenance extensions are part of it, water and sewer main renewals. Once the point system is looked at, it goes to the Water Services Board, and the Water Services Board makes the decision. Now, it's not an easy decision, obviously, because if it's over-subscribed, you're taking a look at some issues related to the point system that address the challenges these communities have. But the board also needs some flexibility, because there might even be emerging issues that they have to deal with in an expedited way, so there is some flexibility built into it. But the point system has worked well. I would say that most municipalities really appreciate the work that Dick Menon and his staff do on a day-to-day basis. I can't stress the fact that not only he personally needs to be thanked, but they do a tireless job trying to work on behalf of our communities.

Mr. Peter Dyck (Pembina): Just the comment you made regarding the sharing of the water and rural municipalities, I'm thinking specifically of the R.M. of Stanley which–now, the other side of it is they were designated as the fastest growing rural municipality in all of Canada last year. But, anyway, regarding the waterfication of the rural municipality, my understanding from the local council is that the federal government has their money there. They have their money ready to go, but it's the Province who is not prepared to continue with the water bringing it to the rural residents. Now, is that accurate or is that not accurate, or where are you at with that one?

Mr. Lemieux: Well, I thank the MLA for the question. I know that his federal cousins appreciate the question, but, quite frankly, the federal money is not there, PFRA money for this particular project. Parts of it have been done, as I understand it, but the federal portion of the dollars currently are not there.

Mr. Dyck: Okay, just to clarify then, the provincial money is there, and they would be able to, if they could access the federal money, then they could move ahead. Am I understanding this correctly?

Mr. Lemieux: Today's dollars and the dollars we have have already been prescribed. But, you know, if they do come up with the money or if their money is there, they certainly would go through the processes that they would have to go through. It's not a slam dunk. It's not just automatic just because someone has the money, just saying, yeah we've got the money now, let's get it done. Thank you.

Mr. Dyck: The other question I would have is regarding the Pembina Valley Water Co-Op and the need for water in order to be able to service the residents along that–there are all the communities, and that's anywhere from Emerson through to Altona and Morden and Winkler. I think even Carman's a part of that whole loop.

But, anyway, could you tell me where they are? I know that at one point in time they were looking at drawing from the Sandilands, I believe it is. Can the minister tell us where that is at right now, please?

Mr. Lemieux: Thank you very much for the question. Just wanting to clarify this issue, they have not come to PFRA or to the federal government agency or to the province with regard to this project. There are groups that are pursuing this, but, as I understand, there's a lot of discussion going on, but they have not come officially to the Province or to the federal government with regard to this project.

Mr. Dyck: Just one more question then. So would you suggest that they come to your department and pursue this? Because I know that in discussions with the city of Winkler and the Town of Morden, and you know the growth that's taken place there that this is really one of the concerns that they have. So, if we need to look at another ministry as to where it's been at, we'll do that, but, just was asking for a suggestion.

Mr. Lemieux: Well, as a provincial government, we're open to having dialogue and discussions and consultations with all communities in Manitoba. If they have challenges around water or sewage treatment or effluent reduction, I mean, we're open to having those conversations. I know the people from PFRA and the federal government are as well. But we don’t have a crystal ball and we can't–you know, we're not able to read into that what they want or what their needs are. So we'd be pleased to talk to people about it.

As the member knows, on these issues related to Water Services branch or the Water Services Board many, many projects are oversubscribed and have been for a while. Yet we know how important water is to communities all over the world, quite frankly, not just in Manitoba. It has become and will become a more important issue in days and years to come.

Mr. Maguire: I just wanted to follow up on that. The federal government makes the dollars available through the PFRA and I know that there's an oversubscription of those funds.

In regard to that, when the prioritization of projects takes place because there are federal dollars involved through PFRA, does PFRA or the federal government become involved in much of a say in regard to the prioritization process that the minister was pointing out to me earlier?

***** (15:30)

Mr. Lemieux: Well, before I deal with that question directly, I'll state this: that agreement is coming to an end. I believe it's March 31 '08. So anything the rural MLAs can do–and I know the Member for Arthur-Virden was a strong advocate dealing with issues of agriculture in days before he became an elected provincial politician. He knows how important these issues are. Yet this program, I believe it's called the National Water Supply Expansion Program. I know the member opposite knows how important this is as well as his other rural MLAs, as I am, and this program really needs to continue. Anything he can do or his colleagues can do to speak to his political cousins in Ottawa to stress the importance of this, or even to members of Parliament of the governing party in Manitoba, would really be appreciated because we've tried to stress from our side how we want this program to continue.

No different, actually, quite frankly, than Prairie Grain Roads. I know he has an appreciation for that as well. The Prairie Grain Roads Program expired. Now you've got this Water Supply Expansion Program expiring. So we see a lot of these programs going by the wayside, and I'm just wondering how the member opposite feels about this program overall, or what he knows of it, or what does he think, whether it's worthwhile pursuing.

Mr. Maguire: I guess my comments would only be that in order to support our rural waterifications as well as those in the north and in the city of Winnipeg, all of our urban regions as well, it's more important that we look at the province as a whole in those areas.

But the federal dollars that the minister gets, albeit if this program ends in May, have they been able to obtain the dollars from the federal government for the projects and the work that's been done so far? Has it come in as the work is done or does it come in at the beginning of the project to be used by the Province at that time?

Mr. Lemieux: We get the money essentially up front from the federal government, which we're very much appreciative of. Then we match projects up against that.

There is a working committee, a working group, I'm not sure of the proper name, but Manitoba puts two people on this management committee, and the federal government puts two people on the management committee, and then they are able to approach the dollars and projects in that manner. We do appreciate–don't mistake what I'm saying, but we do appreciate the money that the federal government is allocating to this program. I wouldn't want to leave the impression that we're not. But in my travels throughout the province of Manitoba, whether it would be north or rural Manitoba, I hear how important this is to the Association of Manitoba Municipalities, as well as to rural Manitoba, northern Manitoba. They really feel this program has served us well.

We, I believe, have taken advantage more than other provinces. That's why it's more specifically important maybe to us than other provinces with regard to these dollars. That's why I think it's imperative that we as elected officials, no matter what political stripe, really push for the extension of this program, not just an extension but the revitalization of this program. I think it's really important that we pursue it.

Mr. Maguire: I'm looking on page 117 in the Estimates book in regard to the sub-appropriation 15-5, just in regard to the minister's comments. It says: "Less: Recoverable from Rural Economic Development." There's $2.9 million; to be exact, $2,984,000 there.

Can the minister indicate if any portion of those $2.9-million recoverable comes from any of those particular programs that he just alluded to?

Mr. Lemieux: On that page 117, the money we're talking about is Manitoba money. There is no federal money within this package. Last year there was approximately $5 million that we had received from the federal government.

Mr. Maguire: Can the minister just indicate where the 2.984 then–I know it comes from rural economic development, I'm assuming. Can he just outline the nature of those funds?

Mr. Lemieux: These dollars come from MAFRI. These are MAFRI dollars. They come from Agriculture and rural economic development. These are dollars that go toward the water and all the issues related to water that we're talking about on this page 117.

Mr. Maguire: Yes, as these dollars come from the Manitoba agrifood and rural initiatives, then would they be–I'm assuming, they would all go into sewer-water projects as opposed to drainage or that sort of thing.

Mr. Lemieux: Yes.

Mr. Maguire: The comments in regard to PFRA, the federal dollars that would go in there, those would be national dollars that would go into the Prairie Farm Rehabilitation Administration assistance across Canada. How does the minister negotiate with the federal government in regard to how many dollars Manitoba's share would be of those dollars? Is it based on population, need, miles of line or can he indicate to me what the prioritization mechanism would be?

Mr. Lemieux: The dollars were part of the Ag Policy Framework agreement, and it was a five-year plan. There were so many dollars allocated into it. We were allocated, essentially, I would think, because of our rural needs and the high needs we had in rural Manitoba. That's how we were able to access these dollars through this five-year Ag Policy Framework agreement. It was initially about $15 million we received out of a larger pot. The agreement stated that if other people aren't using the money, you could try to tap into other dollars if you can. But we do have a large need in Manitoba and that's how we accessed it, through this five-year agreement.

***** (15:40)

Mr. Maguire: I appreciate that. It gives the minister about $3 million a year then, the $15 million received through Manitoba, roughly to work with. I know that if that's the federal third and we match that as a province and the municipalities work on it as well, it gets a small portion, every year, done of the kind of work that we need. But it is certainly, I'm assuming, a help to get those projects on the go.

The minister has indicated to me a little bit about prioritization. I know that there is a need for more funds to continue with this type of project, and I know as much as the minister's just earlier elaborated on his announcement of $125 million for infrastructure for these kinds of projects on bridges and not on water and sewer albeit, another type of announcement, I believe it was from the federal Minister of Environment, yesterday talking about $30 billion in regard to some environmental uses for those funds. I'm assuming that from that there will be funds coming forward, not from Manitoba, not all obviously, and if it's based on the similar kinds of need, there'll be, hopefully, large dollars available there for the city of Winnipeg and all of rural Manitoba as well because of the huge need that's there.

I think they named Montreal, Victoria and one other city, I believe, in today's news about dumping raw sewage still right into the rivers, into the main waterways, and the number of those areas. I think we could include Winnipeg in that, as it happens from time to time with heavy rainfalls and one thing and another in the province here as well.

So my question is just how the minister will be following up on trying to attain some of those dollars, and how can we use those in water services to the best of our ability?

Mr. Lemieux: Just to clarify what Minister Baird was talking about, that $33 billion is a national infrastructure program overall. It's not just to deal with environment. That's the large pot of money dealing with all kinds of issues and all kinds of challenges that we have in Canada. So, obviously, Manitoba wants to receive its fair share.

We talk about in Manitoba, for example, on the Transportation side where we've allocated gas tax or motive fuel tax dollars back to Transportation infrastructure. It's been talked about now almost two years. It will be two years this January, I think, that the last federal election was held, and now-Prime Minister Harper then was Leader of the Opposition, mentioned that provinces would be getting dollars very similar to what was announced by the Martin government to municipalities in that these dollars would be used for various infrastructure programs. Now what Minister Baird was talking about is tapping into that large pot of money that the Prime Minister and their government have made the previous announcement on.

Mr. Maguire: Yes, in regard to specific projects, my colleague from Carman, I'm going to defer to him to just ask on a specific project in his area.

Mr. Blaine Pedersen (Carman): Madam Chair, specific programs, our project is the Lavenham community, southwest of Portage. They have a community well in place which services approximately 20 families. They've been told that under the Water Services branch, they will not be able to use a community well unless it is treated properly and monitored. They are willing to treat it. However, the cost of having someone certified to do the testing and travel costs are always a significant cost. They have been in touch with the R.M. of South Norfolk in terms of testing the water.

I should also add that there is a rural water line coming from Rossendale, but it'll cost each individual household about $10,000 to hook up which is very significant when they have an excellent source of water right now. So can you give me an update as to what's happening for Lavenham?

Mr. Lemieux: Madam Chairperson, first of all, let me just say, before I answer the question, I just want to thank the MLA for Carman (Mr. Pedersen) for the question. This is the first time in Estimates that he's had the opportunity. I will just make a quick, brief comment prior to getting involved in the politics of his own party, but I can tell you that the MLA for Carman before was a strong advocate for the area, raised all kinds of issues with regard to transportation and infrastructure issues. I just want to say, having talked to him briefly, I know that the current MLA will work just as diligently and as hard for his constituents. So let me just make that–without getting into the politics of all this, I just want to put that on the record.

Dealing with the community of Lavenham, we're certainly in discussions with them, with the R.M. of South Norfolk, which they're part of, and to extend water from the Yellowhead regional water supply. So discussions are ongoing and, as the member can appreciate, there are discussions going on on a daily basis with many, many R.M.s about their water quality.

Now, as I understand it, in a lot of cases it's not dealing with E. coli or the kind of contaminants that are in the water. Sometimes the water is just not a good quality of water. I guess I would ask the representative for Carman to maybe pose the question to the Minister of Water Stewardship (Ms. Melnick) because this is an area that the drinking water people I believe are involved in this particular area and this discussion. So it may be a question more appropriate to the Minister of Water Stewardship to address it.

Mr. Maguire: Well, Madam Chairperson, I just wondered if, from the minister's perspective, this wouldn't fall under water services. I don't know whether the Member for Carman can correct me, but, in regard to many water projects across the province of Manitoba that are being done on waterfication right now, they are dealing with drinking water as well. Wouldn't they, under the Water Services Board be certainly dealing with drinking water in some cases, if not all?

Mr. Lemieux: Just a point of clarification, if nothing else, is that the Department of Water Stewardship deals with the regulatory part of the water, but the capital infrastructure piece of doing the capital side, the infrastructure side is related to my department.

Mr. Pedersen: Madam Chairperson, in this particular case, it's not a question of water quality. The water quality is deemed to be safe; however, there are regulations about multiple use on a community well. I believe that falls under Water Services branch. The water quality is not an issue.

Mr. Lemieux: The issues around drinking water are truly important, and The Drinking Water Safety Act is under Water Stewardship. They're the ones to determine whether or not the quality of the water or the water itself reaches is at that acceptable level. That's Water Stewardship that determines that. We deal with the capital side of either transporting water or dealing with that capital infrastructure piece, but it's Water Stewardship that's responsible for The Drinking Water Safety Act. As the member pointed out, there's plenty of water. The quality of water is at issue, and it's Water Stewardship that is responsible for The Drinking Water Safety Act.

***** (15:50)

Mr. Maguire: Just to follow up, I believe the Member for Carman indicated that it wasn't a water quality issue. It's delivery of the product and that sort of thing, so it looks forward to the future development of it.

I wanted to just, while I have a few comments in regard to the prioritization that we talked about earlier, and I know that we've got to be fair around the province in regard to the minimal dollars. Regardless of however many dollars they are, they're a minimal amount of dollars because there's never enough to go around in these projects as has been pointed out.

In regard to waterfication programs in rural Manitoba, in a lot of cases, industry may develop lines that would go straight to an industry in an urban or a rural community area. But in regard to human need, the water will go on to, perhaps if I could use the example of farm yards as well as industries, the water all goes down the same lines in rural areas because, of course, that has to be how it's put in from a cost perspective. Can the minister indicate to me just if there's much of a difference in how urban lines or projects are chosen over rural?

Mr. Lemieux: Just on clarification, there are two pieces to this. The one that's dealing with rural, PFRA plays a role and has a pot of money that can be tapped into; dealing with urban, it's provincial monies only, and it still goes through the management committee and then goes on to the board which will make decisions. My understanding, anyway, is that we primarily looked at existing homes and existing development, not at new development, for example, new developments that may be coming up and need water supplies and so on, so it's always been geared to current or existing development.

Mr. Maguire: I guess, when you're looking at things, it's simplistic to look at just the population base. You've got a rural municipality with not a huge population, and some of them are pretty thin, in regard to a community that might have a thousand, 2,000, 5,000 people living in it which would sort of get a priority because you can hit more people with better water and that sort of thing. Of course, that would be an ultimate objective as well.

But I know in some cases most of the water that would go through some of the rural lines will end up in livestock or some of the smaller processing facilities as opposed to being used for human consumption. That's where I was going in regard to that. I would hope that we don't look at the number of people, I suppose, that may need the water in those areas as opposed to on a population basis as determining priorities in those areas because that's how we need to sustain the rural areas is to provides these kinds of infrastructure needs in their communities.

As I said earlier, you can have all the good roads you want leading to a community or a rural area or the city of Winnipeg for that matter, but without good water and good sewer facilities you're not going to attract the people or the business.

I know my colleague from Minnedosa has just a question in regard to a facility in her region. I would just turn it over to her to ask that question.

Mrs. Leanne Rowat (Minnedosa): Madam Chair, my question is brief, but I wanted just to get the minister's comments on record so that I know how to proceed with this issue.

I met with the R.M. of Whitehead on September 10. It's general practice for me before I go into session that I meet with my municipalities. In our discussion on issues, the water infrastructure project in Alexander or in the R.M. of Whitehead had been raised and there seems to be a grey area. There seems to be now an item that could be very costly, and the community is really concerned about how they fit in the costing of a plastic liner that has to be put in a lagoon.

So I'm wanting to know if the minister has had some discussions with staff on this and if he can provide me with some background on where the province is going in discussions with the community on this because I don't believe that, based on what I'm hearing, they really should be looking at an additional cost for the project based on decisions that were made outside of their control.

Another point with regard to the community is the fire hydrants. They really were of the understanding that they were going to be and wanted to have a town grade 1 and that would have definitely had an impact on their insurance costs. Apparently, when that part of the project was complete, they remain a town grade 3. So their underwriter standards were not met and obviously the ratepayers within that area will not see the benefits of an increased or an improved system of fire safety.

Those are the two points that I'd like just a comment from the minister on, if he can, in consultation with his staff.

Ms. Sharon Blady, Acting Chairperson, in the Chair

Mr. Lemieux: Madam Acting Chairperson, allow me to say that it's a pleasure to have you as an MLA for Kirkfield Park. This is your first occasion to be dealing with Estimates so just wanting to say congratulations to you personally.

Just a clarification about the community of Alexander and Whitehead, it's done. You mentioned about the lagoon and waste water, it's finished.

***** (16:00)

Mrs. Rowat: The community is asking–there seems to be an issue of the liner cost that was outstanding on September 10. Has that been resolved? The community has not received any correspondence and are concerned that there might be additional costs associated to their project.

Mr. Lemieux: Well, there could be some discrepancy with regard to payment and so on, but we'll follow it up and see what's happening because, my understanding–I've been advised that everything has been taken care of.

Mrs. Rowat: Could the minister elaborate on discrepancy with payment? Is there an issue with the costing of the liner and the responsibilities of the municipality or the province on that?

Mr. Lemieux: We'll follow this up and see what's happening with regard to this issue because, as far as we understand, everything's been resolved and that's where it stands.

Mrs. Rowat: I will follow up with the municipality as well, but this definitely was their No. 1 point of issues when I met with them the other week. So I just wanted to determine, since we have the staff here and the minister really wanting to check on the status of this. But if he's saying that things have been resolved, then there seems to be a communication issue and I'll go back to the municipality on that.

Mr. Maguire: Madam Acting Chair, I, too, would like to welcome you to the Estimates process, as well as we did yesterday, with the Member for Fort Rouge (Ms. Howard) as well, I believe it was.

So I want to just go back to the minister in regards to some of the issues around prioritization of the various projects and, of course, I would put a comment in that, you know, people want extremely healthy food today. It's becoming a bigger issue in all areas all the time, and so in regards to waterfication projects, I'll put my two cents' worth in for some of the rural water projects that are going on today because it probably–not probably–it has on environmental programs that I've looked at in the past, helped out in regards to healthier livestock and a number of other areas in certain cases, and so I would encourage the minister to continue to look at as many of those projects as he possibly can.

I know he does continue to work with the ministry and his department on making sure that we maximize as much as we can on those and also dealing with the dollars from the federal counterparts. I know that, at the present time, where he is indicating that there is about $3 million a year coming from the federal department which gives him about $9-million worth of projects. If I am correct on that, can he just expand on whether that's accurate or not?

Mr. Lemieux: Well, at the end of March, the program's over, and that's why I would ask the Member for Carman (Mr. Pedersen), Member for Ste. Rose (Mr. Briese), Member for Arthur-Virden

(Mr. Maguire) and many of the MLAs who are from rural Manitoba, to talk to the members of Parliament and to stress to them how important they feel a program like this is, because the program ends and it's done.

Mr. Maguire: I appreciate the minister's concern, but the question is to do with the $3 million would be roughly $9-million worth of projects this year and in the past?

Mr. Lemieux: I thank the Member for Arthur-Virden for the question. Last year, in fact, we spent more than what was the norm, probably almost I guess $15 million or five times the three. But I can tell you that, as I mentioned about being oversubscribed, the importance of this program shows there's about $200 million to $300 million out there that there's a request for. That's the kind of need that's there on the waterfication of Manitoba and so, again, I just want to reiterate. I'm sure I know he does know how important this is and that's why we need, quite frankly, all-party support to ensure that this program continues, very similar to Prairie Grain Roads. And it worked well.

I know that we have the MLA for Ste. Rose here at the table, that he knows from wearing a previous political hat on how important Prairie Grain Roads was and how that worked well with the input from Association of Manitoba Municipalities and others. So we look forward to all parties pushing, quite frankly, for the resumption of this program.

Mr. Maguire: I know that some of the projects that are on the go, and I just wanted to refer to one in my area and that is; well, there's two, and the minister alluded to one of them earlier. That is the community of Melita getting water coming into Melita from the R.M. of Albert, a good project. I know the town appreciates it and the work that's going on there. It looks like they may be at least looking at starting to get some of the infrastructure in place this fall before freeze up if they can and that's, I believe, ongoing.

There's also, of course, a major project in the R.M. of Wallace that's been undertaken and moving forward very well from their perspective, I think, at this point. There're always concerns about trying to link up with others to look at projects like that. I wonder if the minister can give me an update on both of those projects in regard to where they stand at this time.

Mr. Lemieux: Well, the member mentioned the R.M. of Wallace, and not to put a fine point on it, but there's about $8 million that has been spent with regard to the R.M. and there's an additional $73 million we're looking at, and so this is a huge project for that particular R.M. I know the member raises the point that how important it is that these projects are for rural Manitoba. I just wanted to reiterate that these projects are taking place all over the province, not in one particular area, but all over rural Manitoba.

***** (16:10)

Mr. Maguire: Yes, I understand that. I guess the question that I was looking at was can he provide me with, just with a little bit more detail on where each project is at? I know that there've been dollars spent on each of them, but I believe–actually I should clarify that, on the Melita project just to know where it's at in regard to how much work will be done this fall.

Mr. Lemieux: As of about the middle of September, about 75 percent of the Wallace project is complete. But I think an important point to make as well is that when you're looking at Wallace and the completion of Wallace, there are many R.M.s that have been looking at regional water systems and that includes Pipestone and rural water for Pipestone. So there are many opportunities. Once these lines are completed, you start looking at regional water supplies, which more and more R.M.s now are looking at. Of course, R.M.s are also looking at sewage treatment on a regional basis, which, for many R.M.s would make good financial sense to look at water treatment or sewage treatment, effluent treatment on a regional basis.

So I trust that answers the question with regard to what the Member for Arthur-Virden asked. So Wallace is about 75 percent complete.

Madam Chairperson in the Chair

Mr. Maguire: I appreciate the comments of the minister. I know that sustainable development is of huge importance. It's on everyone's mind these days, and I appreciate the initiative taken by the R.M. of Wallace and the people in that region and the co-operation so far from both levels of government on that. Certainly, I know that the Water Services Board has done an admirable job in regard to trying to accommodate the needs of this group of persons putting this project forward. But sustainable development–the more people you get hooked onto the lines and that sort of thing, the sooner we can make them, I guess, more self-sufficient, if you will, Madam Chair, from that end of it.

The minister has alluded to the R.M. of Pipestone, and I know from speaking with Reeve Tycoles there that they have, I think, proposals forward that they'd like to work with as well. My assumption is that, from what I'm told, they would get their source of water from Pipestone as it comes through the R.M. of Wallace. I wonder if the minister can just give me an update on where that proposal would be at.

Mr. Lemieux: The project that the MLA for Arthur-Virden is talking about is about an $8 million to $10 million, probably closer to $10-million project. Right now that PFRA program is coming to an end. It was always anticipated that there would be cost-sharing involved in a lot of these projects so the projects are in the mix. The dilemma is there's a huge question mark right over top of where the dollars are coming from. Mr. Tweed is the member of Parliament, I believe, for the area, and I would strongly recommend that the R.M. of Wallace and the R.M. of Pipestone talk to their member of Parliament about PFRA dollars and what's going to be happening to the program. I just asked that and I know that the member is a rural MLA as I am, and we're all concerned with a program like this because it truly benefits directly primarily rural Manitoba.

Mr. Maguire: I thank the minister for that. I know it's been kind of talked about here that we would take a bit of a break, I think, in 15 or 20 minutes. I know the Chair and I have chatted about this just as a situation with staffing for five or 10 minutes only, briefly. I'm just raising that now instead of doing it at 4:30 roughly, see if the minister has agreement in regard to a short break at that time, just five or 10 minutes.

Mr. Lemieux: Well, I don't know about the Member for Arthur-Virden, but I drank my quantity of water over the last little while, so I know I would have an appreciation for taking a short break, as possibly others would. But since we're dealing with water issues, I'm not sure what time that would be. Maybe we could just get some clarification from the Chair as to what time that would be.

Madam Chairperson: If it's the agreement of all members, we will take a 10-minute break at 4:30, from 4:30 to 4:40, just to allow members to have a short recess in light of the fact that we are going later this evening. Is that agreed?

Mr. Maguire: That's agreeable, Madam Chair. We may have a few questions of Water Services after that, but I think we'll move forward. Not being one to want to relieve the pressure off the minister here, I want to keep the pressure on him, but I appreciate the answers that he's been giving us as well.

We've spent quite a bit of the afternoon talking about water and the need for good water, so all humour aside, let's move forward.

The Member for Minnedosa would also like to ask a question on waterfication issues in her region. I'll turn it over to her.

Mrs. Rowat: My question for the minister is in relation to the R.M. of Saskatchewan. As I had indicated earlier, I've been meeting with my communities, and, as I'm flipping through my folders, I'm coming across the issues that relate to your area.

They're looking at establishing a rural water pipeline and did a survey within their community and asked the community to get back to the council by September 1. They've indicated to me, and I've been aware that they've been working with Water Services Board and PFRA for a number of years on this. I believe that water is obviously something that is very important for any community. I would like to know if the minister can provide me with some feedback or the status of this initiative for my municipality. Then I would take whatever he has back to my municipality and work with them to make sure that this project does become a reality for them.

Mr. Lemieux: I thank the Member for Minnedosa for the question. There are large issues in rural Manitoba in this particular case with trying to do joint projects and trying to tap into different water sources, whether it's R.M. of Saskatchewan trying to get water from Minnedosa or whether or not they have to come from Oak River or a different direction. I know the Water Services branch has been working and meeting with the R.M. of Saskatchewan trying to get this nailed down.

We're talking about a $5-million project, which is huge money, but there are so many communities in Manitoba that all have their $5-million, $3-million, $2-million projects. Certainly, Water Services branch and Mr. Menon and others are trying to address this. But they're certainly working with the communities trying to find out which is the best source, where that water should come from, and then, once that process has taken place, to look at where the dollars are going to come from.

There is a process that I talked earlier about and a prioritization system that we use. When I say we, I mean Water Services branch and Water Services Board. How do they determine the projects and where they fit. I won't go through the criteria or the point system, it will be on Hansard and people can look at that. I went through the whole list of how projects are determined and how they're selected. Just to capsulize it, it's the water source. Where is it going to come from for the R.M. of Saskatchewan? Is it going to come from Minnedosa or does it have to come the other way from Oak River? That's where the discussions are right now.

***** (16:20)

Mrs. Rowat: Madam Chair, I appreciate the comments. I will reflect back on *Hansard* to the previous question that was placed, and I will work with my municipalities to make sure that due process is followed in that regard.

Yes, I do understand and appreciate that there are different ways, there are different sources of access for those communities for water. But, again, I know that there are a number of communities that are looking for high-end infrastructure. But these are my communities, and it's my prerogative to fight for them. So, I do appreciate that.

Mr. Maguire: I just wanted to return to the questioning that I was doing in regard to that R.M. of Wallace project, in Pipestone.

I know, like the Member for Pembina (Mr. Dyck) where he was looking at the type of project that was coming forward there for sustainability, the projects here–I guess I would ask the minister that–you know, I get the picture that he's talking about, with the PFRA wants everybody to lobby the federal government on that effort, and I have no problem doing that.

I guess the question there is, though, municipalities need to know that if they're lobbying the federal government hard as well–and I'm sure they would do that through the minister as well; he's probably been in touch with them to do that–where would the province be in regard to moving that forward? I know that certainly priority No. 1, I believe, would be to see the Wallace project finished. It's 75 percent complete now, and having that completed, making that project more sustainable, would be, of course, a benefit from having Pipestone on-stream, as–literally–I guess, from my perspective, that's how I would see it at least anyway. I wonder if he could just comment on being able to move forward with those.

Mr. Lemieux: Just on the point about dollars and pockets of dollars: you don't like to start a project and leave it half finished or three-quarters completed and not totally finished. There is a challenge, though, around the dollars, the PFRA dollars specifically, is that not knowing what's going to happen with that, because as the program's coming to an end has created a huge challenge for us–and I'm sure he can appreciate that; I know he has stated that this program is valued, and I believe all his colleagues in rural Manitoba would say the same. As we've gone through a number of questions from different R.M.s, so I can tell you that we have made–municipalities are aware of this issue, quite frankly, and they're very concerned with it.

AMM is also aware of this issue. I'm not sure where they've gone with it, whether or not they've officially written or verbally contacted the federal ministers to make their case, or federal members of Parliament, but I know that AMM certainly is aware of it. They're very concerned about the issue that the PFRA's program is going to be finished and completed as of March of '08. The municipalities are as well, because they can see how many projects are out there and they realize that there is a priority system, there's a good due diligence process laid out, but a big question mark over the dollars from PFRA.

Mr. Maguire: Just for clarification: these are not funds coming out of the Manitoba-Canada Infrastructure Program through the PFRA?

And can the minister give me some indication of his responsibilities in regard to whether he can use those funds in the areas of water and sewer as well?

Mr. Lemieux: I appreciate the question that the member is asking. Certainly, PFRA was one avenue, but it was the Agricultural Policy Framework agreement that was covering a lot of the water extension, the water projects we have been talking about.

Dealing with the Canada-Manitoba Infrastructure dollars, certainly, it's always possible, but there's a huge list of projects that we're talking about when we're talking about the Canada-Manitoba Infrastructure Program. There need to be some criteria, I guess, developed around that. But I understand where the member is coming from, that he's looking at where is there another pocket of money for this, and currently there is a huge demand, of course, on the Canada-Manitoba Infrastructure grants themselves as well.

There's a secretariat. There's a secretariat very similar to the working group we talked about that goes to the Water Services Board and then presents what they have found and their recommendations. Also, there's a secretariat, a Canada-Manitoba secretariat, that also looks at Canada-Manitoba Infrastructure monies as well.

Mr. Maguire: I guess I'll come back to that later, but I just have another question from the Member for Minnedosa.

Mrs. Rowat: I'm not sure if this falls under your area. If it does, I hope you have a good response for me. It was another community, the R.M. of Minto, and there have been a couple of issues. One of them is integrated water management plans. Does that fall under your jurisdiction? I guess that's the question and then I'll proceed.

Mr. Lemieux: It's actually the Department of Water Stewardship that the question is better directed to on this particular issue.

Mrs. Rowat: I'll still put on the record, though, the concern that they've faced. Obviously, these development plans are highly technical. There are a lot of issues or a lot of things that need to be dealt with, water flows, et cetera, and I guess what their concern is is that there seems to be a breakdown in resource supports. There seem to be challenges every time they need to get references or supports in a different area, staff change.

I want to put on the record that this is a serious issue when communities are trying to move forward and trying to meet the plans the that government has set out, and there seems to be some challenges in supports available to them.

Mr. Lemieux: I thank the Member for Minnedosa for the question. I'll pass this on to the Minister of Water Stewardship (Ms. Melnick), just in case she doesn't have the opportunity to raise the question. I'll certainly mention it and pass it on to the minister, that she's raised a concern about it. I'll definitely take it upon myself to pass that on to the Minister of Water Stewardship.

Mr. Maguire: We have another question from our Member for Emerson (Mr. Graydon) as well, if we could go to him, please.

Mr. Cliff Graydon (Emerson): A question for the minister: We all realize that the limiting factor to development in any area is water and more especially in the Red River Valley. We depend a lot on the Red River, but we know that the Red River can get quite low and may not be able to supply the water that we need. Droughts we find are a lot more devastating than what floods are.

So, Mr. Minister, as an alternative, I understand that the Red River Valley co-op or corporation, Pembina water corporation applied for a licence to pipe water from the eastern side of their constituency to the valley. Could you tell me where the status of that application is?

Madam Chairperson: The time being 4:30 p.m., as previously agreed unanimously by the committee, we will take a brief recess until 4:40 p.m.

As announced in the House, the committee will be sitting until 6:30 p.m. As a reminder to all members, the time from 5 until 6:30 p.m. we will be operating under Friday rules, meaning there will be no votes and no quorum. Thank you.

The committee recessed at 4:30 p.m.

The committee resumed at 4:40 p.m.

Madam Chairperson: Will the Committee of Supply please come to order. The floor is now open for questions, and the honourable Member for Emerson had asked a question prior to our recess. You can restate it if you wish or I can just turn it over to the minister.

Mr. Lemieux: Thank you very much and thank you very much for the short break. I think a lot of us appreciated it, including staff and others, and thank everyone for their co-operation.

A quick answer to this is that the Pembina Valley Water Cooperative, PVWC, handles water for–some people around the table are not familiar with the area, primarily west of the Red River, but there's a portion that's in the south just on the east of the Red.

They applied for an environmental licence from the Minister of Conservation a while back, and it was referred to the Clean Environment Commission. The problem with the water, as I understand it, is that when you pump, you're going to draw up a lot of saline water. I guess there's and intrusion into the good water so what's happened is the PVWC has pulled their application for the accessing that aquifer. Basically, that's as much as I know of it, and I'm not sure if the MLA for Emerson has more to add on it, but I understand that because it was referred to the Clean Environment Commission and the problem was with the saline water intrusion and when you do the pumping, and there was a whole issue related to that. Now they've pulled the application with regard to accessing that aquifer.

Mr. Graydon: Mr. Minister, does that mean that the Clean Environment Commission would not issue the licence because I'm not aware of it being pulled?

Mr. Lemieux: Well, I've been advised and I understand that it was referred to the Clean Environment Commission and that it never–I don't think it ever got there. I think that the PVWC pulled their, you know, they essentially pulled their application and then–well, the point I should make is that this is probably a better question that should go to the Minister of Conservation (Mr. Struthers), quite frankly, because he has more details for the MLA for Emerson (Mr. Graydon), but because of that saline, the saline getting into the good water, to the good aquifer, because of the pumping that would be necessary and the kind of water that they need to draw, that created, you know–once people were understanding of this, they had to re-evaluate. Where do they go with this? The MLA for Emerson may want to ask the Minister of Conservation because I don't have any further details and nor does my department on where this is at or the process itself.

Mr. Graydon: I thank the minister for that. I am sure that if that pumping was going to pollute that aquifer, I would agree that it should be pulled. However, having recognized that fact or learned that fact today, the fact remains that the valley is in desperate need of a stable water supply for any future development. They are basically nearing a crisis situation, and the dependency of the Red River is, as you know, not a stable source of water.

Has the minister's department looked at any other alternatives, and I'm going to suggest that they may have, and if they have, what would those alternatives be for that valley?

Mr. Lemieux: Well, there are many Manitobans, unlike some of us around the table here, who live and are close to the Red River and constituencies border on the Red River. They would be surprised by the fact we're talking of lack of water. They're too familiar with hearing in the media and sources that say, like '97 and other years, that there is an overabundance of water, even just this past spring. People are more familiar with that side of it than realizing, you've got the Pembina Valley and you have other communities that have been there, because we know that it's cyclical, the water cycles, and the Red River may not always be full. In fact, it does get fairly low and people who draw off of it, as well as use the water in the region, know that there are challenges about this.

So your point and your question is right on. We know it, but there are many that would not, you know, have this understanding because they're not familiar with the concerns of the area. But my constituency of La Verendrye does border on the Red, and I do have an appreciation for that, and yet we're talking about further south. I know that–I believe it's called the PVWC–is looking at possibly Morris as another alternative, I understand, for a water source.

Now, to the best of my knowledge, we haven't been asked. No one has approached Water Services Board or staff about, you know, what's another alternative? Where do we go then? Again, I've been advised that that saline, the pumping they needed to do, would–I don't want to use the word contaminate–but would alter the kind of water that they would be getting, but again, its Conservation that would have more answers with regard to this, to that application and process.

Mr. Graydon: I'm getting there. Thank you.

Would it be appropriate, Mr. Minister, to look at some alternatives and one of them being the Pembina River through the Pembina Valley? It seems that it is a flooding issue. If I understand right, there has been a study done on this particular river at one time. Is that an alternative to the valley?

***** (16:50)

Mr. Lemieux: I have to tell you, as a minister of the Crown, and one of my first years in this building–which, it's a privilege to be here and I want to congratulate the Member for Emerson (Mr. Graydon) on your election–but I just want to say that Harry Enns, and you probably are familiar with Harry Enns, the Member for Lakeside. So Harry Enns, one of the first opportunities I had of discussion with Harry Enns, was to talk about putting up a dam across the Pembina River or possibly putting a dam structure on the Assiniboine and diverting water to the south, dealing with water retention and talking about those issues.

So I recall this well, because he, and yet he's not from the region but has a huge interest in trying to, well, raising the issue, highlighting the issue about water retention, as opposed to–we're always talking about expanding the floodway, dealing with floods. We often don't talk about the other side of the coin which deals with water retention. I firmly believe, in years to come, if the scientists are correct–maybe we won't be here in that time; some of these young MLAs may be around at the time–but we will, I think, have a challenge about water, you know, the water retention issue about holding water back, keeping water for days and years that are dry and how do we manage that.

So PFRA is not involved, of course, in dam building or putting up dams across the Pembina River and looking at that kind of an alternative. The reason why I mention that is because the Pembina River and the Pembina River Valley is very important, but PFRA is also important on how we work with water issues to the Water Services branch and board.

So I think everyone is looking at alternatives but I just reflect, I digress slightly, but just wanting to raise this issue that Harry Enns approached me one of the first days in this building and he raised this as something that possibly a new government may want to look at, and may want to consider years down the road. So here we are eight years later and there are still people raising this issue about water retention and possibly building dams, diverting water, those kind of things.

So I do appreciate your question, and government is looking at alternatives and taking it seriously as to what do you do about water retention.

Mr. Graydon: In regard to your comment on Harry Enns, he did come from that area. He was more familiar with the Red River probably than you are because he grew up against it.

However, on a point of water retention, I can only agree with you. The Pembina Valley has had a study done one time before and I would ask the minister and his department if they would be interested in sitting down with myself and some of the people in the Emerson constituency to go over that type of a proposal and see if it has merit today. It would involve working with our American neighbours as well. I know that sometimes you don't look forward to that; however, the water does flow north.

The Pembina River does cause a great deal of flooding from time to time and that water causes a great deal of problems in our province. So I think there's a dual benefit that could come from this type of a development. One of those would be recreation. The other would be water retention for the valley, and the other one would be for flooding and could also be used for irrigation.

So there're a number of possibilities that could arise from this type of a discussion, Mr. Minister. Would you be prepared to meet and to discuss that with you and your department?

Mr. Lemieux: Well, we've always, as a government, prided ourselves in consultation. Not only the consultation process, I know the MLA for Transcona (Mr. Reid) is here and he participated in our 2020 Vision consultation process on transportation and transportation infrastructure, and came forward with a great recommendation that we have used as a blueprint and a guide for where we've gone right now.

So consultation is not foreign to us. I don't want to burden staff or overburden them with extra meetings and so on, but I'll certainly consult and talk to them about, you know, is there an opportunity to open discussions. But if you're talking about a study, I would see the federal government having a huge role to play in this whole issue.

I just want to clarify something. I don't mean to be rude to the MLA for Emerson, but I have a lot of good friends in the United States, as we all do. We consider them friends and have a great friendship with the United States, whether it's North Dakota, South Dakota, Montana, Wisconsin, Missouri, and so on, so I don't mean to miss out any states. But I have to tell you that we do have a lot of friends, and we look forward to working with our neighbours to the south. Without having clear dialogue and open dialogue, which we have had on a number of issues, I mean this is not to discuss the issues about the lake that currently often makes the press, but all of us have an appreciation for our neighbours to the south and have a lot of friends there.

So I just want to make that clear, that we do have conversations and open dialogue with our neighbours to the south of us. They have their water challenges, so do we. But, without federal involvement of any kind dealing with international waters, dealing with–I mean the Souris River dips in and out of the United States, comes back in, so we have a common tie, quite frankly, with our neighbours to the south, and that is water. We continue to have dialogue with them, but that's a role that the federal government, I believe, does play, an important role with regard to participating in something like this.

I didn't know Harry Enns, by the way, was from the area. And you're right; Harry Enns will know and knows a lot more than I will ever probably know about the Red River, so I grant the member that.

Mr. Graydon: I didn't mean to leave the impression, Honourable Minister, that you didn't have friends in the United States. I also have friends there, and I'm married to one. So I'm actually handicapped in what I can say at times because I can't cook. But thank you for your candor.

Mr. Maguire: Yes, I would defer, Madam Chair, to the Member for–where is he?–Turtle Mountain.

Mr. Cliff Cullen (Turtle Mountain): Well, Madam Chair, I just want to add some words to what the Member for Emerson (Mr. Graydon) has said. I have the Pembina Valley. The Pembina River flows through my area, too, and a number of communities are looking at some opportunities that we think going forward could be very positive for the area. We've endeavoured to have the Minister of Water, two ministers of Water Stewardship in the last few years, come out to that area and tour the area, particularly Pelican Lake and Rock Lake. We haven't been successful in getting them out there, so we would certainly entertain members of your department if they'd like to come out and look at the options that we think could be beneficial to the area.

In regard to your comment about our American neighbours, it seems that when we talk about water issues south of the border, the Province of Manitoba, at this point in time, seems to be more interested in lawsuits than actually any negotiations which we think could be positive. Clearly, we talk about water retention. We know there are areas in the province that are going to require water, and I think it would be very, very useful to enter into some serious and, hopefully, positive dialogue with our neighbours on how we're going to use that water.

In terms of the Water Services Board, I see the budget is about $10 million. I'd just like to get a bit of a feel for what kind of money or applications come forward from jurisdictions across the province on an annual basis.

***** (17:00)

Mr. Lemieux: Well, the budget is about over $12 million, I believe, just over $12 million or around $12 million, I believe, but I stand to be corrected by a few dollars here or there. So the programs are overprescribed. We talked about contributions coming from elsewhere, but the totals are about $30 million for water services and Water Services branch, but the provincial contribution is around $12 million, as I understand it.

A program like this, not unlike a Community Places grant, where you have many, many more multi-millions of dollars worth of programs or applications that come in for all kinds of–you know, it's not a case of saying that they're not worthy. All these projects have some true benefit for rural Manitoba, and not just for rural Manitoba, any community that is applying. But the criteria, which I won't go through, I did this for the Member for Arthur-Virden (Mr. Maguire). You'll be able to see it in *Hansard*. I tried to go through that and lay out the criteria that are there.

So the Water Services Board and the Water Services branch have a tough–it's a very difficult situation, quite frankly, because you have so many projects that are worthy and yet you have to priorize them somehow. You have to be able to put good projects forward. That also comes from the application process from the communities.

To your point about not wanting to work with people, I don't mean to misquote you, but the Province of Manitoba has always worked with our neighbours to the south and always has had open dialogue. Sometimes that's not always what you read or what you hear on the radio or see on TV, but there are always discussions happening with our good friends from North Dakota and other states of the United States.

With regard to the comment that the MLA for Emerson made, congratulations on your marriage and hopefully everything goes well.

Mr. Cullen: Well, thank you very much, Mr. Minister. The municipalities and towns and communities around Manitoba are facing a lot of pressure with the drinking water regulations that have come forward and I guess the fact that a lot of their waste water treatment facilities and lagoons are quite dated. So we have the Department of

Conservation on one hand regulating them and telling them what they have to do and then saying, okay, here's what you have to do. Go to the other section here, go to the other department and ask for money to get it done. Quite frankly, as you said, we don't have the money to cover what's needed there on an annual basis. So it's very frustrating for those jurisdictions going forward.

Having said that, are you looking at increasing the money that's going to be available for those particular facilities that need upgrading? I guess the second part to that question: I'm assuming that you're having some kind of dialogue with our federal counterparts as well, our federal government as well.

Mr. Lemieux: Well, first of all, even though different responsibilities lie with different departments, I can tell you that the ministers work very, very closely together and so do departmental officials. I don't like to use the word "bureaucrats" but people within the bureaucracy work closely with each other to ensure that they're not duplicating what each other is doing but also working hand in hand to ensure that they work closely with each other.

The question you ask is a budgetary question in the sense that, you know, where are we going with regard to finances in the future. That's something that there's ongoing dialogue with regard to water and also sewage treatment and effluent treatment and looking at phosphorus and nitrogen and all the impacts on our water system overall.

So, to answer your question, the third piece, is there dialogue with the federal government, we have had dialogue, certainly as I understand it. I know we talk about these issues related to PFRA. Agriculture, because there's an agriculture agreement, they are ones who are certainly looking at issues related to PFRA and extension of water lines and so on. So we would want to make sure that dialogue is continuing.

Infrastructure overall, absolutely, we've told the federal government. AMM have told the federal government, I think even going back certainly to when your MLA for Ste. Rose was involved with the AMM. Everyone was telling the federal national government we need some vision here on infrastructure and I believe the vision is there. I think we all are on the same page. We just need to have some cash flowing.

The Department of Conservation, as you rightly point out, is involved, and also Water Stewardship, too, when you're talking about water sources and different regulations involved with water.

But we do work closely together. With regard to the budgetary item, we're certainly reviewing on an ongoing basis as to whether or not there's more dollars needed and how do we approach this whole issue.

Mr. Cullen: Madam Chairperson, seeing that we have the Water Services Board people here, just a couple of updates in my constituency, if you would. The first one is in regard to the Yellowhead project there. I know that MacGregor-Austin is currently being hooked up, but if you could kind of give me a little status of where that project's at just briefly. I guess the second part of that, too, is potential expansion up into that Gladstone district, I believe is in the works. So, if you could, kind of, give me just a brief synopsis of where that project is headed and when you might see that being finalized.

Mr. Lemieux: Just to deal with the Yellowhead regional water supply, I can let the member know that the water supply pipeline, MacGregor to Austin, is under construction and 85 percent complete. The booster station, Yellowhead to Bagot, is under construction at 60 percent complete. The water supply pipeline from Gladstone to Ogilvie is certainly on stream and it's about 98 percent complete; there's just some clean-up to do. Also, the water distribution pipelines 2007 Norfolk has been awarded. It's at the tender stage.

The other comment I'd like to make is dealing with the kind of dollars that have been spent totally right now with Yellowhead. About $15 million have been spent kind of to date. This connects Gladstone, MacGregor, Austin, but there are future plans to extend to the R.M. of South Norfolk and also to the R.M. of Lansdowne. So, people in the department and water services have been working diligently on this, trying to make sure there is a good plan in place to try to connect a lot of these R.M.s. I know the MLA for Arthur-Virden (Mr. Maguire) has mentioned it a couple of times, but the PFRA piece is very important here, and I would hope that all MLAs in the opposition would support making sure the PFRA dollars are flowing because they play an important role in a lot of these projects for rural Manitoba and, specifically, ones that are in the backyard of the MLA for Turtle Mountain, as well.

Mr. Cullen: Madam Chair, I know you said it was in the works in terms of the expansion going toward Gladstone, I believe. I just kind of get a bit of a time frame on that and, in addition then, all that water that will be going north and also into South Norfolk, maybe you can just give a bit of an idea where you're thinking that's going to go. Is that just a farm area? Then all that water, I'm assuming, will be taken out of the Assiniboine River at Portage for that entire project.

***** (17:10)

Mr. Lemieux: Just a point of clarification that the water does come from the Assiniboine but through the city of Portage la Prairie. But all funding in future projects is also tied to PFRA or federal monies, and that's why the urgency about the PFRA program through the ag agreement expiring in March of '08 shines a huge spotlight on the importance of what we've been discussing, quite frankly, for a couple of hours now.

Mr. Cullen: Just on another project then, it's a lagoon project. It's going to be a shared lagoon, I believe, between the R.M. of Riverside and the R.M. of Strathcona. There were some land issues related to the existing lagoon, and they were going to build a lagoon just adjacent to their old one. I'm just wondering if your staff are familiar with that particular project, and if we cleared those legal hurdles to move that project forward.

Mr. Lemieux: I thank the member for the question. The lagoon project, the Riverside-Strathcona one at, I guess, Ninette, is what the reference is being made. There are some land issues but the Canada-Manitoba Infrastructure monies are involved in that particular project.

Just to talk about Pelican Lake, I know that he may have invited people. I don't know if they went there for formal meetings, but many MLAs have visited the Pelican Lake area and know how beautiful it is. I'm not sure what ministers have or have not gone there for official meetings, but I know we've all seen Pelican Lake and know how beautiful it is and what a great tourism attraction it is for our province.

But, to make my answer short and brief, the Canada-Manitoba Infrastructure money is involved with that Riverside-Strathcona project, as I understand it, and also land issues are a huge concern. *[interjection]*

They have been settled? I have been advised that the land issues have been settled.

Mr. Cullen: I appreciate the information and the update on those projects, and certainly, as the MLA representing Pelican Lake and Rock Lake, I would invite you out any time at all. We're certainly working on restocking that lake with fish so that's maybe another issue we can bring up with the Water Stewardship department, but if you could pass that information along to the powers that be, that we'd be certainly grateful. So thank you very much for your time.

Mr. Maguire: I just had a couple of questions in regard to–I know we wanted to get as many of the questions in regard to Manitoba Water Services as we could today, and I appreciate Mr. Menon being here.

I just wanted to go back to a question that my colleague from Turtle Mountain asked. I know the minister, right from the text here, it’s the sewer and water projects for about $12 million. Just for clarification, that would be the $12 million that the Province of Manitoba would make available, so it gives you a much greater–by the time these projects are partnershipped, you could end up with three times that in actual project value?

Mr. Lemieux: Yes, the Member for Arthur-Virden's correct. It expands it a fair bit from 12 to approximately 30.

Mr. Maguire: As these are projects that are to be done this year, can the minister share or provide me with a list of the projects that are already up and running? We're doing these estimates a little bit later in the year than we normally might have, and you know, the year's half over. I'm assuming that there are roughly–and I didn't use that as a means to say that half the money should be spent by now. I'm just saying: Could the minister provide me with a list of the sewer and water projects and their dollar value around each one of them that he has to date, that have been agreed upon to date, at least?

Mr. Lemieux: Yes.

Mr. Maguire: I wonder if I could get a similar list for the 2006-07 year, for the whole year because those projects will be completely completed by now or not completely completed, but the funds will have gone toward all of those for the past few years. I wonder if I could get a list of those for '06-07.

Mr. Lemieux: Well, we believe in open government. It's on our Web site, but I will provide a hard copy. I think we can do that.

Mr. Maguire: I'm going to make a note to myself. Thank you, I appreciate it. Just for the record, the minister is a member of the Treasury Board?

Mr. Lemieux: He is.

Mr. Maguire: I just wanted to touch base. I know that there are a host of projects, as I said. One of the key areas that the Province is concerned about, and I know that the minister is concerned about it as well because some of them have taken place in his jurisdiction, and that is just the–and I know it falls into his jurisdiction at some point because all of the infrastructure projects do come in there. It's sort of around what my colleague alluded to earlier today in regard to the Lansdowne project, I think it was, that he had commented on. That is around the issues of boil-water orders. There are some 60-plus in the province of Manitoba today.

I wonder if the minister can confirm that for me, and what his dealings are with the boil-water order processes.

Mr. Lemieux: No, I certainly can't confirm it. I cannot confirm it. I mean, that's probably a question for Water Stewardship or another minister. You're asking about the boil-water orders. I can't confirm that.

Mr. Maguire: Can the minister indicate then what kind of interaction there would be between Water Stewardship and themselves in regard to–I know Water Stewardship was responsible for the boil-water orders, I assume, from that end of it. I'm just trying to piece the different water pieces under different ministries. The minister's indicated earlier that he's responsible for sort of the projects that go, all the infrastructure.

So how often does he commiserate with his colleagues in regard to the issues of boil-water orders and their infrastructure needs, if I could add that?

Mr. Lemieux: The staff meet on a regular basis, as I certainly do with all my colleagues, all my ministerial colleagues. So we have dialogue often. I wouldn't use the word commiserate. I would just say we share a lot of information back and forth about the issues. But, just with regard to the boil-water orders, at least what we're looking at is possibly three or four municipal systems under boil-water orders. The numbers that the MLA for Arthur-Virden's thrown out, you know I'm not sure where these numbers come from or, you know, what it's based on, but that's news to me.

***** (17:20)

Mr. Maguire: It comes from the open government that the minister referred to earlier, I believe. I haven't done it in the last few weeks, but, earlier, it was on a Web site. I was just looking at it under Water Stewardship. I've been told that there's in that neighbourhood. I do know of one that has been outstanding since 2000, and that's the community of Medora. That's in the village of Medora. That is probably one of the oldest on record now. I know that's in my constituency. I keep bringing it up in regard to the requirement and need for that area. I know there was a water project ongoing, as the member here earlier indicated. Financial outlay of each individual in regard to the project ended up being somewhat higher than the local persons, I believe, were willing to go with, but it became a much bigger project as well. So Melita, of course, it wasn't part of that particular Medora project, but I am happy to see that the community of Melita is going forward with the project that they are, in regard to the waterfication of their community, bringing in the source and treating it in the community as well. I look forward to that being finished next year, I believe it is, and await as a response to their needs. I'm sure it will help them in regard to not only the individual homes, but the maintenance of their hospital in the future and other community businesses that are located in that fine community.

It is a growing community at this point. We've had some situations in the past, flooding in '99, where some issues of concern were raised by town council and others in that area. They have done a tremendous job of coming back on their feet, I believe, in regard to travel and asking the government for future encouragement in regard to roads and bridges in that area.

I just wanted to make the comment that there are a very minimal amount of homes for sale in the community of Melita now. I'll let you know that the oil industry has been a benefit in that area, and young people are moving into that region, you know, to some extent, and it's certainly been a plus for that community. So the water going into that community is going to be a valuable asset for that community in their whole future.

I guess I want to move forward in regard to any particular grants that Water Services might have on industry and development of industries anywhere in Manitoba, if the minister can inform me of what might be available there through his department, the Water Services, I know, in regard to finding of water, quality as Water Stewardship issues we've talked about earlier, but in regard to infrastructure grants to develop some of those projects. I wonder if he could elaborate on that for me.

Mr. Lemieux: The dollars that come for different industries or different businesses, they are not provided by grants through Water Services Board or Water Services branch or Infrastructure and Transportation. They come from other departments. It could be from Agriculture, Food and Rural Initiatives or from different departmental grants that may be available. But the department, through Water Services branch, manages a lot of these projects for these communities or in consultation with the communities whatever the projects are. So the dollars come from different departments as far as grants that may be provided to the different companies or organizations that are looking for assistance. But we just project manage often, but don't supply. At least I've been advised we don't supply dollars directly to companies or corporations or agencies looking for monies to assist them in developing.

Mr. Maguire: I know that there was a situation in the Oak Lake community in regard to a sewer and water project, I think the R.M. of Sifton and the town of Oak Lake, and also some concerns in the futures with some of the cottage lots, not just at Oak Lake, but around the province of Manitoba. I wonder if the minister can respond as to any information that he can provide me on the particular project with the R.M. of Sifton around water, and I believe that they've been contacted on that, and some progress has been made?

Mr. Lemieux: Just to, I guess, maybe a point of clarification on the Water Services Board that the dollars don't necessarily go to recreation lots or cottage lots, they go to residential property. So that has been a policy that I have been advised that has been used. Since we're talking about Oak Lake, or Oak Lake Lagoon, this, again, would be the policy that we've adhered to consistently.

Mr. Maguire: Can the minister indicate to me just the position of that lagoon at this time, at the Oak Lake Lagoon?

Mr. Lemieux: In consultation with staff, we'll have to get back to the MLA for Arthur-Virden just to give you kind of an update where it sits or where it's at. I'm not familiar with that at the moment, but definitely we'll get back to you and let you know. I've asked staff to make sure they do that just to follow it up.

Mr. Maguire: I thank the minister for that, Madam Chair. I know Reeve Harrison and Mayor Sigurdson have had discussions on that issue with the department. I appreciate that update.

I want to, at this time–there may be more questions that come up in regard to Water Services and the board and that sort of thing over the time that we'll have left in Estimates, maybe not today, but tomorrow as well, as we cannot vote on this later today–but I want to particularly thank Mr. Menon and his department, Mr. Menon for coming in today, personally, and taking the time to be here and answer these questions for myself and my colleagues this afternoon.

There might be a colleague that just walked in that might have a question on water in some of those areas, and before I turn it over to him–I don't know if he has or not; I could go there myself–but I want to thank Mr. Menon for coming in, for being here, for providing the minister with support in regard to the questions we've asked today, and my colleagues. And also to take back to his staff and department our sincere thanks for the work that you do throughout the year in regard to providing all of Manitoba with a better environment and better water and safer sewers and lagoons. It's a big job to keep it all straight, to try to appease everyone's needs. I think it's only right that, I, as the critic in opposition, thank you as well, as the minister has, for that level of dedication that you've provided.

I know that the Member for Brandon West (Mr. Borotsik) has come in, as I was referring to him earlier, not earlier, just since he came in, but we've talked about some of the major projects that are on. It reminded me of the project between Maple Leaf and the City of Brandon, and the Province's involvement in that. Is there anything that we can get from the minister before we end that discussion on that particular project and where it's at?

Mr. Lemieux: Well, I thank the member for the question. Maple Leaf, as the member knows, there are discussions ongoing. There is a huge price tag associated with that particular project. I would only be guessing with regard to the kind of dollars that are involved, but you're talking about–I don't know if this is an exaggerated or inflated number–but you're talking about anywhere from $75 to $100 million, which is a huge amount of money. So I just know that it's ongoing dialogue, ongoing discussions going on.

Mr. Daryl Reid, Acting Chairperson, in the Chair

***** (17:30)

Mr. Rick Borotsik (Brandon West): I appreciate the opportunity, Mr. Minister. Certainly, I'll echo Mr. Maguire's comments about Mr. Menon. He and I go an awful long way back. We appreciate the fact that he resides in Brandon and that he has provided a reasonable service to the department over the past number of years.

Two questions, actually. I don't know if Mr. Menon is the one who's prepared to answer this one or not. I don't know if it's even been questioned at this point in time, but one of the major concerns of the environment, certainly at the present time, and it's been mentioned on numerous occasions, is the combined sewer system in the city of Winnipeg. Has that been brought to this table at this point?

We recognize that there are several environmental problems with respect to Lake Winnipeg and, I don't know, is Dick prepared to answer some of these? Or to the Chair?

Mr. Lemieux: Well, let me just say, first of all, congratulations to the MLA for Brandon West.

Mr. Borotsik: Thank you.

Mr. Lemieux: Welcome. I know he is an experienced politician and has had opportunities at the federal level and municipal level, and I just welcome him here.

With regard to issues around the city of Winnipeg, Water Services just deals with issues outside the perimeter; maybe that's the best way to describe it, rural and north, so that's all that we can answer with regard to that. Of course, there are other departments like Conservation and Water Stewardship that also have a role to play with regard to water issues, so it's a–sometimes the questions have been overlapping, and we've had to say, well, ask the Minister of Water Stewardship (Ms. Melnick) when you get a change or the Minister of Conservation (Mr. Struthers) whenever they get into their Estimates, so that's kind of where it stands.

Mr. Borotsik: Thank you, Mr. Minister, for that explanation. I do know that Mr. Menon is responsible for the rural water services, which brings me to another issue. I don't know whether Mr. Maguire, and I do apologize for coming in late, but I was listening to the discussions between the Premier (Mr. Doer) and my leader, which were probably more interesting than Mr. Maguire and the minister.

An Honourable Member: No, no.

Mr. Borotsik: That would be your opinion. Certainly, I was enthralled. The issue with rural lagoons, and, again, I apologize if this has already been dealt with, but there have been a number of rural lagoons in southwestern Manitoba, particularly that have had some of their standards changed and capacity limits changed on those particular lagoons. This has caused some difficulty, some grave difficulty in some of those smaller communities not having the capacity that they once had. Now, that doesn't mean that the hydraulic capacity's not there; it's just simply the capacity that has changed with standards of effluent.

Is the government prepared to look at these particular lagoons where they've changed the standards and help those municipalities fund to a greater degree than the normal infrastructure of funding that has been put forward previously? Is the government prepared to fund a greater portion of those lagoons to assist some of the smaller rural municipalities and, certainly, some of the smaller communities who don't have the financial wherewithal with respect to the taxation to help fund those infrastructure requirements?

Mr. Lemieux: Well, first of all, let me say that I'm not privy to the discussion that took place between Her Majesty's Royal Opposition, the Leader of the Royal Opposition or the Premier, but the issues we're discussing here with water have been highly engaging and very important. So, just to clarify that the discussion around water and sewage may not be very sexy to some people, but, as a rural MLA, I'm sure the Member for Brandon West as well as the other members know how important they are. So I will have to look at *Hansard*, I'm sorry, to take a look at what conversation has taken place in a different room between the Premier and the Leader of the Opposition (Mr. McFadyen), but the discussion here has been a good one.

Just to talk a little bit about the point that the MLA for Brandon West made. This program is hugely oversubscribed, you know, a huge need, and the PFRA program that we tap into is coming to an end in March, March of '08, sorry. And I've been asking MLAs around the table of all political stripes to talk to their members of parliament, whether it's Mr. Tweed or others to ask them to take a serious look at keeping that program in place, because that has a huge impact on what we can do and what more we can do, quite frankly.

The comment that staff made was that we work with rural municipalities and towns and villages to bring to using today's standards, quite frankly. They're funded at a 50-percent level from Manitoba Water Services Board. The point I want to make, though, is that, because they are so oversubscribed and the communities are small, some of them, we are looking at issues around funding, looking at issues–not only did I mention PFRA but our own internal funding as to the need that's out there. And infrastructure, not only roads and bridges are aging but the sewer lines under the–you don't see them and the water lines under the ground, you don't see them, but time has taken a toll on them as well, as well as on lagoons, whether it's population moving in, you know, needing expanded lagoons because of populations that have grown in some communities, other communities just by virtue of age of some of the lagoons.

So it's a huge challenge and we're trying to head it and meet it straight on and trying to deal with it, and now more communities are looking at a regional approach whether it's dealing with lagoons or with water systems now. We've talked about this over the last four hours or so, I believe, about how they've got many communities trying to tap into water pipelines to make it work for each community. It takes a lot of co-operation between towns and villages, and it takes a lot of patience to work and time to work and money actually to work through this.

I'm sorry for the long-winded answer but I just wanted to kind of lay out what we've been talking about over the last little while and just to let the MLA from Brandon West know that.

Mr. Borotsik: Thank you for that explanation. In fairness it may not be sexy, Mr. Minister, but I can assure you that if you've tried to flush your toilet and it doesn't go anywhere, the requirement definitely is one that's necessary.

I appreciate the fact that it does take co-operation within municipalities. I guess the point I was trying to make–and I'd just like to reiterate it right now and get a comment–is we recognize that PFRA had a program. We recognize that it's oversubscribed. We recognize that the feds have only thrown so much money at it. What I was trying to get at is sometimes or on occasion it's the province that controls and regulates the lagoons of the municipalities. It's the province that then will set the standards of those lagoons. It's the province that will then dictate to the municipality as to what capacity they can have and to what requirements there are for change to those lagoons.

The point I was trying to make, if in fact there is no money from the PFRA or if it's oversubscribed, and we know that there are certain programs across Canada that the PFRA funds and Manitoba only gets a certain portion of it, my question to you was, and I appreciate the fact that you did indicate that there is a review of funding. My concern is, with a lot of the municipalities that I've talked to, is that when restrictions are placed on those municipalities, they do not have the financial wherewithal to achieve their contribution, that the province, because they're making the changes to the lagoons themselves in capacity, should it not be a provincial requirement or could it not well be a provincial policy that would fund those infrastructure improvements to a greater degree from the province, granted there should be contribution from the municipalities themselves. I don't think there's any question about that and I don't think there's a municipality that I've ever talked to that wouldn't agree to having their requirement there for their own capital improvements, but should the province not be, because the province is making the requirements for change, should the province not come to the table with more funding to the municipalities?

***** (17:40)

Mr. Lemieux: We do work actually very, very closely with rural municipalities and also the communities within those municipalities. To a certain degree it's based on their financial wherewithal. You know, we don't impose certain funding challenges to them when we know that their ability to raise, or their tax base is not as large as the next community a few municipalities over, and so on. So there is some flexibility that Water Services Board uses with that regard, and we work closely on finding solutions too. Sometimes it's not just replacing someone's lagoon and the big brand-new, you know, kind of spanking brand-new lagoon. It's tying in, trying to have a regional approach as to what can you do with your neighbours.

So there is that approach and we try to work with the communities and I think that it's not only, when we talk about infrastructure, lagoons, water, those issues are often forgotten, and roads and bridges get a lot of the public attention and have a lot of the public attention, and yet the others do not. These are budgetary items that we discuss about what do you do about dollars, and we review that on an ongoing basis, and we take a serious look at that and whether or not we can increase the amounts of dollars because there are many different programs. There's not just Water Services Board; there are all kinds of different programs, whether it's agriculture or industry or other departments that also help contribute to some different challenges they have. So we do take a look at it on an ongoing basis, and we review it with staff and also the input we have from AMM and other people.

Mr. Borotsik: One final question; I'll become a little bit more parochial on this one. It's to do with the city of Brandon. I do appreciate, Mr. Minister, that there are substantial infrastructure projects that are out there. Not only are the lagoons and the water services oversubscribed, but I can assure you that I know and others know that the infrastructure requirements out there are oversubscribed at the same time.

However, in saying that, the city of Brandon–and I do appreciate the fact that you're putting substantial infrastructure in there with respect to bridges at the present time and some roadway work that's going on. But there are two major projects that have been identified. One of them is the eastern bypass, the extension that is to be completed, and I know it's a priority. The second priority in Brandon–and I know you've been there on numbers of occasions–doesn't particularly have a prime entrance. It doesn't have a double-lane highway coming from No. 1 into the community. Eighteenth Street and First Street are both major entrances but they are not of the same calibre that I would like to see for a community of our size. In saying that, we do know that the eastern access is a priority, and I know that your department has been working very hard to complete that project, although it's been on the go for quite a number of years now.

I guess my question is, I've seen the drawings for the 18th Street access from Highway 1. I'm told that those drawings are basically placed in a potential of a 30 to 40-year timeline. Thirty or forty years, Mr. Minister–I don't think you or I will ever sit at this table–but I would love to drive on that road. I would love to drive on that road, and I don't think I have the 30 or 40 years left in me to be able to accomplish that. I would ask you at this time if, in fact, any consideration from your department has been given to accelerate that timeline with respect to 18th Street access up to the No. 1 highway. I do know that there are some land requirements. In looking at the drawings, I do know that there's some dedication or some land acquisition that's required, but again, my simple question is, do you consider accelerating that particular project within the community of Brandon?

Mr. Lemieux: I thank the member for the question. I just want to say that first of all, we're very, very proud of the fact that, as a government, we're putting in the new bridges in Brandon. It's necessary; it's a growing community. The region, it's a regional community, and the bridge is very, very important. Now, the documents the MLA for Brandon West is talking about are planning documents–the documents that the department will use when a decision or if a decision is made to improve the stretch of road.

I can tell you that the land was purchased for the northeast Perimeter in the 1960s, before, actually, our government decided to complete the Perimeter around the northeast side or the east side of the city of Winnipeg. So these documents are planning documents, and they're documents that are used to look ahead into the future as to what we want to do.

To answer your question specifically, we are considering what to do certainly with Highway No. 10 or that entrance into Brandon. The new bridge is going to be going in there. So, we are looking at it in a serious way. No decisions have been made as yet, and I try to be forthright about that, but Brandon is a growing community and will continue to grow. So those challenges will always be there.

Mr. Maguire: Just a last question to the minister while Mr. Menon is still here.

The Member for Russell (Mr. Derkach) has asked me to–he is at another set of Estimates right now–has asked me to ask a question in regards to the Decker Hutterite Colony in regards to the water supply to that particular location.

It's going to need the waterline coming in and I think the choice is either Miniota or Hamiota or somewhere in those areas. I just wonder if the minister is familiar with it, and if he can give us any kind of project report or commitment as to what's required there.

Mr. Lemieux: Just wanting to talk about the Decker Colony project. It's something that they approached the department 10 years ago and wanted to look at alternatives. And actually, there was a solution given, but they turned it down. Now they've re-engaged dialogue with Water Services to see what kind of solutions are there. So, I understand that meetings have been arranged and discussions are going to take place as to what possible solutions are there.

Back to the MLA for Russell, you're certainly, you know, you can pass this on back to him, that there are conversations going to be taking place in the very near future as to looking at solutions. What those are and costs–I am sure you have an appreciation that costs have gone up substantially in 10 years. It may look like quite a deal compared to what 10 years ago would have been, but I will just conclude my remark at that. That is, that they will be talking.

Mr. Maguire: Thank you, for that answer.

Mr. Acting Chair, I thank the minister for his answer. Apparently now that there is a greater need, and I don't know if the water is contaminated in that particular location right now, they are hauling drinking water as I understand it, and they have the facilities to treat water that will come in, from my understanding, and so I'll leave it at that.

I want to turn it over to my colleague from Springfield (Mr. Schuler) in regard to any, some particular questions on that and I'll close by thanking Mr. Menon again for being here. We would, I believe as I said, be able to answer if there's any other questions on water, we'll just have to ask and have the minister get back to us. But I thank you again for your time here today and for coming all the way in from Brandon. Thanks.

Mr. Lemieux: Well, again, I just also want to thank Mr. Menon. He's been a very loyal civil servant, very well respected by municipalities and citizens of Manitoba and I think we all would want to pass that on to him. So, I appreciate the Member for Arthur-Virden's comments and we know his role and his job is very, very important to the citizens.

I just want to ask my critic whether or not we are going to proceed with transportation issues at this point, or where my colleague would like to go with regard to questions.

Mr. Maguire: Yes, I believe I'll just proceed with transportation issues, and my colleague from Springfield will be next.

Mr. Ron Schuler (Springfield): Minister, I have four questions, and I understand that these do involve some technical answers and I would be fine if they were taken as notice and the department could afterward send a letter. I don't know if you want me to give them one at a time. I would just love to have a response at some point in time; it doesn't necessarily have to be tonight.

The first one is PTH 15, the bridge over the floodway. That's the Dugald bridge over the floodway. What kind of a retrofit is the department looking at? Like, what will that involve? One of the questions that we would clearly want to know is what kind of traffic interruption there would be? I believe PTH 15 is one of the most travelled, single-lane, feeder routes into the city. It carries an enormous amount of traffic. So it's not something that need be answered right now, just at some point in time, if I could get that information.

***** (17:50)

Mr. Lemieux: Well, I certainly can answer part of this. We're taking a look at the options with regard to, certainly, the bridge crossing the floodway at this time, also the intersection with regard to the Perimeter and Highway 15. There are a lot of challenges with regard to traffic, of course. The Rosser Road, for example, has more traffic than Highway 15 or Dugald Road does. It might be a moot point, but there is a lot of traffic anyway on Highway 15 as we all know, and I use it as well.

We are very pleased, of course, that the work we've done in the northeast Perimeter is coming along very well. There have been some weather-related issues. I know the Member for Springfield has put out a couple of mailers saying that it's a great thing that the northeast Perimeter is being done, and I thank him for that. We're also pleased to do it, and we look forward to when it's going to be completed. But there are some challenges with regard to the bridge that crosses the floodway at Highway 15, and our department continues to work on some solutions for that.

Mr. Schuler: If the minister could, at some point in time or the department could let me know what kind of a retrofit they're looking at, we don't have to take any more time from the committee.

Great segue, minister, into my next question, that's the Highway 59-Perimeter intersection. When is that bridge, that intersection, that interchange going to proceed?

Mr. Lemieux: Just a clarification, that's Highway 59 where it meets the northeast Perimeter. That's going to be a multi-year project because not only is it going to be costly, but it's going to take a number of years.

The intention right now, the department is looking at starting on that project, hopefully, in the next couple of years, hopefully sooner, but that's something that we're looking at. We know that, again, there's a need there in the northeast Perimeter and the amount of traffic that goes around the city now that the number of different lanes have been twinned. So, we do appreciate the question, and I can tell the MLA for Springfield that we are proceeding internally at looking at design and looking at those kinds of things that need to be done. Again, it's a very costly project, but we're certainly committed to it, and we've said that all along.

Madam Chairperson in the Chair

Mr. Schuler: Yes, and on that one, obviously, a lot of trucks are tipping trying to get from one section of the Perimeter to another because it's a very sharp corner, but the minister, I'm sure, knows that.

On to my third question. Back to Highway 15, east of Anola fire hall to Eastdale Road, the road is in really rough shape, and I was wondering if the department has had the opportunity to have a look at it, and is there any plan to do some resurfacing work there?

Mr. Lemieux: The department is aware of it, and staff from Steinbach in the regional office, they monitor our highways on an ongoing basis, all the highways in their jurisdiction. They're continually looking at the kind of needs that are out there and trying to balance that off with greater needs, I guess if I could put it that way, because they have to prioritize, and it has to be a balance. But they are certainly looking at it, and they're aware of the situation of not only the traffic, for example, on Highway 15, but certainly aware of the shape that the roads are in.

I have to point out, too, that the department also is wanting to ensure that roads are safe; they always do that. That's paramount with regard to any of their planning and any suggestions that they pass on to the deputy minister's office or through the deputy minister to me. So there's ongoing monitoring of all of our roads around the province. So just to let the MLA for Springfield know that they are very much aware of it and are certainly monitoring that particular stretch of road as well as they monitor 15 on an ongoing basis.

Mr. Schuler: My last question is: Highway 15, I take it there are no plans for twinning of Highway 15. The department a while back had looked at the Oakbank corridor. Is that still something that is an active file, or what has happened with the Oakbank corridor?

Mr. Lemieux: A point of clarification. Is the MLA asking about Garven Road and those kinds of connections or is this a new, like a different route as opposed to Oakbank?

Mr. Schuler: No, the Oakbank corridor is a mile road past Oakbank. It is actually Cedar Lake Road, which then would cross the floodway. It crosses the Perimeter and clips into Gunn, and then afterwards it meanders Gunn and then meanders over to Springfield and would come out at 59. The reason why it doesn't take Springfield is because then it would cross right at the railroad tracks because Springfield sort of shaves into the railroad track. That's why it was always Cedar Lake Road. The department did an open house on this. It was agreed that it would be Cedar Lake Road and then it sort of meanders over eventually to Springfield. Then it just sort of quieted down in the late '90s. Is there any discussion in the department on the Oakbank corridor?

Mr. Lemieux: No, there is no serious consideration being given for it right now.

Mr. Gerald Hawranik (Lac du Bonnet): Yes, I have a question with regard to a small bridge that is on PTH No. 12 south, specifically as it intersects with Oakwood Road in the Rural Municipality of Springfield. While it isn't in Lac du Bonnet constituency, many of my constituents are affected by it. I notice that this spring I've had a number of complaints about it because it was restricted to a greater level and extent than the road itself. As a result, and because it's on a provincial trunk highway, I'm wondering what plans the minister has either to replace it and when that will be done or perhaps maybe even be replaced with culverts because it's not a large bridge on PTH 12.

Mr. Lemieux: I thank the member for the question. I'm not sure if they call it Oakwood bridge or what the term is, but I'll certainly ask the department to look into this to find out what the status of that is, or what condition it is. I mean, we're running regular highway weights on No. 12. I'm not sure where the dilemma is because the regular highway weights are being run on over the bridge. I don't know if someone has raised this and said there were flags there or something, but regular weights have been run over the bridge and run on that road.

Mr. Hawranik: That's fair enough. If you could check into that in any event because I've had a number of complaints from truck drivers, particularly saying that it's restricted even more than the road itself. I think, in fact, the signs went up, haven't been there over the last couple of weeks over that particular portion, but the signs went up apparently in May restricting that bridge just after the election, in fact, a couple of days afterwards. So it was toward the end of May, beginning of June, somewhere in that neighbourhood.

Secondly, there's a concern in our area about Provincial Road 302 and, of course, the restricted portion from the CPR railway tracks going north, pretty much to Pescitelli Road as it enters Beausejour. That particular stretch of highway is in poorer shape than the rest of Provincial Road 302. I note that the Rural Municipality of Brokenhead has, in fact, approved a rezoning for a Robert Small Agri-Tel industries along that particular stretch for a biodiesel plant, which means that there's going to be heavier trucks likely going along that stretch of highway.

I've also had had conversations with the reeve of the Rural Municipality of Brokenhead, who's indicated that because that particular stretch of road–it's about four or five miles of roadway–has greater restrictions than the rest of Provincial Road 302 that they're using the gravel roads of the Rural Municipality of Brokenhead to get around that stretch of road. He told me he's considering, in fact, restricting the municipal roads, and that poses a real problem for some of the truck drivers in that area, particularly since LSL Sand is just north of that stretch and so on. So it can create a major problem. I'm wondering what plans the minister has, if any, to upgrade that particular portion of 302.

***** (18:00)

Mr. Lemieux: Knowing that the request is for RTAC and carrying heavier weights, there is no consideration being given to that at this time, but we're certainly looking at doing some repairs on that road, whether it's seal coating and so on, but we're not looking at making it RTAC currently.

The R.M. of Brokenhead has raised this. I've met with them on a number of occasions and I know they've raised it. It is a concern for them, and they're, of course, concerned with rural economic development and how highways tie into that. It's been something that's been raised to us.

Can I just, if I could follow up, actually, just with a question on clarification of the Oakwood bridge. Where is that located, just trying to get a better idea where that's located on No. 12?

Mr. Hawranik: It would be approximately four to five miles north of Anola on PTH 12 at the intersection of Oakwood Road. In fact, all the roads in the Rural Municipality of Springfield are named so I believe it's at the intersection of Oakwood Road and PTH 12.

Mr. Lemieux: We've not known it as that name of a bridge, but we know the location now and we'll certainly look into it. Thank you.

Mr. Stuart Briese (Ste. Rose): Madam Chair, I want to refer to several roads in the north end of my constituency that I would like to know if there's anything planned on them. One is a PR and the other two are market roads. It's my understanding that in the former LGDs, there's a cost sharing with the municipalities on market roads of 50-50. I believe that's the way it works with the province and the former LGDs. These are in the R.M. of Alonsa, one being the Birdinia Road between Highway 50 and Highway 68; that's one of the market roads, another one being east of Rorketon from Rorketon to PR 481, and the third one being PR 481 between Highway 68 and PR 276.

These are all roads that are in terrible shape most of the time, and in the spring of the year almost impassable. It's an area where there are very few roads of any sort and they're not all that well maintained. There's a safety factor, certainly, there. One of those roads goes to the Crane River First Nation and the Crane River Northern Association of Community Councils. I'm told by people who live up there that they have to replace tires on the car twice a year. That's just a kind of a standard because the roads are in such rough shape. I would like to know if there's any plan to do any work on those particular roads.

Mr. Lemieux: Maybe the dilemma that we all face, quite frankly, as rural Manitobans, as Manitobans, is no clearer depicted than questions around transportation, around roads. Each MLA will have a series of roads that are important to them, and it's very difficult to say that the MLA for Ste. Rose's (Mr. Briese) roads are more important than the MLA for Morris (Mrs. Taillieu) or the MLA for Steinbach (Mr. Goertzen), yet, clearly, there has to be a balancing act, even though we have a $4-billion 10-year plan of $400 million a year. Actually, with regard to that, just that we've added on additional today, made an announcement, and an additional $125 million adding to that particular budget.

Even with that expansion, there are some huge challenges around infrastructure and transportation in the province. We are adding, around Highway 68 in the MLA for Ste. Rose's area, about $7-million worth of work just on that Highway 68 in that one stretch. To be frank and forthright with the MLA and, again, this is the first time I have an opportunity to talk to him across this table dealing with Estimates, so welcome and congratulations.

The challenge is still great. There's ongoing maintenance. I'll be frank with you. Ongoing maintenance will take place with regard to those roads, but I'm not sure if the MLA's asking to make sure all of them are paved up to a higher standard or just need more basic tender loving care with regard to these roads. So I'm not sure what the MLA's asking.

Mr. Briese: There are areas on at least one of those roads where the water ran over this year till the end of June. It's below grade level. I believe it's the Birdinia Road at the north end.

You referred to Highway 68 and the amount of money spent on it. Most of that was, I think, spent on the east side of the Narrows, was it not, under the Prairie Grain Roads programs. I believe that's what it was because I was involved in it. I know there was some spent on the west side, but, anyhow, I think the people up there would be happy with just a higher level of maintenance. They're very upset about the quality of those roads. Thank you.

Mr. Lemieux: The $7 million I'm talking about is really, I'm trying to think of Ebb and Flow or the corner that it's at. There's a stretch of 68 that's actually fairly close to Ste. Rose. It's about $7 million. That's a huge amount of money, but 68, again, has been designated as an important route for trade and so on. But the point is well taken from the MLA about roads and the quality of them.

With having 19,000 kilometres of roads in Manitoba to be responsible for, I'm sure he has an appreciation, being involved with the AMM. What we used to call it was the hot seat or the bull pit, the sessions that happened at AMM, and numerous roads are always being discussed. There's a huge oversubscription with regard to ask as to what to do with different roads in the province.

Not unlike other provinces–other provinces across Canada are facing the same dilemma. Our infrastructure is aging, our bridges are aging, infrastructure with regard to sewer and water and so on. We have a huge balancing act as a government, but I believe we're heading in the right direction with this $4-billion 10-year plan. I believe this initiative will take us a long way to addressing our infrastructure challenges that we've got.

***** (18:10)

Mr. Kelvin Goertzen (Steinbach): Irrespective of the fact that I know that the minister has many miles of roads to take care of, I'm still elected to lobby for my miles of roads. So that's what I'll do. With the one question that I have, I'm going to lump in two roads.

The minister knows, being a neighbouring constituency of mine, the growth that we have in the Steinbach region with traffic. He might want to suggest that's as a result of good government; I might say it's good local representation. Probably the truth is that neither of us have anything to do with it, but the fact is it's there. There's lots of vehicle traffic and it's growing as a result of the immigration. I know that he's had many meetings regarding Highway 12 north in the Steinbach area. I believe that highway is actually part of a different report, which designated the intersection of either 12 north and Park or 12 north and Clearspring the most dangerous intersection of its classification in the province, so the need is obviously there in a higher key of other needs.

While there have been some changes to that road as a result of the Superstore being built and Safeway being built–we're running out of grocery stores. I don't know how many other grocery stores are going to put money into redeveloping Highway 12 north, but I would ask the minister, as part of my first question or the first part of my one question, whether or not the council meetings that he had with the City of Steinbach, previous councils, just to see where No. 12 north is on the radar of expenditures.

The other issue that I'll raise and I ask him to address simultaneously is the issue of Highway 311 between Blumenort and Highway 59. The restrictions on there, I believe are at 65 percent. It's caused significant problems for businesses like Bothwell Cheese, for example, who have a difficulty getting their product in and out of the business.

I understand also that more recently the Manitoba Pork Council, it was announced they'll be doing assembly of hogs along 311, so that's going to be causing issues of restrictions. Also, the R.M. of Hanover passed a resolution regarding those restrictions because both the Manitoba Pork Council, who wants to do the assembly of the hogs along that highway through one of the businesses, and Bothwell Cheese–now there are a few others that are in some ways getting a road restricted out of business.

So those two questions: Where Highway 12 north of Steinbach fits onto the minister's radar, and also the restrictions on 311. I want him to be aware of it because the resolution from council has come forward, and there will be a meeting, I understand, with local highway department officials on that issue.

Mr. Lemieux: I thank the MLA for Steinbach for the question.

Steinbach has grown tremendously over the last number of years. I've lived in the region for over 30 years and I know that the MLA, of course, knows it very well equally, certainly, and possibly even better than I. But it has grown and will continue to grow.

Sometimes, and this is not to dodge the question, but sometimes we take announcements of what government does in certain areas in an isolated way. If you take a look at what we've been able to do as a government with regard to Bethesda Personal Care Home, CT scan and so on, the point I'm trying to make here is that often we take what a government does for communities or working with communities in an isolated manner. The point I'm trying to make is that Steinbach is not forgotten by this government.

We have, on the highways side, looked at fixing Clearspring. I believe there's about $2 million budgeted for doing something about that particular stretch, met with recent council, and will continue to meet with council in Steinbach, the newly elected mayor, Chris Goertzen, and others wanting to look at the challenges we have along No. 12.

The reality about the challenges of No. 12 is that businesses have continued to build along No. 12, and they want access to No. 12. So as you start to look at whether it is Penner International, Penner trucking, now they're looking for a new space. Where are they going to put that? They would like to plop it right next to No. 12 highway where you have a lot of traffic going north-south on it on 12 north of Steinbach.

So there are a lot of challenges around the growth, but we're working with the community. We've made a commitment, a budgetary commitment, within our five-year capital plan to address some of them. That's not to say that all of them are going to be addressed, but we're certainly working with council and also wanting to work with the R.M.'s in the area. Hopefully, the R.M.s as well as the City of Steinbach will be able to work in a co-operative manner on a number of different issues, but this particular one is important to the community of Steinbach. We are dedicating dollars from our budget, our five-year capital plan, toward making some changes for the better with regard to safety issues and so on.

With regard to 311 from Blumenort to 59, I've had occasion to speak to some people and people with the R.M. of Hanover. The road is restricted. I'm not sure if it's at 65 or 90. I can clarify that. I think it's 65. Yes, I've been advised that it is 65 percent. Yet it's not that the road is unsafe, but because they're wanting to haul more product with regard to the hog industry related to that road and wanting to get onto Highway 59 they have asked that we consider doing more upgrades. Now I've asked the person who's our regional head to meet with some of the industry to have the discussion as to is it at certain periods of the year that's really hurting them or is it all year round or trying to work around some solution. So just to let the MLA know that there is dialogue going on. We recognize that there are some challenges there with regard to the industry and being able to use larger trucks on those roads.

I understand that Pansy is still on the map, the Manitoba map; it's been put there, just on a lighter note. It was removed accidentally. Now I know that the MLA for Steinbach (Mr. Goertzen) has roots there, so we want to make sure that that community is taking its rightful place on the province of Manitoba map.

Mr. Kevin Lamoureux (Inkster): I wonder if the minister can give indication on when Manitobans can anticipate that the Inkster Boulevard and the construction of Inkster Boulevard would commence.

Mr. Lemieux: Just on that particular project on Inkster, we are very pleased, of course, to be doing a lot of work with regard to that road. We've talked about that particular project on a number of occasions. It's a multi-year project; there's not going to be any hard construction. The design of the project is going to be taking place over the next while.

There's not going to be any construction taking place next year, as I've been advised. But the design is one aspect that has to take place first and the functional design and so on. So just to let the MLA for Inkster know that's really where it stands right now.

Mr. Lamoureux: So we can actually anticipate construction beginning of–you know, in the spring of 2009 roughly?

Mr. Lemieux: There are always challenges around new roads. The challenge, of course, is utilities, land acquisition, those kinds of things. But it's a project that we're doing–and I have to say–in co-operation with the federal government. On occasion I've wanted to hold the federal government's feet to the fire, but in this particular occasion we work very, very closely with the lead minister of the province of Manitoba, the Honourable Vic Toews, as well as Minister Cannon, to ensure that some Asia-Pacific dollars and other monies would come to Manitoba. That particular project was one that we had put out as being very important. I have to take this opportunity to thank the federal government for putting monies into the province of Manitoba on that project. That's not always the case; I won't always be thanking the federal government. But I'll tell you that when it's deserved they will certainly get it from me because I really want to use this opportunity to say so. So we are tied in with them.

The reason why I want to mention to the MLA for Inkster why we're tied in, why this is important and why I raised the Asia-Pacific, because there are some time lines there with regard to spending of monies. So, to make my answer as succinct as possible, we look to start in '09. We're looking to get going as long as the land issues and the issues related to utilities–and once that can be clarified, we'd like to get, and I know the federal government would like to get, moving on this as soon as we can.

***** (18:20)

Mr. Lamoureux: I ask in part because I know not only Manitobans but a number of MLAs are directly affected because of where it's located. To be able to say that at this stage we're looking at engineers and drafters getting together, sometime by the end of 2008 that should be complete, and we're hopeful that in 2009 it will be under construction, that's just to give out kind of like a ballpark explanation to people that might be asking.

What about the portion between Route 90 and Keewatin? I know the City of Winnipeg had talked about it, and there are some trucking companies that are actually in that portion. Is the department aware of what it is the City is doing with that portion?

Mr. Lemieux: To address the question specifically, that portion belongs to the City of Winnipeg that we're referring to. We included that piece within our proposal for the Asia-Pacific monies that the feds would contribute. That was not considered, just the stretch that was provincial road was. To this date, I'm not sure, and the department has advised they're not clear on what the City is going to do with that piece. You're right. It's not a huge stretch, but it is an important stretch, and I know they're considering it.

Mr. Lamoureux: Then I would look to see maybe through the department if they could do all of us a favour and get some sort of a formal response from the City because what we're talking about is right from Main Street, Inkster is virtually doubled. There's just that little section between Keewatin and Route 90. I think that it would be beneficial for all of us, all interested stakeholders, just to understand where the City is at in regard to it. If I could be cc'd a copy of the correspondence, I would appreciate it, in particular if the City responds. This way, it's not the department approaching the City and me approaching the City. I know that they would be very receptive and responsive to what the department requests.

Mr. Lemieux: Well, certainly, the MLA for Inkster can contact the City himself. We are in dialogue with the City on a number of different issues, but there is nothing restricting the MLA for Inkster from contacting the City and saying: Look, what are you going to do about this piece? In fact, it would hold, I am sure, a great deal of weight with the City and the local city councillor to know that the MLA for Inkster is very interested in ensuring that, for safety reasons and other reasons, this piece is addressed.

Mr. Lamoureux: I'll do just that, and I'll cc it to the minister so that he is aware that it has been done, but I do believe it is important that the department should be aware of what is actually being done in that section of Inkster Boulevard, because it would be nice to see that it was done in some form of a co-ordinated effect to minimize traffic problems when construction does get under way. So there should be some sort of co-ordination. That is the reason why I suggested the department needs to also communicate with the City on that point.

The other quick question that I had is in regard to the taxi industry. Recently, I was approached by a cab driver indicating that, you know, they have the cameras inside the taxis. He had indicated that there was a report that was done on one particular incident, and they said, well, because the incident occurred in the front seat, the clarity of the picture isn't as good as it would have been if the incident would have occurred from the back seat. I would have thought that the camera would have had a better reception or more clarity in the front because it is actually on the front windshield. To what degree would the department be aware? Does the minister have staff? I can appreciate he might not have the staff here to answer that question. If that is the case, maybe, again, the minister could get some sort of written response to me.

Mr. Lemieux: Well, I thank the MLA for this. This is something that hasn't been raised to me as an issue or even raised as a point of comment about the clarity of cameras and so on, but I will endeavour to get back to the MLA for Inkster on this. It's the Taxicab Board that, of course, is that regulatory body that works with the cab industry, taxi industry, but I'll certainly look at talking to the chair. There isn't anyone here today to assist me in the answer or to provide me with some clarity, but I will check into it, and I will certainly get back to the MLA for Inkster about it.

Mrs. Mavis Taillieu (Morris): A couple of questions. I, first of all, just want to acknowledge the work on Highway 75, which was necessary, and, I'm sure, will be ongoing. Looking forward to seeing it completed right from the city of Winnipeg down to the border.

Having said that, I wanted to ask a question in regard to the shoofly on Highway No. 1 just west of Headingley. This looks like it is, say, a diversion to allow for a culvert that is going under the highway. If the minister's not familiar with the term "shoofly," it's just a bypass. But I want to question about that because, as we saw the work proceed on Highway 75, the traffic, of course, and it's a larger area, of course, but the traffic was diverted to the opposite side of the highway for quite some time. In this case, it looks like another road or a diversion, a detour is being built specifically to divert the traffic. It also appears that the culvert will be have to be done on the other side of the divided highway as well. I know that there could be issues around turning radius and this kind of thing. But I'd like to ask the minister: What is the cost of this project in the short on the one side of the highway, and then, again, will it be done on the other side of the highway, and how much will that cost?

Mr. Lemieux: Well, thank you to the MLA for Morris for the question. If the MLA doesn't ask these questions, who else is going to? But I just wanted to respond by saying that there are a couple of culvert jobs that need to be done, not on both sides necessarily. I've been advised that we're not looking at doing both sides. The culvert has taken stress more on one side than the other, so it looks like we may be just doing one side. So it won't be necessary to do both sides.

But we haven't tendered the jobs out yet, so I'm hesitant to talk about the kind of monies that are involved in the big project to do both. We're actually doing two culverts at different sections of No. 1. But it's in the millions of dollars to do both of these, and a substantial amount of money is being spent.

I know the MLA didn't purposely leave out all the work that's been done around the community of Headingley and the stretch between the Perimeter and Headingley and the weigh scales. But maybe I can use the opportunity of just mentioning how much work has been done and the tremendous amount of work that's been done on No. 1 west and near the Flying J. We appreciate the co-operation we receive from Flying J as well as others to fix that intersection up, as well as the reeve for the R.M. of Headingley. It's always a pleasure to work with him. We know that there are a lot of other projects we have to work on, but Highway 75 will continue. We made a commitment to ensure Highway 75 would be improved. So I know the MLA for Morris will be pleased to hear that.

Mrs. Taillieu: I do recognize the hard work of the Rural Municipality of Headingley in getting and procuring a Flying J restaurant to that stretch of highway, and the work that has ensued to upgrade the road there.

Just in regard to this particular shoofly on the highway, it's a small detour, but would it not have made sense–and I'm just simply asking the question–to divert the traffic down the other side of the highway? I know there are a number of mile roads that could have happened. I also do recognize, of course, that the turning radius for larger trucks could have been a problem, but it just seems to me that there may have been another alternative.

Mr. Lemieux: I thank the member, the MLA. I know neither one of us are engineers, and we leave it up to the professionals to make those decisions. So we trust their decision is the right one on behalf of the taxpayer and all of us.

Madam Chairperson: The time being 6:30 p.m., committee rise.

AGRICULTURE, FOOD AND RURAL INITIATIVES

***** (15:00)

Mr. Chairperson (Rob Altemeyer): Good afternoon. Will the Committee of Supply please come to order.

This section of the Committee of Supply will now resume consideration of the Estimates for the Department of Agriculture, Food and Rural Initiatives. As had been previously agreed, questioning for this department will proceed in a general manner with the resolutions to be passed once all questioning is completed, with the exception of resolution 3.2, which will be passed once questioning on that section of the department is completed.

Now I'd also like to remind everyone, as agreed to in the Chamber just now, that we will be discussing Estimates for this department until 5 o'clock and then from 5 to 6:30 we will switch to deliberation on Conservation Estimates.

I also understand the minister has a comment to make at the beginning, so we allow that to proceed.

Hon. Rosann Wowchuk (Minister of Agriculture, Food and Rural Initiatives): Mr. Chairman, I would like to provide some information to a question that was asked yesterday, if I could.

The Member for Lakeside (Mr. Eichler) asked a question about how many untendered contracts over $25,000 did MAFRI enter into, in '06-07. During the fiscal year '06-07, MAFRI entered into one untendered contract over $25,000. That contract was with a University of Manitoba Ph.D. student who has extensive expertise in the type of information we were requesting, and that is science-based risk assessment for bovine tuberculosis. We have used this individual in the past, and he provides excellent information.

There was also a sole-source contract in 2006-07 over $25,000, and that was for the rental of all the audio-visual equipment used at Rural Forum in Brandon. This is a sole-source supplier contract with a local business in Brandon. There is another sole-source untendered contract for survey maps, and there is only one supplier for those maps.

Mr. Ralph Eichler (Lakeside): I thank the minister for her information, and her staff. Just for the record, the Ph.D. student for the science-based study, who was that individual, Madam Minister?

Ms. Wowchuk: The student is Ryan Brook.

Mr. Eichler: Thank you, Madam Minister.

Mr. Chair, my colleague from Russell, the critic for Rural Development, has a funeral tomorrow, and we've asked the minister earlier if it would be okay to leave the MASC for now and come back to it tomorrow. The rest of the afternoon will be dedicated to Rural Economic Development Initiatives by the Member for Russell, and I'm sure I'll probably have some questions as well. So, if it's okay, we'd like to proceed on that basis with the minister.

Ms. Wowchuk: Mr. Chairperson, certainly that's okay. I would like to introduce Dori Gingera-Beauchemin, who is the Assistant Deputy Minister of the Agri-Food and Rural Development division, who has now joined us at the table, as well as my deputy, Marvin Richter.

Mr. Chairperson: Very good. The floor is now open for questions.

Mr. Leonard Derkach (Russell): Let me, I guess, begin in a general sense by stating somewhat of a disappointment in terms of how the Rural Development side of this department has been, I guess, responding to the issues that are in rural Manitoba, although I note that this is not a reflection on staff because certainly staff of the department have done everything they possibly can, given the constraints that government has put on them.

This is a direct comment on the policies of the government by diminishing the importance of rural economic development in Manitoba and folding it in with the Department of Agriculture and also stripping a lot of the department budget that was formally in the Department of Rural Development to a point where it has become an ineffective tool, if I might add, in terms of addressing many of the needs of rural Manitobans.

I want to ask the minister first of all whether she can separate and identify for us the global budget for rural economic development in Manitoba.

Ms. Wowchuk: Mr. Chairperson, under the Rural Economic Development Initiatives, the budget is $21.108 million, but that does not include the 11 business development specialists that are outside this amount. They are included in the Go Team alliance. So that's the amount that we have budgeted here.

Mr. Derkach: So a department that used to have a budget of $50 million has now been diminished to a $21-million department. Is that correct?

Ms. Wowchuk: Mr. Chairman, when the reorganization was done, the time that the member refers to was a time when there were other responsibilities under Rural Development, responsibilities such as conservation districts, Water Services Board. We have made some changes and the responsibilities, the Rural Economic Development Initiative is under this department, so it would be inaccurate to say that it has diminished from over $50 million to $21 million. Some of the responsibilities are in other departments and the dollars went with them.

Mr. Derkach: Mr. Chairman, if that is an inaccurate number, can the minister tell me what the accurate number is in terms of how the department has diminished over the course of the last eight years?

Ms. Wowchuk: Mr. Chairman, if you look back to 1998-99, the Rural Economic Development Initiatives had a budget of about $21 million. It was $21 million in 1999-2000. When it came to our department in 2002-2003, that budget was at $16.225 million, and since that time it has come up and it is $21.305 million. So the member is referring to a time when they were in government, 1999, it was at $21,000–$21 million, I should say–and it is at $21.3 million now. So the Rural Economic Development Initiatives are at about the same level that they were in 1998-99.

Mr. Derkach: Well except that the minister forgets that some of the programming that was eliminated also eliminated the dollars with it.

First of all, I'd like to ask the minister where the dollars that were identified for and designated for Grow Bonds, where did that money go to?

There was, I believe, $40 million in total for Grow Bonds at the time. My numbers might be a little dated, but nevertheless that was money that was set aside to guarantee the Grow Bonds program. The government eliminated the Grow Bonds program. The money that was in that file came from video lottery terminals. There was a promise by the former administration, of course, that money generated from VLTs in rural Manitoba and Winnipeg would be split 50-50 and the money that was used from VLTs for rural Manitoba would be used for economic development initiatives.

I'd like to ask the minister where the money from VLTs that was designated for the Grow Bonds program was redesignated for.

***** (15:10)

Ms. Wowchuk: Mr. Chairman, when the member talks about $40 million being available for Grow Bonds, that was the provision for capital authority. That was not the actual amount that was there; that was provincial guarantees, but that would not have been the amount that was budgeted every year. There would have been a budgeted amount, but the whole $40 million would not have been the amount that was budgeted.

So we have gone from a grow bond to a CED tax credit that supports investments in communities and there are some good results with that. I could say to the member that there are still some outstanding provincial guarantees under the Grow Bonds, so there is still money provided there. But we have moved to a system of CED tax credits, Mr. Chairman, and we feel that this is a tax credit that encourages local private investment in Manitoba-based opportunities by providing community-based enterprise development projects with the means to raise the necessary equity capital. That's the purpose of it and it is working.

So there is economic development money available, but it is in a different form than under the previous administration when they were offering the Grow Bonds program. There are also the Community Works Loan Program and the Communities Economic Development Fund that are also available through the funds in this program.

Mr. Derkach: We are getting into the same realm that we were last evening when we adjourned here. Is the minister telling me that the tax credit program is now somehow utilizing VLT dollars? So are we now saying that VLT dollars are being used to shore up a tax credit program for businesses in rural Manitoba? Is that what I'm hearing from the minister?

Ms. Wowchuk: Mr. Chairman, just as the Grow Bonds program uses tax dollars to make grants to raise money for CED, a tax credit encourages local private investments in Manitoba-based opportunities by providing community-based enterprise development projects with a means to raise the necessary equity capital. Just as they raise capital under the grow bonds by selling shares, they raise money under–they use the tax credit as a vehicle as well.

Mr. Derkach: Well, this is getting more interesting as the minister answers the questions. The minister is telling me that we use the Grow Bonds program as a tax credit program. We never did. Nobody ever did. The Grow Bonds program was one where local capital was guaranteed by a Grow Bond, by the VLT money that was set aside for that purpose. Nowhere in that program was there ever a tax credit program given to businesses utilizing VLT money. But the minister here is telling me is that there's somehow, now, a tax credit program developed for economic development in rural Manitoba utilizing VLT money as tax credit dollars. Is that what she's telling us in the House or in this Chamber?

Ms. Wowchuk: Mr. Chairperson, under the previous administration, Grow Bonds or VLT money, as the member opposite talks about, VLT money was used to raise local capital and then VLT money was used to pay off the losses from the Grow Bonds projects that weren't successful. That's what the money was used for.

In this case, it is just a different vehicle that we have chosen, and the CED tax credit encourages local private investment in Manitoba-based opportunities to provide community-based enterprise development projects with a means to raise the necessary equity capital. It's the same used under your administration. You were using VLT money to guarantee Grow Bonds and pay off the losses if there were any. In this case, we are using it to encourage people to invest in their community.

Mr. Derkach: Well, there is a very distinct departure here, Mr. Chair. I'm not an economics major, but I can tell you there's a very, very big difference between using money from Grow Bonds, from the VLTs, to use those monies as a guarantee for money that is invested by local investors into an enterprise and using money from VLTs as a tax credit shore-up for businesses that are starting up.

Can the minister tell me, if I am a business, today, starting up, and I enter the CED tax credit program, I get a tax credit for starting up the business? How is that shortfall made up to government? Is that where the VLT money is used?

Ms. Wowchuk: Mr. Chairperson, the business does not get the tax credit. It is the individual who makes the investment in the local venture and they have to get approval before they can move forward with their tax credit. But, yes, the individual who makes the investment earns a tax credit that they collect on their income tax. Just as under the previous administration, if there was a loss, money was used to pay off the loans.

Mr. Derkach: Excuse me for my lack of understanding as to how the process works. I'm going to ask the minister to explain it once again. As I understand it, the individual who invests in an enterprise gets a tax credit. If that tax credit is $5,000, that individual gets a receipt from the Department of Finance that would give them a tax credit on their income tax of $5,000. Where does the VLT money come in then? How is the VLT money used then? Is the VLT money then used to pay that $5,000 to the government for the tax credit that they give to the individual?

***** (15:20)

Ms. Wowchuk: Yes, this money is targeted for projects in rural Manitoba. So that is why the appropriation is under the rural economic development system. It is a tax credit system and the money flows through the tax system, but, just to say in this case, they get a tax credit. Under the Grow Bonds, if there was a loss, it was a direct payment to the individual for the losses that they might have had on the Grow Bond. It is a different mechanism, but in each case the money is used to encourage rural economic development.

Mr. Derkach: Mr. Chair, let me just try to put this in perspective.

Under the Grow Bonds program a local investor invested in a project. He invested in the project at a particular interest rate. The business that he was investing in had to pay him back the principal and whatever interest rate was determined in the agreement. If the business failed, the province through the Grow Bonds program, through the VLT money, guaranteed that the investor would not lose his or her principal. The interest would be lost but not the principal. That's it. Not every single person who invested in projects got money. They earned their money from investing in the enterprise.

What the minister under this program is telling us is that now individuals can invest in local businesses, and that individual then gets a tax credit on his personal income tax when he files it. That tax credit that that individual gets now, apparently, is shored up to the government, to the tax department, to the provincial treasury, by VLT money. Is that what is really happening under this program?

Ms. Wowchuk: The member surely knows that one of the challenges that people in rural Manitoba face when it comes to starting up a business is to raise equity. That's why, Mr. Chairman, under this program it is just a matter of flowing the, of advancing the money to the individuals sooner rather than later because they make the investment, they get their tax credit up front and then they have the ability to raise more money. The member talks as if some money, paying off somebody's debt if a bad investment is made is different than giving an advance up front. The member may think that that's different, that's fine, but I can tell him that there have been projects that have looked at the CED tax credit and have been able, because of this tax credit, to make viable business ventures in rural Manitoba. This is about looking at ways that we can help people raise money.

I look at Pilot Mound co-op committee. They were able to take advantage of this. Bowsman community store, a grocery store, where there would only have been one if it wasn't for–but they were able to use this tax credit and raise their money. Clearwater Development Corporation used it. Biodiesels were able to use this vehicle to raise the money that they needed. There are many groups that are looking at this as a way to raise the equity that they need in order to build viable projects and viable businesses in rural Manitoba.

The member may not agree with this approach, and he seems to be saying that we are using this money to offset taxes. In reality we are using this money to start businesses, and of the $15.2 million that have been approved, the program–

The member talks about how Grow Bonds didn't pay out as much or this might be paying out money up front. I'm not sure what his concern is, but of $15.29 million approved under the Grow Bonds they paid out $6.689 million in net guarantees. There was money paid out under Grow Bonds, and under this program there is money that is being paid out through a tax credit system to encourage investment in rural Manitoba, and the investment is taking place.

Mr. Derkach: I should illustrate this for the minister if I might. Under the Grow Bonds program, if I use her numbers of $50 million–

An Honourable Member: Fifteen. Fifteen.

Mr. Derkach: There was over 50 invested, I know that. But okay, out of 15, $6 million dollars she said was paid out in loans. Under her program, if that were the budget, $15 million would be paid out, not 6, because under the tax credit program you would have to pay that out.

I want to ask the minister: What rate of interest or what tax credit rate is used when an investor invests? What rate of tax credit do they get? Is it at 10 percent, 15 percent, 30 percent? What is it?

Ms. Wowchuk: A Manitoban who invests in an eligible local enterprise will earn a 30 percent income tax credit on a maximum annual investment of $30,000 or get $9,000 in tax credits, and no individual can acquire more than 10 percent of any issue.

Mr. Derkach: Mr. Chair, the individual who invests gets a 30 percent tax credit and on top of that tax credit that individual then takes a share in the company and would receive a dividend from the company as well. The principal of that individual who invests in a business whether it's $30,000 or $10,000, is there any guarantee on the principal that is invested in that company?

Ms. Wowchuk: No, Mr. Chairman, there is no guarantee under investment, but they can get a 30 percent personal income tax maximum amount.

Mr. Derkach: Does the individual who takes a share in that company, does that individual then get eligibility for dividends from the company, or then is that individual also allowed to share in the profits of the company?

Ms. Wowchuk: If the company is successful then they would be able to share it. I don't think you could get people to invest if they thought that they weren't also going to share in the profits if those profits become a reality.

***** (15:30)

Mr. Derkach: So what the minister is telling us is that the individual gets a 30 percent tax credit, is able to capitalize on the project if in fact the project is a successful one, can earn dividends from the project as well, and can share in the profit if the business is sold.

Ms. Wowchuk: Mr. Chairman, that's what investing is about. That's what all investors expect. They invest because they think a project is going to be successful. They don't invest because they think they're going to get a tax credit. They invest because they want the business to succeed, but they have no guarantee that it will be successful, and that is the risk that they're taking, but ultimately they and we want these projects to succeed.

Mr. Derkach: Mr. Chairman, can I ask the minister how much money has been set aside from the VLT program for this tax credit program.

Ms. Wowchuk: $300,000 in this budget, Mr. Chairman.

Mr. Derkach: So, Mr. Chair, is that what the annual budget is for this program, $300,000 a year of VLT money?

Ms. Wowchuk: That's the amount that is budgeted this year. We could make an adjustment when we're doing the next budget, but that's what it is this year.

Mr. Derkach: So can the minister tell me where all of the VLT money that had been designated for the guarantees now flows?

Ms. Wowchuk: Mr. Chairman, as I indicated, the Rural Economic Development Initiative is at $21.305 million and in that line there is also sufficient provision that has been made for the Grow Bonds that are still outstanding should there be need to pay out that money. It is in there as well.

Oh, I'm sorry. There is also a provision, but it's not within the 21. That's been put aside in previous years.

Mr. Derkach: Well, Mr. Chair, I did not get an answer to my question. It appears that the minister is somewhat confused here, but we need to move on, and I'm going to ask the minister how much VLT money went to the provincial treasury this year. Was it the $300,000, or was that what was set aside from the VLT program to compensate for the tax credit program that was invested in by individuals in Manitoba?

Ms. Wowchuk: I will try to answer the member's question and I hope I'm getting it right, but $300,000 has been set aside out of the budget that I referred to for the tax credit. If I'm not getting the question right, I would ask the member to repeat it.

Mr. Derkach: In simple terms, can the minister tell me how much of the $300,000 was spent?

Ms. Wowchuk: In the last fiscal year we spent $310,510 on the tax credit. This year we have budgeted $300,000.

Mr. Derkach: Surely this can't be for all of rural Manitoba. That number is just too small. Can the minister review that number and tell me whether this meagre amount is for all of the businesses that have started up under this program in rural Manitoba for one year?

Ms. Wowchuk: Mr. Chairperson, last year was the first year of that program. There were three successful applications for the program and that is the amount of the tax credit. We anticipate and in fact there are more applications this year for the program, but we budgeted according to what we had last year. We anticipate that we will probably be over budget because there is an increased number of applications this year, but in the first year that we had the program there were three applications.

Mr. Derkach: A province as large as Manitoba, I don't know how many rural communities, and we have three projects in the province for one year. Is that what the minister's telling me?

Ms. Wowchuk: There were three projects that were approved for a tax credit. There were many other projects of economic development that have taken place in this province. What I'm telling the member is three projects were successful in getting a CED tax credit program and that resulted in a tax credit of $310,500.

Mr. Derkach: Can the minister tell me the disclosed businesses that received part of the program– whatever it was, $310,000, who the businesses were and where they're located?

Ms. Wowchuk: There was a Clearwater Development Corporation in Clearwater, Bifrost Bio-Blends in Arborg, and Intermountain Forage Limited in Dauphin.

An Honourable Member: What is it?

Ms. Wowchuk: Intermountain Forage in Dauphin. Those were the three that were successful in the first year of the program's existence.

Mr. Derkach: I'd like to move to another area because my time is limited, Mr. Chair, and although we could spend hours debating this, I want to ask just one more question on this. The tax credit that is provided, is that a one-time tax credit?

Ms. Wowchuk: Yes, Mr. Chairman.

Mr. Derkach: I'd like to move to another area and that is the area of the cattle slaughter facility in Dauphin, again another failed attempt by this government to do anything constructive in the whole area of product processing in this province. I want to ask the minister if she can explain how it is that that project failed so miserably.

***** (15:40)

Ms. Wowchuk: Mr. Chairman, the cattle slaughter facility in Dauphin grew out of the whole BSE crisis. There was a real recognition that there was need for slaughter capacity in this province and a group of producers got together. This government was very supportive of the project, made a significant amount of money available, took the steps to be sure that the investment in infrastructure was there. But I guess the members opposite could also, I would remind the members opposite that their critics were saying that we didn't need slaughter capacity in this province. They didn't do anything to encourage producers to participate.

At the end of the day, despite the significant support that was put in place, the Ranchers Choice group had been doing fundraising and were not able to raise adequate money to meet the producer's share. I would remind the member that when this got started, the producers told us clearly that they did not want the province to be building a slaughter facility. They wanted support from government. We were there to support them. Unfortunately, they were not able to raise enough of the producer equity that was required, and I guess, I would say, I feel very saddened that this didn't become a reality.

But the slaughter industry is a very tough industry, and there have been others who have attempted to build slaughter processing facilities since the time of BSE and others still look to do it. We will continue to work with the producers of Manitoba or the processors of Manitoba as others look at opportunities to increase slaughter capacity in this province.

Mr. Derkach: Well, Mr. Chair, I don't have to recite history for the minister because this whole project went from bad to worse under her watch.

First of all, it wasn't just the capital that needed to be raised by local producers because I believe that if the government had had the climate correctly, there would have been the investment in the project. You can't create questions in the minds of investors and expect them to invest.

When the Securities Commission pointed out to the government and the project that they had erred horribly in–yes, you were part of that, Madam Minister, and the error that was made with regard to the registration of the project, and the collection of money, and the purchase of equipment before the Securities Commission had actually given the green light; this caused a big question in the minds of people who were wanting to invest. Then, when you had to re-structure the entire project, once again, that raised questions in the minds of people.

Today, government's money is lying in a pile of rubble in equipment that can't be used, and I'd like to ask the minister how much provincial money was wasted on this project to date.

Ms. Wowchuk: I have to correct the member because the issues at the Securities Commission were not our issues. The decisions were made by the board. With their legal counsel they made the decision on how they should apply to the Securities Commission. There was an error made. They had to reapply and work through it. So that's what happened with the Securities Commission. The member, of course, can spin it anyway he wants that this government is responsible for that, but the members opposite are also responsible for a lot of language that they put into the media about no need for slaughter capacity in this province. Issues like that did not help with investments.

With regard to this facility, the member asked about how much money was wasted. Well, you know, it's just like some Grow Bond projects that the member opposite was part of when they thought something could work. It didn't work and money had to be paid out. I think there was a significant investment in Elie that did not work and there was a huge write-off on Grow Bonds. That was a decision made by the previous government. The member asks specifically. I would say that we are in the range of about $4.8 million that was invested in this project. When it is all finalized, the equipment will revert back to the province, and I'm still hopeful that there are others who will be interested in this project.

I can say to you, just last weekend, I met with an individual who was asking about the equipment and whether there is a possibility of him acquiring it. So there are still people that are interested in slaughter capacity in this province, but it was a significant investment and I regret that it did not come to fruition.

Mr. Derkach: I think we all regret that it didn't happen, Mr. Chairperson. But there were other projects on the table that the Province refused to look at. One of them was the proposal by Natural Valley to build a slaughter facility in Neepawa.

When we asked questions of the minister in the House, she refused to even acknowledge that this was a project that they were anywhere interested in and continued to refer to the Dauphin project. Not that the Dauphin project was a negative one, but there was also a desire by people who were investing in Natural Valley to see their infrastructure needs in Neepawa enhanced so that they could proceed with their project. That never happened also.

In addition to that, I understand that when it came to the Dauphin infrastructure issue, both the federal government and the City of Dauphin had made commitments to the infrastructure, whereas this government did not.

Can the minister tell me whether or not their commitment was on the table and how much it was for the infrastructure and the upgrading of the effluent and water treatment plant in Dauphin?

Ms. Wowchuk: I hate to tell the member this, but he is wrong on both counts. On the Dauphin infrastructure, the federal and provincial governments made the announcement at the same time. It was a $10-million project. It was a three-way split between the federal government, the provincial government, the city and the R.M. Our money was on the table.

***** (15:50)

With regard to Natural Valley Beef, I would support Natural Valley Beef. We've told them time and again to come forward with a business plan: Tell us what you're going to do. They have not come forward with a business plan to this point on building a slaughter facility. They are working on another business plan at the present time, but they never came forward with a plan on building this facility. They talked about it, but when you came down to the nitty-gritty they were not able to provide us with the plan and the member would know, from his time in government, before you invest in a facility you have to know what their business plan is and work through it with them as well.

Mr. Derkach: I thank the minister for her response and I stand corrected. She is right about the $10-million announcement that was made. I just forgot, but I know that the Province was dragged into it kicking and screaming in a way. But let me ask a question about the hemp plant in Dauphin now.

Can the minister tell me why it is, here's a plant that was also, I guess designated for the area, significant dollars were invested by producers and now this project has, once again, for about the third time, fallen down and mothballed because, as has been reported in the papers, had the government come in early, the speculation is that we would've helped to attract the balance of money. The delay–that was a comment made by Don Dewar as a matter of fact, and he is a community member of Dauphin. I don't know. Maybe the minister has a cynical view of him, but indeed he is a significant contributor to the community and an investor in the project and so I have to take his word at its face value. I ask the minister why it is that once again we have another failed project under her watch.

Ms. Wowchuk: First of all, I would like to say that we're now joined at the table by Allan Preston, who is Assistant Deputy Minister for Agri-Industry Development and Innovation division. Welcome to the table.

When groups try to raise money and when they run into difficulties, there are some that will say, well, if the government had been at the table we could have raised money. When this group went out to the market, they had a plan to raise money. They didn't say to the producers, well, we are getting this much money from government. When they couldn't raise their money, they looked for additional money, but, had we funded that amount that they wanted, we would have been well over 50 percent of the project and that was just, you know, a significant amount of money.

However, it was the producers that made the decision that they would close their share-offering and return the money. That was a producer's decision, and we are still working with them, looking for a way to redesign the project so that it can fit in with what they are able to raise. So there is a certain point that you can go to and there is a certain amount of money that government can contribute. I could say to the member that we made every effort to get the project scaled down to size, but if you're going to go start scaling down the project, then with their share offering they would be having to refund anyway so rather than–because you're changing the project. They made the decision that they would close their share offering, and we are still working with them to redesign that project.

Mr. Derkach: Mr. Chair, in an article, Mr. Dewar indicates that they were looking for the Province to take an equity position in this hemp processing plant similar to the position that the government had enunciated for Ranchers Choice. Was the province prepared to take the same position with this hemp processing plant as they were with Ranchers Choice?

Ms. Wowchuk: Mr. Chairman, every project has to be dealt with in an individual way because every project is different. When the individuals first came to us, they came to us for a MIOP loan, and the MIOP loan was supposed to help them secure their investors. We made the commitment of the MIOP loan and they went out to the investors. When they weren't able to raise as much money as they thought they were able to, we made a commitment to assist with equipment, with purchasing some of the equipment. That would reduce their capital plan.

So we looked at every way that we could help them, and we met what they had asked for, a MIOP loan and then an investment in equipment, but even with those investments, they could not raise enough local capital so that they could then do the borrowing that they had to do.

Mr. Derkach: Can the minister tell me whether the investors in this project were given the same opportunities as investors in the CED tax rebate program, whether investors in the hemp plant were eligible for a tax rebate program?

Ms. Wowchuk: Mr. Chairman, the group did not apply for a CED tax credit, and I think part of it is they didn't want to make their application complicated, but the other issue is that some of the investment by producers is straw. So that's how they were building up some of their investments and that wouldn't have qualified but, basically, they did not apply for a CED tax credit.

***** (16:00)

Mr. Derkach: I just want to make sure I heard the minister correctly. Did the Province offer the tax credit system to the investors? Now, this is not offering it to the project; you're offering it to the investors in the project because, as the minister said, this is an individual tax credit on an investment in a business.

There is no particular size, as I understand from the minister, in terms of the business, but worthy individual producers or the individual investors, whether it's straw or money, were they offered a tax credit program to try to entice and attract investment into the hemp project, and is that still available to them if they were able to apply for a tax credit for the money that they have invested thus far in the project?

Ms. Wowchuk: The program was discussed with the producers, and if they were going to take advantage of the program, the project would have to make an application through their local economic development board. Yes, there is a cap on the amount that could be used for this. They were aware, but they did not make application.

Mr. Derkach: So the minister is telling me that the project could not attract enough investment, yet there is a 30 percent tax credit program available to people who invest in businesses of this nature. She is telling me that the people who are on the board of the hemp plant chose not to apply for the tax credit program, yet they were seeking investment from investors without offering them a program designed by the government to give them a 30 percent tax credit. Is that what the minister is telling me?

Ms. Wowchuk: Mr. Chairman, this program is targeted at smaller projects. It's targeted. I said to the member opposite they were made aware of the program and they could have applied but there is a cap to the amount. The eligible investment right now is to a maximum amount of $500,000.

So this project would have been greater than that, so if they would have been able to raise it–*[interjection]* So they could have applied for up to that amount of money, but they chose not to.

Mr. Derkach: Can I ask the minister whether or not people who are investing in Ranchers Choice were made aware and given the opportunity to take advantage of the tax credit program?

Ms. Wowchuk: On the hemp project, I can say to the member, this project isn't over. They have talked to us and they have said they want to return their share offering but we continue to work with them. There are further plans to work with them that I'm not at liberty to talk about. But they are working at trying to bring this project to reality.

With regard to Ranchers Choice, this program was available at the time, but I think we have to remember that when they first started Ranchers Choice they were talking of commitment of cattle. They weren't talking about dollars. They were looking for producers; they were signing up cattle. Some of the amounts were very small amounts that were being put in. I guess I can't tell you. They didn't apply. They could have applied, and they were working with people who were aware of the program, but, no, they did not apply for the program.

Mr. Derkach: Again, the minister points the finger at everybody else but herself.

I was approached to be an investor in Ranchers Choice. Our family was. It wasn't cattle that we were initially investing. It was money.

Had the project come to me or to any investor and said, if you invest a thousand dollars you can get a 30 percent tax credit on your money because this is a program that the government has in place, I don't think there would have been a great difficulty to collect the money. The government either completely hid the opportunity for people to get the tax credit who were investing in these enterprises, or somehow misled the enterprises themselves, because I can't see why an enterprise that wants to attract capital would reject the opportunity for people to have a 30 percent tax credit when they invest some money in it. That just doesn't make any sense.

I would like the minister to explain why Ranchers Choice or the hemp plant would reject a 30 percent investment credit program for people who invest in their projects. Can she explain that?

Ms. Wowchuk: Mr. Chairman, it's very difficult for me to answer for a board as to why they didn't apply. There is a producer board. They were given legal advice, and I cannot tell the member why they didn't apply for the tax credit. The program was just getting started at the time. It had been brought in December of '04. That was just about the time that they were starting to raise their money. It may have been the structure. It may have been that they were, I cannot answer the question as to why that board made a decision not to take advantage of the tax credit.

***** (16:10)

Mr. Derkach: I don't want to dwell on this too much more, but I think what is on *Hansard* is important.

Mr. Chair, I just want to ask the minister whether or not this program was offered by the government. The minister knew that there was difficulty in raising capital, both at the hemp plant and at Ranchers Choice. Did she direct her staff to offer the tax credit program to people who were investing in either Ranchers Choice or the hemp plant?

Ms. Wowchuk: Mr. Chairman, when investors come to the government to talk about projects, our staff make them aware of all of the programs that are there. They're made aware of them and then it's up to the individuals to decide which programs they want to take advantage of. Some will come and look for a MIOP loan. Some will come looking to the government to take an equity position. But everything is made available to them, and this program was made available to them as well. They were aware of all the programs we have to offer.

Mr. Derkach: I'm happy that the minister has answered that question because, indeed, this is something that I will pursue because in all my discussions, I had never ever been aware. Even though I was approached as a potential investor, no one had ever offered a program or made me aware that there was an availability of a tax credit program on a personal income tax basis if I were to invest in a project.

Ms. Wowchuk: Remember, that isn't available to an individual. There has to be a sponsorship of the project by the local community development corporation. So maybe they went to the local community development corporation and it wasn't endorsed. I'm not sure whether they went there or not. But they could not come to an individual and say there is a tax credit available if they do not get the endorsement of the project.

Mr. Derkach: Well, Mr. Chair, this is all a question of awareness, because I'm sure that I could go to people whom I know who have invested in the project and ask them whether they were even made aware of the tax credit program availability. I'm sure that in 99 percent of the cases, I will get the answer that they were not aware of the fact that there could be. So how could they even go and lobby their corporation, their community development corporation, if they weren't aware that this project could qualify for a 30 percent tax rebate program?

I can't see, Mr. Chair, how it is that anybody would reject investing in a project that they wanted to see in their community, knowing that they could get a 30 percent tax rebate if they were offered that opportunity. I know that investors around the Dauphin area, if they knew that they could have had a 30 percent tax credit had they got the approval of their local community economic development office, will go to that community economic development office today and ask them why that project was not approved by that community development office, because that's what the minister is saying.

Ms. Wowchuk: That's not what I said. What I said is, when there's a project, it is up to the proponents of the project to take it to the community economic development committee and seek approval. I do not seek endorsement for the project. I do not know what steps they took, whether they went to the economic development–but the individuals would not know about it unless it was approved, endorsed by, and then an application was made for approval.

Mr. Derkach: Well, this is a truly bizarre issue, Mr. Chair, because here we have struggling enterprises who are trying to raise capital from individuals, who are approaching individuals to invest, and yet here is a program that was supposed to have been designed for these very types of economic development initiatives in rural Manitoba that people don't know about. I think it's the minister's responsibility to ensure that, for example, Ranchers Choice had every available tool at their disposal to be able to attract as much capital as they could to the project to make the project viable and successful.

So I regret that that issue is one that wasn't taken advantage of, and I know that in the future I'm going to ensure that Manitobans know that these types of programs are available and they need to be applying through their community economic development office to take advantage of these programs. This is not the end of the world, but certainly it does indicate a management issue on the part of the minister here.

Ms. Wowchuk: Mr. Chairman, when people come to us with projects, our economic development officers, our staff make them aware of every available tool that is there. They were, I'm sure, made aware of this, but there are limitations to this program, and their program, they may have looked at it and the size of their project may have been beyond what was available through this program. But I can assure the member that all of the programs that we have available through government, the proponents were made aware of them, our staff worked very closely with them and indeed spent countless hours as they worked on this project.

Mr. Derkach: Mr. Chair, I don't doubt anything that the minister says in terms of the staff commitment to it.

I want to go to another project, and I'm sorry that we're–*[interjection]*

Mr. Chair, I would like to ask whether or not there has been any discussion with Pizzey Milling regarding the sale of the technology to an Irish firm.

Ms. Wowchuk: This is a sale between Pizzey's and the Irish company. It's a private sale, they have not approached us and we have not had any discussion with them to this point.

Mr. Derkach: Mr. Chair, I'm just interested, and it's only for information. I'm seeking information whether or not any of the departmental staff have had an opportunity to discuss with the Pizzeys in the last six months how it is that we could perhaps retain the intelligence, the knowledge and the development of the products that the Pizzeys have developed over the course of time where the growth and benefit of Manitoba industries rather than this technology now escaping the country for that matter and going to an Irish firm. Or whether or not there's an opportunity for the Irish firm to indeed continue to develop the technologies with regard to flax products here in Canada. I know one of the hurdles is going to be the tax credits that are provided for research and for the development of new products.

I think this is such an important initiative in Manitoba that it would do us all good if we could perhaps enter into some discussions, either with the new company or with Pizzey's, regarding the future of the enterprise for Manitoba and for Canada and also the retention of that plant within this province.

***** (16:20)

Mr. Chairperson: Order.

Ms. Wowchuk: Thank you, Mr. Chairperson. The member raises a very important and interesting issue and the sale has just recently taken place. I can tell the member that we haven't talked directly to Pizzey's or the new company since the sale took place but we have had very close working relationships with Pizzey's.

Our staff had a meeting with them where they did a presentation on rural entrepreneurship. There is a group, a project called Flax 2015 that engages the federal-provincial government and the industry in looking at how you can further move the flax industry along, and Mr. Pizzey is on that board so our staff has regular discussions with him.

We were driving out to Souris the other day and we were having this discussion about how we have to make contact with the new company and see what steps we can take because surely if there's anything we can do to keep the jobs here and advance the technology here in Manitoba, it's what we would want to do.

Mr. Derkach: I thank the minister for that, and I think that's an important initiative for us to undertake on behalf of Manitobans because the innovation that has taken place in that particular industry is important, I think, to us in this province. And I know that we can't interfere in a private deal between two private companies, but if there is something that we can do to retain the technology, to retain the processing here in Manitoba I encourage the minister and her department to undertake to do what they can in that regard.

I certainly don't have the answers, but I am somewhat anxious about the fact that this sale could in fact over time spell the, sort of the closure of that plant here in the province, because there are some real issues facing the location of that particular plant, in that access is the one thing that I think has been enunciated. They have to get their product to market on time and when they face the kind of restrictions that they are facing in terms of bringing their product in and taking it out because of road restrictions, it just is not very business-friendly to a company that has some time-sensitive issues in terms of delivery of product and that sort of thing.

So all I can say to the minister is, I encourage her to continue to do what she can in that regard.

I indicated to the minister in my opening remarks that over the course of the next few weeks there are some exciting projects happening out in my end of the country that I need to talk about. One of them is an ethanol–the potential, I would say right now; I wouldn't say it's a fait accompli, but certainly the potential of–an ethanol plant being located in the area.

In talking to the proponents, there's some frustration with our provincial government in terms of commitments to the capital that is going to be required for infrastructure. I don't think the company is asking for investment by the province into the project itself except that there is a need for the expansion of rail and road work and also the–as I understand it, the hydro is there but the expansion of the gas line is something that is required and that is where the company expects that a province will contribute.

I want to ask the minister if she can update us as to what the status is since this company is quite anxious to get started on the project as soon as possible. It's a commitment I think that I heard the Premier (Mr. Doer) make in terms of expanding the biofuel industry in this province.

Manitoba lags desperately behind other jurisdictions in the development of this industry, and I'm wondering whether or not the minister can give me an update on the commitments that have been made with regard to this particular project.

Ms. Wowchuk: Mr. Chairman, I want to let the member know that, in fact, I, along with staff, have met with the Russell group and representatives of the group from Florida. We talked about their plan. We asked them for a copy of their business plan. I believe some staff are working with them but we have not received the business plan from them yet. The specifics we have not, but we're quite willing to work with them and the ball is really in their court right now. There is outstanding information that they have to provide us with so that we can continue to work with them. *[interjection]*

The staff may have received the business plan but they haven't worked on it to the point where it has come to me or to anyone in government for a decision yet. So they could have got it at the staff level. I have not seen it and we are, as I understand–there's still some outstanding information that we're looking for.

But I can get back to you on this and find out exactly at what stage we are at and whether, in fact, we have received the information that we have been looking for.

Mr. Derkach: I would just encourage the minister to perhaps do some follow-up on this because it appears that I'm getting two messages here, one from the development side and one from the department here. We should try to put this together so that the project can move ahead. There's some, I guess, desire on the part of the company to move ahead with at least some of the earth work as soon as possible–or the proponent or the developer.

So, therefore, I think it's an emergency, and I don't want to see the same thing happen here as has happened in other projects where there's a lot of finger-pointing at the end of the day and it's difficult to sort out where the issues really are.

So I'm just encouraging the minister to do some follow-up on this. I know staff in the department will, but certainly this is an important project I think to the province.

Ms. Wowchuk: I will certainly endeavour to follow up and I can over the next couple of days let the member know what it is we've found and what we're waiting for. But my understanding is that there was a sod-turning planned and that's been postponed. So we'll do some work and I'll get back to you.

***** (16:30)

Mr. Derkach: I'd like to turn to food commercialization, if I might, Mr. Chair. I want to ask the minister, with regard to food commercialization, whether or not the minister has in place a strategic program to assist those producers and processors of functional foods and nutraceuticals to give them some prioritization in terms of having their projects looked at by this province so that they can proceed. I'm speaking specifically of projects that have been in the development phase now for about three years. Because of delays in Manitoba, proponents are moving outside of the province to have their products tested, to have their products commercialized, and to have their products examined for the various components that those products may contain.

So I ask the minister whether or not her department has put any priority on ensuring that these types of projects are given the fastest time possible to do research on their projects and to get back to the proponents, because we've seen some fairly significant delays in Manitoba whereas outside of the province, those results are coming back within a matter of a week or two.

Ms. Wowchuk: The straight answer is, yes, we do put a priority on these kind of products and have made significant investments in development and commercialization so that these products can move forward. Sometimes individuals come to our facility and if we haven't got the equipment, we direct them to another facility that may have a higher or a different level of equipment, and there is a sharing of knowledge across the country. In the case, I believe, the member is talking about, we in fact did direct him to go outside the province because there was better equipment somewhere else, and in fact he is back now, I believe. He is running into difficulty and having his product tested, developed in Alberta, and now he is coming back to work here.

Mr. Derkach: I'm not talking about a specific project. Just to tell the minister, I've heard that our nutraceutical centre in Manitoba is vastly underutilized in terms of what they're capable of doing and in terms of what they are doing. So I want to know from the minister whether or not there is a direct link between our Food Commercialization unit with the department and our nutraceutical centre at the University of Manitoba and at Portage la Prairie to ensure that those entities are used to the maximum possible capacity for the enhancement of products in Manitoba.

Ms. Wowchuk: The member is right. There is a lot of capacity at the nutraceutical functional food centre. It's a new facility. They've come here with a wonderful team of scientists and they are just getting started; hopefully, we will see more activity there.

The Manitoba agrifood health network has been established. This is established to link the three facilities together, the nutraceutical functional food centre, the St. Boniface Research Centre, better known as "R camp", and the Food Development Centre. They have just been established. There are two people working there; they're located in our urban GO team, our urban GO Centre, but we have been–I believe very much that we have to do this kind of joint marketing.

We have a unique cluster here in this province, one where you can develop a product, test a product, and take it to commercialization. As we move forward, I think that this will be an opportunity to attract many projects here. But you are right when you say that it is underutilized because right now, they are just getting started. But I can also say that, under our ARDI program, nutraceuticals are our top area of funding.

Mr. Derkach: Mr. Chair, I note that in total the grants and transfer payments to facilities for food development are in the range of $2.2 million per year.

Has the minister got any intentions to invest more money into this area since it is–since she says it is–a priority area? Two million dollars to me is not a lot of money invested in something that is as important as nutraceuticals. Are there monies in other places that need to be identified?

Ms. Wowchuk: Mr. Chairman, when you look at the $2.2 million per year, that's just the operating money of the Food Development Centre. We made an investment of $13 million into equipment and we're working on that one. So there is a lot more that's in there. So that's for the Food Development Centre. But there is money for the Richardson Centre and the St. Boniface Centre coming from the ARDI side of it from the federal-provincial agreements and that's where the money comes, from those.

***** (16:40)

When the Richardson Centre was being built, we made a significant investment into it as a province.

The St. Boniface Research Centre had just last year got an investment of around $17 million from the federal government. On top of those things we have–since we reorganized the department, we created the Food Commercialization and Marketing Branch of the department. So it's created in Portage la Prairie. There's additional staff that will be working in that department to work on food commercialization and move it along. So, to say that we're only spending 2.2, that is just for the operation of the Food Development Centre.

Mr. Derkach: I think I recognize that, but I'm still not clear on how much money is being invested by the Province into the Richardson Centre for operating on an annual basis. ARDI provides money and that's a provincial-federal program, but how much operating money goes from the province to the nutraceutical centre at the University of Manitoba?

Ms. Wowchuk: When the business plan was put forward for the Richardson Centre there was a request or a commitment of $1.5 million in operating money for five years. The goal is to get them to the point where they're operating without supports. So we give them $250,000 a year per year for five years. As well, we have $2.5 million in ARDI and about 21 percent of that goes into projects there–but that's projects driven–but the operating is $250,000 per year for five years. That was the agreement.

Mr. Derkach: Where is that found in the Estimates book? Because I don't find the line in here for that.

Ms. Wowchuk: You won't see a direct line because that's coming out of ARDI money. That's coming out of ARDI money, but there is a portion of annual grants that cover the lab operating costs for the Richardson Centre, for functional foods and nutraceutical, for the operation of other facilities. But those come through the university budget; it won't show up here. That's where that fund will be identified.

Mr. Derkach: That's exactly my point. I was wondering what the department itself, the department responsible for commercialization of food products rural economic development, is investing in the Richardson Centre to enhance, whether it's small business who want to be processing or large businesses that want to develop production.

I know there are grants that go to the university; there's a partnership in ARDI. I'm talking about specific monies flowing from this department to the Richardson Centre for operating and ensuring that we enhance the ability of people who want to develop products to use the Richardson Centre.

Ms. Wowchuk: When we talk about food commercialization, that does not happen at the Richardson Centre. Food commercialization happens at the Food Development Centre. That's their role. Richardson Centre is research on functional foods and nutraceuticals. So we provide funds to the university, and from the university they make a decision where those funds will go.

For example, we provide a grant of $868,300 to the university and that is used for research in different projects. When this facility was built, what they came to us and asked us for was a specific amount for operating, and that's what we committed to, operating dollars. But we also have created the Department of Science, Technology and innovation, and most grants are allocated out of that department.

So there is what we provide here, but there are many more research grants and supports that come from another department. It is the way we have organized our government, and by creating this new department, that is where additional money would come from.

But certainly Commercialization is Food Development Centre, but this department does not provide direct funding for the universities. That comes from the Department of Advanced Education as well, and there would be funds for research coming from STEM. We provide the amount, as I said, of $868,000 for programming.

Mr. Derkach: I'm running out of time, Mr. Chair, and I have to move on to other little areas that I want to touch on.

One of the areas is the local economic development corporations. We have had significant concerns expressed by the local community economic development officers and the community development corporations that, in fact, their funding is not increasing, it's decreasing, and they're having difficulty in operating.

I want to ask the minister if she can identify for me the area where we can find the grants that are provided to community economic development boards for the enhancement of economic development in the communities.

***** (16:50)

Ms. Wowchuk: Mr. Chairman, the information that the member is looking for is on page 125. It is under

Grants and Transfer Payments, where there is $957,000. It's included in there, and the amount for development corporations is $544,986, and the amount has not gone down. It's the same amount that it was.

Mr. Derkach: So can the minister tell me how much, or what the formula is for economic development officers and development corporations for funding for their particular areas?

Ms. Wowchuk: These grants are following the same model that was established about 10 years ago. It hasn't changed. They were negotiated with the RDCs and no specific formula is followed. It was what was negotiated and it is the same model that's being used now as then. There has been some–*[interjection]*–no, there hasn't. I'm looking at the wrong line. So the amount has basically stayed the same.

Mr. Derkach: So is the minister telling me that over the course of the last eight years the monies afforded to the RDCs has not changed at all?

Ms. Wowchuk: That's right.

Mr. Derkach: The minister's department is getting increases on an annual basis to run her affairs and her offices and her department. How is the minister expecting these RDCs to continue to operate on the same monies that they were given eight years ago?

Ms. Wowchuk: These are municipal entities and they don't only get money from the Province. They have the ability to get money from other sources. There are municipal contributions that go to help them operate and we have not reviewed them; we have not put additional resources in, but we are not their sole funder.

Mr. Derkach: I know that the Province is not the sole funder. I mean it's never been thus, but my issue here is that we have development corporations that are trying to enhance the opportunities in their communities through the hiring of an economic development officer, yet the Province's formula has not changed in eight years. Now this isn't any different than any other entity. If there are increased expenditures because of inflation, because of cost increases, certainly, that has to be reflected in the grants that are given to these organizations.

I want to ask the minister why money hasn't changed over the course of eight years. That's a long time. I can see something staying stagnant for a year or two. We're talking about eight years here, Mr. Chair.

Ms. Wowchuk: The member knows that when we reorganized the department we put additional economic development staff into each of the offices; we hired additional people. These people work very closely with the development corporations. When you have these kinds of corporations and you put in development officers in each region of the province then you have to do some review. I can say to the member that we are doing some review of the corporations, of how do we get them to work more closely with the staff that we have, and they are working more closely. We are doing a review of all the different levels of economic development support that's out there and looking at how we might work more closely together.

Mr. Derkach: Well, Mr. Chair, unfortunately, that doesn't answer the question.

I'm supportive of the concept that was developed regarding the GO centres and the way that they have been operating. I think it's a reasonable concept, one that hasn't diminished the services in the communities. I will put on record that I congratulate the department and the minister for taking that initiative and developing those centres, because I do believe just from watching the operations thus far that they are continuing to work with local community ag offices and economic development offices. I think we need to have a higher level of expertise in these GO centres in the areas of rural development. I believe that we should be utilizing graduates from the Brandon University master's program in rural economic development for those programs, and also utilizing more frequently the expertise of local developers. I think there can be some enhancements there, but I think that will come over time. I do believe that the GO centres are entities that can enhance the ability of rural Manitoba to grow.

I want to end by asking the minister whether she has any commitment to increase the youth program that used to be called the green program, specifically for rural communities and rural Manitoba. The only way that rural Manitoba is going to retain its youth is by ensuring that the employment opportunities are there for them. The Green Team program and the youth program were ones that were, I think, quite readily endorsed by local communities, and we need to enhance that part of the rural development program, and also the round tables that were established to look at the strengths and the weaknesses of communities. I'm just going to give the minister a quick minute for a response.

***** (17:00)

Ms. Wowchuk: I thank the member for raising some important issues. The Green Team is a very important program. I believe that we have about $1.8 million budgeted for that program, and there has been an increase in that program.

On the round tables, I believe that we're moving to the next round of them where we're doing community vitality indicators. There are four communities that we're working with, trying to develop a new model of how we might be able to work and have round tables, but we're piloting it in four communities.

Mr. Chairperson: Order, please. The hour now being 5 o'clock, as previously agreed in the House, this section of the Committee of Supply will now move on to consider the Estimates of the Department of Conservation.

Shall we briefly recess to allow the minister and critics the opportunity to prepare for the commencement of the next department? *[Agreed]*

Five minutes? We will recommence at seven minutes after 5 o'clock.

The committee recessed at 5:00 p.m.

The committee resumed at 5:09 p.m.

Mr. Andrew Swan, Acting Chairperson, in the Chair

CONSERVATION

The Acting Chairperson (Mr. Andrew Swan): Will the Committee of Supply please come to order. We will now be considering the Estimates of the Department of Conservation. I would remind members that, also, as agreed in the House, we are now operating under the Friday rules regarding no quorum requirements and no votes. This means that any vote today which is not unanimous will be deferred until the next sitting of Supply.

Moving on to Conservation, does the honourable minister have an opening statement?

Hon. Stan Struthers (Minister of Conservation): He sure does, Mr. Acting Chairperson, thank you very much.

I want to say that I'm very pleased to embark on a discussion of the Estimates for the Department of Conservation, and I'm very happy that we can put forward such a progressive conservation agenda on behalf of the people of the province of Manitoba.

***** (17:10)

Mr. Chairperson in the Chair

I want to begin by acknowledging the hard work of staff in the department. I don't think we can say enough for the kind of work that the civil servants across government, but, I may be a little biased in saying this, specifically the folks that work in Conservation, from my deputy minister right through to all of those who are in the front lines day to day conversing with the people of Manitoba, protecting the resources of the province of Manitoba. I can think of no other department, from Antler, Manitoba to Churchill to Middlebrow in the southeast that are out on the rivers and the creeks and in the forests and in the communities dealing with issues, issues that are far-reaching and important to Manitobans.

In a few minutes I'll be introducing some of the staff that will be assisting me today. One person that I want to pay some tribute to was a person who won't be joining us here today, who is retired since our get-together on Estimates last year; that was Dave Wotton. Dave was our assistant deputy minister. Dave put a lot of years in with the department and I really enjoyed working with Dave. In particular, one time at Whitehorse, when Dave led up the cause on behalf of all of the ministers in terms of humane trapping and dealing with the federal government on a specific issue that I thought Dave really did well, so I want to wish him a happy retirement.

I want to be really clear that this summer was extraordinary. A number of extraordinary events that were dealt with by extraordinary people in our department, in other departments, right across Manitoba. I toured through the southern part of our province just after the tornadoes–a system of tornadoes, really–went through that area, the one that hit Elie and other areas. I stood in the middle of a farm south of Baldur, a farm that was in that family's name for 126–it was a century farm. After being in the family for 126 it got smashed within 30 seconds. That farm, a number of farms throughout the south–I toured with the EMO officials from Baldur right through to pretty much the Saskatchewan border. I came across emergency officials, municipal officials, Conservation officials, folks from Manitoba Hydro, all going above and beyond the call of duty in making things as good as they could for the people that we all represent.

That same storm went through our Whiteshell Park. It blew down a whole pile of trees. I toured that area and from the air it looked like a combine had gone through and laid over one poplar tree after another. Huge amount of damage to our park. We were lucky that nobody was hurt. But we had fire crews and other officials from the eastern region and around the province step up to the plate and really do a yeoman's job in getting that park up and running again for that July long weekend. That was after the blowdown and after a huge amount of rain that also complicated the work that they were doing there.

We had some very good work done to repair damage and replant trees at the International Peace Gardens, the Peace Gardens, which mean so much to our province and to the state of North Dakota, and we moved very quickly to make sure that we helped out there.

This year I think another very successful, very significant step was in terms of contaminated sites where we set aside $39 million to begin that kind of very important work and I'm very proud of the MOU that we've signed at Grosse Isle with the R.M. of Rosser and their reeve, Alice Bourgouin, and we got some movement on that.

We helped out in others and not just our own jurisdiction, but our officials were called upon to help out fighting fires in Québec. We had a couple of requests that we came through with, and sent 40-some firefighters, forest firefighters, to the States to help with some fires–I believe it was in Montana. That was something that I was very proud of as a Manitoban, seeing Manitobans helping not only each other out, but helping out people in other parts of the country and the continent.

It was a year of success for our parks reservation system. When we inherited the old system, we knew we could do better than that and boy, did we ever. I'm glad that the Member for Lakeside (Mr. Eichler) is right with me on that. We increased by 36 percent the number of reservations that Manitobans and people visiting our province booked. For the first time ever, we exceeded the number 50,000. We're well over the 50,000 mark. But most importantly, we have a system that is built by Manitobans, run by Manitobans, staffed by Manitobans. Manitobans can make decisions from one year to the next, make decisions like multiple reservations, which was a question actually at this table last year in Estimates, and we heard the request and responded in such a way that Manitobans could make multiple reservations.

In the area of protected areas, there are two things I want to just very quickly touch on. One that I'm really proud of is the protection of Little Limestone Lake. Nowhere on the face of this earth is there a better example of a marl lake, a lake that changes colour as the temperature of the day increases. I've been there a couple of times; its absolutely spectacular. It's a stone's throw off of No. 6 highway, about 40 minutes north of Grand Rapids. We're working with the Mosakahiken Cree Nation and with the folks at Grand Rapids to protect that lake, and I think that is something that is very worthwhile doing.

We also have a Memorandum of Understanding that we signed with the City of Winnipeg. I was really pleased to get together with Mayor Katz and make sure that we were able to take a look at some of the very significant green spaces within the city limits, some parts of our capital city that deserve protection, and we're going to work with the city to make sure that that happens.

The other part of our Estimates, of course as well, is an analysis of the Sustainable Development Innovations Fund, and I look forward to talking about some of the good programs that that fund contributes to in every part of our province.

I think the last thing that I'd like to do is welcome the new critic, the Member for Tuxedo (Mrs. Stefanson). Welcome to the wonderful world of Conservation. I think you'll find that the people that are involved in it are great and that the issues we deal with are varied. I know that you know that these are important issues to Manitobans.

If I myself or our staff can be of assistance to any issues, whether they be the kind that grab headlines or the kind that simply need to be worked on, just contact me. The Member for Tuxedo knows where I hang out here at the Leg.

So, with those few words, I look forward to a discussion on my Estimates, Mr. Chairperson.

Mr. Chairperson: We thank the minister for those comments.

Does the official opposition critic, the Member for Tuxedo, have any opening comments?

***** (17:20)

Mrs. Heather Stefanson (Tuxedo): Thank you very much, Mr. Chair, and I thank the minister for his kind words about my recent appointment as the critic responsible for the environment, actually, which, of course, the Department of Conservation falls under the purview of that.

I have had the opportunity already to meet with a number of stakeholders in various communities across our wonderful province, and a number of issues have arisen as a result of those. Certainly, I understand that throughout the course of this Estimates process various colleagues of mine will be coming forward to ask many of those questions as well, because there are a number of issues in our various communities that we would very much like an answer to.

Having said that, I just want to also thank our leader, the Member for Fort Whyte (Mr. McFadyen), for giving me this opportunity. I have found all of the portfolios that I have had the honour of being the critic for challenging and I'm very much looking forward to the challenges within this portfolio as well. I look forward to the days and months and maybe years ahead of questioning and essentially holding the government's feet to the fire and this Minister of Conservation's (Mr. Struthers) feet to the fire when it comes to issues that preserve our environment, that preserve our forests, our wildlife and our lakes and just make us a better province and make us, hopefully, working towards achieving having a much cleaner environment within our province.

So I very much look forward to the challenges that lie ahead. The minister did have a statement earlier with respect to this being National Forest Week, and, unfortunately, in the House I didn't get the opportunity at the time to finish my response to his ministerial statement. I think our leader actually got into some issues after, which I think are of concern certainly to members on our side of the House, but indeed to a number of communities across Manitoba.

I find it somewhat passing strange and a little bit alarming that the Minister charged with the administration of The Manitoba Hydro Act (Mr. Selinger) would come out in the same week with an announcement of their decision to extend the lines down the west side of Lake Winnipeg at a time where it's National Forest Week. There's a number of forests that will be affected as a result of that announcement, and I do have a number. I just think the timing of that announcement is unfortunate. Obviously, a priority is not necessarily placed on our forests and wanting to preserve those but we're looking at making an announcement which makes no sense from an environmental perspective and from a fiscal perspective. Certainly, I think that there are going to be a number of questions surrounding that in the days ahead, that we will have the opportunity to be questioning this minister.

So, having said that, I know that time is limited when it comes to our Estimates process. We have a number of issues that we would like to jump into and question the minister on with respect to various communities across this wonderful province of ours.

I thank the minister again for his kind words on my appointment. Having said those few brief words, I'm looking forward to getting into the Estimates process.

Mr. Chairperson: We thank the critic for those opening remarks.

Under Manitoba practice, debate on the Minister's Salary is the last item considered for a department in a Committee of Supply. Accordingly, we shall now defer consideration of line item 12.1(a) and proceed with consideration of the remaining items referenced in resolution 12.1.

At this time we invite the minister's staff to join us at the table, and I would ask the minister to please introduce them once they've arrived.

Mr. Struthers: Thank you, Mr. Chairperson.

I'm joined by my deputy minister, Don Cook. I'm also joined by four assistant deputy ministers: Bruce Bremner, Regional Operations; Bruce Gray, Finance–we share Bruce with Water Stewardship; Fred Meier, with Programs; and Environmental Stewardship, Serge Scrafield, at your service.

Mr. Chairperson: Does the committee wish to proceed through the Estimates of this department chronologically or to have a global discussion?

Mrs. Stefanson: We would prefer, and I know the minister and I had a brief discussion about this before, and I think he was amenable as well to have a global discussion if possible.

Mr. Struthers: Discuss globally, act locally. I'm agreeable with it.

Mr. Chairperson: All right. Second that.

Just to be clear, we're going to do a global discussion. Thank you.

My faithful assistant here who keeps me on track as Chair has also pointed out that this now means that all resolutions will be passed once all the questioning has been completed. Understood.

Mrs. Mavis Taillieu (Morris): I want to thank the minister for the opportunity to have some questions here, and thank the new critic, the Member for Tuxedo, and certainly congratulate her on her new critic responsibilities. Also, I want to say hello to the staff here and thank them for the job that they do.

I do have a couple of questions from my constituency. In regard to contamination sites, I'm informed that there is a site in St. Malo termed Parc Esso in which there was a service station on the site. It's very close to the water source for the town. I'm informed by the local council there that they have been questioning about this and the removal of this site and have been told, in fact, and I will ask the question because I'm told that this one of the five worst contamination sites in the province but that it's going to take at least three years before they get to cleaning this one.

I'd like to ask the minister in regard to the Parc Esso site in St. Malo if it is in fact one of the five worst contaminated sites in the province, and what is the time line for cleaning up this site?

Mr. Struthers: We have booked $39 million to deal with the contaminated sites that are found around the province. Our specific mandate here, mostly it is to deal with those abandoned gas sites that may have a tank and may be polluting into the environment. The basic premise that we've accepted is that the polluter needs to pay for the mess that they've left behind, and one of the first things we do when we deal with a site is we try to make a determination as to who is responsible to pay for that clean-up.

***** (17:30)

That's where this particular site at St. Malo is. We're trying to assess responsibility for this. I want the site to be cleaned up. I don't want the people of Manitoba to subsidize, in this case, Esso, for the mess that they've made. If we determine that we can't trace that to Esso, we can't in any way pin that responsibility, that liability, onto them, then we as a Province have stated that we would pay for that. We don't want to leave it out there leaking into the water table, and that sort of thing.

So we're at the stage with this right now where we're trying to make that determination at the site. My instruction is that we do that as thoroughly but as quickly as we can, because I don't want the people of Manitoba to unnecessarily have to clean up for a company who has a responsibility to do that. So that's where that one is.

Mrs. Taillieu: Mr. Chair, can the minister confirm then, that it is in the top five contaminated sites in the province?

Mr. Struthers: No, Mr. Chairperson, at this stage, given the work that we've done there, we can't make that determination as to a ranking. It is booked as one of the ones that we need to be moving on. For example, we've got an MOU in Grosse Isle, where we know, where we've done that work, where it's kind of like the No. 1 that we're moving on and there's others that we're doing that and we need to prioritize these. But this one's still at the point where we're figuring out the liability and then making sure that if we can't do that then it does become something that we would pay for a cleanup.

Mrs. Taillieu: Mr. Chairperson, it sounds to me then, that you've prioritized the one in Grosse Isle as the worst one, so you're dealing with that one right now. Is there any way, then, to determine where in the ranking this one is going to fall and how long? Like what time frame is the community looking at here?

Mr. Struthers: In relation to the one at Grosse Isle, when we look at prioritizing, there are a whole number of factors that come into play: the kind of damage, the kind of impact on human health. In that particular case, there are people that have got these–I've seen them, I've been there–these big ugly looking filters that's in the community hall there. It's in some residences. Part of our analysis is the impact on human health: is there a direct line between the contamination and people living in the area? Those sorts of things.

The other part of this is–and part of my job is–to make sure that we've got the resources in place to do these kinds of analysis. We have added five resource staff particularly to do these kinds of evaluations at each of these sites. One site may be smaller than another, but it might have a bigger impact on human health. If there's a school that's over top of a site, that's different than if there's a–oh, I don't know–if there's a golf course over the site. Or whether there's a pasture over the site. Those kind of determinations need to be made on a case-by-case basis. So it really depends–the ranking of this one that my colleague from Morris is interested in–depends on that work that we do in the beginning to analyze the site and its human health impact. That is the assessment that we're doing.

We're looking at about 239, I believe that we've got booked for assessments. So that's going to take some time to go through that, but I understand that some of that work is beginning at this site already.

Mrs. Taillieu: Mr. Chair, the site I'm referring to, the site of the former Parc Esso in St. Malo, I'm told it's very, very close, within a few blocks of the school there. I know that it's very close to the source of the town's drinking water.

I know that the government is concerned about clean drinking water, but, you know, we see a lot of boil-water advisories around the province. We certainly don't want to see any further contamination into any water supplies for the town, for the surrounding area, and, certainly, if there's anything leeching into the soil, it's going to be close to where children are playing. I think that's an issue that needs to be dealt with fairly quickly. I think the rural council of DeSalaberry has written to the minister, so I know he's familiar with this particular site, and I've written as well. I do not think that I have received a reply yet, but I will look forward to that.

I would like to move on to another question and this relates to the strawboard plant at Elie, recognizing that that plant has had many difficulties over its lifespan. However, something was brought to my mind very suddenly just in the last month when we saw an issue of stubble burning that was very close to where those bales are. So I'm thinking, what would happen should those bales catch on fire, because if you think you saw smoke across the highway from a fire in a ditch, you can imagine the fire and the smoke that would arise when there's 160,000 rotten bales sitting there. It would not be a clean burn. It would be an ugly black smoke that would probably blanket the city and blanket the province for a long, long time.

Now, I recognize, of course, that this is a privately owned enterprise at the time, and Dow Chemical has committed to doing something with these bales. However, we do know that they are not operating the plant, so they're not decreasing the number of bales that are stored there. There has been some attempt to decompose those bales and to use them for other purposes, but the fact is there are so many of them that it's going to be a hazard and it is a fire hazard. Not only is it a fire hazard, it's a health hazard.

I guess what I'm saying is that should Dow Chemical or any future owner of that property, should it just revert to the Municipality of Cartier, it is going to be something that I believe the Province will have to deal with as an environmental issue because should there be a fire or anything related to those bales, it will become an issue for the Province and not just for the town of Elie or the Municipality of Cartier.

I'm wondering what kind of emergency plans or has the minister looked at the possibility or the repercussions of any disaster that would result from these bales catching fire.

Mr. Struthers: I think my colleague from Morris has her finger on a very–it's a complicated issue but it's one that she's exactly right, could end up really becoming a problem for a lot of people in that area and throughout the southern part of our province.

The role that we have in this is working with Dow in terms of a decommissioning plan that they had to have in place when they assumed ownership of the site. We've been working with them in implementing that decommissioning plan.

***** (17:40)

The other part of this is that there's not just the bales we're dealing with, with Dow, but there's a private individual with some of those bales on his land as well. I think the Member for Morris (Mrs. Taillieu) is aware of that. So we have to try to not only work with Dow, but we also have to work with that private individual. They've been working at taking apart some of those bales and trying to work it into the land, but that's a lot of bales to work into land. That's going to be part of the solution that they come up with.

Our responsibility is to make sure that Dow Chemical and the private individual follow the decommissioning plan through to the end so that we don't end up with that kind of a smoky hazard that none of us around this table want to see happen. That's the role that Conservation plays in this.

On a bigger picture, I'm hopeful that some day we can find a more innovative process to deal with straw bales, whether it's a 160,000 or 190,000, whatever the total number of bales is. Not to just take care of the bales that are there which are of varying degrees of quality, but also that we can put some people in rural Manitoba to work adding value, not just taking care of a stubble-burning, hay-burning kind of an issue, but also adding value to something that many of our constituents produce, i.e., straw. I think, from a bigger picture, that's where we have to go on this.

But specifically, we work with Dow in terms of their decommissioning plan. The other part of this, too, of the decommissioning plan, is to work with Dow in terms of rodent control. One thing I notice when I drive by there, back and forth to home to Dauphin on the weekends, is a huge number of hawks and other birds of prey licking their beaks as they sit on top of a great big round bale, or a pile of round bales, as they watch for mice and rats and whatever else is down there that they are interested in turning into lunch. Part of our decommissioning plan has to be a rodent control plan to go along with a disbursement of those bales angle to the plan.

Mrs. Taillieu: I do recognize that there has been some work done to try and decompose some of those bales. Of course, the issue is not so much with the straw as with the twine that's holding the bales together. It doesn't decompose and it gets caught up in any kind of machinery that tries to take the bales apart.

I know that there's been some use of those bales for erosion control, for example, in the floodway. Certainly, they've tried to turn them into pellets, I think, that would be used in burning in stoves. I'm not too familiar that, but I've been told about it.

I think, though, that the issue may become one that the bales are going to be left there. You can always fight over about who's responsible for them, but in the end if they should catch on fire, there needs to be a contingency plan to deal with the issue should that arise.

I know that I spoke with the minister in the House a while ago now. It was probably just after the Dow Chemical plant was closing or decommissioning or beginning that process about alternate uses for that plant because it is a plant that's sitting on the Trans-Canada Highway. It's in a good location: rail, highway, energy sources. It's close to the city of Winnipeg as well. There have been a number of proposals, I think, for looking at what can be done in that plant.

This is just some of the things that people have been talking about, but one of them is the use of these kinds of bales as cellulosic material in the production of ethanol, straw bales that can be used in ethanol production. I'm just wondering if the minister has had any conversations with interested parties, or if there's any will on the part of the Department of Conservation to look at doing something in this plant.

Mr. Struthers: Our prime focus in this is as the regulator and overseer of the environment licence and decommissioning plan. From a department's point of view, that is by far our main focus. The Dow reports do us on a quarterly basis. They update us on what they've been doing in a number of angles, I guess, on this, and they do keep us informed of the negotiations they're having with other companies. Maybe another company that might come in, they could have a better use for those bales than having them sit there and be a fire hazard or a house for rodents. So I know that the company itself has been active. I know that they've been in conversations with some of my colleagues in other departments in order to try to facilitate a sale to somebody else or better use for those bales, but our focus really needs to be as a regulator. That's our department's No. 1 job in this and making sure that a decommissioning plan is unfolding as it should.

Mrs. Taillieu: Well, thank you very much for that, Mr. Minister.

Just another question on a different topic again, and this will not come as a surprise, but I need to talk about the deer population. I am speaking both for myself and for the Member for Charleswood (Mrs. Driedger). I know there is an increasing population of deer in that area, and when she speaks about moving the deer out of that area, you know, that moves into my area, and when we move them out they just, you know–they need to go farther away from populated areas because there are a huge number of them. They are causing a number of accidents on roadways, I think, which is a major, major concern. With the number of accidents, car collisions with animal life, particularly deer on the roads, I think that MPI premiums probably are going to see a rise because there have been so many deer accidents.

So I guess my question is: What can be done? What is the Department of Conservation looking at doing to curtail the deer population or move them?

Mr. Struthers: Yes, I kind of thought the Member for Morris might bring this to the Estimates procedure and I've got to say, if I were in her shoes, I'd do the same. I'm not saying this in a way to discourage her from bringing it forward or to excuse the number of deer that she's dealing with, but every single region of our province is experiencing tons of deer. We became aware of many problems in terms of the deer, so much so that we actually did a deer survey in the Capital Region.

An Honourable Member: How many responded?

***** (17:50)

Mr. Struthers: Well, we mailed them all letters and we're taking the response that if they don't respond to us, then there's no problem, and then the Member for Morris doesn't really have a concern. But we're counting the deer, let's put it that way. We divided the city up into grids just like you would do over the Duck Mountain to count moose or elk or deer or bear or whatever you're doing, and I don't know if that's ever been done over the city of Winnipeg before, but just the volume of calls that we were getting about deer indicated to us that we had to do something like that, No. 1, so that we could share that information with agencies like MPI, the City of Winnipeg and others, so that we could all sit together and talk about some things that we have to do.

One of the things that was very clear that we need to do is that we needed to get, fairly quickly, into the hands of people living where the deer numbers are high, some very practical advice to people about what they should and shouldn't do. There were some people who, well, they like the fact that maybe a deer wandered through their lawn; they put a little food out for the deer and next thing you know, they got 30 in their backyard. So we've had to get some very practical tips to people on what to do and what not to do.

So we did get a pamphlet out. We did get a pamphlet, a brochure, into mailboxes here in the city of Winnipeg and we–I guess what maybe one of my worries over the long haul is that, with what we see projected in terms of climate change, every winter seems to be getting milder and the one person that can do the most to help us in this is Mother Nature. We haven't had a cold winter and we haven't had the kind of losses in deer that we've seen in a while and that's part of the natural cycle. What we end up with is, I think, an unnatural cycle where you end up with too many deer and not enough controlling factors that are just natural controlling factors.

So part of my worry is that this is a problem that's going to be with us for a while and we've got to work out ways in which us and the City of Winnipeg and other municipal leaders in the R.M.s that form the Capital Region can work together on to try to minimize the damage that these deer do.

Mrs. Stefanson: I know the Member for Morris (Mrs. Taillieu) was asking these questions on behalf of her constituents and the constituents of Charleswood and my constituency in Tuxedo. About a third of the constituency is actually in Charleswood and I think there is no question about the fact that there is a problem with the deer population there. I know the minister has sort of talked about, you know, how they're sort of trying to come to realize that there is a problem, but there's lots of these sort of studies and round table discussions and all of these sorts of things. We already know that there's a problem and I guess, the question is, what are you going to do about it?

Mr. Struthers: Part of what the member refers to as studies and discussions is centred around what other communities have done that have been successful. Between us and the City of Winnipeg and others who we've been working with on this, we've been looking at other communities to see what they have tried. The first lesson that has come out of that is to get information out to people as quickly as you can. Useful information. The city of Philadelphia tried some sort of a euthanization/sterilization scheme that landed everybody in hot water who had anything to do with it, and didn't really prove to be all that effective.

So our approach is to draw from other jurisdictions who have been into this some useful information that we can then get into the hands of people who are living in the city with a lot of deer. I think that's the most useful thing that we can do to help residents who are putting up with deer in their lawns and in their gardens. I think that's the best approach.

Mrs. Leanne Rowat (Minnedosa): I have a couple of just quick housekeeping issues from my communities and then I have a couple of issues that reflect my critic area.

The first issue is with regard to the provincial park in the Chimo Beach area in the R.M. of Daly. I understand that there's some development happening in that area. I'm curious to know what type of consultation that has taken place with the municipality and the town of Rivers and the development of some of the lots in that area.

Mr. Struthers: Could my colleague from Minnedosa clarify? Is it a consultation that we are doing in terms of more campsites or is it cottages? And this is at Rivers Park?

Mrs. Rowat: Sorry, it's near the dam up toward Chimo Beach, so it's on the highway heading west. No, sorry, east. Out of town.

Mr. Struthers: We're very much in the planning stages in terms of electrifying some campsites that are in there. We're at a very early stage, and at the appropriate time we'll be including the R.M. and the town. That's standard practice that we do in an area. It's part of our camping initiative.

What we've found is that we have many campsites that are unserviced go unused, and we have people being turned away because there's not enough electrified sites. So this is one of the parks where we want to provide more accessibility for Manitobans, for her constituents. But as per normal course, we would be talking to the local people that she has talked about.

Mrs. Rowat: Mr. Chairperson, I have met with the R.M. of Daly and the Town of Rivers prior to coming to session, and this was an issue that was raised by those municipalities just wanting to know what was going on. They didn't seem to feel that they were being included in, you know. They don't own that property or that area, but they do definitely have an interest in what's going on in their district. So I would encourage the next opportunity, that staff can take some time and meet with the municipalities and just give them an update. They're very curious and they're very supportive of any initiative that would increase or enhance the quality of campsites within their community. They appreciate the park there and they would really like to be a part of "the know" of what's going on.

On another point, provincial park signs: The community has indicated that that is an issue and they would strongly recommend that the minister consult with staff and determine whether that is a viable option. They feel that there's not enough signage indicating there's a provincial park just on their doorstep. So they would like to see your involvement and your support in providing better signage for that park especially along No. 10 highway where people may just want to scoot off No. 10 and come down the highway and enjoy the park.

Just wanting to know what the status is of any discussions that have occurred there and whether a decision has been made, and if there has been a decision made, is there an appeal process if the decision has been negative?

***** (18:00)

Mr. Struthers: Well, first of all, just to add to what the Member for Minnedosa said about the approach to provincial parks. We find that quite often when we sit down with the neighbouring R.M. or the neighbouring town, we get some good ideas on what we do. We've improved our park system a number of times by talking with local First Nations, local R.M.s, and have been able to offer something that's much more in tune with what the local area believes would be successful. So that's good advice.

We have been dealing with the signage, not just at this park but at others. I think we've got some great parks and I want more people in them. I don't want people driving past them on the highway, not knowing where to turn off. We've initiated that in terms of this park and others. We worked with the department of Transportation who, I understand, ultimately sticks the sign in the ground. Our instructions have been clear that we want people to know where our parks are and we work with Transportation to make sure that that happens.

Mrs. Rowat: I would like to know what the status then is of the Town of Rivers and the R.M. of Daly's request to have signage. Can you give me a time line?

Mr. Struthers: I think I should undertake to get back to the Member for Minnedosa on that. My view is the sooner the better on that one and others. It is a regulation that falls within the Department of Transportation so we have to work with them on that. They know that our wishes are to make sure there are signs showing where are parks are, but if there's any more detail on it, I can get back to the member.

Mrs. Rowat: Thank you. I'll hold the minister to that and I'll be tracking you down on that issue. I appreciate that.

Highway 1 bridge near the Grand Valley Road: This has been on my radar screen now for two years. There's debris that was in under the bridge. We've asked staff to remove the debris. They've removed it out of the water and they've put it on the side of the bank. I don't know if this is your area or not, but I'm raising it.

That debris is now on the side of the bank. As soon as the water levels increase this coming spring, that debris will just go back right into the river. It's a continuing issue. I've had several people call me on it. The debris is on the side of the bank under the bridge. It needs to be removed. It's a hazard. It's an eyesore. So I don't know if this is your area, but I would strongly recommend somebody move the wood.

Mr. Struthers: I'm trying to understand just where it is, under a bridge on the highway over a river. If we could get some more details, I'd like to get our guys out there to lead the clean-up of that. But, again, it's almost like what we were talking before with the polluter pay. I know R.M.s, I've had people come to me, a farmer who's bulldozed a bunch of trees into the ditch and then refuses to clean it up. Then the R.M. will send him a bill. They very consistently follow the polluter pay.

I'd like to know exactly where it is but also who's responsible for cleaning that mess up. I don't want it to end up back in the river. That's not good, but I don't want somebody just tossing out debris into the river and letting the provincial government come to clean it up.

Mrs. Rowat: I agree, and there have been carcasses found in some of that debris so there is a major issue with, you know, health issues as well with that. This has been ongoing for two years. I can send you the e-mails. I probably have a good dozen from, you know, at least two individuals that have continually e-mailed me and saying, I'm driving down No. 1 highway, I'm crossing the bridge, that debris is still there. I will gather up my e-mails, and I will get them to the minister. Hopefully, we can get rid of the debris and rid of the health concerns regarding carcasses and move on. So I will get that to you and hopefully get that debris moved out of the river bank.

The next question is regarding health inspectors. I know that at one point, about a year ago or so, there were vacancies which were fairly alarming in the area of health inspectors. I just wanted to know what the present number of health inspectors are in the province and if there are any vacancies and where they are, and we'll go from there.

Mr. Struthers: In my opening remarks, I was talking about some of the successes that we've had over the course of the year. This is one of those that we can put in the area of a success, not because we transferred it over to Health but because, before we transferred it over to Health, we offered an incentive package and some salary improvements that encouraged some people to apply for some PHI positions, and we filled those vacancies.

What has happened is that those health inspectors have been returned to the Department of Health where they came from in about 1973, I think, '72-73, and that's now under the purview of the Minister of Health (Ms. Oswald). It was felt that that was a better fit, that there were a lot more advantages to being in Health with some of their other colleagues that they could have some synergies with, such as the Medical Officer of Health, for example, out in the regions. So that has taken place. I don't want people to think that it's successful because we transferred it. It's a success because we did have some people step up and fill those positions.

Mrs. Rowat: Mr. Chair, my understanding is there were 30 positions, 30 public health inspector positions, under your watch or within your department. Did you transfer 30 staffing years to the Department of Health?

***** (18:10)

Mr. Struthers: When PHIs are part of our department, they work closely with the environment officers. Between the public health inspectors and the environment officers, there were 62. There was an overlap and a co-ordination of jobs between the two.

What was felt was necessary to transfer over to Health was 27 FTEs on the public health side. The thinking was that on the Health side, there was already staff there that would complement the 27 PHIs. I believe that their belief was that they came out ahead on this because of that. We still have within our purview the environment officers. The work that they do is more suited to the mandate of our department and public health inspectors were more suited to the mandate of Health.

Mrs. Rowat: So, just to clarify, there are 27 positions that moved into the Department of Health. My question would be which area in Health did they get transferred to and have their roles remained the same, if you have that information. Also, are these full-time positions that have transferred over?

You've also indicated that–Oh, I'll leave it at that, and I've got one more question regarding the number of environment.

Mr. Struthers: Yes, first off, they are full-time. They're full-time; they are FTEs, so that they're full-time. The advantage that they saw in being part of Health is that they are now able to concentrate on, to do the jobs that they were intended to do, the jobs that they were trained for as opposed to an overlap with environment officers. Now they could do their job 100 percent of the time. So, that was a real advantage to them. But, yes, they are full-time.

Mrs. Rowat: Thank you. You've indicated there were 62 in total between the two areas, the health inspector positions as well as the environment positions. How many positions now would be considered in the environment role of the leftover?

Mr. Struthers: Yes, if the Member for Minnedosa would permit me, I could get back to her with that information. Part of the problem is the environment officers are spread out throughout the regions, over four divisions. There are livestock people; there are people who work on Environment Act licences. These are all environment officers: on-site waste water management, disposal grounds, petroleum, the contaminated sites that we had worked on before. We've got people working on emergency response and the dangerous goods and handling transportation stuff, plus the ones in the regions. I don't have a total number available to me right now, but I can commit to come back with that.

Mrs. Rowat: Thank you, I will follow up on that. I am very curious to see where these positions have moved around to and the roles that they play and what type of responsibilities these individuals have. So, thank you.

Mr. Cliff Graydon (Emerson): Mr. Minister, in your preamble, you spoke of a tornado that did extreme amount of damage throughout the province recently. The question I would pose: has there been any payment to individuals or municipalities for the damage that was caused by that terrific windstorm?

Mr. Struthers: I hate to sound like I'm going to pass the buck, but I'm going to pass the buck. The minister responsible for disaster financial assistance, the Minister of Intergovernmental Affairs (Mr. Ashton) is responsible for those. The R.M.s that I met with and the towns that I met with, I encouraged all of them to get their resolutions to the Minister of Intergovernmental Affairs. I saw a list of those who did and it was a fairly–I think all of the ones that I'd heard about had put their resolutions forward. Then the minister responsible for that would then be following up with those R.M.s. I hope I didn't sound too much like I was passing the buck, but that is another department.

Mr. Graydon: In the situation of the blowdown in the Big Whiteshell, is there a salvage project underway for the timber that's there?

Mr. Struthers: Yes, that was a massive blowdown. Our worry is, first of all, when those trees dry out, they become prime area for a fire to start and to move in an area that is surrounded by cottages and recreational facilities and lodges and a whole lot of infrastructure that's important to us all.

The other thing we're worried about, of course, is that that's prime area for disease. We do not want to give any opportunity for pests to be getting a foothold and causing damage as well. I was really proud of my staff who worked really hard to do the clean-up out in that area, and also worked with the southeast quota holders to give them an opportunity to make use of that wood rather than just letting it hang around as a fire hazard.

Yes, we've actually estimated a half a million cubic meters of a blowdown. That's a pretty sizable annual allowable cut for any quota holder. There are multiple quota holders that we're working with to provide them with some economic opportunity, but also provide us with some of the safeguards against fire and disease.

The other thing we've done is we've had an open house in the area, so the people in the area could understand exactly what we're doing with that blowdown. I think it's important to assure people that we are acting promptly with that so that we minimize any kind of danger that exists.

***** (18:20)

Mr. Graydon: In regard to that particular blowdown in regard to the quota system that you made available or the quota that you made available to the logging outfits in the southeast, is it my understanding that the roads leading out of there will only carry a half load and become an economic deterrent to doing any logging in that area?

Mr. Struthers: Yes, the member has got his finger on a challenge that we face in this. We actually faced it in his riding in the Sandilands, I believe the year before last, where there was a blowdown there as well. On these kind of issues, we work very closely with the Department of Transportation.

The roads, and it's not just the roads, it's the bridges as well that we need to be creative with. We want to get that wood out of there for all the reasons we stated earlier, but we don't want to beat the daylights out of the roads and the bridges and cause even more of a problem on the way out.

I've really been pleased with the approach that our people and Transportation have had. I think they're trying to be creative in getting that wood out of there. My understanding is in the winter it'll be a different story with the road conditions, but we want to get that wood out of there as quickly as we can. So Transportation and us have been working on ways in which we can do that without causing irreparable damage to our bridges and roads.

Mr. Graydon: Thank you for that, Mr. Minister. The reference that you made to the Sandilands brings to my attention that on Friday there will be a tree planting with Manitoba Forestry and Qualico Group of Companies who will be doing a tree planting there.

I would like to also bring to the minister's attention that although there has been a certain amount of logging done in that area, there was a lot of the timber that was not logable or not usable, and I would question his department for not cleaning that up. It still remains to be a fire hazard. The trails through the Sandilands are not usable at this time for either snowmobiles or ATVs and the question would be: When would the minister see that that problem and fire hazard is rectified?

Mr. Struthers: Yes, I said some kind words today about the Manitoba Forestry Association and handed out the seedlings. We're aware of the tree planting that's taking place.

At the time of the storm at Sandilands, I was really very proud of how quickly our department got in there, quicker than any other agency involved in that particular event. We also went in there quickly with the southeast quota holders again, and what we did was we looked at the trees that were closest to the community that represented the biggest threat to the community and worked. I was pretty impressed with the kind of planning that went into it, starting at a small circle closest to the community, getting rid of the trees that were down, and then working our way out to a bigger radius around the community.

If there are other areas there that need to have that attention, then I'll see to it that that happens. But we prioritized in terms of the trees that were of the most danger. They had to be out first, and we did really do a good job of that, but I'll follow-up with the suggestion that the Member for Emerson has made.

Mrs. Stefanson: Just to jump into the cottage lot draw process which is obviously being affected by the blockade set up by the Hollow Water First Nation. Originally, as I understand, according to the government's Web site, the lot selection meetings were to be held in the order of eastern Manitoba, western, northwestern, Interlake, et cetera, et cetera. Now this being the eastern area which was scheduled for Sunday, September 23, I gather it's been postponed until further notice. The next one is scheduled in the western area for this Saturday, September 29.

What is happening with respect to the meeting that was scheduled for September 23? Will that meeting be held prior to the meeting that will be held in the western area on September 29?

Mr. Struthers: Because of the events that we've been reading about in the paper and the member has put her finger on, we decided it was prudent to take any of the lots that were associated in this draw with the eastern region, to take them off, to postpone that for now. So we're moving forward with the west, the Interlake, Lake Manitoba area, and some of the north. In the west, we've got, I believe we have about 120 lots in the western region, with about 200 or more people interested in them.

The other thing that I want to note is that for this draw we've made a change, I think, that will help people move these lots, and that is they can put their names in for lots in a number of these different regions, and we will draw until those lots have all been claimed. We thought it would be prudent, given the timing, to postpone the lots that are involved in the eastern region.

Mrs. Stefanson: Well, as I understand that in the cottage lot process, various applicants will choose first choice, second choice lots. If people have chosen lots in the eastern area as their first choice and maybe the western area or another area as the second choice, they're obviously placed in a very serious predicament. Obviously, the entire process is sort of turned upside down. I think that it's obviously going to be very unfair for those people who fall into this kind of a category.

I'm wondering if the minister could answer. Obviously, we need to resolve this–

Mr. Chairperson: The hour being 6:30, and as previously agreed in the House, committee rise.

EXECUTIVE COUNCIL

***** (15:00)

Madam Chairperson (Bonnie Korzeniowski): This section of the Committee of Supply has been dealing with the Estimates of Executive Council.

Would the First Minister's staff please enter the Chamber.

We are on page 31 of the Estimates book.

Hon. Gary Doer (Premier): Yes, there were a number of issues I took as notice yesterday.

Did the budget reflect the decrease in positions from 44 to 36? Yes, the transfer is reflected in the '05-06 budget. The budget was $3.4 million in the '03-04 and $2.6 in '05-06. This reflects a transfer of eight FTEs from the Executive Council.

There is a discrepancy, the question of a discrepancy would be Public Accounts and the printed vote. Public Accounts adds $950,000 to Executive Council as essentially the flow through, as I indicated yesterday, from the international MCIC grants of $950,000, so the matter is reconciled, I think.

Which political staff, quote-unquote–because they're all working for the public, of course, in the political office–Alison DuBois, Mark Veerkamp and Jackie Friesen are three political staff appointed in the last 12 months that are presently working in Executive Council.

Pay increments on Mr. Balagus: No, there are no bonuses, standard pay increments. The salary was $131,000, not $135,000. The increases reflect, as previous practice in the Premier's office, the payment in lieu of pension; the vehicle allowance, which is attributed to and accounted to in the Public Accounts; and the increments in regular pay increases, one of which was retroactive, so there's been no extra increment or similar provision.

The Hydro, I was correct, paid for the charter flight to Nelson House for that announcement that I was on. It was with the Executive's Hydro. I believe the CEO of the corporation and at least one of the vice-presidents, if not two, were on that flight. I think the other people came from Thompson who were there for the announcement.

If there were any positions in Executive Council being reclassified: No.

What is the Goldin contract? We talked about that. Actually this is a Canadian firm. There was some controversy in the past about the pins we hand out. The pins typically cost about 25 cents apiece, tremendous demand from Legions, sport teams and other community groups.

The projects under Hydro, I don't think I took that as notice, but it was Kettle project. It was the first one in '66-67, and there were further ones negotiated in the seventies. That would be under, I presume, Ed Schreyer, Jenpeg and Long Spruce, so the Kettle and Jenpeg were separated by different governments.

Mr. Hugh McFadyen (Leader of the Official Opposition): Thanks to the Premier for those clarifications. There are a couple which remain outstanding from yesterday, and I just wonder if in addition to the, quote-unquote, political staff that joined Executive Council in the past 12 months, if he could indicate the names of those who left Executive Council, and just indicate where those individuals are employed currently?

Mr. Doer: I made a mistake. Alison DuBois left, and she is gone to take her Ph.D., and Jackie Friesen was appointed to Executive Council. Mark Veerkamp was transferred from Executive Council to CEDC. And in terms of the list that you've got, Andrea Coulling worked in government before, in January '07, and she has departed for the private sector.

Mr. McFadyen: The transfer, it was Mark Veerkamp, I think the name was, to CEDC. Is that a transfer into a permanent civil service position as contrasted with an Order-in-Council serving at the pleasure position?

Mr. Doer: I'll have to take that as notice. I'll report back tomorrow on that. I don't know the how-to. *[interjection]* Pardon? *[interjection]* Is it a yes? Okay. Well, I'll double-check. I always like to double-check.

Mr. McFadyen: The beauty of double-checking with Estimates is eventually you get to the last day and then there's 12 months before we get to follow up again. But I'll leave that as an aside. *[interjection]* It does fly, actually, when you're having fun.

I didn't quite understand: the Premier said something to the effect that Jackie Friesen had been transferred within Executive Council, or was an employee of Executive Council but left. It wasn't clear to me where she went to.

Mr. Doer: Jackie was doing her part for population increase in Manitoba. She left government and was reappointed to government in a position she held most effectively in Cabinet Communications.

Mr. McFadyen: Well, in that case, I want to extend my congratulations to her.

Madam Chair, I just want to come back. There was one other response the Premier provided as a follow-up to questions that were asked yesterday, and I would just note before I get to that question that he indicates salary was $131,000 for Mr. Balagus, not $135,000. The $135,000 reflected other benefits that were non-salary benefits, which I understand, which means that there was an increase of roughly $26,000 over three years from a base of about $101,000, which still sounds like something in the range of 8 percent. The Premier says those are related to standard merit increments.

It sounds high to me, an 8 percent increase from one year to the next, average of eight years, when you consider what's going on with cost of living in other sectors. I just wonder if he could just provide some additional explanation.

Mr. Doer: In essence, there are close to four wage increases because one is retroactive. We apply the public service settlement to all excluded people in the public service after the contract is negotiated and ratified.

I'm just recalling, but in '03, the contract was not negotiated before the election, and it certainly wasn't negotiated quickly after the election. There was a certain lag time, so there would have been that retroactively and, of course, we didn't start Mr. Balagus at the top of his range. We started him in a position where he got increments, a very comparable practice to when the Leader of the Opposition was in the former premier's office. The increments flowed to the staff, and then you could sometimes get increases. Obviously, the increment and the general wage increase can produce results that are higher for a short period of time until the increments are over.

I can get even a further delineation, but that's the explanation of it, and, again, it was exactly as Mr. Sokolyk had received in the sense that he'd been there three or four years, I believe, and got increments and general wage increases. There was no adjustment. I would require an Order-in-Council to adjust the salary from 2003 to add an increment. I would require an Order-in-Council, and if I did that, it would be fully divulged to the opposition because they're public documents. I don't recall, and I've asked people to double check, whether there was any increase beyond the regular increases that do not require statutory approval, and there just wasn't an extra payment.

But there was an extra situation with the salary increase that did come in retroactively, so he would have had, in a very short period of time, the increase. I think almost every civil servant in 2004 got a 2003 retroactive increase. If I recall correctly, the MGEU filed for arbitration. Then there was a subsequent settlement, so that delayed, during the period of time that we may or may not have gone to arbitration, there was a definite gap of time which would result in the increase being–you'd have to go back to '03 because it was higher because of the retroactivity.

I did not sign an Order-in-Council. I got the nod. I'm pretty sure I would remember that. Actually, I'm pretty sure somebody would ask a question about it the second–before the ink dried, as you would expect.

***** (15:10)

Mr. McFadyen: I assume when the Premier talks about somebody wanting to ask a question before the ink dried, he's referring to members of his Cabinet. I leave that as an aside, Madam Chair. I know that members of senior staff are not always popular with other members of Cabinet, so that's why I make that comment, not that I ever had conflict with members of Cabinet in the day. *[interjection]* Well, that's what I saw on the ad. I did see that in an ad.

Back to the Premier again, just coming back to the staffing numbers within Executive Council. He indicated, and this name is reflected on a chart that we were provided that's dated September '07, Andrea Coulling as a member of staff. He indicated one member of staff who left and then returned and then two others who departed.

I wonder, is there a vacancy created by virtue of that? You've got one new staff and two departing staff over the last 12 months or was that vacancy filled? Is there another new member, I guess is the question, from the past 12 months?

Mr. Doer: On September 28 when Andrea leaves, we will have a vacancy, both in person and in spirit.

Mr. McFadyen: Thank you for that clarification. I thought that you had said that she had joined within the past 12 months. *[interjection]* She did and she's departing. Okay, all right, it's a revolving door.

Madam Chair, I just want to ask the Premier, just to come back on one other question. I asked yesterday whether there were any other departments or Crown corporations or provincial government agencies that covered the Premier's travel expenses. He was good enough to confirm that Hydro had paid for the expenses, which makes sense to me, for the flight to Nelson House in connection, I presume, with the Wuskwatim announcement.

I just want to ask the Premier whether there were any other departments, Crown corporations or provincial government agencies that covered any other travel expenses in the course of the past 12 months.

Mr. Doer: I mentioned Intergovernmental Affairs. I'll double-check the other departments. The total will be provided consistent with FIPPAs. The quantum will be provided. The source, I can also get to the member. It's primarily Intergovernmental Affairs, but it may have been other departments from time to time, giving speeches, et cetera. But I'll get the exact–I'm just thinking of the internal trade discussions that Bernard Lord and I led. Sometimes the budget came out of the Trade department. But the quantum, the total, would be obviously disclosed, including any memberships in Davos.

Mr. McFadyen: I wonder if, just to go back over the period of time since our last Estimates which were in May of last year, May of 2006, which in some respects seems like a lifetime ago but really wasn't all that long ago, if the Premier can just give an overview of the–before I get to the question, I just want to premise it by repeating what I said yesterday, that travel is an important part of the Premier's job. Representing Manitoba is a critical component of the Premier's responsibilities, so there's no issue at all with respect to the need to travel from time to time on important trips.

But I do want to just ask if the Premier can provide a summary of his travel from last year's Estimates, May of 2006, until the present, his official travel. We don't need to hear about Lac Lu.

Mr. Doer: Well, I can provide that. I'll get that. I think it's going to be available. I actually like to read it sometimes. I've noticed the odd time there's been a double-counting of something, not by anybody. I sometimes want a reality check to make sure it's accurate.

We also are subject to FIPPA obviously on the travel and I believe we're looking at having a regular disclosure of that information similar to members' allowances and expenses.

Mr. McFadyen: Madam Chairperson, I wonder if, when he returns with that information, the Premier can just outline the purpose of the trip, the destination, and who accompanied the Premier on those trips in terms of the delegation.

I just want to ask the Premier, going back beyond the previous 14 months, if he, in any official capacity, has travelled with a Mr. Costas Ataliotis.

Mr. Doer: No. I don't even have to check that.

Mr. McFadyen: Madam Chairperson, I want to ask the Premier whether he's travelled, going back to 2000, with either the chair of Crocus, Mr. Rob Hilliard, Sherman Kreiner, and/or James Umlah over that time period.

Mr. Doer: No.

Mr. McFadyen: Thank you. Just coming back on the issue of Crocus. This is the first time we've had Estimates since the Cabinet document was made public. That was the November 2000 Cabinet document that contained within it two fairly startling statements: one that Crocus was headed towards a liquidity crisis, and, secondly, that it was operating outside of its prospectus.

I want to ask the Premier if he could explain what direction he gave to his Minister of Finance (Mr. Selinger) when that paper came forward to Cabinet, given the very startling and serious nature of the statements in that document that were signed off by his then and current Minister of Finance.

Mr. Doer: Well, it's also the first time since the member opposite argued that the government withheld those documents from the Auditor General and the Auditor General's office confirmed that it made up the Auditor General's report. It was considered by the Auditor General. I still haven't got an apology from the Leader of the Opposition to the Minister of Finance.

I'm also quite concerned that the member opposite has had correspondence with the legal team suing the Government of Manitoba. Of course, our concern is for the taxpayers of Manitoba. The lawsuit goes back prior to our administration in government. It's not just the Province of Manitoba. I know that that's a fact conveniently overlooked, but I'm going to be very careful on any comments I make here because we're fully accountable in any lawsuit and we'll be judged accordingly.

We also have the Auditor General's report which, contrary to allegations made, did have the document, did consider the document. So I'll be dealing with issues in a lawsuit before the whole provincial government back to 1992 and I'll be very careful.

Mr. McFadyen: Thank you. I agree on the need to be careful, which is why it's important to get the chronology right in terms of the Cabinet document that the Premier is referring to, that there was a rushed letter issued by the new Auditor General who was not a part of the Crocus audit, the contents of which were leaked to the media by the Minister of Finance (Mr. Selinger) before the letter was released the next day.

At the next Public Accounts meeting, the gentleman, whose name I will double-check, who actually oversaw the audit issued a document which backed away from what the new Auditor General had said about that document. In fact, the individual within the Auditor's office who issued the statement indicated that the document had not been provided to the Auditor's office by the Premier (Mr. Doer) or the Minister of Finance (Mr. Selinger), which is exactly what I and the leader of the third party had said.

***** (15:20)

In fact, what had happened was that the Auditor's office stumbled upon the document in the course of reviewing monitoring files within the Department of Industry and, when confronted with that document, chose to not make reference to it in the Auditor's report. It was background knowledge that was possessed by the Auditor's office, but it was not referred to in the report.

The problem that the Auditor's office was confronted with when coming across the document was that in 2001 the Premier and Minister of Finance had amended the Auditors act to prevent the Auditor General from having access to Cabinet documents without the prior permission of Cabinet. That permission was never sought, and the document was therefore not specifically referenced in the Auditor's report.

Anybody who has read the Auditor's report in its entirety will know that the specifics of that document were not referenced in that report. So it is important, as the Premier says, to get the record right and be factual about what actually happened, which is why I would suggest that if anybody owes anybody else an apology, the Premier may want to apologize for not proactively giving the Auditor access to the Cabinet document and for not proactively granting permission to the Auditor's office to make use of that document in the course of their audit.

So, coming back to the question, because that's a long diversion but I think important to correct the record. Coming back to the question, I wonder if the Premier can indicate why he didn't direct his Minister of Finance to warn Crocus investors of what they were aware of along with a public plan for getting the fund back up on its feet and heading off its liquidity problems and instead chose to keep it secret.

Mr. Doer: I would point out that the former Auditor General said, and I quote, in the *Winnipeg Sun* that the documents would not have made any difference to the findings in the audit. The Auditor General did comment on issues of pacing, and we did take responsibility for that when the Auditor General reported.

I would point out that we're aware that the member opposite has had–his office has had communication with the defence lawyers or the lawyers from the group that is suing the government. It is our responsibility to protect taxpayers. It is the primary responsibility to protect taxpayers and we have the Auditor General's report.

We have a civil suit that is proceeding or before the court. It goes back to 1992-93 when the legislation was passed. The Province of Manitoba is defending the lawsuit that goes back to the previous Premier and the Auditor General report stands. I certainly support the findings of the Auditor General, accept responsibility for them and accept the fact that we took a proactive approach when Crocus was balking at the documents being released. We wrote a letter to Crocus, said that the new legislation we brought in allows for the Auditor General to go into private companies, i.e., Crocus. The Auditor General has the authority to do that, and we will back up the Auditor General in court. So we did take a proactive approach.

The law provides access to every document, every file in every department dealing with any audit. That's just plain and simple, and the Auditor General, of course, has access, power, subpoena and anything else so it's completely open, but the Auditor General report stands. It's a document for this Legislature and the member opposite may want to join the legal team of the plaintiffs. That's his right, but I'm not here to try the court case in Estimates of the Premier.

Mr. McFadyen: We certainly share the frustration of all Manitobans, which includes the 34,000 Manitobans who lost money in Crocus who are the plaintiffs in a lawsuit, at their inability to get at the facts and the truth and to shed some light on exactly what happened in the lead-up to the fund's collapse and for that reason make no apology for communicating with advocates for those 34,000 plaintiffs, with a view commonly to get at all the facts so that we can establish what happened and allow Manitobans to know what happened and ultimately arrive at a fair settlement for those who have been impacted–fair both to taxpayers who are funding the defence of this lawsuit, the protracted, expensive "Russian winter" defence that the government is mounting to the lawsuit, which is at the expense of taxpayers. We think that full disclosure of the facts to the people of the province of Manitoba is in the interest of both taxpayers and Crocus shareholders and make no apology for working with others who may have information that is relevant.

We certainly contrast that with the witness tampering that went on by his former Minister of Health and Minister of Family Services in the 1990s which was the subject of some comment, and we certainly are not in the business of trying to influence the testimony of witnesses. We are simply interested in gathering information as it becomes available, Madam Chair.

So the Premier (Mr. Doer) hasn't responded to the question. They've launched a cover-up strategy for more than four years after they became aware of the problem. Shortly after the Cabinet discussion in November of 2000, in fact, the first opportunity after that discussion, they introduced amendments to the Auditor's act which did two things: one is open up labour-sponsored funds to scrutiny; secondly, to close off access to Cabinet documents. So, certainly, the government was prepared to allow the funds to be held accountable and to be scrutinized but wasn't prepared to be scrutinized itself. So, when the Premier says that all documents are available to the Auditor, the fact is that the Auditor is not in a position to make use of Cabinet documents without Cabinet's permission. That sets up a barrier to the Auditor. It slows down the audit and creates a vacuum in terms of the information that's available to the public.

I just want to ask the Premier because it would have seemed–the Premier is known for being a smart political operator–it would've seemed to me that it would have been politically prudent at the time of that Cabinet discussion to have made disclosure of the problems, and I certainly would have expected they would have made every attempt to blame the problems that were coming to the surface on the previous government. That does happen sometimes after governments change and then embark on a program of attempting to correct the problems. I don't understand why they wouldn't have taken that course of public disclosure, outlining what the problems were, providing some explanation as to what might have caused them, and embark in a public process of working out the problems in full view of those who were to invest in the fund. I wonder if the Premier can just explain why the choice was made to take a cover-up strategy as opposed to an open and transparent strategy.

Mr. Doer: Well, we have full accountability with the Auditor General's review; we'll have full accountability with the lawsuit. I'm surprised that the member opposite is working in concert with people that are trying to sue the previous government and this government when he confirmed that he is working with the advocates for the plaintiff. I think that there is a–I guess our concern is the taxpayers. The member opposite, a year ago, said he would settle the lawsuit after he urged me not to settle it in the House. We are defending the position and we're actually defending the former government. Part of the allegations in the lawsuit deal with the existing legislation that was passed as far back as '92-93.

So, my job here is–and the member opposite is working in concert with the plaintiffs' lawyers, you know. I'm working in co-operation with defending both our government and the previous government on the lawsuit. We believe that taxpayers are our responsibility, and we're fully accountable and we will continue to be accountable.

The member opposite used the White Russian metaphor, the "Russian winter." I hope he's not Napoleon in this regard and I think he might be.

***** (15:30)

Mr. McFadyen: Without getting bogged down in the confusing historical reference, I want to just come back to some of the things the Premier said which are just dead wrong. This defence is about protecting the Premier, members of his Cabinet and his friends at Crocus. It's got nothing to do with protecting Manitoba taxpayers because if he was interested in protecting Manitoba taxpayers, he would have been prepared to get to the bottom of what had happened and then work out something that's fair instead of this protracted defence which is now being undertaken. The lawyers representing the government are very good lawyers. They bill accordingly.

I just want to ask the Premier if he can indicate what the cost of the defence to taxpayers is to date.

Mr. Doer: I'm sure you could have your critic ask in the Department of Competitiveness. I'll double-check who the actual authority is for the expenditure of money. The member opposite indicated that he was willing to settle. That in itself is expensive. That's his position. Our position is to defend, not only our government but the previous government. The case goes back to '92-93. It goes back to the original legislation. It goes back to the directors appointed. The original directors were appointed under the legislation. The original team of directors goes right back to an initial document signed off by one Eric Stefanson. It includes our time and the previous government's time.

We certainly know that the cost was $12 million for an inquiry. We asked that question, which is also expensive. I've called inquiries before when I thought that some of the other checks and balances were not adequate. Driskell is one, Sophonow is two, and I promised to have an inquiry on the unfortunate death of Phoenix Sinclair after the alleged murder charges have been dealt with. But I'm conscious of the costs and the benefits of any inquiry. Obviously, I will be accountable in court, as we said before, and we will provide our answers under cross examination with no fear of providing those answers. I'm certainly knowing that the member opposite has confirmed that he's working with the plaintiff's lawyers. Just to say that this court case is before the courts and it goes back to the previous government and our government, and we'll defend our actions.

Mr. McFadyen: Thank you, and I know that his lawyers are in communication with the plaintiff's lawyers, and I've said that we are interested in gathering facts wherever we can so that the people of the province know what happened, and we can get past the cover-up.

The Premier has made some incorrect statements in his response. He indicated–or misleading statements, I guess may be a better way of describing them–that the lawsuit goes back to the former government. If you read the statement of claim, which I know he has, he knows that the allegations of negligence and abuse of public office and the serious allegations arise from 2000 forward under his government. Certainly, the statement of claim lays out facts in order to provide some contextual background that goes back to the 1990s in terms of the start-up of the fund, the legislative framework and other things. But the allegations relating to negligence and other serious abuses of public trust, all are directed at his NDP government. I think that's important to have that on the record.

It's not surprising, when we consider what we know to this date, which is that the warnings were coming forward through 2000 in terms of the looming liquidity problems at the fund and the fact that the government was aware that the fund was operating outside of its prospectus and not disclosing that to the public. Clearly, it doesn't take a lot of common sense to view that as outrageous behaviour when it comes to protecting the public interest, and now, as a result of that, Manitoba taxpayers are faced with a $200-million claim, with legal costs mounting and interest running on that claim as well.

So my advice and my position is that we should get to the facts as quickly as we can, stop paying the lawyers, cut off the interest payments, and, on the basis of the facts that are available, cut taxpayers' losses. What the Premier's decided is to put himself and his friends at Crocus first, allowing the interest to climb, allowing the legal bills to mount, so that Manitobans are left in the dark, and I think that's unfortunate. But, clearly, the Premier's not in any mood to make any admissions, and so it will go on and on and on, I would assume, Madam Chair.

I just want to come back to a statement the Premier made with respect to the motion the government had brought to strike the claim, and the Premier made a statement in the media that he could pretty much guarantee the government was going to win that motion and have the claims struck out. As we now know, Justice Hanssen rejected the government's motion, did not strike out the claim, believed there was enough merit to the claim that the lawsuit should continue, so I wonder if the Premier wants to apologize now for wrongly predicting and trying to suggest that the government had an easy case on this motion to dismiss.

Mr. Doer: Yes, in fact, the member opposite, when he first took the position, he said that we should move to the motion to dismiss, and then he took a different position four weeks later that we should settle. So it's a very convenient legal position on the one hand and on the other hand. So we've been consistent in terms of defence. The issues will be resolved in the court. There are appeals, potentially, Wellington West and Pricewaterhouse, the Securities Commission, a number of individuals. I would point out the seven, quote, so-called "insiders" to Crocus that were named in the lawsuit were all under the–six out of the seven were under the Conservative regime. I know the member opposite only focussed in on one in his questions and the media accordingly did the same.

The lawsuit's statement of claim goes back to March 21, 1992. It covers seven and a half years of the previous government and four years of our government and, as I say, six out of the seven, quote, "insiders" were obviously appointed by the previous government. The legislation that arises, the first allegation is dealing with the legislation, the Auditor General already raised that issue. So we'll be accountable in court and we accept that.

Mr. McFadyen: Well, the Premier conveniently, in giving the chronology, again fails to make the point that the allegations of negligence and abuse of public trust and other issues all arise from the period 2000 forward. Certainly, there's contextual background going back a number of years, but certainly none of the serious allegations relate to anything that happened under the previous government. I know that, if they had evidence to support that position, they would have produced it by now and they haven't. So I would suggest that–he's cast aspersions on Mr. Stefanson and other members of the former government routinely in his defence on this case–rather than doing that without any evidence to support it, the Premier might want to be cautious and careful in terms of how he tries to spin the chronology that's laid out in the lawsuit.

But, moving on to a related question, I want to ask the Premier whether he had discussions with GrowthWorks and was privy to any of the discussions or played a role in connection with the GrowthWorks takeover of the management of ENSIS that was recently announced.

Mr. Doer: I didn't have discussions with GrowthWorks. I mean, GrowthWorks was in the public domain in terms of even Crocus back in–a few years ago, I guess, '05.

***** (15:40)

Just in terms of chronology, the lawsuit's statement of claim goes back to March 21, 1992. That's not something that's spinning; that's the fact of the case. Secondly, on aspersions, I just stated the fact–and I'll table in the House tomorrow–the Memorandum of Agreement between the Manitoba Federation of Labour and the provincial government at the time that was signed off as the basis for the genesis of the legislation, and that is a factual statement. It was in and around the time of March 21; I know it was 1992. I'll provide it to the member. I'm not casting aspersions. I'm just stating the chronological facts when a case begins.

The case is against the Province of Manitoba. The Province of Manitoba is cited from March 21, 1992 until its seven and a half years under the Conservative government, four years under our government, and it's still the Province of Manitoba. We've had other cases before where lawsuits emanate from different administrations and carry on from one administration to the other. The initial allegation is dealing with the initial legislation that has already been commented on in the Auditor General's report.

Mr. McFadyen: Again, not to continuously go over the same ground, but the allegations of negligence and other serious misconduct related to the period from 2000 until 2004.

I want to just come to statements that the Premier made in the House in response to questions prior to that Cabinet document coming to light. He made a statement in this House that all representations to us were that Crocus was strong. Given the Cabinet document that he had seen six years earlier that said it wasn't strong, I wonder if the Premier wants to take the opportunity to apologize and correct the record.

Mr. Doer: Well, you're taking my comments out of context as usual. I know they do that in moot court at the university. But if you read the whole statement you'll find that I was talking about my dialogue with Mr. Chipman. I was dealing with him on the development of the proposed MTS Centre, which was opposed by the Conservatives. I was also discussing with him–informally he mentioned the great success of National Leasing. But if you go back in *Hansard* there's a context. If you want to keep taking things out of context, don't expect me to answer out-of-context questions.

Mr. McFadyen: The Premier, I will acknowledge, is very good at parsing and picking the part of the question that he wants to respond to and giving half-answers. So that's why we have to sometimes keep coming back on these issues. That's a common tactic of people who don't want to be candid. He'll provide a narrow response to a question but is certainly not prepared to be candid on the issue of what they were told. *[interjection]*

Well, there was an exchange that went back and forth over what he knew about Crocus, and the statement was deliberately narrow. In any event, we now know that he didn't think Crocus was strong and that he had had representations from his own Minister of Finance (Mr. Selinger) that it wasn't. Presumably he takes the advice of his Minister of Finance seriously and doesn't completely disregard it. There are times when probably he should, but presumably he takes it seriously, and it's interesting that he would choose to leave that out of his response when we're talking about his knowledge of what was going on.

Just moving forward on this issue to recent events. The Premier indicated he didn't have any communications with anybody at GrowthWorks with respect to their takeover of ENSIS. I just wonder if he can indicate whether any members of his staff or any government staff had such communications who may have then reported those to him.

Mr. Doer: I'll check to see if anybody had. I heard the media reports on it.

I think GrowthWorks was something I was aware of in the media with the different options that the former board of Crocus was looking at. There was an issue there of liability and the government. We did not proceed to protect the board members with liability. We did proceed to have the tax reduction extended. But I'll double check on GrowthWorks. I'm trying to–I saw Bill Watchorn a couple times socially, I don't think he–I'm trying to recall our conversations–it was a golfing fundraising event. I'll check with my staff, but I certainly knew the announcement when it was made, and it was a private deal.

Mr. McFadyen: I just want to ask the Premier whether he shares the concern that we have expressed that the takeover of the management of ENSIS by a Vancouver-based firm in effect shifts head office decision-making responsibilities out of Manitoba.

I know in the short run, other than Mr. Watchorn who's joining the board of GrowthWorks, the officers and staff at ENSIS are, at least in the short run, protected, but the decision-making power, broadly, has been shifted out of Manitoba consistent with a trend that we've seen over the last number of years in the number of head office jobs declining in Manitoba.

I want to ask the Premier whether he is concerned about the fact that the transfer of head office responsibility to ENSIS has left Manitoba.

Mr. Doer: Well, if the member opposite will recall, I was concerned that the pension decision on teachers back in the '90s, prior to my election, was transferred to the head office and management of that fund. So I think it's Greystone, or I'll try to get the right name. I'm just trying to remember. The company was transferred to Regina out of Winnipeg.

To be consistent I would prefer the management and ownership in Winnipeg. Having said that, I listened to Mr. Watchorn's explanation in the media about the need to get bigger funds to survive. I don't know whether it's, quote, a red flag, but I was aware in the media that there were financial statements about ENSIS, before Crocus, dealing with some companies that were losing money. After Crocus it certainly accelerated in terms of the participation rate.

Mr. Watchorn also talked about the performance or lack of performance of other labour-sponsored funds, but I believe that there have been some positive developments with funds in Manitoba, the Canterbury fund that was established by a number of prominent Winnipeggers in Manitoba. Mr. Weinberg, of course, has been involved in that fund initially.

I also know that the Richardson fund has established again a venture fund here in Manitoba, an investment fund rather, in Manitoba and there is more head office capital here now with the creation of that new fund in Manitoba over the last four years. I think those are positive developments.

Obviously Crocus and ENSIS, Crocus is a very negative development, and ENSIS, I would have preferred it to be managed here in Manitoba. But I did listen to Mr. Watchorn's reasons for making that decision, and his view was, as the manager of the fund responsible for private-sector criteria, that this was in the best interest of the shareholders. He therefore made that decision as he saw fit, and I assume it was ratified by a body that is responsible for the ratification of those decisions, not by government.

Mr. McFadyen: I would just note the Premier's acknowledgment that the Crocus fiasco played a role in the problems that ENSIS faced and contributed to a need on the part of ENSIS to find a manager or a partner that had national reach in terms of marketing.

I certainly want to acknowledge the success of Marty Weinberg's fund as well as the Richardson fund. They've done a good job of raising capital, important to note, of course, that they're not restricted to investing here in Manitoba, although my understanding is that they're either looking at or have invested in Manitoba companies. But much of it is invested outside the province. Notwithstanding that, it is a strength of our province that we've got people with the capability to manage funds of that size.

***** (15:50)

Danny Bubis is another individual in our city who has taken on significant responsibilities in managing mutual funds, very significant ones. So certainly we have some talent. It is disheartening, however, when the focus is outside the province in terms of the investment targets for those funds.

Just back to the topic of head office jobs, I wonder if the Premier can indicate, and if he would be prepared to table the log of, any communications he had with Mr. Schmidt, the CEO of the former Sask Wheat Pool, now CEO of the new merged company with Agricore, about head office jobs here in Manitoba.

Mr. Doer: Well, they are private correspondences, but I have met with Mr. Schmidt on the Agricore-Sask Pool decision. Obviously, they're keeping all their operations here including the malt plant in Portage la Prairie, the oats plant rather. The head office jobs, some of them have remained in Manitoba. We've met with Mr. Schmidt. We know that some of the jobs were purchased by Richardsons to deal with competitive issues. Other jobs were purchased by a second company, and we certainly are worried that he's made it very clear publicly in Regina and in Winnipeg that the merger would reduce head office staff. He's been clear about that.

He's also made it very clear that there would be a process of reviewing all operations in both places over the next 12 months to determine the staffing and the location. Obviously, if we were quite worried when a Regina-based company purchased a Winnipeg-based company, we were quite worried about that. We see mergers the other way, though, you know, all the time. When Great-West Life buys another company and merges it and reduces its staffing, or Investors buys another company–and I was just meeting with the principals of those two companies this summer as well–it is a net gain. In fact, in the financial services sector, there's a considerable amount of gain in jobs and employment over the last number of years with the successful mergers that have taken place.

But this one, the head office right now is in Regina, of the company. If it was a bidding contest between the Richardsons and Sask Pool, obviously we're working with the successful bidder because they won, but, you know, when there're two companies bidding, one located in Regina and one located in Winnipeg, we start from the belief that–and I'm not talking about this situation because I don't want to offend Mr. Schmidt in my discussions with him–but my general principle, not with this case, of course, it doesn't apply to this case, but the general principle is we prefer Manitoba companies to be the buyer not the buyee.

Mr. McFadyen: The numbers that we see on a net basis on head office jobs in Manitoba are disconcerting in that there's been a steady decline in the number of head office jobs, an increase in the number of actual head offices, but the number of jobs declining. It's the job number that's the relevant one when a person is looking at where they want to have their future. Whether they're a graduate of engineering or commerce or any other faculty or a graduate of a community college, they're looking at their opportunities to progress up through the ranks of companies. As head office jobs move to other places, it's certainly discouraging for people who are trying to make decisions about where to go.

I'm not suggesting that as of today we are in, by any means, a crisis, but we have a concern with the direction things are moving in, relative to other places and, in particular, the recent decision by James Richardson International to locate their Canola crushing operation in Saskatchewan rather than Manitoba.

The movement of jobs by the successful bidder in the wheat pool bidding contest of head office jobs from Manitoba to Saskatchewan and so many other indicators of growth in Saskatchewan in that economy and relatively poor growth in Manitoba, and in the case of head office job numbers, negative growth, decline in terms of head office job numbers.

I wonder if the Premier can indicate what, if anything, he has in mind as a strategy to reverse this trend.

Mr. Doer: The member opposite mentions a couple of examples.

I would point out that the Canola crushing plant in Yorkton has not proceeded. I would point out that the regime of attraction in Brandon, from the community of Brandon and from ourselves, was as attractive, if not more attractive. But the whole issue of transportation costs with the number of Canola producers has put the cost benefit closer to the majority of Canola producers–or the number of Canola producers–in Saskatchewan. We didn't agree with the decision, but we certainly believe that–and we've had, from Mr. Richardson, confirmed that the bids were positive.

We've had a couple of other value-added jobs in plants announced in Brandon just recently in the food processing industry, particularly related to the health food industry. Just a few years ago, we were competing, with the Simplot operation, against Saskatchewan, Alberta and Idaho for potatoes, which went ahead. We've been competing on value-added jobs in hemp. We've been competing on value-added jobs in the hog industry; Maple Leaf has announced and then shelved their plans to expand dramatically, even with considerable public money, the Mitchell plant in Saskatoon and has proceeded with their own amount of money in the expansion of the second shift in Brandon. I talked about Great-West Life with its takeovers of other companies and the additional jobs, considerable jobs, in this community. Investors, with its takeover of the Mackenzie Financial services, and the movement of jobs to Winnipeg. I'll have to look at the financial services jobs numbers.

The overall job creation situation is extremely positive in Manitoba. The GDP is predicted to be positive. The earning rates are positive. There's still a lot more work to do. Every possible opportunity comes available. There are some that argue that the government should not put any, quote, money, in. I notice that some of these investments, like Motor Coach, with a small investment in the composite location, has ended up producing hundreds of jobs, some at Boeing, 300 extra jobs at Boeing. I was just talking to Minister Prentice about it last week when we were in Ottawa, besides the other issues that the member and I worked on together. We talked about the composite potential for the C17 repair and what it could mean. So that has been a very positive investment in manufacturing. But I'll check the actual jobs in the financial services sector.

Obviously, we are getting growth in a number of very, very major companies that are producing very significant careers. Just recently, as I said, I met with the principals, with the Power Corporation people in terms of their long-term planning, their long-term success and their great belief in Manitoba.

In terms of strategy, we believe education and training is the No. 1 priority for any government. I note that the Member for Brandon West (Mr. Borotsik) was just recently at an announcement where we further announced developments in the ACC college, the movement to the mental health site with expanded courses. We also are providing investments, seven percent to universities, to try to continue to invest in the future from where we were in the past, where cuts were the order of the day.

Ms. Erna Braun, Acting Chairperson, in the Chair

***** (16:00)

Of course, the member opposite pretty well duplicated the tax reductions we made to the corporate sector, the corporate tax reduction that we brought in. We had the highest corporate tax rate in Canada at 17 percent in 2000. It's now moving down to 12, and it's still more work to do. We had no change in the corporate capital tax. We've had no change in the manufacturing tax; we've reduced that. We've had no change on the machinery depreciation which we have matched the federal government's budget of February 2007, which to some degree has been helpful with the dollar and its rise of 15 percent in just less than a year and, of course, we pledge to eliminate the small business tax in Manitoba. We have the lowest small business tax in Canada, and we have pledged to eliminate that tax over the term of this mandate.

So we continue to chip away at the taxes on the corporate side, the education side, and on the personal side. You know, we've started from a pretty high base, and we continue to try to lower them on the corporate side but we don't believe in just the policies on taxes. We also believe in policies dealing with regulations. I think we've been evaluated to have the third best, but not the best in regulations. We're trying to continue to move in that area, behind B.C. and Alberta. We think we should do better. We believe in internal trade agreement in Canada, and we also believe in education and training as a key part of an economic strategy.

Mr. McFadyen: Well, the Premier likes to cite examples of companies and I know he likes to, any chance he gets, assign blame to previous governments for things that have gone wrong, but I note the list of companies that he indicated that are performing well in Manitoba are companies that were established here well before his government was elected. To be sure, the insurance companies controlled by Power Corp, Great-West Life, Investors Group and others–I find it surprising that you would be trying to take credit for the success of those organizations given how long-established they have been in Manitoba. I don't think that it would be entirely honest to say that it's as a result of any great initiative by his government that they have managed to be successful in this environment.

I also note the credit for the Maple Leaf expansion in Brandon and the reason for that is that Maple Leaf has the most modern plant in the country in Brandon. That was a plant that was built under the previous government, and so the rationale for Maple Leaf consolidating in Manitoba is because the previous government took steps–many of them opposed by him when he was in opposition–to create a good environment for those investments. Certainly, we're seeing the fruits of that today. In the case of Maple Leaf we see, in so many of the other examples he cited, companies that were established well before the life of this government.

So he talks about jobs. I would only note that we've gone from having the lowest unemployment rate in the country, now we've dropped four notches on that front, we now have the fourth lowest. We have discouraging numbers according to Stats Canada on the head office job front on a net basis. You can single out examples where there's been growth, but you have to subtract from those where we've lost jobs such as in the case of Agricore and in other cases where there's been a shift in head office responsibility.

So I wonder if rather than going over existing companies that are performing well in Manitoba, performing well because of the growth in the North American economy, not because of anything happening here, if the Premier can just outline what significant private-sector investment has taken place in Manitoba over the past 24 months.

Mr. Doer: First of all, I want to make it clear that there were two–there were about three or four questions posed by the member opposite in his previous question and one was "what are we doing" and the other question is "what is the status."

On the status side, I mentioned the issue of some of the companies that I've been meeting with this summer, and I want to give credit to the management, to the ownership and to the employees of those companies that continue to grow, and I would certainly want to ensure that that is the obvious case. There are issues on a go-forward basis when people are locating employees and manufacturers are interested in the manufacturing policy, which includes energy costs, which includes issues such as costs to compete in terms of education and training and other tax policies related to manufacturing, and they do make decisions every day about where to locate future work as does the financial sector.

On the financial side, I think one of the areas in our budget that we did announce two years ago and we implemented in the current budget, which the member opposite has basically adopted in his election campaign, was to eliminate the non-banking capital tax. That is an extremely important issue for companies going forward because there's no such thing, even though companies that have been established in Manitoba they make decisions on an ongoing basis of where to locate, and it's not just in Canada. It's at minimum, you know, a North American market, at minimum.

I'm not saying that that is the reason. I want to make it very clear. I think one of the areas that really is good for Manitoba has nothing to do with politics or government, and that is the whole issue of getting a well-trained person that is very loyal to the company that they work in. You hear this over and over and over and over again in Manitoba. This is a culture of loyalty and hard work that goes back to our parents and grandparents. I want to give credit long before this generation of political figures, and I want to make that very clear. If I said anything to do the opposite it's certainly my belief any time I'm dealing with a competitive issue that it starts with the hard work and skilled work of people, whether it's in the financial sector, the manufacturing sector. When I go on a shop floor at Motor Coach or when I go on a shop floor at Boeing or I go on a shop floor at Flyer or I go on a shop floor in a company in northern Manitoba, and I go to a fair amount over the year to keep in touch, it's always what comes back to me from management, and it includes managements moved in from the United States, is the creativity of people and the work ethic in this province. We debate about, you know, the cup being half full and the cup being half empty or full or empty, and the credit goes to a lot of really smart people that are working around Manitoba.

From time to time we do have competition. I mention the Simplot potato plant that was predicted to never proceed in Manitoba. I acknowledge that the former government proceeded with the Maple Leaf processing plant. We supported it in opposition, and we have worked with Mr. McCain to improve both the employment levels at the plant, but also the water protection, the new water protection that the Maple Leaf company has put in place. Another possibility to combine it with other companies in the area, adjacent to the area, is a market improvement from where it was in 1997-98 when the licence was improved, and I think that the Assiniboine River and the watershed will be better off for it because Maple Leaf has gone to the new nutrient and phosphorus levels. I applaud them for that and I think it's obviously the right decision, and the initial investment in that expansion was made entirely by them. They want to have a more co-operative proposal with the city of Brandon and other companies adjacent to it. But I do want to acknowledge the hard work of people, and I just wanted to make that very clear.

On the specific question of the financial sector, I said I would get those numbers. I would point out that the unemployment rate fluctuates with the labour force numbers on a monthly basis. The latest numbers are different than fourth in Canada. Just on average, we're averaging close to 7,000 jobs a year on average in the last number of years. We were averaging 3,000 a year in the '90s so we're moving in the right direction, and the public knows this. We can sit here and talk stats all day long. People know whether their economic situation is better today than it was before. They actually know that. No amount of statistics between politicians is going to change the reality of people's lives, whether it's better or worse.

***** (16:10)

On the issue of private-sector investment, between 55 percent and 60 percent of the new jobs this year, in 2007, are I believe in the private sector. I'll double-check that number, but I think it's close to that in terms of private-sector employment

Mr. McFadyen: I'm pleased the Premier is acknowledging the energy and ingenuity of business leaders in our province, many of whom have had success over significant periods of time and continue to adapt and excel in what they do. We do have a conversation in this Chamber about the environment within which they operate, the political environment which includes tax policy and a variety of things, and there are very often companies that will succeed in spite of a negative environment, and from time to time you'll have companies that fail in a good environment.

The debate is really around our assessment of the environment in Manitoba in comparison to other places which is really the most important consideration because people have so much freedom and this is a good thing, that they have so much freedom now to make decisions about where they want to invest and live and do business, that we are in a competitive world. I know the Premier will certainly acknowledge that in comments, but sometimes we note that it doesn't seem to be backed up by action and policies, and that's where we have concerns.

I know that lots of Manitobans today feel reasonably comfortable, but we also know that some of the early indicators of problems can arise and are very often flagged by people who are in leadership roles in different companies and organizations. I know, and I think the Premier can probably candidly say that he is hearing from people more often now, particularly in the last short while, concerns about where things are going in Manitoba but also how things are going more broadly. But the concern focusses to a large extent around Manitoba's position to weather difficult times.

Our Finance critic has certainly had the opportunity to touch on the point in Question Period, but it bears some further discussion here because it is so significant, every aspect of what goes on in the province if the economy turns down and we don't have the money for health care and education and universities and Family Services and all these other areas, roads, all these things that are important to us.

So I would say and I think would have a hard time finding anybody to disagree with me that having an economic strategy with the foresight to prepare for these negative developments has got to be a very, very high priority because of the fact that the economy underpins everything else, including funding Family Services and other areas.

So I asked the Premier the question whether he could list significant private-sector investments made in Manitoba in the past 24 months. He took the question as notice. Normally, when there's a major private-sector investment in a province, it doesn't take very much recall, especially for a skillful politician like the Premier, to recall those success stories and happily trumpet them at every opportunity.

So I want to ask him again if he could just, without taking the question as notice, list off new significant private-sector investments that have been made in Manitoba over the past 24 months.

Mr. Doer: Well, there was just one a couple of weeks ago in Brandon dealing with omega-3 products.

Madam Chairperson in the Chair

There's potential new development on hemp in Dauphin. I mentioned the Maple Leaf investment. I think they put $11 million into the existing plant. There's considerable amount of conversations on other major developments. There's of course OlyWest, an operation the member opposite is aware of, that was proposed and is still proposed in Manitoba.

Those are just a couple of examples. I can get a full list for the member. But we get advice about operations that are contemplating new investments all the time. Sometimes that's confidential and I respect that. But those are just a couple of examples.

Mr. McFadyen: I appreciate the requirement for confidentiality on things that are not yet announced, but the four examples, again Maple Leaf consolidating, because they've got a modern plant in Brandon built under the previous government. I was in Dauphin recently. There is frustration at the slow rate of progress on the hemp investment in Dauphin and a sense that there isn't a lot happening in terms of government attention and support in moving that investment forward. There was a reference to a Brandon investment which I'd be curious to know more about.

Then OlyWest, which is taking the position that they'll invest in Manitoba notwithstanding the negative environment that's been created by the moratorium, but because Manitoba, geographically, is well positioned for such a plant, and to take advantage of other developments in places like Québec, Saskatchewan and other places where they're going through downsizing and restructuring. Given our centrally positioned geography, there's logic in developing in Manitoba. We're glad to see that development. We think that OlyWest are very good corporate citizens and have served Manitoba well, and we look forward to that investment happening. I want to, in the spirit of non-partisanship, assure the Premier that we'll certainly applaud that investment when it is announced and confirmed.

But the four examples are not very compelling. Not very many of them have anything to do with action taken by government. This brings us back to our concern about a lack of focus and energy going into developing and encouraging private investment in Manitoba. We look at the jobs being created. A lot of them are spin-offs from major public investments: the floodway, the Hydro tower, highway construction. All things that are public sector investments, which obviously contribute to stimulating the economy in the short run, but don't form the basis for any new wealth-creation in the province which will sustain us going forward.

Obviously, our increasing dependence on transfer payments from Ottawa is a signal that Manitoba's capacity to support itself through its own source revenue is not as good as it could or should be. So I would just ask the Premier and suggest and put on the record our concern about the fact that there seems to be a lack of focus on economic development and a lack of strategy. Certainly, it shows up when we have such tepid reports of interest in investors here in Manitoba in major private-sector investments.

Now we see the dollar on par. The Premier talks about Motor Coach. We see the layoffs at General Motors in Ontario. We see a downturn in the U.S. housing market which, obviously, creates issues for companies in Manitoba like the strand board, Louisiana-Pacific at Swan River, and all of those companies engaged in manufacturing and exporting to the United States.

So I wonder if the Premier can indicate whether his thinking in terms of current economic policies, the incrementalist approach to dealing with taxes; the lack of energy going into attracting private investment; and the environment here, which is a difficult one with respect to labour laws–and in particular when you see situations like Mayfair Farms–whether he wants to revise his thinking and adopt a more pro-investment approach, and more energetically position Manitoba to be successful, because, certainly, we fear that these developments in the United States and the upward movement of the Canadian dollar will, down the road, start resulting in job losses and insecurity here in Manitoba. Even if people don't feel it today, our concern is that if the action isn't taken today, that they are going to feel it tomorrow and down the road.

I wonder if the Premier is prepared to, for example, take a more aggressive approach to dealing with property taxes in Manitoba, to dealing with the payroll tax, and in dealing with income taxes in the province of Manitoba, in addition to those other taxes as one part of that strategy, but also to be more aggressive in outreach and attracting potential private-sector investors.

***** (16:20)

Mr. Doer: I expect you do and are aware of the Husky plant that's now been multiplied by 10 times their ethanol plant. It's not open yet. It's open soon, but it's gone from 10 million litres to 125 million litres in Minnedosa. The company I was thinking of is Shape Foods in Brandon.

I want to come back to Boeing because they now have 75 engineers working on the 787 aircraft, and, again, this is work that you don't get automatically just because you did the previous aircraft. And the composite centre that we invested in here in Manitoba is being utilized by Motor Coach and other manufacturers, which was an idea that we developed in the early 2000s. We'd been told directly that that co-investment between the private sector and the public sector has made a considerable difference, the 300 employees on the shop floor in Boeing, and there is more work coming to that plant in Manitoba.

So there's an example where it's private sector driven, private-sector creativity, but the training facility at the airport, the college credit course, and the example that I raised with the composite centre has been very, very important. Light manufacturing is important for a more energy-efficient transportation product, whether it's a bus or an airplane, and it's going to continue to be very, very important.

The private capital investment in Manitoba will rise 6.5 percent this year. It's the second best in Canada and three times the national average. So when you talk about private capital investment, it's considerably higher than in previous decades and certainly it's doing quite well. The manufacturing capital investment in Manitoba will grow by close to 30 percent in 2007, the third best in Canada and again considerably higher than the national average of 5.3.

We've had record numbers of building permits in Manitoba, and we continue to believe that this is extremely important. So, you know, you could talk about these issues but I know that business feels, yes, worried about the rising Canadian dollar, but feels that things are doing quite well in Manitoba. The economy's doing quite well, and the numbers–well, again, the stats are not as relevant as people's opinions about their place in the economy.

On the issue of the dollar, we met with the manufacturers when the dollar was at 65 cents, and it looked to us like it was going to rise. We were told by the manufacturers of Manitoba that they could sustain up to an 80 cent dollar with the exports to United States. They were quite concerned and remain concerned when the dollar goes up so high, particularly when small short-term interest rates are higher in Canada than United States. They were in the past when the fiscal policy, the financial policy was to raise the short-term interest rates and really increase the rapidity of the rise of the dollar, and many companies lost their accounts receivables in a very short period of time. They may have shipped something 60 days to pay their bills and then lose the money in that period of time.

We agreed with Jerry Gray when he chaired a committee on the manufacturing sector. We joined with him in a proposal called Lean Manufacturing which dealt with labour costs, dealt with energy costs; it dealt with the manufacturer's tax credit which we've accelerated in three budgets. It dealt with the depreciation of equipment in a more rapid state.

I was just talking to Jim–Minister Flaherty–and I mentioned to him that we matched that when he brought in his budget last year or this current year, current fiscal year. We are concerned about where the dollar's going to go. One of the advantages we have is energy costs. One of the advantages we have is labour productivity in terms of the work ethic of employees. One of the advantages we have is education and training. More of the recent reports indicate that Winnipeg was the third most competitive community in Canada. Many companies that are small business companies that feed the manufacturing sector is where the biggest growth is taking place. And that's why we've gone from the highest small business tax to the lowest small business tax in Canada. The rate is now below Alberta. When we came in we were double that of Alberta, and we think that that is stimulating not those high-profile, ribbon-cutting kinds of announcements, but every day making a difference in terms of the economy because small business is extremely important to the Manitoba economy. We have had discussions on the dollar at par, you know, the U.S. financial policies. I'm sure members opposite followed Mr. Greenspan in his discussions. I haven't read his book yet.

An Honourable Member: You're still reading Mulroney's.

Mr. Doer: What was that?

An Honourable Member: You're still reading Mulroney's.

Mr. Doer: Still reading Mulroney's? Well I've read portions of Mulroney. I haven't read the whole thing yet. I've cherry-picked the CF-18 discussion and some of the ones that are more topical to Manitoba, a little bit of the Meech Lake. I haven't read the appendix yet, but I understand it's interesting. Everybody's got a book on it, Mrs. Carstairs and now Mr. Mulroney. I'm sure there's more coming over time. So I've read part of that, but I want to read Mr. Greenspan's book. I think it would be enlightening. I saw his interview with Mr. Russert this weekend and it was an interesting interview.

I mean, I've always been worried about the U.S. economy. I could say, well, I've always worried when conservatives are in charge of an economy, but I won't say that. But I've always worried when there's a combination of–you don't have to be a Ph.D.–I always worry when I hear that, I mean, the elements of a lack of medicare sustainability. Again, if you listen to Mr. Russert's interview with Mr. Greenspan, he says the social security gap is not as great as what people purport it to be. It could be managed with a small percentage of GDP over the medium term. But he indicates that there's a huge and growing problem in the United States on health care and the health care gap, both in terms of the sustainability of the existing system and the coverage of that system, which by the way when we meet with companies from different countries that are looking at either Canada or the United States, the issue of a medicare plan is a competitive advantage for Canada relative to the United States.

Another issue of competitive advantage is less lawyers in Canada. I want to say that, and I don't mean anything personally to the member opposite, but this is not a litigious society, as litigious a society as United States. So those are two of the competitive advantages we have.

The U.S. dollar is depreciated against the Euro, against the Australian currency, against many other currencies, and to some degree the Canadian dollar rise is to do with, according to Mr. Flaherty, all governments running surpluses and investing in productivity. But one could argue the other side of that. It's also to do with the fact that the United States has a situation where they're running a huge deficit. They're decreasing taxes–and you know my opinion about decreasing taxes and running a deficit–and also trying to finance a very expensive war and those are just the current economic realities of United States. You've got the sub issues and the sub prime issue and how it affects capital in the markets and the availability of capital in the markets. You've just got some retail numbers yesterday from companies that should concern all of us. It concerns me even though the stock market went up because the energy prices went down. I think the whole issue of the currency parody is going to remain with us because of the challenges on a go-forward basis with the U.S. fiscal situation.

***** (16:30)

So I think that we have to live with the dollar and that's why we adapted and adopted the lean manufacturing strategy in Manitoba with the manufacturers. We didn't sit in an office; we went with them a number of times and came up with a number of recommendations that they gave to us. We're going to continue to work with them because we recognize that it's extremely tough for them, and it's been extremely tough to compete. As I say many of them have exceeded what they thought they could do when the dollar was–they said to us they could live till 80 cents, 85 cents, but now it's going up and it went up 15 percent just in less than 12 months in Canada. So we're quite worried about it, but we're going to continue to work with these sectors that are established. What may be not a real problem for one sector, like the financial sector, may be a real problem for another sector.

Mr. McFadyen: I'll withdraw the point of order, Madam Chair. I was going to rise on the length of the response. It was getting dangerously close to the length of the clerk's Ph.D. thesis. I haven't read it, but I assume it's a weighty document.

In any event, I just want to come back that everything the Premier said is acknowledgment of the fact that we have economic problems in the U.S. which could have a negative impact on Manitoba. Our concern, when you look at the private investment story in Manitoba over the past 24 months, is that it hasn't been a great story. We could talk about an increase projected for this year. Projections don't always come out in reality, but when you're starting from a relatively low base compared to other provinces it is sometimes possible to have misleadingly high numbers in percentage terms when you start from a lower base. I would just leave that as a comment on the record.

I would also just indicate that representatives of small business, as an example, within small business, the restaurant and food service industry indicating disappointment at the sluggish situation within that industry, the lack of growth. We get new restaurants that come up from time to time but others are closing. These are businesses that have very narrow margins, and many of them are run by people who are not wealthy people, or people who are real entrepreneurs and who put up capital at their own risk. Sometimes they borrow money against their mortgages on their homes. In many cases, they're new Canadians who have come here and are going into business and taking risks to support themselves and their family and to provide a service to their community.

What I hear from people in that industry is concern about the fact that, while there's been tremendous growth in other provinces, there hasn't been such great growth here. There's a sense of stagnation. That's one industry that's highly sensitive to people's after-tax incomes. It's one of the first things you cut out, if your income is stagnant or goes down, is restaurant eating, and it's a good bellwether. I would just say to the Premier for the record that, when you hear those sorts of reports coming from people in that industry, it is time to be more alarmed and more concerned and to consider it a red flag that calls for more energetic and more significant action from the government to head off what may be a downturn in the Manitoba economy.

The Premier talks about this being academic in nature. I don't know if he used the word "academic," but something that people don't relate to at present because they think about their own circumstances. But the fact is that, when you see warning signs on the horizon, this could very well and very quickly move from being an academic discussion to being a discussion about people's lives and jobs and mortgages and homes and ability to get by, with an impact on health care and education and family services and these other areas.

We've certainly made the point, I've made the point, about the urgency. We think the government should be doing more, should be more pro-business, should be pursuing lower taxes and a better regulatory environment. We're on the record saying that, and I guess we shall see what transpires in the months and the years ahead.

Just coming back on a specific issue that came up last spring, there was some media around the fact that Ainsworth was looking at investing in Manitoba. I wonder if the Premier can just update us on the status of that proposed investment.

Mr. Doer: I just want to deal with a couple of issues. One, in the election campaign–I assume that's still your platform–the member opposite did not promise dramatic decreases in business taxes in Manitoba. He actually made a statement. After we had promised to eliminate the small business tax in this term, he basically said that the tax reductions on the corporate side, the small business side, the capital tax, would all be honoured by his "government." He then made a further adjustment uncosted, or not costed, on the payroll tax deduction being moved up moderately. So, really, where he blew his money, his income was a potential revenue issue. He spent $200 million on a proposal to lower the sales tax by one point.

Now, I'm not giving the member advice for the next election campaign, but if you wanted to get a bigger bang for your business buck and consumer buck, I would argue strongly that that was a very uneconomic proposal. I could think of four or five other proposals that business trying to compete with other provinces would prefer more than that.

So you have $200 million out the window in the first couple of days of the campaign, out the window in terms of ongoing revenue. Then you had other promises that were interesting to say the least. You never did cost the marina in Point Douglas. You know we didn't know how many houses you were going to bulldoze there and how many boats you were going to park there and all kinds of other things, but I would suggest that you, sir, have copied–can't use Xerox, that's an old term–but have taken off the electronic press, release of our business announcements and budgets and virtually brought them forward as your own.

We're flattered. I know that you had to work fast because we made the small business tax reduction in Brandon at the Chamber of Commerce luncheon, the independent Chamber of Commerce luncheon that we attended at that meeting. We certainly were happy that the member ran quickly to catch up but, you know, I would like to have some of those taxes lower. I wish we would have started on the corporate tax side. It's at 14 percent and now we'd be equal to Alberta. We started at 17 and we've lowered it every year since 2001, every year.

We've lowered the small business tax every year, every year. I wish we didn't start at eight percent. My brother's an accountant, and he tells me that we had the highest business taxes in Canada when we came into office.

An Honourable Member: They were during your time.

Mr. Doer: Well, you had no change in the corporate tax since the second World War. No change, so I take responsibility. I guess Premier Bracken was in, but it was 17 percent, including under NDP governments from 1945 to 2002. We started lowering it in 2002. We had it in the 2001 budget. Maybe we lowered it in 2001, but we lowered it down each year, and we have to do more. We have to do more, I acknowledge that.

An Honourable Member: Ainsworth.

Mr. Doer: Yes. I'm going to get to that, but you go on in a five-minute statement. You make statements and I have to have–this is a debate. This is not moot law school at Robson Hall. This is actually a two-way conversation, and I get to respond to some of your issues as opposed to–I know the member opposite loves that profession and someday he might go back to it, but here we have a discussion and, if you make a statement, I have the responsibility to deal with statements made. So I would point out that the–

Madam Chairperson: Order, please.

I'd just like to take a moment to remind all members to speak through the Chair and there'll be less temptation to respond.

Mr. Doer: Yes, Ainsworth is still interested in investing. They are still consulting with First Nations. They are slowing down all of their North American investments with the market the way it is, but they're still consulting with First Nations.

***** (16:40)

Mr. McFadyen: The Premier has completely left out in his response several points of importance. One is that it was he that raised the sales tax from six to seven points on June 1, 1987, when he was in Cabinet, and it was his government, NDP government, that set taxes at the record-high levels they were at. Certainly, with deficits and cutbacks in transfer payments through the 1990s, a recession in the early 1990s, there was limited room for tax reductions, and the Premier, I think, has said already that he doesn't think we should reduce taxes if it's going to create a deficit. So that's why he voted for the Filmon budget in 1999 and why he supported all of the Conservative economic policies when he ran successfully in 1999. He had to run as a conservative in 1999 to win the election. So I hope he'll at least be honest enough to acknowledge that.

We've also said that property taxes, education property taxes, should be reduced in Manitoba. This is a huge driver of property values which has an influence on one's ability to borrow against that value to invest in new businesses and create jobs. It was the Saskatchewan NDP that cut their sales tax by two points. Prime Minister Harper, whom the Premier has praised many times, is a Prime Minister who's cut the sale tax at that level. I think, every now and then, that regular people deserve a tax break, and that's why we think that sales taxes are worth going after.

But not alone by any means, Madam Chairperson, we think the payroll tax should be reduced. Over a longer term, the government should look at eliminating it completely. We're one of three provinces that still has one. It's a major issue with anybody we speak to in the business community that is investing in growing, particularly as you hit the threshold and the tax is applied retroactively to the full payroll. It's a significant blow, and it's a significant disincentive to invest. The proof is in the record. That's why the Premier can't name a significant new, private-sector investment in the past 24 months, and why he doesn't seem to be able to offer us any sense of optimism but what might be in the pipeline in terms of new investment in Manitoba. Even Ainsworth, which was rolled out in the middle of the damage control campaign last May, when the Crocus lawsuit was filed, appears not to be moving forward. The Premier blames North American conditions, but, again, we're discouraged by the fact that we don't see very much good news on the horizon, in the pipeline, and lots of reasons to be concerned. We see a poor record of private-sector investment and a lack of commitment going forward.

I want to just come to the issue of the Spirited Energy campaign, which, I think, was meant to be the government's substitute for an economic development strategy. I want to ask the Premier whether he continues to believe that the Spirited Energy brand is the right way to go. Is it creating the sense of excitement in the province that he said it would, and does he feel good about the millions of dollars in taxpayers' money that have been spent on that campaign to date? So I'll stop there with those questions, and we'll ask more when we hear the response.

Mr. Doer: Well, I mentioned a number of private-sector investments. You talk about pipeline; the Tundra Oil and Gas company has quadrupled their investments in Manitoba. We changed a number of tax policies on oil and recyclable materials in the extraction of oil. We're now working with Tundra on carbon sequestering. When you talk about pipelines, it's another development in southwest Manitoba.

I would point out that in 1999 I did vote for the budget. In fact, one columnist accused me of being co-opted by the former premier. In fact, the premier didn't just drive away with me, or he didn't just co-opt me; he put me in the back of a Jimmy and drove off with me. But I won't cite who that author was because you never want to admit you read any of it. So it's very important that you never admit you read anything because never let them see you sweat.

An Honourable Member: You do read his articles.

Mr. Doer: Oh, it was a lot easier to read them in opposition.

I did make a certain set of promises in 1999. We voted for two budgets, and I don't have any apologies for that. I actually think from time to time, if you agree with the majority of what's in a budget and if it's mostly what you've been saying in Question Period, you should vote for it. I didn't have any problem voting for, I believe, it was the 1999 budget or '98 budget, and the member opposite I know he–

Some Honourable Members: '88, '89 and '99.

Mr. Doer: No, we didn't vote for the '88 one. We voted for two budgets of the Conservatives, and I'll check the dates when they were introduced.

I don't have any difficulty with that. I recall one Liberal member who's no longer in this Chamber saying, why are we voting against this budget? Basically, it was some tax reductions that I certainly supported. It was for middle income families, lower income families. It actually was sensible in a minority government. We voted for it.

I remember some of the members saying, oh, why aren't we voting against it, or why are we voting for it? Some of the Liberals were huddling around the NDP, and I know that the member opposite was one of the gurus of Madam Carstairs' team, part of the small elite group that advised her, but I remember some of the people that said, why are we voting against this? I said we're voting for it; I don't know why you're voting against it. You know, they were out of this Legislature, the majority of them, after following that advice when they collectively poured gasoline on their head and lit the match. They were out of this Legislature months later, but they were able to go around, we voted against the budget we're great. You know, in this House, I want to tell people, the public is smarter than all of us, and never lose track of them.

On the '99 issue, we did change some things that I didn't agree with in the past. It had been implemented. One was actually the flat tax. We got rid of that flat tax in the income tax rates, and we didn't campaign on this, but we started to reduce business tax. It became obvious to all of us within the first year of office that we really were being in a negative situation with small business tax, corporate tax, and eventually we got around to the capital tax.

On the education property tax, the record is clear. You can find these numbers out. The taxes went up on average 68 percent in the '90s on education tax for home-owners, and it is now, CBC argues, up until the last budget it was 9 percent. We think it's 10 percent. We believe this latest budget advanced it further, and we're going to continue to lower the education taxes for home-owners in Manitoba. We're going to continue to do that. We've also promised to eliminate, or not eliminate, but to go to 80 percent reduction of education tax on farmland. You know, members opposite raised the farmland portioning. We lowered it. We think those are very good developments.

On Spirited Energy, we had a recommendation from the business community to allow them to run a campaign. We knew there would be low-hanging political fruit from members opposite if we allowed the business community to come forward with a campaign. We also felt that other provinces and cities were spending a lot more money, and we, basically, said to the business community that we're volunteering that we would fund a campaign. They said they would go out and get gifts in kind, and some gifts in contribution, and when it became an issue that it was perceived to be part of a pre-election campaign, even though the second stage was to be out of province, we put it on hold, and we put it on hold until after the Auditor General will report. We supported the idea of sending it to the Auditor General, and we don't think we did it perfectly, but we think that many other municipalities have signed on to the campaign. I know that there's controversy any time anybody agrees to a campaign. I also knew that it would be, as I say, low-hanging opposition political fruit, and it has been. You know, we're just prepared to take the advice of the Auditor General and some of the allegations that were made and take the advice of the business community. I have great faith in the people that are driving this. I have great faith in them.

***** (16:50)

It's not inconsistent with how we've operated in tourism. The former government used to have the Tourism portfolio close to their chest, or vest rather, and have a situation where they would have decisions on advertising made close to the government. We don't make decisions on advertising for any of the tourism campaigns. We have a group of business people in a committee volunteering their time to try to decide what is the best market and what is the best way of advertising that market. We created a council of people chaired by Mr. Robson, who used to be the ADM of Tourism. It is made up of prominent people in the business community in the tourism sector. We took the issue and decision, which is usually perceived as a partisan decision, you know, whoever advertises for you during a campaign gets the advertising contract of tourism, and that's gone back over a number of years. We took it outside of government and we moved it to–well, the money is from government, but the decision making is removed from government. So that's what we did with the tourism business.

We did the same thing with Spirited Energy, and I'll await the Auditor General's report. But I just want to pay tribute to the business people who have been involved in it and have supported it through thick and thin. We all knew–I said that it would be really easy to criticize this and it's going to be attacked from different quarters all over the place because it's easy to do. They wanted to do it. They felt it's in the best interests of Manitoba, and they recommended it to us. They recommended the two stages. We put the second stage on hold and we'll await the Auditor General's report.

Mr. McFadyen: The business community certainly has an interest in seeing our province prosper and succeed and be well positioned to outsiders. I certainly know that, when people volunteer time, they do so in good faith; I have no doubt about that. They are naturally inclined to take things at face value. I don't begrudge them that one bit. But, when we dig beneath the surface and look at the facts as to who's driving this campaign, who's paying for it, who's driving it, who's administering it, it is very much a political NDP operation. It's not disrespect to the individuals, but they're all political NDP operators that are running the day-to-day operations. We certainly have volunteers from different sectors come in for meetings from time to time, and I respect them for doing that, but the facts are that we've got millions of tax dollars that have gone into the campaign. We have a former communications director to the Premier overseeing it. We have a former executive director of the NDP administering the invoices and the payments with respect to taxpayers' dollars, and I don't blame Manitobans for being as cynical that this is really all about politics and not very much about what's best for the province and getting value for tax dollars.

So the Premier talks about the wisdom of the people and that they are smarter than us. I agree with that statement. So that's why I would ask the Premier why he ignored the advice of the real people who attended the focus groups who said that they didn't like Spirited Energy. It left them cold. They thought it was weird. Those were some of the comments. When the idea was tested with real Manitobans, it didn't achieve the objective that you would want to achieve with a branding campaign.

I know the Premier knows something about market research and focus groups, that you sometimes come forward with ideas and sometimes they test well, sometimes they don't. This one didn't test well. So why did they go ahead and spend millions of dollars in taxpayers' money on a campaign that real people were telling them wasn't going to work?

Mr. Doer: Well, here we have three examples of where we have given responsibility in terms of decision making to an outside body, in this case, Mr. Silver, Mr. Angus, Mr. Starmer, I believe, Mr. Modha.

Yes, there has been staff support, but the people that–I'm shocked to hear the list of people that have been involved in the committee and making the decisions, Mr. Ziegler, were, quote, "NDP hacks." That is just quite a dismissive term.

It came out of a recommendation, including where the existing mayor recommended, said that Winnipeg and Manitoba's absolute image has got to be modernized. They came out with a number of recommendations, some on small business taxes, some on education and training, some on using Hydro, an Aboriginal employment summit. They came out with at least 10 good recommendations, and one of the agreements I had with them is that we weren't going to have them operate as business people, have a meeting, pat them on the head and ignore their advice. So they cited cases after and examples of where documents are prepared, they work hard on it, they go out and have sector meetings, they get all this work done, and then reports gathered dust. They cited that to me. So I promised them at the outset that we would look at and we would try to make sure that this is a body that had not only the leadership from the business community and labour and universities, but also have not only the leadership responsibility but the authority to do so.

I used the same model that we used in tourism. We took tourism experts and allowed them to cancel the old patronage practice of putting out advertising and having focus groups and whatever else. I don't read the focus groups on tourism. I mean, we use business people to do it, and we also used, in the case just recently of Louis Riel, where we said that the students would have a set of meetings and discussions and come out with names. We didn't say that we were going to overrule them, and we didn't.

With the case of Spirited Energy, we supported the idea of the business community, who said, "We don't want government to run this thing. We want to run it and develop it ourselves." So I didn't micro-manage it; I didn't read the focus groups, didn't attend the focus groups, and they asked for and got the authority.

Madam Chair, I have to take a one-minute break.

Madam Chairperson: Is it the will of the committee to recess? *[Agreed]*

We are accordingly recessed.

The committee recessed at 4:57 p.m.

The committee resumed at 5:01 p.m.

Madam Chairperson: Committee of Supply will continue.

Mr. McFadyen: Back on Spirited Energy, I wonder if the Premier (Mr. Doer) would provide some clarification. One of the pieces of information that was released when the government finally, after months of asking and weeks and months of stonewalling, when it finally released the documents related to the Spirited Energy campaign, it showed that there had been retainer payments made on a monthly basis to the advertising firm, which is a good firm, but what would appear to be unusually high monthly retainer payments to the firm. I can't recall the exact number, but I think it was something in the range of $30,000 to $35,000 per month.

I wonder if the Premier would be prepared to inquire as to whether any of those payments were then used to pay subcontractors who may have worked underneath the advertising firm, and who those subcontractors were and what amounts they received, because it's common that firms, as he will know, will use subcontractors on these sorts of projects. I think in the interests of full public disclosure, would he be prepared to ask for disclosure, who the subcontractors were and how much they received under those payments?

Mr. Doer: Well, thank you. I'll inquire whether the Auditor General has that information. I'm not aware of any timing issues, but I'll ask the question as well. The contract was tendered, that's all I know.

Madam Chairperson: The honourable Leader of the Official Opp–

An Honourable Member: I'll be just a few minutes.

An Honourable Member: Brandon West.

Madam Chairperson: The honourable Member for Brandon West.

Mr. Rick Borotsik (Brandon West): Thank you very much. Thank you for the opportunity to speak, first of all, to the Premier. I do appreciate that, and thank you for acknowledging me as the Leader of the Official Opposition, which isn't, in fact, the case–which is not the case, I can assure you of that.

It is a pleasure, certainly, to be able to question the Premier. I do know that the Premier does have his heart in the province of Manitoba. I recognize that, and I certainly accept that. During the last election, he did spend an awful lot of time in Brandon, and I appreciated that as well.

As he was spending the time, the Premier had an opportunity to make a number of promises, election promises to my constituents in my constituency, and I appreciate that. I do know that the Premier is a man of his word. One of those election promises was very important. It was a redevelopment of a sports field at Vincent Massey High School. In fact, it was well publicized. It was a very good photo opportunity for the Premier at the time, and everyone, including the school board and the school trustees, was certainly very appreciative of that.

I do know that the Premier did put some financial terms on it. However, I found out now that it seems that it's not quite what it was going to be. It seems that now the school board has been requested to submit an application under Community Places grants, which was not the vehicle by which the school board was originally believing it to be. There are two issues here: No. 1 is, did the Premier at that time believe that it should be Community Places grants, or was there going to be another opportunity to fund this from another funding pool? If, in fact, that isn't the case that it was Community Places grants, does he not believe that the community of Brandon itself would be affected by having other projects that would be looking at those funds under Community Places not then having their projects approved?

Mr. Doer: I went through the list of commitments in August and I was told that that was on track, so if the interpretation of on track is different than what I intended it to be, I'll check that.

I made a promise to Mr. Grindey and the football team and I intend on keeping it, so I will raise it with my staff tomorrow morning and follow it up. I intend on keeping that commitment. It's interesting that not only has Israel Idonije come out of that program, but also I notice the receiver from Hamilton was a prominent member of that football team and I think his name is–they've obviously got a good football team. I think it's safe to say we don't want kids playing on fields that injure their ankles before they even start tackling.

Mr. Borotsik: Thank you, Mr. Premier. I do appreciate you taking that under advisement. This did come to my attention just recently from the school board themselves, and I should say that having Community Places as being part of the criteria was certainly not what their intention was, it certainly was the impression during that announcement.

Second thing is, and again, it's a very exciting project for the city of Brandon. I see the Member for Brandon East (Mr. Caldwell) here as well who was very involved in the project with respect to the relocation of Assiniboine Community College from its current site to the Brandon Health Centre, and certainly there's been a lot on this. As a matter of fact, the Premier's alluded to that on a number of occasions, even in the debate with my leader.

It's very positive. We all recognize that a post-secondary education is extremely important for Manitoba, for, certainly, the people who are coming through the high school system. They require post-secondary education and, certainly, the community college in Brandon is a very positive step for them as well as Brandon University.

In saying that, I have some concerns, I suppose, and perhaps the Premier could speak to those, is the lack of a plan. We do know that there've been an awful lot of announcements, and I appreciate that, but politically there's going to be a lot of sod-turnings and a lot of announcements and a lot of photo ops, but there doesn't seem to be any really well thought-out long-term plan as to how the facility will be relocated to the BMHC.

One of my concerns, and the Premier can hopefully deal with it, is that at some point in time the government may well say that the funding is not available for the complete relocation of ACC at the BMHC, which certainly is not what the original plan was intending. When I say there's no plan it seems to be only one building or one function at a time, and it should lay out a complete schematic as to the time line, as to when the full facility will be relocated to the new site. Thank you.

Mr. Doer: Well, there is a plan. It has been amended to include an increase in the number of trades and apprenticeship positions or spots which we announced an overall increase in the province, and we did announce a plan. We said that that would go for two reasons: One, we have a shortage and a waiting list in Brandon and across Manitoba; and two, there's a real gap for purposes of businesses at the ACC site and across Manitoba in terms of skilled workers. So for those two reasons we moved up the apprenticeship building and trades building.

We also were originally going to co-locate it in the Parkland Building, but there is more work necessary on the Parkland Building. These are historic–well, the nurses' residence is historic and it's come in on time, on budget; the Parkland Building was originally going to have the trades centre moved to it, but because we have to expand it and because of the inadequacies of part of the Parkland Building we have to alter that. So, rather than Parkland Building being phase 2, it's now phase 3, but the real gap is phase 2, the trades and apprenticeship program for which I announced the time lines in Brandon.

***** (17:10)

We're still awaiting the final number on the renovation on the Parkland Building, but, certainly, we intend on moving courses and students to that phase 3. That should complete the transfer from Assiniboine College. One of the great advantages of colleges is that they're more agile, perhaps, than universities. If there is something else like the trade shortage that we see, it may alter or amend parts of the phases.

But the phases are phase 1, the nursing residence. Well, I guess, phase 1 was making the decision, and that was not easy because the original numbers would not have supported it. I want to congratulate the mayor because the original decision, if we didn't have the operating costs down like we do at Red River College here, it would be the added cost of an historic building, environmental-lead technology and the student costs; it would have been too prohibitive to do it. But all things came together with the discussions and the costs.

The third phase will be the Parkland Building, and it will be after the trades building, which we are working as quickly as we can to get it going because right now there is a line-up. I think it is very unproductive to have youth interested in a trade or an apprenticeship, businesses needing them and a gap because we don't have the space to do it. That's why we're expanding the space in Brandon and in Winnipeg and in the University College of the North.

Mr. Borotsik: As I mentioned in the preamble from the last question, we all agree, I'm sure, everyone in this Chamber that education is extremely important, not only for the province of Manitoba, but for the children that we have coming up through the high school system. As part of that opportunity, the post-secondary education is Brandon University. Brandon University as well as two universities here in Winnipeg are certainly well suited to accept the students coming out of the high school system.

However, when dealing with the administration of universities, all universities in Manitoba, the one thing that continually comes up, obviously, are the shortcomings of funding from the Province backfilling the funding requirements that are there because of the tuition freeze that has been put into place. Of the administrators that I've talked to in the universities, this is one area that they certainly would like to see rethought, retooled. Tuition freezes, currently, are affecting the students, the classes, the ability to acquire capital for the programs, for the labs. Certainly, the tuition freeze is having an impact on the ability for the universities to provide the education that they should provide for their students.

I wonder if the Premier would like to share with us now, in fact, from a policy perspective, he and his government would look seriously, over the not-too-distant future, perhaps as early as the next budget, with respect to the lifting of that particular freeze so universities can get on with the business that they were intended to do, and that was to educate our children.

Mr. Doer: Well, thank you very much for the question. Is it the advice from the Member for Brandon West to lift the tuition freeze?

Mr. Borotsik: The question was posed to the Premier as to what his policy changes may well be with his government in the next budget with respect to the tuition freeze.

Mr. Doer: Well, I'm curious to know whether the member opposite has a different position than his leader who campaigned on a tuition freeze. So, if he talks about the weakness of that position, he is talking about the weakness of the Tory platform, by definition.

The other part of his question was dealing with the budget. The budget will be presented in due time. All things will be revealed to the member opposite at that time.

Mr. Borotsik: I would like to, certainly, for the record state that I have not said one way or the other. All I said is I've talked to–

An Honourable Member: You're a Liberal now.

Mr. Borotsik: I have talked to the administrators. The Liberals left. That's not even a good heckle at this point in time. The Liberals have gone.

The fact is I've talked to administrators. I've talked to the administrators. I've talked to the president of Brandon University. I do know the position of the University of Manitoba. I do know what their position is, and the question simply was placed to the Premier: Is he prepared to look at the policy that is currently in place, by himself and his government, with respect to the tuition freeze? I do know and I can bring data and information from my own president at Brandon University and what his views and his thoughts are with respect to the tuition freeze. I'm sure that he has imparted those views to the Premier himself, personally, and, on behalf of my president of my university in Brandon, I would like to know whether in fact the Premier certainly is prepared to stay with this policy, or if he's prepared to look at any changes to that policy.

Mr. Doer: I've had a consistent policy over the years. I'm curious to know–I actually thought the one thing we'd get from the Member for Brandon West was a kind of a frank, open, you know, kind of being-his-own-person kind of approach to politics, and I see he's a wishy-washy Liberal in his second day in the Chamber.

What are you recommending to me, sir? I'm listening, I always listen to everybody here in the Chamber. Are you recommending that we lift the tuition freeze, or do you want us to maintain the tuition freeze?

Mr. Borotsik: I could give you the recommendations that have been forwarded to myself. I have also talked to the president of Brandon University, who has, in his own words, suggested that–not only suggested, has demanded that the tuition freeze be lifted.

I can tell you of the position of my president at Brandon University who has suggested in strong terms that the tuition freeze be lifted. I've talked to administration in the University of Manitoba who have suggested quite strongly that the tuition freeze be lifted, so I can impart that information to this particular individual, the Premier.

As for wishy-washy, I suspect that the answer coming back to my question is probably equally if not more wishy-washy than the question that the Premier suggests is put to him.

Mr. Doer: Well, I already campaigned on a tuition freeze and that's pretty clear. We campaigned–in our budget, we brought in a tuition freeze again.

I would point out to the member, I'm glad he's the surrogate for one part of the stakeholders in Brandon. There are students. What are the opinions of students there? What about families in the Brandon community? I think that, when people went to the doorstep in Brandon, they liked affordable education and training.

In fact, the idea for a tuition freeze actually came out of a visit I had to a Brandon high school. A few of the kids were going to go to British Columbia because the tuition fees at that time were lower than Manitoba and they had also at that time a tuition freeze. So I'm curious to know, representing your constituents, what is the advice to me? We will make the decision in the budget, but you have a chance now to influence the budget. Do you want the freeze lifted or do you want the freeze to stay the same?

Mr. Borotsik: I guess I can't put it any more plainly. My advice to you is, and by the way if you're talking about the students, yes, I have had discussions with the president of the student union. It doesn't get any better than that. I believe he represents the students in Brandon University. The president of the student union has told me that in fact they would like the tuition freeze lifted.

The president of Brandon University has told us that his position would be that the tuition freeze be lifted. I can't be anymore plain than that. The people I represent, the stakeholders I represent, have asked me to pass on that information to the government of the day, which in fact is the Premier sitting before me, so I pass on that information for what it's worth. If you wish to have that reflected in the budget, then certainly those stakeholders would love to see it happen. Is the Premier prepared to look at that?

Mr. Doer: We obviously prepare a budget and we'll prepare accordingly, and I'll pass on the advice of the Member for Brandon West (Mr. Borotsik) who wants us to lift the tuition freeze. He cites the president of the Brandon student union and the president of the university.

***** (17:20)

Mrs. Bonnie Mitchelson (River East): Madam Chairperson, I'm pleased to have the opportunity to have a little bit of dialogue, discussion and maybe ask a few questions of the Premier.

First of all, we both represent the same area of the city of Winnipeg, the northeast quadrant of the city of Winnipeg, and I know we've both worked together on many projects that have enhanced that community, both being in government and in opposition, one of them, of course, being the Chief Peguis Trail. I know we're both very supportive of the extension of the Chief Peguis Trail and the twinning of the Perimeter Highway in the northeast quadrant. I know it's shaved about 15 minutes off my trip to the lake, and I'm sure the Premier has probably noticed a significant difference in his travel time too.

One of the areas that I have a bit of concern about is Henderson Highway as it goes out to East St. Paul. I know that Henderson Highway within the city of Winnipeg is a city responsibility, but it's a Capital Region issue also. We have significant growth outside of the Perimeter in East St. Paul; and, as we see some new development on Henderson Highway–namely, I see sort of right in our local community the new liquor store that's going in at the corner of Henderson and Bonner–I sense that there will be significant additional traffic and maybe some backlog. The area of Henderson Highway from Gilmore out past the Perimeter is a dangerous area where we have a lot of stop signs, very few traffic lights and a lot of heavy traffic. It's very hard to get across Henderson Highway.

I know a lot of other routes that go outside of the city of Winnipeg right around the province have significantly better roads and access. They have medians and turning lanes and lots of opportunity for people to get partway across a very busy thoroughfare. I'm just wondering, I'd like to ask the Premier whether he's had any discussions. I am extremely supportive of getting improvements made to Henderson Highway.

Also, with the new condominium development that is on the west side of Henderson Highway, it's made it very dangerous to get across, very dangerous for pedestrians and also dangerous for cars that are driving and trying to turn across a very busy road.

I'm extremely supportive of improvements, and I'm just wondering if the Premier has had any discussion with the City of Winnipeg, or if he might consider making it a priority, or one priority, when we're looking at Capital Region. Is there any sense that the province might be involved in any way in trying to work with the City to enhance the traffic flow on Henderson Highway?

Mr. Doer: Well, it's certainly a road I travel on to various sporting events with my two daughters, so I'm very aware of it. I'm aware of three challenges in the northeast quadrant of the city. One is the completion of the Perimeter Highway, in which I believe we're on time and on budget for on that quadrant. Certainly, that will be an improvement. Secondly, the interchange at Lagimodiere and the Perimeter Highway, which also is important; and, three, the Chief Peguis Trail. When we increased our funding for the city of Winnipeg, some of it was for infrastructure and some of it was for new capital. This certainly allows the City to move this up.

I believe that the issue of Henderson Highway–I'll have to get a determination. We have built some infrastructure out in the northeast quadrant; outside of the Capital Region, I think there were some investments in highways, on Highway 59. There's a lot of work on Highway 59 now up until the turnoff on the road, I forget the name of the road that goes to Elmhurst and Pine Ridge. I'll try to see the traffic flows. I think that there are some issues of traffic.

One of the concerns we had when the zoning was agreed to in some of the development in northeast Winnipeg was the lack of any highway impact, water impact, and a school impact. We said that in opposition. Sometimes we get pressure for a high school now. I think the enrolment now has reached a bubble. We get pressure on roads now, and we think that part of that should have been managed in the development and supported by some of the development decisions, which would have been quite lucrative in the area just northeast of Winnipeg. But there are some situations, and I'll raise it with our highways people because the jurisdiction of the road ends at the bus loop, I think. One is the responsibility of East St. Paul and the Province, and the other is the responsibility of the city, but I'll definitely look at it.

The priority is the completion of the Perimeter, the interchange and the Chief Peguis Trail, and two of those projects are completely within the purview of the Province and responsibility of the Province. One is the responsibility of the city, but we have quadrupled the money for maintenance and construction of roads and bicycle paths.

Mr. Leonard Derkach (Russell): A question to the Premier regarding an issue that I keep going at from time to time, every session I guess, regarding a commitment that was made back in 2003 and reiterated by the Premier in a question that I asked just prior to the election, and that is the staffing and the ensuring of the opening of the emergency part of the Erickson hospital. This hospital serves an area that is equivalent to the population of Brandon just to the north, and has been bypassed because there are no emergency services available in the hospital and, also, the doctors have not been recruited for that area. The community has recruited a doctor on a part-time basis to act in the area during the summer months, but that doesn't really allow for full emergency services in that area. Currently, I don't know if the Premier is aware that we do have an ambulance stationed in Onanole or in Clear Lake during the summer months, but that is hardly adequate service in this day and age for medical emergencies that arise, especially in an area that is a fairly significant tourism area in our province.

I want to ask the Premier whether he's committed to following up on the commitment he made and ensuring that the people in that area receive the kind of medical services that should be available to all Manitobans.

Mr. Doer: I'll have to check with the Department of Health on the existing status of it. I feel there're some compelling reasons for emergency services in Erickson. We did talk about that. I remember raising it before I went out and called the election, not because we thought necessarily that it was going to be an election issue, but because I knew at the last minute that the election would be potentially around the long weekend date. I didn't know it would be exactly a day after, I have to confess, but I certainly knew it would be in and around the four-year mark. People were getting too predictable. So you have to be always unpredictable. So keep your running shoes on at all times. I want to say that.

***** (17:30)

So I'll check on the status of what happened this summer. We have increased the support for emergency staff and support for support staff, but I want to take a good look at it. I did say it. I did like the idea about Clear Lake, and I did talk about that in 2003. My preference is to have it, but I don't always get my preference and so I am going to do some work but, because doctors are actually not civil servants, or they can't be moved around like chess pieces necessarily, not that any of us can be, there is a certain freedom that they have to practise, and we haven't been successful. I'll check what happened this summer. You would know better than I, but I do agree. I have friends that go to Clear Lake every weekend. The winter recreation is increasing as it is all along the west side, by the way, as you know. I'll find out what's going on on it and what the status is. I will get back to you. I don't know what happened all week and all summer at Clear Lake, but I know you would know, and just an ambulance, I think, for some of those weekends is not ideal.

Some Honourable Members: Oh, oh.

Madam Chairperson: Order, please.

Mr. David Faurschou (Portage la Prairie): The Premier is aware of the significant undertaking by the City of Portage la Prairie and the Rural Municipality of Portage la Prairie in a commitment to provide to the Central Region a new multiplex sporting facility. During the election, the Premier attended to Portage la Prairie and pledged his support and his government's support to the new multiplex sporting facility.

I would like to ask the minister at this time, the commitment being made, there was a very exciting press conference last Thursday where the Portage Industrial Exhibition Association came on board for this project and are lending their site on Island Park to the new sporting-plex. I would like to ask the Premier at this time the process to which he would suggest that the now three very significant entities, the R.M. of Portage la Prairie, City of Portage la Prairie and the Portage Industrial Exhibition proceed with this. Is there a point person in regard to the government's commitment to support this project? I believe it was in the amount of about $5 million.

Mr. Doer: Well, our desire when we made the announcement was to have the gap–first of all, I want to give credit to the people of Portage and the leadership. They've done a magnificent job of bringing together a lot of resources and a lot of co-ordination to get this project a lot of funding and a lot of support. It's a good proposal, and they've done a lot of good work. There's a gap there that I said the Province would participate in. We are raising with the federal government in terms of both of us doing it like we did at Dauphin and Thompson and, obviously, MTS Centre and, in a different kind of context, the Keystone Centre. We think that it's an item that I think–I do think–I don't want to speak for the honourable minister. Maybe I better wait a week. I don't want to get collateral damage from the member of Parliament statements. Notwithstanding that–I know Kelvin will pass that on to his good friend–the Member for Steinbach, I mean–I think it's a lot of a proposal. I know that a local member of Parliament is supporting it, and I'm sure the member is aware of that. So there is the political will and leadership in the community, and there is the political will on our part. It didn't evaporate just because the results weren't what we would have preferred in the riding. I want to congratulate the member, but we thought it was a good announcement at the time.

Also, we pledged to support a number of projects with the money we announced in the election campaign for community recreation. We think there are more kids and people participating in sports, not just kids, seniors and a lot of other people. More people are active. They want to be more active. They need more facilities. People are travelling way too many miles. Just this last week we did the University of Manitoba proposal, and I didn't kick a soccer ball with a pair of shorts on, but I still thought it was a good proposal. I have legs like iron, but I didn't put shorts on. It was in the middle of the day. We think it's a good proposal, and so it's a matter of just closing the gap with the feds and ourselves, and I think it's definitely doable.

The point person is the person dealing with federal-provincial relations, and I'll make sure that that person or a person in her office gets hold of you, but also gets hold of the organizing committee. I did raise it at one of the staff meetings a couple weeks ago, just where is this, along with the Brandon football field. I'll follow it up again.

Mr. Kelvin Goertzen (Steinbach): Madam Chairperson, I wish I could provide the Premier (Mr. Doer) with a shocking question, one that he doesn't expect. I doubt that this would be one of those.

Prior to the election, the Premier made comments that his election timing call had a lot to do with landing planes and making sure that they got down on the ground and off the radar. One of the planes that didn't land before the election was the proposed and hopeful expansion of the Bethesda Hospital emergency room along with the operating rooms. I do know that during the campaign in the context of an announcement made in Ste. Anne for the expansion of their operating capacity, and, you know, I'm not specifically speaking of that, but there was a commitment made to deal with the needs of the Bethesda Hospital. Specifically, the Premier won't be shocked to know, I'm sure he's had the statistics. I provided him information prior to the last session or the sitting in June and in providing him information from doctors, he agreed to look at that and personally review it, and I trust that he did that. I know he said that he did that in a letter back to me. I appreciated that.

More specifically, the Steinbach emergency room was built to handle about 10,000 people a year. They are now getting 24,000 visits a year. So it's twice the number of visits annually that it was built for when it was constructed, so he knows that there're pressures on. I talked to the doctors who said that there're regularly four or five people in the hallways of the emergency room waiting to get a room to just be examined in, in the ER. I've been told by the doctors that there are many fire codes that are being broken as a result of the over-crowding at Bethesda Hospital and also in relation to the operating rooms that were built in the 1960s and haven't had improvement since then. There are other issues, obviously, related to the growth of the region and what it's doing to the work of the Bethesda Hospital, and I have already provided information to the Premier on that.

What I am asking now today, both as a reminder and a request, to determine where on this now post-election radar the Bethesda Hospital falls because I know that he'll want to fulfill the commitment to the people of the region to ensure that the health-care needs of the Bethesda Hospital are being met. So I look forward to the Premier indicating when he expects to fulfil that election promise.

Mr. Doer: Well, we made both announcements together as the member pointed out on the Ste. Anne and Bethesda Hospital. First of all, I want to thank the staff at both hospitals. Some of the investments we've made in the operating capacity and staffing decisions at Bethesda to try to take pressure off of lineups both locally and further afield in the area. Even here in Winnipeg from time to time people go there. It's been really positive; so the evaluation has been extremely positive.

***** (17:40)

We have a capital cap in government each year. We're working that through our capital cap, but we're working it together. We're not going to say bye, bye to the Member for Steinbach because we think the patient needs are real. I say that because my first question I got on the community college from a number of volunteers in Steinbach, they said, oh, oh, we've elected this NDP government; what have we done and what's it going to mean to the college. I met with them and said, listen, if you can raise the money in the field and everything else, it's got nothing to do with the fact that we got four votes in Steinbach; it's got everything to do with the merit of the proposal. So they were shocked to hear that, and they just said that what we want is a yes or a no. The committee said, we're business people, we just want to know. Is it yes or is it no? And I said, well, we think there's a need for training in that area. We'll go back and look at it.

So I will be able to report soon. I expect no later than this session, as short as it's alleged to be, and we are working it through our capital cap. We will not make an announcement, I don't believe. It will be my goal to make the announcement of Ste. Anne's and Bethesda together or, you know, make the decision certainly together because we think they're related in terms of patient need in the area. That's why it was in the press release, not because I thought we were peaking too early in Steinbach in the election campaign.

Mr. McFadyen: I did have a brief moment of concern when I saw Steinbach announcement, but the tracking established that it was a very genuine and non-partisan announcement. I'm pleased to hear the Premier's response.

We're on the theme of local issues, so I just want to take the opportunity to raise a question of local interest to my constituents. Then we'll come back to some of the other broader themes that we'd been on earlier.

My question relates to the need for a public high school in the Fort Whyte constituency. I know it's an issue the Premier's familiar with. I know he met at one point with various parties involved from the school board, representatives of the community involved, and the high school lobby group. I believe there may have been involvement, either at that meeting or the later meeting, among staff from federal and civic governments when they're looking at a potential proposal that might involve some recreation facilities in combination with a potential high school.

The consistent response that's come back from both the Premier and the minister has been that it's not a matter of if but when in terms of the construction of a high school. I'm aware that Pembina Trails school board has put forward to the Public Schools Finance Board within its capital plan requests that it submits to the PSFB annually over several years a request that the high school be considered within the department's capital plans. I'm recently advised that the PSFB has undertaken a review, is doing a study to establish the case, we assume, for building the high school to help inform the capital planning process and the decision around the high school. I'm advised that there's a meeting taking place between officials from PSFB and the school board in October to present that report and discuss it.

I wonder if the Premier could indicate whether it's still a commitment of him and his government to proceed with the high school, whether he's able to provide any more detail in terms of the timing of that announcement and of the work and whether he would be prepared to allow the school board and/or PSFB to release that report to members of the community who have an intense interest–people with young children who are looking to the future, wanting them to be able to go to high school in the local community, looking at the reality of Waverley West coming on and the other developments in that corner of the city and just planning for the future–whether he'd be prepared to allow that report to be released publicly after that discussion has taken place.

I know there are several questions embedded there. I'm hoping you might be able to respond to each of them. Thank you.

Mr. Doer: I was just wondering whether it was several questions embedded in the report that I hadn't read yet that the member opposite might have, but I'm not paranoid. I'll get briefed on this.

Certainly, we believe that over the medium term there will be demand for the school. We said that before. You can't, in our view, make a decision on the expansion of housing and not have in the plan a consideration of schools. We were encouraged by the previous government's local concern about–I actually liked the idea that former Minister Alcock had proposed that we should look at recreation, community recreation and school recreation and leisure together. I thought that was a smart way to go. I don't know where that is with the demise of his Treasury Board career. I'm not sure where he will be on–I guess he's not a candidate in the next election, I don't know. I don't keep track of all those things– *[interjection]* I beg your pardon. *[interjection]* Oh, okay. I'm just chattering. I'm sorry. I apologize, Madam Chairperson. That's my fault. Loewen, he's back. Well, it will be interesting. *[interjection]* You know, the–

Madam Chairperson: Order, please.

Mr. Doer: I'll keep answering the question, but I always said to him he should have waited one year and he could have run in Lloyd Axworthy's seat. However, I digress.

I will find out about the report. I don't know what's in it. I'll get a copy of it. I normally believe that that kind of report should be available, but we should get more definition. I'm going to get the advice of what they're saying to us. It is a non-politically appointed body now. I know the member opposite is not being political in his question at all, and I'm not being political in my answer, but I'll find out their advice and whether we have to ask questions about that. Then we will also ask the second question: At what point is it a public document that can be released to the public?

I'm not aware of how this works exactly, but I'll inquire on all the points you raised. I take them seriously because I do believe over time we will need the school. I just don't know when.

Mr. McFadyen: I think I heard the Premier suggesting that deputy ministers aren't subject to political influence, but let's leave that for another discussion. We're going to have a debate about the public service and politics. Let's not do that right now though. Let's get on to other things. *[interjection]*

Madam Chairperson: Honourable First Minister.

Mr. McFadyen: Sorry, no, that was just a digression on my part. So I do have a question here, and I want to come back just with a loose end on Spirited Energy, with apologies to staff for–

Madam Chairperson: I still have to recognize you. The honourable Leader of the Official Opposition.

Mr. McFadyen: Was any of what I just said on the record, or was I not recognized when I was making all those comments?

Madam Chairperson: No. Then I recognized the First Minister when he was interjecting, and now I'm just putting you back.

Mr. McFadyen: Oh. Okay. So, in any event, what I was saying was that there were some loose ends on Spirited Energy I just want to come back to, with apologies to staff who are going to be going through *Hansard* and trying to figure out the flow of all these questions. But, in any event, the question relates back to the focus groups that were undertaken by the Premier's Economic Advisory Council.

He indicated that he didn't sit in on those groups. I wonder if he could advise or come back with information as to who did sit in on those focus groups and, in particular, were Mr. Flanagan and Ms. Britton part of that, and whether or not they were, if you could just indicate who did sit in on that focus group process. The reason that's important, of course, is that we know the focus groups didn't go well, and so, clearly, there are questions around how that information was communicated back to the decision makers, and why it was that the advice of regular Manitobans who were in those focus groups was ignored.

***** (17:50)

Mr. Doer: Well, as I say, I'll find out who was there, but, secondly, as I understood it, we released the report and the report was given to the principals that were making the decision. So I'll take the question as notice, but I do understand that there was a report written, which I never read either because I basically established that we'd set up this Spirited Energy similar to what we did in tourism. I'll inquire on that. But there was a report written and the people have received the report, the marketing people. They are experienced in marketing. They're not people that are, they're not politicians. They're business people and they receive marketing reports, I assume, all the time because they're in the markets a lot more than politicians on selling this or selling that or identifying this market or that market. I'm not aware but, usually, you find focus groups on the one hand or on the other hand. I could just say the odd one I've read in the election campaign, or got briefed on in the election campaign. They're people's opinions and they range. There's advice, but at the end of the day you still have to go with your own mind about what's best.

Mr. McFadyen: I guess, at the end of the day then whose mind was it that decided to go ahead with the campaign after the focus groups?

Mr. Doer: Well, the committee made up of the business representatives. You know, they asked for the authority. There's a report recommended that the business community have a budget and authority and responsibility to engage in an implementation of a recommendation dealing with the image of Manitoba. These are people who are experienced in dealing with this kind of marketing. They recommended that. I had to either accept it or reject it, and I accepted it.

I had another model to go by because we had established a similar arm's-length body from the issue of tourism. Now, people sometimes get advice from focus groups and don't follow the advice. I could ask the member opposite, did you follow the advice of focus groups on the, I promise to bring back the Jets? It's a legitimate question in terms of how people make decisions after they get information. Curious, very curious, but I did not substitute my judgment for the business people that were leading the exercise.

Mr. McFadyen: I'm debating whether or not to take the bait, Madam Chair.

I want to maybe ask the Premier if a focus group advised him to say that the chances of NHL hockey coming back to Winnipeg are about as good as him ending winter. I think that's what he said during the campaign, only to be contradicted by Gary Bettman a couple of weeks later. That's not my question, that's just an editorial comment for the record, which he'll probably choose to respond to.

Madam Chair, I just want to come back to one of the frustrations that we, and I know the media and members of the public, experience with this government–it's not just this government, it's other governments as well–it's access to information. Certainly, FIPPA provides a framework of rules and laws that require government to provide information in certain circumstances and subject to some exceptions. There are deadlines put in place and procedures that people have to follow and fees and all those things.

Sid Green has made the point that a spirit of openness within government and transparency is far preferable to a series of laws that require government to do things in certain ways because we know that laws can sometimes allow government the excuse to comply only with the letter of the law and use exceptions and other ways of getting around providing transparency to the people that they serve, the people of the province who elect them and pay taxes and deserve openness and accountability. So we certainly have frustrations with delays. Spirited Energy was a good example of that, delays in getting information to us. Media made the comment that the delays were unwarranted and frustrating. It certainly is a concern shared by us.

More specifically on the topic of information and privacy, the Premier has a longstanding commitment to establish an information and privacy commissioner in Manitoba to bring us in line with what's happening in other provinces. I wonder if he can indicate whether he intends to follow through, and if so when.

Mr. Doer: First of all, I want to thank the Ombudsman on the issue of Spirited Energy because there were issues related to the private sector and the public sector. Not only did the Ombudsman perform a very, very important role in identifying the material that could be released, there was also work that she performed on behalf of the public to identify what couldn't be released, that would be confidential with the private company. I wanted to make sure that, certainly, I respect her advice and her office's advice in this regard. I'll have to see the status of that recommendation on the privacy commissioner. We're certainly consulting with the Ombudsman's office in that regard, and I'll report back on the timing and the content.

Mr. McFadyen: I would make a comment that, in looking at the invoices that were released under Spirited Energy, you see decisions made to black out certain pieces of information. It's disclosed that they had wine and beer at a meeting, and a Mediterranean buffet, but they black out the quantities of glasses of wine and bottles of beer but leave in place the amount charged. There seems to be some absurdity built into the process. Common-sense people would look at that and wonder what it was that the government was trying to hide when you see these things blacked out.

So I think if your objective is to try to reduce public cynicism in the sense the government is hiding things from people, that you might want to, and we might want to as Legislators, look at the act and consider whether either the way those provisions are being applied or the provisions themselves need to be addressed and changed so that people look at information coming out with these, what would seem to be fairly arbitrary decisions about what to block out, and it leaves them feeling as though they're having the wool pulled over their eyes. It doesn't seem to do anything to advance the cause of protecting third-party confidentiality which, of course, is important.

But I would make the suggestion that most people who deal with government as suppliers or contractors or advisors or people who are in partnerships with government of one kind or another would do so with some expectation that there's going to be some public disclosure of the transactions and how the money flows, how the money is used and a degree of accountability. It's an issue that's been debated all over the democratic world when you've got more and more private-public partnerships and arm's-length bodies, et cetera. But it is an issue that should be revisited. I wonder if the Premier, in the spirit of openness and accountability, would agree to undertaking a review to see whether either they waive that those provisions are being applied, or the provisions themselves need to be changed in order to provide more accountability for these sorts of transactions and dealings.

Mr. Doer: The whole issue of disclosure, in my view, is that, in general terms, it's always better to have the disclosure. I would concur with the principle on the private-sector entity. The Auditor General now has the authority to audit books in the private sector that have relationships with the government, because there are lots of things we would have liked to have looked at. I know in opposition some land deals, and I won't go any further than that, but I have my list.

***** (18:00)

Thirdly, the complicating part for this, as I understand it, and I'll look forward to the advice of the Ombudsman because I think we can get a more inclusive strategy rather than just having these as one-off decisions that take too long to release. Sometimes you have issues, not of disclosure, but you have, perhaps, national companies that provided some benefit to Manitoba through a campaign who worry about whether then all the other jurisdictions will demand the same gift in kind, if you will. So that's where there is some sensitivity. Not to the idea that if we just lived in Manitoba this would be fine, but are they going to get requests that are equal and proportionate to a population even greater for a company that does business outside of Manitoba.

So that was one of the issues that I heard raised by representatives of the private sector, but I didn't hear it specific; I heard it specific to the campaign itself. So I'm sure that that was part of the consideration, but I hope out of this we can improve because I don't think this is the ideal way to go. I hope we can improve out of this, and I certainly concur that there has to be improvements, particularly when the people are getting legal opinions about what can or can't get released when usually releasing things is better rather than not.

Mr. McFadyen: Certainly, the feedback that we get from regular citizens and from members of the media is that it is more difficult than ever to get information out of government, that every rule and regulation is applied in such a way to allow for the lowest possible amount of disclosure to take place in any given situation. I don't think anybody thinks that's healthy for our democracy and does anything to enhance public confidence in government.

I want to just move, but before I move from that, I don't know if I got an answer to the question about the privacy and information commissioner. I wonder if the Premier can indicate whether he intends to follow through on that commitment.

Mr. Doer: There are some discussions going on with the existing Ombudsman now and I'll report. I haven't got anything this moment, but I'll catch up on that issue.

Mr. McFadyen: Just coming back to a point that my colleague, the Member for Brandon West (Mr. Borotsik) raised when I was out of the Chamber, and it's to do with the tuition freeze on the universities. I wish I was here for that exchange because I probably could have added something to the record which might have, hopefully, provided a clearer picture of what's been said to date on the issue. The government has now had that freeze in place, this would be, I believe, the seventh year going into this academic year. The institutions that are affected by it are reporting serious strain; apparently there are ongoing issues with retention of staff, people who are highly qualified and highly educated and highly mobile, and this is having a significantly detrimental impact on the universities, particularly when the freeze is coupled with a policy of not funding universities to the level that they need to be funded at in order to be competitive. So it’s the double policy of leaving the tuition freeze in place at the same time as not increasing grant funding from the government to the university that’s having this impact.

I understand UMFA, the faculty association union, took a strike vote, I believe, either yesterday or the day before and there're serious strains in terms of both the capital and maintenance side of what's going on in the universities, but just, if not more importantly, the ability of the universities to retain highly qualified staff. The Premier knows, because we've had this discussion, that I had commented that the freeze shouldn't be lifted until the government can address two issues: one is fairness to students; the other is adequate financial arrangements for the university, and that was reported on some time ago. In the course of the campaign, I said that we took the position that it should be reviewed by people who are knowledgeable about such things, who will undertake a consultation with students who are going to be impacted by policy changes, but also with leaders in the university.

I note from the Premier's public comments, I believe it was on CJOB a couple of weeks ago, that he hasn't committed to extending the freeze beyond this year. So what we are suggesting and proposing is that the government look at some kind of shift in policy that takes into account the need for kids from lower-income families to be able to access universities, so that the smartest kid from the poorest family in the province is able to go through university without finances being a barrier to university education access or college education access.

So I want to ask the Premier what his current thinking is on the policy and whether he is open to lifting the freeze in some reasonable way and adopting policies that will ensure access is there for kids who may need some financial help. By way of example, the Premier will know this initiative well, Dr. Axworthy has embarked on a project with the support of an outstanding young person named Kevin Chief, who's there in an administrative capacity in the support of others to provide credits to young people from economically disadvantaged backgrounds as they work their way through school, financial credits along the way as they achieve certain milestones that would be banked, effectively, and used by them against tuition costs when they get to university. It's an interesting idea. It's got longer term implications. There are lots of good ideas out there.

I'm wondering what the Premier's current thinking is and whether he is prepared to undertake a review and signal that he is prepared to move away from the current policy, which combined with inadequate funding is having a detrimental impact on our institutions and the quality of the degrees and the reputation of the degrees for students who are graduating and looking to the future.

Mr. Doer: Well, I don't know whether to start with your history as the board of governor's representative from the former government or as your key Cabinet role that one had–*[interjection]*

Obviously, the enrolment has gone up over 30 percent since we've been elected. We're pleased about that. We've increased dramatically bursaries, and it doesn't get a lot of media coverage. It is really important for lower income families. We don't see tuition fees, itself, as the key point for the lowest of income people. We see bursaries being the most important ingredient for that potential student population. We're looking at other bursary proposals, which we think are important.

We're looking at the other end of the equation. We made an announcement last year on tax reductions with students after they've completed education to their staying here in Manitoba and making that more affordable for student debt to have a reduction.

On the issue of tuition freeze, I would point out that we did fund the reduction to begin with. We did increase the operating expenses to deal with the 10 percent tuition reduction when we first came into office, and maintained that in the operating budget ever since.

We also increased the capital budgets in the universities dramatically. With the University of Manitoba, we've pledged $50 million. We have up to $200 million in private pledges, and we also gave the university the ability to proceed earlier so they can combine projects like eliminating asbestos with new capital so it wouldn't be inefficient for proceeding. It's one of the issues that is a notional debt on the books. So, when the member raises that, it's one of the issues of capital that is important.

The other issue that we deal with is the operating amount for the university. We've supported universities in two ways. One is the tax reduction. We've eliminated the education property tax on universities, and two, the operating grant to universities. This year, the operating grant to universities is 7 percent. Even if you had a 5 percent operating grant, the 2 percent would more than equal a considerable tuition increase of 4 or 5 percent, I believe. A 2 percent operating grant to the whole university is worth equivalent of 5 percent tuition increase. So the 7 percent makes up a lot of the room. I don't know many other entities in government that have got a 7 percent increase.

***** (18:10)

So I know things are tough, but we're slowly and surely making a difference. The capital plan of the University of Manitoba is in a lot better shape than it was seven years ago. We are investing in new innovations at the university with the Richardson nutraceutical and bio-food centre. We're also looking at other capital, the new engineering and computer science building. So there are other developments that are taking place there, but the issue of the tuition freeze will be determined in our deliberations going into the budget.

We'll take into consideration the member opposite's views. We'll take into consideration the views of the Member for Brandon West (Mr. Borotsik), who wants an immediate removal of the freeze, and we will take into consideration the views of administrators at universities, students, faculty and families that really want their kids to have the chance to go to school. So all of that will be factored in going into the budget in 2008.

Mr. McFadyen: I thank the Premier for that response. We would again repeat our commitment to be supportive of changes. Obviously, we reserve the right to comment on details in terms of how they're enacted, but we are certainly supportive of the principle of making some changes in that area in accordance with the principles that we've set out around protecting students and families, as well as funding our universities at adequate levels.

When I asked the Premier just about the coming over to a major capital project under way right now at the City of Winnipeg as part of the effort to clean up the rivers and lakes of the province, we know the tremendous movement backward in terms of Lake Winnipeg over the last several years. It's been an evolutionary process. It's not a purely political comment, but anybody that's been to the lake knows and has seen the deterioration over the last number of years. So we support the objective of dealing with the nutrients that ultimately make their way into Lake Winnipeg, but focussing specifically on the major expenditure being undertaken by the City of Winnipeg pursuant to the direction provided by the provincial government through the environment department, Conservation Department, which project is now estimated to be in excess of a billion dollars.

The scientific advice that we have received from several people knowledgeable about water and water quality issues is that the most prudent way to proceed would be to remove phosphorus first. There's a certain process that's used at wastewater plants to remove phosphorus from the affluent before it flows into the river. The advice is that the removal of phosphorus will quite probably have the desired effect in terms of reducing blue-green algae blooms, and then to consider nitrogen at a later date. Nitrogen requires a separate process, which is a highly expensive process. So I wonder if the Premier has taken account of that scientific advice as the City of Winnipeg embarks on a very expensive project, which is largely going to be funded by City of Winnipeg ratepayers. There is a very nominal contribution being made by the provincial government with, obviously, ultimately funded by provincial tax payers. But, in the scheme of the overall project, it's a relatively small contribution. City of Winnipeg sewer and water ratepayers are paying the lion's share of the bill, and the City is looking at significant rate increases in order to fund the reserve that's required for this project.

So I wonder if the Premier has considered the scientific evidence and whether he is prepared to consider the advice which has been provided, which is to proceed first with phosphorus removal before going ahead and requiring the removal of nitrogen.

Mr. Doer: Well, the Clean Environment Commission received a lot of advice, a lot of technical advice. The advice they received from outside experts and most of the inside experts in government recommended both phosphorus and nutrients. Nutrients is another word for another more graphic term, the member knows, and it would be consistent with water that flows to Winnipeg from places like Calgary, from places like Regina. Brandon is moving in that direction with even the second shift at Maple Leaf. Portage la Prairie is looking at similar investments again with the Province.

It is unfortunate that in 1988 when the environmental licence exemption was removed from the City of Winnipeg, which was always a source of contention for people living outside of Winnipeg, you know, here we had an environmental law, but a bubble of exemption. Since that time, well over $600 million or $700 million of unallocated money has gone from the Province to the City. So, if they would have had a bit of the will to move on with this, which has been recommended for years, obviously, the city–this is the old inner city–with the raw sewage and then, of course, the phosphorus. There are proper allocations. The Schreyer government took action for all new suburbs to have retention ponds which would affect the level of water, I might add, in Bunn's Creek, but the retention ponds to allow for the adequate treatment of water in the new suburban areas, but unfortunately the old city of Winnipeg has not had the appropriate investments in old single-sewer system and the combined system.

We're trying to implement the Clean Environment Commission's decision, and I would say it was their decision, and it's a licensing decision in the most prudent way as possible for the City of Winnipeg. One area that we're still working on is discussions with the national government on what the allocation will be for Manitoba. We're still working with them on this file. We think we're close, and then we can sit down with the City and say this is how much it's going to be to what we consider to be the number one priority of infrastructure in Winnipeg.

I might point out that in our last investment, a decision with Winnipeg, the former MP insisted on the underpass, the former mayor insisted upon rapid transit, and we insisted on sewage treatment, and we got as part of that agreement 50 percent. I think the member opposite is chief of staff, and the city would know that 50 percent of it was allocated thankfully to the treatment plants. We're getting some completion on one of the three plants that have to be done on some of the projects. The whole issue of the spreading of raw sewage has been documented in the Clean Environment report. The issue of the pipes is a huge expenditure and then, of course, the treatment plant is not the whole billion dollars. The treatment plant to remove phosphorus and nutrients is less than that, and it constitutes a real important development for water quality in Lake Winnipeg. I know people use the term "nutrients" and a lot of the public don't know what it means, but if you say to the people what it means they don't like it so much, and that's why people use "nutrients" and not the real term that is much more graphic in their minds and in their view.

I've got to have a further discussion with the City of Winnipeg because we've got to nail down this federal amount so we can give the city some predictability into their budget process. It's starting in earnest right now. It's really important, I think, and it's a legitimate question. How much is coming from other levels of government? We were able to increase the road amount and the infrastructure amount, but this is still an important priority for us and for them. I would point out there is an allocated amount about $45 million a year in the City budget from the Province of Manitoba. It could be used at any time for sewage treatment as well.

***** (18:20)

Mr. McFadyen: I'm certainly aware of the amount that's been committed to date by the provincial and federal governments, and the Premier knows that against the backdrop of a project which is now in the range of a billion dollars plus that a commitment in the range of $60 million represents only 6 percent of the total project costs, so the lion's share of the cost and, of course, the lion's share of the credit rests with the mayor and City Council and the citizens of Winnipeg who are going to be funding this, but I certainly appreciate and we'll look forward to hearing more in terms of contributions from senior levels of government to the project.

I would only note that there is a theme which we sometimes see with this government that they'll take positions on issues and will act as the champion on the issue and then leave it to others to pay the actual cost of achieving whatever the goal is. It certainly is happening with the City of Winnipeg and City of Winnipeg ratepayers. It doesn't mean the objective is wrong and, in fact, the objective is right, but sometimes it can rub people the wrong way when you see people taking credit for things that other people are paying for.

That theme, as it applies to the City of Winnipeg applies equally as well to private landowners in rural Manitoba who are working very hard every single day to run agricultural operations which have been buffeted over many years by different factors, sometimes created by government policy, sometimes created by international markets or weather and climate.

People are working hard to make a living in agriculture who were alarmed and concerned when the government came out with its approach to regulating private land use that there was an insensitivity to the reality of agriculture and a lack of concern for the fact that for many people who are struggling, and when an operation is marginal, every regulation that comes along that tells you that there's something you can't do on your land diminishes the value of that land, makes the enterprise more difficult. We, certainly, heard loud and clear, and I raised concerns about the way in which the regulations were being proceeded with and the lack of sensitivity to what was going on in rural communities.

I want to ask the Premier, because they've made some noises about working in a spirit of co-operation, I wonder if he can commit at the same time as he's working with senior levels of government to secure funding for the City of Winnipeg project, will he commit similarly to seeking funding and providing support to private landowners who are being asked to make significant changes. Many of them have made changes voluntarily as it is.

I always say, and I believe firmly that farmers are the best stewards of the land. Their livelihood depends on sound, long term thinking when it comes to what they do with their land, so lots of changes have been made. They deserve credit for that, but to the extent the government has required them to go further, eliminating some land from use which may be appropriate from an environmental perspective, but are they taking into account the negative impact on those landowners? Are they prepared to show a greater level of co-operation and partnership and move toward incentives and partnership as opposed to confrontation and a dictatorial approach which many people feel has been taken today?

Mr. Doer: Well, the Water Stewardship plan that was released last year and now is before the Clean Environment Commission did include incentives, did include some transition, did include timing, did include consultations on some of the issues of standards that were recommended by KAP and others did include set aside timing, issues of set aside for manure on water. So it didn't happen right away. There are people who are very critical of that being too long from now. There are other people that say it's too quick. All those issues have been submitted to the Clean Environment Commission.

I'm sure that there are issues that any individual would wrestle with if they had to be an arbiter over these decisions. For example, did we wait too long on livestock adjacent to rivers, you know, and waterways? That'll be raised I'm sure in the hearings. We get criticized from both sides. Sometimes when you take the balanced approach you are criticized from both directions, and I accept that.

Moving ahead on water stewardship with all sectors, and I include agriculture, but also homeowners that have phosphorus in their fertilizer and phosphorus in their dishwater detergent. We would prefer to have a national policy to lower the prices of those consumer products. I noticed in la belle province they just made a point of saying that there's more to this than just farmers. Jean Charest said that yesterday, and we agree with him.

On the issue of a dictatorship, I have never been accused of being a dictator by anybody I know, except my most immediate friends.

Mr. McFadyen: Part of what generated the negative reaction through rural Manitoba, and I attended one of the meetings that was held by the Conservation Department–Mr. Williamson came on behalf of the government–was the noted absence of a minister to provide political leadership and feedback at these meetings and discussions. There was even a meeting that had been scheduled with the then-Water Stewardship Minister, who is the former Water Stewardship Minister, that was organized and then cancelled at the last minute. People came out because they thought they were going to have a chance to hear directly from the minister, and were disappointed when he cancelled. I don't know what the circumstances were, but the message that it sends when you send an official out, as capable as they are, the message at the political level is that there's not a real political interest in what's going on. So much of the negative reaction was a sense that new rules were coming from government issued from Broadway, and that there wasn't a genuine dialogue going on with producers as to how best to implement the new measures.

I understand the give-and-take and the push-and-pull on these issues. People have cottages at wonderful places like Rock Lake in the Pembina Valley, who have concerns about water quality there, and they see from time to time livestock grazing in waterways and would see that as a contributor to the problem. You can also see the perspective of the producer who is trying to make a living on marginal land with grazing. So I think what you need to do in those circumstances to make progress is to have dialogue as to how you bring about those changes in a co-operative way. I would only say that there was a genuine sense through much of the province that that was not taking place under the former minister.

I know there were main concerns over details. I would just say in the spirit of not being overly partisan I sense that there's a feeling that progress is being made on them. I would simply ask the Premier to ensure that the direction continues to be that there's a genuine dialogue, and that we're not expecting producers to bear the brunt of the load when it comes to achieving this objective, and that there's a real commitment to fairness, both in terms of what actually happens and the way it's perceived by people. I think that's important and would ask the Premier to commit that that spirit of partnership be the way this proceeds and not one of confrontation or, if not confrontation, simply lack of interest on the part of ministers in his government until the present.

Mr. Doer: I may not know about the specific meeting, but I have heard sometimes criticism of the minister that misses a meeting and they're at a funeral. I understand why people would be very upset. So, if you're expected to be there, you better have a good reason. If you've confirmed to be at a place, we all know this rule: You better have a good reason for not being there and sending a very qualified person in your place.

Secondly, we just talked about the city of Winnipeg and all the pressure now to deal with phosphorus and nutrients, and then we talked about agriculture, I think the fact that the questions followed each other indicates that there are many sources for the challenges of water and water quality and water degradation. Therefore, there are many sources that we have to look at.

As we get gavelled down–

Madam Chairperson: As previously agreed, the hour being 6:30 p.m., committee rise.

Call in the Speaker.

IN SESSION

Madam Deputy Speaker: Being after 6:30 p.m., as previously agreed, this House is adjourned and stands adjourned until 10 a.m. tomorrow (Thursday).

CORRIGENDUM

Vol. LIX No. 9B – 1:30 p.m., Tuesday, September 25, 2007, page 319, the first column second paragraph should read:

I know that the Member for Lac du Bonnet, the Opposition House Leader (Mr. Hawranik), along with the Government House Leader (Mr. Chomiak) and others travelled to Saskatchewan recently to have a discussion with people in that jurisdiction about the way Public Accounts works in Saskatchewan and, I think, came back impressed with some of the things that have been happening there.

LEGISLATIVE ASSEMBLY OF MANITOBA

Wednesday, September 26, 2007

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Second Session - Fortieth Legislature

of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
(Hansard)

Published under the
authority of
The Honourable Daryl Reid
Speaker

Vol. LXV No. 10 - 1:30 p.m., Monday, December 3, 2012

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MANITOBA LEGISLATIVE ASSEMBLY
Fortieth Legislature

Member	Constituency	Political Affiliation
ALLAN, Nancy, Hon.	St. Vital	NDP
ALLUM, James	Fort Garry-Riverview	NDP
ALTEMEYER, Rob	Wolseley	NDP
ASHTON, Steve, Hon.	Thompson	NDP
BJORNSON, Peter, Hon.	Gimli	NDP
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BRAUN, Erna	Rossmere	NDP
BRIESE, Stuart	Agassiz	PC
CALDWELL, Drew	Brandon East	NDP
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CHOMIAK, Dave, Hon.	Kildonan	NDP
CROTHERS, Deanne	St. James	NDP
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EWASKO, Wayne	Lac du Bonnet	PC
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GERRARD, Jon, Hon.	River Heights	Liberal
GOERTZEN, Kelvin	Steinbach	PC
GRAYDON, Cliff	Emerson	PC
HELWER, Reg	Brandon West	PC
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IRVIN-ROSS, Kerri, Hon.	Fort Richmond	NDP
JHA, Bidhu	Radisson	NDP
KOSTYSHYN, Ron, Hon.	Swan River	NDP
LEMIEUX, Ron, Hon.	Dawson Trail	NDP
MACKINTOSH, Gord, Hon.	St. Johns	NDP
MAGUIRE, Larry	Arthur-Virden	PC
MALOWAY, Jim	Elmwood	NDP
MARCELINO, Flor, Hon.	Logan	NDP
MARCELINO, Ted	Tyndall Park	NDP
MELNICK, Christine, Hon.	Riel	NDP
MITCHELSON, Bonnie	River East	PC
NEVAKSHONOFF, Tom	Interlake	NDP
OSWALD, Theresa, Hon.	Seine River	NDP
PALLISTER, Brian	Fort Whyte	PC
PEDERSEN, Blaine	Midland	PC
PETTERSEN, Clarence	Flin Flon	NDP
REID, Daryl, Hon.	Transcona	NDP
ROBINSON, Eric, Hon.	Kewatinook	NDP
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ROWAT, Leanne	Riding Mountain	PC
SARAN, Mohinder	The Maples	NDP
SCHULER, Ron	St. Paul	PC
SELBY, Erin, Hon.	Southdale	NDP
SELINGER, Greg, Hon.	St. Boniface	NDP
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SWAN, Andrew, Hon.	Minto	NDP
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WHITEHEAD, Frank	The Pas	NDP
WIEBE, Matt	Concordia	NDP
WIGHT, Melanie	Burrows	NDP
WISHART, Ian	Portage la Prairie	PC

LEGISLATIVE ASSEMBLY OF MANITOBA

Monday, December 3, 2012

The House met at 1:30 p.m.

Mr. Speaker: O Eternal and Almighty God, from Whom all power and wisdom come, we are assembled here before Thee to frame such laws as may tend to the welfare and prosperity of our province. Grant, O merciful God, we pray Thee, that we may desire only that which is in accordance with Thy will, that we may seek it with wisdom and know it with certainty and accomplish it perfectly for the glory and honour of Thy name and for the welfare of all our people. Amen.

Good afternoon, everyone. Please be seated.

ROUTINE PROCEEDINGS

INTRODUCTION OF BILLS

Bill 15–The Employment Standards Code Amendment Act (Minimum Wage Protection for Employees with Disabilities)

Hon. Jennifer Howard (Minister of Family Services and Labour): I move, seconded by the Minister of Justice (Mr. Swan), that Bill 15, The Employment Standards Code Amendment Act (Minimum Wage Protection for Employees with Disabilities); Loi modifiant le Code des normes d'emploi (protection du salaire minimum pour les employés ayant des incapacités), be now read a first time.

Motion presented.

Ms. Howard: I want to start by noting that today is the United Nations day of people with disabilities, and we're joined by many people in the gallery who were out marking that day this morning at a forum held at the convention centre that I was honoured to be able to speak at. And many people in the gallery today have fought very hard for the bill that we are introducing, and it is a bill that will eliminate the ability for employers to apply to Employment Standards to pay less than minimum wage to someone simply because they have a disability.

This is a recommendation from the Labour Management Review Committee. It's a consensus of the employer and employee reps on that committee. Currently there are fewer than 20 such permits issued. This bill will allow for those remaining permits to be in effect as a result of discussions that have been had with those individuals and their families. It will allow the director to make changes to those permits in order to ensure employees are protected.

As I said, I want to thank the people who are with us in the gallery today who have fought hard not only for this change but so many changes that make Manitoba more inclusive and a more accessible province for all of us. Thank you.

Mr. Speaker: Is it the pleasure of the House to adopt the motion? *[Agreed]*

Bill 17–The Consumer Protection Amendment and Business Practices Amendment Act (Motor Vehicle Advertising and Information Disclosure and Other Amendments)

Hon. Jim Rondeau (Minister of Healthy Living, Seniors and Consumer Affairs): I move, seconded by the Minister of Family Services and Labour, that Bill 17, The Consumer Protection Amendment and Business Practices Amendment Act (Motor Vehicle Advertising and Information Disclosure and Other Amendments); Loi modifiant la Loi sur la protection du consommateur et la Loi sur les pratiques commerciales (publicité et communication de renseignements visant les véhicules automobiles et autres modifications), be now read a first time.

Motion presented.

Mr. Rondeau: I apologize for the cold for the Minister of Healthy Living.

Anyhow, Mr. Speaker, this bill adds to The Consumer Protection Act dealing with motor vehicle advertising and information disclosure. Prohibition against false advertising and providing false information about a motor vehicle are included. Advertisements must include the price of a vehicle. The advertised must be the total price, including all fees charged as levies and taxes except GST and PST, and it must indicate whether the vehicle is new or used. And requirements for disclosure about the vehicle are moved from The Business Practices Act to The Consumer Protection Act, and consumer compliance orders can be issued and publicized by the director. It also makes other changes that will be involved in the legislation. Thank you very much.

Mr. Speaker: Is it the pleasure of the House to adopt the motion? *[Agreed]*

Any further introduction of bills? Seeing none–

PETITIONS

Provincial Trunk Highway 1

Mr. Larry Maguire (Arthur-Virden): I wish to present the following petition.

And the background of this petition is as follows:

(1) The provincial government presently maintains a freeway system for PTH 1 through the province of Manitoba.

(2) By definition this would lead to the elimination of all traffic lights on PTH 1 by building overpasses at every major intersection along the highway.

(3) The Town of Virden and the local planning district have never adopted a 1997 Manitoba Infrastructure and Transportation overpass plan for the community at the junctions of PTH 1 and King Street, 83 Highway and PTH 257.

(4) This freeway system overpass plan is impeding business development in Virden. Presently, a Virden businessman is virtually prohibited from relocating his business to his own land because it sits on the footprint of the planned overpass, even though his relocated business would generate $700,000 in provincial sales tax annually for Manitoba.

(5) Manitoba's infrastructure deficit has reached a record high. This deficit, paired with the number of existing projects still awaiting completion throughout Manitoba, will render the proposed overpass project financially unfeasible for decades to come.

We petition the Legislative Assembly as follows:

To request the Minister of Infrastructure and Transportation consider abandoning the Manitoba freeway proposal for the junction of PTH 1 and Virden's three intersections, particularly the King Street junction.

This petition is signed by L. Flett, J. Barkley, K. Gabrielle and many, many others, Mr. Speaker.

Mr. Speaker: In keeping with our rule 132(6), when petitions are read they are deemed to have been received by the House.

St. Ambroise Beach Provincial Park

Mr. Ian Wishart (Portage la Prairie): I wish to present the following petition to the Legislative Assembly.

And the reasons for these–for this petition are as follows:

The St. Ambroise provincial park was hard hit by the 2011 flood, resulting in the park's ongoing closure and the loss of local access to Lake Manitoba, as well as untold harm to the ecosystem and wildlife in the region.

The park's closure is having a negative impact in many areas, including disruptions to local tourism, hunting and 'fissing'–fishing operations, diminished economic and employment opportunities and the potential loss of the local store and decrease in property values.

Local residents and visitors alike want St. Ambroise provincial park to be reopened as soon as possible.

We petition the Legislative Assembly of Manitoba as follows:

To request the appropriate ministers of the provincial government consider repairing St. Ambroise provincial park and its access points to their preflood conditions so the park can be reopened for 2013 season or earlier if possible.

This petition's signed by K. Lipke, A. Lachappelle and M. Taylor, many, many more fine Manitobans.

***** (13:40)

Vita & District Health Centre

Mr. Dennis Smook (La Verendrye): I wish to present the following petition to the Legislative Assembly.

The reasons for this petition are as follows:

The Vita & District Health Centre services a wide area of southeastern Manitoba and is relied on to provide emergency services.

On October 17th, 2012, the emergency room at the Vita & District Health Centre closed with no timeline for it to reopen.

This emergency room deals with approximately 1,700 cases a year, which includes patients in the hospital, the attached personal care home and members of the community and surrounding area.

Manitobans should expect a high quality of health care close to home and should not be expected to travel great distances for health services.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Health consider reopening the emergency room in Vita as soon as possible and commit to providing adequate medical support for residents of southeastern Manitoba for many years to come.

This petition is signed by J. Hryciuk, P. Thiessen–P. Friesen and H. Mark and many more fine Manitobans. Thank you.

Provincial Road 520

Mr. Wayne Ewasko (Lac du Bonnet): I wish to present the following petition to the Legislative Assembly.

The background to this petition is as follows:

The rural municipalities of Lac du Bonnet and Alexander are experiencing record growth due especially to an increasing number of Manitobans retiring in cottage country.

The population in the RM of Lac du Bonnet grows exponentially in the summer months due to increased cottage use.

Due to population growth, Provincial Road 520 experiences heavy traffic, especially during the summer months.

PR 520 connects cottage country to the Pinawa Hospital and as such is frequently used by emergency medical services to transport patients.

PR 520 is in such poor condition that there are serious concerns about its safety.

We petition the Legislative Assembly as follows:

To urge the Minister of Infrastructure and Transportation to recognize the serious safety concerns of Provincial Road 520 and to address its poor condition by prioritizing its renewal.

This petition is signed by T.J. Johnson, B. Summerfield, B. Buck and hundreds of other fine Manitobans.

Provincial Trunk Highways 16 and 5 North–Traffic Signals

Mr. Stuart Briese (Agassiz): Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

The junction of PTH 16 and PTH 5 north is an increasingly busy intersection which is used by motorists and pedestrians alike.

The Town of Neepawa has raised concerns with the Highway Traffic Board about safety levels at this intersection.

The Town of Neepawa has also passed a resolution requesting that Manitoba Infrastructure and Transportation install traffic lights at this intersection in order to increase safety.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Infrastructure and Transportation to consider making the installation of traffic lights at this intersection–at the intersection of PTH 16, PTH 5 north–a priority project in order to help protect the safety of the motorists and pedestrians who use it.

This petition is signed by E. Waldner, K. Dalglish, M. Pearson and many, many other fine Manitobans.

Personal Care Homes and Long-Term Care–Steinbach

Mr. Kelvin Goertzen (Steinbach): Yes, good afternoon, Mr. Speaker. I wish to present the following petition.

These are the reasons for this petition:

The city of Steinbach is one of the fastest growing communities in Manitoba and one of the largest cities in the province.

This growth has resulted in pressure on a number of important services, including personal care homes and long-term care space in the city.

Many long-time residents of the city of Steinbach have been forced to live out their final years outside of Steinbach because of the shortage of personal care homes and long-term care facilities.

Individuals who have lived in, worked in and contributed to the city of Steinbach their entire lives should not be forced to spend their final years in a place far from friends and from family.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Health ensure additional personal care homes and long-term care spaces are made available in the city of Steinbach on a priority basis.

Mr. Speaker, this petition is signed by D. Rempel, J. Funk, B. Bartel and hundreds of other fine Manitobans.

TABLING OF REPORTS

Hon. Ron Lemieux (Acting Minister charged with the administration of The Manitoba Lotteries Corporation Act): I'd like to table Manitoba Lotteries' second-quarter report for the six months ending September 30th, 2012.

Introduction of Guests

Mr. Speaker: Prior to oral questions, I'd like to draw the attention of honourable members to the public gallery where we have with us today from Selkirk Junior Parliament 36 grades 7 to 9 students from East Selkirk Middle School, Walter Whyte School, Lockport School and École Selkirk Junior High under the direction of Deanna Cameron, Kelly Murray, Jennifer Magnusson and Scott Andrews. These folks are the guests of the honourable member for Selkirk (Mr. Dewar) and also the Minister of Entrepreneurship, Training and Trade (Mr. Bjornson). On behalf of all honourable members, we welcome you here this afternoon.

And also in the public gallery, we have with us today Kirstie Grimmer from the Chancellor School Advisory Council, who is a guest of the honourable member for St. Norbert (Mr. Gaudreau). On behalf of honourable members, we welcome you here today.

ORAL QUESTIONS

Manitoba Hydro
Export Market Concerns

Mr. Brian Pallister (Leader of the Official Opposition): The top priority for investments by Manitoba Hydro has always been Manitobans' best interests in the domestic market, not foreign exports of hydro. And yet the government has it upside down. It seems like they're saying that the reason for going ahead with this supersizing of Manitoba Hydro is–well, the quote the Premier's known for is: It's about power exports to the US, he says. They're willing to pay premium international prices.

Interestingly, those prices are leading to increases in rates for Manitobans, Mr. Speaker, up to 40 per cent or more over the next decade, 6 per cent in the last three months.

So my question, I guess, is this: Why? Why double the size of Manitoba Hydro? Why speculate in the risky US energy market? Why place the interests of American power buyers ahead of Manitobans who really own Manitoba Hydro, not the NDP?

Hon. Greg Selinger (Premier): Mr. Speaker, the experience of the opposition never changes when it comes to Manitoba Hydro. They always are looking for a reason to not build it, to mothball it. And as a result of that, we lost a decade in the '90s.

They criticized Limestone as a project that was uneconomic. It was built and it paid itself back within 10 years, and then that power was available, having been paid off by export revenues available to Manitobans. The capital was paid off by the export revenues to Manitobans.

The Leader of the Official Opposition needs to understand that export revenues keep rates lower in Manitoba than they would be if we did not have export revenues. The absence of export revenues would make prices rise higher in Manitoba, as we're seeing in other jurisdictions across the country.

Mr. Pallister: The Premier's degree from London School of Economics obviously isn't in economics.

The fact is that export prices have declined to half the level of five years ago while he's caught in the headlights. The reality is today's price per kilowatt hour is 3 and a half cents. The reality is the cost of production is 13 cents. The reality is that we're going to be losing money if we follow the NDP's bullheaded plan.

The NDP business plan calls for the largest megaproject investment in the history of our province, Mr. Speaker, and it is concocted. It's on false urgency. It's based on skyrocketing supply, but they're ignoring the skyrocketing supply, and they're ignoring the sinking markets.

Now, previous premiers, including Edward Schreyer, had the wisdom to listen to his advisers and put the brakes on projects when it was appropriate. Why is this Premier acting like a deer caught in the headlights?

Mr. Selinger: Mr. Speaker, the member clearly has his head stuck in the sand; that's his problem when it comes to understanding the future of Hydro. The spot sales have shown a decline in prices. Firm sales remain very strong. Firm sale prices are the kind of prices that reduce the cost of building new hydro in Manitoba. Those export revenues–over $20 billion of export revenues over the next 20 years–will generate benefits that pay down the capital of new hydro installations and make those installations available to the Manitoba economy, which is a growing economy, an economy that's growing with people.

It's growing with clean energy; it's growing with new people investing in Manitoba; and as this economy grows, there will be a demand for clean, green energy.

When we build it now and export it, the price that comes back from those exports keeps the cost lower in Manitoba and allows us to get ahead of the curve on clean, green energy in the province of Manitoba.

***** (13:50)

Mr. Pallister: Manitobans deserve more than jolly Pollyanna for Premier here, Mr. Speaker.

The reality is that the Premier is telling everybody in the province to hurry up and get in the car; let's go for a 50-year US vacation, and they'll all–they'll pay for the freight. But the fact is he spends a lot of his time looking in the rear-view mirror; he can't see what's coming. The reality is he hasn't got any headlights on the car and he can't see the problems right in front of him. The reality is he hasn't got any brakes on the car either and once we start the car rolling, Mr. Speaker, there's no stopping. The reality is that he is telling everybody to listen to him that we're going to stay free down in the States on this vacation. And they're saying, we're booked; there's no room right now and there won't be any room for 50 years.

So, former and present NDP experts, former and present hydro experts, they're all saying the same thing: sober second thought, take a look at this, what's the rush? Len Evans, Len Bateman–smart men, smart people–are saying, bad idea.

So why get in the Premier's car when he doesn't have a map and, like many men, he doesn't have the brains to ask for directions either?

Mr. Speaker: I want to caution the honourable Leader of the Official Opposition–in fact, all members of the House–I very much, as your Speaker, want this to be a respectful workplace. So I'm asking for the co-operation of all honourable members to ensure that that happens. And I caution the honourable Leader of the Official Opposition, please, sir, pick and choose your words very carefully.

The honourable First Minister, to respond to the question.

Mr. Selinger: Yes, Mr. Speaker, I appreciate the question, without the editorial comments, but the question allows me to put on the record the following.

We have signed contracts in the United States for additional power sales. This is something the member seems to skip over.

We listened very courteously when the member put his very rude question, Mr. Speaker. Perhaps he could do the favour of listening to us when we give him the answer. Or is that beyond his capacity at this early stage in his career as Leader of the Opposition? Clearly seems to be.

We have signed contracts for over $7 billion of noon sales–new sales. We have ongoing contracts where we provide up to 10 per cent of the hydroelectricity to the great state of Minnesota. We have people looking for clean, green power in the United States that's reliable power, power that could be provided by Manitoba Hydro.

And just like the Limestone project, which they criticized and denigrated every step of the way, that–those power sales paid themselves back in 10 years and then made that capital investment in new dams available to all Manitobans, which allowed us to grow our economy and keep the lowest rates in North America. The lowest rates in North America is what we have right now here in Manitoba in spite of the mothballing of the members of the opposition.

Manitoba Hydro
Export Market Concerns

Mr. Ron Schuler (St. Paul): Mr. Speaker, hydro rates are expected to go up by 45 per cent by 2021 as a direct result of NDP mismanagement. Manitobans will be forced to pay for export-driven projects that the PUB says are not likely to break even, let alone make money, in the coming decade.

Why is the NDP forcing these plans ahead without the proper integrated economic reviews?

Hon. Dave Chomiak (Minister charged with the administration of The Manitoba Hydro Act): Mr. Speaker, I think the member is reading the wrong briefing note. Power rates are going up in the next year 41.4 per cent in BC. They're going up 23.9 per cent in Saskatchewan, and they're going up 42 per cent in Nova Scotia.

Mr. Speaker, in Winnipeg the monthly cost of residential power is $76.25. In Regina, it's $125.48. In St. John's, it's $125.48. In Halifax, it's $150.06. In Calgary–Calgary, the energy capital of the country–it's $117.41, almost double what it is in Manitoba.

I will take those rates, the lowest in the country, in front of the rhetoric the member is trying to inaccurately put on the record any time.

Manitoba Hydro–Bipole III Needs For and Alternatives To Review

Mr. Ron Schuler (St. Paul): Mr. Speaker, the minister is a little defensive on this one.

The minister has ordered a needs for and alternatives to, or NFAT, for Keeyask and Conawapa to ensure that they are economically sound, but not Bipole III. The Conservation Minister also cut a proposal to have the NFAT review done at the environmental hearings.

Is the minister afraid to send bipole through–III through an NFAT because it would fail?

Hon. Dave Chomiak (Minister charged with the administration of The Manitoba Hydro Act): As the member probably is aware, we've already announced an NFAT for Conawapa and for Keeyask.

Mr. Speaker, just let me repeat. The monthly rate for an average Manitoban, of a thousand kilowatts an hour, is $76.25 for the average Manitoban. For the average person in Halifax, it's $150, which is more than double. For the average person in BC–in BC, which has hydro–it's $87.77. For the average person in Regina next door, it's about $50 a month more. That equates to $600 a year per person. We have the lowest rates in the country. We're going to keep it that way.

If we had done what the Tories had asked us to do before, Mr. Speaker, we'd have the highest rates. They want market rates. They want to go back to coal. They want to use natural gas. They want to use systems that are foregone. Why don't we go to coal?

Mr. Speaker: Order, please. Order, please. The minister's time has expired.

Mr. Schuler: Mr. Speaker, this is a minister in a government that promised no tax increases and then increased them, said they would balance the budget by 2014–got those numbers wrong. There's nothing this minister can put on the record that we believe at this point in time. But thank you very much for that.

Export sales to the US can't be fully judged without evaluating the cost of getting it there. Bipole III is estimated to cost 3 cents per kilowatt hour to transmit power, which has a big impact on both export sales and domestic use.

Will the minister put bipole through–III through NFAT at the same time as Keeyask and Conawapa so we can get a clear picture of the integrated economics of this $18-billion project?

Mr. Chomiak: First off, Mr. Speaker, bipole doesn't cost $18 billion. The cost of transmission for reliability for bipole is almost not calculable in terms of what would happen if those two lines that are nearby each other were to go out. It's for reliability.

It's one of the reasons why we have signed contracts with the United States. It's one of the reasons why we're negotiating with Saskatchewan. We're negotiating with the province next to us to provide power to them.

It's one of the reasons why companies come to Manitoba every single day, because of our rates, and want to relocate to Manitoba. And you know what?

An Honourable Member: Name them.

Mr. Chomiak: Name them? Just you wait, Mr. Speaker. Just you wait.

Phoenix Sinclair Inquiry Responsibility for Missing Documentation

Mrs. Leanne Rowat (Riding Mountain): For those following the tragic replay of Phoenix Sinclair's life as the inquiry unfolds, there remain a lot of unanswered questions. It seems that someone does not want these questions answered, as notes on the child welfare file have gone missing. The minister has recently admitted the notes did exist, are missing and were perhaps destroyed.

Mr. Speaker, I ask the minister: When did she become aware that the notes were missing, and what has she done to investigate this very serious situation?

Hon. Jennifer Howard (Minister of Family Services and Labour): Thank you very much, Mr. Speaker, for the question. I think, as I've said before, watching the inquiry unfold, hearing the stories that are being told of the tragic life and even more tragic death of Phoenix Sinclair is a painful experience for all of us.

I find the fact that there's missing documentation extremely distressing. It would be my wish that all the documentation was available, because the reason why we called the inquiry was to get the full story so that we can make the changes that are necessary to be made. I am–I understand that there has been an extensive search for that documentation and–many times by many people involved in the system.

I look forward to the inquiry's conclusion. I look forward to the recommendations that they bring forth, and I look forward to continuing to making changes–

Mr. Speaker: Order, please. Minister's time has expired.

Mrs. Rowat: Based on her comments, I believe–and I believe Manitobans believe–that she didn't do what needed to be done to protect those files.

Mr. Speaker, several reviews were done at the time Phoenix Sinclair was murdered. Over 300 recommendations were made.

If the minister–is the minister not concerned that these notes may have been deliberately removed to impair the work of the inquiry? Mr. Speaker, will the minister today indicate whether the fire–files were available when all these reviews were done?

Ms. Howard: Well, Mr. Speaker, I want us all to be clear in this Chamber. I don't want us to–any of us to put forward allegations for which there is no evidence, and there is no evidence that any notes were deliberately removed–no evidence that I'm aware of.

If the member opposite has that evidence, I would ask her to share it with me, because that would be very, very serious. That would be very, very serious if there is–if there are those allegations and she has evidence to support those allegations.

***** (14:00)

As I've said, I think that the missing information is troubling. It's something that we wish was available because it would give us a full picture. Documentation has been an issue and was identified in several of the reviews of this case. That's why we've made moves to increase training, to increase standards to ensure the documentation is made in a timely way.

Mr. Speaker: Order, please.

Mrs. Rowat: Mr. Speaker, the Phoenix Sinclair inquiry was called over six years ago. Why wasn't this minister being proactive or this government being proactive in ensuring that those documents were secure? The inquiry has been stalled and delayed and now key documents are missing.

Given the seriousness of this situation, why were the documents not protected, kept in a safe place so that full disclosure would have been made available to the public during the inquiry? This government failed to give instruction that all files be kept safe, Mr. Speaker. It's obvious; they're missing.

Why did she fail to have these documents sealed and protected?

Ms. Howard: I think, clearly, there are standards in place when it comes to documentation. There are standards in place when it comes to the security of information. We have made moves to strengthen those standards, to increase the training available, to make sure that there's resources in place to help people make sure that the data is entered correctly and we'll continue to make those moves.

And we will take the recommendations from this inquiry very, very seriously, and if there are further moves that we need to make to ensure the documentation is done appropriately and done well, then we will make those changes, Mr. Speaker. That's why we called the inquiry, because we want to get the full story of what happened and information on how we can improve the system as much as anybody. Thank you.

Phoenix Sinclair Inquiry
Responsibility for Missing Documentation

Mrs. Bonnie Mitchelson (River East): That answer isn't good enough. It was this government that called the inquiry six years ago. Mr. Speaker, it was up to this government to ensure the integrity of the files that were available so the inquiry and the commissioner could do his work.

Why did this government fail to ensure that those documents were in a secure place and protected so that the commissioner could do his work?

Hon. Jennifer Howard (Minister of Family Services and Labour): We called this inquiry because we wanted the whole story, the full story, to become available. We wanted people to hear–and I think what's unfolding in the inquiry is an unprecedented look at how the child welfare system works and how it doesn't work. And I think that doing that, while it is very painful for the people involved, I think it is necessary and it will be necessary so that we can take a look at what happened in this case, so that we can make more changes. Many changes have been made, but so that we can make more changes into the future to ensure that the system is in a place where it can protect children and help families.

Mrs. Mitchelson: Under law, the Minister of Family Services has the ultimate responsibility to ensure that children are protected. When Phoenix Sinclair fell through the cracks and was murdered, Mr. Speaker, this government called an inquiry. That inquiry should have been full and the commissioner should have had all of the information for him to do his job and it was up to the minister and the government responsible to ensure that those files were there.

Why did they fail to protect the documents?

Ms. Howard: Well, I think, Mr. Speaker, as I've stated, there has been an exhaustive search for those documents. Everybody wants to make sure that that–those documents, all the information that the commissioner needs, is turned over to the commissioner and they have full access. There has been extremely good co-operation, I think, between the government and the commission in making information available.

I don't know what allegations the members opposite have evidence to support. I'm open to hear that evidence if they have some allegations and we'll take that very seriously.

The things that we have done to make sure that children are protected in the wake of the tragic death of Phoenix Sinclair is invest in front-line social workers to the tune of over 200 more people in the system, make sure that standards are brought up to date that are in place, standards that include things like having every child seen every time. And there's much more to do, Mr. Speaker, and we will hear those recommendations and we'll take them seriously.

Mr. Speaker: Order, please.

Mrs. Mitchelson: The evidence that we do have is that this government failed to protect the files and ensure that they were secure so that the commissioner and the inquiry could do their job.

Mr. Speaker, they have failed Phoenix Sinclair through their lack of accountability and their incompetence. Why wasn't a directive sent to ensure that those documents were in a safe place so that Manitobans–excuse me–could have all of the information and all of the facts as the inquiry unfolded?

Ms. Howard: Well, Mr. Speaker, the truth is that there are standards in place to make sure that all information in the child welfare system is kept secure and is kept confidential. People take that very, very seriously. In this situation, as I've said before, there has been extensive searches for these documents. They haven't been found. I wish that they were available because I think that they would be useful to the commissioner.

We have worked to co-operate with the commission. We called the commission of inquiry because we wanted there to be a full disclosure of what happened in this case and because we wanted to be able to learn how to strengthen the system, and that commission will continue and that inquiry will continue and we will take our lessons from the commissioner.

Taxation
Possible Increases

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, for two weeks now this NDP government has refused to say if they will raise taxes again to pay for the spending mess that they've created. It is troubling that this Minister of Finance babbles on about all kinds of things, but he refuses to answer the question.

So I'd like to ask him again: Will the NDP raise taxes again in their next budget to pay for their spending addiction?

Hon. Stan Struthers (Minister of Finance): You know, Mr. Speaker, it's quite rich that the member opposite would complain when we come forward, not only just complain but vote against a measure in terms of reducing RHAs in this province to contain costs and have those costs transferred to the front lines that Manitobans care about.

She talks about babbling on. Well, last week I guess I babbled on about a–$1.2 billion in tax savings for individuals, property and business. Now, I have fairly thick skin, I can handle her calling–

saying I babble on, but those were real tax savings for Manitobans. I don't know if they think I was babbling on or not.

Mrs. Driedger: Well, Mr. Speaker, in the last election we saw this government raise taxes by $184 million. He's neglecting to talk about that.

Mr. Speaker, the federal government has said that they will not raise taxes in their next budget, but for some reason this NDP government here won't give Manitoba taxpayers the same straight answer.

And it's a very simple question: Will the NDP guarantee, like the federal government has, that they won't raise taxes in their next budget?

Mr. Struthers: Well, Mr. Speaker, in the last election–the member across the way is incorrect. In the last election we talked about protecting services that Manitobans value more than others. We talked about protecting health care. We talked about protecting education. We talked about protecting services that protect kids. We talked about very strategic investments in our economy to grow that economy.

We have taken on seriously reductions in spending, a streamlining of government, offering our services to Manitobans in a different way that's more efficient and more effective, and they do not support that. They work against–

Mr. Speaker: Order, please. The minister's time has expired. Order, please.

Balanced Budget
Government Timeline

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, the federal government has also said they are going to balance their books by 2015, yet this NDP government refuses to say whether they will balance their budget here in Manitoba.

Mr. Speaker, the lack of responses by this NDP government on both those issues of raising taxes and balancing the budget is becoming shocking. They're not giving a clear answer to Manitoba taxpayers.

So I'd ask him today for a very clear answer: When will the NDP government in Manitoba balance the budget?

***** (14:10)

Hon. Stan Struthers (Minister of Finance): Well, Mr. Speaker, the federal government has also had five different dates over the last 20 months as to when they're going to come back into balance. The federal government has also laid off Manitobans and left unprotected some of the services that matter most to Manitobans.

Our commitment has been very clear, Mr. Speaker. We're going to take on decisions that reduce the spending that we do have. We're not going to do it in such a way that we lay people off, and we're not going to do it in such a way that we hurt health care, that we hurt education, that we hurt our ability to protect kids in this province.

We're not going to take your advice–Mr. Speaker, we're not going to take their advice and go into these with deep cuts that put our–that would risk putting our economy–

Mr. Speaker: Order, please. Order, please. Minister's time has expired.

Balanced Budget
Government Timeline

Mrs. Heather Stefanson (Tuxedo): During the last election, the Premier (Mr. Selinger) promised that he would balance the budget in Manitoba by 2014, and he said that he would do so without raising taxes, Mr. Speaker.

Well, Manitobans have two questions for him: No. 1, when will he balance the budget, Mr. Speaker? And, No. 2, will he do so without raising taxes?

Hon. Stan Struthers (Minister of Finance): Mr. Speaker, we've employed a very balanced approach to our economy. The balance includes both revenue and expenditure decisions. Members opposite will see that kind of a balanced approach come forward.

What we will not be doing, Mr. Speaker–what we will not be doing–is taking advice from members opposite who for some reason think it's a good–a good way to do this would be very draconian cuts to services, very deep, heartless cuts, if I may say so, deep cuts that would (a) leave our–Manitobans without the services that they desire and (b) would run the risk of putting our economy further into an economic downturn.

Mr. Speaker: Order, please. The minister's time has expired.

Mrs. Stefanson: And these are not trick questions that we are asking the Minister of Finance. In fact, Mr. Speaker, we have asked these questions several times, in fact, every day in question period in the last few–couple of weeks.

My question for the Minister of Finance is quite simple: Is it his intention to balance the budget at all, Mr. Speaker? Yes or no.

Mr. Struthers: Mr. Speaker, this is the same group of people who came into this Legislature with a resolution–with a resolution that would have cut deeply into the services that Manitobans really want us to protect.

They came in and they put that resolution on the table. They all stood and they voted for it. Those were deep cuts that would've kicked our economy into recession.

Then the election comes along, and what do they do? Eleventh hour, just before the election, the night before the election, they decide we're not coming back into balance 'til 2018. The people with credibility problems on this issue are sitting to your left, Mr. Speaker.

Mrs. Stefanson: Mr. Speaker, the Minister of Finance can't even answer a simple yes-or-no question. That's–it's concerning for Manitobans. They want to know whether or not this Minister of Finance has any intention at all of ever balancing the budget.

Will he answer that question, Mr. Speaker? Will he–does he have the intention of balancing this budget ever?

Mr. Struthers: Well, Mr. Speaker, when we talk about these issues, I think it's very important to remember what the debt-to-GDP ratio is today as compared to what it was a number of years ago. If we want to really measure the effectiveness of government actions, that is a very good way to do it.

Mr. Speaker, 33 per cent represents the number in 1999, back in the days when the member of–the Leader of the Opposition thought that they were blessed with having that government, back in the days when the–that was a intelligent way of governing. Thirty-three per cent, more than a third of our debt to GDP existed at that time.

Today, we've worked that down to 27 per cent, Mr. Speaker, because we have–

Mr. Speaker: Order, please. Minister's time has expired.

**Phoenix Sinclair Inquiry
Responsibility for Missing Documentation**

Hon. Jon Gerrard (River Heights): Mr. Speaker, with regard to the missing supervisor's notes at the Phoenix Sinclair inquiry, the minister insists that there were standards in place. Presumably, these were standards for storing records, for accessing records and for records security. She also says it's unknown why these files were missing. But one supervisor, Andy Orobko, took his notes home, had them there for several years and then destroyed them.

I ask the minister: Will the minister tell us which standard this follows, and will the minister today table the standards that she's so–referring to earlier on?

Hon. Jennifer Howard (Minister of Family Services and Labour): Well, clearly, the destruction of notes does not follow a standard; that is clear. I don't think anybody would purport to say that it does follow any standard of good recordkeeping.

I'd be pleased to share with the member opposite the standards that are in place when it comes to documentation. I don't have them with me today, but I'd be pleased to make that information available to him.

Mr. Gerrard: Mr. Speaker, I look forward to the minister tabling those as soon as possible.

Mr. Speaker, in Saturday's Winnipeg Free Press, Lindor Reynolds wrote of the missing CFS supervisory notes on the Phoenix Sinclair file. She said: The notes may become the inquiry's version of the infamous 18 and a half missing minutes of taped conversation between US President Richard Nixon and his chief of staff used to determine the President's role in covering up the Watergate scandal.

I ask the Minister of Family Services: What action did senior CFS management make to make sure the CFS supervisory notes for Phoenix Sinclair were not lost, and can the minister completely tell us what action had been taken to try and retrieve these lost notes?

Ms. Howard: I think it's worth noting, again, for members opposite, that it was this government that called the inquiry. We called the inquiry because we wanted to have a full airing, and it has provided, really, an unprecedented look at the child welfare system. We have had people testify who worked on the case. We've had people testify who were supervisors of that case, and as that inquiry unfolds, we will also hear what has happened since the death of Phoenix Sinclair, and then we will also move into a discussion of some of the issues that we all confront in our society that leads to the neglect and abuse of children. So the inquiry is going to teach us much about how we can improve the system, and we'll look forward to those recommendations.

As I've said before, the standards that are in place speak to the security and confidentiality of records–

Mr. Speaker: Order, please. Minister's time has expired.

Mr. Gerrard: Mr. Speaker, the processes and procedures to ensure that CFS notes do not get lost, misplaced, or destroyed are the responsibility of the Minister of Family Services and of other senior CFS officials like, for example, Darlene MacDonald was at the time. While the decisions related to what was said then on what happens to an individual child and family may depend a lot on the front-line worker, the procedures and processes which are vital to the integrity of the system are those of the minister and the senior management.

And I ask the minister: Why has the revolving door of NDP CFS ministers allowed the CFS department to be run in such a way that critical notes of CFS supervisors have gone missing and the media is now comparing NDP governments to Watergate?

Mr. Speaker: Order, please. Order, please.

Ms. Howard: You know, I'm not going to engage in the cynicism of the member opposite on this file. We come to work here every day because all of us want to do better for our communities, and I come into my office every day with the heavy responsibility but the welcome responsibility for making sure that children and families are cared for and protected, and I take that responsibility extremely seriously. And I am not going to give up on that responsibility, and I'm not going to give up in the face of the kind of cynicism that the member opposite brings into this Chamber, Mr. Speaker.

We are paying very close attention to this inquiry. I believe this inquiry will come out with a report that will transform the way children and family services are delivered in this province, and I welcome the opportunity to put that into effect.

***** (14:20)

Seasons of Tuxedo Geothermal System

Mr. James Allum (Fort Garry-Riverview): Winnipeggers and Manitobans are excited about the new retail development boom that is happening in our great city, which creates economic growth and creates jobs. What they may not know is that one of these developments, the Seasons of Tuxedo, is one of the greenest in the world.

Could the Minister for Innovation, Energy and Mines please inform the House about the–how the Province helped support this energy efficient development with green tax incentives and geothermal grants?

Hon. Dave Chomiak (Minister of Innovation, Energy and Mines): I was honoured to be able to be present at the 275,000-square-foot retail development, the largest retail development with a geothermal system of its kind probably in the world, Mr. Speaker, which was–which has provided green and clean energy with a payback to both the tenants and the owners of eight years, and which was assisted by the Green Energy Equipment Tax Credit as well as the district geothermal grant.

We were able to help these come to Manitoba, keep the Manitoba economy expanding and keep it expanding in a green, sustainable way, with sustainable, green jobs going into the future. That's what Manitobans want to have dealt by their government.

Manitoba Public Insurance Corporation Collection Agency Garnishee Order

Mr. Cliff Graydon (Emerson): Bill Turner received a speeding ticket driving home one evening. He's never disputed that he was in the wrong and should have to pay it. He tried to pay the ticket online where he was told that there was no record of the ticket; it didn't exist. The ticket was issued to the wrong address. He had recently moved and had registered this with MPI. The ticket, however, was mailed to the wrong address. Because of this error, a $354.75 ticket became a ticket in excess of $400, with late fees, garnishment fees and court costs, plus an additional $1,340 to renew his licence and registration.

Mr. Speaker, I want to ask the Minister of Justice: Why must Mr. Turner pay for MPI's mistakes and mismanagement?

Hon. Andrew Swan (Minister charged with the administration of The Manitoba Public Insurance Corporation Act): Although I can't discuss the specific case, it is clear the member does not have all the information.

There is some advice I can give the member, and indeed, all Manitobans: No. 1, don't speed on our highways; No. 2, make sure that you give MPI your current address because it is very important if they need to get a hold of you; No. 3, if you speed and you're caught and you're handed a ticket by the RCMP or by a police officer, you should pay it in accordance with the terms written on ticket. If you want to oppose it, you should do so in accordance with the terms printed on the ticket. If you don't pay it in accordance with those terms or oppose it, it is not surprising there is then collection action that can be taken for the outstanding amount of the ticket. And when you go to renew your driver's licence or your vehicle registration, you may find there's a hold that's been placed against it. Now, even–

Mr. Speaker: Order, please. Order, please. The minister's time has expired.

Mr. Graydon: Due to the mismanagement of MPI, the collection agency and the justice system received inaccurate information. The minister responsible for MPI and the Minister for Justice are one and the same. When his office was contacted, they acknowledged it was some confusion on what was owed and sent Mr. Turner the wrong phone number to call and rectify the situation.

Mr. Speaker, the minister still has an opportunity to do the right thing and commit to refund the extra fees to his–through his department's failures.

Mr. Swan: Good–some more information I can provide to the member opposite and all Manitobans is that if you do get a ticket, when you do pay the ticket, you still have to pay for your vehicle registration and the cost of your driver's licence, which, unfortunately, was incorrect in the information put forward by the member opposite and the Tory press releases. They continue, Mr. Speaker, to aim lower.

But, you know, this morning I stood shoulder to shoulder with the RCMP out at Headingley as they again announced their annual Check Stop program. We support the RCMP. We support their efforts to make our roads safer, to keep them safe from impaired drivers, to make sure that individuals are wearing their seatbelts, not distracted, and one of the most important issues is to make sure individuals are not speeding on our highways. We stand shoulder to shoulder with the RCMP to reduce the deaths in our province caused by people speeding on our highways. We take it very seriously. I know the police take it very seriously–

Mr. Speaker: Order, please. The minister's time has expired.

Mr. Graydon: *[inaudible]* cannot renew his insurance on his vehicle in a monthly or quarterly installments as he has done previously. He will be unable to renew his driver's licence without undue hardships. For a man that commutes to work every day from Gretna to Winkler, this is a tall order.

When my office notified the minister, they continued on their reckless path and sent a collection agency after him, and Mr. Turner has had enough.

Mr. Speaker, can the minister commit to meeting with Mr. Turner and resolve all the issues involved in a ticket, including Mr. Turner's reputation and his credit rating?

Mr. Swan: My first response–I did explain some of the challenges, and it's some of the things that all Manitobans need to do, and it is true, if you receive a park–if you receive a speeding ticket and you're either convicted or you say you'll pay it and you don't, if you don't pay that fine, there may be action taken. And Manitoba Justice does pursue individuals with outstanding fines. We believe it's important.

I thought the member for Brandon West (Mr. Helwer) thought that was important, but that was a different week. And then he did and he didn't, but that's another point.

But we believe that drivers who break the law, who break The Highway Traffic Act, actually should have to pay when they receive tickets.

And, again, I would point out to all Manitobans, it's very important that they continue to advise Manitoba Public Insurance of their correct address because that's the only place MPI–

Mr. Speaker: Order, please. Order, please. The minister's time has expired.

There are a few seconds left.

Phoenix Sinclair Inquiry
Responsibility for Missing Documentation

Mrs. Bonnie Mitchelson (River East): Mr. Speaker, I think the answers from the Minister of

Family Services today left a lot of unanswered questions.

Very simple question to the minister: Why did the government not ensure that the files and the documents that should have been available to the commissioner from the Phoenix Sinclair murder, why did she, Mr. Speaker, why did her government not ensure that those files were in a secure, safe place so that Manitobans would have all of the answers and the commissioner would be able to do his work?

Hon. Jennifer Howard (Minister of Family Services and Labour): Mr. Speaker, well, as I've said before, there were and there are standards in place that speak to the confidentiality and the security of information, and that is our expectation when it comes to recordkeeping with regards to all child welfare cases.

We called this inquiry because there are unanswered questions, and we called this inquiry because we want to hear the answers to those questions. We want Manitobans to hear the answers to those questions, but more importantly than any of that, Mr. Speaker, we want to hear how we can go about improving not only the system designed to protect children but improving all of our province so that children aren't in need of that kind of protection. That's what we await to hear from the inquiry. Those are the recommendations that I think will be very important to transforming the future of Child and Family Services, and we'll take those recommendation as they come.

Mr. Speaker: The time for oral questions has expired.

MEMBERS' STATEMENTS

Charleswood Historical Society Centennial Committee

Mrs. Myrna Driedger (Charleswood): Charleswood turns 100 next year. The Charleswood Historical Society is busy planning this centennial, and I would like to congratulate them on their dedication and energy to fulfill their motto, Celebrating our Past; Embracing our Future.

The centennial committee has identified a wide range of ideas and events to celebrate the centennial next year. Once again, the people of Charleswood are stepping up to volunteer their time and energy to help with these celebrations. They have already published a calendar with wonderful photos of old Charleswood, and these calendars are now available for sale through the Charleswood Historical Society.

Dan Furlan is the chair of the centennial committee, and plans are well underway for many exciting events. The Charleswood 100 logo was designed by local resident Doug Coates and will be used to brand all of the centennial activities.

The volunteer committee has big plans and hopes for the year. Some of the plans under consideration includes improvement and recognition of the historical sites of The Passage and Kelly's Landing, recognition of 100-year families and veterans and a canoe dock at Caron House. Research is also being done into the Red River buffalo hunt and the significance of the Buffalo Pound Hunting Site. Also proposed are the establishment of two trails off the Harte Trail: First Nations tribute trail and Old Pembina trail habitat preservations trail to save habitat and preserve our Red River cart trail history.

The Charleswood Legion plans to have a wall of pictures of Charleswood residents. A committee plans to go into schools to do presentations about local history. Other ideas include a children's fair, a lecture series, Doors Open Winnipeg at Caron House, fireworks, business improvement beautification, fashion show and car show and probably many, many others. The ideas are endless, and it should be a year of lots of celebration. We invite people outside of Charleswood to join with us in celebrating our 100th birthday. It is definitely time to celebrate.

Mr. Speaker, I wish to congratulate and thank all of the wonderful volunteers in Charleswood who are so enthusiastic about planning and carrying out this year-long event. Good luck to them with all of the events and activities, and they are indeed an inspiring group to work with. And I look forward to participating with them.

Thank you.

***** (14:30)

Chancellor School Advisory Council

Mr. Dave Gaudreau (St. Norbert): As a society, one of the greatest things we can do for our children is to ensure their education and socialization. Schools play a key role in achieving this goal and it takes many people to create a positive learning environment. While staff members are irreplaceable and vital to all educational institutions, advisory council volunteers are also important to the growth and prosperity of every school. The Chancellor School Advisory Council or CSAC in St. Norbert is one such wonderful example.

CSAC is a group of parents and guardians that support students and staff at Chancellor elementary school. It's actively involved in the school by means of classroom volunteering, field-trip supervision, helping with reading and special lunch-day assistance. Outside of school hours, this dedicated council organizes fun events for the students and their family including movie nights, a Peak of the Market fundraiser, a holiday concert auction. While some of these events act as a fundraiser for the school, they, most importantly, all bring the community together. Notably, the fundraisers are chosen carefully to reflect the council's values: social justice, nutrition, literacy and development.

Successful fundraising efforts have allowed CSAC to support Chancellor School in various ways. Recent council initiatives have included a $2,000 subsidy towards the purchase of agenda books, kindergarten welcome bags, classroom grants, student leadership rewards, post-immunization snacks and an end-of-the-year grade 6 farewell celebration. Last year, the council focused on improving the school's play structure making it more accessible, adding more pieces and improving drainage. Every project the council has pursued has been prioritized in response to the needs of the students, their families and staff.

Mr. Speaker, the dedication of the Chancellor School Advisory Council to bettering the education experience of children is tremendous. Having attended the school functions, I have witnessed the phenomenal council teamwork and can assert that the students at Chancellor School are certainly fortunate. Thank you to the many council members who volunteer their time to improving their school's community. The council's positive impact on the community is, in fact, immeasurable and deserving recognition.

Thank you, Mr. Speaker.

Les Kletke

Mr. Cliff Graydon (Emerson): I rise today to recognize an outstanding writer and public speaker from my constituency.

Les Kletke from Altona has spent more than 25 years in the communication industry working as a book coach, freelance writer and a highly regarded speaker on numerous issues. Throughout those 25 years, he has published six books as well as writing for many newspapers and magazines, winning numerous awards in the process.

Les studied economics and agriculture at the University of Manitoba, which led him to studying as a Nuffield scholar, allowing him to gain new agriculture experience in Britain. His work in the agricultural sector also allowed him to travel to Russia, the United States, Korea, Brazil, New Zealand, Mongolia and China. Les is also trained as an auctioneer, and is involved in many charity auctions for worthwhile causes.

Mr. Speaker, all of these skills have led Les to being named Canada's representative to the global farmers roundtable, world food symposium, in Des Moines, Iowa. The event invited 20 producers from all over the world to discuss trade and technology in the agricultural sector, and to better understand and address the challenges of filling an increased food and nutritional security gap.

The second part of Les's trip is to attend the World Food Prize event in which many, many more farmers and those employed in the agricultural industry will debate and discuss other issues in the industry, like food security, conservation solutions and emergency technologies in agriculture.

Mr. Speaker, Les is a respected voice in the agricultural industry and is well respected in publishing industry as well. His work helps many understand complex issues, and is a great educator in both fields.

I would ask all members of this House to join me in congratulating Les on all of his successes and wish him the best of luck in his future work.

Thank you, Mr. Speaker.

Guru Nanak

Mr. Mohinder Saran (The Maples): Mr. Speaker, on December 2nd, 2012, our honoured Premier (Mr. Selinger) and I were honoured to attend the Sikh Society of Manitoba's celebration of the birthday of Sri Guru Nanak Dev Ji, the founder of the Sikh religion.

While this celebration was held this past weekend, Guru Nanak was born on November 28, a month of great significance to Sikhs. It is a month of pride but also one of sadness.

Political instability and philosophical friction within the Indian state led to the 1984 genocide of Sikh people in New Delhi and many parts of India outside of Sikhs' homeland. People were tortured and set on fire, and women were raped and made to wander the streets naked.

This state failed to protect them. After 28 years nobody is convicted. The democracies of the world appeared to sympathize with the victims.

The month of November brings sorrow to the Sikh community, but also great pride, pride because they did not take revenge upon the innocent, though many innocent Sikhs were slaughtered, but chose instead to donate blood to save lives as well as to commemorate the memory of the victims of the 1984 genocide. The campaign of blood donation in North America began in November 1999 and has saved since then thousands of precious lives.

Mr. Speaker, I would like to take the time for us to stop here today and honour these many people, the Sikh people, for their sacrifice, and remember the religious freedom we enjoy in Canada and in the world today because of people like Sri Guru Nanak Dev Ji and Sri Guru Teg Bahadur Ji, gurus of Sikhism who taught us lessons of integrity and sacrifice.

Thank you.

Magnus Eliason Recreation Centre

Mr. Rob Altemeyer (Wolseley): Mr. Speaker, the Magnus Eliason Recreation Centre, known as the MERC, is located on Langside Street in the heart of the Spence neighbourhood. Led by the Spence Neighbourhood Association and the Youth Agencies Alliance, the MERC provides local youth with a safe place to play sports and take part in after school drop-in programs.

In October, our provincial government and Manitoba Lotteries partnered with the Spence Neighbourhood Association and none other than the National Basketball Association to unveil the newly renovated gymnasium at the MERC.

The new features include everything from a refurbished gym floor to new wall pads, new backboards, several dozen new NBA basketballs, new scoreboard, shot clock, timer, and many other features.

I was really pleased to join our Premier (Mr. Selinger) at the grand opening for this amazing celebration where kids from the local neighbourhood had a chance to meet NBA legend and hall of famer Clyde the Glide Drexler. Members of the Minnesota Timberwolves and the Harlem Globetrotters were also on hand to help kids with their locals–help local kids with their skills and show off some off some of their professional moves.

Mr. Speaker, our government has really fought to promote the benefits of giving kids an opportunity to play sports in all parts of our province. I know from my own experience as a youth athlete, youth are able to grow as individuals and learn to work together as a team and, in turn, sport helps foster healthy neighbourhoods and communities where citizens can learn and work together and trust each other. The MERC is an essential part of this process in the Spence neighbourhood and the gymnasium's revitalization is an essential part in the amazing accomplishments that this community is achieving.

Today in the gallery we have with us: Jamil Mahmood, the executive director of the Spence Neighbourhood Association; Chino Argueta, the recreation and sports coordinator for the Youth Agencies Alliance; and Adam Wedlake, the executive director of Basketball Manitoba. These community organizations were essential in creating this lasting legacy in Spence neighbourhood, and I'd ask all of my MLA colleagues here in the House to join me in thanking them for their tireless efforts on behalf of today's youth.

Thank you.

Mr. Speaker: Grievances. Seeing no grievances–

ORDERS OF THE DAY

GOVERNMENT BUSINESS

House Business

Hon. Jennifer Howard (Government House Leader): Mr. Speaker, could we proceed with second reading of Bill 3, followed by Bill 12, 9, 14 and–yes, and 14.

Mr. Speaker: We'll now proceed with second readings of bills in the following sequence: Bill 3, Bill 12, Bill 9, and then Bill 14.

SECOND READINGS

Mr. Speaker: So we'll now call Bill 3, The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child).

Bill 3–The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child)

Hon. Jennifer Howard (Minister of Family Services and Labour): I move, seconded by the Minister of Finance (Mr. Struthers), that Bill 3, The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child); Loi modifiant le Code des normes d'emploi (congés en cas de maladie grave, de décès ou de disparition d'enfants), be now read a second time and be referred to a committee of this House.

Motion presented.

***** (14:40)

Ms. Howard: I'm proud to be able to introduce this bill and speak a little–to sec–move this bill to second reading, speak a little bit about it today.

This bill, of course, provides for new leaves for parents of critically ill children or parents of children who have disappeared or died as a result of a crime. The Employment Standards Code will be amended to provide job protection up to 37 weeks for parents of a critically ill child, up to 104 weeks for parents of children who have been murdered, and for parents of a child gone missing as a result of a crime, up to 52 weeks.

Consistent with other leaves under the code, an employee who has been employed by the same employer for at least 30 days would qualify for the leave, although, of course, I think it always bears saying that employers and employees can make their own arrangements as long as it doesn’t provide for less than what's provided for in the code.

For an employee to be eligible for the critically ill leave, a physician has to issue a certificate stating that the child is critically ill as a result of a life-threatening illness or injury and requires the care or support of the employee.

In the case of a murdered or missing child, the leave would be available where it is probable in the circumstances that they child died or disappeared as a result of a crime.

And, of course, these definitions are patterned after the federal bill that will provide for income support for parents who take advantage of these leaves. The leave, under the code, will enable parents to access newly announced federal benefits. The federal government has indicated that it will provide a federal income support for parents of murdered and missing children as of January 1st, 2013. That's why we're hopeful that we'll have co-operation of the House in order to move this bill through to third reading and proclamation before the House rises.

In addition, a new employment insurance benefit will provide up to 35 weeks of benefits to eligible parents who take leave from work to care for a critically ill or injured child. This income supplement is expected to be available in June, 2013.

I can't imagine the kind of trauma that parents who find themselves in these situations face. Certainly, my–one of the questions that was asked of me, when we brought in this bill, by the media, was how many parents would use this leave. And my answer was, I hope none. It's not a number that any of us, I think, can forecast.

In many cases, we know that parents whose children go missing, whose children may have been murdered–they face great uncertainty for a long period of time about how to put their life back together, if they ever can. They're involved with the police and the courts–processes that can be difficult to navigate and take time to resolve. In many cases, they may face attending in court for many, many months.

The uncertainty also exists for parents tending to a child with life-threatening illness. Parents who take leave from their job to care for a critically ill child or to deal with the aftermath of the murder or disappearance of a child often worry about their job–often worry that their job may disappear while they're away from work and they're focused on their child. And we know that the ability to get some income support benefits is important so that people can take the time that they need.

Dealing with these situations can require a significant period of time for parents to heal and attempt to overcome the tragedy. These parents require time to grieve, to address the severe psychological effect that they may be faced with and to deal with the stresses they face. And we believe that no parent should have to, on top of that, face the worry or fear that they may not have a job to go back to. That's why we've brought in Bill 3, to implement the consensus recommendations of the Manitoba Labour Management Review Committee, which will provide job protection for parents who take these leaves.

I also just want to let the House know that we will be bringing forward an amendment at committee just for extra clarity, that in the event that a parent would be convicted of a crime that led to the death or disappearance of the child, of course, that parent wouldn't be eligible for that leave. It did seem to be practically assured in the federal bill they aren't eligible for the benefits, but we want to make very sure that they wouldn't be eligible for the job leave also. And I want to thank the members of the opposition for putting forward some constructive suggestions when it came to that.

So thank you very much, Mr. Speaker, for the opportunity to speak to this bill. We have had an opportunity to brief the opposition and, as I say, I look forward to the ability to pass this bill before the House rises at the end of this week. Thank you.

Hon. Jon Gerrard (River Heights): Mr. Speaker, I rise to speak to Bill 3, The Employment Standards Code Amendment Act, dealing with leaves related to the critical illness, death or disappearance of a child. I welcome this legislation because I think it's helpful, useful and can be important in terms of helping parents adjust when there is a child who is critically ill, or on the death or disappearance of a child which is related to a crime.

I think that there are some areas which this legislation may need some clarification. Certainly, from my point of view, I want to speak from my experience as a physician looking after children with cancer, having dealt with many children who have been critically ill with cancer and be able to talk in that context on terms of how this might work and some of the flexibility that should be needed to be sure that is there in order for this bill to work optimally.

I think that the–it will be very important, as well, once this bill passes, that there be information on how this time is used that's very clear for parents, that's on the web or on information brochures but certainly readily accessible. At the time of–a child is critically ill, it's not a time when parents have lots of time to be figuring out things so that the–needs to be very easy and accessible and straightforward, so that people can use these measures and use these measures easily and readily.

One of the aspects that I think is pretty important is when one is–for instance, has a child who has a form of cancer. Very often there is some intensive treatment, during which time the child may be in a hospital or certainly often fairly sick for a period and need absolute day-to-day attention. But, then, over the next–and it may go on for a year or two or three sometimes, depending on the treatment, there will be intermittent times when a child is very sick. It could be as a result of the cancer; it could be as a result of the chemotherapy and the treatment; could be as the result of an infection that occurs.

And it would be very important, in my view I offer to the minister, that this be flexible, so that a parent might be able to take a month at the start of a very severe illness, but might be able to take the other weeks at intervals of their choosing at later times, that the 37 weeks shouldn't have to be a continuous 37 weeks and that this be very clear in the legislation, in the regulations around the legislation. You know, if you–again, an example where a child may need–or parents may need to be there, you know, all the time for the first month but, then, after that it may be at 'intervittent' periods. And it may be, in fact, a year or two or sometimes even longer down the road that the child–the cancer comes back, and sad as though that may be, it may be another period of very intensive care and attention that is needed by parents.

But I think that it is important not only that there be that flexibility for parents to use that time which, when it works for them, but that they're–parents know this right at the beginning, and so that the parents can then plan and use the time optimally. Because the last thing you want, for example, is for a parent to use up the 37 weeks and, then, on the 38– week, the cancer in a child comes back and you have another very intensive period that you need to have a significant amount of flexibility.

* (14:50)

And I would suggest that, if this is not adequately covered in this legislation, that there be an amendment. And if it can be covered in regulations, that you have some consultation with professionals who are in this area so that you can, in fact, make sure that it is optimum for parents of children who may be very seriously ill. That the–and it's not just with cancer. It may be with other illnesses that–they can be very serious, and the treatment may work for a while or there may be–not only a relapse, but a child, for example–I can give you a child who's now grown up and is a woman: when she was very young and she had a condition which left her in a very disabled state and that she had during her early years several bouts when she was very, very severely ill and could, in fact, have died, but these were not all in one 37-week period. They were at this time, you know, and then maybe a couple of years later and then maybe three or four years later.

But there needs to be a level of flexibility, I believe, if this is going to work well. And that level of flexibility needs to be very clear in the rules, but it also needs to be made very clear to the parents when the child first gets sick so that they can plan adequately and know how best to use this type of a leave. It's not like a maternity leave where you have–a child is born and then you have a certain period of time, but this can be a, certainly, very on-again, off-again process, and the legislation and the regulations, I believe, need to recognize that very well.

I think that the situation with the death of a child–now, I've certainly got a lot more familiarity with the death of a child from cancer than from a child who has died after murder, but what I would say to you is this: that the parents may go through periods when they are, you know, just really consumed by what has happened to their child. And I think what is good is to have the longer period in this circumstance. But again, it may well be that this can be a–somewhat intermittent when the parent has these periods when they are totally consumed by what's happened to their child and they're really unable to work. And so I think, again, there should be some level of flexibility in these circumstances as well, and I think it would be important that that would be there.

The second aspect which I think may need a little bit of clarity, the–in sections 59.8(2) and later on in 59.9(1), where we have the definition of the employee who is entitled to leave under the section, part (a) says, a parent of the child. Now, I'm presuming, but I may be wrong, that this is a biological parent of a child that the minister is referring to, and if that's the case, maybe that should be there.

If that's not the case, it seems to me that the (b), (c), (d) and (e) spell out most of the tie–instances where we're dealing with non-biological parents, but there would be some special interest–incidences, certainly, I would suggest, and perhaps refer this to the minister. For example, where you have a surrogate mother who would be a biological parent in certain circumstances, and where does this precisely fit in and who has the lead? And what–and with these sorts of things need to be thought through ahead of time because of the variety of families that we have now. And I think that it needs to be clear and that there shouldn't be, you know, uncertainty here in these definitions.

So I suggest to the minister that whether it is in the bill itself or is in regulations that there needs to be a little bit of additional clarity in terms of ensuring that you have the parents covered or the other people who we're looking at in terms of the guardian or foster parent, the person with whom the child has been placed for the 'pursopses' of adoption, et cetera. And one presumes, but–you know, that this applies to all who may be parents or involved in this circumstance. So that in–or for an individual child, there could be in some circumstances where you've got parents, presumably biological parents, the spouse of–where the parents are divorced, you may have two spouses of parents, you could have–where a child has been–has biological parents and there's been a divorce and there's two spouses and two biological parents and then the child has been adopted, you could have a fairly–a fair number of people who might be eligible to apply for leaves under the circumstances.

I don't have a quarrel with making sure we're inclusive, but I just want to make sure that the intent is clear in terms of what I presume is the minister providing that each and every one of these people in a particular circumstance would be able to have such leave.

I am fully supportive of this legislation. I think it's an excellent and worthwhile idea. I know that it's complementary to legislation which is coming at the federal level. And I'm certainly willing to work with the minister and others to get this passed as soon as possible. But I look forward to people who may come and present tomorrow. I believe it's going to be at committee stage, presuming we pass this, and I look forward to the ongoing discussion in having this in law as soon as possible.

Thank you, Mr. Speaker.

Mr. Kelvin Goertzen (Official Opposition House Leader): Mr. Speaker, our critic will have more comments to put on the record on third reading on this bill, but at this point we're prepared to move this committee–to committee in an expeditious fashion.

Hon. Nancy Allan (Minister of Education): Oh, sorry. Sorry.

Mr. Speaker: Is the House ready for the question?

An Honourable Member: Question.

Mr. Speaker: The question before the House is Bill 3, The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child).

Is it the pleasure of the House to adopt the motion? *[Agreed]*

House Business

Hon. Jennifer Howard (Government House Leader): Mr. Speaker, on House business.

Mr. Speaker: On House business.

Ms. Howard: Would you please canvass the House to see if there's leave for the Standing Committee on Human Resources to meet concurrently with the House starting at 11 a.m. on Tuesday, December 4th, 2012?

Mr. Speaker: Is there leave of the House for the Standing Committee on Human Resources to meet concurrently with the House starting at 11 a.m. on Tuesday–tomorrow, December the 4th, 2012? *[Agreed]*

The honourable Government House Leader, on House business.

Ms. Howard: On House business, I would like to announce that the Standing Committee on Human Resources will meet on Tuesday, December 4th, 2012, at 11 a.m., to consider Bill 3, The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child).

Mr. Speaker: It has been announced that the Standing Committee on Human Resources will meet tomorrow, Tuesday, December the 4th, 2012, at 11 a.m., to consider Bill 3, The Employment Standards Code Amendment Act (Leave Related to the Critical Illness, Death or Disappearance of a Child).

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Mr. Speaker: We'll now proceed with Bill 12, The Community Schools Act.

***** (15:00)

Bill 12–The Community Schools Act

Hon. Nancy Allan (Minister of Education): I move, seconded by the Minister of Family Services and Labour (Ms. Howard), that Bill 12, The Community Schools Act; Loi sur les écoles communautaires, be now read a second time and referred to a committee of this House.

His Honour the Administrator has been advised of the bill, and I table the message.

Mr. Speaker: It has been moved by the honourable Minister of Education, seconded by the honourable Minister of Family Services and Labour, that Bill 12, The Community Schools Act, be now read for a second time and be referred to a committee of this House.

His Honour the Administrator has been advised of the bill, and the message has been tabled.

Ms. Allan: The transformative power of education in schools is well recognized and documented. This power works best when students and families are positioned to take full advantage of investments in our public education system and the rich learning opportunities that it offers to all students.

Some students and families, however, are unable to take–make maximum advantage of these educational investments and opportunities due to a variety of personal, family and community circumstances, sometimes related to health, mental health, food and nutrition, and poverty. These circumstances can impede attendance, learning and high school graduation. They can also create challenges beyond what schools can be expected to handle alone.

The community school philosophy and way of practice provides an integrated response to address these challenges. With this approach schools serve as hubs of educational, social, recreational and cultural activities and interagency outreach services, deploying community, government and corporate resources to help students and families overcome barriers to learning so they can achieve success and participate in our economy.

Since 2005 the government of Manitoba has supported the expansion of schools adopting the community school philosophy and model in urban, rural and northern sites throughout the province. To date, there are 29 schools in 14 school divisions who have reported a variety of positive responses about the impact of this strategy on students and their families. This act will further strengthen community schools programming throughout the province by establishing an operational infrastructure. It will better assist schools in forging partnerships, mobilizing and leveraging resources and accessing training, thereby giving every student the best possible chance to succeed.

Bill 12 outlines the key features of a community school philosophy and model practice, including the various types of supports that may be required to overcome impediments to learning and assist students' success in school. While this approach is an asset for any community, the most significant value and impact occurs in vulnerable neighbourhoods with very diverse and sometimes vulnerable populations.

Consequently, Bill 12 calls for the establishment of the community schools program that will be comprised of schools serving socio-economically disadvantaged communities. As part of the legislation, schools participating in the program will be required to an–assign an employee to act as a community liaison at the school. This role helps to fulfill the essential function of developing and co-ordinating partnerships and mobilizing resources that align with the needs of students and families and the school's core 'instructural' programing.

This bill also calls for the establishment of the community schools unit and lays out the unit's responsibilities related to the provision of support to participating community schools.

I'm also pleased to add that this bill will establish a community schools network. The network will provide any public school interested in exploring the community school model and philosophy of practice with access to planning information, tools, study sites and a range of professional learning and training events and opportunities. The community schools unit will co-ordinate and maintain the community schools network.

The bill will establish a deputy minister's committee on community schools to provide overall direction to the program. Working collaboratively around a common agenda, the committee will help to provide timely responses to emerging issues, more effective policy and program alignment, efficient use of resources and stability for the long-term partnership development. A community schools advisory committee, also set out in the bill, will further strengthen the work of the community schools unit and the deputy minister's committee by providing guidance around program planning and the identification and provision of community assets and resources.

The Community Schools Act will help schools to better support students' educational success, break–build stronger families and improve communities all across our province.

Thank very much, Mr. Speaker, and I encourage all members to support the passage of Bill 12.

Ms. Melanie Wight (Burrows): Mr. Speaker, I am honoured to be here today speaking on Bill 12, The Community Schools Act, and I'm proud to be part of a government that has the vision to have come up with this originally and looking at schools as a community centre almost.

And it's just–I have one in my area, and it's called the Elwick village Community School, and the principal there is a woman by the name of Verland Force–and that, Mr. Speaker, is a fabulous name for her because she is completely a force in that community and a force for good along with all the people that work with her. And that school is the perfect description of a hub. It is just always full of activity and fabulous things going on in the community, and it has become a place of real trust for the community and it's a very diverse community.

So building trust within the community groups and all the different combinations of people that happen to live there hasn't been an easy thing, and I think that that–making that school a community–of a community school has really worked towards that goal of having everyone in the community working together for the betterment of the kids in their area, and it's pretty impressive.

We have, I think, spent about $841 million in public schools, in capital in schools, and so I think it's so important that we really be making use of those assets, Mr. Speaker, to their fullest. And that is a piece of what this act is about. It helps our schools really reach out to the communities. This one's going to include having a liaison worker assigned who's going to be working to do that, to really be reaching out and making sure that those assets that Manitobans have invested in are being fully used.

They're not just being used from 8 o'clock in the morning 'til 4 o'clock in the afternoon. They're going to be used in the evenings and on the weekends, and I just can't think of a better way to make use of those buildings to be reaching out to our kids in that way.

And it's going to be for so many different things Mr. Speaker. It's not only, you know, reaching out in the area of sports, but it also is adult literacy programs, and I know we have those happening in schools in my community in The Maples. They have them in their school and other different areas where we have adult education going on. We have health and mental health services happening in there, early childhood education programs. Well, of course, you're aware that all the new schools that are built in this province now include early childhood education programs, and we can't stress the importance of that.

And I'm really proud to see that we are a Province that has not been cutting our education. I was just at a meeting last week with one of the school divisions and they were sharing some of the information of what the other provinces are doing. And they have made some significant cuts to education in various provinces throughout Canada. I'm very pleased to see we're not doing that. One of them was they cut kindergarten completely out of the program, and in a time when we are learning more and more and more how important early childhood education is to the future of our children, I'm certainly pleased to say that I'm in a province where I don't think that will ever happen as long as we're in government. And it's just so important to me and to Manitobans.

***** (15:10)

I'd also like to mention just some of the things that we've done, in addition to this, that show our commitment to the children of our province. And one of my favourites is the K-to-3 classroom sizes because that is one where we know the effects of that added attention and how important it is to the future success of our children. And so, I think it's an investment where we're going to see returns well beyond anything that we can imagine as we start doing those kinds of things in education.

I love the legislation to keep kids in school until they're 18, Mr. Speaker. I think it's just tremendously important, again, to the future of our youth and really helps people find creative ways to work with kids and find what their area is that they're going to really excel in, and I think keeping them those extra years is really, really 'verly' valuable.

So, I would just like to again state how excited we are about this act, and pray it will go forward.

Thank you, Mr. Speaker.

Hon. Kevin Chief (Minister of Children and Youth Opportunities): Just like to say it's an honour to put a few words on the record on The Community Schools Act. There's a–there's, of course, many things I could talk about of the importance of the–of a community schools, but there's a–three, in particular, that I'd like to highlight and share. We, of course, are seeing how incredibly diverse classrooms are becoming, how incredibly important schools are becoming, particularly for young people that come that have, maybe, socioeconomic barriers, who maybe are–who are new to our country, new to our province. And, you know, schools have become a real hub of activity and a place where, you know, families really feel a strong sense of belonging.

And as we look at the importance of schools in our community, teachers and educators and people that work in our communities talk about the importance of young people being able to connect in–with a enriched curriculum, Mr. Speaker, and how important school projects become. So, you know, point 1 is when we have community schools that reach out to the community and bring people in. I think a really good example of that would be the emphasis that we put on the Aboriginal Academic Achievement Grant, where performers can come in, where storytellers can come in.

You know, we can find ways in which to enrich the curriculum. Another good example of that would be in a local school that is a community school working really closely with the University of Winnipeg on a program called the Eco-U on campus, where grades 4, grades 5, grade 6 students actually go on campus and learn science by tenured 'facuty' professors, Mr. Speaker. A lot of them first time being on campus, and they're learning science by professors. This is a really great example of how schools can do outreach with, you know, local and post-secondary institutions. In fact, they–we–we're able to coin a phrase called, a tap on the shoulder, which basically says that all young people, regardless of their background, regardless of they come from, that they should get a tap on the shoulder to say post-secondary is for you. We're not waiting 'til, you know, grade 9, 10, 11, 12 to give young people a tap on the shoulder; we're starting that at grade 4, starting that at grade 5, starting that at grade 6, so that teachers and educators can work in partnership with non-profit organizations in partnerships with our post-secondary. So we're able to enrich the curriculum, highlight some of the very unique things going around and–with school projects on highlighting diversity.

Number 2, the other thing that community schools really puts a lot of emphasis on is this idea for unique programs. Someone like myself, Mr. Speaker, when I was in school, I had a natural draw to sport, and so I was able to, you know, join the cross-country team, the volleyball team, the basketball team. And so there was a natural structure there for me to participate in because of my love for sport. But for a lot of young people that may have low self-confidence, low self-esteem, that might not've had the enrichment opportunity because their mom and dad might not've been able to afford to put them in, they need some unique programs to build their self-confidence and self-esteem. And we're seeing how much work that we're seeing around, you know, cultural programs, recreation programs, leadership programs and a lot of that exists in the community. Now, often what can happen is we want to make sure that young people that are in school can connect to those programs, and school and these partnerships, the community schools, can start connecting these programs with schools, Mr. Speaker.

You know, I was just very proudly able to announce our After School Leaders program. It's a great example how–of how Community Schools Act is going to be very supportive. You have a private sector, the Winnipeg Jets True North Foundation, working in partnership with the Winnipeg School Division, in essence to start five local high schools puts an emphasis on mentorship, leadership, you know, employment opportunities. There is a big impact on that work in the classroom because it's a partnership with the schools, Mr. Speaker, and the big thing is is that we're starting to connect these things. We understand that young people that are involved in positive things outside the 'clashroom' has a direct impact on what happens to them inside the 'clashroom.'

The community schools are saying that it's a great hub of activity to take a non-profit organization, a private sector organization, and match it up with what's going on in the schools. When you have administrators, principals, vice-principals, you know, promoting the idea of schools, the idea of community to teachers, teachers promoting that to their students and then students promoting that to their families what you do is you do get academic achievement, you do increase the ability for young people to learn, develop and grow. And so, when we're able to provide these unique programs what ends up happening, Mr. Speaker, is young people, through their communities, start develop a level of self-confidence and of self-esteem that they start to try out for school sports teams, they get more involved in leadership, they get more involved in cultural programs connected to their school community. So being able to bridge that gap is going to support some of the young people who may be, at times, struggling to have that self-confidence to try out for mainstream school activities.

And No. 3, Mr. Speaker, it puts a lot of emphasis on the idea of parents, caregivers, people who really care about their children or care about children doing well in school. We understand how important it is to make sure that, you know, parents are going out to parent-child–parent-teacher interviews, they're involved in their child's educational career. And sometimes there needs to be some additional outreach. Sometimes there needs to be some additional support. Sometimes barriers need to be removed to help with that. Some of our parents, some of our grandparents don't always have the best experiences at school when they were young. And so, the idea of community schools is going to help parents and caregivers and older brothers and sisters and aunties and uncles get a sense of belonging within the school community.

You know, some of the other pieces why this becomes so important, Mr. Speaker, is that we want to make sure that young people in our province that we're able to develop their talents, develop their gifts. A great example of this is is I always share the story of I Love to Read. And, you know, I Love to Read is one of these things that we do together in the country where we get role models to come out and read to children, and the idea is that you can read to kids and you inspire them to want to read and the idea of a role model is anyone who can create and influence change–that's what a role model is. And so, one of the things we do in public ed every year in February is we get people to come out and do I Love to Read. I'm a former basketball player, and so I always used to get asked to do this as a basketball player. Now, being in politics, of course, and being someone who worked in the community, I always get asked to go and read to kids and tell them how important that is.

Well, every year, Mr. Speaker, I always bring a young person with me. This past year, I brought a young girl–she was 14 years old. Her name is Jessica. She runs–she looks after young people as part of summer employment. And I got to read to some students, and I got to read a book and I brought Jessica to read a book. And we both read to these kids.

The great thing is about when you read to children, grade 1s, grade 2s, grade 3s, they all sit down and you read to them and you ask them do you have any questions after you're done reading. All their hands go up. They all have questions for you. Often, they don't ask you questions anything to do with what you read to them, but they got a lot of questions for you. So I read the book because I was invited as the role 'moder'–role model, and I brought Jessica with me, who's 14, so we asked all the kids: You have any questions? All the hands go up. Eight out of 10 questions, they don't ask me; they ask Jessica. And they ask Jessica because she's younger, because they see Jessica as someone they can relate to. Now, if a role model is anyone who can create, influence change, well then who's the more effective role model, me or Jessica? Well, clearly these kids are asking her because they look up to her. That's how you create and influence change.

***** (15:20)

Community schools, what it does is it gives Jessica the structure to be able to inspire children to read, to inspire young people to do good things, to do positive things. What it does is it removes barriers for Jessica so she can actually go out in the community and develop her skills and develop her talents. It also is going to allow young people like her, through a variety of activities and initiatives, to give back to her community. And I've said here many times that we should be defining generosity by not how much money you have, but your ability to give up something that means a lot to you: your ability to give up time. And there are thousands of young people in our province, Mr. Speaker, who may not have a lot of money, but they're always willing to give up their time. They're always willing to volunteer. They're always willing to do things to make their community better. This–The Community Schools Act will allow young people to be able to do that.

What it does is it not only builds a strong structure for people to do that, Mr. Speaker, but it puts in good supervision. It puts in that type of mentorship we need. You know, teachers are some of our most powerful role models. So the supervision is there. It also is going to build skills of young people. That's the importance of mentorship and leadership and those types of things.

Mr. Speaker, so I'm very proud of the commitment of our government on The Community Schools Act. I know that it's going to continue to build a lot of partnerships. It's going to maximize the services and resources within our neighbourhoods and our communities. It's going to support young people who may have barriers, particularly young people who come from backgrounds of, you know, low socio-economics. And so very proud of this bill that I'm proud to be able to stand and put a few words on the record.

Thank you, Mr. Speaker.

Mr. Matt Wiebe (Concordia): I'm thrilled to stand to speak to Bill 12 and to this exciting piece of legislation that we're moving forward with. So I'm also very proud to be following the Minister of Children and Youth Opportunities, and I think some of the points that he made with regards to the work that he's doing in his department and the initiatives that they're taking and how that fits in with this particular piece of legislation, I think, is exciting work. And I think there's a lot of opportunities there that we need to explore.

I don't think you'll get much debate on the idea of education being an integral part of our success in this province and an integral part of how we see our future going forward, but it is interesting to note that we're putting in the investments necessary to see those things through. And there certainly was a time when that was a very different story here in Manitoba, but I digress and I won't get too far down that road.

But I do want to, in particular, speak to this bill, because it's something that I do have knowledge about and some experience with, the community schools model, and it's a model that I've seen in action and I've seen how it can affect families and how it can affect the students and really change how a community sees itself and how it can see itself moving forward and how it can see itself building it–going into the future.

In my community I have a community school, and it's a place where we have some of the best educators. We have some of the best programming, and with the community schools framework around it are able to connect those resources to, frankly, the kids in my neighbourhood that do need it the most and the families that need it the most. It's really building a hub and it's building an access point for families and for students that, you know, frankly we sometimes think that the programming that we do, you know, it fits a certain need or it fits a certain segment of the population. But sometimes they have trouble accessing that and I think that's what the community schools–this is where it's been unique and successful in that it brings those programs down to the level of the folks in the community.

So, you know, the students are already spending their time in the classroom and in the school setting, and by offering those programs to the students and through the students to their parents makes all the difference for how the folks in the community can then see that programming.

And, again, you know, I talk a lot about the idea that we sometimes as legislators are at 30,000 feet, you know, and we're looking at the community and saying, well, this is a good program; this fits this need and this will address this particular problem. But unless that actually connects with families and that actually connects with the people that need it, we're not going to be successful.

Mr. Mohinder Saran, Acting Speaker, in the Chair

So I think that's what's the key in this particular legislation and how it will be successful going forward. You know, we talk about how the programming–how the–we want to connect folks to the programming, and it's not just, you know, what's happening in the classroom and it's not just what's happening even before and after school, although those are very particularly important programs. But it also connects people with adult skills training. It connects people with the financial literacy training that's so important, to nurse practitioners and to the health of the community, and it really gets them to the level where they can start seeing how they can help their own community and they can feel strong and they can feel a sense of identity.

One of the most successful programs in particular in my neighbourhood has been–it has an Aboriginal focus and it's been connecting the parents and the students with teachers around that–around their Aboriginal heritage, and it brings them together, allows them to discuss issues in that context. It allows them to feel community and build community based on that common thread, and it helps them develop what our programming will look like going forward. So we're getting feedback from what's happening on the grassroots level and it's coming back up into the programming, and we know that this is stuff that's working and it's working to make the lives of families better.

But, you know, I think really what the purpose of this legislation is, is to say that this is just the beginning, that we've seen how it can work but that there's so much more potential, and so I'm so proud to see that we're putting the resources in that will make that difference, that we see that it will go to the next level, that we will have dedicated folks within the schools to see this programming connected, and also an oversight–a general oversight to get this programming, continue it and to make it–keep it going forward.

So, with those few comments, Mr. Speaker, I appreciate the opportunity to speak to this legislation, and I commend the Minister of Education (Ms. Allan) on her initiative in bringing this forward and on continuing to move Manitoba forward in this regard.

Thank you, Mr. Speaker.

Mr. Kelvin Goertzen (Steinbach): I move, seconded by the member for River East (Mrs. Mitchelson), that debate now be adjourned.

Motion agreed to.

The Acting Speaker (Mohinder Saran): Now we are going to move the Bill 9, the Teachers' Society amendment, second reading.

Bill 9–The Teachers' Society Amendment Act

Hon. Nancy Allan (Minister of Education): I move, seconded by the Minister of Entrepreneurship, Training and Trade (Mr. Bjornson), that Bill 9, The Teachers' Society Amendment Act; Loi modifiant la Loi sur l'Association des enseignants du Manitoba, be now read a second time and be referred to a committee of this House.

Motion presented.

***** (15:30)

Ms. Allan: The Manitoba Teachers' Society has requested of government that certain amendments be made to The Teachers' Society Act. This request came to government following the society's most recent annual general meeting where proposed changes to the legislation were discussed and endorsed by their membership.

Mr. Speaker in the Chair

While it is important to note that the changes in the bill do not impact the department's responsibility for the certification of teachers–in other words, the authority to set the requirements necessary to grant a licence to teach as well as to remove that licence in appropriate circumstances–they do enhance the capacity of the society to perform its critical function of establishing, maintaining and enforcing standards of professional conduct and a code of conduct for its members. The changes to the legislation expand the range of penalties for members who, following an investigation and hearing, are found to have engaged in unprofessional conduct or conduct unbecoming to a teacher. In addition to the current provisions enabling the review committee to admonish or censure a member or recommend to the minister that the member's teaching certificate be suspended or revoked, it can also direct that a teacher be suspended or terminated as a member of the society or impose such other penalty as the bylaws of the society may prescribe. Importantly, the bill also sets out that the society, again, through its bylaws establish a process whereby a teacher whose membership has been terminated may be reinstated.

To this point, the cost of an investigation and hearing on an allegation of unprofessional conduct have been borne entirely by the society. The society has expressed the view, supported by its membership, that if a teacher is proven to have engaged in unprofessional conduct, it is reasonable for that teacher to bear some portion of the costs if so ordered by the review committee. Therefore, the bill enables the review committee to order the payment of costs up to a maximum of $5,000. Further, if it becomes necessary to do so, the bill allows the society to file an order for payment of those costs in the Court of Queen's Bench, which then allows for enforcement of that order.

I support the society's request and believe the changes are reasonable and sensible. Parents, students and community members and, of course, teachers themselves believe that high professional standards are critical in the vocation of teaching. This bill enhances the capacity of the society to address issues of unprofessional conduct in a more comprehensive way. The government supports this endeavour and commends the Manitoba Teachers' Society for taking these important steps to ensure the highest professional standards. I recommend to the House that Bill 9 be supported and passed.

Thank you very much, Mr. Speaker–Deputy Speaker.

Mr. Kelvin Goertzen (Steinbach): I move, seconded by the member for Midland (Mr. Pedersen), that debate now be adjourned.

Motion agreed to.

Mr. Speaker: We'll now call Bill 14, The Education Administration Amendment and Public Schools Amendment Act (Parent Groups for Schools).

Bill 14–The Education Administration Amendment and Public Schools Amendment Act (Parent Groups for Schools)

Hon. Nancy Allan (Minister of Education): Mr. Speaker, I move, seconded by the Minister of Finance (Mr. Struthers), that Bill 14, The Education Administration Amendment and Public Schools Amendment Act (Parent Groups for Schools); Loi modifiant la Loi sur l'administration scolaire et la Loi sur les écoles publiques (groupes de parents œuvrant en milieu scolaire), be now read a second time and be referred to a committee of this House.

Motion presented.

Ms. Allan: Education is critical to the future success of our children and our province, and we all collectively play a part in it. No one, Mr. Speaker, plays a more important role than that, of course, of parents. Parents act as first teacher and because of the bond which they share with their children are intimately invested in their educational well-being. Studies have shown that children perform better academically when their parents are active and supportive in their children's school and in their learning. Support for the classroom teacher and school administration, advocacy as appropriate, and participation in school-based decisions through parent groups are all ways in which parents shape and improve the learning experience of their children.

Bill 14 addresses the formal role parents can and do play in schools. To begin, the bill recognizes the Manitoba Association of Parent Councils, MAPC, as the representative organization for school-based parent groups for school divisions other than the Division scolaire franco-manitobaine, the DSFM. The Fédération des parents du Manitoba, the FPM, is the organization representing the interest of parents in the francophone community. I am very pleased to make reference in legislation to MAPC, as this organization has, through the dedicated efforts of its executive and administrative staff, expanded its number of member schools, provided helpful resources to parents, given constructive advice to parents through its advocacy project and been an important resource to me in helping inform my perspectives and decisions related to the K-to-12 public education system.

I'd like to express my thanks to the president of MAPC, Judith Cameron, her executive and the executive director, Naomi Krause, for the ongoing good work of the organization. This bill will set out the requirement of the minister to meet with MAPC at least annually, something which I enjoy doing every year.

I must also say how appreciative I am of the contributions that MAPC makes at the provincial oversight committee. Along with all of our other education stakeholders, MAPC's perspective has been so helpful in our deliberations regarding the new provincial report card that has been just sent out to all of our schools for the first time in the history of this province. And I have to tell you, the feedback that we are getting back on the provincial report card is wonderful at best. At–they are also sitting on our committee now to help us in our deliberations around the kindergarten to grade 3 class-size initiative, and I know they will make a huge contribution as we move forward with the–our class-size initiative.

Bill 14 also formalizes at the school level the role of the parent council in the development of the annual school plan. Where a council exists the principal of the school will consult with that group on the plan's preparation. The bill so–also sets out the role of the principal in providing to parents information on the role and function of parent groups, the manner in which one may be established and the right of parents to become a member of such a group. I am gratified by the knowledge that this already happens in many of our schools, with principals taking a proactive approach in providing information to parents and encouraging their participation and support.

Mr. Speaker, children do better in school and our education system is strong when parents are actively engaged as partners in education. This bill recognizes the good work of MAPC in supporting parents at the school level and encourages greater parental involvement. And I am pleased we are debating this bill on the very day that my colleague the MLA for St. Norbert did a member statement recognizing the Chancellor School Advisory Council for their contribution to the enhancement of the education experience. When parents are involved in their schools, everyone does better.

I support wholeheartedly the amendment sent out in Bill 14 and recommend their passage to this House. Thank you.

***** (15:40)

Mr. Dave Gaudreau (St. Norbert): Well, Mr. Speaker, it's a great pleasure to rise today in support of this and to talk a little about parent advisory councils.

Earlier on today, I had a member from my parent advisory council from Chancellor School here in the gallery and was able to present her with a nice plaque on the words that I spoke about, how important the parent advisory councils are in our area.

Last year, parent advisory council at Chancellor, they raised money to create an accessible playground for some of the children in the area who are bound to wheelchairs. So that council has taken on roles in the community of looking at what is good for everyone and they're teaching social responsibility to their children who go there. And they involve–not only did they involve the school administration, they involved all the children in the school in this project, too. So the children are learning that there's great things that can be accomplished when we all work together.

I also want to recognize that Bonnycastle School, which is in my area, has another fantastic parent advisory council. And through the work that I've been doing with them and they've been doing with the school division and the school, we had a great announcement a few weeks back with the Education Minister and the Premier (Mr. Selinger), so we're going to be doing a eight-classroom expansion, which is a part of our commitment towards lower classroom sizes on the K-to-3 initiative. And we're also adding into that, we're adding a daycare facility–74-seat daycare facility in the area, which is a fantastic announcement for the area and for the school.

And all of that is made possible through partnerships with these advisory councils letting me know and letting the trustees know what's needed for the area. So these councils are very important for all of us.

I have another great council in the area at Parc La Salle School, and this weekend I had the honour of working their breakfast with Santa. I worked the door and sold tickets to everybody as they came in and had breakfast with Santa. And all of the kids of the area come and get to sit on Santa's lap and get to tell him what their wishes are for Christmas. And that advisory council is so active in their community and they raise money every year for great projects like a gardening project that they're going to be doing this next summer. That council is one of the fun ones that I get to work with in the area.

Also La Barriere Crossings, their advisory council there, the principal there meets with everybody once a month and asks the parents what they'd like to hear on topics that are related to the school. And every month she presents them with things that are going on in the school. Great information for the parents and for myself to hear, in the school and in the community.

So these kinds of groups are really important, and I'm confident that the opposition is going to come forward and support this because they had that speech about how great volunteers are and how, you know, they were pointing out all the volunteer organizations in our communities and how much money they've raised and how fantastic it is that we have all these organizations and all these volunteers. So these parent advisory councils are just another step–they're another part of all these volunteers that do great work in our community.

Now, it's interesting because today in the paper we reported that they're having–themselves, having trouble finding volunteers for any of their stuff. It doesn't seem to be that way in the Pembina Trails School Division; we have fantastic volunteers that come out and all of the school division volunteer groups are fully–every seat is fully filled and they're a fantastic group of people. So, maybe I'll work together with the opposition and see if some of those members can come out and work with them to do some of the literature jobs that they're desperately needing.

But, you know, I just think it's very important that we recognize that these people are absolutely the cornerstone of our schools, and working with them and the parent advisory council and the principals, and all of the vice principals and all of the teachers in the school, we can make the–great things happen.

I mean, if you look at what our policy has been over the last 12 years, we've been growing schools. We're–actually had a great announcement where a school is going to be built in the Leader of the Opposition's riding. It's too bad he didn't attend, but I was there, because, you know what, it's important for Manitobans; it's important for everybody. So, you know, I decided to attend even though that he decided not to be there. We're going to be putting $28 million into a school in the opposition leader's–of the opposition's riding. I think that just shows what caring and great education system we have.

We're also going to be building a new school at some point in the future in Bridgwater–point–sorry, Pointe West area. And–you know, and I'm committed to working with the community on that.

And we're going to move along and keep building towards new schools and education, as opposed to in the '90s when we saw rollbacks of 6.6 per cent, Mr. Speaker–6.6 per cent rollbacks. Schools were, you know, being closed, education was not important. So, you know, if we want to do a contrast, I'm sure that the Leader of the Opposition will stand up and support this bill, even though he didn't stand up and come out for his community on the day that the announcement was made for a record investment in his community of $28 million in a brand new school. Which, Mr. Speaker, I might add, also includes another 74 daycare spots, which is a total of 148 new daycare spaces in our area, partnered with education. *[interjection]* Thank you. This is fantastic news for the south area of the city, and, you know, if the member for the opposition, if the leader, doesn't know about these things, I'm glad to inform him because I go to those meetings. I can totally tell him anytime something like this comes up. Glad to work with him, you know. *[interjection]* Yes, it's fantastic, Mr. Speaker.

We're not–you know, we're not cutting things. We're actually building our province. We're growing on education. We're growing the capacity to teach our kids. We've got great things going on, and these parent advisory councils are just one other aspect of how we can all work together to make our communities better. And every one of these councils in my area is fantastic to work with. They are all have such a commitment to the school and to the education of their children. You know what? Some of the students as they move along to other schools their parents still sit on those councils because they believe so much in what is going on in the community. So we have to give them absolute credit for being there all the time even once their children have moved along to other schools.

So it's with great pleasure that I stand up here to support this parent advisory council bill. And I think that, you know, one of the greatest things that we do in our society is educate our children, and it's towards the future of everything that our province is building for. If you look at all of our jobs that are coming up, all of the economic growth and development, all of this stems back from the fantastic education system that we have and how we're going to train those workers for tomorrow. So, with that, Mr. Speaker, I support this motion and I thank you very much.

Mr. James Allum (Fort Garry-Riverview): It's always an honour to get up and speak in the House, and it's always an honour especially to get up and speak in support of bills aimed at education in our province. And I'm honoured to work with the Minister of Education (Ms. Allan). She is a change agent for a progressive education system in the 21st century here in Manitoba, and Bill 14 is just one example of many examples that we will bring forward–certainly, talk about–myself, in the next few minutes, about our government's contribution to education in Manitoba.

Now, I think I've told the House about all they really want to know–all they want to know–about my own educational background. I did end up spending a lot of my teenage years and then my adult life in academic institutions–was lucky enough to get a Ph.D. and also lucky enough to do that when I was raising my own three kids. I come from a school of teachers–a family of teachers, Mr. Speaker. My oldest sister, who's almost 14 years older than me, was teaching grade 1 when I was in grade 1 and so that was always useful; I actually brought her home information that she could use in her own classes that I'd learned that day myself. Also, my older brother taught English in southern Ontario for nearly 30 years and is a fantastic teacher. And then I'm also proud to say that my own oldest daughter, who's now 25–I can hardly believe it, is a teacher, and she's teaching in Kuwait right now, but she's got both languages. She has French immersion; she learned that here in Manitoba's great education system. So I'm always proud to get up and speak to matters that relate to public education in Manitoba.

And when I look back at our record on education since we've been in government in 1999, I'm just blown away at the things that we've been able to achieve. We believe in a balanced approach, and I think everyone knows that. I–certain that the members opposite are becoming more and more aware of that particular phrase. They operate in an imbalanced kind of way. But funding for schools has increased at or above the rate of economic growth for the last 13 years. That's a pretty remarkable statistic considering the uncertain economic times that we live in. So that increase is all–actually over 53 per cent, or more than $411 million has been added to the public school education budget since 1999. I think that's really remarkable. And then on top of that is another $841 million has been invested in public school capital projects since 1999, as the member for St. Norbert (Mr. Gaudreau) just indicated. We continue to build educational institutions. We continue to make sure that they have child-care centres associated with them. What we want to make–do is make sure the children of all Manitobans have an opportunity to get the full value of their education.

***** (15:50)

Our grad–as a result of this investment, Mr. Speaker, our graduation rates have increased to 83.5 per cent, as of 2011, from 71 per cent in 2012, which, to help with math on that side of the House, that's a 17 per cent improvement since 2002.

But, then, if you look at those are just the statistical financial issues, then you look at sort of the quality control that also goes on in schools: commitment to reduce K-to-3 class sizes to 20 students by 2017–fantastic commitment on our part; legislation to keep kids in school until they're 18–another fantastic piece of legislation on our part, to show them that education matters and that they need to stay in school; a new parent-friendly plain language report card. And I know that when I was a parent and my kids were coming home with their report cards, and they were all doing fantastic, I'm sure, I often didn't understand what they said, so a plain-speaking, plain-language report card can only enhance parents' participation in the education of their own children.

We've come up with common in-service days within school divisions to help families co-ordinate their busy schedules; God knows with three kids, and I think others would understand that as well, we'd come home after a day of trying to organize how their life went and then we'd find out that there was teachers' day the next day and have to organize all that. So we've done practical, simple things that make–improve the quality of education on the one hand, but make life better for families on the other. And that's the whole objective.

Now, education is a–partly about making sure that we have sustainable economic growth in the future. Education is also about expanding the knowledge base among our–among Manitobans. But, more than that, education is about building citizenship, participation in the community. We're more than just taxpayers here in this province. We are citizens of a greater community, and education teaches us quite a bit about what we can do from a citizenship point of view.

So Bill 14 is in that vein. It tries to encourage a more parental participation that is already going on in schools to this day, and last week I had the opportunity to go to a Winnipeg School Division No. 1 meeting that brought parent councils together with school trustees and, frankly, MLAs from this side of the House. I don't see anybody from the other side of the House at the meeting; perhaps they were there. I know my friend from Burrows was there. It was very educational. And from–

An Honourable Member: Tyndall.

Mr. Allum: From Tyndall Park, of course, my friend was also there. We sat together with parent councils, with administrators, with teachers, with principals, and we talked just about what we should be doing to advance public education here in Manitoba.

It was a fantastic meeting and quite valuable, and I was proud to be there with my colleagues as well as members from parent advisories–councils in my constituency. And I've had the pleasure, Mr. Speaker, of going to all the parent advisory councils at the schools–I think there's 8 or maybe 9 schools in my constituency–and I'd met with these folks and I'm just in awe of the work that they do. They not only do the school lunch programs, which are fantastic from a nutrition point of view, make sure every kid's got a full belly to go on learning during the day, they do fundraising activities to support school trips and other enhancements at the school, and then in addition to that, they're all involved in school transformation, school playground transformation projects that just blow you away because it's no longer just thinking of that asphalt pad outside the school where kids are supposed to go for recess. Now we think of those as actual schoolrooms, as places to learn and to grow and develop.

And so, when I see the work of parent advisory councils and the work that they do throughout the full school day and on behalf of schools, I'm just blown away by their contribution to the welfare of our communities.

And so Bill 14 tries to enhance what's already going on. It recognizes the Manitoba Association of Parent Councils, or what we call MAPC, as a representative organization for school-based parent groups for all English-speaking school divisions, and I think that's fantastic.

In addition, it also–Bill 14 formalizes the role of the parent council in the development of the annual school plan. And so where a council exists at a certain school, the principal of the school will consult with that group on the plan's preparation, and what I really like about that is that it gets parents involved, not just in fundraising activities which are absolutely incre–important, but in terms of their participation in the annual school plan. And I think that that's just something that makes all the difference in the world. Parents feel like they're part of the school. Kids feel, obviously–are part of the school, but they feel like their parents are engaged, and it makes a real difference in the attitude that the student has each day to be willing learners.

So Bill 14–and in giving more roles to the parent advisory groups, certainly recognizes the role and function of parent groups, the manner in which they'll be established and the right of parents to become a member of such a group. And if I could make any suggestion at all, it's to make sure that more parents become part of parents advisory groups, to take full advantage of that opportunity to be an important player in what the school's doing and also to send a clear signal to your son or daughter that education matters.

Education certainly matters in this–to this government. We've been leaders, not only in Manitoba but across the country, in public education. I'm pleased today, Mr. Speaker, to stand and support Bill 14.

Thank you.

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, I move, seconded by the member for Spruce Woods (Mr. Cullen), that debate now be adjourned.

Motion agreed to.

Hon. Jennifer Howard (Government House Leader): Mr. Speaker, will you please call second readings on Bill 8 and Bill 10.

Mr. Speaker: We'll now call second reading on Bill 8, The Provincial Court Amendment Act.

Bill 8–The Provincial Court Amendment Act

Hon. Andrew Swan (Minister of Justice and Attorney General): I move, seconded by the Minister of Advanced Education and Literacy (Ms. Selby), that Bill 8, The Provincial Court Amendment Act; Loi modifiant la Loi sur la Cour provinciale, be now read a second time and be referred to a committee of this House.

Motion presented.

Mr. Swan: This bill will provide for the use of electronic documents in the Provincial Court. The Criminal Code of Canada, the federal law which governs criminal matters, allows the use of electronic documents in relation to matters under that statute, provided their use is in accordance with either the rules of the Provincial Court or an act of the Legislature. This bill will enable their use for Criminal Code matters as well as matters related to other provincial or federal enactments. This bill will support ongoing work to develop and implement an electronic system in court and eliminate most of the paper processes currently used by the Provincial Court.

Mr. Speaker, the Provincial Court is a very busy court. It handles the vast majority of charges–in fact, 97 per cent of charges moving through the criminal justice system. Currently, almost the entire process is paper-based. Moving to allow the acceptance of electronic documents in the court system will increase the efficiency of our courts, our police and other law 'enforshment'–enforcement officials and other partners in the justice system, and will continue to modernize and streamline the justice system. Eliminating paper will streamline the criminal justice system and significantly reduce its paperwork.

This amendment specifies that electronic documents may be filed with and created by the Provincial Court. The amendment also specifies that if a document is filed and is required to be signed, an electronic signature–a secure electronic signature as specified in the regulations–will be considered valid. Scanned documents can also be received and used to process matters in Provincial Court.

This is one of the many measures we're taking, Mr. Speaker, to innovate and streamline our justice system. We've worked with many partners across the system. We've assisted our police through investments in things like the police cadet program, through the helicopter, through amendments to amend Manitoba Public Insurance legislation to free up officers from having to take reports which would only be duplicated at MPI sometime later.

We've also worked within the court systems to make sure that we're getting the most we can out of the individuals who work very hard within that system. As many will know, we have a new director of innovation who's been working very hard with our partners to find different ways that we can streamline things and move things more swiftly through our justice system.

When we do things, Mr. Speaker, we intend to do them right, and we're moving ahead on this measure to reduce the amount of paper flowing into our court system, make sure that matters aren't delayed or that documents aren't misplaced. And I can advise this House, there will be many other advancements on the justice front to come, as we continue to build a better, stronger and swifter justice system.

So, Mr. Speaker, I do look forward to the support of this House in having this bill passed.

Mr. Reg Helwer (Brandon West): I move, seconded by the member for Spruce Woods (Mr. Cullen), that debate be adjourned.

Motion agreed to.

* (16:00)

Mr. Speaker: We'll now call Bill 10, The Correctional Services Amendment Act.

Bill 10–The Correctional Services Amendment Act

Hon. Andrew Swan (Minister of Justice and Attorney General): I move, seconded by the Minister of Entrepreneurship, Training and Trade (Mr. Bjornson), that Bill 10, The Correctional Services Amendment Act; Loi modifiant la Loi sur les services correctionnels, be now read a second time and be referred to a committee of this House.

Motion presented.

Mr. Swan: This bill seeks to clarify the authority to intercept, monitor and restrict inmate communications in provincial correctional facilities. This will enhance the security of those facilities while at the same time enhance public safety. Now, I know we will have the opportunity to discuss the bill in more detail at the committee stage, but there are some important points that I'd like to bring to the attention of honourable members.

Mr. Speaker, the control of inmate communications is a vital aspect of institutional security and public safety. It is necessary and desirable for incarcerated individuals to be able to maintain communications with people in the community, be they friends, family members or legal counsel.

However, it is also necessary to ensure that inmates do not use the available communications systems in our correctional centres to plan or commit illegal acts or to carry out criminal enterprises while incarcerated. Such acts, of course, could affect the security of the correctional facility, including attempts to introduce illicit drugs or other contraband into facilities, or they may be directed at members of the public, such as attempts to threaten or intimidate domestic partners, witnesses and victims. They may also attempt to contact individuals, including former domestic partners, in violation of court orders made against them, and because of this it's essential that correctional authorities have clear authority to control inmate communication.

Mr. Speaker, this bill provides corrections officials with the clear authority to intercept all inmate communications, and where reasonable grounds exist to do so to monitor and restrict those communications. The bill also describes clearly what constitutes these reasonable grounds as well as protecting privileged communications such as communications between inmates and their legal counsel from interception or monitoring.

In addition, Mr. Speaker, this bill includes provisions for more detailed regulations with respect to the control of inmate communications including the handling, retention and disposal of inmate communications as well as the various procedures respecting the interception, monitoring and restriction of inmate communications. The control of inmate communications has proven to be an effective and essential means of protecting institutional and public safety, and this bill will enhance the ability to do so.

I do want to take a minute to thank the individuals who work on our correctional system. It is not an easy job that they do. We know that there are certain challenges, and I know that our correctional officers continue to meet those challenges to a high degree of–in a very professional way.

So, Mr. Speaker, I look forward to the support of this House in having this bill passed.

Thank you.

Mr. Reg Helwer (Brandon West): I moved– *[interjection]* no, sorry. Oh–

Mr. Speaker: All right, I'm sorry, the honourable member for St. James.

Ms. Deanne Crothers (St. James): Thank you, Mr. Speaker. My apologies.

I'm happy to stand and speak in support of Bill 10, correctional services amendment. As the minister stated, this bill is designed to create greater protection for the public by preventing incarcerated criminals from continuing to harass the public from jail. As some of their behaviour has led to being convicted of a criminal offence while free, it is reasonable that we would not allow that same type of behaviour to continue while serving their time.

If there is a belief that an inmate is using a call for criminal activity or harassing partners, victims, witnesses or the general public and reasonable grounds for this have been established, corrections officials can monitor or listen in to the call. Inmates are notified that telephone calls may be monitored, however, some calls considered privileged communication won't be, such as a call between a lawyer and client. This amendment still respects the need and right for privacy, but not at the expense of a victim of a crime or abuse. And speaking of expenses, the cost associated with amendment is cost neutral.

What I find particularly satisfying about seeing this bill in the House, is that it complements our provincial domestic violence strategy so well. The work that we have done to decrease domestic violence will be enhanced by this amendment. That strategy was developed with input from province-wide public consultations. With the public's guidance and input, we have created the strategy which Bill 10 supports.

Women who are caught in a cycle of abuse with a partner, who have found the courage to press charges, may find that their abuser can continue to harass and intimidate even after they have been arrested and placed in jail. It is difficult to prove that someone is harassing you under these circumstances, and I suspect many women or victims of a crime who have found themselves in this type of situation would likely feel unable to prove definitively that this is taking place. Likely, they have simply tried to cope with it. It seems exceptionally unfair to anyone who has had the courage to stand up to an abuser or someone who has committed a crime against them, only to find themselves still burdened by their dark intentions even if they have been physically removed.

The amendment will allow provincial facilities to have a way to prove that a criminal indeed acting in a way that harms a member of the public and will allow them to stop it by being able to record and listen in on conversations. Where the criminal is co-ordinating with others to act on their demands, we create an opportunity to prove their actions and no longer allow them to continue. It will allow victims of abuse or victims of crime and the public at large to know that justice continues to function as it should for criminals even after they have been incarcerated. Those who most need the protection of the law after being a part of the process as a victim will continue to have the assurance that the person responsible for their abuse or for causing them to be a victim will not be able to continue influencing their lives.

I feel very good about being a member of a party that recognizes and acts on the needs of the public, with the public.

I hope that all members of the Legislature will support this bill. I appreciate having an opportunity to speak in support of Bill 10 and would like to thank the Minister of Justice (Mr. Swan) for bringing this valuable piece of legislation forward.

Thank you, Mr. Speaker.

Ms. Sharon Blady (Kirkfield Park): It is a privilege to put a few words on the record about Bill 10. As someone that has had the privilege and opportunity of working in the larger domestic violence prevention strategy and in the interpersonal violence and technology network, this bill is very significant in what it does for victims. And it balances the need for the privileged communication for those who are incarcerated for what–their rights, but at the same time it provides a protection from ongoing harassment and from the possibility of someone misusing the access that they have to communications to either engage in ongoing illegal activities and/or to continue to victimize members of–whether it's their own family, whether it's a variety of people that can be victimized.

And this legislation is very significant as part of the larger provincial domestic violence strategy. And as part of a multi-year strategy that has been developed with input from province-wide public consultations, research and strategy review committees, this particular piece is one more crucial piece into–in providing peace of mind for victims and giving them a layer of prevention by denying access to them. And then also, at the same time, provides a layer for justice to be able to locate and prosecute those that do engage in that kind of behaviour once they have already been incarcerated and don't necessarily realize the full consequences of their actions and feel that they are at liberty to continue engaging in such negative and destructive behaviour.

So I would just like to thank the Minister of Justice for the work that he continues to do with the Minister responsible for the Status of Women, and the entire team that has been working both in Corrections, in Victims Services, and to the many community partner organizations and shelters, because this is one more piece that helps protect women and other victims of domestic violence.

Thank you very much for your time, speak–Mr. Speaker.

Mr. Reg Helwer (Brandon West): I move, seconded by the member for Lac du Bonnet (Mr. Ewasko), that this bill referred to the committee of this House–*[interjection]*–oh–sorry–sorry, the debate be adjourned. Yes, we're corrected, Mr. Speaker–

Mr. Speaker: It's been moved–

Mr. Helwer: Sorry.

Mr. Speaker: It's okay. It's been moved by the honourable member for Brandon West, seconded by the honourable member for Lac du Bonnet, that debate be adjourned. Is that agreed? *[Agreed]*

Mr. Speaker: We will now move on with Bill 10, I believe. *[interjection]* No, that was Bill 10.

Hon. Jennifer Howard (Government House Leader): Could we move ahead with second readings on Bill 4 and then move to Bill 6 and then Bill 7.

Mr. Speaker: Okay. We'll call bills in the following order: Bill 4, followed by Bill 6, and then Bill 7, starting with Bill 4, The Personal Health Information Amendment Act.

***** (16:10)

Bill 4–The Personal Health Information Amendment Act

Hon. Theresa Oswald (Minister of Health): I move, seconded by the Minister of Justice (Mr. Swan), that Bill 4, The Personal Health Information Amendment Act; Loi modifiant la Loi sur les renseignements médicaux personnels, be now read a second time and referred to a committee of the House.

His Honour the Lieutenant Governor has been advised of the bill, and I table the message.

Mr. Speaker, I need to retract what I just said and start again. I made a mistake.

I move, seconded by the Minister of Justice (Mr. Swan), that Bill 4, The Personal Health Information Act; Loi modifiant la Loi sur les renseignements médicaux personnels, be now read a second time and be referred to a committee of this House.

Motion presented.

Ms. Oswald: When we discuss details about our own health and health care with our doctor or nurse practitioner or any other provider we have a right to know that the information will be kept confidential. Bill 4 will further strengthen The Personal Health Information Act to provide improved protection of patients' private and confidential health information. The Personal Health Information Act, or PHIA as it has come to be known, already provides strong protections for patient privacy.

Under the current legislation, Mr. Speaker, an employee can be charged with an offence and subject to a fine for wilfully disclosing personal health information without authorization. However, if they wilfully access or otherwise use personal health information appropriately but do not disclose it, no such penalties currently apply under the act. We would commonly refer to this as snooping, and, indeed, it is unacceptable.

These amendments that we're putting forward represent a response to recommendations, but made by Manitoba's Ombudsman. The Ombudsman looked at an issue because, indeed, this very situation happened: an employee at one of our organizations, our health-care organizations, accessed the personal health information of a patient when, indeed, they had no business to do so. It was a clear violation of a patient's privacy and it was unacceptable.

Once the amendments are in force, Mr. Speaker, employees will have to ensure that they have proper authorization before accessing someone's personal health information, better protecting people across the province.

In addition, Mr. Speaker, we're also making it a finable offence to knowingly falsify personal health information. This particular notion has been implemented in a few other jurisdictions and we will add this to our legislation as well, feeling that it is prudent to provide even better protection for patients.

Instituting penalties for snooping and falsifying information sends a strong message throughout the health-care system that such actions will not be tolerated. Under the amended act individuals will face a fine of up to $50,000 if convicted.

Mr. Speaker, we must, however, recognize that there are many, many instances where it does, indeed, benefit a patient for someone else to know certain details of their medical situation. Obviously front-line health-care professionals having access to information that directly affects their patient's individualized care and treatment plan is very important and we would not want to stand in the way of that kind of authorized access.

There are also a number of circumstances, Mr. Speaker, where family can and should have access to the health information of their loved ones. We know, in a modern society, that families' loved ones can be very important partners in the care of their loved one. They have critical information to provide to caregivers and in turn, can react to information when it is provided to them about the care of their loved one. We know that when The Personal Health Information Act first came into being, there was something that came to be known as PHIAnoia that developed, and that the system in some respects seized up and was very reticent to share information, even when the sharing of that information was very appropriate and would have resulted in better care for a patient.

We did a lot of work with patient safety advocates, Mr. Speaker, and amended The Personal Health Information Act some years ago to clarify and address what I believe was always intended with the original legislation, thus making it sure that information was protected but indeed that family members and other appropriate individuals would have access to information when it could enhance the care of an individual.

So, certainly, I agree wholeheartedly with what the Ombudsman has suggested to us, which is why we're bringing forward these amendments today, to protect against snooping and against falsifying information, but we want to make sure that we also send an equally strong message, that we need to be partners and we need to share in the responsibility of caring for our loved ones, and that in no way will these amendments cause us to retreat to a time when information was not shared when appropriate.

So with those few words, Mr. Speaker, I recognize the need for protecting that which is most sacred to us, our most private, intimate and personal health information and the details therein, while at the same time ensuring that patients in our facilities get the best possible care from a united, cohesive, collaborative and co-operative discussion about that person's care. Thank you very much.

Mr. Speaker: Any further debate on the legislation? The House ready for the question?

Some Honourable Members: Question.

Mr. Cameron Friesen (Morden-Winkler): Mr. Speaker, I move, seconded by the member for Brandon West (Mr. Helwer), that debate be adjourned.

Motion agreed to.

Mr. Speaker: We'll now move on with Bill 6, The Highway Traffic Amendment Act (Flexible Short-Term Regulation of Vehicle Weights and Dimensions).

Bill 6–The Highway Traffic Amendment Act (Flexible Short-Term Regulation of Vehicle Weights and Dimensions)

Hon. Steve Ashton (Minister of Infrastructure and Transportation): Mr. Speaker, I move, seconded by the Minister of Local Government (Mr. Lemieux), that Bill 6, The Highway Traffic Amendment Act (Flexible Short-Term Regulation of Vehicle Weights and Dimensions); Loi modifiant le Code de la route (réglementation provisoire des poids et des dimensions des véhicules) be now read a second time and be referred to a committee of this House.

Motion presented.

Mr. Ashton: Mr. Speaker, this bill provides more flexible process for short-term variations in terms of permissible vehicle weights on our highways. I think, as members will be aware, this is a challenge at various times of the year, particularly in the spring, and what this is aimed at doing is addressing a number of types of scenarios.

When road conditions permit higher weights, such as early winter conditions, when highway upgrades are completed and emergency situations where detours are necessary due to events such as floods or landslides, and, of course, we've had a significant experience with that, just the last number of years.

Currently, highway classifications and permissible weights on highways are prescribed by Lieutenant Governor-in-Council under the vehicle weights and dimensions and classes of highways regulations; long-term classifications of permissible vehicle weights on highways will continue to be set by these regulations. However, the regulatory process can be somewhat lengthy, in terms of the implementation of increased permissible vehicle weights.

***** (16:20)

These amendments will allow the minister and his or her delegate to issue orders for temporary short-term variations to the permissible vehicle weights on highways or to highway classification. Ministerial orders can be implemented much more quickly than regulatory amendments, reducing any potential delay in the implementation increase permissible vehicle weight. The proposed ministerial order-making powers will be limited to a maximum of a two-year period. Decisions regarding the ability of a highway or a roadway to carry heavier weights will continue to be based on acceptable engineering standards and, of course, road and weather conditions.

Proposed new provisions clarify the ability for the minister and his or her designate to impose spring road restrictions by order and enable seasonal RTAC routes to be established by order, rather than by regulation.

Sessional RTAC routes or highways are currently only classified in the vehicle weights and dimensions, and classes of highways regulations, as RTAC routes from December 1st to the last day in February of every year, after which point, they go back to lower highway classification. This will give greater ministerial order powers and greater flexibility in setting the dates for seasonal RTAC routes.

I do want to note that the Keystone Agriculture Producers have praised this proposed move to a weather-based approach rather than a rigid calendar schedule.

And I know I got the attention of members opposite. I'm sure they'll want to join with us with our continuing partnership with the agricultural community and, in fact, now approaching 13 years of listening to our agriculture community, because I can indicate that this has been a significant concern with our ag producers. They asked for it and we are delivering, Mr. Speaker.

And I want to indicate that this is also reflective of climate change. We're certainly seeing a significant shift, and when these kind of restrictions need to be put in place, we're seeing, for example, in some parts of the province, you know, quite a significant shift to when winter begins and when spring comes. I think everybody in this province, over the last weekend, is certainly aware that winter is with us. And I think that it's important to note that we're anticipating this kind of flexibility will be needed on a greater basis in upcoming years with climate change.

And I do want to indicate that there are amendments that deal with signage, affected periods, et cetera, and there are a couple of minor amendments as well.

But I do want to just conclude by saying, Mr. Speaker, I do want to thank our trucking industry. We work very closely with our trucking industry in this province.

And I invite members to check out the new highways map, which is just one more symbol of the degree of which–*[interjection]* Yes, I was going to say, the member for Lakeside (Mr. Eichler) just may–maybe put his own picture on the back. He doesn't like the picture on the back. I know that's been a practice of some MLAs. That's fine, Mr. Speaker.

But the Manitoba Trucking Association has long argued for this. And also I want to indicate, Mr. Speaker, this is continuing with the kind of work we're doing with Saskatchewan, where we've got greater synchronization with the province of Saskatchewan when it comes to RTAC weights, both the total weight now and also our seasonal restrictions. And so I think it's something that the Manitoba Trucking Association is very supportive of. It's something Keystone Agriculture Producers played a lead role in asking for. We're bringing it in. I know *[inaudible]* will be onside.

And I look to members opposite: we might be able to make this unanimous and perhaps move it through quickly. I think it would be very useful if we could get this in place prior to next spring, particularly with a potential for early spring conditions. So I look forward to members opposite joining with us, joining with the trucking association–Manitoba Trucking Association–joining with farmers as represented by the Keystone Agriculture Producers, and perhaps, getting on board with this excellent piece of legislation, which, I think, will make a real difference for everyone in the trucking industry, many people in the farm sector, and many of the businesses that are part of our growing economy here in Manitoba.

So the time is now, Mr. Speaker, and I hope members opposite will support this.

Mrs. Mavis Taillieu (Morris): Mr. Speaker, I move, seconded by the member for Lakeside (Mr. Eichler), that debate now be adjourned.

Motion agreed to.

Mr. Speaker: We'll now call Bill 7, The Planning Amendment and City of Winnipeg Charter Amendment Act.

Bill 7–The Planning Amendment and City of Winnipeg Charter Amendment Act (Affordable Housing)

Hon. Ron Lemieux (Minister of Local Government): I move, seconded by the Minister of Housing and Community Development (Ms. Irvin-Ross), that Bill 7, The Planning Amendment and City of Winnipeg Charter Amendment Act (Affordable Housing); Loi modifiant la Loi sur l'aménagement du territoire et la Charte de la ville de Winnipeg (logement abordable), be now read a second time and be referred to a committee of the House.

Motion presented.

Mr. Lemieux: Mr. Speaker, as communities grow in many of our cities and towns across Manitoba, community leaders are concerned about the availability of affordable housing.

We have seen great population growth in Manitoba over the recent years, particularly in the Winnipeg region and other areas of Manitoba, including Brandon. Manitoba's population reached 1.2 million in 2011, an increase of 5.2 per cent or almost 60,000 people from 2006. Growth rates in these areas are expected to continue to rise as Manitobans move–sorry, as Manitoba moves forward with our successful strategy to bring more immigrants to work in our province. This rate of growth, which has not been seen in generations, will increase the need for a range of housings housing families across a variety of income levels. Having a place to live is still a key component to the Manitoba success story. This is true for new Manitobans and established ones as well.

Community leaders have asked for more tools to increase the amount of affordable housing available in their community. I am proud to introduce this legislation that will give municipalities throughout Manitoba another mechanism to ensure Manitobans have access to affordable housing. This authority, which is commonly known as inclusionary housing–

or inclusionary zoning refers to two–sorry–refers to bylaw provisions that either require or encourage developers of market residential projects to include units for low- and moderate-income households.

It's fundamental objective is to ensure affordable housing is available on a permanent basis to a wider mix of incomes in all new residential developments. Over time, this means that a wider range of housing options are available to all income groups across the entire community.

We know mixed income developments enrich local culture and support diversity that reflects the community overall. It also ensures greater access to improved services and a range of neighbourhood amenities for all Manitobans. Thus, inclusionary housing is presented as an outcome in comparison to exclusionary housing. It's a way–excuse me–to see our communities.

The legislations–the legislation being presented holds new provisions that are enabling to municipalities. It will be entirely up to the members of a municipal council or planning district board whether they use this tool, and if they do, whether they seek voluntary developer involvement through incentives or take a mandatory approach. Local authorities will decide to use this tool based on their local needs and conditions.

In addition, as well, with all zoning bylaws, the municipality will be required to hold a public hearing on an inclusionary housing bylaw before it can be officially adopted. This way, we ensure the public is engaged in the process as well.

As we were bringing forward this legislation, we made sure to consult with key stakeholders. Consultations were held with the Department of Housing and Community Development, the Association of Manitoba Municipalities, the cities of Winnipeg and Brandon, and we have heard from the community-based non-profit and affordable housing groups that indicated general support for the concept of bylaws to require or enable affordable housing. We've also had conversations with the Urban Development Institute.

The amendments to The Planning Act and the City of Winnipeg Charter clearly empower all municipalities to pass bylaws to require or encourage affordable housing when warranted by community conditions.

The legislation incorporates the following provisions: enabling authority for a planning district board or municipal council to pass a zoning bylaw to require a specified percentage of the residential units within a development be affordable to low- and moderate-income households; (2) is to–enabling authority to relax some provisions in the zoning bylaw, including density. If a developer provides a public benefit in return, increased density is a very important tool to achieve affordable housing. Smaller lot or unit sizes can lower per-unit housing costs and provide for more effective use of infrastructure. Existing legislation in British Columbia and Ontario use similar provisions, called density bonusing, as a way to achieve the construction of affordable housing by developers; No. 3, a condition that a zoning bylaw for a new residential development requiring affordable housing may be imposed only if a definition of affordable housing is specified in the bylaw. Municipalities will define affordable housing based on local context and needs, which can defer greatly from community to community. However, resources like those provided by the Canadian Mortgage and Housing Corporation can guide municipalities as they seek to properly defining affordability for their community, provisions for development agreements between a municipality and developer to specify the required number, type and extent of affordable housing units and the necessary measures to protect the ongoing affordability of the affordable housing units.

***** (16:30)

This legislation will complement HOMEWorks!, Manitoba Housing and Community Development's long-term housing strategy and policy framework, to promote quality and affordable housing markets and encouraging more housing options for Manitobans.

I look forward to debate on Bill 7 from all members, as we surely all see that Manitoba is growing and we must provide the right tools to municipal leaders as we are seeing many new communities develop in all corners of this beautiful province.

Thank you, Mr. Speaker.

Mr. Blaine Pedersen (Midland): Mr. Speaker, I move, seconded by the member for Spruce Woods (Mr. Cullen), that debate now be adjourned.

Motion agreed to.

Hon. Jennifer Howard (Government House Leader): Would you please call Bill 11 and Bill 13.

Mr. Speaker: We'll now proceed to call Bill 11, followed by Bill 13. Starting with Bill 11 first.

Bill 11–The Proceedings Against the Crown Amendment Act

Hon. Peter Bjornson (Minister of Entrepreneurship, Training and Trade): I move, seconded by the Attorney General (Mr. Swan), that Bill 11, The Proceedings Against the Crown Amendment Act; Loi modifiant la Loi sur les procédures contre la Couronne, be now read a second time and be referred to a committee of this House.

Motion presented.

Mr. Bjornson: I'm very pleased to stand in the House today to speak to the amendments to The Proceedings Against the Crown Act. Right now all provincial, territorial and federal signatories to the Agreement on Internal Trade are taking steps to ensure that awards under the agreement of internal trade are enforceable in the same manner as orders against the Crown.

In particular, the current amendment is needed by all parties to the agreement in the event that a compliance panel in a person-to-government dispute under the AIT awards a monetary penalty against a party for failure to implement a panel ruling. The amendments we are making to The Proceedings Against the Crown Amendment Act fulfills Manitoba's commitment to fully honour its obligations required to implement the recently revised dispute resolution chapter of the Agreement on Internal Trade. Upon ratification and entry into the force of the 14th protocol of Agreement on Internal Trade, the revised dispute resolution chapter will include monetary penalties for failure to comply with the dispute panel recommendation for persons-to-government disputes. As of November 2012, four jurisdictions have ratified and signed the 14th protocol of amendment, being Manitoba, Alberta, Canada and Québec.

So, to put this in context, Mr. Speaker, Manitoba previously amended the proceedings to the Crown act in 2009 to incorporate specific articles in the agreement relating to potential monetary penalties awarded in government-to-government disputes. Specifically, the 2009 dispute resolution chapter of the agreement includes monetary penalties for failure to comply with the dispute panel recommendation for government-to-government disputes as determined by a compliance panel. The maximum potential penalties range from 2,000–$250,000–pardon me–to $5 million, depending on the size of the jurisdiction. In the unlikely event of a penalty against Manitoba, the highest the penalty could be is $1.5 million.

Now, with the recent agreement to extend such awards to person-to-government disputes, we can now simplify this provision by making a more general reference. We can do this by removing references to specific articles in the AIT, and this means that no further Crown act amendments would be needed, even if future editing changes were required, such as the renumbering of articles in this chapter of the Agreement on Internal Trade.

The alternative, Mr. Speaker, would be to list at least 12 specific articles from the agreement in total, and further amendments to the Crown act would be required at a future date as and when article numbers are amended.

As background, the Agreement on Internal Trade is an agreement that governs trade in key areas between the jurisdictions within Canada. Effective in 1995, the federal government, all provinces and two territories at the time signed the agreement. Its purpose is to reduce and eliminate barriers to internal trade.

As a co-lead with New Brunswick on the Council of Federation's initiatives on internal trade, Manitoba has consistently taken the leadership role in both the negotiations and implementations of this agreement. We've worked diligently to improve the effectiveness of the agreement, eliminate trade barriers, enhance the competitiveness in businesses and address the common concerns of individuals, businesses and governments.

This amendment is necessary to provide that the order for a monetary penalty or cost order issued by a panel under the Agreement on Internal Trade may be filed with the Court of Queen's Bench in Manitoba and would be enforceable as an order for the payment of money made by the court against the Crown. As noted earlier, cost orders can be issued by a panel under both government-to-government and person-to-person dispute processes. The first changes under the government-to-government procedures were made to ensure dispute resolution procedures were more enforceable, effective and fair, and, namely, an appeal process was added with respect to panel decisions. A compliance review was implemented which could lead to monetary penalties against parties that were found to have an inconsistent measure but had not rectified it. A summary review was also implemented allowing parties to obtain and expedite a compliance review for existing disputes during a transition period, and a potential suspension of dispute resolution privileges provided further incentive to ensure the implementation of panel rulings.

These revisions addressed concerns that the record of implementing panel decisions was very disappointing despite sound panel decisions. The implementation of panel rulings was further improved by establishing provisions allowing for possible monetary penalties of up to $5 million in the event that a government fails to implement a panel ruling. Individual penalties reflect both the seriousness of the violation and the impact on the market. A tiered approach to monetary awards also took into account the size of the population of the jurisdiction, and, as I've mentioned before, in Manitoba's case the maximum potential penalty would be $1.5 million.

This early work was followed by revisions to the person-to-government dispute process in June 2012. These revisions essentially mirror the previous improvements and provide for the same additional reviews and effective procedures. This means that if a private individual or business can successfully prove that an–to an AIT panel that a measure has been contravened, the AIT–they may be awarded a cost order to recover reasonable costs incurred to bring compliance. In the event that a jurisdiction does not bring its measure into compliance with the AIT, the compliance panel may award a monetary penalty. All monies from the monetary penalty over and above the cost of the awards will be provided to a research or educational project in support of international trade, and these projects will be under the direction of the committee on internal trade. This approach ensures that jurisdictions have an incentive to be compliant with the AIT and at the same time that individuals do not have an incentive to reap windfall gains. This current change to the dispute resolution chapter fulfills the commitment made by the premiers and the ministers to internal trade to enhance the dispute resolution procedures under the agreement.

We can attest to the effectiveness of the changes to the dispute measures. Manitoba has successfully used the revised government-to-government dispute mechanisms to ensure that the rights of Manitobans under the AIT are respected. Manitoba successfully led a 2011-2012 dispute against Ontario, and once again the western provinces worked together as Saskatchewan, Alberta and BC joined the compliant–joined this complaint, pardon me, as interveners. Ontario has since revised its legislation that it be compliant with the agreement, and Ontario will now allow certificate-to-certificate recognition of the certified general accountants practising public accounting from Manitoba without any further training required. While we won on behalf of Manitobans, accountants from any province or territory in Canada also benefited from this panel ruling.

It is also useful to point out that, in keeping with our commitment to honour our obligations under the agreement, not a single Manitoba measure has been subject to a dispute panel. I am pleased to say that we are doing our part as a Canadian jurisdiction to ensure the compliance with our obligations, and we expect all other parties to do the same–all other parties to the AIT.

***** (16:40)

Thus, in conclusion, Manitoba has consistently–*[interjection]* Well, I know the members opposite would like to hear more. I know they'd like to hear more but, in conclusion, Manitoba has consistently advocated a national approach to improving internal trade. Let me emphasize national approach to improving internal trade. And the participation of all parties to the agreement helps us achieve our objective of a single market within all of Canada.

So, with the introduction of this bill, Mr. Speaker, Manitoba demonstrates a further–its further leadership on internal trade by being one of the first jurisdictions in Canada to act on these obligations under the AIT.

I thank you very much, Mr. Speaker.

Mr. Cliff Graydon (Emerson): I move, seconded by the member for La Verendrye (Mr. Smook), that the debate be adjourned.

Motion agreed to.

Mr. Speaker: We'll now proceed with Bill 13, the Fish and Wildlife Enhancement Fund Act.

Bill 13–The Fish and Wildlife Enhancement Fund Act

Hon. Gord Mackintosh (Minister of Conservation and Water Stewardship): I move, seconded by the Minister of Local Government (Mr. Lemieux), that Bill 13, The Fish and Wildlife Enhancement Fund

Act, be now read a second time and be referred to a committee of this House.

His Honour the Administrator has been advised of the bill, and I table the message.

Mr. Speaker: It's been moved by the honourable Minister of Conservation and Water Stewardship, seconded by the honourable Minister of Local Government, that Bill 13, The Fish and Wildlife Enhancement Fund Act, be now read for a second time and be referred to a committee of the House.

His Honour the Administrator has been advised of the bill, and the message has been tabled.

Mr. Mackintosh: Mr. Speaker, this bill would set in place in law, for the first time in Manitoba, a dedicated support for fish and wildlife projects in this province. I want to, at the outset, thank the member for the Interlake (Mr. Nevakshonoff) for bringing this idea forward to my office and, as well, giving support to the Manitoba Wildlife Federation's interest in having legislation like this put into place when it comes to wildlife protections.

The member for the Interlake did a tremendous job dealing with stakeholders and consulting to determine if there was an interest in proceeding at this time with legislation and, as well, provided a lot of important recommendations in terms of how the legislation could be designed.

The bill, first and foremost, establishes the Fish and Wildlife Enhancement Fund. Under this enhancement fund, monies will fund fish enhancement initiatives as well as wildlife enhancement initiatives. It, of course, builds on the efforts, the experience of the fish enhancement fund that is in place in Manitoba, the work in large part of David Carrick and many others that are stakeholders on that fund.

What is particularly different here, of course, and what is, I'm confident, attractive for those who have been involved in fish enhancement initiatives is that this now entrenches in law the fund and, as well, for the first time, requires it to be a dedicated fund.

The fish and wildlife enhancement initiatives include, of course, projects that can serve fish and wildlife populations. It includes projects or programs to promote, manage and restore the habitats that species rely on. Initiatives under the bill include studies on fish and wildlife populations, hunting, trapping and angling education programs, as well as the acquisition of property by purchase or lease to protect critical habitat that the species may need to survive.

I might add that I certainly have heard time and again an interest by–particularly hunting stakeholders of the need to expand aerial surveying and making sure that we understand populations and trends and, of course, top of mind comes–top of mind is the interest in ensuring a healthy moose population in Manitoba.

Payments into the fund include fees placed on fishing, hunting and trapping licences. We want, of course, these licences to remain affordable so the fees will necessarily have to be nominal, and we will discuss with the stakeholders what the fee structure should be and listen to the interests of others as well to make sure that we meet the objectives of both the enhancement fund and affordability.

The monies generated from fish-related fees will be directed to the fish enhancement account. Monies from the hunting and trapping-related fees will be directed to the wildlife enhancement account.

The bill also provides the ability to prescribe certain fees on other types of licences, permits, certificates and other authorizations respecting fish and wildlife. Gifts or grants or bequests, donations and other contributions can also be placed into the fund.

I might add we are also looking at the experiences in other jurisdictions. Many of the other provinces on both sides of us have approaches that are similar to this.

To ensure ministerial government accountability, of course, the minister is responsible for the management of the fund overall and may make or authorize payments from the fund to support fish and wildlife enhancement initiatives and also the operation of government fish hatcheries. The cost to administer the act in relation to these initiatives will also be covered by the fund.

The bill establishes the fish and wildlife enhancement committee. The committee consists of a chair, members of the fish enhancement subcommittee and members of the wildlife enhancement subcommittee, all of whom are appointed by the minister. The majority of the members of the fish enhancement subcommittee can be nominated by organizations that represent anglers. We, of course, want to ensure continuity with the existing fish enhancement fund, and we will want to see that membership continue as a majority on the new committee. Organizations that represent hunters and trappers can also nominate the majority of members to the wildlife enhancement subcommittee.

The fish enhancement subcommittee must review all proposals submitted for funding related to fish enhancement initiatives, and the wildlife enhancement subcommittee must review all proposals submitted for funding related to wildlife enhancement initiatives. The subcommittees must then provide to the minister each subcommittee's funding recommendations respecting enhancement initiative proposals. The minister must take the recommendations into account in determining which initiatives receive funding, and, as I recall, there was a time restriction placed on the timeliness of the ministerial decision. The bill also allows regulation-making powers, of course, for the minister to create prescribed fees as well as prescribe the types of permits, licences, certificates and other authorizations under regulation.

So Manitoba now has the ability to dedicate funding for fish and wildlife management in this province if this bill proceeds to passage. The creation of the fund, through the act, is widely supported by anglers, hunters and trappers of Manitoba. I would like to commend this bill to the House, and I look forward to any insights from members and from the public and further insights from stakeholders.

I would particularly like to thank the Manitoba Wildlife Federation for their vision here that we are following up on now, and it's been a pleasure to work with the Wildlife Federation. We'll continue to do that as we design the terms of reference and other regulations including the fees, and, as well, I want to recognize the ongoing advice of David Carrick and the fisheries groups, the Manitoba Lodges and Outfitters Association as well as the Manitoba Trappers Association, which has expressed their support, and it'll be important, of course, to engage trappers as well because we shouldn't forget that it's not just about hunting and fishing but trapping as well that will benefit from this.

In short, I think what this fund offers is a greater opportunity for a greater fishing and hunting and trapping experience for Manitobans and for those who visit our province. It will help ensure going forward that, when you go out for that deer, you're going to have a better story to tell, and when you're going out fishing, oh well, you know, the stories were told anyway. Yes. But, no, we really hope that, and expect that, this fund will ensure the ongoing and healthy stocking of our lakes and, as well, the healthy–healthier populations when it comes to hunting and trapping as well.

So, with those remarks, I again, just ask the House to recognize the role of the member for the Interlake (Mr. Nevakshonoff), given his passion for this fund, and I look forward to the debates and the proceedings in the committee. Thank you, Mr. Speaker.

***** (16:50)

Mr. Tom Nevakshonoff (Interlake): It is my honour and a distinct pleasure to arise to speak on Bill 13 this afternoon, and I want to thank the Minister of Conservation and Water Stewardship for his kind words just now and for the leadership and enthusiasm that he has expressed in regard to this most important act. It's–kind of follows up a little bit on an act that was passed through the Legislature here just a short time ago with joint co-operation of both sides of the House, The Hunting, Fishing and Trapping Heritage Act. Members opposite, I'm sure, recall that; had a lot to do with the genesis of that act; and I acknowledge their good works in that regard and hope that they will speak favourably in regard to this latest endeavour on behalf of wildlife and our fish populations and our hunters and fishers across this beautiful land of ours.

Now, I've had some experience in this field. My family owned a fishing lodge up in northern Manitoba–my brother currently owns it–so I was raised on the lake. I was guiding Americans when I was 10 years old, as a matter of fact, so it's been–it had nothing to do with my Uncle Cubby, I may add. This was strictly an endeavour that my father, Mike Nevakshonoff, got started in–back in 1966 or '67, I think. *[interjection]* Well, members opposite seem to have some interest in this and I'm very glad that they're expressing this interest.

Most important, I think, to put on the record that this was a major component of TomorrowNow-Manitoba's Green Plan that was announced by the Premier (Mr. Selinger) in June. So this is just one of the many ways that our government is expressing this. Just goes to show that we have truly the interests of rural Manitoba at heart. And that goes right into the very heart of the bush, I might add.

In addition to being a fisher, of course, I'm an active hunter, and we'll put on the record: I did get my deer this year. I still have to send the forms in and–so that we can do proper recordkeeping which is fundamental to the maintenance of our wildlife stocks. If we don't spend the money to do the counts–the wildlife counts–so that we actually know what we have out there, then it's difficult, as a government, to make the decisions as regards hunting licences, either the length of them, or whether you're harvesting one deer or two, or what have you. So all of these factors, this particular bill will give us the enhanced ability to monitor our fish stocks, our wildlife stocks, and not just to monitor them, but to make fundamental investments in the habitat itself, which is not just to be taken for granted.

A number of very good people, I might add, have worked on this project throughout the course of its coming to pass. I do want to acknowledge some of them on the record today, Mr. Speaker.

First and foremost would be a former director of wildlife, then moved on and spent the end of his career as the regional director for the Interlake region. His name was Brian Gillespie, a very good friend of mine. I've known him since I was first elected in 1999. Him and I are cut from the same bolt of cloth, but I do recall our meeting, I'd have to say. I'd phoned one of his staff people and–to talk about whatever, drainage or elk depredation on hay. Very quickly, the director phoned me back and said that I should be talking to him, so I arranged for a meeting and the two of them met across his desk and kind of glared at each other a little bit, but we very soon came to realize that we both had the same things near and dear to us, the preservation of wildlife and good water management, and became fast friends. And he was very instrumental in advising me through the course of this bill. He was heavily involved in the expansion of the wildlife management areas back in the 1970s and was instrumental in the reintroduction of the Manitobensis species of–subspecies of elk back into the Interlake–very successful program that is evident today. Truly, one of the crown jewels of our province is the elk herd in the Interlake. So I acknowledge Brian Gillespie's good works in that regard.

Also, Barry Verbiwski, who currently works for us–very often, we tend to overlook our staff, how hard they work behind the scenes. Barry Verbiwski, as we went back and forth on this bill–and it went back and forth quite bit, I have to say, Barry was the guy that carried that heavy load. He was the one that did all the writing and all the revisions, so I really want to acknowledge his good works as well as other people like Dr. Brian Parker, who is the Fisheries director now. Brian joined Jim Duncan, our current wildlife director, and Blaire Barta as well, who was working on the draft, as well as many others. This is–was a combined effort that I take my hat off to all of our staff, past and present, for the good works that they do on behalf of the people of Manitoba, and help us to do a hard job as elected officials as well.

You know, part of our mandate, the expansion of, you know, of protected areas in our province, whether it's parks, wildlife management areas, what have you, and I don't have to look very far outside of my constituency. In fact, within my constituency, just in the last year or so, we did create a brand-new park, the Fisher Bay Park, which is more a water park, which is unique in itself, and there again acknowledge the good works of the chief of the Fisher River Cree Nation, Dave Crate, who lobbied very hard, very long, and very effectively in that regard.

So I see that time is almost up. I would like to speak so much more about some of the other people who have contributed toward this, about some of our plans to include First Nations people as a part of this process, very important, but time is of the essence and the clock is ticking and my time has pretty much run out, so I just hope that members opposite are fully in support of this worthy endeavour.

Thank you very much, Mr. Speaker.

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, I move, seconded by the member for Tuxedo (Mrs. Stefanson), that debate now be adjourned.

Motion agreed to.

Hon. Jennifer Howard (Government House Leader): Mr. Speaker, would you please call Bill 5.

Mr. Speaker: We will now proceed to call Bill 5, The New Home Warranty Act.

Bill 5–The New Home Warranty Act

Hon. Jim Rondeau (Minister of Healthy Living, Seniors and Consumer Affairs): This bill established mandatory minimum warranty protection for the–oh, I move, seconded by the Minister of Housing (Ms. Irvin-Ross), that Bill 5, The New Home Warranty Act; Loi sur la garantie des maisons neuves, be now read a first–a second time and be referred to a committee of this House.

His Honour the Administrator has been advised of the bill, and I table the message.

Mr. Speaker: It has been moved by the honourable Minister of Healthy Living and Seniors, seconded by the honourable Minister of Housing and Community Development, that Bill 5, The New Home Warranty Act, be now read for a second time and be referred to a committee of the House.

His Honour the Administrator has been advised of the contents of this bill, and the message was tabled.

Mr. Rondeau: Good day, Mr. Speaker. This bill will establish mandatory minimum warranty protection for new homes built in this province. It ensures new homes built for sale are covered by a warranty against defects and materials, labours, design and structural defects.

Mr. Speaker, this bill's on the let's make a better deal commitment where we want to continue to expand protection for consumers. The purchase of a new home is one of the largest purchases that most consumers and families can make. Most consumers don't buy many homes in their lifetime.

The complexity of a new home or a construction of condominiums–it can make it difficult to understand all the systems, components and structural elements that go into building of a new home. Many people may not be aware of the potential defects and consumer-related problems that might appear after they move in, and it's a very tough system.

And so, Mr. Speaker, only three provinces have mandatory new home warranty legislation: Ontario, Québec, British Columbia, and the most recent of these existing programs was developed in BC as a response for the leaky condo crisis. That happened in the 1990s. It worked well and others have joined us.

Manitoba's not alone in moving forward–

Mr. Speaker: Order, please. Order, please.

When this matter's again before the House, the honourable Minister of Healthy Living and Seniors–will remain standing in the name of the honourable Minister of Healthy Living and Seniors.

The hour being 5 p.m., this House is adjourned and stands adjourned until 10 a.m. tomorrow morning.

CORRIGENDA

On November 29, 2012, page 275, first column, seventh paragraph, should have read:

The NDP government tries to use its Crown corporations as cover for their own mismanagement. They tried to raid MPI before and they're doing it again, Mr. Speaker. They've done it with Hydro as well.

On November 29, 2012, page 302, second column, sixth paragraph, should have read:

This year we announced the province's biggest population gains since modern-day recordkeeping began in 1971. Mr. Speaker, 16,045 people came to Manitoba between April of 2011 and April of 2012. That's a record. We want Manitoba to be a destination choice for people from around the world.

LEGISLATIVE ASSEMBLY OF MANITOBA

Monday, December 3, 2012

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The Legislative Assembly of Manitoba Debates and Proceedings
are also available on the Internet at the following address:

http://www.gov.mb.ca/legislature/hansard/index.html

Tab 8

Dams and development:
A new framework for decision-making

Overview of the report by the World Commission on Dams

December 2001

The present paper is a summary of the final report produced by the World Commission on Dams, which was published in November 2000. A full copy of the report titled *Dams and Development: A New Framework for Decision-Making*, can be obtained from bookshops or Earthscan Publications Ltd, 120 Pentonville road, London N1 9JN, UK. Email: earthinfo@earthscan.co.uk and http://www.earthscan.co.uk. The report is also downloadable at http://www.dams.org/report/.

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SUMMARY

What are the real costs of dams? Who pays for them? And who benefits from them? The construction of large dams is now one of the most hotly contested issues in sustainable development. Supporters talk up the social and economic benefits of irrigation, electricity, flood control and water supply; while opponents highlight their negative impacts, such as cost overruns and debt burden, the displacement and impoverishment of people, the destruction of important ecosystems and fishery resources, and the inequitable distribution of costs and benefits.

The rivers, watersheds and aquatic ecosystems harnessed and affected by dams provide the basis for life and livelihoods. The considerable benefits that dams can provide must therefore be weighed against the negative consequences of introducing structures that transform the surrounding landscape, impacting on every species living within it. The World Commission on Dams (WCD) was set up to undertake the huge task of assessing the past performance and future role of large dams.

Dams and Development: A New framework for Decision-Making is the product of over two years of intense study, dialogue and reflection by the WCD, the WCD Stakeholders' Forum and hundreds of individual experts on all aspects of dams. Providing a comprehensive, global review of their performance and contribution to development, the WCD report is relevant to everyone working with or concerned by dams, from governments and international organisations, the private sector and civil society groups, to the communities most intimately affected by dams. This paper presents a brief overview of the issues addressed by the report, summarising its main recommendations and proposals.

Building on an analysis of how and why dams succeed or fail to meet development objectives, the report addresses key issues at the heart of the debate on dams, and recommends fundamental changes in the manner in which water development options are assessed and project cycles planned, implemented, monitored and evaluated. Working on the premise that dams are but one means of improving human welfare on a sustainable basis, the Commission proposes that they should be judged accordingly, supported if they offer the best way of achieving this goal, and avoided should other, better options be available.

Such judgement requires a new, more inclusive approach to dams as a development option: an approach that begins by identifying the broad range of stakeholders potentially affected by new initiatives, recognises their rights and the risks attendant upon a proposed programme, and ensures their informed participation in the decision-making processes that shape the development of water and energy resources. To support this new framework for decision-making, the Commission outlines seven strategic priorities, with criteria and guidelines that should enable stakeholders at all levels to seek and attain the most appropriate means of exploiting and protecting water and energy resources. Vital reading on the future of dams and the changing development context, *Dams and Development* leaves no doubt that business as usual is simply no longer an option.

INTRODUCTION: A BRIEF OVERVIEW OF DAMS AND DEVELOPMENT

There is nothing new about dams: for thousands of years people have been building them to manage flood waters and supply water for drinking, irrigation and, more recently, industry. By the 1950s, as national economies and populations expanded, dams were increasingly viewed as a means of meeting water and energy needs, and since then, at least 45 000 large dams have been constructed. Nearly half of the rivers in the world now house at least one large dam, and hydropower produces over 50% of the electricity in a third of countries across the world, with large dams generating 19% of electricity overall. Half of the world's large dams were built exclusively or primarily for irrigation, and some 30-40% of the 271 million hectares irrigated worldwide rely on these constructions.

Dams have been promoted as an important means of meeting water and energy needs, and as a long-term, strategic investment with the ability to deliver multiple benefits, some of which are typical of all large infrastructure projects, while others are unique to dams and specific to particular projects. Regional development, job creation and fostering an industrial base with export capability are often cited as additional considerations when building large dams, while other goals include the generation of income from export earnings, either through direct sales of electricity or by selling cash crops or processed products from electricity-intensive industries.

However, such benefits need to be weighed up against the social and environmental impacts of large dams, which have become increasingly obvious over the last fifty years. Rivers have been fragmented and transformed, and worldwide, an estimated 40-80 million people have been displaced by reservoirs. The enormous investment required to build large dams, and their huge social, environmental and economic impact, have fuelled opposition to them. As decision-making processes in many countries have become more open and transparent, the future of large dams is increasingly being called into question.

Changing context

A number of global reports have documented the dramatic impact of withdrawing water from the world's lakes, rivers and underground aquifers, as withdrawals doubled over the second half of the last century to an estimated 3800 cubic kilometres per year. Sustainable management of water resources has been pushed to the top of the global development agenda by the need to supply growing populations and economies with water, while groundwater sources are depleted, water quality is declining and increasingly severe limits have been imposed on surface water extraction.

Over the past few decades, water has ceased to be seen as a free commodity, and is now valued as a limited natural resource, an economic good and a human right. As such, it should be allocated in an equitable manner, but in 1990, over a billion people were estimated to have less than the 50 litres per person per day recommended as sufficient for basic human requirements, while households in industrial countries and wealthy city-dwellers in developing countries were consuming four to fourteen times this amount.

Leading analysts predict that competition for water to meet the demands of industry, agriculture and human consumption will increase, forecasting that by 2025, there will be a total of 3.5 billion people living in water-stressed countries. Empirical evidence suggests that limited water supplies, current agricultural practices and population growth will make it increasingly difficult for various countries to achieve food self-sufficiency, which will intensify the focus on food security and the protection of other environmental resources. Clearly, action is required to address both current and future needs, and dams are at the heart of the debate about how this might be achieved. While there are many threats implicit in this pressure on water, it could also act as a catalyst for positive change in water-related policies, creating new opportunities for development initiatives.

Cure or curse? The debate on dams

Between the 1930s and the 1970s, when the construction of large dams peaked, they were viewed by many as synonymous with development and economic progress. Hydropower, irrigation, water supply and flood control services were widely seen as sufficient justification for the huge investments required; while other benefits, such as the economic prosperity brought to a region by multiple cropping, the installation of electricity in rural areas, and the expansion of physical and social infrastructures, such as roads and schools, were used to justify dams as the most economically and financially competitive option.

However, a growing body of knowledge and experience about the performance and consequences of dams has raised questions about the reported returns on the investments required, and the level and distribution of benefits actually delivered. Initially focusing on specific sites, opposition has now evolved into a global debate about dams: their impact on neighbouring communities, livelihoods and ecosystems, and whether they represent the best investment of public funds and resources.

The debate ranges from the gap between the promised benefits of a dam and the actual outcomes, to the challenges of developing water and energy in terms of 'nation building' and resource allocation. Proponents maintain that dams have generally performed well as an integral part of water and energy development strategies in over 140 nations, for the most part providing an indispensable range of water and energy services. Opponents claim that better, cheaper options for meeting water and energy needs, from small-scale, decentralised water supply and electricity options to large-scale end-use efficiency and demand-side management options, have often been ignored, despite the fact that they may offer more sustainable and equitable development benefits.

While protagonists may agree on the need to take the environmental and social costs of dams more seriously, and systematically to consult with the people affected by their construction, there are still deep divisions over issues such as:

- the extent to which alternatives to dams are viable for achieving various development goals, and whether alternatives are complementary or mutually exclusive;

- the extent to which adverse environmental and social impacts are acceptable;
- the degree to which adverse environmental and social impacts can be avoided or mitigated;
- the extent to which local consent should govern development decisions in the future.

Today, the decision to build a large dam is rarely only a local or national one. The debate has been transformed from a local process of assessing costs and benefits to one in which dams in general are the focus of global concern about development strategies and choices.

THE WORLD COMMISSION ON DAMS

It was against this background that a meeting to discuss issues relating to large dams was convened in Gland, Switzerland, in April 1997. Supported by the World Bank and the IUCN – World Conservation Union, the meeting was attended by thirty-nine participants from governments, the private sector, international financial institutions, civil society organisations and people affected by dams. It resulted in a proposal to establish the World Commission on Dams (WCD), with a mandate to:

- Review the effectiveness of large dams as a development option, and assess alternatives for developing water resources and energy;
- Develop internationally acceptable criteria, guidelines and standards, where appropriate, for the planning, design, appraisal, construction, operation, monitoring and decommissioning of dams.

Members of the Commission were selected to reflect regional diversity, expertise and stakeholder perspectives; and to act in an individual capacity, rather than representing institutions or countries. In May 1998, the WCD started work on the first independent global review of the performance and impact of large dams and the options available for water and energy development. This involved preparing eight detailed case studies of large dams, country reviews for India and China, and a briefing paper on Russia and the Newly Independent States. Surveys were conducted on one hundred and twenty-five large dams; seventeen thematic reviews written on social, environmental and economic issues, alternatives to dams and governance and institutional processes; and nine hundred and forty-seven submissions and presentations made at four regional consultations. These inputs formed the

core of the WCD Knowledge Base, which served to inform the Commission on the main issues surrounding dams and their alternatives.
With the focus as much on the process as on the product, public consultation and access to the Commission were key components of the review, which was conducted in consultation with the WCD forum, a sixty-eight-member group representing a cross-section of interests, views and institutions. Taking care to involve all interest groups in the debate, the WCD also pioneered a new funding model, and fifty-three public, private and civil society organisations pledged funds to the WCD process.

The main components and findings of the WCD Global Review

The review was structured around three main components:

1. An assessment of the technical, financial and economic performance of dams, their impact on ecosystems and people, and the distribution of project gains and losses;
2. An assessment of the alternatives to dams, and the opportunities and obstacles relating to them;
3. An analysis of the planning, decision-making and compliance issues underpinning the selection, design, construction, operation and decommissioning of dams.

Evaluation of performance was based on the targets set for large dams by their proponents – the criteria providing the basis for government approval and financing. While recognising the substantial benefits derived from dams, the review also focuses on why, how and where they failed to achieve the results intended, or produced unanticipated outcomes. An integral part of the research involved documenting the good practices developed to address the shortcomings and difficulties experienced in the past. These practices suggest that there is cause for optimism about improving the benefits, increasing the beneficiaries and reducing or mitigating the negative impacts and conflicts caused by dams.

The principal findings of the review, which form the basis for the new approach developed within the report, are summarised below:

- Dams have made a significant contribution to human development, and considerable benefits have been derived from them;
- An unacceptable and often unnecessary price has been paid to secure those benefits, especially in social and environmental terms, by

displaced people, communities downstream from the dam, taxpayers and the environment;
- Compared with other alternatives, the value of dams in meeting water and energy development needs is questionable, particularly in view of the lack of equity and uneven distribution of benefits;
- By bringing to the table all those whose rights are involved, and who bear the risks associated with different options for developing water and energy resources, it should be possible to address competing interests and resolve conflicts in a positive manner;
- Negotiation can be used as a tool to increase the effectiveness of water and energy development projects, by eliminating inappropriate projects at an early stage and offering only those options that key stakeholders agree are the best for meeting the needs in question.

A new approach to improving the outcomes of dams and water development projects

Like any development project, dams and their alternatives must respond to a wide range of needs, expectations, objectives and constraints. This can only be achieved by transforming the development process, so that it includes all relevant stakeholders and is based on negotiation and consensual decision-making. For this radically different approach to work, participants need to have a clear understanding of and agreement about the shared objectives and goals of development, which should be underpinned by five core values identified by the Commission:

- Equity
- Efficiency
- Participatory decision-making
- Sustainability
- Accountability

The endorsement of these values is a key theme of the report and its recommendations, and there is significant support for rights, particularly human rights, to be considered as a fundamental reference point in any debate on dams.

In view of the importance of rights-related issues, and the nature and magnitude of the potential risks for all protagonists, the Commission proposes that an approach based on the recognition of rights and assessment of risks (particularly the rights at risk) be developed as a tool for guiding future planning and decision-making. This will also provide a more effective framework for integrating the economic, social and environmental issues at stake when assessing development options and implementing projects.

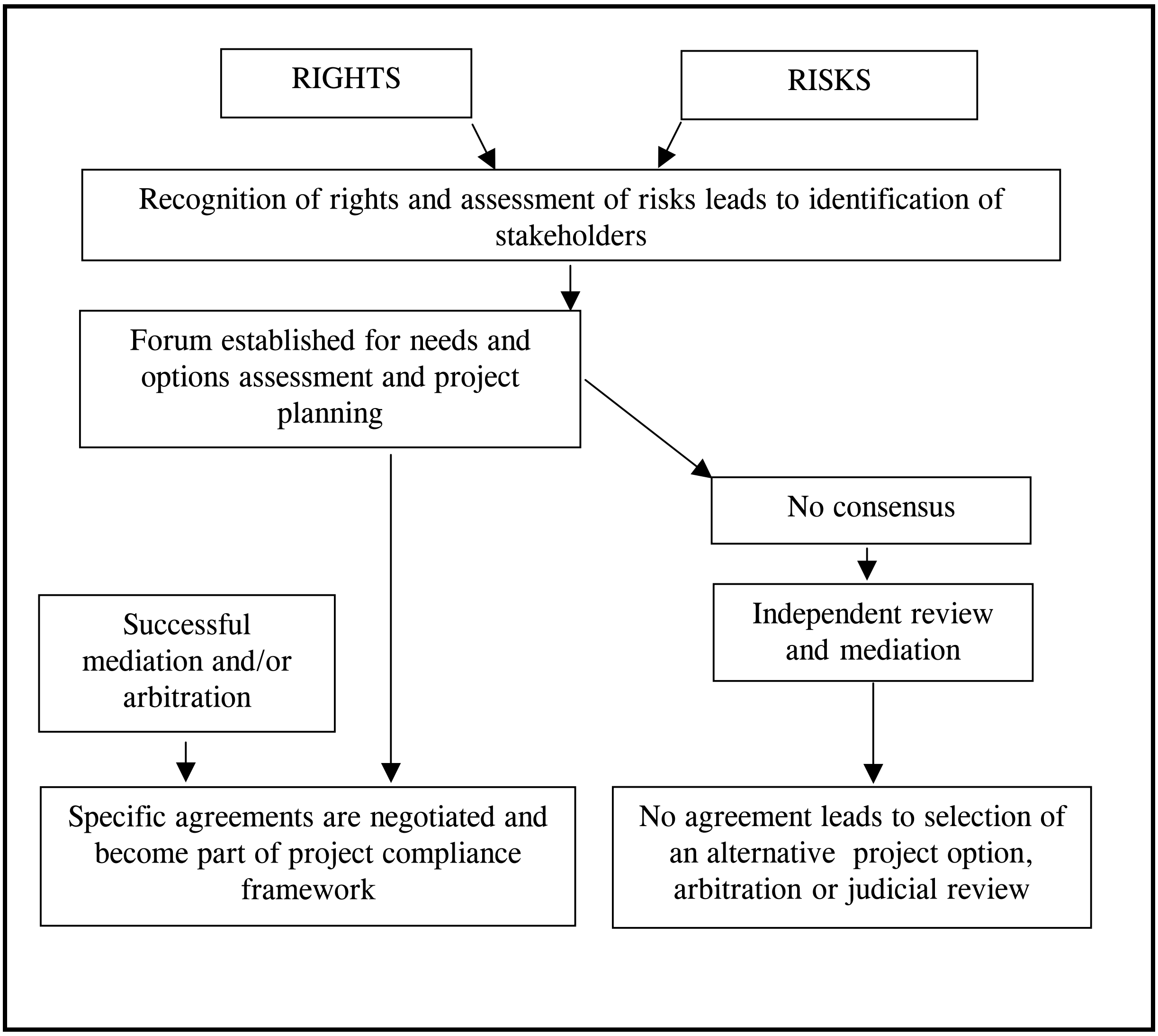
In order to identify the legitimate claims and entitlements potentially affected by a proposed project or its alternatives, it is essential to clarify the rights at stake, as a pre-requisite to identifying all the groups entitled to a formal role in the consultative process. These stakeholders should be actively involved from the start, and party to negotiating project-specific agreements on issues such as benefit sharing, resettlement or compensation.

The notion of risk adds an important dimension to understanding how, and to what extent, a project may have an impact on such rights. Traditionally, the definition of risk was limited to the capital invested and returns expected by developers or corporate investors. These voluntary risk-takers can determine the level and type of risk they wish to take, and explicitly define its boundaries and acceptability. As the Global Review shows, water development projects have often created a far larger group of involuntary risk-takers, who find that their livelihoods, quality of life and very survival are at stake, and that the risks imposed upon them are managed by others. Typically, these involuntary risk-bearers have little or no say in overall water and energy policy, the choice of specific projects, or project design and implementation.

Like rights and entitlements, these risks must be identified, articulated and addressed. This will involve formal recognition of the fact that governments or developers are not the only parties at risk, and that the communities affected by a project, as well as the environment, also have much to lose.

A rights-and-risks approach to assessing options and implementation will provide an effective framework for determining who has a legitimate place at the negotiating table, and which issues need to be on the agenda (see Figure 1 below). Although this approach may be more demanding in the early stages of options assessment and project design, inclusive and transparent decision-making processes aimed at negotiated outcomes should legitimise subsequent stages of the project, thereby helping to resolve the many and complex issues surrounding water, dams and development.

Figure 1: From rights and risks to negotiated agreements: a framework for options assessment and project planning



Having taken the five core values outlined above as the basis for developing a rights-and-risks approach to the development process, the Commission then uses the broad framework of existing and emerging policy at local, national and international levels to identify seven strategic priorities and corresponding policy principles:

- Gaining public acceptance
- Comprehensive option assessment
- Managing existing dams
- Sustaining rivers and livelihoods
- Recognising entitlements and sharing benefits
- Ensuring compliance
- Sharing rivers for peace, development and security.

These priorities provide the basis for an innovative and constructive framework for decision-making, moving away from the traditional, top-down, technology-oriented approach towards a much more inclusive method of assessing options, managing existing dams, gaining public acceptance and negotiating and sharing benefits. Presented as outcomes to be achieved, the seven strategic priorities are supported by a practical set of principles and guidelines designed to be adopted and adapted by everyone involved in the debate about dams.

1. Gaining public acceptance

In order to develop water and energy resources in an equitable and sustainable manner, it is essential that there is public acceptance of such initiatives. This entails recognising the rights, addressing the risks and safeguarding the entitlements of all interested groups, by ensuring that they are informed about the issues at stake, able effectively to participate in decision-making processes, and that there is demonstrable acceptance of key decisions. Particular care should be taken to include the most vulnerable parties, such as women, the poor and certain indigenous groups, and that decision-making processes are guided by their free, informed and prior consent.

2. Comprehensive options assessment

The most appropriate development initiatives for a particular area can only be identified by assessing food, water and energy needs and clearly defining programme objectives. The full range of policy, institutional and technical options, which may well include alternatives to dams, should then be comprehensively assessed in a participatory process that accords the same significance to social and environmental considerations as to economic and financial factors. This process of assessment should continue throughout the planning, development and implementation of the project.

3. Managing existing dams

Dams and the context in which they operate are not static over time. Their benefits and impacts may be transformed by changes in priorities for water use, physical and land use changes in the river basin, technological developments, and changes in public policy expressed in environmental, safety, economic and technical regulations. Management and operational practices should be continuously assessed and adapted to changing circumstances, in order to optimise the benefits, address social issues and improve measures to limit and restore damage to the environment. This process should extend beyond the life of the project, so that the performance, benefits and impacts of all existing large dams can be monitored and evaluated on a long-term basis, and appropriate action taken to improve all aspects of their service delivery.

4. Sustaining rivers and livelihoods

Dams transform the landscapes they inhabit, with potentially irreversible effect. It is essential to understand, protect and restore ecosystems at river basin level, in order to minimise their negative impact, limit and mitigate harm to the health and integrity of the river system and those dependent upon it, and promote equitable human development and the welfare of all species. These are key issues when selecting sites and designing projects. Governments should develop national policies for maintaining in their natural state selected rivers with high ecosystem functions and values, and look for alternative sites on tributaries when assessing proposals for dams on undeveloped rivers.

5. Recognising entitlements and sharing benefits

Rather than benefiting from them, many of those affected by dams are aware only of their negative impacts. To redress the balance, a process of joint negotiation with such groups is required, based on recognition of rights and assessment of risks. The aim of these negotiations is to agree on legally enforceable mitigation and development provisions, which recognise entitlements that improve livelihoods and quality of life. States and developers are responsible for resettling and compensating all affected people, and satisfying them that their livelihoods will be improved by moving from their current situation. Legal means, such as contracts and accessible recourse at national and international levels, should be used to ensure that responsible parties fulfil their commitments to agreed mitigation, resettlement and development provisions.

6. Ensuring compliance

In order to win and maintain public trust and confidence, governments, developers, regulators and operators must meet their commitments for planning, implementing and operating dams. Compliance with applicable regulations, criteria and guidelines, and project-specific negotiated agreements should be ensured at all critical stages of project planning and implementation. A set of regulatory and non-regulatory mechanisms, incorporating incentives and sanctions, and flexible enough to accommodate changing circumstances, is needed to enforce social, environmental and technical measures. A clear, consistent and common set of criteria and guidelines to ensure compliance should be adopted by sponsoring, contracting and financing institutions, and compliance subjected to independent and transparent review. Legislation, voluntary integrity pacts, debarments and other instruments should be used to eliminate corrupt practices.

7. **Sharing rivers for peace, development and security**

The storage and diversion of water on transboundary rivers can cause considerable tension within and between countries. As specific interventions for diverting water, dams require constructive co-operation, and states or political units within countries need to agree on the use of resources in order to promote regional co-operation and peaceful collaboration.

Rather than focusing on allocating water as a finite resource, states need to work on sharing rivers and their associated benefits. This will involve negotiating a wide range of issues, and making provision in national water policies for basin agreements in shared river basins. These agreements should be based on the principles of equitable and reasonable use, no significant harm, prior information and the Commission's strategic priorities.

If an objection by a riparian state to a proposal for a new dam on a shared river is upheld by an independent panel, construction should not be carried out. Furthermore, where a government agency plans the construction of a dam on a shared river in contravention of the principle of good faith negotiations between riparians, external financing bodies should withdraw their support for projects and programmes promoted by that agency.

A NEW FOCUS FOR PLANNING AND DECISION-MAKING

In order to act on the strategic priorities recommended by the Commission, a new focus is required for planning and management in the water and energy sectors. This can best be achieved by focusing on the key stages in the decision-making process that influence final outcomes, and where compliance with regulatory requirements can be verified. The Commission identified five critical decision points for water and energy options. The first two relate to planning, and lead to decisions on a preferred development plan:

1. Needs assessment – validating needs for water and energy services;
2. Selecting alternatives – identifying the preferred development plan from among the full range of options.

When a dam is selected as a preferred development option, there are three further critical decision points:

3. Project preparation – verifying that agreements are in place before the construction contract is put to tender;
4. Project implementation – confirming compliance before commissioning;
5. Project operation – adapting to changing contexts.

The decision made at each of these points represents a commitment to action that will govern the course of future conduct and the allocation of resources. It is at these points that ministries and government agencies need to test compliance with preceding processes, before giving the green light to go on to the next stage. They are not exhaustive, and within each stage many other decisions have to be taken and agreements reached. The five stages and associated decision points need to be interpreted within the overall planning contexts of individual countries; and the Commission also noted that even when these decision points have been passed, there are certain steps that should be taken to improve outcomes (see Box 1 below).

Box 1 Dams in the pipeline

It is never too late to try and improve the outcomes of projects, even the many dam projects currently at various stages of planning and development. *Dams and Development* calls for an open and participatory review of all ongoing and planned projects, to see whether changes are needed to bring them into line with the WCD strategic priorities and policy principles. In general, regulators, developers and, where appropriate, financing agencies, should ensure that such a review:

- Uses stakeholder analysis based on the recognition of rights and assessment of risks to identify a stakeholder forum that is consulted on all relevant issues;
- Enables vulnerable and disadvantaged groups of stakeholders to participate in an informed manner;
- Includes a distribution analysis to see who bears the costs and who enjoys the benefits of the project;
- Develops agreed mitigation and resettlement measures to promote development opportunities and benefit displaced and adversely affected people;
- Avoids, through modified design, any severe and irreversible impacts on the ecosystem;
- Provides for an environmental flow requirement, and mitigates or compensates any unavoidable impacts on the ecosystem;
- Designs and implements recourse and compliance mechanisms.

The process of review implies added investigations or commitments, the renegotiation of contracts and the incorporation of a Compliance Plan. However, additional financial costs will be recouped in lower overall costs to operators, governments and society in general, as a consequence of avoiding negative outcomes and conflicts.

In the past, decision-making processes have taken little account of social, environmental, governance and compliance issues. The Commission therefore developed a set of criteria and twenty-six guidelines to complement the body of knowledge on good practices, and add value to current national and international guidelines, including those on the technical, economic and financial aspects of development. Used in conjunction with existing decision-making tools, these criteria and guidelines provide a new direction for appropriate and sustainable development. Bringing about this change will require concerted action from a number of quarters:

- Planners need to identify stakeholders through a process that recognises rights and assesses risks;
- States should invest more at an earlier stage of the process, to screen out inappropriate projects and facilitate integration across different sectors within the context of the river basin;
- Consultants and agencies have to ensure that outcomes from feasibility studies are socially and environmentally acceptable;
- All players should promote open and meaningful participation during planning and implementation, to achieve negotiated outcomes;
- Developers should take contractual responsibility for effectively mitigating social and environmental impacts;
- Independent reviewers need to improve compliance;
- Dam owners must apply the lessons learned from regularly monitoring past experiences and by adapting to changing needs and contexts.

WHAT NEXT?

The findings presented in *Dams and Development* are aimed at everyone involved in dams, from governments and the private sector, developers and owners, to civil society groups, international organisations and affected communities. The challenge now is to use the insights and proposals made in the report to reassess established procedures and involve all stakeholders - from the most powerful international players to the smallest communities - in making and implementing decisions about fundamental water and energy development choices.

The Commission proposes a number of entry points to help organisations start to act on the report, by:

- Carefully reviewing and actively disseminating the report;
- Issuing public statements of support for the approach taken;
- Using WCD criteria and guidelines to review dams currently being developed;
- Supporting investment in building capacity, particularly in developing countries, for options assessment and improved decision-making.

Specific proposals are included for national governments and line ministries, civil society groups, the private sector, bilateral aid agencies, multilateral development banks, export credit agencies, international organisations and academic and research bodies. These actions, outlined in Box 2 below, would facilitate permanent change and advance the principles of a more inclusive and equitable approach to development.

Box 2 Selected recommendations for key stakeholders in the debate on dams

National governments:

- Review existing procedures and regulations relating to large dam projects;
- Use time-bound licences for both public and privately owned dams;
- Establish an independent, multi-stakeholder committee to address unresolved issues caused by dams.

Civil society groups:

- Monitor compliance with agreements and assist any aggrieved party in resolving outstanding disagreements or seeking recourse;
- Actively assist in identifying stakeholders potentially affected by dam projects, using the rights-and-risks approach.

Organisations representing communities affected by dams:

- Identify unresolved social and environmental impacts and convince the relevant authorities to take effective steps to address them;
- Develop support networks and partnerships to strengthen the technical and legal capacity for needs and options assessment.

Professional associations:

- Develop processes for certifying compliance with WCD guidelines;
- Extend national and international databases, such as the ICCOLD World Register of Dams, to include social and environmental parameters.

Private sector:

- Develop and adopt voluntary codes of conduct, management systems and certification procedures for best ensuring and demonstrating compliance with the Commission's guidelines, including, for example, through the ISO 14001 management system standard;
- Abide by the provisions of the anti-bribery convention of the OECD;
- Adopt integrity pacts for all contracts and procurement.

Bilateral aid agencies and multilateral development banks:

- Ensure that any dam options for which financing is approved have been selected from an agreed system of ranking, and respect WCD guidelines;
- Accelerate the shift from project- to sector-based finance, by increasing financial and technical support for effective, transparent and participatory needs and options assessment, and by financing non-structural alternatives;
- Review the portfolio of projects to identify any that may have under-performed in the past or still present unresolved issues.

A considerable element of trust between all players will be needed to move forward with these proposals. This will require early and resolute action to address various unresolved issues, and assurances to countries in the early stages of economic development that, within certain parameters, dams may still be a viable water and energy development option.

While the debate over dams will continue for many years, the Commission has shown that it is possible to find common ground without compromising individual values or losing a sense of purpose. The framework for a new approach to dams as a development option has been established, but its strength and effectiveness will depend on all parties pursuing the process in good faith and signing up to fundamental changes in priorities and practices. The report leaves no doubt about the challenges ahead, ending with an explicit call to action:

> "*We have conducted the first comprehensive and global review of the performance of dams and their contribution to development. We have done this through an inclusive process that has brought all significant players into the debate. And we believe that we have shifted the centre of gravity in the dams debate to one focused on options assessment and participatory decision-making. The rights-and-risks approach we propose will raise the importance of the social and environmental dimensions of dams to a level once reserved for the economic dimension. We have told our story. What happens next is up to you.*"

Tab 9

MANITOBA
ORDER IN COUNCIL

DATE: **August 17, 2011**

ORDER IN COUNCIL NO.: **00304 / 2011**

RECOMMENDED BY: **Minister**

ORDER

1. Manitoba Hydro is authorized to enter into an agreement with Minnesota Power, an operating division of ALLETE, Inc. dated May 19, 2011 for the sale by Manitoba Hydro and the purchase by Minnesota Power, an operating division of ALLETE, Inc. of 250 megawatts of electrical generating capacity and associated energy.

2. Manitoba Hydro is authorized to enter into an agreement with Wisconsin Public Service Corporation dated May 19, 2011 for the sale by Manitoba Hydro and the purchase by Wisconsin Public Service Corporation of 100 megawatts of electrical generating capacity and associated energy.

3. Manitoba Hydro is authorized to enter into such agreements and do all things proper or necessary for the due exercise of the above.

AUTHORITY

The Manitoba Hydro Act, C.C.S.M. c. H 190, states:

Powers of corporation with approval of L. G. in C.
16(1) With the approval of the Lieutenant Governor in Council the corporation may

(h) supply power generated in Manitoba to any other province or state of the United States, or to any person in that other province or state;

(j) enter into agreements and do all things proper or necessary for the due exercise of the powers mentioned in this section.

BACKGROUND

1. Manitoba Hydro, Minnesota Power and Wisconsin Public Service have signed the subject agreements, subject to the approval of the Lieutenant Governor in Council.

2. The construction of new power generation and transmission facilities in the Province of Manitoba will be necessary in order to Manitoba Hydro to fulfil its commitments pursuant to the agreement.

Tab 10

What You Should Know About Megaprojects, and Why: An Overview

By
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Draft 9.2

Full reference: Bent Flyvbjerg, 2014, "What You Should Know about Megaprojects and Why: An Overview," *Project Management Journal*, vol. 45, no. 2, April-May, pp. 6-19, DOI: 10.1002/pmj.21409

Abstract

This paper takes stock of megaproject management, an emerging and hugely costly field of study. First, it answers the question of how large megaprojects are by measuring them in the units mega, giga, and tera, concluding we are presently entering a new "tera era" of trillion-dollar projects. Second, total global megaproject spending is assessed, at USD 6-9 trillion annually, or 8 percent of total global GDP, which denotes the biggest investment boom in human history. Third, four "sublimes" – political, technological, economic, and aesthetic – are identified to explain the increased size and frequency of megaprojects. Fourth, the "iron law of megaprojects" is laid out and documented: Over budget, over time, over and over again. Moreover, the "break-fix model" of megaproject management is introduced as an explanation of the iron law. Fifth, Albert O. Hirschman's theory of the Hiding Hand is revisited and critiqued as unfounded and corrupting for megaproject thinking in both the academy and policy. Sixth, it is shown how megaprojects are systematically subject to "survival of the unfittest," explaining why the worst projects get built instead of the best. Finally, it is argued that the conventional way of managing megaprojects has reached a "tension point," where tradition is challenged and reform is emerging.

Keywords: Megaproject management; Scale; Four sublimes; Iron law of megaprojects; Break-fix model of megaprojects; Hirschman's Principle of the Hiding Hand; Survival of the unfittest; Tension points

Mega, Giga, Tera: How Big Are Megaprojects?

Megaprojects are large-scale, complex ventures that typically cost a billion dollars or more, take many years to develop and build, involve multiple public and private stakeholders, are transformational, and impact millions of people.[1] Hirschman (1995: vii, xi) calls such projects "privileged particles of the development process" and points out that often they are "trait making," that is, they are designed to ambitiously change the structure of society, as opposed to smaller and more conventional projects that are "trait taking," i.e., they fit into pre-existing structures and do not attempt to modify these. Megaprojects, therefore, are not just magnified versions of smaller projects. Megaprojects are a completely different breed of project in terms of their level of aspiration, lead times, complexity, and stakeholder involvement. Consequently, they are also a very different type of project to manage. A colleague likes to say that if managers of conventional projects need the equivalent of a driver's license to do what they do then managers of megaprojects need a pilot's jumbo jet license.[2] And just like you would not want someone with only a driver's license to fly a jumbo, you don't want conventional project managers to manage megaprojects.

Megaprojects are increasingly used as the preferred delivery model for goods and services across a range of businesses and sectors, like infrastructure, water and energy, information technology, industrial processing plants, mining, supply chains, enterprise systems, strategic corporate initiatives and change programs, mergers and acquisitions, government administrative systems, banking, defense, intelligence, air and space exploration, big science, urban regeneration, and major events. Examples of megaprojects are high-speed rail lines, airports, seaports, motorways, hospitals, national health or pension ICT systems, national broadband, the Olympics, large-scale signature architecture, dams, wind farms, offshore oil and gas extraction, aluminum smelters, the development of new aircrafts, the largest container and cruise ships, high-energy particle accelerators, and the logistics systems used to run large supply-chain-based companies like Amazon and Maersk. Below we will see just how big megaprojects and the megaprojects business are. We will also understand what drives scale.

To illustrate just how big megaprojects are, consider one of the largest dollar figures from public economic debate in recent years, the size of US debt to China. This debt is around one trillion US dollars and is considered so large it may destabilize the world economy if the debt is not managed prudently. With this supersize measuring rod, now consider the fact that the combined cost of just two of the world's largest megaprojects – the Joint Strike Fighter aircraft program and China's high-speed rail project – is more than half of this figure, at 700 billion dollars (see Figure 1). The cost of a mere handful of the largest megaprojects in the world will dwarf almost any other economic figure, and certainly any investment figure.

[Figure 1 app. here]

However, not only are megaprojects large, they are constantly growing ever larger in a long historical trend with no end in sight. When New York's Chrysler Building opened in 1930 at 319 meters it was the tallest building in the world. The record has since been surpassed seven times and from 1998 the tallest building has significantly been located in emerging economies with Dubai's Burj Khalifa presently holding the record at 828 meters. That is a 160 percent increase in building height over 80 years. Similarly, the longest bridge span has grown even faster, by 260 percent over approximately the same period. Measured by value, the size of infrastructure projects has grown by 1.5 to 2.5 percent annually in real terms over the past century, which is equivalent to a doubling in project size two to three times per century (author's megaprojects database). The size of ICT projects, the new kid on the block, has grown much faster, as illustrated by a 16-fold increase from 1993 to 2009 in lines of code in Microsoft Windows, from five to 80 million lines. Other types of megaprojects, from the Olympics to industrial projects, have seen similar developments. Coping with increased scale is therefore a constant and pressing issue in megaproject management.

"Mega" comes from the Greek word "megas" and means great, large, vast, big, high, tall, mighty, and important. As a scientific and technical unit of measurement "mega" specifically means a million. If we were to use this unit of measurement in economic terms, then strictly speaking megaprojects would be million-dollar (or euro, pound, etc.) projects, and for more than a hundred years the largest projects in the world were indeed measured mostly in the millions. This changed with the Second World War, Cold War, and Space Race. Project costs now escalated to the billions, led by the Manhattan Project (1939-46), a research and development program that produced the first atomic bomb, and later the Apollo program (1961-72), which landed the first humans on the moon (Morris, 1994; Flyvbjerg, 2014). According to Merriam-Webster, the first known use of the term "megaproject" was in 1976, but before that, from 1968, "mega" was used in "megacity" and later, from 1982, as a standalone adjective to indicate "very large."

Thus the term "megaproject" caught on just as the largest projects technically were megaprojects no more, but, to be accurate, "gigaprojects" – "giga" being the unit of measurement meaning a billion. However, the term "gigaproject" never really caught on. A Google search reveals that the word "megaproject" is used 27 times more frequently on the web than the term "gigaproject". For the largest of this type of project, costs of 50-100 billion dollars are now common, as for the California and UK high-speed rail projects, and costs above 100 billion dollars not uncommon, as for the International

Space Station and the Joint Strike Fighter. If they were nations, projects of this size would rank among the world's top 100 countries measured by gross domestic product, larger than the economies of, for example, Kenya or Guatemala. When projects of this size go wrong, whole companies and national economies suffer.

"Tera" is the next unit up, as the measurement for a trillion (a thousand billion). Recent developments in the size of the very largest projects and programs indicate we may presently be entering the "tera era" of large-scale project management. If we consider as projects the stimulus packages that were launched by the United States, Europe, and China to mitigate the effects of the 2008 financial and economic crises, then we may speak of trillion-dollar projects and thus of "teraprojects." Similarly, if the major acquisition program portfolio of the United States Department of Defense – which was valued at 1.6 trillion dollars in 2013 – is considered a large-scale project, then this, again, would be a teraproject (United States Government Accountability Office, 2013: 2). Projects of this size compare with the GDP of the world's top 20 nations, similar in size to the national economies of for example Australia or Canada. There is no indication that the relentless drive to scale is abating in megaproject development. Quite the opposite; scale seems to be accelerating.

How Big Is the Megaprojects Business?

But megaprojects are not only large and growing constantly larger, they are also being built in ever greater numbers at ever greater value. The McKinsey Global Institute (2013) estimates global infrastructure spending at USD 3.4 trillion per year 2013-2030, or approximately four percent of total global gross domestic product, mainly delivered as large-scale projects. *The Economist* (June 7, 2008: 80) similarly estimated infrastructure spending in emerging economies at USD 2.2 trillion annually for the period 2009-2018.

To illustrate the accelerated pace at which spending is taking place, consider that in the five years from 2004 to 2008, China spent more on infrastructure in real terms than in the whole of the 20th Century. That is an increase in spending rate of a factor twenty. Similarly, from 2005 to 2008, China built as many kilometers of high-speed rail as Europe did in two decades, and Europe was extraordinarily busy building this type of infrastructure during this period. Not at any time in the history of mankind has infrastructure spending been this high measured as a share of world GDP, according to *The Economist*, who calls it "the biggest investment boom in history." And that's just infrastructure.

If we include the many other fields where megaprojects are a main delivery model – oil and gas, mining, aerospace, defense, ICT, supply chains, mega events, etc. – then a conservative estimate for the global megaproject market is USD 6-9 trillion per year, or approximately eight percent of total global gross domestic product. For perspective, consider this is equivalent to spending five to eight times the accumulated US debt to China, *every year*. That's big business by any definition of the term.

Moreover, megaprojects have proved remarkably recession proof. In fact, the downturn from 2008 helped the megaprojects business grow further by showering stimulus spending on everything from transportation infrastructure to ICT. From being a fringe activity – albeit a spectacular one – mainly reserved for rich, developed nations, megaprojects have recently transformed into a global multi-trillion-dollar business that affects all aspects of our lives, from our electricity bill to how we shop and what we do on the Internet to how we commute.

With so many resources tied up in ever-larger and ever-more megaprojects, at no time has the management of such projects been more important. The potential benefits of building the right projects in the right manner are enormous and are only matched by the potential waste from building the wrong projects, or building projects wrongly. Never has it been more important to choose the most fitting projects and get their economic, social, and environmental impacts right (Flyvbjerg el al., 2003). Never has systematic and valid knowledge about megaprojects therefore been more important to inform policy, practice, and public debate in this highly costly area of business and government.

The Four Sublimes

What drives the megaproject boom described above? Why are megaprojects so attractive to decision makers? The answer may be found in the so-called "four sublimes" of megaproject management (see Table 1). The first of these, the "technological sublime," is a term variously attributed to Miller (1965) and Marx (1967) to describe the positive historical reception of technology in American culture during the nineteenth and early twentieth centuries. Frick (2008) introduced the term to the study of megaprojects and here describes the technological sublime as the rapture engineers and technologists get from building large and innovative projects with their rich opportunities for pushing the boundaries for what technology can do, like building the tallest building, the longest bridge, the fastest aircraft, the largest wind turbine, or the first of anything. Frick applied the concept in a case study of the multi-billion-dollar New San Francisco-Oakland Bay Bridge, concluding "the technological sublime dramatically influenced bridge design, project outcomes, public debate, and the lack of accountability for its [the bridge's] excessive cost overruns" (239).

Flyvbjerg (2012, 2014) proposed three additional sublimes, beginning with the "political sublime," which here is understood as the rapture politicians get from building monuments to themselves and their causes. Megaprojects are manifest, garner attention, and lend an air of proactiveness to their promoters. Moreover, they are media magnets, which appeals to politicians who seem to enjoy few things better than the visibility they get from starting megaprojects. Except maybe cutting the ribbon of one in the company of royals or presidents, who are likely to be present lured by the unique monumentality and historical import of many megaprojects. This is the type of public exposure that helps get politicians re-elected. They therefore actively seek it out.

Next there is the "economic sublime," which is the delight business people and trade unions get from making lots of money and jobs off megaprojects. Given the enormous budgets for megaprojects there are ample funds to go around for all, including contractors, engineers, architects, consultants, construction and transportation workers, bankers, investors, landowners, lawyers, and developers. Finally, the "aesthetic sublime" is the pleasure designers and people who appreciate good design get from building, using, and looking at something very large that is also iconically beautiful, like San Francisco's Golden Gate bridge or Sydney's Opera House.

All four sublimes are important drivers of the scale and frequency of megaprojects described above. Taken together they ensure that strong coalitions exist of stakeholders who benefit from megaprojects and who will therefore work for more such projects.

[Table 1 app. here]

For policy makers, investment in infrastructure megaprojects seems particularly coveted, because, if done right, such investment:

- Creates and sustains employment.
- Contains a large element of domestic inputs relative to imports.
- Improves productivity and competitiveness by lowering producer costs.
- Benefits consumers through higher-quality services.
- Improves the environment when infrastructures that are environmentally sound replace infrastructures that are not (Helm, 2008: 1).

But there is a big "if" here, as in "if done right." Only if this is disregarded – as it often is by promoters and decision makers for megaprojects – can megaprojects be seen as an effective way to deliver infrastructure. In fact, conventional megaproject delivery – infrastructure and other – is highly problematic with a dismal performance record in terms of actual costs and benefits, as we will see below. The following characteristics of megaprojects are typically overlooked or glossed over when the four sublimes are at play and the megaproject format is chosen for delivery of large-scale ventures:

1. Megaprojects are inherently risky due to long planning horizons and complex interfaces (Flyvbjerg, 2006).
2. Often projects are led by planners and managers without deep domain experience who keep changing throughout the long project cycles that apply to megaprojects, leaving leadership weak.
3. Decision-making, planning, and management are typically multi-actor processes involving multiple stakeholders, public and private, with conflicting interests (Aaltonen and Kujala, 2010).
4. Technology and designs are often non-standard, leading to "uniqueness bias" amongst planners and managers, who tend to see their projects as singular, which impedes learning from other projects.[3]
5. Frequently there is overcommitment to a certain project concept at an early stage, resulting in “lock-in” or “capture,” leaving alternatives analysis weak or absent, and leading to escalated commitment in later stages. "Fail fast" does not apply; "fail slow" does (Cantarelli et al., 2010; Ross and Staw, 1993; Drummond, 1998).
6. Due to the large sums of money involved, principal-agent problems and rent-seeking behavior are common, as is optimism bias (Eisenhardt, 1989; Stiglitz, 1989; Flyvbjerg el al., 2009).
7. The project scope or ambition level will typically change significantly over time.
8. Delivery is a high-risk, stochastic activity, with overexposure to so-called "black swans," i.e., extreme events with massively negative outcomes (Taleb, 2010). Managers tend to ignore this, treating projects as if they exist largely in a deterministic Newtonian world of cause, effect, and control.
9. Statistical evidence shows that such complexity and unplanned events are often unaccounted for, leaving budget and time contingencies inadequate.
10. As a consequence, misinformation about costs, schedules, benefits, and risks is the norm throughout project development and decision-making. The result is cost overruns, delays, and benefit shortfalls that undermine project viability during project implementation and operations.

In the next section, we will see just how big and frequent such cost overruns, delays, and benefit shortfalls are.

The Iron Law of Megaprojects

Performance data for megaprojects speak their own language. Nine out of ten such projects have cost overruns. Overruns of up to 50 percent in real terms are common, over 50 percent not uncommon. Cost overrun for the Channel tunnel, the longest underwater rail tunnel in Europe, connecting the UK and France, was 80 percent in real terms. For Denver International Airport, 200 percent. Boston's Big Dig, 220 percent. The UK National Health Service IT system, 400-700 percent. The Sydney Opera House, 1,400 percent (see more examples in Table 2). Overrun is a problem in private as well as public sector projects, and things are not improving; overruns have stayed high and constant for the 70-year period for which comparable data exist. Geography also does not seem to matter; all countries and continents for which data are available suffer from overrun. Similarly, benefit shortfalls of up to 50 percent are also common, and above 50 percent not uncommon, again with no signs of improvements over time and geography (Flyvbjerg et al., 2002, 2005).

[Table 2 app. here]

Combine the large cost overruns and benefit shortfalls with the fact that business cases, cost-benefit analyses, and social and environmental impact assessments are typically at the core of planning and decision-making for megaprojects and we see that such analyses can generally not be trusted. For instance, for rail projects an average cost overrun of 44.7 percent combines with an average demand shortfall of 51.4 percent, and for roads, an average cost overrun of 20.4 percent combines with a fifty–fifty risk that demand is also wrong by more than 20 percent. With errors and biases of such magnitude in the forecasts that form basis for business cases, cost–benefit analyses, and social and environmental impact assessments, such analyses will also, with a high degree of certainty, be strongly misleading. "Garbage in, garbage out," as the saying goes (Flyvbjerg, 2009).

As a case in point, consider the Channel tunnel in more detail. This project was originally promoted as highly beneficial both economically and financially. At the initial public offering, Eurotunnel, the private owner of the tunnel, tempted investors by telling them that 10 percent "would be a reasonable allowance for the possible impact of unforeseen circumstances on construction costs."[4] In fact, costs went 80 percent over budget for construction, as mentioned above, and 140 percent for financing.

Revenues have been half of those forecasted. As a consequence the project has proved non-viable, with an internal rate of return on the investment that is negative, at minus 14.5 percent with a total loss to the British economy of 17.8 billion US dollars. Thus the Channel tunnel detracts from the economy instead of adding to it. This is difficult to believe when you use the service, which is fast, convenient, and competitive with alternative modes of travel. But in fact each passenger is heavily subsidized. Not by the taxpayer this time, but by the many private investors who lost their money when Eurotunnel went insolvent and was financially restructured. This drives home an important point: A megaproject may well be a technological success, but a financial failure, and many are. An economic and financial ex post evaluation of the Channel tunnel, which systematically compared actual with forecasted costs and benefits, concluded that "the British Economy would have been better off had the Tunnel never been constructed" (Anguera, 2006: 291). Other examples of non-viable megaprojects are Sydney's Lane Cove tunnel, the high-speed rail connections at Stockholm and Oslo airports, the Copenhagen metro, and Denmark's Great Belt tunnel, the second-longest under-water rail tunnel in Europe, after the Channel tunnel.

Large-scale ICT projects are even more risky. One in six such projects become a statistical outlier in terms of cost overrun with an average overrun for outliers of 200 percent in real terms. This is a 2,000 percent overincidence of outliers compared to normal and a 200 percent overincidence compared to large construction projects, which are also plagued by cost outliers (Flyvbjerg and Budzier, 2011). Total project waste from failed and underperforming ICT projects for the United States alone has been estimated at 55 billion dollars annually by the Standish Group (2009).

Delays are a separate problem for megaprojects and delays cause both cost overruns and benefit shortfalls. For instance, preliminary results from a study undertaken at Oxford University, based on the largest database of its kind, suggest that delays on dams are 45 percent on average. Thus if a dam was planned to take 10 years to execute, from the decision to build until the dam became operational, then it actually took 14.5 years on average. Flyvbjerg et al. (2004) modeled the relationship between cost overrun and length of implementation phase based on a large data set for major construction projects. They found that on average a one-year delay or other extension of the implementation phase correlates with an increase in percentage cost overrun of 4.64 percent.

To illustrate, for a project the size of London's 26 billion dollars Crossrail project, a one-year delay would cost 1.2 billion dollars extra, or 3.3 million dollars per day. The key lesson here is that in order to keep costs down, implementation phases should be kept short and delays small. This should not be seen as an excuse for fast-tracking projects, i.e., rushing them through decision making for early construction start. Front-end planning needs to be thorough before deciding whether to give the green light to a project or stopping it (Williams and Samset, 2010). But often the situation is the exact opposite. Front-end planning is scant, bad projects are not stopped, implementation phases and delays are long, costs soar, and benefits and revenue realization recedes into the future. For debt-financed projects this is a recipe for disaster, because project debt grows while there is no revenue stream to service interest payments, which are then added to the debt, etc. As a result, many projects end up in the so-called "debt trap" where a combination of escalating construction costs, delays, and increasing interest payments makes it impossible for income from a project to cover costs, rendering the project non-viable. That is what happened to the Channel tunnel and Sydney's Lane Cove tunnel, among other projects.

This is not to say projects do not exist that were built on budget and time and delivered the promised benefits. The Guggenheim Museum Bilbao is an example of that rare breed of project. Similarly, recent metro extensions in Madrid were built on time and to budget (Flyvbjerg, 2005) as were a number of industrial projects (Merrow, 2011). It is particularly important to study such projects to understand the causes of success and test whether success may be replicated elsewhere. It is far easier, however, to produce long lists of projects that have failed in terms of cost overruns and benefit shortfalls than it is to produce lists of projects that have succeeded. To illustrate, as part of ongoing research on success in megaproject management the present author and his associates are trying to establish a sample of successful projects large enough to allow statistically valid answers. But so far they have failed. Why? Because success is so rare in megaproject management that at present it can be studied only as small-sample research, whereas failure may be studied with large samples of projects.

Success in megaproject management is typically defined as projects being delivered on budget, time, and benefits. If, as the evidence indicates, approximately one out of ten megaprojects is on budget, one out of ten is on schedule, and one out of ten is on benefits, then approximately one in a thousand projects is a success, defined as on target for all three. Even if the numbers were wrong by a factor two – so that two, instead of one, out of ten projects were on target for cost, schedule, and benefits, respectively – the success rate would still be dismal, now eight in a thousand. This serves to illustrate what may be called the "iron law of megaprojects": *Over budget, over time, over and over again* (Flyvbjerg, 2011).[5] Best practice is an outlier, average practice a disaster in this interesting and very costly area of management.

The "Break-Fix Model" of Megaproject Management

The above analysis leaves us with a genuine paradox, the so-called "megaprojects paradox," first identified by Flyvbjerg et al. (2003: 1-10). On one side of the paradox, megaprojects as a delivery model for public and private ventures have never been more in demand, and the size and frequency of megaprojects have never been larger. On the other side, performance in megaproject management is strikingly poor and has not improved for the 70-year period for which comparable data are available, at least not when measured in terms of cost overruns, schedule delays, and benefit shortfalls.

Today, megaproject planners and managers are stuck in this paradox because their main delivery method is what has been called the "break-fix model" for megaproject management.[6] Generally, megaproject planners and managers – and their organizations – do not know how to deliver successful megaprojects, or do not have the incentives to do so, and therefore such projects tend to "break" sooner or later, for instance when reality catches up with optimistic, or manipulated, estimates of schedule, costs, or benefits; and delays, cost overruns, etc. follow. Projects are then often paused and reorganized – sometimes also refinanced – in an attempt to "fix" problems and deliver some version of the initially planned project with a semblance of success. Typically lock-in and escalation make it impossible to drop projects altogether, which is why megaprojects have been called the "Vietnams" of policy and management: "easy to begin and difficult and expensive to stop" (White, 2012; also Cantarelli el al., 2010; Ross and Staw, 1993, Drummond, 1998). The "fix" often takes place at great and unexpected cost to those stakeholders who were not in the know of what was going on and were unable to or lacked the foresight to pull out before the break.

The break-fix model is wasteful and leads to misallocation of resources, in both organizations and society, for the simple reason that under this model decisions to go ahead with projects are based on misinformation more than on information. The degree of misinformation varies significantly from project to project, as documented by the large standard deviations that apply to cost overruns and benefit shortfalls (Flyvbjerg et al., 2002, 2005). We may therefore *not* assume, as is often done, that on average all projects are misrepresented by approximately the same degree and, therefore, we are still building the best projects, even if they are not as good as they appear on paper. The truth is, we don't know, and often projects turn out to bring a net loss to the economy, instead of a gain. The cure to the break-fix model is to get projects right from the outset so they don't break, through proper front-end management.

Hirschman's Hiding Hand, Revisited

One may argue, of course, as famously done by Hirschman (1967a: 12-13), that if people knew in advance the real costs and challenges involved in delivering a large project, "they probably would never have touched it" and nothing would ever get built. So it is better not to know, because ignorance helps get projects started, according to this argument. The following is a recent and particularly candid articulation of the nothing-would-ever-get-built argument, by former California State Assembly speaker and mayor of San Francisco, Willie Brown, discussing a large cost overrun on the San Francisco Transbay Terminal megaproject in his *San Francisco Chronicle* column (July 28, 2013, emphasis added):

> "News that the Transbay Terminal is something like $300 million over budget should not come as a shock to anyone. We always knew the initial estimate was way under the real cost. Just like we never had a real cost for the [San Francisco] Central Subway or the [San Francisco-Oakland] Bay Bridge or any other massive construction project. So get off it. In the world of civic projects, the first budget is really just a down payment. *If people knew the real cost from the start, nothing would ever be approved*. The idea is to get going. Start digging a hole and make it so big, there's no alternative to coming up with the money to fill it in."

Rarely has the tactical use by project advocates of cost underestimation, sunk costs, and lock-in to get projects started been expressed by an insider more plainly, if somewhat cynically. It is easy to obtain such statements off the record, but few are willing to officially lend their name to them, for legal and ethical reasons to which we will return. Nevertheless, the nothing-would-ever-get-built argument has been influential with both practitioners and academics in megaproject management. The argument is deeply flawed, however, and thus deserves a degree of attention and critique. Hirschman's text contains the classic formulation of the argument and has served widely as its theoretical justification, as has Sawyer (1952), who directly inspired and influenced Hirschman.[7] A recent celebration of Hirschman's thinking on this point may be found in Gladwell (2013).

Hirschman (1967a: 13-14) observed that humans are "tricked" into doing big projects by their own ignorance. He saw this as positive because just as humans underestimate the difficulties in doing large-scale projects they also underestimate their own creativity in dealing with the difficulties, he believed, and "the only way in which we can bring our creative sources fully into play is by misjudging the nature of the task, by presenting it to ourselves as more routine, simple, undemanding of genuine creativity than it will turn out to be." Hirschman called this the "principle of the Hiding Hand" and it consists of "some sort of invisible or hidden hand that beneficially hides difficulties for us," where the error of underestimating difficulties is offset by a "roughly similar" error in underestimating our ability to overcome the difficulties thus helping "accelerate the rate at which 'mankind' engages successfully in problem-solving."

Sawyer (1952: 199, 203) – in a study of early industrial infrastructure projects that he called a work "in praise of folly" – similarly identified what he called "creative error" in project development as, first, "miscalculation or sheer ignorance" of the true costs and benefits of projects and, second, such miscalculation being "crucial to getting an enterprise launched at all." Sawyer argued that such "creative error" was key to building a number of large and historically important projects like the Welland Canal between Lake Erie and Lake Ontario, the Panama Canal, the Middlesex Canal, the Troy and Greenfield Railroad, and early Ohio roads. For these and other projects, Sawyer found that "the error in estimating costs was at least offset by a corresponding error in the estimation of demand" (p. 200). Hirschman (1967a: 16) explicitly mentioned Sawyer as an inspiration and his "creative error" as a close "approximation" to the Hiding Hand principle.

It is easy to understand why Hirschman's and Sawyer's theories have become popular, especially with people who benefit from megaprojects. The theories encourage promoters and decision makers, like Willie Brown above, to just go ahead with projects and not worry too much about the costs or other problems, because the Hiding Hand will take care of them, eventually. And, in any case, who wants to be the killjoy stopping large projects from going ahead by an overdose of truth? Hirschman (1967b) was an immediate hit with practitioners, from Washington's policy establishment to the United Nations to the World Bank. The head of the bank's Economics Department told Hirschman, "You've helped in part to remove the unease that I have had in reflecting on the fact that if our modern project techniques had been used, much of the existing development in the world would never have been undertaken" (Adelman, 2013: 405). Hirschman's thinking also eventually penetrated academia. Teitz and Skaburskis (2003) follow the Hiding Hand logic when they ask of the huge cost overrun on the Sydney Opera House, “Did people really think that the Sydney Opera House would come in on budget? Or did we all agree to accept the deception and engage in wishful thinking in order to make something that we really wanted happen? ... [D]o Australians really regret those dramatic sails in the harbour? Or would they have regretted more the decision [not to build] that would most reasonably have been based on a fair prediction of costs?”

The logic is seductive, yet precarious. In retrospect, of course Australians do not regret the Sydney Opera House, given what it has done for Australia – though at first the building was not called "dramatic sails in the harbour," but “copulating white turtles” and “something that is crawling out of the ocean with nothing good in mind” designed by an architect with “lousy taste” (Reichold and Graf, 2004: 168). Non-Australians may feel regret, however, for instance the architect of the Opera House, what's his name? Does anybody know? Only few do, which seems surprising given we are talking about the architect of arguably the most iconic building of the 20th century. And if anybody knows the architect is the Dane Jørn Utzon, how come they can hardly ever mention another building designed by him? Because the overrun on the Opera House and the following controversy destroyed Utzon's career and kept him from building more masterpieces. He became that most tragic figure in architecture, the one-building-architect. This is the real regret – and real cost – of the Sydney Opera House. Not premier Joe Cahill's deliberate deception about the cost – to get approval in Parliament – and the consequential huge cost overrun (Flyvbjerg, 2005).

In a meeting held in support of Utzon at Sydney Town Hall in March 1966 – six weeks before the controversy made Utzon leave Australia and the Opera House, in the middle of construction and never to return – the Vienneseborn Australian architect Harry Seidler said, “If Mr. Utzon leaves, a crime will have been committed against future generations of Australians” (Murray, 2004: 105). Seidler was more right than he could have imagined, except the crime would not be limited to Australians, it became a crime against lovers of great architecture everywhere. After winning the Pritzker Prize – the Nobel of architecture – in 2003, Utzon again became widely acclaimed, even in Australia, where the Sydney Opera tour guides for years had been forbidden to even mention his name. But it was too late. Utzon was now 85 and he had not built anything major for decades. So instead of having a whole oeuvre to enjoy, as we have for other architects of his caliber, we have just the one main building. Utzon was 38 when he won the competition for the Opera House – how would the work of the mature master have enriched our lives? We will never know.

As a thought experiment, consider the collected works of architect Frank Gehry, who is in the same league as Utzon; then consider which building you would choose, could you choose only one, and the rest would have to go. So if you chose, say, the Guggenheim Museum Bilbao, then Los Angeles' Disney Concert Hall, Chicago's Jay Pritzker Pavilion, Prague's Dancing House, Seattle's Experience Music Project Museum, etc. would be eliminated. This illustrates the high price the government of New South Wales has imposed on the world by mismanaging the planning of the Sydney Opera House and deliberately playing the game of creative error and Hiding Hand. Even if the Opera House may be an extreme case, Sydney drives home an important point: managing by creative error is risky and disruptive, sometimes in drastic and unexpected ways, and the Hiding Hand isn't big enough to hide all, or even most, errors.

Hirschman's and Sawyer's theories are also flawed at a more basic level, that of validity. A close look reveals the theories to be based on small samples and biased data. Hirschman studied only 11 projects, or a few more if we count subprojects, Sawyer ten to 15. This important fact is typically ignored when the Hiding Hand principle is discussed. Hirschman (1967a: 7, 14) seemed aware of the weak foundations and limited applicability of the principle when he called it "speculative" and useful only "[u]p to a point." To a colleague he admitted at the time of publication that his book was "an exploration, an experiment;" to another he said he had deliberately biased his analysis "to emphasize unexpected successes" (Adelman, 2013: 404-5). Even so, Hirschman went on to call the Hiding Hand a "general principle of action" and brazenly used a name for it with clear connotations to Adam Smith's famous Invisible (Hidden) Hand. Evidently, the temptation to formulate an "economic law" was too strong, despite the weak and biased data. Sawyer (1952: 204) warned the reader up front that his study must be considered a "marginal and distinctly limited note." He admitted the study considers only a "quite special kind of case" and neglects projects that were "failures" in order to focus on projects that were "successful" in the sense that "an original gross miscalculation as to costs ... was happily offset by at least a corresponding underestimation of demand." Sawyer's results thus do not describe a general characteristic of large projects, but a characteristic of his biased sample that includes only projects lucky enough to have had large underestimates of costs compensated by similarly large or larger underestimates of demand. Some would call this data fishing and the only redeeming factor is that Sawyer was disarmingly honest and tongue-in-cheek humoristic about it. He appears to not have expected to be taken wholly seriously, which unfortunately he was by some, including Hirschman.

Today we have much better data and theories on megaproject performance than at the time of Hirschman and Sawyer. We now know that, while there may be elements of truth in these authors' theories for certain types of projects and contexts, their samples and conclusions are not representative of the project population. In particular, their odd asymmetrical assumption that optimism would apply to cost estimates but pessimism to estimates of benefits has been solidly disproved by Kahneman and Tversky (1979a, b) and behavioral economists building on their work. They found that optimism bias applies to estimates of costs and benefits, both. An optimistic cost estimate is low and leads to cost overrun, whereas an optimistic benefit estimate is high and results in benefit shortfalls. Thus errors of estimation do not cancel each other out, as Hirschman would have it; the exact opposite happens, errors generally reinforce each other.

Megaproject planners and managers would therefore be ill advised to count on Hiding Hands, creative errors, or any other general principle according to which underestimates of costs would be balanced by similar underestimates of benefits. We also now know it would be equally foolhardy to assume that downstream human creativity may be generally counted on to solve problems that planners and managers overlook or underestimate when the decision is made to go ahead with a project. The data show that for too many projects with front-end problems such creativity never materializes and projects end up seriously impaired or non-viable. Initial problems, if not dealt with up front, tend not to go away. The iron law of megaprojects, described above, trumps Hirschman's Hiding Hand at a high level of statistical significance, and we know why. The Hiding Hand is itself an example of optimism and does therefore not capture the reality of megaproject management. For such capture, and true explanatory power, we must turn to theories of optimism bias, the planning fallacy, strategic misrepresentation, and principal-agent behavior.

Survival of the Unfittest

In sum, one does megaprojects – and megaproject management – a disservice if one claims they can only be done through the Hiding Hand, creative error, or downright deception. It is, undoubtedly, quite common for project promoters and their planners and managers to believe their projects will benefit society and that, therefore, they are justified in "cooking" costs and benefits to get projects built (Wachs, 1990; Pickrell, 1992). Such reasoning is faulty, however. Underestimating costs and overestimating benefits for a given project – which is the common pattern, as described above – leads to a falsely high benefit-cost ratio for that project, which in turn leads to two problems. First, the project may be started despite the fact it is not financially and economically viable. Or, second, it may be started instead of another project that would have shown itself to yield higher returns than the project started, had the real costs and benefits of both projects been known. Both cases result in Pareto inefficiency, that is, the misallocation of resources and, for public projects, waste of taxpayers' money. Thus for reasons of economic efficiency alone the argument must be rejected that cost underestimation and benefit overestimation are justified to get projects started.

But the argument must also be rejected for legal and ethical reasons. In most democracies, for project promoters, planners, and managers to deliberately misinform legislators, administrators, bankers, the public, and the media about costs and benefits would not only be considered unethical but in some instances also unlawful, for instance where civil servants would intentionally misinform cabinet members, or cabinet members would intentionally misinform parliament. In private corporations, Sarbanes-Oxley-like legislation similarly makes deliberate misrepresentation a crime under many circumstances, which in the US is punishable with prison up to 20 years.[8] There is a formal "obligation to truth" built into most democratic constitutions – and now also in legislation for corporate governance – as a means for enforcing accountability. This obligation would be violated by deliberate misrepresentation of costs and benefits, whatever the reasons for such misrepresentation may be. Not only economic efficiency would suffer but also democracy, good governance, and accountability.

A first answer to the skeptics' question of whether enough megaprojects would be undertaken if some form of misrepresentation of costs and benefits was not involved is, therefore, that even if misrepresentation was necessary in order to get projects started, such misrepresentation would typically not be defensible in liberal democracies – and especially not if it was deliberate – for economic, legal, and ethical reasons.

A second answer is that misrepresentation is not necessary to undertake projects, because many projects exist with sufficiently high benefits and low enough costs to justify building them. Even in the field of innovative and complex architecture, which is often singled out as particularly difficult, there is the Basque Abandoibarra urban regeneration project, including the Guggenheim Museum Bilbao, which is as complex, innovative, and iconic as any signature architecture, and was built on time and budget. Complex rail projects, too, like the Paris-Lyon high-speed rail line and the London Docklands light railway extension have been built to budget. The problem is not that projects worth undertaking do not exist or cannot be built on time and budget. The problem is that the dubious and widespread practices of underestimating costs and overestimating benefits used by many megaproject promoters, planners, and managers to promote *their* pet project create a distorted hall-of-mirrors in which it is extremely difficult to decide which projects deserve undertaking and which not.

In fact the situation is even worse than that. The common practice of depending on the Hiding Hand or creative error in estimating costs and benefits – thus "showing the project at its best" as an interviewee put it in a previous study – results in an inverted Darwinism, i.e., the "survival of the unfittest" (Flyvbjerg, 2009: 352). It is not the best projects that get implemented in this manner, but the projects that look best on paper. And the projects that look best on paper are the projects with the largest cost underestimates and benefit overestimates, other things being equal. But the larger the cost underestimate on paper, the greater the cost overrun in practice. And the larger the overestimate of benefits, the greater the benefit shortfall. Therefore the projects that have been made to look best on paper become the worst, or unfittest, projects in reality, in the sense that they are the very projects that will encounter most problems during construction and operations in terms of the largest cost overruns, benefit shortfalls, and risks of non-viability. They have been designed like that, as disasters waiting to happen.

The result is, as even the industry’s own organ, the Major Projects Association, has said, that “too many projects proceed that should not have done” (Morris and Hough, 1987: 214). One might add that projects also exist that do not proceed but should have, had they not lost out, not to better projects but to projects with “better” creative error, that is "better" manipulated estimates of costs and benefits.

Light at the End of the Tunnel?

Fortunately, signs of improvement in megaproject management have recently appeared. The tacit consensus that misrepresentation is an acceptable business model for project development is under attack. Shortly after taking office, President Obama openly identified “the costly overruns, the fraud and abuse, the endless excuses” in public procurement for major projects as key policy problems (White House, 2009). The *Washington Post* rightly called this “a dramatic new form of discourse” (Froomkin, 2009). Other countries are seeing similar developments. Before Obama it was not common in government or business to talk openly about overruns, fraud, and abuse in relation to megaprojects, although they were widespread then as now. The few who did so were ostracized. However, as emphasized by Wittgenstein (2009), we cannot solve problems we cannot talk about. So talking is the first step.

A more material driver of improvement is the fact that the largest projects are now so big and consequential in relation to individual businesses and agencies that cost overruns, benefit shortfalls, and risks from even a single project may bring down executives and whole corporations. This happened with the Airbus A380 superjumbo, when delays, cost overruns, and revenue shortfalls cost the CEO and other top managers their jobs. The CEO of BP was similarly forced to step down and the company lost more than half its value when the Deepwater Horizon offshore oil drilling rig caught fire and caused the world's largest oil spill in the Gulf of Mexico in 2010. At Kmart, a large US retailer, the entire company went bankrupt when a new multi-billion-dollar ICT enterprise system, which was supposed to make Kmart competitive with Walmart and Target, went off the rails (Flyvbjerg and Budzier, 2011). In China, corruption and related safety issues on the country's 300 billion dollar high-speed rail program have caused massive reputational damage, and cost the railway minister his political life in 2011. Today, if you are a CEO, minister, permanent secretary, or other top manager and want to be sure to keep your job, you will want to manage your megaprojects properly. Episodes like these have triggered leaders to begin looking for better megaproject delivery.

Even the wealth of whole cities and nations may be affected by a single megaproject failure. In Hong Kong, months of hiccups at the opening of a new international airport made traffic go elsewhere resulting in a fall in GNP for the entire city state. For Greece, a contributing factor to the country's 2011 debt default was the 2004 Athens Olympics, where cost overruns and incurred debt were so large they negatively affected the credit rating of the whole nation, substantially weakening the economy in the years before the 2008 international financial crisis. This resulted in a double dip, and disaster, for Greece, when other nations had only a single dip. Likewise, in Japan 2011, the nuclear tragedy at Fukushima significantly and negatively impacted the national economy as a whole. It is becoming increasingly clear that when megaprojects go wrong they are like the proverbial bull in the china shop: it takes just one to smash up the entire store. It is becoming similarly clear to many involved that something needs to be done about his.

In the UK at the beginning of the century, cost underestimation and overrun was rampant in so many projects in so many ministries that the reliability of national budgets suffered, leading the chancellor to order a Green Book on the problem and how to solve it (HM Treasury, 2003). This move inspired other countries to follow suit. Lawmakers and governments have begun to see that national fiscal distress and unreliable national budgets are too high a price to pay for the conventional way of managing megaprojects. In 2011, the UK Cabinet Office and HM Treasury joined forces to establish a Major Projects Authority with an enforceable mandate directly from the Prime Minister to oversee and direct the effective management of all large-scale projects that are funded and delivered by central government. In 2012, the Authority established, in collaboration with Oxford University, a Major Projects Leadership Academy – the first of its kind in the world – to train and authorize all UK civil servants in charge of central government major projects.[9]

Outside of government, private finance in megaprojects has been on the rise over the past twenty years. This means that capital funds, pension funds, and banks are increasingly gaining a say in management. Private capital is no panacea for the ills in megaproject management, to be sure; in some cases private capital may even make things worse (Hodge and Greve, 2009). But private investors place their own funds at risk. Funds and banks can therefore be observed to not automatically accept at face value the cost and revenue forecasts of project managers and promoters. Banks typically bring in their own advisers to do independent forecasts, due diligence, and risk assessments, which is an important step in the right direction (Flyvbjerg, 2013). The false assumption that one forecast or one business case may contain the whole truth about a project is problematized. Instead project managers and promoters are getting used to the healthy fact that different stakeholders hold different forecasts and that forecasts are not only products of data and mathematical modeling but also of power and negotiation. Why is this more healthy? Because it undermines trust in the misleading forecasts often produced by project promoters.

Moreover, democratic governance is generally getting stronger around the world. Corporate scandals, from Enron and onwards, have triggered new legislation and a war on corporate deception that is spilling over into government with the same objective: to curb waste and promote good governance. Although progress is slow, good governance is gaining a foothold even in megaproject management. The main drivers of reform come from outside the agencies and industries conventionally involved in megaprojects, which is good because it increases the likelihood of success. For example, the UK Treasury now requires that all ministries develop and implement procedures for megaprojects that will curb so-called "optimism bias" (Flyvbjerg, 2006). Funding will be unavailable for projects that do not take into account such bias, and methods have been developed for doing this (UK Department for Transport, 2006). Switzerland and Denmark have followed the lead of the UK (Swiss Association of Road and Transportation Experts, 2006; Danish Ministry for Transport and Energy, 2006, 2008). In Australia, the Parliament of Victoria has conducted an inquiry into how government may arrive at more successful delivery of significant infrastructure projects (Parliament of Victoria, 2012). Similarly, in the Netherlands the Parliamentary Committee on Infrastructure Projects did extensive public hearings to identify measures that will limit the misinformation about large infrastructure projects presented to the Parliament, public, and media (Dutch Commission on Infrastructure Projects, 2004). In Boston, the government has sued to recoup funds from contractor overcharges for the Big Dig related to cost overruns. More countries and cities are likely to follow the lead of the UK, Australia, Switzerland, Denmark, the Netherlands, and Boston in coming years.

Finally, research on how to reform megaproject management – examples of which has been referenced above – is beginning to positively impact practice. Such research has recently made great strides in better understanding what causes the many failures in megaproject delivery, and how to avoid them. For instance, we now understand that optimism bias and strategic misrepresentation are significantly better explanations of megaproject outcomes than previous explanations, including Hirschman's Hiding Hand and Sawyers creative error discussed above. And with a better understanding of causes has followed a better grasp of cures, from front-end management (Williams and Samset, 2010) to reference class forecasting (Kahneman, 2011: 243-254; Flyvbjerg, 2006) to institutional design for better accountability (Scott, 2012; Bruzelius et al., 1998). Moreover, research is beginning to help us understand success and how to replicate it. Perhaps most importantly, researchers have begun to take seriously the task of feeding their research results into the public sphere so they may effectively form part of public deliberation, policy, and practice (Flyvbjerg, 2012; Flyvbjerg et al., 2012).

With these developments things are moving in the right direction for megaproject management. It is too early to tell whether the reform measures being implemented will ultimately be successful. It seems unlikely, however, that the forces that have triggered the measures will be reversed, and it is those forces that reform-minded individuals and groups need to support and work with in order to improve megaproject management. This is the "tension point" where convention meets reform, power balances change, and new things are happening. In short, it is the place to be as a megaproject planner, manager, scholar, student, owner, or interested citizen.[10]

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Figure 1: Size of selected megaprojects, measured against one of the largest dollar-figures in the world, accumulated US debt to China.

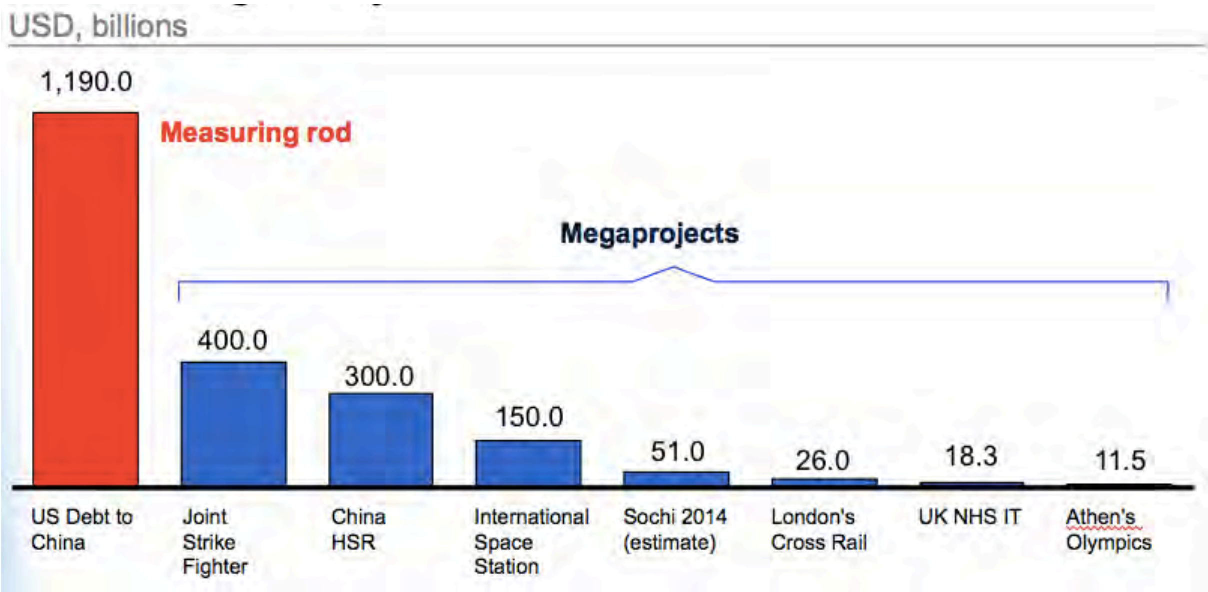

Table 1: The "Four Sublimes" that drive megaproject development.

Type of Sublime	Characteristic
Political	The rapture politicians get from building monuments to themselves and their causes, and from the visibility this generates with the public and media
Technological	The excitement engineers and technologists get in pushing the envelope for what is possible in "longest-tallest-fastest" type of projects
Economic	The delight business people and trade unions get from making lots of money and jobs off megaprojects, including for contractors, workers in construction and transportation, consultants, bankers, investors, landowners, lawyers, and developers
Aesthetic	The pleasure designers and people who love good design get from building and using something very large that is also iconic and beautiful, like the Golden Gate bridge

Table 2: Large-scale projects have a calamitous history of cost overrun.

Project	Cost Overrun (%)
Suez Canal, Egypt	1,900
Scottish Parliament Building, Scotland	1,600
Sydney Opera House, Australia	1,400
Montreal Summer Olympics, Canada	1,300
Concorde supersonic aeroplane, UK, France	1,100
Troy and Greenfield railroad, USA	900
Excalibur Smart Projectile, USA, Sweden	650
Canadian Firearms Registry, Canada	590
Lake Placid Winter Olympics, USA	560
Medicare transaction system, USA	560
National Health Service IT system, UK	550
Bank of Norway headquarters, Norway	440
Furka base tunnel, Switzerland	300
Verrazano Narrow bridge, USA	280
Boston's Big Dig artery/tunnel project, USA	220
Denver international airport, USA	200
Panama canal, Panama	200
Minneapolis Hiawatha light rail line, USA	190
Humber bridge, UK	180
Dublin Port tunnel, Ireland	160
Montreal metro Laval extension, Canada	160
Copenhagen metro, Denmark	150
Boston-New York-Washington railway, USA	130
Great Belt rail tunnel, Denmark	120
London Limehouse road tunnel, UK	110
Brooklyn bridge, USA	100
Shinkansen Joetsu high-speed rail line, Japan	100
Channel tunnel, UK, France	80
Karlsruhe-Bretten light rail, Germany	80
London Jubilee Line extension, UK	80
Bangkok metro, Thailand	70
Mexico City metroline, Mexico	60
High-speed Rail Line South, The Netherlands	60
Great Belt east bridge, Denmark	50

Notes

[1] As a general rule of thumb, "megaprojects" are measured in billions of dollars, "major projects" in hundreds of millions, and "projects" in millions and tens of millions. Megaprojects are sometimes also called "major programs."

[2] The colleague is Dr. Patrick O'Connell, Practitioner Director of Major Program Management at Oxford University's Saïd Business School.

[3] "Uniqueness bias" is here defined as the tendency of planners and managers to see their projects as singular. This particular bias stems from the fact that new projects often use non-standard technologies and designs, leading managers to think their project is more different from other projects than it actually is. Uniqueness bias impedes managers' learning, because they think they have nothing to learn from other projects as their own project is unique. This lack of learning may explain why managers who see their projects as unique perform significantly worse than other managers (Budzier and Flyvbjerg 2013). Project managers who think their project is unique are therefore a liability for their project and organization. For megaprojects this would be a mega-liability.

[4] Quoted from "Under Water Over Budget," *The Economist*, 7 October 1989, 37–8.

[5] *The Economist* (March 10, 2012: 55) describes the near-certainty of large cost overruns and delays in transportation infrastructure projects as "the iron law of infrastructure projects." Our data show the iron law is not limited to infrastructure; it applies to megaprojects in general and covers benefit shortfalls in addition to cost overruns and delays.

[6] The author owes the term "break-fix model" to Dr. Patrick O'Connell, Practitioner Director of Oxford University's BT Centre for Major Programme Management.

[7] Two versions of Hirschman's text exist (1967a, 1967b). The version of the text referenced here is the one published in *Development Projects Observed* (Hirschman 1967a), which is the original text. The differences between the two texts are minor and are mainly due to the editing of Irving Kristol, editor of *The Public Interest* at the time of publication (Adelman 2013: 405).

[8] The Sarbanes-Oxley Act of 2002 pioneered this area in the US, but many other countries have since followed suit with similar legislation. Section 802[a] (18 U.S.C. § 1519) of the original act states that whoever knowingly alters, destroys, mutilates, conceals, covers up, falsifies, or makes a false entry in any record, document, or tangible object with the intent to impede, obstruct, or influence the investigation or proper administration of any matter within the jurisdiction of any department or agency of the United States or any case filed under title 11, or in relation to or contemplation of any such matter or case, shall be fined, imprisoned not more than 20 years, or both.

[9] For full disclosure: The author was involved in the planning, start up, and delivery of the UK Major Projects Leadership Academy.

[10] See Flyvbjerg et al. (2012) regarding the use of tension points for triggering change in policy and practice, including for megaprojects.

Tab 11

RISK.1027

Estimate Accuracy: Dealing with Reality

John K. Hollmann, PE CCE CEP

ABSTRACT—This paper reviews over 50 years of empirical cost estimate accuracy research and compares this reality to common but unrealistic management expectations. The empirically-based accuracy research of John Hackney, Edward Merrow, Bent Flyvbjerg and others on large projects in the process industries is summarized. The paper then highlights risk analysis methods documented in recent AACE Recommended Practices that yield outputs based upon and comparable to empirical reality. Tragically, many cost engineers are facilitating management's collective and sometimes willful biases regarding accuracy by using flawed, unreliable risk analysis methods; those who use empirically valid practices face the fate of Cassandra. The paper is intended as a fundamental reference on the topic of accuracy as well as a call for our profession to use reliable practices and speak the truth to management. Attendees will gain an understanding of estimate accuracy reality, the risks that drive it, management's biases about it, and methods that analyze risks and address the biases in a way that results in more realistic accuracy forecasts, better contingency estimates and more profitable investments.

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Introduction

Accuracy is a measure of how a cost estimate will differ from the final actual outcome. It is also a measure of cost uncertainty or risk (these terms are essentially synonymous in TCM). Empirical estimate accuracy data has been researched for over 50 years [30]. In addition, reasonably reliable practices for quantifying project cost uncertainty have been recommended by AACE and others. However, the level of industry understanding of the reality of accuracy and how well risk analysis methods forecast it is generally poor. Investment decision makers seem particularly unaware of our research and recommended practices. Sometimes they are aware but seem to ignore them. Worse, many cost engineers facilitate management ignorance by standardizing their wishful thinking (i.e., tunneling or neglecting sources of uncertainty) as exemplified by bias towards 10% contingency and +10/-10% range [42]. Poor investment decisions may result from using risk analysis methods that are known to be a "disaster" when systemic risks are present [27].

One researcher said this behavior verges on "criminal" [19]. Cost disasters and criminality are economic in nature, but deadly serious to owners, investors and tax-payers; one must ultimately take responsibility for our role in their economic well-being. To help improve on the situation, this paper surveys the research facts (reality), exposes flawed practices and highlights better practices.

The paper summarizes data from well referenced studies by others; however, the data confirms the author's experience. The author's data and observations are added as well as observations by others. While fact and opinion are mixed, it is hoped that readers will draw the same conclusions as the paper and work to improve the situation.

Studies of Overall Estimate Accuracy

How accurate have cost estimates been for owners? To answer this, references providing empirical data on estimate accuracy and cost uncertainty were sought. This paper focuses on engineering and construction projects in the process (e.g., oil, gas, chemicals, mining, metals, utilities, etc.) and infrastructure (often associated with process plant projects) industries. These are generally characterized by complexity, unique work scopes, design change and sometimes new technology. The chosen references represent academic, research, consulting and industry practitioner sources. Empirical research on defense, aerospace and IT projects was found but excluded; their experience is analogous but more extreme [13,16, and 20].

Estimate accuracy and cost uncertainty data from 12 empirical studies are summarized in Table 1. These include over 1,000 projects with samples ranging from about 20 to 250 projects each. The projects were typically large enough to affect enterprise success (i.e., typically one million US dollars up to megaprojects). The costs studied are the costs to the owners. Study purposes varied; however, the typical the questions were: "*what is the accuracy of our estimates and why*?" in reaction to a perceived preponderance of cost overruns.

Study Attributes				Estimate Accuracy of Sample		
Study Reference	**Projects**	**Reference Point**	**Adjusted?**	**P10 or similar**	**P50 or mean(µ)**	**P90 or similar**
[14] Figure 1	63 Mining and Metals	From Bankable Feasibility	No	~<3>%	+16%	~+70%
[15] Page 8	100 Mining	From Authorized Feasibility	Scope & time	<15>%	0%	+43%
[19] Figure 1	258 Transport	From estimate at "Decision"	Time	~<15>%	~+15%	~+100%
[22] Figure 18.1	22 Process Plants	<500 Rating (assumed funding)	Scope & time	+2%	+10%	+39%
[31] Table 2	167 Road/Rail	Varied reference	No	~<32>%	µ= +15%	~+62%
[36] Table 4.1	47 Mega Process Plant	From start of "Detailed Engr"	Time	<14>%	µ= +88%	+190%
[35] Table 4.3	30 Process New Technology	RAND Class 2	Scope & time	+7%	µ= +28%	+59%
[34] Page I.3.4	56 Hydropower	From "Appraisal"	Time	<15>%	µ= +24%	+65%
[39] Database	188 US Pipeline 2000-2008	From FERC filing	No	<21>%	0%	+34%
[40] Figure 3	Water Projects-5 Aus. States	From Budget	No	µ for best state = +8%		µ for worst state = +80%
[43] Figure 2	36 Refinery Turnarounds	From Budget	Uncertain	+8%	µ= +23%	+38%
[46] Table 1	21 Mining and Metals	From Feasibility	Time	3 of 21 underran	µ= +17%	2 worst µ= +55%

Table 1—Empirical Estimate Accuracy Studies (Typically From the Funding Estimate)

In summary, the approximate range of ranges for accuracy or uncertainty around the reference amounts are as follows:

- P10: -32% to +8% (average about -9%)
- P50 or mean: 0% to +88% (average about 21%)
- P90: +34% to 190% (average about 70%)

The "accuracy" shown is the percentage variation of the final actual cost from the reference estimate. The reference estimate was usually the basis for an actual or *defacto* investment decision by the owner. Estimate names are industry specific; for example, "feasibility" is the funding estimate for mining projects, but not for projects in other industries. The reference estimates usually include contingency; therefore, the accuracies are understated in respect to base estimates without contingency. From the author's experience, the contingency applied at sanction is usually between 5 and 15 percent.

The statistics provided ranged from mean and standard deviations alone to distribution charts or tables or values at various confidence levels. For comparison, the accuracies in table 1 are summarized at *approximate* p10/p50/p90 confidence levels where the "p" value indicates the percentage that underran. If a mean was provided (μ), it is shown as such. If p-values were not provided, they were approximated from the mean and standard deviation assuming a normal distribution; i.e., p90 equals the mean plus 1.28 times standard deviation (the ~ symbol indicates an approximation.) This approximation underestimates the high range when actual/estimate accuracy data is skewed to the high side (i.e., actual data is not normally distributed).

The project samples were not scientifically random, but were not selected specifically because their estimates were inaccurate; the authors generally considered the projects in their samples to be reasonably representative. Studies done in reaction to overruns may be biased toward that experience; however, the number of studies and the variety of industries, regions and project types covered indicate that cost overruns are prevalent for large process industry projects.

The quality of the datasets varied, but in general the authors lament the poor state of historical project records. For many studies, the only reliable data was the cost at the time of project funding approval (i.e., sanction or investment decision) and the cost at completion. However, some studies were corrected for major scope changes and escalation which many practitioners would not expect an estimate to cover.

The key observation is that <u>in no case was the nominal p90 value ever less than +34% of the funding estimate</u> (i.e., about +40 to +50% of the base estimate). Also, the average mean or median overrun is about 21%. This is the best picture we have of reality for large process industry projects with all their imperfections and risks (unfortunately, causal data is lacking).

Arguably, the most notable studies are by John Hackney and Edward Merrow because these are the foundation for process industry phase-gate project systems [22, 35]. However, the studies by Dr. Bent Flyvbjerg are perhaps best known in the popular press [19]. Dr. Flyvbjerg has made the following statements regarding industry estimating practices: "*We conclude that the cost estimates used in public debates, media coverage, and decision making for transportation infrastructure* *development are highly, systematically, and significantly deceptive." "(those) who value honest numbers should not trust the cost estimates presented by infrastructure promoters and forecasters."* He adds, "*institutional checks and balances—including financial, professional, or even criminal penalties for consistent or foreseeable estimation errors—should be developed to ensure the production of less deceptive cost estimates* [19]."

Merrow disagrees with Flyvbjerg in the following: *"There is widely held belief that large public sector projects tend to overrun because the estimates are deliberately low-balled. Our (IPA's) analysis of large private sector projects suggests that no Machiavellian explanation is required. Large projects have a dismal track record because we have not adjusted our practices to fit the difficulty that the projects present* [33]."

Regardless of motives and causes, large process and infrastructure projects (and defense, aerospace and IT) are frequently overrunning our funding estimates and by very large margins. The search found no research that showed otherwise. Further, as "forecasters" (as one is referred to by Flyvbjerg) we are failing to reliably predict the proper point of funding including contingency, but the *range* of project cost uncertainty.

Studies of Estimate Accuracy Progression Versus Level of Scope Definition
It is generally agreed that the less well defined the project scope is, the wider the estimate accuracy range will be. This is a premise of phase-gate project systems. Table 2 summarizes accuracy studies from among they paper's sample that also addressed accuracy and uncertainty at various levels of scope definition *approximated* to AACE classifications (Class 5 to 1).

	Conf. Level	Class 5	Class 4	Class 3	Class 2	Class 1
		Actual % Difference from Estimate (or as stated)				
Hackney [22] -Conventional process plant -Range around the **Base Estimate** -Adjusted for scope and time	P10	+36	+34	+9	+2	-1
	P50	+60	+41	+15	+6	+4
	P90	+80	+45	+21	+12	+11
RAND [35] -Process plant; newer technology -Range around the **Funded Amount** -Adjusted for scope and time	P10	+39	+18	+9	+5	-1
	P50	+100	+60	+28	+20	+7
	P90	+260	+150	+58	+41	+18
Harbuck [23] -Avg. of 3 Transport Study Averages -Range around the **Construction Estimate** (<u>not the final actual costs</u>) -No adjustment for scope & time	Mean	+49	+37	+18	study base	n/a

Table 2 - Empirical Estimate Accuracy Studies (Progression by Level of Scope Definition)

Complicating the comparison, each study has different data attributes and uses different scope definition rating schemes (i.e., AACE classification ratings were not used). However, the author's experience is that process industry funding decisions are being made based on scope definition somewhat better than AACE Class 4, but worse than Class 3. Research indicates that the design development necessary to thoroughly mitigate definitional risk includes *issued-for-design,* signed-off process and instrumentation diagrams (P&IDs) for all process and utility units; the author rarely sees this level of definition at the time of funds authorization [4].

The key observation from Table 2 is that even projects funded on better scope definition (AACE Class 3) tend to be overrun; there is a huge potential for overruns if the scope is more poorly defined than Class 3. Note that the Hackney and RAND models based on this data are available in working Excel tools found at the AACE website (www.aacei.org [11]).

What Our Estimates Say and What Owners Want Are the Same (i.e., Wishful Thinking)
The next question is "are the overrunning projects within the cost range of our risk analyses?" Unfortunately, they usually are not. The author has reviewed many industry risk analyses by owner companies and their EPC contractors and their p90 forecast is rarely great than 30% over the base estimate excluding contingency. Table 3 provides an indicative sample of risk analysis outcomes.

Project Type	Estimate Class	Preparer	P10	P50	P90	Method	Notes
Mega, Expansion, Refining	Class 4	Owner	<15>%	+13%	+45%	Ranging w/M-C (validated)	Exceeded P90 at next estimate
Large, New, Mining	Class 4	EPC	+7%	+13%	+19%	Ranging w/M-C	Remote, developing country
Small, Revamp, Refining	Class 3	Owner	<3>%	+5%	+13%	Ranging w/M-C	Plant-based project
Mega, New, Metals	Class 4	EPC	+0%	+5%	+13%	Ranging w/M-C	Low wage country
Mega, Expansion, Refining	Class 4	EPC	+2%	+10%	+18%	Ranging w/M-C	Largest in region, low wage country
Mega, Upgrader	Class 4	EPC	<3>%	+12%	+28%	Ranging w/M-C	Remote, severe winter

Table 3 - Reported Accuracy Ranges from Owner and EPC Contractor Risk Analyses

The first project risk analysis shown in Table 3 had a p90 value of +45%; however, the risks on this project were extreme and while the team captured some of them, the range was overrun by the next phase estimate. P50 values are often as little as 5% even for highly risky projects. The author's experience is that despite extensive risk registers and brainstorming sessions, most risk *quantification* is dominated by an estimator's bias in which the team consciously or unconsciously perceives uncertainty in terms of estimate and takeoff assumptions and math (i.e., "estimator's risks"). A high (p90) range of about +30% reflects the perceived worst case uncertainty around quantities, rates, pricing and productivity while unrealistically assuming the scope is fixed, the execution strategy and plan is never changed, no risk events occur and if they do, risk responses are always effective. The result is a range that seems to be what the owner wants to hear.

So the next question is "what does the owner want to hear?" Table 4 provides an indicative sample from different industry segments of owner accuracy range expectations as stated in their phase-gate project scope development processes.

	CLASS 5	**CLASS 4**	**CLASS 3**
	AACE 18R-97 RANGE of RANGES		
	-20/50% to +30/100%	-15/30% to +20/50%	-10/20% to +10/30%
COMPANY	**OWNER "TARGETS"** • *Most misquote AACE (AACE has not quoted target ranges for 15 years)* • *NONE state what the confidence interval statistically represents*		
Oil Sands	-30 to +50%	-20 to +30%	+/- 10%
Power	-30 to +50%	-15 to +30%	-5 to +15%
NOC Oil	-/+50%	-/+30%	-/+15%
Mining	-/+50%	-/+25%	-/+10%
Integrated Oil	-15 to +50%	-10 to +30%	-10 to +25%

Table 4 - Owner Phase-Gate Target Accuracy Ranges Vs. AACE Classes and Empirical Studies

The table compares the owner targets to the range-of-ranges in the **AACE Recommended Practice 18R-97** [4]. Is it coincidence that the owner p90 targets in table 4 are about the same as the p90 values estimated in table 3?

By quoting specific accuracy range targets in their processes, owners display a dangerous misunderstanding of risk and estimating. Once a project plan reaches the target level of scope definition (e.g., Class 3), the residual risk and its potential impact is a project scope attribute and no estimator can appreciably improve the accuracy range by doing a "better estimate." For a project with substantial risks (most large projects), the company accuracy ranges in table 4 have <u>no relevance.</u> Unfortunately, targets tend to pre-determine risk analysis outcomes; i.e., they drive the risk analysis outcomes seen in table 3 (owners get what they ask for). Targets are *prima facie* evidence of risk ignorance (tunneling) driven by the inflated expectations that phase-gate processes alone will manage risks.

Further, the communication of targets by many owners is statistically meaningless. First, many misquote AACE Recommended Practices by stating that the targets are "per AACE" when no AACE document includes specific targets [4]. Also, few state the confidence interval represented or the reference value that the range is around (the base or the funded amount?).

To wrap up the target/as-estimated versus actual accuracy discussion, figure 1 shows the averages of table 1 (Reality) and table 3 (As Estimated) as log-normal curves with p10/50/90 values comparable to the table 1 and 3 averages for those confidence levels.

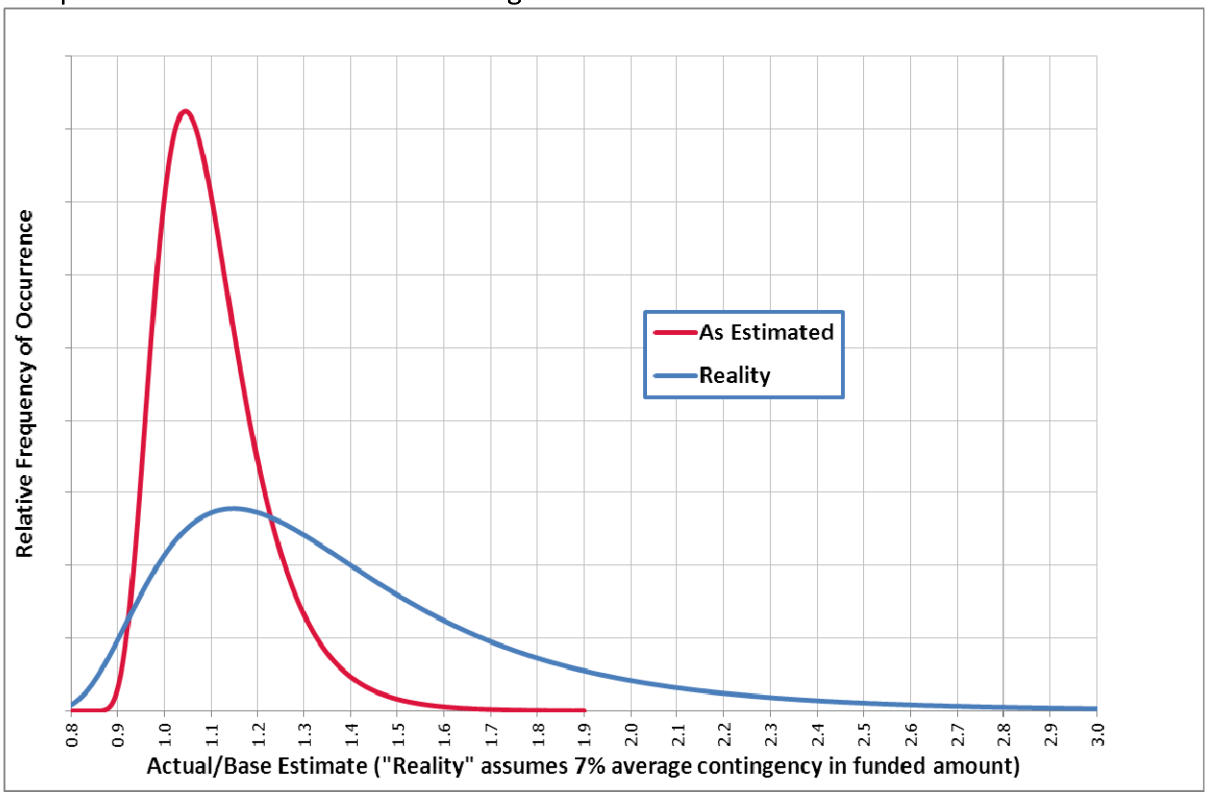

Figure 1 - As Estimated (and Target) Accuracy Vs. Empirical Accuracy at Funding

Several of the studies and the author's experience suggest that the lognormal distribution of actual/estimate data is representative [14,35]. Teams are assuming a p10/p90 accuracy range around the base estimate of about -10/+30% with a p50 value of about 10%, while the reality is closer to -20/+120% with a p50 of about 20%. Arguably, a 20% or even 30% overrun will not render most projects unprofitable; however, a 120% overrun at p90 would.

Challenging the Data : Nowhere to Hide

The following are likely challenges to this paper's findings along with the author's responses:

<u>1) The actual data includes the impact of major scope changes and escalation.</u>

Major scope change and escalation are by definition excluded from contingency [3]. In table 1, 7 of the 12 studies corrected for price changes over time and 3 corrected for major scope changes (i.e., changes to basic project premises such as plant location, product specifications or capacity). Studies show wide accuracy ranges with or without correction. In the author's benchmarking experience, major owner scope change (as opposed to design changes which owner costs must cover) is uncommon (this may be less true for public projects).

2) We cannot forecast volatility and/or black swan events (i.e., unknown unknowns).

While any *one* black swan event is improbable, the probability of *any* black swan or an equivalent confluence or compounding of lesser risks occurring during the extended duration of large projects is likely. The accuracy findings appear to hold for all time periods and regions, in both hot and cold economies. For example, Ernst & Young found that mining projects estimated during hot markets (when market risks were known) were still overrunning during the post-2008 recession; "*Of the companies that reported project overruns publically (between Oct 2010 and March 2011), the average overrun was about 71% of the original project cost estimate*"[37]. Another mining article referenced a series of studies which indicate that overruns have been the norm in every time period since 1965 [38]:

- "A study of 18 mining projects covering the period 1965 to 1981 showed an average cost overrun of 33 per cent compared to feasibility study estimates.
- A study of 60 mining projects covering the period from 1980 to 2001 showed average cost overruns of 22 per cent with almost half of the projects reporting overruns of more than 20 percent.
- A review of 16 mining projects carried out in the 1990s showed an average cost overrun of 25 percent".

Historical experience alone is enough to quantify the probability and impact "unknown-unknowns" as a class. We may not know the risk's name, but we know about what it will cost (i.e., Table 1.)

3) Some systemic risks are difficult to measure and/or politically sensitive.

The tools for rating scope development as well as competency and project system discipline (e.g., weak change management) are well established [4,21,22,35,and 45]. While including "incompetent management" in a risk register is problematic, it is necessary to identify and quantify such risks. The risk analyst must have sufficient independence to do so.

4) Estimating "all" project cost risk is not part of the job (not in my work scope).

If one declared in the *Basis of Estimate* reports that "most significant risks were excluded" and/or "past experience with similar projects was ignored,' this challenge might have some validity. However, in the author's experience, such statements (or confessions) are rarely made. Unfortunately, breaking risk down (e.g., operational, project, strategic, enterprise, contextual, global, background, etc. [42]) and disseminating responsibility for its analysis and quantification is a potential recipe for forecasting failure. Risks interact and often compound and cannot readily be parsed for quantification like elements in a work breakdown.

In summary, it is the author's experience that these "challenges" are usually just reasons for our failings; they do not excuse them. One knows better and the data is clear; with empirical insight added to other methods, risk is always quantifiable albeit imperfectly.

Flawed Practices and Lost Credibility

Flawed practices such as a bias toward estimator's risk, misguided targets, tunneling and parsing risk quantification have been mentioned. The 1990s also brought reengineering and downsizing to the industry with the loss of empirical data and analytical skills. Concurrently, Monte Carlo simulation (MCS) for spreadsheets was introduced which made risk analysis seem simple and doable regardless of skill level. Unfortunately, MCS was applied in "line-item ranging" (as opposed to range estimating) in which the team assigns cost ranges to line-items in their estimate (i.e., contributing to estimator's bias) based on brainstorming, and then runs the MCS, usually without considering line-item dependency [24]. The risks listed in the register (which tend to exclude systemic risks) are not explicitly included in these models. This is the method that research has shown to be a "disaster" for projects with systemic risks [27]. "Line-item ranging" (or activity duration ranging for schedule) fails in part because of faulty application (i.e., no dependencies) but also because brainstorming is unable to elicit the impacts of systemic risks on individual estimate line items or activities, and finally, the impact of risk register events are difficult to ascribe to individual estimate line items in aggregate. This method is not an AACE Recommended Practice.

It is easy to conclude from the research and observations that <u>our risk analyses and contingency estimates are not credible</u> for large process industry projects. Decision analysis expert John Schulyer defines a *credible analysis* as "one that gets used [44]." The following statements by industry executives indicate that our analyses are not useful (self-criticism by owner executives is understandably more difficult to find):

- Schlumberger CEO Andrew Gould stated: *"...while not wishing to embarrass any of my customers, I would add that many greenfield (upstream oil) projects suffer significant cost overruns. Indeed, as a general rule 30 percent of such projects experience budget overruns of 50 percent* [41]."
- Financier Jasper Bertisen of Resource Capital Funds (RCF) had this observation: "*the vast majority of mining projects have been coming in way over budget for the past couple of decades. As a result, RCF now automatically factors in an average cost overrun of 25% when it considers the cost of mining projects* [28]."

The prevailing use of flawed analyses has damaged our collective credibility. This will be difficult to remedy because poor practices have become institutionalized. For example, in the mining industry, the author commonly finds companies funding projects at a p80 level of confidence. This has evolved because (as indicated by prior quotation) managers intuitively understand that the p50 values we provide in our estimates are too low (i.e., often <10% contingency on even the riskiest projects) and they feel that the p80 level of about 15 to 20% contingency is more realistic. However, it is "more realistic" because in fact <u>this forecast p80 is the p50 of the "reality" that we fail to predict</u>! Cost engineers who do use realistic risk quantification practices are treated like Cassandra; management will not believe the truth after being fed unreality for decades. The *real* p80 or p90 is likely to be unprofitable; as shown in studies, the *least* p90 capital cost growth is >40 to 50%. If management faced this reality, no project would ever be authorized without stellar scope definition and optimization, top-notch planning, team building, risk management and all of the other best practices we know of. Isn't that the point? Why would anyone facilitate anything less? Why would one let them assume that poor practices are a safe bet when they are courting *disaster*!

The lesson from the empirical history (table 1) and the practice history (table 2) is that one needs to address the entire scope of risks (project-specific, systemic, and escalation) and the empirical "reality" of uncertainty on large process industry projects. Research by others points in the same direction [16,17,18,19,22,27,32,33,42]. AACE is currently developing a Decision and Risk Management Professional (DRMP) Certification that will focus on risk identification and quantification competencies, including AACE Recommended Practices that document reliable methods.

The Project Size Dichotomy

There is less empirical research of small project estimate accuracy because these projects are individually less of a threat to overall profitability and shareholder's perceptions. However, we know that the realities of small and large projects differ; small projects are biased to overestimating and underruns. As stated by one researcher, "*when a project team sets a soft (cost) target, about half of the unneeded funds are usually spent…about 70% of small projects underrun*" [29]. This research also indicated that in small project systems, overruns tend to be punished. To avoid punishment (in less disciplined cultures) teams avoid overruns by including "fat" (i.e., above-the-line contingency) in the base estimate because high visibility contingency is often poorly received by management for any project size. This can bias a company's perception of risk and partly explain their misguided targets.

Few researchers study small projects because not only is record keeping lax, but underruns are rewarded and are not seen as a problem despite being associated with wasteful capital spending. Figure 2 shows a representative distribution of actual/estimate values observed by the author for small project portfolios; often, no projects overrun by more than 10%. In this "cresting wave" pattern, most projects spend all their funds, while some return all or some of the excess; for this outcome, management and/or teams are rewarded. The more that funds are wasted, the sharper the peak between 0.9 and 1.1. Perversely, the more "accurate" the outcome, the less desirable (though best rewarded) it is; underruns and tight accuracy often indicate overfunding and wasted capital rather than excellent project control discipline

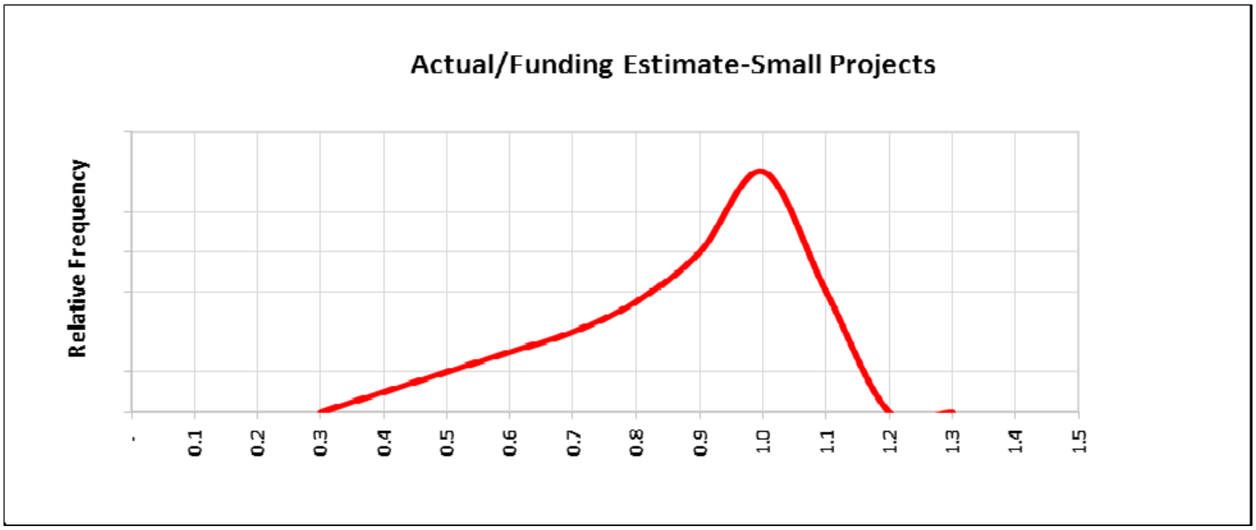

Figure 2 - Actual Cost/Appropriation Estimate For Small Projects

The small vs. large project overrun dichotomy can induce a kind of corporate schizophrenia. Many owner companies have “major project” organizations that are separate from small or plant-based organizations. A newly formed major project group will often inherit the small project system trait of risk-ignorance (expectation of underruns.) They do not appreciate that EPC contractors for major projects prepare base estimates with less fat because reviews expose fat and there is sometimes a bias to keep estimates low to see the project get funded. The combination of small project target-reinforced tunneling and risk-free base estimates is a recipe for overruns on large projects.

Looking at an entire company project portfolio, the combined distribution of accuracy data for small and large projects can look serenely “normal.” Benchmarking data observed by the author indicates that in a population of all project sizes, the P10/P90 range is about +/-20% around the funding estimate as illustrated in figure 3. Given just one distribution, management will be unaware that there are two conflicting realities.

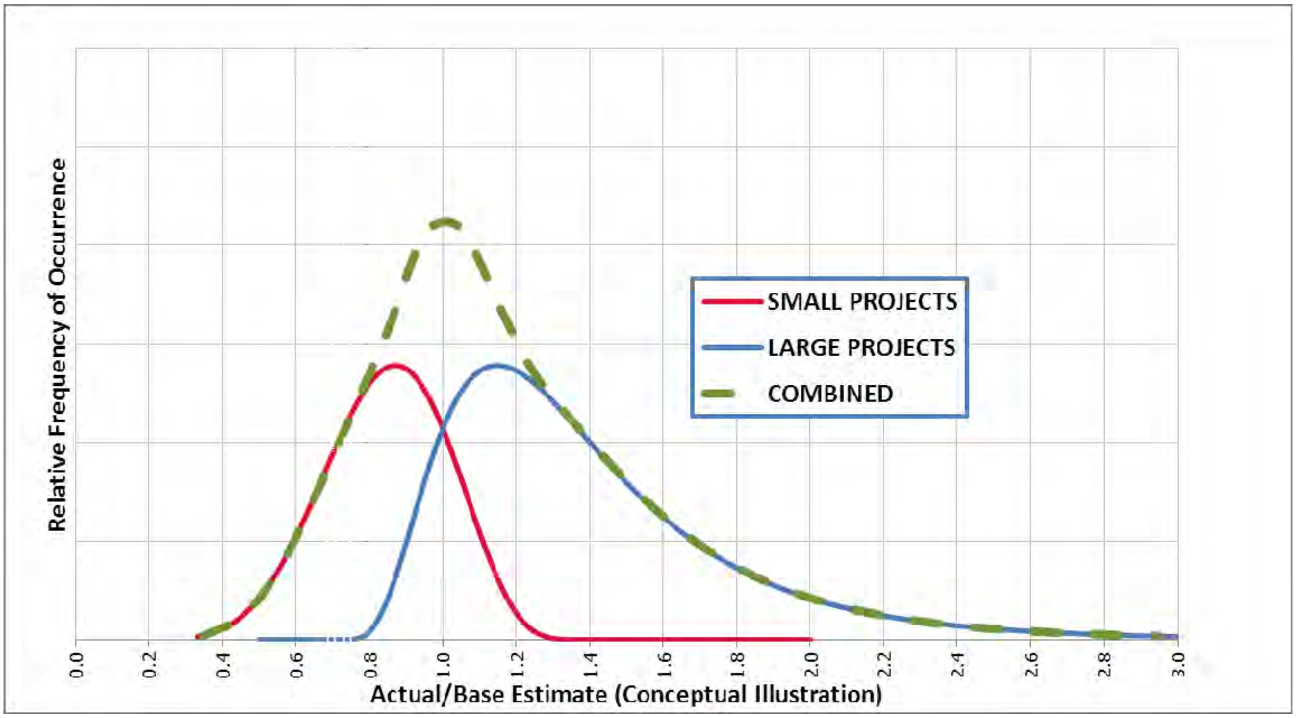

Figure 3 - Balancing Of Over and Underruns When All Project Sizes Are Studied Together

The Measurement Dilemma

Unfortunately, accuracy (i.e., actual/estimated cost) is often misused as a measure of *estimate "quality"* (as in "*a high quality estimate is an accurate estimate*") or estimating performance. This is inappropriate because, as discussed, the only way for an estimator to deliver a targeted accuracy for a given scope is to over-estimate the cost; risk and project performance are not in the estimator's control. Faced with overruns, estimators and the team tend to hide behind the excuses discussed previously. Accuracy should be used to measure the performance of the *risk management process* (not the estimating process) in conjunction with project historical data including causal information so we can improve our risk identification, analysis and quantification, and treatment. Tight accuracy may indicate wasted capital funds; accuracy measures must always be accompanied by measures of project control process discipline and project cost competitiveness (lower absolute costs) or cost bias.

AACE Recommended Practices (RPs)

There is an AACE RP that guides the selection and development of risk quantification and contingency estimating methods [2]. This RP provides "principles" that any method should align with including;

- start with identifying risk drivers;
- link risk drivers and cost/schedule outcomes; and
- employ empiricism.

Note that the previously discussed "line-item ranging" method is not explicitly in accordance with any of above principles.

Risks differ in how they impact project costs and therefore methods vary in how the risks are quantified. To cover the whole scope of risks, AACE has defined a risk breakdown [24] in respect to quantification methods that includes:

- **Project-Specific Risk**: risk affecting the specific project and plan;
- **Systemic Risk**: artifacts or inherent attributes of the system, enterprise or strategy; and,
- **Escalation Risk**: driven by economics (which regionally may involve politics).

Analogies for these risks suggested by others include: operational (project), strategic (enterprise), and contextual (global) risks respectively [42]. Methods that address these risk types can be integrated to generate a "universal" cost risk profile to support decision making. AACE also recommends that cost and schedule risk analysis be integrated.

For each risk type, there are AACE RPs for risk analysis methods that apply as follows ("how-to" descriptions for these methods are covered in the references):

- **Project-Specific Risk**:
  - 41R-08: Risk Analysis and Contingency Determination Using Range Estimating [12].
  - 44R-08: Risk Analysis and Contingency Determination Using Expected Value [9].
  - 57R-09: Integrated Cost and Schedule Risk Analysis Using Monte Carlo Simulation of a CPM Model [8].
  - 65R-11: Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Expected Value [7].
- **Systemic Risk**:
  - 42R-08: Risk Analysis and Contingency Determination Using Parametric Estimating [10].
  - 43R-08: Risk Analysis and Contingency Determination Using Parametric Estimating – Example Models as Applied for the Process Industries [11].
- **Escalation Risk**:
  - 58R-10: Escalation Principles and Methods Using Indices [6].
  - 68R-11: Escalation Estimating Using Indices and Monte Carlo Simulation [5].

Regardless of the risk analysis methods used, the findings of this paper suggest that, at a minimum, you always test your p90 outcomes (the "high" scenario given to the business organization to test the robustness of their decision) against the empirical reality. If no other historical data is available, this paper provides actual examples to consider. If your p90 is 25% or less over the base estimate, ask why NO study ever showed less than about 40% for p90; what risks are you missing? what impacts have you underestimated? Finally, and most important, ask "how can one improve project practices and scope in consideration of the risk reality?"

Conclusion

As a student of cost engineering and the editor/lead author of AACE's Total Cost Management Framework process [26], one is dismayed by the extreme disconnect between our practices and the long-known reality as shown in Figure 1. There is an ongoing failure to effectively address the reality of project cost uncertainty and there is a lack of good historical data with causal information. This has led to a credibility crisis. It also raises an ethical question (if not a criminal one per Flyvbjerg); what does it mean if we understand reality but continue to use failed methods known to be contrary to experience to the potential detriment of our employers and clients? The AACE Canon of Ethics (item 2g) states: "*When, as a result of their studies, members believe a project(s) might not be successful…they should so advise their employer or client*" [1]. In respect to large process industry projects, readers of this paper can consider themselves so advised.

There are of course practitioners who do address the entire scope of cost risks (in AACE terms; systemic, project-specific and escalation), capture data and consider the empirical record [16,17,18,21,42, and 43]. However, in the author's experience, the application of robust practices is uncommon. At a minimum, teams should at least test their worst case analysis outcomes against the empirical reality. They should study this paper's references and their own enterprise's historical experience (watching out for the small versus large project behavioral dichotomy). And, they should then seek to improve their practices to improve on past outcomes. The author does not agree with Dr. Flyvbjerg's approach to using empiricism (i.e., "reference class forecasting" [19]) which implies that biases are so intractable that we are doomed to repeat the past.

The paper also points out that companies should not use accuracy as a cost estimating quality measure; it is a risk management and project control process quality measure. Tight accuracy is often an indicator of wasted capital; measures of project control process discipline and project cost competitiveness must accompany accuracy measures.

In summary, this paper references and summarizes over 50 years of empirical cost estimate accuracy research on large projects in the process industries. It shows how this reality compares (or does not compare) to what we say and do. Recommended risk analysis methods have been highlighted. Failed methods are exposed. It is hoped that the facts, observations and opinions brought together here will serve as a valuable reference on the topic of cost accuracy and uncertainty so that we can better speak the truth among ourselves and with management. The path to more realistic uncertainty forecasts, better contingency estimates and more profitable investments is clear and documented by AACE International.

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Tab 12

M A N I T O B A

O R D E R I N C O U N C I L

DATE: **October 10, 2018**
ORDER IN COUNCIL NO.: **301/2018**
RECOMMENDED BY: **Minister of Crown Services**

ORDER

1. Gordon Campbell is appointed as commissioner to inquire into Manitoba Hydro's development of the Keeyask Generating Station and the Bipole III transmission line and converter station project.

2. The inquiry is to be conducted in accordance with the attached Terms of Reference.

3. Nothing in paragraph 2 limits the commissioner's right to request the Lieutenant Governor in Council to expand the terms of reference to cover any matter that the commissioner considers necessary as a result of information that comes to his attention during the course of the inquiry.

4. The commissioner must complete the inquiry and deliver a final report containing the commissioner's findings and recommendations to the Minister of Crown Services (the "minister") by December 31, 2019. The commissioner may give the minister any interim reports that the commissioner considers appropriate to address urgent matters. All reports must be in a form appropriate for public release, but release is subject to *The Freedom of Information and Protection of Privacy Act* and other relevant laws.

5. To avoid duplication of effort, the commissioner may rely on the record of proceedings before, and the findings, reports and orders of, The Public Utilities Board and the Clean Environment Commission, and other regulatory bodies, concerning Manitoba Hydro.

6. Government departments and agencies and other bodies established under the authority of the Manitoba Legislature must assist the commissioner to the fullest extent permitted by law.

7. The commissioner may hold proceedings in public or private as he considers advisable in the course of the inquiry.

8. Except as required to be summarized for context in a report, the commissioner must ensure that any information reviewed by the commissioner that is subject to subsection 19(1) (Cabinet confidences) of *The Freedom of Information and Protection of Privacy Act* remains confidential and is not further disclosed to any other person. The commissioner must also ensure that information the disclosure of which may reasonably be expected to cause undue financial loss to, or significantly harm the competitive position of, Manitoba Hydro or its customers, or parties with whom it has contracted, is adequately protected.

9. The commissioner may grant any individual whom the commissioner is satisfied has a substantial and direct interest in the subject matter of the inquiry an opportunity during the inquiry to give evidence and to examine or cross-examine witnesses personally or by counsel on evidence relevant to that individual's interest. The commissioner may approve funding, at reasonable rates approved by the minister, in respect of the costs incurred for that purpose by the person.

10. The commissioner must perform his duties without expressing any conclusion or recommendation about the civil or criminal liability of any person or organization.

11. The budget for the conduct of the inquiry is $2.5 million. The minister may, in consultation with the commissioner, revise the budget to accommodate any change in circumstances.

12. The Minister of Finance may pay the following amounts from the Consolidated Fund, at the request of the minister:

    (a) fees and salaries of any technical advisors or other experts and assistants employed or retained for the purpose of the inquiry;

(b) travelling and other incidental expenses that the commissioner incurs in conducting the inquiry;

(c) any other operational expenditures necessary to support the inquiry.

13. This Order is effective immediately.

AUTHORITY

Subsection 83(1) and section 96 of *The Manitoba Evidence Act*, C.C.S.M. c. E150, state in part:

Appointment of commission
83(1) Where the Lieutenant Governor in Council deems it expedient to cause inquiry to be made into and concerning any matter within the jurisdiction of the Legislature and connected with or affecting

(a) the good government of the province or the conduct of any part of the public business thereof;

(b) the conduct of any provincial institution or of any institution within the province receiving provincial aid;

...

(f) any matter which, in his opinion, is of sufficient public importance to justify an inquiry;

he may, if the inquiry is not otherwise regulated, appoint one or more commissioners to make the inquiry and to report thereon.

…

Power to make rules
96 The Lieutenant Governor in Council may make provision, either generally in regard to all commissions issued and inquiries held under this Part, or specially in regard to any such commission and inquiry, for

(a) the remuneration of commissioners and persons employed or engaged to assist in the inquiry, including witnesses;

(b) the payment of incidental and necessary expenses; and

(c) all such acts, matters, and things, as are necessary to enable complete effect to be given to every provision of this Part.

TERMS OF REFERENCE

Manitoba Hydro proceeded with developing the Keeyask Generating Station project ("Keeyask") and the Bipole III transmission line and converter station project ("Bipole III") during a time when the market price for energy was declining. Continuing with these projects has required Manitobans to deal with the costs, and the billions in related cost overruns, through increases in electricity rates that far exceed the expected rate of inflation.

As a result, the commissioner is to

(a) inquire into the following matters:

1 With reference to the actual or proposed in-service dates of Keeyask and Bipole III, to what extent did Manitoba Hydro pursue these two projects when they were not necessary, or not necessary at the time, to meet the province's then-anticipated electrical needs in a timely and cost-effective manner?

2 With reference to Keeyask and Bipole III, to what extent did the directions that the government gave to Manitoba Hydro

(i) promote economy and efficiency in the generation, transmission, distribution and supply of power in the province; and

(ii) result in Manitoba Hydro having to address matters beyond its statutory mandate?

3 To what extent were the estimated net benefits projected at the planning stage for Keeyask and Bipole III

(i) determined in accordance with best practices then applicable for such projects;

(ii) demonstrably superior to the estimated net benefits of proceeding with other options then available for addressing the province's then-anticipated electrical needs in a timely and cost-effective manner; and

(iii) based on sound export market forecasts?

4 To what extent did the Keeyask and Bipole III planning and approval processes of Manitoba Hydro and the government, and any other applicable approval or review processes, appropriately

(i) evaluate the commercial risk associated with each project and the risks of the two projects proceeding concurrently;

(ii) assess the allocation of the risks among those involved in the construction of the projects; and

(iii) consider the immediate and long-term fiscal implications of the projects for the province and Manitoba taxpayers and Manitoba Hydro and its ratepayers?

5 Given the magnitude of Keeyask and Bipole III and the time lines necessary to complete them, to what extent did the oversight process that was followed after these projects were approved

(i) reflect best practices then applicable for such projects; and

(ii) mitigate the associated commercial risk and accommodate changing circumstances as they occurred?

(b) make recommendations about the following matters:

1 How should Manitoba Hydro's and the government's oversight of any similar project proposed in the future, including the planning, approval, procurement and construction processes for the project, be strengthened to ensure that

(i) there is appropriate transparency and accountability for decisions;

(ii) the commercial risk associated with the project is appropriately evaluated and allocated, both on an individual project and on a systemic basis; and

(iii) the financial and fiscal implications of the project for Manitoba Hydro and the province are assessed in an appropriate and timely manner?

2 Should Manitoba Hydro's statutory mandate be clarified to ensure that decisions concerning any such future project are in the best interests of Manitobans?

3 Should the planning and approval processes for such a future project include additional regulatory approvals or an external review? If so, what form and manner should the regulatory approvals or external review take?

4 If such a future project is approved to proceed, how should the project oversight process be improved so that

(i) changes in circumstances are accommodated in a timely and cost-effective manner; and

(ii) verification is carried out at appropriate junctures to ensure that the project continues to be in the best interests of Manitobans?

5 Are there prudent steps for the government and its Crown corporation Manitoba Hydro to take to restore the corporation's financial health, given the government's ongoing obligation to ensure that provincial finances are managed responsibly and that Manitoba has an attractive investment environment?

The Joint Keeyask Development Agreement is not within the scope of these terms of reference.

Tab 13

DAYMARK ENERGY ADVISORS

~~CONFIDENTIAL~~

INDEPENDENT EXPERT CONSULTANT REPORT: EXPORT PRICING AND REVENUES REVIEW

NOVEMBER 16, 2017

PREPARED FOR

Manitoba Public Utilities Board

PREPARED BY

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AEO	Annual Energy Outlook
CT	combustion turbine
EEPF	Electricity Export Price Forecast
EIA	U.S. Energy Information Administration
EPF	Energy Price Forecast
FRAP	Fixed Resource Adequacy Plan
GRA	General Rate Application (2017/18 & 2018/19)
GW	gigawatts
IRP	Integrated Resource Planning
ISO	Independent System Operator
LMPs	Locational Market Prices
LRZ	Load Resource Zones
LTRA	Long-Term Reliability Assessment
MATS	Mercury and Air Toxics Standards
MEC I	Mankato Energy Center Combined Cycle
MH	Manitoba Hydro
MINN HUB	MISO's Minnesota Hub
MISO	Midcontinent Independent System Operator
MPUC	Minnesota Public Utilities Commission
MTEP	MISO Transmission Expansion Planning
MWh	megawatt-hours
NERC	North American Electric Reliability Corporation
NFAT	Needs For and Alternatives To
NSP	Northern States Power
PRA	MISO's Planning Resource Auction
PUB	Manitoba Public Utilities Board
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SMEs	subject matter experts
SPLASH	Simulation Program for Long-term Analysis of System Hydraulics

EXECUTIVE SUMMARY

Manitoba Hydro's (MH) 2017/18 and 2018/19 General Rate Application (GRA) seeks approval from the Public Utilities Board (PUB) for an increase in its rates. MH has developed the rates proposal with a goal of restoring its Equity Ratio to 25 percent within 10 years, 5 years earlier than the previous plan. The need for rate increases on sales to its domestic customers is driven, in part, by a decline in MH's expectations for revenues. MH's integrated financial forecast includes a long-term forecast (20 years) of export revenues as a key input.

The PUB retained a team of Daymark employees as Independent Expert Consultants (Daymark IEC Team) to conduct an Export Pricing and Revenues Review. The objective of the review was to determine the accuracy and reasonableness of the export revenues forecast and assumptions included in MH's request for rate increases and its long-term financial forecasts. This report contains our analysis and findings resulting from that review.

We conclude that MH's export revenue forecast is conservative/low relative to a value that is consistent with MH's stated goal that it will have a 50 percent chance of achieving the equity ratio target within 10 years. The key issues we identify here are:

- The reference case energy market price forecast and the resultant energy revenues are susceptible to be biased low.
- MH assumes that no revenue will be received for capacity or any other premium values from the substantial surplus dependable energy in the forecast.
- The uncertainty analysis that MH has conducted demonstrates the asymmetrical nature of the risk, with energy price risk skewed toward higher values, where the expected value of the forecast will be higher than the reference case value.

The components of the export revenue forecast that we reviewed and found to be reasonable include the forecast of surplus dependable energy and opportunity sale energy and MH's forecast of revenues to be derived from existing firm contracts.

The vast majority of MH's export sales are made to U.S. entities operating in the markets administered by the Midcontinent Independent System Operator (MISO). Our review of the characteristics of the MISO marketplace found the following.

- The 61 GW of coal generation in the MISO market is likely to decline significantly over the next decade with the age of the fleet and the economic pressure of low natural gas prices being primary drivers. About 88 percent of the existing coal capacity is over 50 years old today. A number of planned coal retirements have been announced in MISO plans or in utility resource plans.
- MISO needs assessments indicate that the current system surplus capacity is expected to erode within 5 years based on current assumptions and information on existing, committed, and planned changes in capacity resources, with the need for new resources of about 24 GW occurring by 2031. This need is driven primarily by expected retirements of aging coal generation. The replacement resources will be determined by the generating companies in the region, with natural gas generation and renewable generation featured as prominent options considered in the resource plans we reviewed.
- State polices have significant influence on resource choices. In Minnesota, policies governing utility resource planning are placing increased importance on greenhouse gas emission reductions and renewable resources. As examples, Northern States Power and Minnesota Power each show coal retirements and increasing natural gas and renewables in their plans for the coming decade. Wisconsin state policy shows some similarities to Minnesota, while North Dakota requires planning to consider least cost.

Our report contains our review and findings on the components of our scope of work:

1. A discussion of factors influencing the MISO market
2. A review of MH's electricity export price forecasts
3. A review of MH's forecast of exportable surplus energy
4. A review of changes in MH's methodology regarding premiums
5. A review of MH's forecast of revenues from existing contracts
6. A review of MH's 20-year forecast of net extraprovincial revenue

I. INTRODUCTION

A. Scope of the Report

Daymark Energy Advisors (Daymark)[1] offers this independent expert report to describe our export pricing and revenues review and provide our expert opinion regarding the treatment of those topics by Manitoba Hydro (MH) in its 2017/18 & 2018/19 General Rate Application (GRA).

On August 21, 2017, the Manitoba Public Utilities Board (PUB) retained a team of Daymark employees as Independent Expert Consultants (Daymark IEC Team)[2] to conduct an Export Pricing and Revenues Review and a Load Forecast Review. This Export Pricing and Revenues Report (Export Report), and the companion Load Forecast Report, are now provided to present the results of the work requested by the PUB.[3] The full text of the scope of work for the Export Report is included in Appendix A, which includes:

1. A review of MH's electricity export price forecasts;
2. A review of MH's forecast of exportable surplus energy;
3. A review of MH's 20-year forecast of net extraprovincial revenues;
4. A review of changes in MH's methodology regarding premiums; and
5. A discussion of factors influencing the MISO market.

The objective of this scope of work is to determine the accuracy and reasonableness of the export revenues assumptions included in MH's request for rate increases for consideration by the PUB. MH's export revenues projections rely on information that is highly sensitive and confidential and rely on MH's proprietary models and third party forecast information, including confidential information shared directly with the Daymark IEC team. For this reason, the Daymark IEC Team is charged with preparing a

[1] Daymark Energy Advisors is the new name of the firm formerly known as La Capra Associates.The name change occurred on November 9, 2015.

[2] The Daymark IEC Team includes specific individuals within Daymark Energy Advisors. A separate set of Daymark employees have been retained by the PUB as Advisors. The Daymark IEC Team conducted its work and maintained documents separate from all other Daymark employees in accordance with the terms of a non-disclosure agreement executed with Manitoba Hydro.

[3] On October 25, the PUB added a third task to the Daymark IEC Team scope of work. That task will be a review of the economic case for the Manitoba-Saskatchewan Transmission Line and export sale to Saskatchewan Power. A report on that review will be submitted separately on or before December 15, 2017.

full, confidential report on our findings to the PUB, and providing a report suitable for the public record that does not disclose any confidential information.

B. Daymark Approach

The Daymark IEC Team conducted the scope of work considering:

- MH's GRA filing, minimum filing requirements, and interrogatory responses;
- Certain information on export revenue projections from prior rate proceedings and the NFAT proceeding;
- Information provided directly and confidentially to the Daymark IEC Team by MH resulting from direct discussion with the MH subject matter experts (SMEs); and
- Publicly available documents obtained by the Daymark IEC Team from research on the export markets.

MH provided direct access to its SMEs for the Daymark IEC Team to conduct our review, including:

- Meetings in MH's offices in Winnipeg with the MH SMEs and staff on September 13 and 14, 2017;
- Weekly coordination calls with the SMEs;
- Frequent conference calls with certain SME's on each of the sub-topics included in the reviews; and
- Transfer of documents identified over the course of these meetings.

In working with MH's SMEs, the Daymark IEC Team solicited certain documentation necessary to complete our scope of work and reviewed those materials with the SMEs that developed them to understand how each analysis was conducted. MH established a secure file transfer mechanism to provide electronic copies of documents identified in this process to the Daymark IEC Team, with those documents held in a secure file server location with access limited to the members of the Daymark IEC Team.

Throughout this report we footnote all materials sourced from a specific document. At the end of this report, Appendix B provides a full annotated listing of all documents relied upon by Daymark in the production of this report.

This report is structured to provide a clear discussion of the work performed by the Daymark IEC Team and to clearly identify the inputs used to reach the expert opinions related to each scope item. We have modified the order of the scope items discussed in this report to better sequence the information, such that the initial sections provide foundation for the later sections. The following report sections correspond to the scope of work as follows.

Table 1: Mapping of Report Sections to Scope Items

REPORT CHAPTER	SCOPE ITEM
Section II: Factors Influencing the MISO Market	5
Section III: Export Prices	1
Section IV: Export Energy and Capacity	2
Section V: Changes in Forecasting Methodology	4
Section VI: Firm Contracts	3
Section VII: Revenue Forecast	3

II. FACTORS INFLUENCING THE MISO MARKET

A. Overview

The most significant wholesale market neighboring the MH system is the Midcontinent Independent System Operator (MISO). MISO and the utilities in MISO's footprint provide a significant opportunity to buy and sell energy, including in firm bilateral deals, shorter-term opportunity sales, and direct participation in the MISO day-ahead energy market. In a typical year, MH exports close to 25 percent of its production to the US through MISO.[4] Over 90 percent of all energy exports included in MH's export revenue forecast are through MISO.[5]

MISO is one of the largest Independent System Operators (ISOs) in North America with primary functions that include the operation of the transmission grid, administration of the wholesale markets, coordination of regional planning activities, and the enforcement of regional and federal reliability standards.

In this section of our report, we discuss the market fundamentals in the MISO region and how they may influence MH's participation in the various MISO markets.

The material presented in this section provides background and context for the subsequent sections of our report regarding MH's export revenue forecast.

B. Scope of Investigation

This section of the report discusses the factors influencing the MISO market and trends that are affecting market prices. This section also serves to provide background information supporting other elements of our work. MH's export sales include several longer-term contracts and the GRA filing includes a longer-term forecast of export sales and revenues. Accordingly, several elements of the scope of work call for information regarding longer-term trends and forecasts, as well as information on near-term market conditions. The information we provide here relies principally on publicly available information on near-term conditions and longer-term trends. Our scope of work does not include preparation of an independent forecast or consideration of confidential forecast information available to MH.

[4] Manitoba Hydropower's website, accessed November 2017, available at: http://www.manitobahydropower.com/who-we-are.shtml

[5] Derived from confidential SPLASH results

We have modified the order of the topics discussed in this section to better sequence the information, such that the initial sections provide foundation for the later sections. The following report sections correspond to the scope of work as follows.

Table 2: Mapping of Report Subsections to Scope Item #5

SUBSECTIONS		SCOPE ITEM
II. C.1	Existing Generation Mix	5 (b)
II. C.2	Forecasted Retirements for the Next 20 Years	5 (d)
II. C.3	Expected New Generation to be Installed in the Next 20 Years	5 (c)
II. C.4	Supply and Demand Balance in the Northern MISO Region	5 (e)
II. C.5	State and Federal Policies on Electricity Generation and Emissions	5 (a)
II. C.6	Factors that may Affect Manitoba Hydro's Ability to Export Energy and Capacity into the MISO Market	5 (f)

To perform this scope of work, Daymark reviewed publicly available documents including reports from MISO, for the North American Electric Reliability Corporation (NERC), and data from SNL Financial, an entity that provides electric industry-specific market data obtained from public and private companies worldwide.[6] A specific list of these documents is provided in Appendix B.

C. Analysis

MISO administers the U.S. wholesale market neighboring the MH system. MISO coordinates the movement of electricity across all or parts of 15 U.S. states, largely in the corridor between Minnesota and Louisiana. MISO operates its wholesale markets only within its market footprint and coordinates reliability under a larger reliability footprint.

MH's relationship with MISO differs from other entities that serve load and/or own generation within the MISO market footprint. MH's load is not served under the MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff, and its generation is not directly dispatched by MISO. Under MH's governing legislation, the delegation of authority of MH's assets to a third party is not authorized except only to limited instances and subject to Lieutenant-Governor in Council approval. As a result, MH participates as a coordinating member in the MISO market via three agreements.

[6] http://www.snl.com/

Two of the agreements pertain to transmission coordination between MISO and MH and the third is a MISO market participation agreement required by MISO for all market participants.[7]

The table below provides a brief overview of the MISO's characteristics.[8]

Table 3: MISO at a Glance

Generating Capacity	174,724 MW
Peak Demand	127,125 MW (Summer) 109,336 MW (Winter)
Transmission Lines	65,800
Annual Billings	$25.3 Billion
States Served	15
Generator Units	6,567

The figure below depicts MH's transmission interface limits to three neighboring regions including the U.S. MH is connected via one 500-kV transmission line and one 230-kV transmission line with Minnesota and two 230-kV transmission lines with North Dakota. The figure also provides the transfer capability of the three different interconnections under the best-case scenario.[9]

[7] NFAT Chapter 5 – page 41-61
http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/nfat_business_case_chapter_05_the_manitoba_hydro_system_interconnection_and_export_markets.pdf

[8] https://www.ferc.gov/market-oversight/mkt-electric/midwest.asp

[9] http://www.manitobahydropower.com/who-we-are.shtml

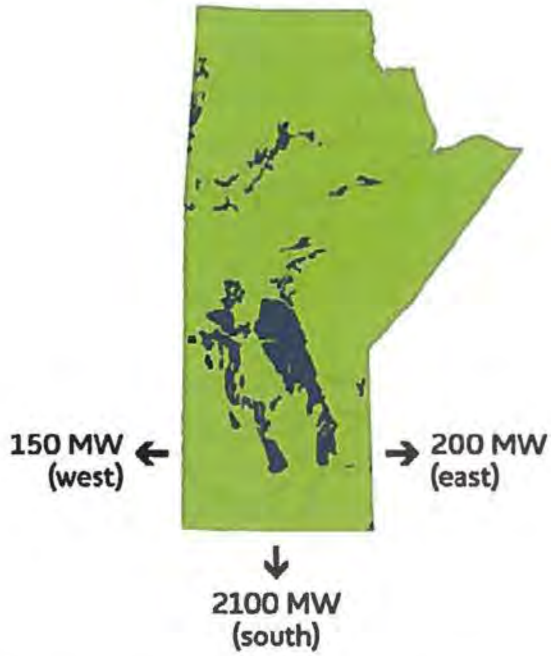

Figure 1: MH's Transmission Interconnections to Neighboring Regions

1. Existing Generation Mix

The MISO system is comprised of a variety of generating resources such as coal, natural gas, nuclear, renewables, and others. Natural gas and coal resources are the predominant sources of capacity, each providing approximately one-third of the total, with a mix of other sources providing the remainder as depicted in the table below[10]:

Table 4: Percentage of Total MISO Capacity by Fuel Type

Fuel Type	2017 Market Capacity Share	2017 Market Capacity (MW)
Gas	41%	71,637
Coal	35%	61,153
Nuclear	8%	13,978
Renewables	13%	22,714
Other	3%	5,242
Total	**100%**	**174,724**

[10] MISO website, accessed in November 2017, available at : https://www.misoenergy.org/AboutUs/Pages/FactSheet.aspx

As recently as 2012, the MISO region was one of the most coal-dependent regions in the U.S. with close to 66 GW of coal-fired generating capacity. Over 5 GW of coal generators have retired since 2012, reducing the amount of available coal resource capacity to 61 GW.[11] According to the 2016 MISO Transmission Expansion Planning (MTEP), MTEP16, 4,847 MW of generation capacity retired in 2016 with an additional 67 MW slated to retire in 2017. The report indicated that the data suggested that the majority of retirements in 2016 were related to compliance with the Mercury and Air Toxics Standards.[12]

These economic factors and tighter environmental regulations, described in the *State and Federal Policies on Electricity Generation and Emissions* section below, have stimulated several unit retirements in the MISO region. The retirement of resources has been slower than other regions[13] due to smaller amounts of economic natural gas resources compared with other regions. However, based on the MTEP16 report retirements have accelerated over the past year.[14]

[11] SNL Financial

[12] MTEP16 Full report – page 75

[13] Electric System Reliability and EPA's Clean Power Plan: The Case of MISO Page 12 and figure 4, Analysis Group

[14] MTEP Full report – page 76

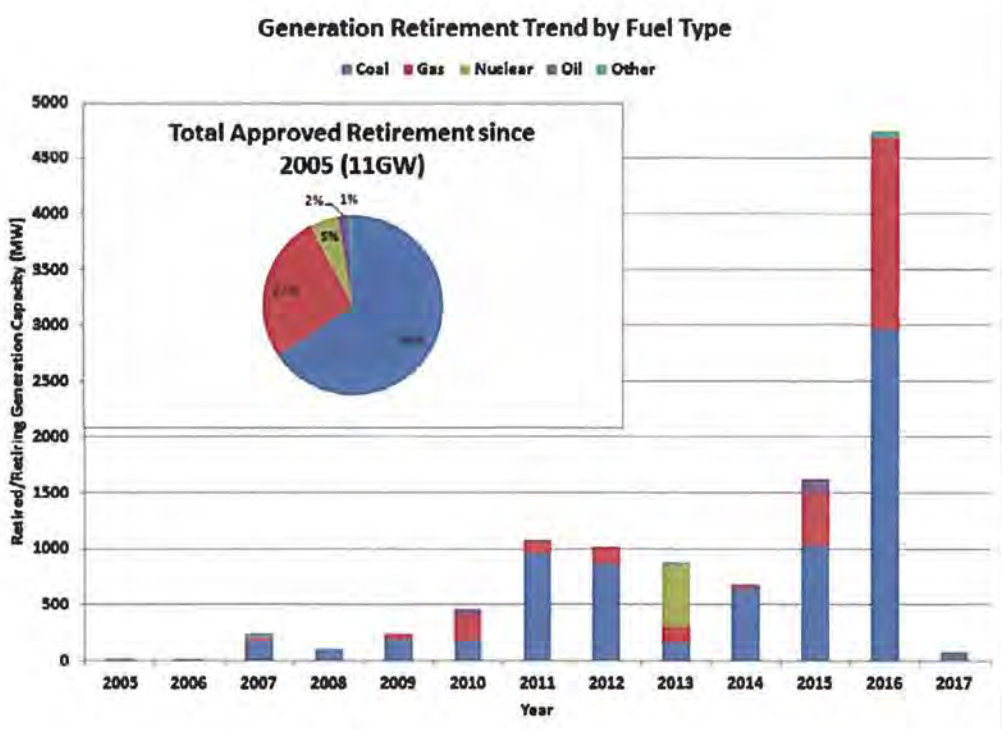

Figure 2: Generation Retirement Trend by Fuel Type, 2005-2017

The reduction in available coal capacity and the less advantageous economics for the coal resources reduced the amount of energy production from coal as depicted below.[15] The shale gas revolution and the resulting lower natural gas prices influenced all Regional Transmission Organizations (RTOs) and ISOs, including MISO's generation, and stimulated a transition to a fuel mix with increasing dependence on natural gas-fired generation compared to coal.

The overall MISO generation mix became larger and more diverse with the integration of Entergy's utilities into MISO in 2013, having considerably more natural gas-fired capacity than the rest of the MISO zones. The graph below indicates the magnitude of the gas resources added to the MISO system by the integration of MISO South, as compared to the rest of MISO, described as MISO North/Central.[16]

[15] SNL Financial

[16] Today's Trends, Tomorrow's Energy Needs - Wisconsin Public Utility Institute – slide 13 – 2016 YTD is depicted as of March 2016

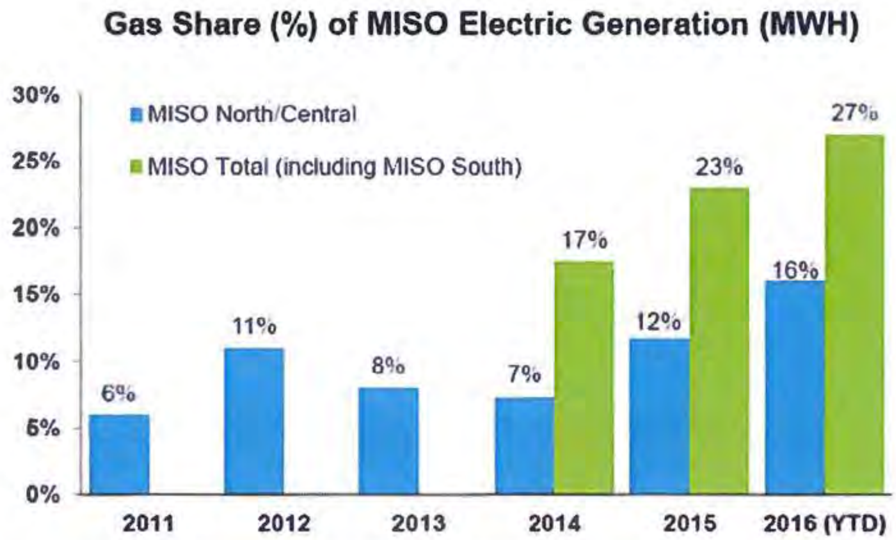

Figure 3: Gas Share (%) of MISO Electric Generation (MWh)

Despite the increase in gas share, the MISO real-time energy market is frequently priced based on coal. Natural gas resources set prices approximately 40 percent of the time, compared to approximately 10 percent of the time in 2012.[17] The 2016 State of the Market Report presents the following graph of monthly price setting by fuel.[18]

[17] 2012 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS, page A-7

[18] 2016 State of the Market Report for the MISO Electricity Market, Analytic Appendix – Figure A1, page 2.

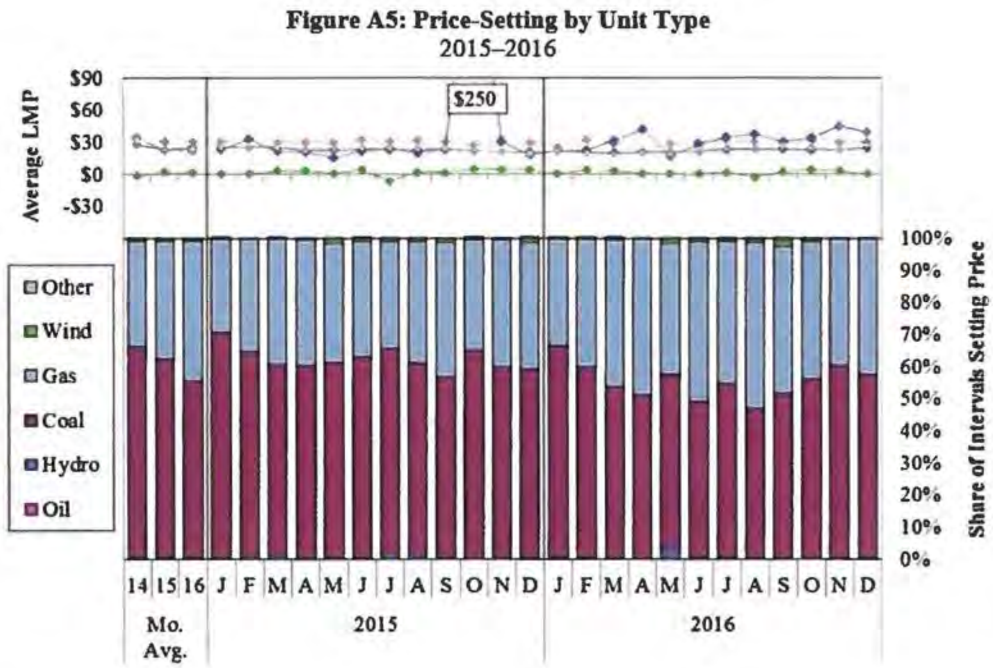

Figure 4: Price Setting by Unit Type, 2015-2016

2. Forecasted Retirements for the Next 20 Years

Even with the recent retirements of coal plants in the MISO markets, coal generation remains a significant part of the MISO mix. Looking forward, there will continue to be pressures that will bear on future coal plant retirements, including the aging of existing units, environmental regulations, and the cost of alternatives.

With respect to alternatives, the shale gas revolution and significant investment in pipelines throughout North America have made low-priced natural gas available and have eliminated the price separation between the regions that had persisted for decades. The U.S. Energy Information Administration (EIA) graph below presents the estimated natural gas production potential in the U.S., indicating a continued expansion of the availability of natural gas over the next 20 years and beyond.[19] High availability of natural gas for the longer term provides a basis for natural gas generation to be a competitive alternative to coal in the MISO market in the longer term.

[19] https://www.eia.gov/outlooks/archive/aeo16/MT_naturalgas.cfm#natgasprod_exp

Figure MT-46. U.S. dry natural gas production by source in the Reference case, 1990–2040

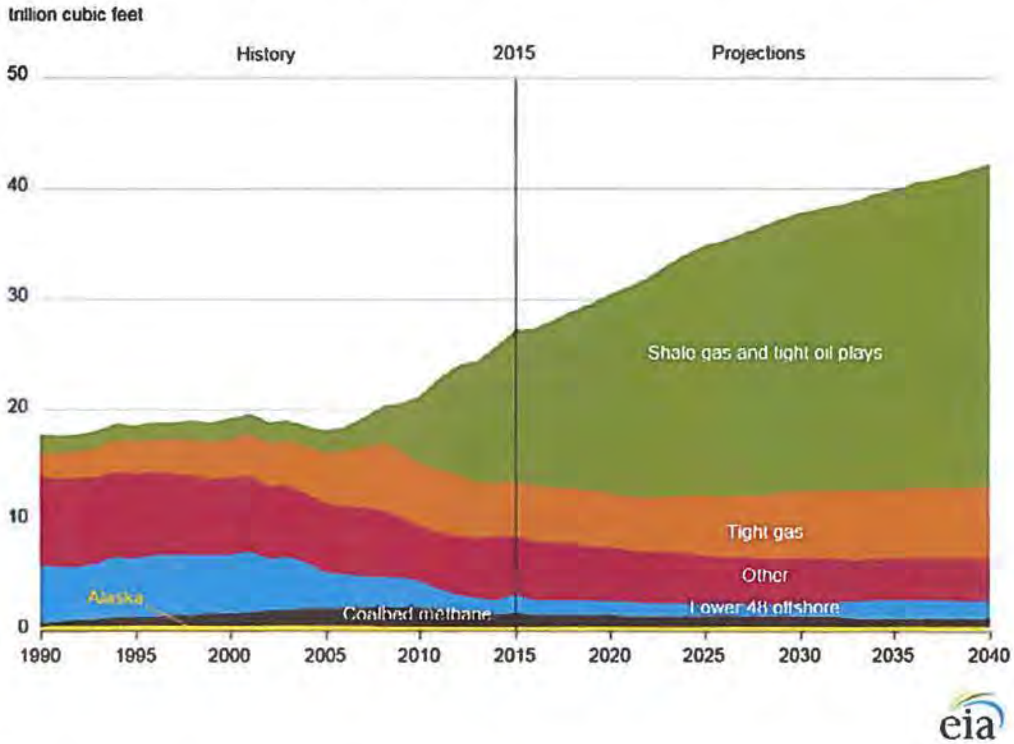

Figure 5: U.S. Dry Natural Gas Production, 1990-2040 (Trillion Cubic Feet)

Another critical factor of the existing MISO fleet that may stimulate retirement is plant age. Nearly 88 percent (55 GW) of the MISO's coal capacity is at least 50 years old and 52 percent (~30 GW) is at least 60 years old, as shown in Figure 6.[20] Coal generating units have traditionally been built with an assumed design and economic life span of about 30 years, with the implicit assumption that the generator engine and critical components would be replaced after that period. Therefore, it is common for coal resources to remain in service much longer than 30 years after critical components are replaced, extending their life span to 50-60 years. As they age, generators face substantial reliability, efficiency, and performance problems, which in turn increase operating costs.

[20] MISO Fleet Changes – slide 9

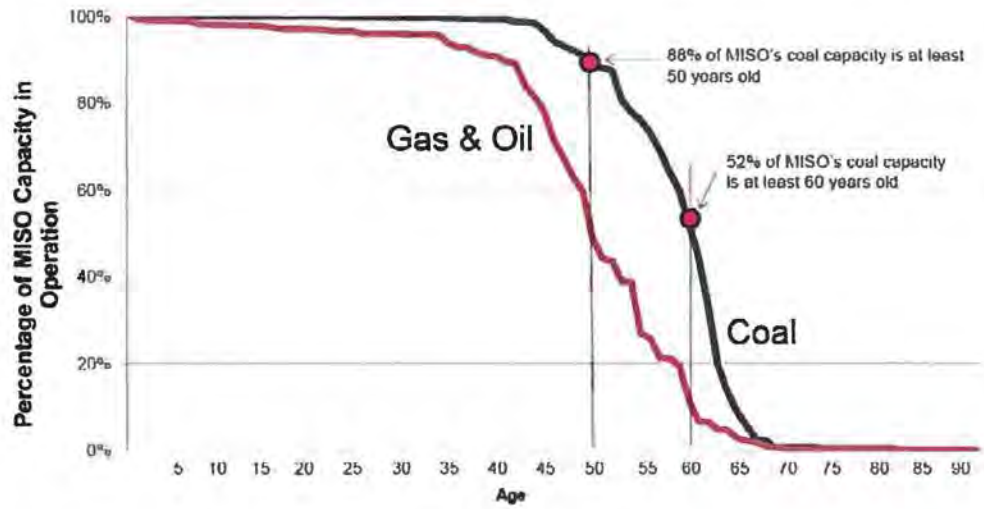

Figure 6: Age Distribution of Operating Coal Capacity and Gas & Oil Capacity in MISO

MISO has determined that 91 percent of the MISO coal capacity that has retired, retired prior to its assumed 65-year useful life and 48 percent retired by age 60. If this trend persists, then close to 50 percent (30 GW) of the coal fleet is at risk for retirement in the next decade and more over the next 20 years.

These changing market conditions and the potential for accelerated retirements have been reflected in various reports from MISO and the NERC. In its 2016 Long-Term Reliability Assessment (LTRA), NERC identified a resource adequacy need by unconfirmed resource retirements over the next few years. The graph below describes the impact of these retirements on the reserve margin in the region.[21]

[21] Reliability Assessments DL_2016 Long-Term Reliability Assessment, p 8

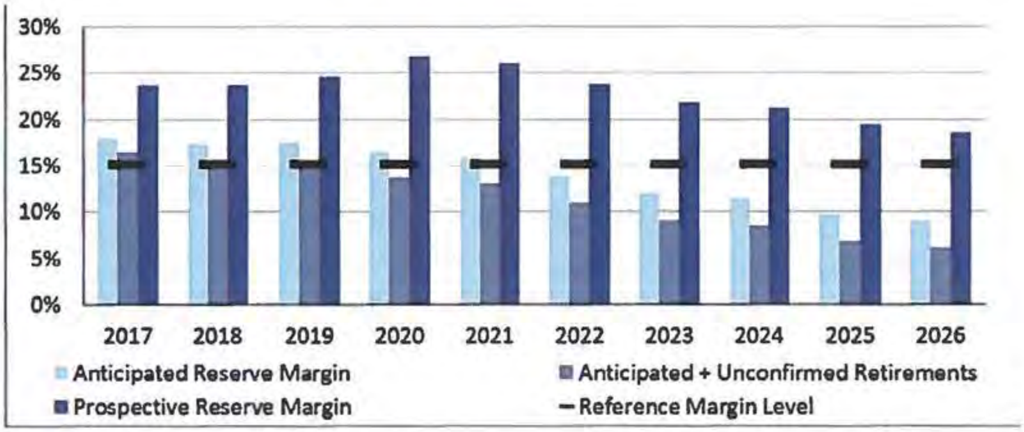

Figure 7: Impact of Retirements on Reserve Margin, MISO

Furthermore, in the draft MTEP17, MISO projects a range of approximately 8 to 24 GW of coal retirements between now and 2031, with 1.7 to 4.8 GW of that amount in MISO zones 1 and 2 (zones neighboring Manitoba). These values are shown in Figure 8.[22]

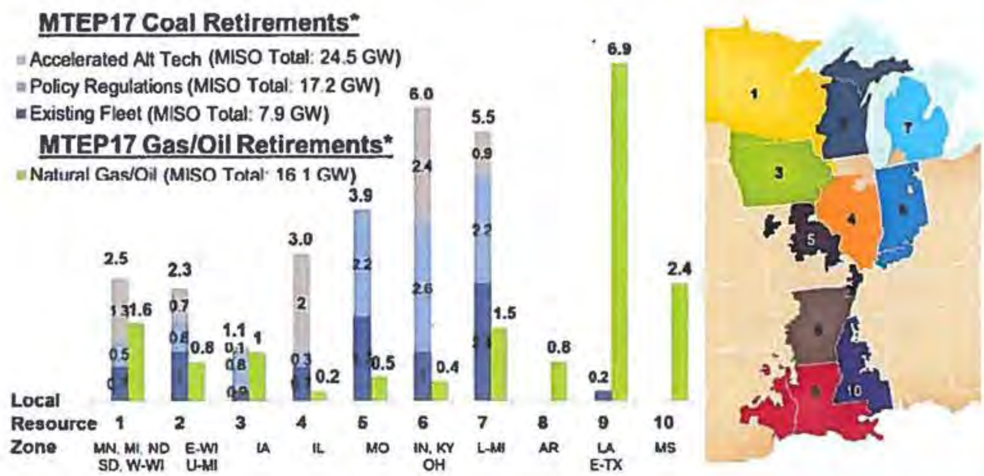

Figure 8: MTEP17 Retirement Assumptions by Zone by 2031

Unit age is the main driver of retirements in MTEP17. The Mercury and Air Toxics Standards (MATS) compliance deadline ended in April 2016 and the MTEP17 assumes no further unit retirements due to environmental compliance assumptions (retirements, retrofits or coal-to-gas conversions).

[22] MTEP 2017 draft, Appendix E2, pp 17

MTEP17 also provides information on the location of most of the older units that are located within the MISO region and what is considered to retire based on age or environmental policy. Figure 9 is a visual depiction of the locational distribution of the retirements assumed in MTEP17.

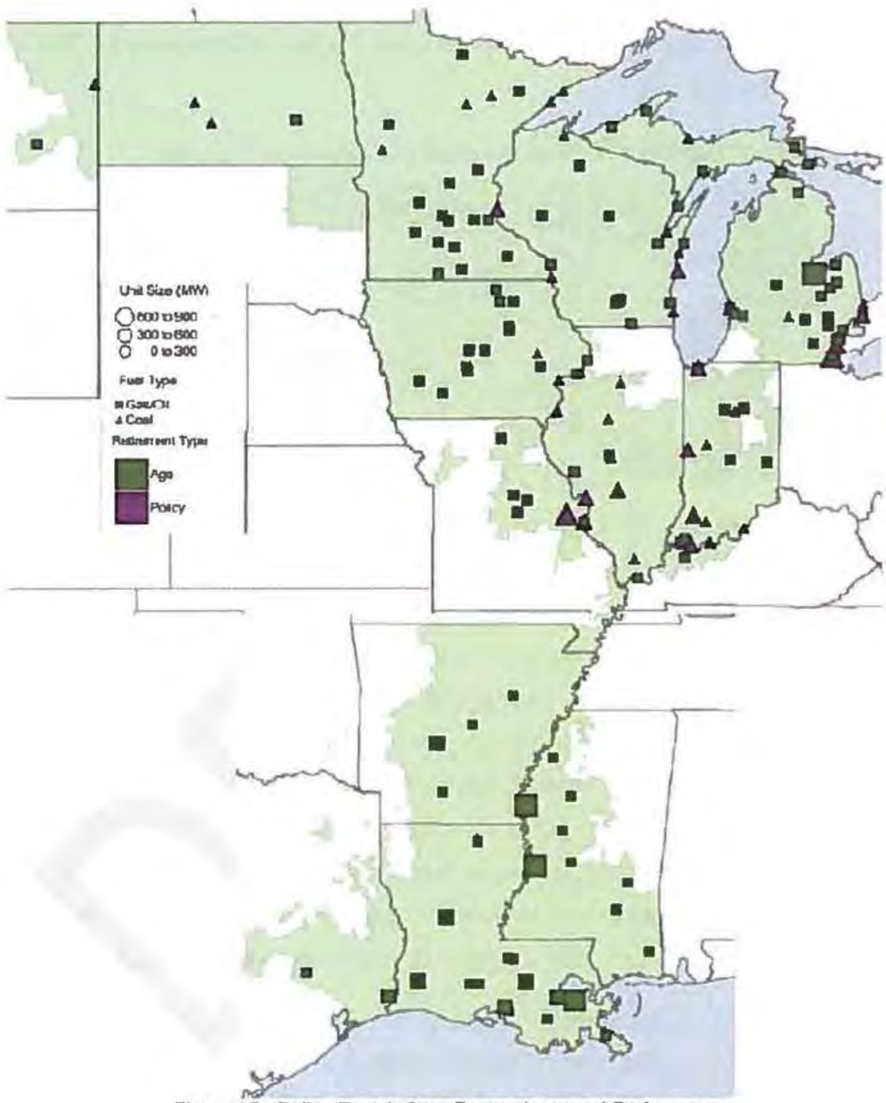

Figure 15 : Policy Regulations Future Assumed Retirements

Figure 9: Assumed Retirements in MTEP17

3. Expected New Generation Over the Next 20 Years

The potential significant amount of generation retiring over the next few years will create a need for new resources in the region. In its draft MTEP17, MISO indicates that in order to maintain resource adequacy within its footprint, close to 4.5 GW of new resources are projected to enter the market as described in the Table 5, below.[23] The table's resource projections are based on the latest Organization of MISO States-MISO survey results.[24]

Table 5: Expected New Generation over the next 10 Years

In GW (ICAP)	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28
(+) Existing Resources	150.0	149.3	148.9	148.6	146.7	145.0	144.7	144.2	144.0	144.0
(+) New Resources	2.0	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
(+) Imports	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.1	3.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
(-) Low Certainty Resources	1.0	1.1	1.4	1.5	1.5	2.3	2.3	2.4	2.4	2.4
(-) Transfer Limited	2.5	2.3	2.1	1.8	1.1	0.0	0.0	0.0	0.0	0.0
Available Resources	148.5	150.4	150.3	150.4	149.2	147.8	147.5	147.0	146.8	146.8
Demand	125.9	126.5	127.0	127.6	128.3	128.9	129.4	129.1	128.9	128.9
PRMR	145.8	146.5	147.1	147.8	148.5	149.2	149.9	149.5	149.3	149.3
PRMR Surplus / Shortfall	2.7	3.9	3.2	2.6	0.6	-1.4	-2.4	-2.5	-2.5	-2.5
Reserve Margin Percent (%)	17.9%	18.9%	18.3%	17.9%	18.3%	14.7%	14.0%	13.9%	13.8%	13.8%

With respect to the expected new generation over the next 20 years, there is significant need for new capacity resources in years 6 to 20 for which the MISO participants have not yet identified the resources to be developed to meet the need. The MISO MTEP17 analysis indicates that the current system surplus capacity is expected to erode within 5 years based on current assumptions and information on existing, committed, and planned changes in capacity resources. This assessment assumes no reduction in imported capacity through 2028. Longer term (year 2024 and later), absent any action to add new capacity resources to the system, the MISO market would be short of the capacity needed to meet reserve margin requirements. For example, in MISO's MTEP16 report, it included an assessment that 24 GW of new resources would be needed by 2031 to meet the need in that year (this analysis was not updated in the MTEP17 draft).

The region can accomplish the procurement of needed, but as yet unidentified, resources via established processes both at the state and regional level. Each state's Integrated Resource Planning (IRP) process and the MISO's capacity market ensure that

[23] MTEP17 draft – Table 6.2-1 MISO anticipated PRMR details

[24] PMMR is the Planning Reserve Margin Requirement. Low certainty resources are resources that may be available to serve MISO load but do not have firm commitments to do so. The 2016 OMS- MISO results can be found here: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/OMS-MISO%20Survey/2016OMS-MISOSurveyResults.pdf

this need will be met in the most cost-efficient way to the consumers. The IRP process is described in more detail in the *State and Federal Policies on Electricity Generation and Emissions* section of this report. In this section, we will provide information related to MISO's capacity market. Under the IRP construct, a utility may forecast a supply adequacy need and propose to build a new plant to fill the need. Utilities that need capacity will weigh the cost of developing new resources relative to the cost and availability of bilaterally-sourced existing supplies from neighboring systems. For instance, it may be more cost-effective to procure excess capacity from neighboring utilities or uncontracted IPPs rather than build new resources. The MISO capacity market provides a measure of the cost and availability of existing surplus capacity as an option to meet the utility's capacity needs.

4. Supply and Demand Balance in the Northern MISO Region

For the purposes of this report, Daymark defines the Northern MISO Region to be comprised of Minnesota, Iowa, Wisconsin and parts of North Dakota, South Dakota, and Montana – the states that are most proximate to MH. MISO defined nine Load Resource Zones (LRZ) in its system, defined by major internal transmission interfaces where transfers may be limited between LRZs. MH connects to MISO LRZ 1, which includes most of Minnesota, North Dakota, and portions of Montana and Wisconsin (see map in Figure 10).

The MISO Northern Zones are currently transfer limited, meaning capacity is surplus in those zones with the surplus capacity exceeding the ability of the transmission system to allow that surplus to be transferred to and used by zones with short supply to the south. Currently, LRZ 1 has an export limit of 600 MW and has surplus capacity in excess of this limit. Figure 10 is an illustration of this current surplus condition in LRZ 1.

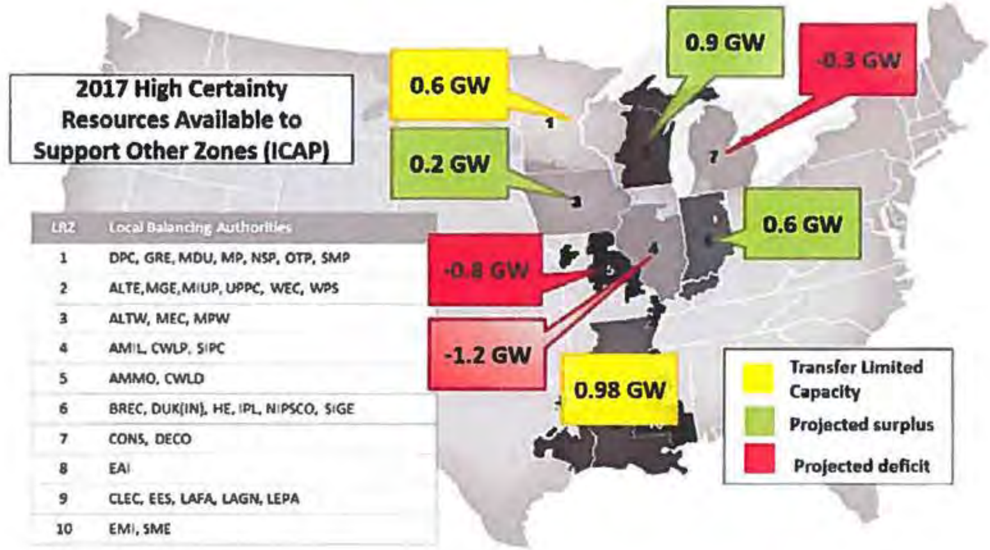

Figure 10: MISO Capacity Zones: Capacity Surplus/Deficit[25]

Table 5, above, included an amount of capacity that is transfer-limited, and therefore unavailable to meet MISO requirements in the 2018-2023 period. That analysis indicates that the system is not expected to be transfer-limited thereafter.

The retirement of capacity in the northern zones, as shown in the figure, eliminate that export-constrained situation by 2023. Figure 9 shows a significant number of retirements in the northern MISO zones.

MISO North's load growth on average is below 1 percent, with LRZ 1, 2, and 3 having slightly higher load growth than most of the other zones.[26]

[25] Source: 2016 OMS MISO Survey Results, June 2016
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/OMS-MISO%20Survey/2016OMS-MISOSurveyResults.pdf

[26] 2016 MISO Independent Load Forecast - https://www.misoenergy.org/Library/Repository/Study/Load%20Forecasting/2016%20Independent%20Load%20Forecast.pdf

Table 6: Summer Non-Coincident Peak Demand with EE/R/DG/Adjustments, LRZ Peak Demand Forecasts

LRZ PEAK DEMAND FORECASTS

Table 19: Summer Non-Coincident Peak Demand with EE/DR/DG Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2015	16,935	11,604	8,751	9,280	8,361	17,297	19,994	7,486	21,071	4,755
2016	16,807	11,399	8,444	9,622	8,775	17,332	19,800	7,291	18,986	4,765
2017	17,062	11,656	8,507	9,693	8,890	17,581	20,047	7,488	19,548	4,874
2018	17,322	11,918	8,594	9,739	9,006	17,825	20,413	7,635	19,951	4,943
2019	17,589	12,112	8,713	9,807	9,107	18,079	20,681	7,721	20,111	5,030
2020	17,869	12,256	8,829	9,869	9,213	18,320	20,824	7,767	20,237	5,118
2021	18,125	12,380	8,920	9,902	9,306	18,552	20,871	7,804	20,279	5,213
2022	18,390	12,537	9,014	9,931	9,403	18,764	20,973	7,857	20,382	5,302
2023	18,635	12,702	9,114	9,961	9,510	18,967	21,079	7,927	20,552	5,383
2024	18,868	12,862	9,218	10,002	9,623	19,171	21,254	8,004	20,762	5,465
2025	19,110	13,005	9,329	10,039	9,732	19,373	21,413	8,085	20,896	5,550
2026	19,355	13,162	9,444	10,082	9,832	19,578	21,556	8,169	21,070	5,637
Annual Growth Rates (%)										
2015-2016	-0.76	-1.76	-3.51	3.68	4.95	0.20	-0.97	-2.60	-9.89	0.22
2016-2017	1.52	2.25	0.74	0.74	1.31	1.43	1.25	2.70	2.96	2.28
2017-2018	1.52	2.24	1.03	0.47	1.30	1.39	1.82	1.96	2.07	1.41
2018-2019	1.54	1.63	1.38	0.71	1.13	1.42	1.31	1.12	0.80	1.76
2019-2020	1.60	1.19	1.33	0.63	1.16	1.33	0.69	0.60	0.62	1.76
2020-2021	1.43	1.02	1.04	0.33	1.01	1.27	0.22	0.48	0.21	1.85
2021-2022	1.46	1.27	1.05	0.29	1.04	1.15	0.49	0.67	0.51	1.71
2022-2023	1.33	1.32	1.11	0.30	1.13	1.08	0.51	0.89	0.83	1.53
2023-2024	1.25	1.26	1.15	0.42	1.20	1.08	0.83	0.98	1.02	1.51
2024-2025	1.28	1.11	1.19	0.36	1.12	1.05	0.75	1.00	0.65	1.56
2025-2026	1.29	1.21	1.24	0.43	1.03	1.06	0.66	1.04	0.84	1.57
Compound Annual Growth Rates (%)										
2015-2020	1.08	1.10	0.18	1.24	1.96	1.16	0.82	0.74	-0.80	1.48
2015-2026	1.22	1.15	0.69	0.76	1.48	1.13	0.69	0.80	0.00	1.56
2017-2026	1.41	1.36	1.17	0.44	1.12	1.20	0.81	0.97	0.84	1.63

5. State and Federal Policies on Electricity Generation and Emissions

State and federal policies regarding environmental performance of electric systems – particularly with respect to requirements for renewable and clean energy content and with respect to reliability and operational requirements in power markets – can lead to opportunities for premium pricing for MH contract offerings.

Environmental policy associated with U.S. electric systems has shifted to a more state-centric approach. The Obama Administration was actively advancing policies to reduce greenhouse gas emissions in the electric sector, most notably in the form of the Clean Power Plan rules pursued by the Environmental Protection Agency. Following the election, the Trump Administration has acted to withdraw from the Paris Climate

Agreement and has suspended the Clean Power Plan. While the Clean Air Act requirements will remain important to planning for the future of the electric system, the policy initiatives for renewable and clean energy are most active at the state level, with several states recently placing more emphasis on renewables and greenhouse gas emission reduction policies.

In this section, we discuss policy issues in Minnesota, Wisconsin and North Dakota as examples that are most relevant to Manitoba. We also discuss the development of capacity markets in the MISO market, driven by federal policy to ensure resource adequacy (sufficient generation reserves).

State Policy Drivers

Since most new capacity at MISO is procured through IRPs, state policies have a significant impact on what capacity is procured. With respect to MH's potential counterparties, key states to review are:

- Minnesota;
- Wisconsin; and
- North Dakota.

Minnesota

Minnesota is a state with aggressive renewable energy and carbon reduction policies. The state has a renewable portfolio standard (RPS) requiring 25-30 percent renewable energy by 2025 or 2020, depending on the utility.[27] The Minnesota Public Utilities Commission (MPUC) recently acted to increase the range of CO_2 pricing in resource planning assessments.[28]

One of the key counterparties for MH – Minnesota Power – is even more aggressively pursuing renewable power. Minnesota Power recently announced a new plan with a goal of 44 percent of the company's energy supply coming from renewable resources in the near term (2025) and a long-term goal of reducing coal to one-third of its energy mix, with two-thirds being renewable energy and natural gas.[29]

[27] http://programs.dsireusa.org/system/program/detail/2401

[28] *Minnesota agency raises state's CO2 values, rejects federal cost of carbon*, July 28, 2017, S&P Global Market Intelligence.

[29] https://minnesotapower.blob.core.windows.net/content/Content/Documents/Company/PressReleases/2017/201767_NewsRelease.pdf

Northern States Power (NSP), an Xcel Company, is another MH counterparty that serves load in Minnesota as well as in North and South Dakota. According to "*Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues*," pages 14-15,[30] the latest IRP for NSP identified the following "energy resources" as scheduled to retire in the 2020s:

- 2023: Blue Lake Units 1-4 (natural gas combustion turbines (CTs)) cease operation (153 MW);
- 2023: Sherco Unit 2 (682 MW coal) retirement;
- 2025: Manitoba Hydro contracts expire (850 MW);
- 2026: Cottage Grove Combined Cycle Energy Center contract expires (262 MW);
- 2026: Sherco Unit 1 (680 MW coal) retirement; and
- 2027: Mankato Energy Center Combined Cycle (MEC I) contract expires (375MW).

The MPUC has approved NSP's plan. The document states that new baseload will not be needed until 2026 in NSP's service territory, but NSP does indicate that aging of its coal and nuclear facilities will require planning to address the loss of 75 percent of the energy-producing resources on the NSP system in its next IRP.[31]

In addition to the above, Minnesota has been a leader in developing value of solar methodology that assigns externality value to solar.[32]

Finally, Minnesota has the Next Generation Energy Act, which sets goals of reducing carbon emissions by 80% of 2005 levels by 2050, with interim goals.[33]

Wisconsin

The Public Service Commission of Wisconsin produces a Strategic Energy Assessment[34] every 2 years. The purpose of that document is to evaluate, "*the adequacy and reliability of Wisconsin's current and future electrical capacity and supply*." The latest version of that assessment predicts that there will be about 520 MW of retirements in the state by 2020. This includes one 320 MW coal facility. The remainder are natural gas units.

[30] https://puc.sd.gov/commission/dockets/electric/2017/informational/2017infoel1.pdf

[31] *Upper Midwest Resource Plan 2016-2030*, Northern States Power, page 3, available at: http://www.ci.becker.mn.us/DocumentCenter/View/421

[32] http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

[33] https://www.pca.state.mn.us/air/greenhouse-gas-emissions-minnesota-0

[34] https://psc.wi.gov/Documents/SEA2022.pdf

Additionally,_Wisconsin has an RPS that requires LSEs to increase their renewable supply percentages by 2 percent by 2010 and 6 percent by 2015. The Strategic Energy Assessment projects a surplus of renewable energy, as shown in Figure 11.

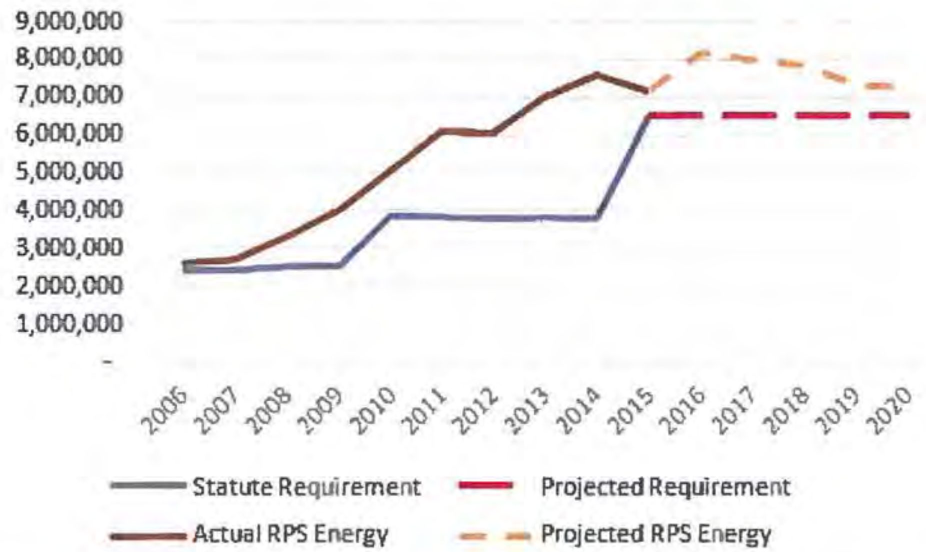

Figure 11: Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2020)[35]

[35] Projection out to 2020 based on 0 percent energy growth. Source: Commission Staff 2015 RPS Compliance Memorandum (PSC REF#: 285744).

North Dakota

North Dakota's policy environment differs from Minnesota and Wisconsin. By law, utilities cannot consider environmental externalities in their resource planning decisions. This difference is punctuated by a recent Northern States Power filing with the MPUC and the North Dakota Public Service Commission, seeking a process to separate the IRP processes in those states due to the differences in policy.[36] From a policy perspective, utilities in North Dakota would not apply any premium on renewable or clean energy attributes.

With respect to the need for power in North Dakota, the discussion of system needs in the NSP system would apply in North Dakota, as well, because NSP's system planning is currently completed for its multi-state service territory.

MISO Resource Adequacy

MISO has established a uniform resource adequacy standard that requires an aggregate quantity of installed capacity to meet peak demand plus a determined minimum reserve margin. The capacity requirement is estimated at a level expected to produce a loss-of-load event no more than once every ten years. Each utility or load serving entity in the region is obligated to procure enough capacity resources to meet their own coincident peak plus a reserve margin. The aggregate requirement is comprised of all the LSE and utility requirements. The resource adequacy process includes a location-specific aspect to account for transmission limitations on moving capacity between specific areas of the system. The figure below depicts the current planning resource zones at MISO.[37]

[36] Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues, Northern States Power, December 31, 2016. MPUC Docket No. E-002/M-16-223 and NDPSC Case Nos. PU-12-813, et. al.

[37] https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf, slide 6.

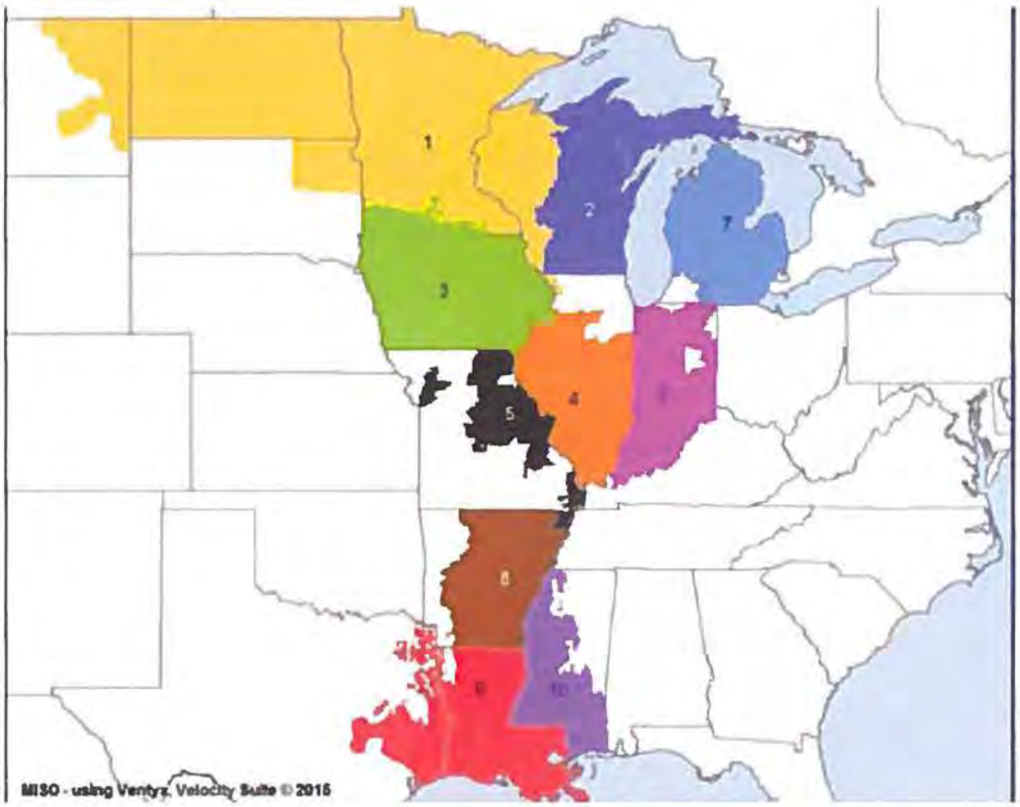

Figure 12: MISO Planning Resource Zones

Each LSE or utility can meet their requirement using a combination of self-supply, bilateral contracts, and procurements through MISO's Planning Resource Auction (PRA). MISO's hybrid model is necessary because most of the LSEs are regulated utilities with resource commitments selected within integrated resource plans well in advance of the delivery year. MISO's capacity maket can be considered as the last opportunity for LSEs to fill any deficiency in their capacity obligations. This auction is the only opportunity for market participants and the MISO to view the aggregate impacts of locational supply and demand balance and to ensure that local obligations are met.

An LSE seeking to pre-plan for its resource adequacy requirement can obtain resources by either self-scheduling resources or by submitting a Fixed Resource Adequacy Plan (FRAP). In the MISO PRA auctions, the majority of the capacity that clears is either self-supply or FRAP. In the 2017/2018 Planning Auction Resource Results report[38], out of

[38] https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf

134,753 MW of total committed capacity, 129,017 MW of it was either FRAP (49,463 MW) or self-scheduled (79,554 MW). Thus, 96 percent of the cleared capacity was identified by LSEs prior to the balancing auction. This indicates the critical part that IRPs and bilateral transactions play in meeting MISO's resource adequacy needs.

The capacity market at MISO has produced low prices since its inception, mainly due to the significant amount of surplus capacity. The recent retirements of various resources have reduced the amount of surplus, changing the market dynamics and potentially resulting in higher prices to incentivize new investment. The table below indicates how prices in the region have fared over the last few periods and the MISO's estimate on the amount of resources exiting and entering the market. Historically, the entities MH has transacted with are in zones 1 and 2.

Table 7: Capacity Market Prices, by Zone, 2014/15-2017/18

	$/MW-day			
Zone	2014/15	2015/16	2016/17	2017/18
LRZ 1	$ 3.29	$ 3.48	$ 19.72	$ 1.50
LRZ 2	$ 16.75	$ 3.48	$ 72.00	$ 1.50
LRZ 3	$ 16.75	$ 3.48	$ 72.00	$ 1.50
LRZ 4	$ 16.75	$ 150.00	$ 72.00	$ 1.50
LRZ 5	$ 16.75	$ 3.48	$ 72.00	$ 1.50
LRZ 6	$ 16.75	$ 3.48	$ 72.00	$ 1.50
LRZ 7	$ 16.75	$ 3.48	$ 72.00	$ 1.50
LRZ 8	$ 16.44	$ 3.29	$ 2.99	$ 1.50
LRZ 9	$ 16.44	$ 3.29	$ 2.99	$ 1.50
LRZ 10			$ 2.99	$ 1.50

For a resource to enter the market, it will have to be economically feasible. In theory, merchant generation will not enter unless average future prices are expected to be at least the Net Cost of New Entry (Net CONE), which is the gross cost of new entry, less the variable profit the resource is expected to earn from energy, ancillary service, and other market services. While most capacity does not enter the market through this mechanism, it is still an important indicator of the total revenue requirement of new capacity.

MISO calculates the CONE[39] and for the 2016/2017 planning year has produced the following expectations.

Table 8: Cost of New Entry, by Zone, Planning Year 2017/17

Zone	PY 2016/17 CONE ($/MW-yr)	Zone	PY 2016/17 CONE ($/MW-yr)
LRZ 1	$94,170	LRZ 6	$94,340
LRZ 2	$95,110	LRZ 7	$94,830
LRZ 3	$93,130	LRZ 8	$90,360
LRZ 4	$94,630	LRZ 9	$91,690
LRZ 5	$96,430	LRZ10	$89,810

Even though most new capacity at MISO is procured through the established IRP processes, the MISO capacity market provides an indication of the value of capacity in the region. Utilities that seek to build new resources to meet their resource adequacy requirement assess – among other things – the capacity market environment at the time and whether it is sensible to procure the required capacity through the market, build it on their own, or enter into a bilateral contract. Failure to procure enough capacity to meet capacity requirement results in deficiency charges.[40]

The expectations that MISO will be moving from the current capacity surplus position to one of potential shortages and need for capacity and energy additions will increase the importance of the capacity market structure in MISO. Other regions have seen material changes in capacity market design to better align the market to the need for resources.

6. Factors That May Affect Manitoba Hydro's Ability to Export Energy and Capacity into the MISO Market

MH interconnects with MISO via multiple transmission lines. This interconnection provides reliability and economic benefits to both Manitoba and MISO. In a study conducted in 2013, MISO evaluated the benefits from MH's large and flexible system in terms of its ability to reliably and economically integrate wind.[41]

[39] MISO does not calculate net CONE

[40] An LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10 of the MISO Tariff – Module E

[41] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Planning%20Materials/Manitoba%20Hydro%20Wind%20Synergy%20TRG/Manitoba%20Hydro%20Wind%20Synergy%20Study%20Final%20Report.pdf

In brief, the study identified that there are significant benefits derived from integrating an incremental amount of MH resources, which are realized as:

- **Production cost savings** after less-economic resources are displaced by inexpensive MH resources;
- **Load cost savings** after the region experiences lower energy prices;
- **Reserve cost savings**, due to an added ability to share reserves, enabled by the increased transmission capacity between the two regions; and,
- **Wind curtailment reduction**, since MH resources are easily dispatchable and able to mitigate wind intermittency over the long term.

As the region continues to invest in wind resources, the benefits articulated in the MISO wind-hydro synergy study should continue to provide strong incentive for MH and their U.S. counterparties to continue to derive benefits from bilateral contracts for power and capacity.

D. Daymark Findings

Based on our analysis, we make the following observations:

- MISO's existing generation mix is becoming more diversified. Over 5 GW of coal retirements and increases in natural gas and renewable production in recent years leaves coal as the leading energy source in the MISO market, but with natural gas and renewables having increasing market shares. Natural gas is the fuel setting market prices about 40 percent of the year.
- The 61 GW of coal generation in the MISO market is likely to decline significantly over the next decade with the age of the fleet and the economic pressure of low natural gas prices being primary drivers. About 88 percent of the existing coal capacity is over 50 years old today. A number of planned coal retirements have been announced in MISO plans or in utility resource plans.
- MISO needs assessments indicate that the current system surplus capacity is expected to erode within 5 years based on current assumptions and information on existing, committed, and planned changes in capacity resources, with the need for new resources of about 24 GW by 2031. This need is driven primarily by expected retirements of aging coal generation. The replacement resources will be determined by the generating companies in the region, with natural gas generation and renewables being prominent options under consideration in resource plans we reviewed.

- State polices have significant influence on resource choices. In Minnesota, policies governing utility resource planning are placing increase importance on greenhouse gas emission reductions and renewable resources. As examples, Northern States Power and Minnesota Power each show coal retirements and increasing natural gas and renewables in their plans for the coming decade. Wisconsin state policy show some similarities to Minnesota's priorities, while North Dakota requires that utility planning primarily consider least-cost resource options.
- Federal policies that will be important in the coming decade will likely center on market mechanisms. With MISO expecting an end to its historical capacity surplus conditions by 2025, the MISO capacity market will become increasingly important. FERC has been very active in capacity market design policy across the U.S. and in MISO.
- The continuous and rapid integration of renewables will add significant value to the energy and capacity provided by MH due to its reliability and dispatchability characteristics. The MISO wind-hydro synergy report identified several market and reliability benefits. We expect these to increase over time upon the potential creation of new ramping and/or other market products.

III. EXPORT PRICES

A. Overview

The Export Prices section of this report provides a more detailed assessment of MH's electricity export price forecast with an emphasis on the primary export market in the U.S., which is administered by MISO.

MISO administers a complex competitive wholesale market for energy, reserves, and capacity. The energy markets are day-ahead and real-time exchanges that establish market clearing prices by location on 5-minute intervals (Locational Market Prices or LMPs). The capacity market is a voluntary auction process allowing entities with load serving obligations to buy or sell capacity entitlements for the coming year, a market that is locational by zone across the MISO system.

Market participants can buy or sell energy and capacity directly into the organized MISO markets or they can enter into bilateral contracts directly with other market participants. In either case, market participants will consider historical market prices and estimates of future market prices when making decisions about energy and capacity transactions. It is common practice for market participants to develop or obtain a forecast of market prices to forecast costs and revenues from transactions in the markets as well as to provide a price benchmark in evaluating bilateral transactions.

In this section, we describe our review of MH's market price forecasts used as inputs to the export revenues forecast included it its GRA application. We describe, (i) the scope of our investigation, (ii) the analysis we conducted, including detailed findings, and (iii) a summary of our findings.

B. Scope of Investigation

Daymark has prepared this section of the report to address the first part of the Scope of Work and support other elements of our work that rely on the materials in this section. The specific section of the Daymark Scope of Work addressed in this section is:

> *"Review Manitoba Hydro's electricity export price forecast and third party consultant forecasts, including the low and high case forecasts, in the context of current MISO market conditions and factors influencing future MISO prices. The third party consultant forecasts are to be taken as a "given" and are to be assumed to be reasonable and accurate with respect to the other tasks in this*

Scope of Work. Notwithstanding that the third party consultant forecasts are to be accepted for the purposes of this review, if the IEC identifies significant issues or inconsistencies with the third party consultant forecasts in the course of its general review, those issues or inconsistencies are to be identified in the IEC's reports."

To perform this scope of work, Daymark interviewed MH personnel responsible for the MISO energy forecasts and reviewed public and confidential MH documents, including the actual third-party forecasts and the contracts between MH and the third-party vendors. A specific list of these documents is provided in Appendix B.

C. Analysis

The Daymark IEC Team investigated both the reasonableness of the process used by MH in obtaining and vetting the price forecasts received from the third-party consultants and the reasonableness of the price forecast derived by MH based on those forecasts. We also reviewed MH's development of the price inputs used in its various processes and planning applications used to develop the export revenue forecast.

1. Background

Fundamentally, there are four services or commodities that MH may export:

1. **Energy:** Actual electrical energy generated, as measured in MWhs.
2. **Capacity:** Ability of generation units to generate energy, as measured in MWs.
3. **Ancillary Services:** Services necessary to support the transmission of capacity and energy from generation resources to consumers while maintaining reliable power grid operation. These services include Regulation, Operating Reserve, and Black Start services.
4. **Environmental Attributes:** Additional value of energy from certain types of generators, generally either renewable or low-emission, as defined by environmental policies and regulations.

These components of power can be sold either in a direct contractual arrangement with another utility, often referred to as a bilateral transaction, or be sold in an organized market where multiple sellers can offer these components to multiple buyers through a competitive market structure. The primary export market for Manitoba is the MISO market to the south of the province.

One can view the price forecast in two horizons that align with energy resource decisions: (i) the short-term or operating horizon and (ii) the long-term planning horizon.

2. Short-Term Forecast

The short-term forecast (months to a year out) relies on one independently-produced forecast. [redacted] is the company that provides a monthly price forecast for the upcoming 3a
months. Like the long-term forecast, the prices reflect the consulting firm's view of the market based on factors that, in their opinion, will influence the MISO markets over the forecasting period.

The short-term price forecast is provided to the MH staff on a monthly basis and is reviewed internally before it is used as an input to various planning applications. One of the critical components of this review is the MH staff's adjustment to the [redacted]-produced 3a
prices. According to MH staff, this adjustment is necessary to account for historical deviations between forecast and actuals. The graph below depicts a 12-month average on-peak price variance between the actual forecast and [redacted] short-term forecast.[42] 3a

[redacted] 3a

Figure 13: 12-Monthly Average On-Peak Price Variance

[42] 2[redacted] Performance Review - CHARTS CONF 3a

Based on the information provided by MH, these adjustments:

- Were selected by evaluating differences between [redacted] and other market providers[43], and considering the past 12-month historical values; and,
- Were based on approximate comparisons to other forecasts, forward prices, and historic prices for same time of year. 3a

MH applied their judgement to [redacted] forecasted energy prices in [redacted] months and [redacted] months to reflect what they saw as a systematic [redacted].

The two graphs below depict the on- and off-peak [redacted] forecast, the adjustment, the actual forecast used in the planning applications, and the average of the 3 independent consultants and ICE forwards. 3a

[redacted] 3a

Figure 14: On-Peak Forecast Comparisons ([redacted], Adjustment, Actual, Average) 3a

[43] Manitoba Hydro uses short term forecasts from 3 independent consultants and ICE forwards to benchmark [redacted] forecast 3a

[redacted] 3a

Figure 15: Off-Peak Forecast Comparisons [redacted], Adjustment, Actual, Average) 3a

For the 2016 forecasts, MH staff incorporated [redacted] 3b

This practice was also used in 2017. We have reviewed the data and the methodology for this use of historical data and we find it reasonable.

3. Long-Term Forecast

MH uses the long-term forecast to develop price inputs to its long-term planning model called SPLASH. In this context, the long-term period begins in the second future year in the planning period and extends to the end of the planning period.

Under the long-term forecast process, MH acquires four independent market price forecasts from various consulting firms that have established expertise in North American energy markets. Each consulting firm uses an electricity price forecast model. While the contracts between MH and the vendors do not specify what tools will be used to produce the forecasts, these vendors are well known consulting firms in the industry who typically use production cost models capable of simulating the operation of the power system over a specific period. Each consultant considers their models and market price models to be confidential and proprietary.

While differing in the specifics, the products purchased from the independent consultants all provide MISO-specific outputs and some level of information on the factors that affect pricing outcomes within its region. More specifically, the models used to produce the prices are based on key inputs such as:

- Load characteristics and estimated load growth rate;
- Existing generator characteristics like generator size, fuel, and heat rate;
- Retirements and additions to the generator fleet;
- Thermal fuel forecasts; and,
- Potential changes in the regulatory environment regarding emissions and RPS requirements.

MH received electronic information from each vendor, which represented the entirety of the information available for reviewing and characterizing the forecast received. For all four vendors that information was provided via one or more spreadsheets. All four vendors provided annual energy and capacity prices. Some provided monthly energy prices as well. MH used a consensus approach, taking the average of the annual energy and capacity prices to create a single forecast, which MH called their reference energy price forecast.

The reports provided to MH staff for the 2017 reference energy price forecast are described below.[44]

- [redacted]
- [redacted] 2b
- [redacted]
- [redacted]

[44] Vintage of Consultant Forecasts for MH 16 Update

Details of each vendor contract and the product provided are included in the next four subsections.

[redacted]

[redacted] 2b

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] 2b

[redacted]

[redacted]

[redacted]

2b

[redacted]

[redacted]

[redacted] 2b

Key Inputs

To review the reasonableness of the consensus methodology and the resulting energy price forecast, Daymark reviewed the key inputs: natural gas prices, carbon prices and capacity retirements. Natural gas forecasts varied across the four vendors. Figure 16 provides an MH graph comparing the four natural gas forecasts and the resulting 2017 Reference natural gas forecast based on the MH consensus methodology.

[redacted] 2b

Figure 16: Comparison of Natural Gas Price Forecasts, by Independent Consultant

To test the reasonableness of the results, Daymark compared the consensus natural gas forecast to the 2017 Annual Energy Outlook (2017 AEO) from the U.S. EIA. The 2017 AEO is a good benchmark because it is publicly available and contains descriptions of the underlying fundamentals that drive their forecast. Figure 17 shows that comparison with the consensus view being somewhat lower in the short term and close to the AEO in the longer term.

[redacted] 2b

Figure 17: Comparison of MH Consensus Natural Gas Price Forecast to EIA 2017 AEO

In addition to natural gas prices, carbon pricing assumptions are an important assumption used in many energy price forecasts. Figure 18 provides a MH graph comparing the four carbon forecasts and the resulting 2017 Reference Carbon forecast based on the MH consensus methodology.

[redacted] 2b

Figure 18: Comparison of CO_2 Price Forecasts, by Independent Consultant

Range of Results

The following charts provide the price at the MHEB energy pricing node and the range of the independent consultant forecasts for on-peak energy, off-peak energy, and capacity.[49] Since the independent consultants provide only 20-year forecasts, MH extrapolated prices for all additional years at a constant real rate. Figures 19 through 21 provide the 2017 reference case prices as a result of the consensus methodology, accompanied by the range of the independent forecasts prices.

[redacted]

2b

Figure 19: On-Peak Energy Price Forecast at Pricing Node MHEB

[49] Information provided by Manitoba Hydro in 2017 Energy Price Forecast

[redacted] 2b

Figure 20: Off-Peak Energy Price Forecast at Pricing Node MHEB

[redacted] 2b

Figure 21: Capacity Price Forecast at Minnesota

Forecast Variance

As discussed in the section results above, the energy and capacity price forecasts show significant variance between the four independent consultants. Given that one of the forecasts was three months older than the others, Daymark investigated the impact of the oldest forecast to understand the impact of its inclusion.

Market price forecasts rely on information that is knowable about future market conditions at the time the forecast is prepared. Forecasts prepared at different points in time will vary, even from the same forecaster, if new information becomes available (e.g., updated forecasts of fuel prices, retirements, or market designs). We reviewed the vintage of the four forecasts to assess whether they were reasonably contemporaneous and, if not, if any change in market conditions were evident in the differences in the forecasts.

MH's On Peak Consultant Comparison graph provides an example of the range of forecasts. [redacted] 2b

[redacted] 2b

Figure 22: Comparison of On-Peak Energy Price Forecasts, by Consultant

50 [redacted] 2b

A look at the capacity price forecast graph from MH shows another view of the difference in the [redacted] forecast (See Figure 32). 3a

[redacted] 2b

Figure 23: Comparison of Capacity Price Forecasts, by Independent Consultant

[redacted] 2b

Lack of Detailed Input Review

The issue of report variance is exacerbated by the lack of detailed review that was done with regards to the forecasts themselves. As was discussed above, the four forecasts provided different levels of insight into what input assumptions were used. The documentation provided by the vendors did not provide the level of information a price forecaster would need to be able to assess the forecasts to determine if they each represented their company's reference forecast. Nor do the documents define how MH should view these forecasts within a range of possible outcomes. Only one of the four, [redacted] even uses the term "reference" when referring to the product being provided to MH. 2b

Furthermore, there is no evidence that MH attempted to perform a deeper review of the forecasts, or assess the possibility that one or all of the forecasts might not qualify as "reference". The four forecasts provided price strips for energy and capacity and, after performing some basic due diligence on the natural gas and carbon prices, MH used the average of the four forecasts.

Neither the information available in the contractual arrangements with each vendor, nor the forecast materials provided by each vender contain any information on the vendors' views on the probability that prices will be higher or lower than the forecast provided. In each case, a single forecast was provided; there were no high or low alternative cases delivered that might serve to provide some context on their view of how the delivered forecast fits within the range of uncertainties.

As a result, we found no means to determine if the four forecasts are prepared on a consistent basis or if they were prepared with a specific objective to be a "50/50 reference forecast".

Apparent Inconsistencies between MH and Third-Party Forecasts

After looking in more detail at the data provided by the independent consultants we identified inconsistencies between MH's market view and the consultants' views. More specifically, one of the primary reasons for MH to remove the capacity premium from a subset of modeled products in its planning applications (See Section VII) was that the capacity prices will remain low "as coal closures have been delayed under the Trump administration, increasing capacity supply."[51] [redacted] 2b

[redacted]

[51] PUB MFR 79 Updated - CONFIDENTIAL

Adjustments for Congestion and Losses
The consulting firms provide a forecast for MISO's Minnesota Hub (MINN HUB), which is an aggregation of generation and load pricing nodes in the Minneapolis area. Since MH delivers its power at the border between Manitoba and the U.S. represented by a pricing node called MHEB or Manitoba interface, MH calculated an adjustment and applied it to account for the historical transmission congestion and marginal transmission line losses. [redacted] 3b

4. High and Low Cases Methodology

Following reduced interest by its stakeholders and to minimize cost, MH began in 2017 to produce the high- and low-price cases in-house. MH considered a variety of methodologies with the goal of producing a forecast that used publicly available information, had scientific accuracy, and provided a reasonable deviation from the reference case.

The methodology chosen included information provided by the U.S. EIA on an annual basis via its AEO process. The AEO outlook includes projections of energy production, consumption, fuel oil prices, and other prices through 2050. The data is provided in a reference case that describes the EIA's view of the future[52] and seven sensitivities around the base case that capture fundamental economic drivers such as growth, oil prices, resource and technology changes, and others. In brief, the seven sensitivities capture the industry changes as mentioned above based on variances in oil and natural gas prices, technology differences, and economic growth.

[52] "The Reference case projection assumes trend improvement in known technologies, along with a view of economic and demographic trends reflecting the current central views of leading economic forecasters and demographers. It also assumes current laws and regulations will remain unchanged" Annual Energy Outlook 2017 with projections to 2050.

As an example, the total energy production is represented in Figure 24.

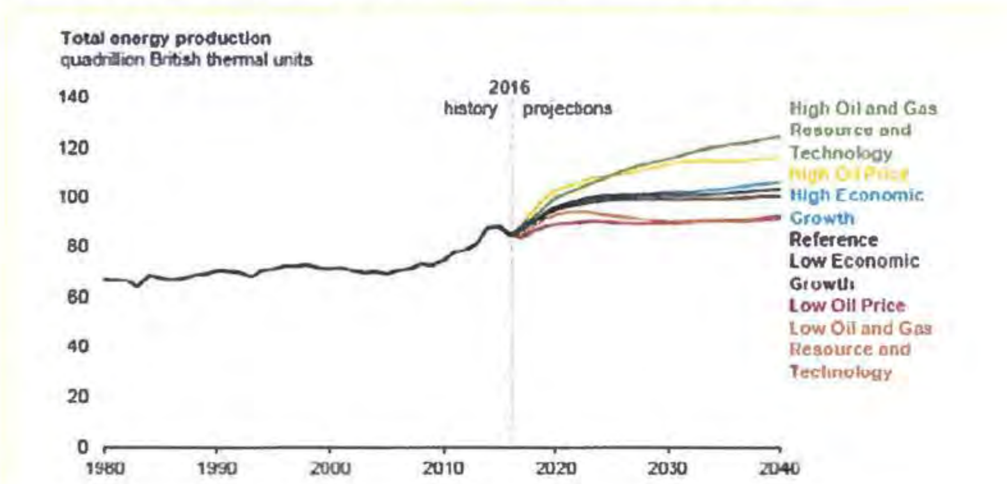

Figure 24: Total Energy Production, Annual Energy Outlook

MH chose two of the seven sensitivities to represent the high and low cases[redacted] A natural gas price deviation was then calculated between the reference AEO case and the two chosen boundary cases.[redacted] 3b

After estimating the prices, MH staff used the following formula to derive a heat rate:

Heat Rate = Power Price ÷ Natural Gas Price

Finally, the high- and low-price cases were developed by changing the natural gas price in the above calculation and keeping the heat rate consistent.[53] The resulting high and low cases for 2017 – for both on-peak energy and off-peak energy[54] - are presented in Figure 25 and Figure 26, respectively.

MH also eliminated the production of the high and low capacity forecasts, since they were not used by the stakeholders.[55]

[redacted] 3b

[54] 2017 Energy Price Forecast v3 – tab charts

[55] PUB MFR 79U-CONF

[redacted] 3b

Figure 25: On-Peak Energy Price Forecasts (Reference, High, Low) at MHEB

[redacted] 3b

Figure 26: Off-Peak Energy Price Forecasts (Reference, High, Low) at MHEB

D. Summary of Findings

We offer the following observations regarding the third party consultant forecasts and MH's reference case forecast:

- MH's purchased off-the-shelf energy and capacity price forecasts from four third-party consultants that offer these services to the industry broadly on a subscription basis.
- In each case, MH purchased a single case or scenario and did not purchase high or low case alternatives. The single case forecasts and associated documents did not include any characterization of the design objectives of the case with respect to the likelihood that values could be higher or lower than the case presented.
- MH used the average of the four forecasts as its reference case.
- MH's resultant reference case forecast has the following characteristics:
  - [redacted]
  - [redacted] 3b
  - [redacted]

We offer the following observations regarding the low and high case forecasts:

- MH elected to develop high and low case forecasts in-house, rather than purchase such forecasts from third-party consultants as it had done in prior years.
- MH defined those cases by calibrating its reference case to its high and low cases using EIA AEO low, reference, and high cases.
- [redacted] 3b
- MH did not provide a low or high capacity price forecast.
- [redacted] 3b

As we discuss further in Section VII, we understand that "reasonableness" in this context is whether the forecast is a balanced, with the values being used representing assumptions that fall in the middle of the range of plausible values (i.e., a P50 value). In that context, our observations on the reasonableness of the market price forecasts are:

- Assuming the four third-party forecasts reflect each vendors' view of a P50 forecast, MH's reference case method of weighting the four equally is a reasonable basis for a forecast.
- [redacted]
  - [redacted]
  - [redacted] 3b
  - [redacted]
- [redacted]

IV. EXPORT ENERGY AND CAPACITY

A. Overview

This section describes the work undertaken to understand the forecasting methodology used by MH to determine the exportable energy and capacity, considering the flow and inflow conditions, reservoir levels, as well as other hydrologic inputs that are applied to the Emma/Splash modeling. Additionally, we discuss changes in forecasting methodology between the NFAT and today.

B. Scope of Investigation

The MH16-Update projections were classified as short-term (2017/18 and 2018/19) and long-term (2019/20 to 2051/52). Our analysis in this section is sub-divided into *Short-Term Hydrology* and *Long-Term Hydrology.* Due to the differences in calculation of water inflows between Year 1 (2017/18) and Year 2 (2018/19), the *Short-Term Hydrology* subsection is further organized into *Year 1 Inflow Calculations* and *Year 2 Inflow Calculations*, before combining the outputs of the two into the short-term forecasting model, as explained below.

For this assessment, Daymark used all confidential documents in relation to hydrology provided by MH, as well as publicly available sources of information on historical hydrologic trends. Documents relied upon in the performance of this work are listed in Appendix B.

C. Analysis

The assessment by Daymark showed that the methodology used by MH for both the short-term and the long-term periods appeared to be reasonable. The short-term hydrology methodology has changed from previous years and it is dependent on initial storage condition assumptions that result from that change. However, the change in methodology and the resulting energy and capacity values appear reasonable. The long-term hydrology methodology is consistent with the approach used in previous rate filings and Daymark did not identify any concerns with respect to the hydrologic calculations.

Details of the work performed are organized into the following subsections:

- Short-Term Hydrology Analysis
- Long-Term Hydrology Analysis

1. Short-Term Hydrology Analysis

Based on information provided by MH, the hydraulic generation values and net export revenues are dependent on the following two important factors:

- Inflow conditions; and
- Starting reservoir/lake storage level elevations.

From IFF16, Tab 3.1,[56] the short-term forecast methods used in IFF16 and MH16-Update can be summarized as follows:

- For Year 1 (2017/18):
  - Actual inflow conditions until May 2017
  - 'Expected' inflow conditions[57] determined through statistical (regression) analysis for June 2017 through March 2018
  - Actual reservoir and lake level elevations
- For Year 2 (2018/19):
  - Inflow conditions calculated based on an average of 104 water flow cases[58] – referred to as the 'multiflow' method
  - Expected starting reservoir and lake level elevations assumed to be carried forward from Year 1

Year 1 – 2017/18 Inflow Calculation Overview

The Year 1 methodology and calculations were reviewed in detail. Year 1 hydrology is based on the state of actual hydrology as of the date the analysis is done plus an expected rest-of-year hydrology using regression analysis designed to predict balance-of-year hydrology from the previous month's results.

No issues were found with the Year 1 methodology or results.

Year 2 – 2018/19 Inflow Calculation Overview and Inputs

MH used the 'multiflow' technique for the Year 2 forecast of inflow conditions in preparation for the MH16-Update. This methodology differs conceptually with the previously-used 'median flow year method'. Daymark analyzed the two methods, including the rationale for the change and the supporting documents articulating the results.

[56] GRA Submission, Appendix 3.1, pp. 16.

[57] PUB-MH II-37a-b, pp. 2.

[58] Correction from 102 flow cases to 104 flow cases by the Company as indicated in MH PUB 1.19a, pp. 1.

Multiflow Method

For Year 2 (2018/19)[59], using MH's operational modeling capability, the average of 104 river flow cases (1912/13 to 2015/16) was considered for inflow conditions. The resulting hydrology for the IFF was the average of all flow cases.

Median Water Flow Year Method

From the documentation provided by MH[60], the 'median water flow year' method can be summarized as a calculation technique for inflow conditions based on a single flow year, where the single flow year would be the median water flow year among 80 years.

Comparison between the Two Methods using Starting Storage Conditions

An important factor to understand is the asymmetrical relationship between water flow conditions and hydro generation. The river flow conditions might not directly depict an impact on the hydro generation due to the limitations in storage conditions. If the median water flow year is determined to be a high-flow year, this could result in more water than the capability of hydro generating units, resulting in capped generation. This could consequentially result in lesser downstream energy production.

Given the uncertainty surrounding future hydrology, an average of all flow years is more likely to capture the asymmetry than a single flow case, even the median one. Based on that, Daymark determined that the analysis using the 'Multiflow Method' in MH16-Update was reasonable.

2. Long-Term Hydrology Analysis

From IFF16, Tab3.1[61], the long-term forecast method used in IFF16 and MH16-Update can be summarized as follows:

- It applies to years 3 and beyond (2019/20 and beyond); and
- The forecast is determined by averaging revenues across inflow conditions for the past 102 years.

This approach is consistent with methods used in the NFAT and previous GRAs. The principle tool used in this approach continues to be Simulation Program for Long-term

[59] PUB-MH I-19d, pp. 1-2.

[60] COALITION-MH I-62a-e, pp. 2., PUB-MH I-19d, pp. 1-2.

[61] GRA Submission, Appendix 3.1, pp. 16.

Analysis of System Hydraulics (SPLASH). SPLASH has been thoroughly tested over many years and remains a reasonable tool for modeling the specific MH system.[62]

Dependable Energy Results

One of the key outputs of the modeling efforts is the available dependable energy. Figure 27 shows the opportunity sales, firm (contract) sales and available dependable energy, all in GWh.[63]

[redacted]

5b, 5c

Figure 27: Annual Firm and Opportunity Exports and Dependable Surplus

Long-term Hydrology Observations

The methodology used in determining the hydrology for the long-term period appears to be reasonable and consistent with the previously-reviewed and approved methodology. Furthermore, the post-processing calculations of the SPLASH output data have been appropriately represented to be the average of 102 flow cases for each load year and are properly being used in the export revenue forecast. To the extent that proper price and firm energy assumptions are assumed, the results are reasonable.

[62] Manitoba Hydro, "Peer Review of Manitoba Hydro's Splash Model", May, 2005, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_74-Attachment_2.pdf.

[63] The dependable energy numbers are from Appendix 7.3, pp 22 and 23. Because 7.3 assumed Keeyask in service in 2019/20, the dependable energy values for 2020/21 and 2021/22 were adjusted to estimate the impact of the delay of Keeyask. Firm and Opportunity Sales come from confidential SPLASH documents provided to Daymark via MH's SharePoint site.

D. Summary of Findings

Daymark concludes that the hydrology used by MH for the MH16-Update appears reasonable and consistent with previously-used methodology. Calculations of dependable and total energy are reasonable.

V. CHANGES IN FORECASTING METHODOLOGY

A. Overview

MH regularly conducts forecasts of export revenues for its annual financial planning for resource planning studies. The export revenues are generated from the sale of surplus energy including sale of surplus dependable energy via existing long-term contracts (as discussed in Section VI) and through the sale of additional surplus energy. The additional surplus energy can include surplus dependable energy (surplus energy in dry year conditions) and additional surplus opportunity sales (additional energy available in average year conditions). In this GRA, MH's methodology and assumptions for forecasting the revenues from the surplus energy that is not committed via long term contracts – surplus dependable and surplus opportunity –differs from those used by MH in the NFAT proceedings and prior financial projections.

B. Scope of Investigation

Scope item #4 requires Daymark to "*assess the reasonableness of changes in MH's forecasting methodology that eliminates the assumed premiums for surplus dependable energy and capacity sales.*"

Our approach to this work centers on MH's response to PUB MFR 79 (Updated), in which MH offers it explanations of the changes in methodology, along with the 2016 Electricity Export Price Forecast (2016 EEPF).[64] We discussed the response and the methodology changes with MH SMEs and reviewed associated analysis of export revenue sales. We also rely on our work on presented in Sections II, III, and IV of this report to assess the reasonableness of the methodology.

C. Analysis

MH included a Long Term Dependable Product forecast in its EEFP in 2013, 2014 and 2015, as well as in the analysis MH provided in the NFAT proceeding. MH removed the assumption of a premium for that product in its 2016 EEFP and has continued the assumption of no premium in the export revenue projections provided in the GRA proceeding. In more recent analyses, MH made additional changes to its method of forecasting prices for that product.[65] In this Section V, we discuss the change in the assumption regarding the premium, which is the subject of our

[64] The 2016 EEPF is an internal MH document, dated August 9, 2016 provide as a confidential document to the Daymark IEC Team via SharePoint. The 2016 EEFP is identified in the response to PUB MFR 79 (Updated).

Scope Item #4. In Section VII, we discuss the full set of changes to the forecasting methods that have been implemented in the current export revenues forecast.

In the NFAT proceeding, and in the 2013 to 2015 EEPFs, the long-term forecast was used for both spot/opportunity sales and non-committed firm sales. The non-committed sales – an important component of MH's Preferred Development Plan during the NFAT – were defined as firm sales not yet under contract that were priced at premium prices.

In this period, MH defined a Long Term Dependable Product to be On-Peak Energy (5x16) and associated capacity sold in a long-term contract of 5 years or more. The price premium [redacted] was used to represent the additional amount that buyers would pay for price and volume certainty over the long term and for the environmental advantages of hydropower.[66] The value of the premium was [redacted] 7b 7b

Figure 28 illustrated the forecast results of the reference case for the Long Term Dependable product, broken out by component, at MHEB in 2015 US$/MWh.[67]

[65] PUB MFR 79U, page 1.
[66] 2015 EEPF, page 14.
[67] 2015 EEPF, page 15.

[redacted] 3b, 3c

Figure 28: Reference Case Forecast, Long Term Dependable Product, by component

In MH's 2016 EEPF, the [redacted] premium for the Long Term Dependable Product was removed due to MH's assessment of then-current market conditions. MH removed the premium based on the following concerns:[68] 3b, 7b

- [redacted]
- [redacted] 3a
- [redacted]
- [redacted]
- [redacted]

With respect to the 2017 Energy Price Forecast (2017 EPF), MH's observation on the current market conditions [redacted] 3a The premium was not used in the 2017 EPF.

The primary question we have been asked to address is the reasonableness of the assumptions regarding the premium for the surplus dependable energy and capacity.

[68] 2016 EEPF, pages 12-13.
[69] PUB MFR-79U-CONF, page 4.

We have been asked to consider the 20-year forecast of export revenues and consider the entirety of that term in this assessment. As we discuss further in Section VII, we understand that "reasonableness" in this context is whether the forecast is a balanced view, with the values being used representing assumptions that fall in the middle of the range of plausible values (i.e., a P50 value).

We also observe that the forecast of surplus available energy is significant for most of the 20-year forecast period. The values are shown in Figure 27 in Section IV, with roughly 2,000 GWh/yr in the near term and over 4,000 GWh/yr for a ten-year period and remaining above the 2,000 GWh/yr level thereafter. These values make the longer term pricing assumptions important to the reasonableness of the forecast.

Upon review of the reasons for first instituting a premium and then removing the premium, we believe the elimination of the premium in its entirety for the 20-year forecast is not well supported and not consistent with the information available to MH from the independent market consultants (see Section III) or the information from MISO, NERC and utility IRPs (see Section II). With that said, we agree with MH's assessment of the softening of the market for exports in the near-term over the past several years. The explanations of the market conditions associated with this issue from the 2017 EPF are very focused on the current and near term market conditions. We do not see any consideration of the potential for materially different circumstances to be prevailing beyond the near term.

Based on our review of the information on the longer-term trends in MISO (as documented in Sections II and III), the near-term market conditions that are adversely affecting the ability to sell firm power at a premium are not expected to persist for more than a few years. Our observation that the 20-year plus long-term outlook prepared by MH, assuming no premium at any point in time, is inconsistent with the rationale for instituting the premium in the first instance for years 6 to 20 of the forecast.

D. Summary of Findings

Based on our analysis, we make the following observations:

- The changes to the forecast methodology over the testing period indicate a more conservative approach than was previously used.
- The primary reason for the premium is to reflect the added value to buyers, beyond the commodity energy and capacity value, for attributes such as long term price certainty and stability and the environmental attributes of hydropower.

- The primary reason for the change in methodology is a view that lower natural gas and capacity market prices, along with surplus capacity conditions have made the market soft in recent years.
- The elimination of the premium appears reasonable for the near term.
- The elimination of the premium in the longer term is not consistent with the longer-term outlook for energy, capacity and clean energy requirements in the Northern MISO region. Based on Daymark's MISO market assessment provided in Section II and the independent consultants view on capacity needs in the near future, an opportunity for premiums in long-term contracts is a distinct possibility, as was observed by MH when it initiated the premium in 2013.

VI. FIRM CONTRACTS

A. Overview

Firm energy and/or capacity export contracts represent a significant portion of MH's forecasted revenues. The Daymark IEC Team reviewed the accuracy and reasonableness of the revenue forecasts associated with these firm export contracts.[70]

MH currently has a substantial portfolio of contracts exporting firm energy and/or capacity to extraprovincial counterparties. The volumes of committed energy and capacity over time from existing executed contracts are summarized in Figures 29 and 30.

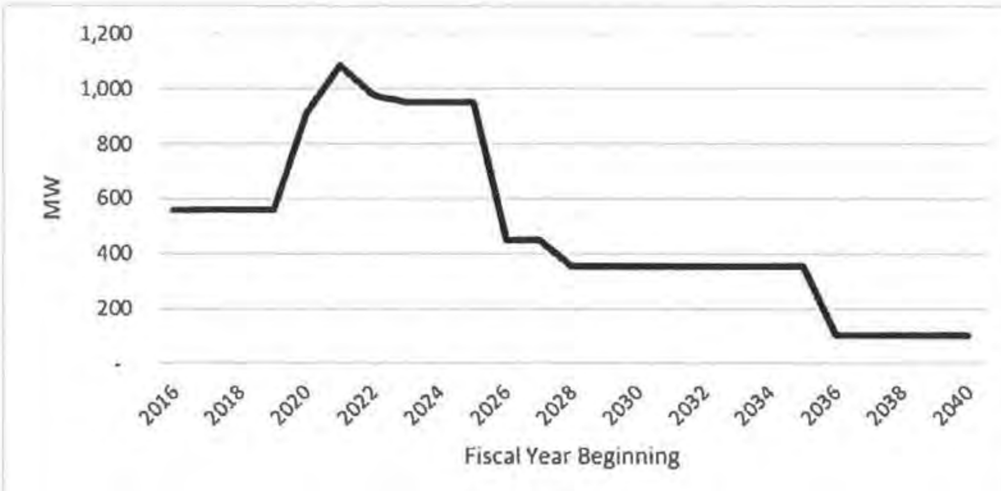

Figure 29: Firm Export Capacity under Contract[71]

[70] Unless otherwise specified, all references to calculations of contract revenues refers to calculations done for the updated MH16 analysis that is part of the presentation in Tab 3.6

[71] Compiled from export contracts provided by MH. Note that the value for each FY includes the sum of maximum monthly value for each contract for that FY. For example, if a contract exporting 100 MW expires midway through FYB 2020, the total will include 100 MW from that contract.

[redacted]

1d, 3a, 7b

Figure 30: Firm Export Energy under Contract[72]

Forecasted revenues from these contracts reach a peak of [redacted] (see Figure 31 below). 1d, 3a, 7b

[redacted]

1d, 3a, 7b

Figure 31: Firm Export Energy and Capacity Revenue[73]

The Daymark IEC Team reviewed the reasonableness of MH's forecasted revenue from these firm export contracts.

[72] MFR 84, Annual export contract volumes and revenues.

[73] Ibid.

B. Scope of Investigation

This section covers the work done to complete the review of revenues sourced from contracted energy and capacity sales, as contemplated in Scope Item #3. The review of the remainder of the components of the 20-year forecast of export revenues, as contemplated in Scope Item #3, is addressed in Section VII below.

Our investigation of firm contracts included both those contracts that were executed prior to the NFAT filing (referred to here as "carryover contracts") as well as new contracts that were executed since the completion of the NFAT proceeding.

The scope of our investigation varied slightly for carryover and new contracts. For carryover contracts, the revenue forecasts were reviewed in detail during the NFAT proceeding. The Daymark IEC Team was asked to take as a given that the forecasts of the carryover contracts are correct, so long as MH's revenue forecast aligned with the evaluation conducted for the NFAT proceeding, subject to changes in escalation and exchange rates.

For new contracts, the Daymark IEC Team reviewed the contract terms to create an independent forecast of firm energy and capacity revenues, and compared this analysis to MH's forecast.

The documents used in this evaluation are listed in Appendix B.

C. Analysis and Detailed Findings

The Daymark IEC Team conducted analysis on each of the contracts included in the revenue forecasts for both the NFAT and GRA analyses. As discussed above, there are two primary categories of export contracts: carryover contracts consisting of those predating the NFAT proceeding, and new contracts that have been executed since the NFAT proceeding concluded. There are four contracts that were listed in MH-CSI #36[74] that were not included in the GRA analysis; these contracts are considered "excluded" because they are not included in MH's forecast of firm extraprovincial export revenues in the current analysis. The table below lists the carryover, excluded, and new contracts, and identifies the products transacted in each contract.

[74] "LCA-CSI-34-Supp Att-LCA Comparison to MH CSI 36.xlsx", tab "MH CSI 36". This document contains the analysis of extraprovincial energy and capacity export contract revenue from the NFAT proceeding. This document was provided by MH and was used by the Daymark IEC Team to assess forecast consistency.

Table 9: List of Contracts (Carryover, Excluded, and New)

	CONTRACT ID	ENERGY	CAPACITY
Carryover	MP 250	X	X
	MP 50	X	X
	NSP 125	X	X
	NSP 375/325	X	X
	WPS 100	X	X
	WPS 108	X	X
Excluded	MPEE	X	
	NSP 350 Div Exch	X	
	GRE Div Exch	X	
	WPS 308	X	X
New	SP 2020-2040	X	X
	SP 25	X	X
	NextEra 100 ZRC		X
	NextEra 30 ZRC		X
	AEP 79/50 ZRC		X
	Basin 50 ZRC 2018-2020		X
	Basin 50 ZRC 2020-2021		X
	MP 50 ZRC		X

Carryover Contracts

The Daymark IEC Team evaluated the carryover contracts to confirm that the revenues included in MH's forecast are reasonable given the contract terms and the analysis was structured to confirm that the methods used by MH to forecast the energy and capacity revenues are consistent with the methods used during the NFAT proceeding. The terms of individual contracts vary, so the specific analysis conducted was structured specifically for the contract. For example [redacted] 1d, 3a, 7b

The Daymark IEC Team reviewed the revenue forecasts that were evaluated and approved during the NFAT proceeding and updated the key assumptions to those forecasts that impact pricing terms – [redacted] 1d, 3a, 7b [redacted] The Daymark IEC Team compared these updated forecasts to the export contract revenue assumptions used by MH in the GRA, provided in MFR 84.[75] 1d, 3a, 7b

Through the review of documentation provided by MH, discussions with MH staff, and independent analysis of the contracts, the Daymark IEC Team has concluded that the revenue forecasts assumed by MH for carryover contracts are reasonable.

The Daymark IEC Team also found that there were four contracts listed in the MH-CSI #36 documents that were not listed as firm contracts in the GRA materials.[76] These excluded carryover contracts are addressed below.

Excluded Carryover Contracts

Four contracts were included in the MH-CSI #36 accounting of firm energy and capacity revenue that were excluded from MFR 84. The Daymark IEC Team investigated these contracts by reviewing documentation provided and through conversations with MH.

The MPEE contract is an energy exchange contract with Minnesota Power [redacted] 1d, 3a Through discussions with MH, the Daymark IEC Team determined that while it is not listed in MFR 84, the MPEE contract is included in the Company's financial forecasts. The accounting associated with the MPEE contract is consistent with the treatment in the NFAT proceeding, despite the difference in categorization.

NSP 350 Div Exch and GRE Div Exch are diversity exchange agreements with Northern States Power and Great River Energy, respectively. Diversity exchange agreements allow MH to essentially trade energy with these counterparties across seasons. As a winter-peaking system, MH would receive energy in the winter and deliver energy in the summer. The contracts are structured such that MH has a specified amount of energy it must offer into the counterparty's market during specified hours. [redacted] 1d, 3a but that the revenue is still accounted for in the financial forecasts used in the

[75] MFR 84 contains the Company's forecast of extraprovincial energy and capacity export contract volumes and revenue.

[76] MFR #84

GRA. Despite the difference in labeling and classification, the forecast of revenue from the sale of the diversity exchange energy is calculated in the same manner as it was in the NFAT forecasts.

The WPS 308 contract was an agreement with Wisconsin Public Service that was contingent on the approval and construction of the Conawapa project. The MH-CSI #36 forecast included energy and capacity revenue from that contract beginning in 2026. As that project is no longer proceeding as anticipated in the NFAT filing, the WPS 308 contract is no longer included in MH's revenue forecast.

Based on the review of documentation and conversations with MH, the Daymark IEC Team has determined that the exclusion of these contracts from the firm energy and capacity revenue forecast is reasonable.

New Contracts

To evaluate MH's forecasts of energy and capacity revenue from new contracts executed since the NFAT proceeding, the Daymark IEC Team reviewed the executed contracts, as provided by MH, and calculated an independent forecast of revenues based on contract terms. These independent forecasts were compared to the contract-by-contract forecasts developed by MH.[77]

The eight new contracts are categorized into two groups. Six of the contracts are capacity-only contracts, [redacted] 1d, 3a

The remaining two contracts (SP 2020-2040 and SP 25) are firm energy and capacity contracts, with specified quantities of annual energy and capacity that remain constant throughout the term [redacted] 1d, 3a

For the capacity-only contracts, the calculations performed by the Daymark IEC Team matched the revenue forecasts provided by MH in MFR 84.

In comparing annual forecasts for energy and capacity under the SP 2020-2040 and the SP 25 contracts, there were some very slight discrepancies in MH's forecast and the calculations conducted by the Daymark IEC Team. In total, these discrepancies amounted to less than 0.5 percent of total revenue forecasted from these contracts.

[77] MFR #84

Based on the evaluation of the energy and capacity contracts, as well as the capacity-only contracts, the Daymark IEC Team concluded that MH's forecasted revenue for new contracts is reasonable.

D. Summary of Findings

Based on our review of the export contract revenue forecasts for capacity and energy provided by MH, the Daymark IEC Team makes the following findings:

- With some exceptions (detailed next), MH's treatment of carryover contracts included in both the NFAT and the GRA is consistent. The energy and capacity revenue forecasts used in the GRA analysis reflects a reasonable estimate of firm extraprovincial revenues from these contracts.
- The exception to this conclusion on carryover contracts relates to four specific contracts that were included in the summary of NFAT contracts (MH-CSI #36), but were not included in the GRA summary (MFR 84). The Daymark IEC Team investigated the discrepancy and concludes that for three of the contracts, the actual treatment of these contracts by MH and the method of forecasting revenue from these contracts has not changed, only the classification of the contracts has changed. The final contract was removed due to MH's failure to gain approval for the Conawapa project. The Daymark IEC Team does not recommend any adjustment be made for these contracts.
- The new export contracts executed since the NFAT proceeding were treated in a manner consistent with the carryover contracts. The forecast of energy and capacity revenue included in the Company's extraprovincial revenue forecast reflects reasonable treatment of these contracts, and the Daymark IEC Team has no concerns with these forecasts.

Based on the foregoing findings, the Daymark IEC Team has verified the reasonableness of the extraprovincial revenue forecast.

VII. REVENUE FORECAST

A. Overview

MH's forecast for export revenues and fuel and power purchases (net export revenues) for the next 20 years is a key input to its determination of the need for revenues from domestic ratepayers within the GRA rate period and its longer-term assessment of the attainment of a 25 percent equity ratio target within ten years. MH's forecast of net export revenues for the first 20 years is provided in Figure 32 below.

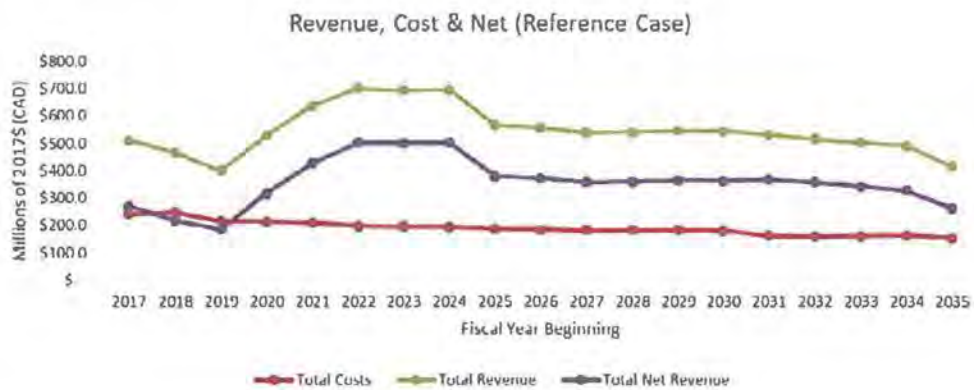

Figure 32: Forecast of Net Export Revenues, 2017-2035

B. Scope of Investigation

This section presents our assessment of the reasonableness of MH's net export revenue forecast, the primary objective included in Scope Item #3. This section builds on the work from Sections II through VI, which contain assessments of key inputs to the forecast: the market context, market prices, forecast of surplus energy and capacity, and revenues from existing export contracts. Our reasonableness review focuses on MH's forecast of overall export revenues used to define its requested rate increase proposal, which we refer to as the Reference Case export revenue forecast. We also include a discussion of the implications of the uncertainty analysis MH provided in Tab 4 to provide information on the uncertainty and risk inherent in the forecast.

Our review tests the reasonableness of the forecast in two ways.

First, we review each of the key inputs and the analysis used to assemble the forecast to verify the soundness of the methodologies and the accuracy of the results.

Second, we consider whether the forecast is a reasonable balance of risk between MH and its domestic ratepayers. In Tab 4, MH observes that *"By the end of the 10-year forecast period, there is a 50% chance that Manitoba Hydro will achieve the minimum 25% equity ratio target."*[78] Figure 4-10 from Tab 4 of MH's filing (See Figure 33 below) provides the context for MH's presentation of the uncertain impact those revenues would have on the company's financial performance.

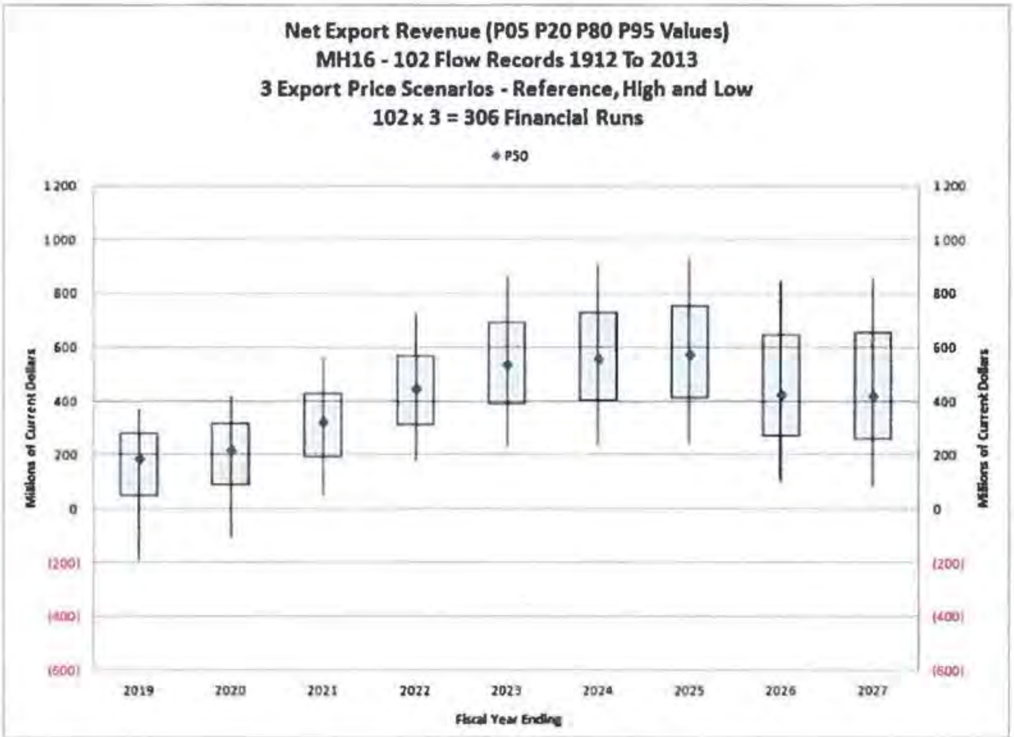

Figure 33: Net Export Revenues, and Impacts of Uncertainty

We understand from this statement, and from our discussions with MH SMEs, that MH intends for the Reference Case forecast to be a "P50" case – a reference case where there is equal chance that the results are higher or lower than forecasted.

[78] GRA Submission, Tab 4, pp. 24.

C. Reference Case Observations

There are a few areas where we believe that the assumptions or methods of producing the current export revenue forecast are not in keeping with a P50 reference forecast. These items are:

- The methodology for forecasting the export energy and capacity prices;
- The assumption that no firm energy sales will be made from the forecasted surplus dependable energy;
- The assumption that no extension of sales will occur with existing buyers when current firm contracts expire; and,
- The assumption that MH will not receive any capacity revenue associated with surplus dependable energy or opportunity sale energy over the study period.

This subsection discusses these items and the ramifications of these omissions on the reasonableness of the export revenue results.

Export Price Forecast Methodology and Result

Daymark identified several concerns with the methodology and results of the price forecasts themselves, as discussed in Section III. These concerns, when taken together, suggest that the market price forecast may be conservative relative to a P50 forecast of energy and capacity prices.

The most significant concern is that the limited of documentation of the third-party vendors forecast does not provide sufficient information to determine whether any of the vendors consider the forecast provided a P50 forecast. Consequently, the MH price forecast cannot be shown to be a P50 forecast since it is a simple average of the four forecasts. Understanding the nature of the forecasts and the assumptions underpinning them is necessary to ensure that they are being used appropriately in MH's efforts to produce a P50 forecast.

No Forecasted Capacity Revenue

MH's export revenue forecast assumes that there will be no capacity revenues derived from the uncommitted surplus dependable energy or opportunity sale energy. While it may be reasonable to assume MH cannot make additional capacity sales in the short run due to market and policy factors, those factors are short-term drivers of market dynamics. As is the case with the removal of the premium for surplus dependable (discussed in Section IV), this is a change from the assumptions used in the 2013-2015 EEPF. The capacity revenue component included at that time is depicted in Figure 28.

As discussed in Section II, there are many sources -- utility IRPs, MISO reports, state and federal processes, and others – that indicate that it is likely that MISO will be short capacity within the next ten years, possibly as soon as 2025. Further, NSP and Minnesota Power each discuss significant need for new capacity and energy in that same timeframe in their most recent IRPs. State environmental policies, particularly in Minnesota, will result in some percentage of that required capacity to be sourced from low- or zero-carbon emitting resources.

As with the discussion of the premium in Section V, we believe the elimination of capacity revenues for surplus dependable energy and opportunity sales in its entirety for the 20-year forecast is not well supported and not consistent with the information available to MH from the independent market consultants (see Section III) or the information from MISO, NERC and utility IRPs (See Section II). With that said, we agree with MH assessment of the softening of the market for exports in the near term over the past several years. The explanations of the market conditions associated with this issue from the 2017 EPF (discussed in Section V) are very focused on the current and near-term market conditions. We do not see any consideration of the potential for materially different circumstances to be prevailing beyond the near term, as is evident in the third-party forecasts and MISO planning.

Given that, a reasonable P50 forecast should include capacity revenues from the considerable dependable energy surplus (see Figure 27). Eliminating all forecasted capacity revenues associated with surplus dependable energy represents a very conservative assumption, as it is the lowest conceivable revenue outcome for the capacity value that the surplus energy can provide.

No Firm Energy Sales

As was discussed in Section V, during the NFAT, MH projected future firm sales from surplus dependable energy. In the GRA, all available energy (after meeting provincial load and existing contracts) was presumed to be sold in the MISO energy market as opportunity sales throughout the study period.

This is a conservative assumption, as it presumes that all surplus energy, including surplus dependable energy, will only receive energy revenues and will not receive any revenues for capacity or any other attributes (e.g., long term firm pricing, storage flexibility, clean energy, or price hedging). With respect to the energy sales, the value is based on MH's market energy price forecast. For all other attributes, the assumption of no value is clearly the lowest possible value.

As has been discussed in Section II, the MISO market is widely understood to be moving from a period of surplus to a period where considerable new capacity is needed. This is reflected in the capacity market price forecasts that MH received from each of its independent market price consultants. We believe there is clearly a range of plausible market values for capacity that MH does not consider in its Reference Case, particularly for MISO planning years 2023/24 and later. Similarly, Section II describes areas where state policy in Minnesota is increasingly valuing resources with low greenhouse gas emissions. This means that none of the uncertainty surrounding MHs ability to make firm sales or obtain added value for other attributes of its power are included in this forecast.

No Assumed Replacements for Expiring Firm Sales

In the current forecast, as fixed contracts that MH currently has in place begin to expire (see Figure 31 in Section VI), there is no assumption that these contracts will be replaced. This means that all capacity under contract receives no revenue after the contract ends and all energy is only priced as non-firm. Given that the counterparties will need to replace those products it is extremely conservative to presume, as MH has, that no amount of the energy can be resold above the spot energy price and that the capacity will have a value of zero after the contracts expire.

Available Dependable Energy

The conservative nature of the previous assumptions is further highlighted by a review of MH's filing. In the "*2016/17 Resource Planning Assumptions & Analysis*" document (Tab 7.3), MH indicates that "*the need for new resources is driven by a sustained dependable energy shortfall beginning in 2038/39*."[79] Table 1 of that same Appendix shows surplus dependable energy of roughly 1,000 GWh or more through 2036/37.

[79] GRA Submission, Appendix 7.3, pp. 12.

Figure 34 shows the forecast of exports split between opportunity sales and firm energy sales. [redacted] 5b, 5c Furthermore, since there is already a large volume of opportunity sales in those hours, the SPLASH opportunity pricing blocks that have the best prices will be utilized in most SPLASH runs. This means that, in addition to only pricing the energy at spot market prices, it will largely be priced below the forecasted monthly prices.

[redacted] 5b, 5c

Figure 34: Annual Export derived from SPLASH Output

D. Uncertainty Analysis Observations

MH included an uncertainty analysis to illustrate MH's view on risk by analyzing three key drivers of uncertainty: water supply variability, interest rates, and export prices.[80] Daymark reviewed this analysis at a high level to understand the context that MH provided around the reference case results.

[80] GRA Submission, Tab 4, pp. 8.

Expected Value and Risk Assignment

Uncertainty analysis is generally designed to understand what the "expected value" outcome is. Expected Value is a predicted value of a variable, calculated as the sum of all possible values, each multiplied by the probability of its occurrence. As MH stated in their filing, "*The uncertainty analysis is a sophisticated analytical tool which evaluates the impacts of the variation of multiple planning variables in order to determine a range of possible financial outcomes for the utility. The uncertainty analysis presented below combines multiple risk factors which reveals a more extensive picture of the risks facing the Corporation*."[81] This analysis is intended to show the risk that MH faces relative to meeting its 25 percent goal as well as the risks that will be borne by customers if rates are increased.

This idea that uncertainty analysis shows risks for either the Company or the customer is an important one, because while some of the risks identified are completely exogenous, whether viewed from the perspective of MH or the customer, other risks are of the type that MH has some ability to control. In particular, as was discussed in Section VII.A., the risk associated with export pricing is not completely out of the control of MH with respect to the marketing of the surplus dependable energy to obtain capacity and other premium values. This has implications for determining an equitable assignment of risk to both parties.

Asymmetrical Risk

When reviewing the export revenue forecast, Daymark noted two risk components that are more likely to lead to higher revenues than to lower revenues.

First, with natural gas prices at historically low levels and without a formal market process for pricing carbon, there are more factors that could exert upward pressure on energy prices than downward. Second, with the assumption that there will be no future firm energy or capacity sales, there is no risk of a lower forecast for those values and some unexplored possibility of increased revenues.

This asymmetrical risk profile means that there is a greater weighting on forecasts above the reference case than on those below. This then leads to an expected value above the reference case. So even if the reference case was a true P50, there would be strong argument for a higher export revenue forecast as more appropriately sharing risk between the company and its customers.

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[81] Ibid.

Impact on Financial Results

In addition to the question of risk profile, the potential impact of a high or low scenario on the financial results is not necessarily symmetrical. Daymark requested that MH run their uncertainty analysis step by step to show the impact of each key variable on the range of results. Figure 35 below shows the results of their analysis for the step involving Export Revenues[82]:

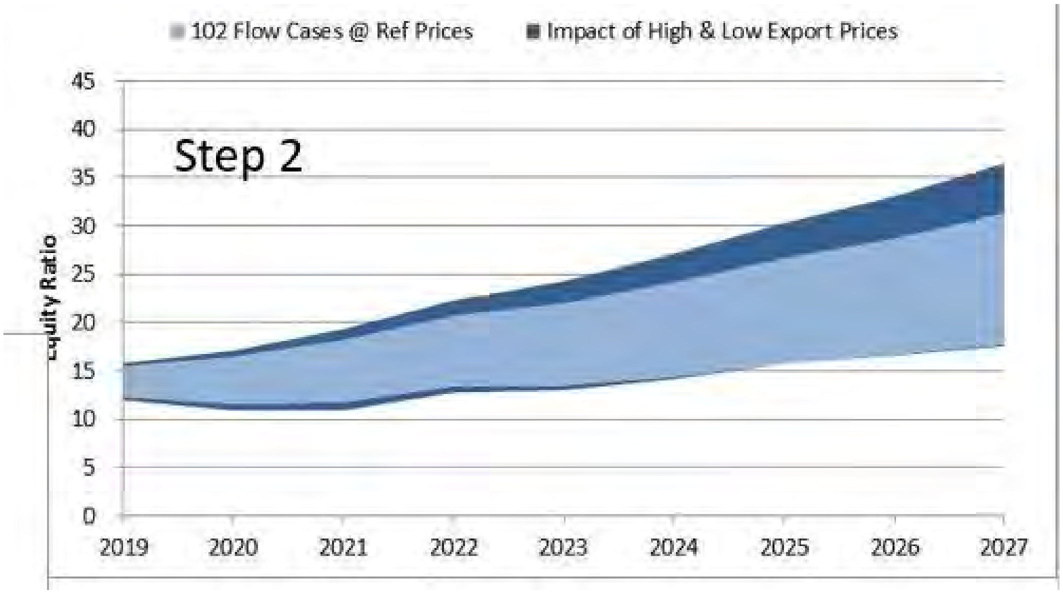

Figure 35: Isolated Impact on Equity Ratio for Hydrology & Export Revenues

In this graph, the light blue area represents the range of uncertainty around the forecast of hydrology. This was produced by accumulating the results of the 102 hydrology runs against the reference export price forecast and the reference interest rate. The dark blue color represents the additional uncertainty range produced by adding the high and low export price forecasts into the analysis, creating 306 total runs (102 hydrology runs against all 3 export price runs, all still with the reference interest rate). The results show that higher export prices have significantly more impact on the financial results than lower export prices.

[82] MH prepared confidential analysis, *Isolating impacts each comp uncertainty analysis - Tab 4*, provided via the MH confidential SharePoint site.

E. Summary of Findings

Based on our review of the export revenue forecasts for capacity and energy provided by MH, the Daymark IEC Team makes the following findings.

We have identified the follow components of the export revenue forecast that cause the forecast to be conservative/low relative to a value that is a P50 value:

- MH assumes that no revenue will be received for capacity or any other premium values from the substantial surplus dependable energy in the forecast.
- The energy market price forecast and the resultant energy revenues energy forecast is susceptible to be biased low.
- The uncertainty analysis that MH has conducted demonstrate the asymmetrical nature of the risk, with energy price risked skewed toward higher values, where the expected value of the forecast will be higher than the reference case value.

The components of the export revenue forecast that we reviewed and found to be reasonable include the forecast of surplus dependable energy and opportunity sale energy and MH forecast of revenues to be derived from existing firm contracts.

APPENDIX A

Daymark Energy Advisors

Scope of Work

DAYMARK ENERGY ADVISORS

Scope of Work

Export Pricing and Revenues Review

1. Review Manitoba Hydro's electricity export price forecast and third party consultant forecasts, including the low and high case forecasts, in the context of current MISO market conditions and factors influencing future MISO prices. The third party consultant forecasts are to be taken as a "given" and are to be assumed to be reasonable and accurate with respect to the other tasks in this Scope of Work. Notwithstanding that the third party consultant forecasts are to be accepted for the purposes of this review, if the IEC identifies significant issues or inconsistencies with the third party consultant forecasts in the course of its general review, those issues or inconsistencies are to be identified in the IEC's reports.

2. Review and assess Manitoba Hydro's forecast of exportable surplus energy and capacity by on-peak and off-peak period, taking into account expected inflow conditions, reservoir levels, and tie line capacities.

3. Review Manitoba Hydro's forecast for export revenues and fuel & power purchases for the next twenty years and assess whether the forecast of net extraprovincial revenue is reasonable. As an independent review of the extraprovincial revenues arising from contracted energy and capacity sales was undertaken at the 2014 NFAT (Exhibit LCA-5 in response to CSI Undertaking UT-34), a review of Manitoba Hydro's export contracts and estimation by the IEC of firm energy revenues and capacity revenues is not required for any contracts that were contemplated and assessed at the NFAT. Manitoba Hydro's updated export revenues, volumes, and unit prices by contract and by year will be provided as part of PUB MFR-84. The firm energy and capacity revenues in PUB MFR-84, for those contracts evaluated by the IEC at the NFAT, are to be taken as "given", so long as the firm energy and capacity revenues are aligned with the independent analysis from the NFAT after adjusting for changes in forecast exchange rates and escalation.

4. Assess the reasonableness of changes in Manitoba Hydro's forecasting methodology that eliminates the assumed premiums for surplus dependable energy and capacity sales.

5. Provide comments on the factors influencing the MISO market and trends that are affecting market prices, including but not limited to:

(a) state and federal policies on electricity generation and emissions;

(b) existing generation mix;

(c) expected new generation to be installed in the next 20 years;

(d) forecasted generation retirements in the next 20 years;

(e) supply and demand balance in the northern MISO region; and

(f) factors that may affect Manitoba Hydro's ability to export energy and capacity into the MISO market.

6. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

7. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

Public and Commercially Sensitive Load Forecast Review

8. Review Manitoba Hydro's 2017 Load Forecast and assess the changes with respect to the 2014 Load Forecast.

9. Assess Manitoba Hydro's load forecasting methods for Residential, Mass Market, and Top Consumers segments and compare to industry best practices with respect to:

(a) the econometric and end-use forecasting methodology;

(b) the elasticity methodology used to evaluate how Manitoba Hydro evaluates the implications of rate increases and new technology on electricity demand.

(c) Manitoba Hydro's economic assumptions including population growth, GDP growth, and price elasticity;

(d) the reliability of the short and long-term domestic load forecast modelling;

(c) the extent to which Manitoba Hydro has used appropriate scenario planning to examine the potential impact of changes in the industry, the Manitoba and Canadian economies, available technology (generation and loads) and energy efficiency measures (costs and cost effectiveness);

(f) the appropriate use of probability analysis of projected load forecasts;

(g) the extent to which retrospective load analysis provides confidence in the load forecast;

(h) the reasonableness of peak demand and energy trends including seasonal variations in load forecasting; and

(i) impacts on load forecasts resulting from potential fuel switching, particularly in light of rocent trends in the cost of natural gas and potential carbon taxes.

10. Assess other aspects of the load forecasting methodology including transmission and distribution losses.

11. Evaluate the historical performance of Manitoba Hydro's load forecasting methodologies for Residential, Mass Market, and Top Consumers segments.

12. Review the commercially sensitive load forecast for Top Consumers and assess the reasonableness of the forecasting methods and forecast.

13. Coordinate with other IECs who are reviewing price elasticity impacts on electricity demand in order to minimize duplication of analysis.

14. Provide a report to be placed on the public record that provides the Consultant's findings, opinions, and non-commercially sensitive supporting information.

15. Provide a non-public report to the PUB that provides commercially sensitive information and additional calculations supporting the findings.

APPENDIX B

Daymark Energy Advisors

Documents Relied Upon

Consistent with the agreement between Daymark Energy Advisors and the Manitoba Public Utilities Board, the following appendix provides a reference to the documents that were relied upon to develop this Independent Expert Consultant Report.

This appendix is organized into two sections. The first is a list of the documents relied upon that are already part of the record in this docket. The second is an annotated bibliography of additional documents relied upon that are not already part of the record in this docket.

Documents in the Record

Document Name:	Confidential or Non-Confidential:	
GRA Submission, Appendix 3.1, "*Integrated Financial Forecast (IFF16)*", April 2017.	Non-Confidential	
GRA Submission, Appendix 7.3, "*Manitoba Hydro 2016/17 Resource Planning Assumptions & Analysis,*" July 25, 2016.	Non-Confidential	
GRA Submission, Tab 4, "*Financial Targets and Uncertainty Analysis,*" May 12, 2017.	Non-Confidential	
Vintage of Consultant Forecasts for MH16 Update	Confidential	
PUB MFR 79 Updated - CONFIDENTIAL	Confidential	
1-b RAW [redacted] FORECAST EastLTTables052317CONF table 20	Confidential	3a
2017 Energy Price Forecast V3	Confidential	
2 [redacted] Performance Review - CHARTS CONF	Confidential	3a
2017 Energy Price Forecast V3	Confidential	
2015 EEPF Final	Confidential	
PUB MFR 79U-CONFIDENTIAL	Confidential	
2016 EEPF	Confidential	
Staff Report to the Secretary on Electricity Markets and Reliability	Confidential	
2017 Energy Price Forecast V3	Confidential	
PUB-MH II-37a-b	Confidential	
MH PUB 1.19a	Confidential	
PUB-MH II-37a-b	Confidential	
PUB-MH I-19d	Confidential	
COALITION-MH I-62a-e, PUB-MH I-19d	Confidential	
PUB-MH I-19d	Confidential	
MFR 84	Confidential	

Annotated Bibliography of Additional Documents

Document Name:	**Confidential or Non-Confidential:**
Manitoba Hydropower's website, accessed November 2017, available at: http://www.manitobahydropower.com/who-we-are.shtml	Non-Confidential
SNL Financial, an entity that provides electric-industry-specific market data obtained from public and private companies worldwide, http://www.snl.com/	Non-Confidential
NFAT Chapter 5, available at: http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/nfat_business_case_chapter_05_the_manitoba_hydro_system_interconnection_and_export_markets.pdf	Non-Confidential
Federal Energy Regulatory Commission, *"Electric Power Markets: Midcontinent (MISO)"*, accessed November 2017, available at: https://www.ferc.gov/market-oversight/mkt-electric/midwest.asp	Non-Confidential
MISO website, accessed November 2017, available at: https://www.misoenergy.org/AboutUs/Pages/FactSheet.aspx	Non-Confidential
MISO, *"MTEP16 MISO Transmission Expansion Plan"*, Full Report 2016, available at: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf	Non-Confidential
Analysis Group, *"Electric System Reliability and EPA's Clean Power Plan: The Case of MISO,"* June 8, 2015, available at: http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf	Non-Confidential
Wisconsin Public Utility Institute, *"Today's Trends, Tomorrow's Energy Needs"*, slide 13; 2016 YTD is depicted as of March 2016.	Non-Confidential
Potomac Economics, Independent Market Monitor for MISO, *"2012 State of the Market Report for the MISO Electricity Markets,"* June 2013.	Non-Confidential

Document Name:	Confidential or Non-Confidential:
Potomac Economics, Independent Market Monitor for the Midcontinent ISO, *"2016 State of the Market Report for the MISO Electricity Market, Analytic Appendix,"* June 2017, available at: https://www.misoenergy.org/Library/Repository/Report/IMM/2016%20State%20of%20the%20Market%20Analytical%20Appendix.pdf	Non-Confidential
U.S. Energy Information Administration, *"Annual Energy Outlook 2016, Market Trends: Natural Gas"*, September 15, 2016, available at: https://www.eia.gov/outlooks/archive/aeo16/MT_naturalgas.cfm#natgasprod_exp	Non-Confidential
MISO, *"MISO Fleet Changes"*, June 2017, available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/MISO%20Fleet%20Changes.pdf	Non-Confidential
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MISO, *"2016 OMS MISO Survey Results,"* June 2016, available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/OMS-MISO%20Survey/2016OMS-MISOSurveyResults.pdf	Non-Confidential
State Utility Forecasting Group, *"2016 MISO Independent Load Forecast,"*, November 2016, available at: https://www.misoenergy.org/Library/Repository/Study/Load%20Forecasting/2016%20Independent%20Load%20Forecast.pdf	Non-Confidential
MISO, *"2017/2018 Planning Resource Auction Results,"* April 14, 2017, available at: https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf	Non-Confidential

Document Name:	Confidential or Non-Confidential:
MISO, *"FERC Electric Tariff, Module E-1 – Resource Adequacy,"* effective on November 19, 2013.	Non-Confidential
NC Clean Energy Technology Center, *"DSIRE®,"* Minnesota Renewable Energy Standard, last updated November 19, 2015, available at: http://programs.dsireusa.org/system/program/detail/2401	Non-Confidential
S&P Global Market Intelligence, *"Minnesota agency raises state's CO2 values, rejects federal cost of carbon,"* July 28, 2017.	Non-Confidential
Minnesota Power, *"Minnesota Power proposes next step in EnergyForward plan,"* for release June 7, 2017, available at: https://minnesotapower.blob.core.windows.net/content/Content/Documents/Company/PressReleases/2017/201767_NewsRelease.pdf	Non-Confidential
Xcel Energy, *"Resource Treatment Framework,"* January 4, 2017, available at: https://puc.sd.gov/commission/dockets/electric/2017/informational/2017infoel1.pdf	Non-Confidential
Northern States Power Company-Minnesota, an Xcel Company, *"Upper Midwest Resource Plan 2016-2030,"* available at: http://www.ci.becker.mn.us/DocumentCenter/View/421	Non-Confidential
Minnesota Department of Commerce, Division of Energy Resources, *"Minnesota Value of Solar: Methodology,"*, April 1, 2014, reformatted on April 9, 2014, available at; http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf	Non-Confidential
Minnesota Pollution Control Agency, *"Greenhouse gas emissions in Minnesota,"* accessed November 2017, available at: https://www.pca.state.mn.us/air/greenhouse-gas-emissions-minnesota-0	Non-Confidential
Public Service Commission of Wisconsin, *"Final Strategic Energy Assessment, Energy 2022,"* Docket 5-ES-108, July 2016, available at: https://psc.wi.gov/Documents/SEA2022.pdf	Non-Confidential
Public Service Commission of Wisconsin, *"2015 Renewable Portfolio Summary Report,"* PSC REF#: 285744, April 26, 2016.	Non-Confidential
Northern States Power, *"Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues,"* MPUC Docket No. E-002/M-16-223 and NDPSC Case Nos. PU-12-813, et. al, December 31, 2016.	Non-Confidential

Document Name:	Confidential or Non-Confidential:
MISO, *"Manitoba Hydro Wind Synergy Study, Final Report,"* available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Planning%20Materials/Manitoba%20Hydro%20Wind%20Synergy%20TRG/Manitoba%20Hydro%20Wind%20Synergy%20Study%20Final%20Report.pdf	Non-Confidential
MISO, *"Multi Value Project Portfolio Analysis,"* accessed November 2017, available at: https://www.misoenergy.org/planning/transmissionexpansionplanning/pages/mvpanalysis.aspx	Non-Confidential
MISO, *"2016/2017 Planning Resource Auction Results,"* April 15, 2016, available at: https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2016-17/2016-2017%20Planning%20Resource%20Adequacy%20Results.pdf	Non-Confidential
[redacted]	Confidential
[redacted]	Confidential
[redacted]	Confidential
MH Exhibit 8 2010-11 GRA and Risk Review - modelling excerpts	Confidential
"Expected flow forecasting 1 of 3 (example single tributary inflow forecast).pdf", "Expected flow forecasting 2 of 3 (description of expected flow scenario and forecasting" pp. 57-70., "Expected flow forecasting 3 of 3 (MH Exhibit 123 from 2010-11, system flow forecast).pdf"	Confidential
"Market Forecast Disaggregation - ST CONF.pdf"	Confidential
KPMG, "*Manitoba Hydro External Quality Review*", April 15, 2010, http://www.pubmanitoba.ca/v1/exhibits/mh-4-7.pdf, pp. 35-37.	Non-Confidential
"IFF16-Update Forecast Interchange Revenues - Generation Costs CONF.pdf"	Confidential
"Hydraulic Schematic of Nelson-Churchill Basin and MH Generation CONF.pdf"	Confidential
Manitoba Hydrologic Forecast Centre, River Conditions, https://www.gov.mb.ca/mit/floodinfo/floodoutlook/river_conditions.html	Non-Confidential
"IFF16-Update Forecast Interchange Revenues - Generation Costs CONF.pdf"	Confidential
Manitoba Hydro, *"Peer Review of Manitoba Hydro's Splash Model,"* May 2005, available at: https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_74-Attachment_2.pdf.	Non-Confidential

2b

Document Name:	Confidential or Non-Confidential:
FlowCases_GenEstimate_MH16UPDATE_RefPrices.xlsx	Confidential
GenEstimate_MH16_RefPrices.xlsx	Confidential
2017 Energy Price Forecast V3.xlsx	Confidential
All Manitoba Hydro energy and capacity contracts, including amendments	Confidential
LCA-CSI-34-Supp Att-LCA Comparison to MH CSI 36.xlsx	Confidential
"Isolating impacts each comp uncertainty analysis – Tab 4.pptx"	Confidential

Tab 14

MANITOBA	**Board Order 99/11**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**July 29, 2011**

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair

AN INTERIM ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

Table of Contents

Contents

Executive Summary

Among other requests, Manitoba Hydro (MH or the Corporation) applied to the Public Utilities Board (Board) for across-the-board 2.9% rate increases to take effect both on April 1, 2010 and April 1, 2011, and for a further 0.9% rate increase to take effect August 1, 2011. As is always the case with applications made to the Board, the onus is on the applicant, in this case MH, to fully and adequately support requests made. In this case, MH failed to discharge that onus.

In past Board orders arising out of public proceedings concerning MH, the Board has raised concerns with the scale of capital expenditures and new debt MH plans to undertake, plans premised in large part on the expectation of "profitable" net export sales. In those past orders, the Board has suggested there was a risk that if the Corporation's plans were implemented MH may not be able to both meet its domestic and export commitments and achieve its financial targets without having to (with the Board's approval) increase domestic rates not only beyond the levels now projected by MH, but above a level consistent with both public expectations and the general public interest.

Accordingly, within the proceeding just concluded, which not only considered MH's requests but, also, other related matters, the Board undertook an in-depth review of MH's operational business risks and its risk management practices. This review included consideration of the probabilities of occurrence, and possible cost consequences of occurrence, of all identified operational and business risks – this in the context of the Corporation's planned capital spending and concurrent pursuit of export contracts with American utilities.

Unfortunately, in the public hearing that concluded on July 4, 5 and 7 of 2011 (with the closing statements of both interveners and MH), the Corporation either refused or failed to provide the Board information that the Board considers critical to it reaching a comprehensive and final perspective on the prudency of MH's actions and plans, and the implications for domestic rates of MH's operations and plans.

In particular, MH not only failed to provide the Board a fully updated 20-year Integrated Financial Forecast (IFF) – to include recognition of presently very low spot, opportunity and average export prices, and financial scenarios, with stated assumptions, based on capital expenditure plans differing from MH's "preferred development plan", but also refused to comply with a subpoena issued by the Board on July 6, 2011 that seeks the filing of MH's export contracts.

MH intends to seek leave to appeal to the Manitoba Court of Appeal towards its objective of quashing the Board's subpoena. This Board will oppose the granting of leave to appeal and, if granted, plans to oppose MH's effort to quash the Board's subpoena. (The position of the Board with respect to its access to the export contracts is set out in Board Order 95/11, issued July 22, 2011, available on the Board's website: www.pub.gov.mb.ca.)

With respect to alternate capital development scenarios (models providing forecasts of financial results out twenty years) not provided by MH, one scenario among others that the Board wants to be modelled involves the deferral (potentially partial, and potentially to represent a "staggering" of elements of MH's current capital development plan) of the Corporation's current major capital development plan along with the modelling of the expected consequences of the construction of a combined cycle natural gas generation plant in southern Manitoba.

In this Order, and based on the evidence available to it, the Board establishes its concerns with MH's preferred capital expenditure development plan. That plan would have MH construct two new hydro-electric generating stations (a third new plant, Wuskwatim

Generation Station, is nearing completion) and Bipole III, and the Corporation entering into new export contracts towards meeting the costs of advancing the construction of the planned new generation stations well ahead of expected domestic electricity load requirements.

Since MH's plans were conceived "much has changed" – the expected costs of constructing MH's planned new generation and transmission assets has soared by approximately $3.5 billion (to-date); the price MH receives from its American utility counterparties for spot and opportunity export sales – which are anticipated to represent at least 50% of the Corporation's export sales - has fallen dramatically. (MH generally expects "firm" export sales, sales made at prices set in long term contracts, to represent no more than 50% of its total export sales, with the remaining sales being spot or opportunity sales at then-market prices.)

For an extended period of time, and since the fall 2008 when the global credit crisis and recession began to the present time, MH's off-peak spot and opportunity export sales have realized prices as low as 0.5¢/kWh, reducing the average price received for its exports, including its "firm" and peak sales, to below 3.5¢/kWh.

The presently low export prices are generally understood to be attributable to:

a) the employment of new natural gas extraction methods, allowing for the production of natural gas from seemingly abundant shale deposits in North America, and, as well;
b) a reduction in industrial demand, in both Manitoba and in its export market, from previous levels.

The reduction in industrial demand, and reduced projections of future industrial load growth, are due in part to the slow recovery, particularly in the United States, from the recession, and, also, here in Manitoba with the recent closure of a pulp and paper plant and an announcement of an impending closure of an existing Manitoba smelter and refinery operation in Thompson (which follows the closure of another industrial smelter in Flin Flon).

From the evidence currently available to the Board (and in advance of receipt of the export contracts for which the Board has issued a subpoena), the Board is concerned that if MH proceeds with its "preferred development plan" the consequences for Manitoba ratepayers, as to be evidenced in rate increases, may be much higher than MH currently projects.

Ahead of regulatory approvals in both Canada and the United States, MH has already expended hundreds of millions of dollars (and it continues to spend to "protect" the planned in-service dates of its planned new generation and transmission), on its capital development plan, a plan outlined in more depth within the body of this Order.

The Board believes a thorough 'Needs For and Alternative To' (NFAAT) process should be held to consider MH's planned major capital expenditure plans and related new export contracts far in advance of MH making final commitments to enter into its proposed export contracts and undertaking massive new investments.

While MH currently projects that the implementation of its capital expenditure and export contract plans will result in domestic rate increases cumulating over twenty years at approximately 70%, the Board fears that MH has both understated the costs of its preferred development plan and overstated future export sale revenue, with the result potentially being a compound overall increase in domestic rates over the twenty year period twice that forecast by MH.

MH's primary objectives include serving domestic load reliably, and at rate levels consistent with Manitoban expectations. The Board indicates within this Order its concern that if MH proceeds with its development plan "as is" the inadvertent result could be domestic ratepayers subsidizing export sales to the United States. The Board is not at all confident that the risk tolerance exhibited by MH is shared by the majority of its ratepayers.

Thus, despite the lengthiest, most complex and certainly most expensive public proceeding ever held by the Board, a hearing that has involved several interveners and numerous expert witnesses, the Board concludes that, on an interim basis, it must deny not only MH's requests for the finalization of interim rate increases but also approval of a further rate increase at this time.

This is the first of two Board Orders to be issued arising out of the recent public hearing, and, as suggested above, it is focused on MH's rate requests, risks and risk management. The second Order will follow in due course, and will not only address in more depth matters dealt with herein, but also provide the Board's findings on other matters considered in the recent hearing (including ex parte interim rate orders outstanding with respect to MH's Surplus Energy Program, SEP, and MH's Curtailable Rate Program; MH's application for the Temporary Billing Demand Concessions for General Service Medium and Large customers provided in Board Order 126/09 being made permanent; the "firmness" of MH's equity components; the prudency of MH's expenditures; and, the approach to be taken with respect to lower income customers and other rate design matters, including Cost of Service issues).

The second Order will also provide commentary and findings with respect to the participation in the proceeding of interveners and expert witnesses, and address the recommendations made by the interveners and their expert witnesses.

1.0 Application

In November 2009 and pursuant to *The Public Utilities Board Act* and *The Crown Corporation Public Review* and *Accountability Act*, MH applied to the Board for the following:

a) *Approval of rate schedules incorporating an across-the-board 2.9% average increase in General Consumer's rates effective April 1, 2010 (with the exception of Area & Roadway Lighting Class;*

b) *Approval of rate schedules that incorporate a further across-the-board 2.9% average increase in General Consumers' rates effective April 1, 2011;*

c) *Final approval of all Surplus Energy Program ("SEP") ex parte rate orders outstanding;*

d) *Final approval of Curtailable Rate Program ex parte Orders /09 and 63/11; and*

e) *Final approval of Order 126/09, which resulted from MH's application for Temporary Billing Demand Concessions for General Service Medium and Large customers related to the impacts of the economic downturn. MH requests that the Temporary Billing Demand Concessions be made permanent under the program.*

2.0 Background

MH's preceding General Rate Application (GRA) was held in 2008, and was the subject of Board Orders 90/08, 91/08 and 116/08, all of which are available on the Board's website (www.pub.gov.mb.ca).

In Order 90/08, as in prior Orders going back to 2004, the Board raised many concerns about the risks faced by MH. In particular, and more recently, the Board has raised concerns with the scale of capital expenditures and new debt MH plans to incur over the next 15 years. The Board also suggested that there is a risk that the Corporation may not be able to meet its domestic and export commitments without having to resort to high-priced imported power and/or Manitoba thermal generation (also at a high cost), and both with environmental implications during years of lower than median water conditions.

The Board, in Order 90/08, granted a 5% rate increase effective August 1, 2008. In granting the increase, the Board stated:

> *"Despite the Board's limited mandate with respect to capital costs, the Board expresses concern, not to be confused with opposition, with the unprecedented capital expenditure levels, and questions whether the export revenue stream from new generation and transmission projects will be sufficient to cover the financial obligations related to these works, given the inherent risks that are present and lie ahead.*
>
> *The Board will seek further assurances from MH that new contracts are priced at or above forecast average export prices."*

The Board also directed MH to file information in support of a 4% conditional rate increase, which was to be effective April 1, 2009. MH filed additional information that included updated financial forecast information (IFF 08-1). Upon a review of the information, the Board, in Order 32/09, revised the 4% conditional rate increase to 2.9%, and noted recent improvements in MH's published financial position to be balanced with the Board's ongoing concerns related to the Corporation's multiple and major risks.

In that Order, Board Directive 4 required:

> *"MH to file by September 30, 2009 for Board approval, a conceptual line for an in-depth and independent study of all of the operational business risks facing the Corporation. The study to be a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending taking into account export revenue growth, variable interest rates, drought, inflation experience and risk, and potential currency fluctuation."*

On December 1, 2009, MH filed a General Rate Application (GRA) seeking across-the-board 2.9% average rate increase in General Consumer rates effective both April 1, 2010 and, also, April 1, 2011.

In accordance with previous directives issued by the Board, MH filed (in confidence with the Board) documents related to its risk management assessment and practices. Through a review of the information, the Board determined that a special hearing process was required to consider how best to address the confidential information that would allow for an appropriate review of MH's risk management.

Accordingly, on December 10, 2009 and December 22, 2009 the Board held Pre-Hearing Conferences, the first considered whether and how to incorporate a review of MH's risks and risk management into the GRA process; the latter dealt with which Interveners should be approved for participation in the GRA public process and the establishment of a timetable for the orderly exchange of evidence (to lead up to public hearings, then-planned to commence in 2010).

Among the issues canvassed was whether the Board should retain an independent risk consultant. Subsequently, the Board issued Order 17/10 (dated February 9, 2010) which concluded that a detailed risk and risk management review would be addressed in the GRA.

Order 17/10 also approved the following parties as Interveners to the GRA:

i) Consumers' Association of Canada (Manitoba) Inc., Manitoba Society of Seniors (CAC/MSOS);
ii) Manitoba Keewatinook Ininew Okimowin, (MKO)
iii) Manitoba Industrial Power Users Group (MIPUG);
iv) City of Winnipeg (City); and
v) Resource Conservation Manitoba (now Green Action Centre) and Time to Respect Earth's Ecosystems (RCM/TREE).

The Board then issued Order 30/10 (dated March 26, 2010), and, in Schedule C of that Order, the Board provided the terms of reference for the engagement of independent experts by the Board to undertake an independent risk and risk management review. Additionally, Southern Chiefs Organization (SCO) was added as an Intervener.

Matters related to the risk review and other procedural matters led to a lengthy delay in the commencement of the GRA, which was held over 41 hearing days (commencing January 5, 2011 through and including June 9, 2011). Closing submissions by Interveners were heard by the Board on July 4 and 5th of 2011, followed by MH's closing submission provided on July 7, 2011.

Due to the delay in the commencement of the hearing, the Board heard submissions from MH and Interveners on January 19, 2010 to consider whether an interim rate increase should be granted effective April 1, 2010. The Board (in Orders 18/10 and 33/10) provided an interim approval of a 2.9% across-the-board rate increase (except for the Area and Roadway Lighting Class, for which no rate increase was approved). Subsequently in 2011, the Board received submissions from Interveners and MH as to whether an additional interim 2.9% rate increase (as applied for by MH) should be granted effective April 1, 2011. Following receipt and consideration of submissions, the Board issued Order 40/11, which approved an interim 2% across-the-board rate increase for all classes (again except for the Area and Roadway Lighting Class, for which no rate increase was approved).

In MH's closing submission of July 7, 2011, MH requested the two interim rate Orders be finalized and an additional 0.9% rate increase be granted (the latter to take effect August 1, 2011).

To respond to MH's request for the finalization of the two interim rate Orders and approve an additional 0.9% rate increase to be effective August 1, 2011, the Board issues this interim Order, it being the first of two planned Orders to address all issues raised in MH's GRA. Findings and information in this first Order are to be expanded upon in the second Order, which is to follow in due course. The positions of MH, Interveners and experts on various issues will be detailed in the second Order, which may also include additional Board findings and directives.

3.0 Key Information

3.1 Operating Results

In support of its Application, MH filed an Integrated Financial Forecast (IFF), MH IFF 09-1 for its electric operations, as well as a Capital Expenditure Forecast (CEF) CEF 09-1, both forecasts extended from MH's fiscal year 2009/10 to fiscal year 2019/20. Updated forecasts (IFF MH 10-1 and CEF 10-1) were filed later in the hearing. IFFs and CEFs are prepared to provide an indication of the long-term financial direction, plans and expectations of the Corporation, and are based on numerous assumptions.

MH's actual results for fiscal year 2009/10 and its forecasts for fiscal years 2010/11 and 2011/12 (the annual report of MH, to include its audited financial statements for 2010/11 has yet to be released) projected accumulated net income for fiscal years 2009/10 to and including 2011/12 will be $148 million higher (pursuant to IFF 10-1) than was indicated in IFF 09-1 (IFF 09-1, the IFF which was filed in the Application).

The projected improvement in accumulated net income and period ending retained earnings (retained earnings represent MH's "equity" or capital) was primarily attributed to lower than forecast depreciation, finance expense and fuel & power purchase costs. As well, the forecast represented a continuation of MH's accounting practice of capitalizing and deferring expenses incurred in current and past periods associated with the Corporation's plans to construct additional generation and transmission assets.

MH's IFF 09-1 indicates MH achieved its 75:25 debt to equity ratio financial target. While the 75:25 debt to equity ratio target has generally been accepted as being representative of an adequate capital structure, this Board has questioned the "firmness" of components of the equity factor (which include contributions in aid of construction, Accumulated Other Comprehensive Income, and intangible and deferred costs – all "illiquid"), and has raised doubts as to whether the present target ratio of 75:25 will remain adequate if MH's proceeds to expend (largely based on additional borrowings) approximately $20 billion on new major generation and transmission assets over the next ten or so years).

MH's IFF 10-1, a partially updated forecast still largely based on assumptions that underlie IFF 09-01, supports in part the Board's interim rate approvals of 2.9% and 2% effective April 1, 2010 and April 1, 2011, respectively.

MH's actual and currently forecast operating results compared to forecasts of the preceding 2008 GRA are as follows:

Table 1

Pro Forma Statement of Operations & Retained Earnings

($ Millions)	**Actual**			**IFFIO-1**		
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**Total 2008-2012**
Revenue						
Domestic	1,006	1,014	980	1,006	1,048	
Estimated PUB Approved Increases	77	130	162	195	224	788
Export	625	623	427	444	461	
Total Revenue	1,708	1,766	1,569	1,645	1,733	
Expenses	1,371	1,478	1,409	1,496	1,612	
Non Controlling Interest					4	
Net income(loss) Actual/[IFF 10 -1]	337	288	160	149	125	
Compared to 2008 GRA Forecast						
Net income(loss) [IFF 10 -1]	264	156	105	116	114	
Net income difference	73	132	55	33	11	304
Retained earnings Actual/IFF 10 -1	1,790	2,078	2,238	2,354	2,479	
Retained earnings IFF07-1	1,735	1,891	1,996	2,112	2,226	
Cumulative Retained Earnings difference						
2008 GRA vs 2011 GRA	55	187	242	242	253	

Note: Board approved increases granted in prior Applications: 5% effective August 1, 2004 (a $48 million addition to annual revenue); 2.25% effective April 1, 2005 ($21.8 million of additional annual revenue); and, 2.25% effective February 1, 2007 (an additional $23.0 million of annual revenue). The interim increases provided as of April 1, 2010 and 2011 represent a further addition to annual revenue of, in aggregate, approximately $48 million.

Overall, and on the "face of it" (setting aside the Board's ongoing concern with respect to MH's practice of deferring and/or capitalizing a significant amount of its annual OM&A expenditures), MH's financial position since the 2008 GRA is projected by MH to improve by approximately $253 million over the period 2007/08 through to and including 2011/12.

It is important to note that since 2008, this Board has approved rate increases that are expected to provide MH over $788 million in accumulated additional revenue through to and including fiscal 2011/12.

In the decade prior to 2004/05, in essence domestic rates remained "frozen" and MH relied on net export revenues to meet its increased reported annual expenditures and pursue its financial targets (debt to equity ratio, interest coverage and capital expenditure coverage).

3.2 Financial Targets

MH's most recent financial targets (as established by MH's Board of Directors and generally accepted by this Board – with reservations given the components of equity and the plans for massive borrowing - and Interveners to MH GRA proceedings, to-date) are as follows:

1. Achieve and maintain a minimum debt to equity ratio target of 75:25 by no later than 2011/12;
2. Achieve and maintain an annual gross interest coverage ratio of 1.20 annually; and

3. Fund all new capital construction requirements (except major new generation and/or major new transmission facilities, plus the new head office), from internal sources (net income and non-cash expenditures).

Debt to Equity

The debt to equity ratio has been the focus of attention at this and prior hearings and this ratio has been employed as one means of assessing the capital adequacy of MH – i.e. its "financial strength", by comparing MH's debt to its equity.

While MH's debt is secured for its lenders by the guarantee of the Province (which annually charges MH a 1% debt guarantee fee), lenders and credit rating agencies relied on by lenders, given the significant percentage of overall Provincial Government debt that is comprised of MH borrowings, pay attention to the reported capital adequacy of MH when considering the interest rates the Province itself will have to bear when it issues debt.

At the 2008 GRA, MH's filed IFF 07-1 did not project MH reaching its debt to equity target of 75:25 during the then-forecast ten year period through fiscal 2017/18. However actual events and the latest forecast suggest a changing "landscape".

MH's actual and forecast debt to equity ratios for its fiscal years 2007/08 to and including 2017/18, from IFF 10, as compared to IFF 07-1 as it was filed at the preceding GRA, are as follows:

Table 2

Debt to Equity Ratio Comparison

	Actual			Forecast		
Fiscal Year	2008	2009	2010	2011	2012	2018
Actual/IFF10	73:27	77:23	73:27	74:26	74:26	82:18
IFF07-1	77:23	77:23	77:23	78:22	78:22	78:22

Based on MH's IFF 10-2, again a partially updated version of IFF 09-1, MH will continue to meet the 75:25 debt to equity ratio target as of March 31, 2011, continue to meet the target through to the end of fiscal 2011/12, then, as a result of planned capital expenditures, fall below the equity target.

Since the 2003/04 drought, where a loss of $436 million was reported driving up the debt component of the debt to equity ratio, MH's capital structure (as reported by MH) has improved.

MH's "reportedly" improved financial position relates to three major factors:

a) higher than expected extra provincial revenue (net export revenue) in fiscal 2006 – this driven in large part by a spike in natural gas prices following hurricanes Katrina and Rita that "drove up" opportunity export sales prices at a time of high water flow conditions;
b) rate increases granted by this Board in 2004 (5%), 2005 (2.25%), 2007 (2.25%), 2009 (5%), and interim increases granted as part of the current proceeding in 2010 (2.9%) and 2011 (2.0%); and,
c) a decrease in borrowing rates, particularly short-term rates, this largely the result of government actions following the global credit crisis and recession (the former commencing in the fall of 2008 and both concluding in 2009/10).

On an overall basis, domestic electricity rates have increased, on a compounded basis, by over 22% since 2004 – an increase that exceeds the general rate of inflation through the period.

MH having attained the debt:equity target (again, this Board has reservations with respect to how MH's calculates the equity component of the ratio), and despite the Corporation's forecasts of annual rate increases of 3.5% for the years 2013 through 2021, a rate of increase much higher than the expected rate of inflation, MH does not anticipate maintaining its target debt:equity ratio. MH projects that its debt to equity ratio will "slip" (deteriorate) due to MH's planned major capital program.

MH currently forecasts, (forecasts having only been partly updated) that its debt to equity ratio will decline to 82:18 as of March 31, 2018, a ratio worse than that MH contemplated in its IFF 07-1 (filed in the 2008 GRA). MH's capital structure is forecast to weaken even further after 2018, before the Corporation's anticipated in-service dates of both Keeyask and Conawapa generation stations, with the debt to equity ratio now projected by the Corporation to reach 84:16 as of March 31, 2021.

In support of its most recent Application, and as previously indicated, MH filed IFF MH 09-1 and CEF 09-1. MH then-anticipated capital spending of $13.1 billion on three major Generation and Transmission projects (Keeyask Generating Station, Conawapa Generating Station and the Bipole III Transmission line). MH concurrently forecast that its long term debt would increase from $7.8 billion (as of March 31, 2010) to $17.7 billion as of March 31, 2029, a projected increase of $9.9 billion.

However, MH has since revised its capital cost projections for the three major projects. As reflected in MH's IFF 10-2, MH now projects the capital cost of the three major projects to be in the range of \$16.6 billion – approximately \$3.5 billion higher than MH forecast in CEF 09-1, only one year earlier. Concurrently, MH also increased its forecast of required additional debt, now projected by the Corporation to increase by over \$15 billion, and to reach \$23 billion as of March 31, 2029, an increase in projected long term debt in excess of \$5 billion from the Corporation's previous forecast.

As a result of the increased capital expenditure forecast, MH has now projected that its debt to equity ratio as of March 31, 2029 will change from the 51:49 projected in its IFF 09 forecast (that forecast represented an expectation that significant annual net income results would result in what the Corporation denoted as its "decade of return", which was projected to follow MH's "decade of investment") to 72:28 (that ratio drawn from MH's partially updated IFF 10). It is important to note that MH's revised debt to equity ratio projection of 72:28 still does not take into account the current low prices being received for spot, opportunity and average export sales.

The change in MH's forecast of its debt to equity ratio as of March 31, 2029, a date at which MH currently plans to be operating Keeyask, Conawapa (relying on Bipole III), and exporting significantly increased volumes of power to the United States, represents a material negative financial change – one that appears to acknowledge the new and higher capital cost forecast and the impact of higher capital expenditures on forecast annual amortization and finance expense.

Changes to Generally Accepted Accounting Practices (GAAP), with the move to International Financial Reporting Standards (IFRS) expected to occur in MH's fiscal year 2012/13, raise the potential for an expensing (write-off to retained earnings) of Rate Regulated Assets of over \$300 million (OM&A expenditures that were deferred, not included as a period expense in the year of incurring, and now classified as an "asset" in MH's balance sheet). If this occurs, MH's debt to equity ratio will be negatively affected.

3.3 Operating, Maintenance and Administrative Expenses (OM&A)

3.3.1 Capitalization of Operating and Administrative Expenditures

While MH's rates are largely driven by its capital assets (generation, transmission and distribution), they also reflect the Corporation's Operating, Maintenance and Administrative (OM&A) expenditures. In setting rates, the Board's goal is that those rates are not only just and reasonable, but also reflect prudent expenditures (the concept of prudency extends not only to capital expenditures, but also to OM&A costs).

A particular difficulty in setting what is to be "just and reasonable rates" reflective of prudent actions by the Corporation is that the Board does not have jurisdiction with respect to MH's capital expenditures. Since the Corporation is wholly owned by the Province, i.e. it is a Crown Corporation, the practice of disallowing expenditures, whether capital or OM&A, considered not to be prudent is more problematic than in the case of privately owned utilities, where disallowance affects private not public interests. To disallow an expense of a Crown Corporation would, in effect, send a "message", but as to who is to "pay the cost", it would simply "move" the disallowed cost from the utility's ratepayers to the taxpayers of the Province.

As previously indicated, MH defers and/or capitalizes certain of its operating, maintenance and administrative expenditures. A significant percentage of MH's annual OM&A expenditures incurred in its fiscal years have been or are to be capitalized or deferred (and then categorized as "assets" and not expensed), to be amortized over a period of years (with the amortization period for certain of those capitalized expenses to begin only after the "in service" date of a new Generating Station or transmission line).

The outcome of "capitalization" is, in essence, the transfer of a cost incurred in one particular fiscal year to other years, as the initial cost could be amortized over the expected service life of the "asset" it is associated with. With capitalization of OM&A, the rates of current ratepayers are restrained, with responsibility, in the form of impact on rates, transferred to future generations of ratepayers.

Private corporations, which pay income taxes, tend to "write-off" period expenses rather than capitalize or defer them, the effect of doing so reduces the income tax liabilities of the corporations while relieving future annual statements and, potentially, customers, of costs that would, if capitalized, fallen in future years.

MH segregates its costs between operating activities, which are a direct charge against the operating income for the year the expenditure occurs, and "capital" activities, which are deferred or capitalized in the year of incurrence and charged to future periods and amortized over the future life of the respective capital project. In addition, MH also capitalizes a significant component of its annual administrative overhead by applying predetermined overhead rates to all capital projects.

Over 75% of operating and administration costs (OM&A) relate to labour costs, including employee benefits. Manitoba Hydro had total (OM&A costs before capitalization or deferral of $543 million in 2003/04, an annual amount that increased to over $688 million in 2010, and was recently forecast to increase further to $704 million in fiscal 2010/11 and $714 million in 2011/2, before capitalization and/or deferral.

In 2003/04, MH capitalized or deferred a significant portion of its period costs, including approximately 28% of labour and benefits costs.

Actual and forecast operating and administrative expenses, before and after capitalization, for the fiscal years 2007/08 to and including 2011/12 are as follows:

Table 3

Operating and Administrative Costs ($000's)

	Actual			**IFF10-01**	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Labour					
Wages, Salaries	$359.3	$380.0	$408.0	$415.2	$424.8
Overtime	$41.8	$45.9	$50.3	$48.1	$49.2
Employee Benefits	$76.8	$83.7	$82.7	$93.0	$95.2
Labour and Benefits	$477.8	$509.9	$541.0	$556.3	$569.1
Employee Safety & Training	$3.7	$4.2	$4.6	$4.8	$4.9
Travel	$28.3	$31.8	$32.4	$33.0	$33.7
Motor Vehicle	$22.4	$24.1	$24.3	$23.1	$23.7
Materials & Tools	$27.8	$29.4	$26.9	$26.2	$26.8
Consulting & Professional Fees	$7.5	$9.7	$14.8	$10.9	$11.2
Construction & Maintenance Services	$15.9	$18.4	$20.1	$21.8	$22.3
Building & Property Services	$25.7	$29.0	$22.9	$20.7	$21.2
Equipment Maintenance & Rentals	$11.7	$13.0	$14.4	$13.9	$14.2
Consumer Services	$4.7	$5.3	$5.8	$5.7	$5.8
Computer Services	$1.1	$0.9	$1.0	$0.7	$0.7
Collection Costs	$5.3	$5.0	$4.6	$4.5	$4.7
Customer & Public Relations	$6.7	$6.9	$8.2	$6.0	$6.2
Sponsored Memberships	$1.2	$1.5	$1.3	$1.3	$1.3
Office & Administration	$14.4	$14.7	$15.3	$15.7	$15.9
Communication Systems	$1.4	$1.5	$1.8	$1.6	$1.6
Research & Development Costs	$3.0	$3.1	$4.0	$4.1	$4.2

	Actual			IFF10-01	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Contingency Planning				$5.4	$3.9
Operating Expense Recovery	($23.3)	($21.5)	($21.6)	($16.5)	($16.7)
Total Costs	**$638.6**	**$687.2**	**$723.0**	**$740.2**	**$755.6**
Operating and Administration Charged to Centra	($56.3)	($59.0)	($61.0)	($63.4)	($64.0)
CICA Accounting Changes*		$5.0	$9.0	$9.0	$9.0
Provision for Accounting Changes				$18.0	$13.5
	$582.3	**$633.1**	**$688.0**	**$703.8**	**$714.1**
Capital Order Activities	($192.3)	($203.1)	($224.3)	($235.0)	($239.7)
Capitalized Overhead	($67.3)	($65.7)	($69.2)	($71.0)	($72.5)
O&A Attributable to Electric Operations	**$322.7**	**$364.3**	**$377.6**	**$397.7**	**$401.9**

The amount of annual labour and benefits being capitalized has increased to the point where MH now capitalizes over 32% of its annual labour and benefit costs. The increase in amounts capitalized mutes, or masks, the growth in OM&A expense recorded on an annual basis.

If MH were to expense, i.e. charge against annual revenue/net income, labour and benefit costs that it now capitalizes, MH would, in the absence of larger rate increases than those now projected for future years, report net losses in many of its forecast future operating years, rather than forecasting annual net income for every one of its projected future years as it currently does.

Including overheads, in total MH forecast the capitalization of $306 million ($235 million with respect to in capital asset construction activities and $71 million of administrative overhead) of OM&A expenses in fiscal 2010/11, and over $312 million ($240 million in capital order activities and $72 million in overhead) in fiscal 2011/12, representing over 43% of its annual electric operating expenses in those two years.

A further analysis and discussion of the cost deferral and capitalization practices of MH will be provided in the subsequent second Order of the Board to arise out of the recent hearing.

3.3.2 Growth in OM&A

Operating and Administration Expenses, as recorded in MH's audited financial statements – after capitalization, have increased from $323 million in fiscal 2007/08 to $364 million in fiscal 2008/09; the two "test years" from the 2008 GRA (and representing an increase in one year of 13%). OM&A expenses, as recorded as an expense in MH's accounts, further increased to $378 million in 2010, an additional $13 million or 3.6% change from the prior year.

From fiscal 2004/05 through fiscal 2009/10, MH's OM&A expenses have grown at a compound average growth rate of almost 5% annually, while inflation for that period has been under 2% per year. MH forecast OM&A expense to be $380 million in fiscal 2010/11 and $403 million in fiscal 2011/12. And, MH provided an update at the hearing with its IFF 10-1, wherein the OM&A expense projection was revised, to $398 million for fiscal 2010/11 and $402 million for fiscal 2011/12 (as reflected in the above table).

MH attributed the increases in part to accounting changes (to conform with changes to GAAP, as GAAP transitions to comply with International Financial Reporting Standards, IFRS). Canada is in the process of converging its accounting practices with international accounting standards, which will, when the transition is complete, become the new Canadian GAAP.

OM&A increased in 2009/10 by $11 million, and MH recently forecast further increases in the order of $31 million for fiscal 2010/11 and $27 million for fiscal 2011/12 (incorporating provisions for expected IFRS mandated accounting changes to impact OM&A by $18 million and $14 million, for the respective years).

OM&A are direct expenses within the control of MH (some of these direct expenses have a "fixed" aspect – required annual expenses such as insurance premiums and building operation costs, while others are more of a variable nature, such as external legal and consulting fees, more susceptible to reduction).

MH indicated in the recent proceeding that it plans to "control" and restrain OM&A spending by implementing a number of measures, including a "general" hiring freeze (which provides for exceptions), restricting travel to only "out of Province" trips deemed very essential, and extending the service life of computer equipment (which lowers annual amortization expense, while extending the number of years amortization expenses occur related to those assets).

These actions, together with other measures related to targeted initiatives, were forecast by MH to save between $11 million to $13 million in expenses in the current year, fiscal 2010/11. MH also considered freezing management and executive salaries, an action that would have been consistent with the freezing of civil service salaries undertaken by the Province, but did not do so, asserting that to do so could risk the loss of key personnel to other utilities in other provinces. (MH testified that it had lost five employees to Saskatchewan Power over the last year, this out of a total complement of approximately 6,700).

A further discussion and analysis of MH's OM&A expenditures and the Board's perspective on the prudency of MH's OM&A expenses and its recent cost constraint measures will be provided in the subsequent Order of the Board.

3.3.3 Staffing Levels

A major driver of increases in OM&A expense (both before and after capitalization of OM&A) is increased staffing levels, which, despite MH's assertion that it seeks to restrain hiring, have been projected to increase from 5,769 Equivalent Full Time (EFTs) in 2004 to 6,669 EFTs, an increase of 900 EFT's (over 15%).

The increase in staffing levels and related labour costs was attributed by MH to be largely due to increased work requirements, with the largest additions to staffing levels taking place in three of its operating divisions: Power Supply (an increase of 498 EFT), Transmission & Distribution (an increase of 151 EFT), and Customer Service & Distribution (an increase of 146 EFT).

MH indicated that a large percentage of those recently hired were engaged to work on current and planned capital projects.

3.3.4 International Financial Reporting Standards (IFRS) Transition

Canadian accounting standards for financial accounting and reporting by publicly accountable private businesses and government business entities (the latter includes MH) are established by the Accounting Standards Board (of Canada, AcSB). AcSB's decisions represent Generally Accepted Accounting Principles (GAAP) in Canada. The International Accounting Standards Board (IASB) – which assumed the responsibilities, in 2001, of the previous International Accounting Standards Committee - establishes accounting standards meant for universal global adoption.

Standards adopted by IASB are denoted as International Financial Reporting Standards (IFRS), and AcSB has adopted IFRS as the new GAAP for Canadian enterprises, and is transitioning to that end.

The opinions of auditors of publicly accountable enterprises on the financial statements of those enterprises are based on compliance with GAAP, and those opinions, and the associated financial statements, are carefully considered not only by the general readership of such statements, but also investors in, lenders to (also the credit rating agencies relied upon by lenders) and regulators of those enterprises.

While the general accounting principles of what was Canadian GAAP are similar to those of IFRS, there are differences, and those differences, as IFRS has prevailed, have already affected and, particularly in the case of rate regulated utilities, will continue to affect financial reporting in Canada. IFRS provides a principle-based approach that values substance over form, relies more on fair (market) value, and seeks to achieve enhanced transparency. "Fair value" accounting, as compared to previous GAAP, has and will require adjustments to enterprise balance sheets and income statements.

IFRS was adopted as Canadian GAAP effective January 1, 2011. However, Canadian utilities were granted an optional one year deferment of implementing of IFRS, this to allow for an orderly transition from current Canadian GAAP accounting standards that recognize "rate regulated" assets and liabilities to those that do not.

Rate regulated assets represent expenditures currently allowed under Canadian GAAP to be capitalized or deferred, and not recorded as period expenses (for later amortization, over periods of time extending as much as 60 years), but which will be required to be recorded as period expenses under IFRS for fiscal years commencing on or after January 1, 2012.

MH has advised that it will be required to prepare IFRS compliant financial statements for its fiscal 2012/13 year, with comparative financial information for 2011/12.

MH has advised that its pending implementation of IFRS has prompted it to delay undertaking certain long outstanding Board-requested studies, including: a) an Independent Benchmarking Study of Key Performance Metrics, to compare MH's operational costs against those of other utilities; and, b) an Asset Condition Assessment Report, to assess the present condition of MH's assets and provide for possible future action such as asset upgrades and/or replacements.

These studies, which remain outstanding, were ordered to be developed and filed with the Board by way of Directives 4 and 7, respectively, of Order 150/08.

Pursuant to IFRS, and as previously indicated, MH reported that it may be required to write-off "rate regulated" assets, and that doing so would be expected to reduce its retained earnings by over $300 million (which would negatively affect MH's present and future debt to equity ratio).

MH has indicated that it will propose to the Board an approach that would allow for the continuation of "rate regulated" assets for rate setting purposes, although no details of such an approach has been provided. The Board would have to accept amendments to MH's audited accounts for rate setting purposes (i.e. "two sets of books"), if it were to agree to the approach being considered by MH.

A further discussion of IFRS and related accounting matters will be provided in the subsequent Order of the Board.

3.4 Power Resource Planning

The Wuskwatim Clean Environment Commission (CEC) hearing of 2003 (two members of the Public Utilities Board sat on that panel with members of the Commission) reviewed MH's then-plans to construct Wuskwatim Generating Station and related Transmission (at a cost then projected to be of approximately $900 million. CEC is an advisory body, not a quasi judicial administrative tribunal such as the Public Utilities Board.

While the CEC's review considered MH's Wuskwatim proposal, then based on an expected cost of $900 million, as being advanced for export sales and not domestic purposes, the latest estimate is $1.6 billion, approximately 75% higher, while MH first adjusted its view of the project, suggesting that it was required for domestic load requirements; it has reverted to its initial expectation that Wuskwatim will be employed for export sales.

Projects advanced for export purposes are expected to produce annual profits representing an acceptable rate of return on investment, whereas projects required for domestic load do not. With Wuskwatim now expected to be in-service in fiscal 2011/12, its generation understood to be sold, at least until new export sales contracts "kick-in", at spot or opportunity export sales prices, which, currently, are only one-third of Wuskwatim's expected per unit in-service costs.

The experience of Wuskwatim suggests that MH's planning for future investments in generation and transmission require significant testing ahead of approval, yet MH has put forward a very limited range of development scenarios with respect to meeting future domestic load growth.

Since 2004/05, MH's Power Resource plans have contemplated new major generation to meet projected future increases in domestic load requirements. The following table provides a snapshot of the progression of MH's expectations with respect to "dependable" hydraulic generation output:

Table 4

Dependable Hydraulic Growth

POWER RESOURCE PLAN YEAR	POST-WUSKWATIM DEPENDABLE HYDRO GWh	RECOMMENDED POWER RESOURCE PLAN GENERATION GWh/Additions	ALTERNATIVE POWER RESOURCE PLAN ADDITIONAL GWh/Additions
2004/05	22,500	26,900 – Conawapa (2024/25)	25,400 – Keeyask (2024/25)
2008/09	22,500	25,400 – Keeyask (2018/19) 29,800 – Conawapa (2022/23)	28,900 – 400 MW CCCT (2018/19) 30,400 – Conawapa (2020/21)
2009/10	22,500	25,400 – Keeyask (2018/19) 29,800 – Conawapa (2022/23)	26,900 – Conawapa (2021/22) 30,400 – 40 MW CCCT (2023/24)
2011 Outlook	22,500	25,400 – Keeyask (2020/21) 29,800 – Conawapa (2023/24)	Not Identified

For MH's recommended major development plan (the construction of Wuskwatim, nearing completion, plus Keeyask and Conawapa Generation Stations and Bipole III), the Corporation's dependable hydraulic power resources can be compared to domestic load requirements (and hydraulic shortfalls) as follows:

Table 5

Power Resources, Domestic Load and Dependable Hydraulic Shortfalls

Forecast Year	Projected 2020/21 Domestic Load (GWh)	Shortfalls (GWh)	2025/26 Projected Domestic Load (GWh)	Hydraulic Shortfalls[1] (GWh)
2004/05 Forecast	26,600	4,100	27,900	1,000
2008/09 Forecast	29,700	4,600	31,200	1,400
2009/10 Forecast	28,800	3,400	30,600	800
2011 Outlook	27,000	4,500 Pre-Keeyask 1,600 Post-Keeyask	28,900	900

It should be noted that each of these forecasts rely on about 4,000 GWh/year of non-hydraulic dependable resources in MH's fiscal year 2020/21. However, in MH's Outlook IFF 10-2 that level of shortfall of dependable hydraulic energy requirement is, pre-Keeyask, the same as it was in MH's 2004/05 forecast.

MH's preferred Power Resource Plan remains essentially unchanged since 2008/09, a time when domestic load forecasts were about 2,500 GWh/year higher than MH's most recent forecasts. In the absence of the recently announced additional export sales to Minnesota Power, Wisconsin Public Service and Northern States Power, it would appear MH could defer Keeyask G.S. (G.S., generation station) by about six years, rather than the one year deferral modelled in MH's IFF 10-2.

During the proceeding, MH modelled only two alternatives: a) build (MH's preferred approach - the construction of Wuskwatim, Keeyask, Conawapa and Bipole III, a plan that requires new export contract commitments); and, b) "no build", i.e. the development of Wuskwatim, Conawapa and Bipole III, to service domestic load when required and sell excess generation through opportunity export sales).

MH's witness, ICF, provided an estimated present value of MH's preferred approach which indicated that the approach, compared to the "no build" scenario (which omits Keeyask), the only other scenario seriously modelled by MH, could be expected to be moderately beneficial for domestic customers.

However, that estimate was made prior to ICF's awareness of the recent increases to MH's capital cost projections and the steep "fall off" of average export prices. As well, there has been a substantial "run-up" of the Canadian dollar (export sales to American counterparties are prices in USD), and a change in the outlook for carbon pricing has occurred. MH has reported that in its new export contracts with American counterparties, all "environmental" attributes or benefits associated with "clean" power is to go to the counterparties, and not to MH.

When ICF was cross-examined at the hearing, the witness acknowledged that the now expected $3.5 billion increase in the capital cost of MH's development scenario invalidated the consultant's earlier estimate.

MH also advised that it had, earlier, considered an alternative approach beyond that of the "no build" option, one relying on the construction and use of Combined Cycle Combustion Turbine (CCCT) thermal generation (refer to MH's 2008/09 and 2009/10 Alternative Development Sequences), MH did not, in the end, consider employing CCCT generation as a means to defer new hydro generation, and possibly transmission, as is now proposed for in its capital development plan.

The deferral of new hydro-electric generation in favour of the diversification of supply through the construction of CCCT generation would represent an approach that may not require additional firm export contracts.

MH asserted that Keeyask G.S. cannot proceed without Bipole III being in place. While the primary rationale for Bipole III has been to enhance reliability, MH asserts Bipole III is also required if Keeyask or Keeyask and Conawapa are to be built.

While there is no doubt Bipole III is required to transmit Conawapa generation, based on the capacity of the current system, existing Bipole I and II transmission appear capable of handling perhaps 80% of the maximum capacity of Keeyask/Kettle/Long Spruce/Limestone Generating Stations. This approach would have been adequate to transmit the entire output of those generating stations in 29 of the last 30 years, and without Bipole III.

Further discussion and analysis of these matters not only follow later in this Order but will also occur in the subsequent Order, and, presumably, would be one of the matters to be considered in a NFAAT proceeding.

3.5 Capital Expenditures

MH's capital estimates for major generation and transmission projects have been subject to significant periodic and dramatic upward cost adjustments.

In total, the estimated cost of MH's planned major generation and transmission expenditures has risen from $16 billion (from MH's CEF-08) to $20.5 billion (March 2011's CEF), and, more recently, to at least $23 billion (this estimate includes $1.9 billion now apparently required to upgrade Point du Bois, circa 2031).

As the volume of additional power that would be generated from Wuskwatim, Keeyask and Conawapa exceeds expected domestic requirements for decades, MH's "business plan", or strategy, seeks to sell the generated power that is expected to be in excess of domestic requirements to export customers, those primarily being American utilities. In fact, MH expects to obtain approximately 40% of its foreseeable future total electricity revenues from the export market.

In short, export sales would not be a “by product” of MH generation directed to fulfill domestic needs, but a significant market component in itself, one undertaken with the “hope” that domestic ratepayers would not be negatively impacted. To accomplish such a high level of overall revenue coming from export sales, MH plans to advance, well ahead of projected Manitoba demand, new major generation and transmission projects.

MH’s recommended and preferred development plan was first outlined in its 2008/09 Power Resource Plan, and, as well, in MH’s CEF-08. The focus of the plan is the construction of three major projects – Keeyask, Conawapa and Bipole III. The purpose for Wuskwatim, originally conceived as a generation source for export sales, was revised by MH in this proceeding as being required for domestic purposes, although domestic load is not expected to require additional generation until 2019.

Generation and transmission to meet domestic requirements are not subject to an economic evaluation, whereas plants constructed for export purposes do. The increase in the capital cost of Wuskwatim (which was first forecast at $900 million and is now forecast at $1.6 billion), in conjunction with the currently low average export sales prices and reduced domestic load growth, is unlikely to allow for a positive “economic” evaluation at this time.

The Board acknowledges that events post-2008, which have “dimmed” future immediate year net income prospects for the generation to flow from Wuskwatim, could not have been anticipated at the time of the CEC hearing.

Since MH's 2008/09 Power Resource Plan, the estimated construction costs for the three major projects have been adjusted upward, as follows:

Table 6

Major Generation and Transmission Projects Capital Cost ($billions)

	CEF-08	CEF-09	MAR/2011 CEF	LATEST
Bipole III	$ 2.25	$ 2.25	$ 2.25	$ 3.20 to $4.1 [1]
Keeyask G.S.	$ 3.70	$ 4.59	$ 5.64	$ 5.64
Conawapa G.S.	$ 4.98	$ 6.33	$ 7.77	$ 7.77
TOTAL	$10.93	$13.17	$15.66	$16.61 to $17.5

[1] The higher estimate has not been endorsed by MH.

3.5.1 Keeyask & Conawapa

Keeyask G.S.

In MH's 2004/05 Power Resource Plan, MH's cost estimate for Keeyask G.S. was $1.7 billion. This has subsequently been increased as follows:

CEF-08	$3.70 B	
CEF-09	$4.59 B	(25% increase)
CEF-10	$5.64 B	(18% increase, accumulated increase 52.4%))

MH cited material supply and labour shortages (which MH claimed resulted in "sticker shock") as the primary cause of cost forecast escalation when it submitted CEF-09; no specific cause was identified for the most recent increase.

Conawapa G.S.

When (circa 1990) MH looked to building Conawapa G.S. (then in order to service an expected Ontario export sale), the estimated construction cost was $3.8 billion for the Generating Station - this similar to the estimated cost of $4.0 billion reflected in CEF-04 for the project.

MH's CEF-05 and CEF-06 reported escalations in the projected cost of Conawapa, first to $4.5 billion and then to $5.0 billion. MH did not further increase its cost estimate for Conawapa in either its CEF-07 or CEF-08 reports. However, MH's CEF-09 indicated a further 25% increase in the estimated cost for Conawapa, to $6.3 billion, and, with MH's CEF-10, the cost estimate was increased by a further 25% to $7.8 billion (73% over the CEF-05 and CEF-06 estimates).

MH has not provided any specific details to support these large increases.

3.5.2 Bipole III

Bipole III, then with an "east side" of the Province alignment, was proposed initially in 1990 to accommodate a then-expected 1,000 MW sale to Ontario, at a cost of $1.7 billion for the transmission line and converters. The building of this line, as well as Conawapa G.S., was cancelled when the Government of Ontario repudiated its power purchase agreement with MH (Ontario compensated MH for most of the costs expended by MH on the project, MH advised that a "relatively" low charge against retained earnings took place).

With the vast majority of Manitoba's population being in southern Manitoba and with the majority of MH's power generation located in northern Manitoba, the reliability of MH's transmission from the north is of the highest importance. In October 1996, a severe wind event destroyed towers on both Bipoles I and II, and the event, understandably, changed MH's view of the adequacy of Bipole I and II's reliability. Subsequently, MH has planned on constructing additional transmission to reduce the risk of "brown-outs" in southern Manitoba (a distinct possibility given an event such as 1996's wind storm).

In both MH's CEF-03 and CEF-04 forecasts, MH proposed building additional HVDC transmission on the east side of Lake Winnipeg. The new transmission was intended to address reliability concerns (the evident risk of a failure of either Bipole I or II, or both), and was also expected to reduce HVDC line losses. However, at that time, the proposed HVDC project cost was estimated to be only $350 to $400 million.

MH's CEF-05 and CEF-06 forecasts both included a $1.88 billion cost estimate for an east side of Lake Winnipeg routing, now including converting resources, while MH's CEF-07 increased the projected costs of Bipole III to reflect a western route, preferred by the Province. The cost estimate then rose to $2.248 billion, the additional cost reflecting the longer distance inherent with a "western" rather the "eastern" routing.

The switching to a western route from the initial plan for an eastern route came about as the result of concerns related to environmental matters, and general public, First Nation and American acceptability of an east side alignment for Bipole III. (The potential for another HVDC line through the Interlake, paralleling Bipole I and II, was rejected, being viewed as compounding existing risks).

The Board's understanding is that a reliability concern with respect to a substantial outage of Bipole I and II similar to the 1996 event could be met by several means. Two of these (applied to a forecast 2018/19 situation) being:

1. An outage of Bipole I and II up to 2018/19 (one that occurred during the summer peak season) could, it appears, be adequately served by the addition of 600 MW (plus reserve capacity) of CCCT thermal generation, or, alternatively by the in-service of Bipole III. Such an outage could be triggered by any of forest fires, wind storms and/or right of way flooding during the summer. Outage impacts are anticipated to be less in the spring and fall.

2. An outage of Bipole I and II (up to 2018/19) that occurring during the winter peak season could be met by the addition of 1,800 MW (plus reserve capacity) of CCCT thermal generation, or by Bipole III. Such an outage could result from winter blizzards and/or extreme cold temperatures. Ice storms are also a possibility, but less likely in mid-winter.

It seems that an outage shortfall would more probably be in the 800 to 1,500 MW range, which could be met either by new CCCT generation or Bipole III. (The Board understands that employing CCCT generation to meet the shortfall would disqualify the output from being certified as "green power" by Minnesota and Wisconsin.)

Failure of the existing Bipole (Bipole I and II) presents the greatest risk to Manitobans in the winter when domestic demand is generally at its highest. Peak winter domestic demands in 2018/19 are estimated in the order of 5000 MW. Loss of the existing Bipole would then require that domestic loads be served by AC connections (that are not dependant on the Bipole), existing thermal resources and emergency imports. Manitoba Hydro has approximately 1600 MW of hydro generation capacity not connected to Bipole, 370 MW of thermal resources and an emergency import capability of approximately 1500 MW. Therefore, to completely meet Manitoba's peak domestic loads in the winter, if Bipole III were not available Manitoba would need a gas plant having a capacity of approximately 1500 MW. This represents a worse-case scenario should a

Bipole failure coincide at the moment in time of the peak winter demand. In the summer, the situation is not as difficult as peak domestic summer demands are in the order of 3900 MW. In the absence of Bipole III failure of the Bipole lines in the summer would require a gas plant in the order of 400-500 MW.

A Question of Credibility and Process

While MH did not revise its new Bipole III (with converting station costs) estimate of $2.248 billion in either its CEF-08, CEF-09 or CEF-10 forecasts, even though MH then-raised its capital cost estimates for both Keeyask G.S. (by $0.9 billion) and Conawapa G.S. (by $1.3 billion), MH did cite 'sticker shock' as one of the reasons for the 25% jump in the estimated costs of the generating stations.

Subsequently, a September 2009 capital cost estimate for Bipole III surfaced in the fourth quarter of MH's 2010/11 fiscal year, suggesting that the projected cost had increased to $3.9 billion. This Capital Project Justification Addendum (CPJ, a form employed by MH to record and, potentially, "approve" project cost estimates) was rejected by MH's senior management, although it was signed on September 10, 2009 by two MH division vice-presidents. MH advised that while the estimate was discussed by senior management it was not brought forward to MH's Board of Directors.

Ahead of that discovery, the matter of the cost estimate for Bipole III was reviewed by Board Counsel in discussion with Mr. Warden, MH's Senior Vice-President and Chief Financial Officer. What follows are excerpts from the record of the hearing:

MH Senior Vice-President and Chief Financial Officer testified that an internal process exists with respect to changing construction cost estimates. Apparently, the division or divisions with responsibility for the proposed project "bring forward proposals for approval of (MH's) executive committee which, if approved, gets incorporated in the integrated financial forecast (IFF) …" and that "… in the case of Bipole 3, there was no revision approved".

So, from the time when CEF-07 was developed, and although four years had passed, during which the cost forecasts for Wuskwatim, Keeyask and Conawapa had substantially increased, MH "stayed with" with its forecast of $2.248 billion for Bipole III.

With respect to the CPJ signed by two MH vice-presidents which projected Bipole III at $3.9 billion, MH's Senior Vice-President and Chief Financial Officer initially testified, in response to a question from Board Counsel ("… with respect to Bipole 3, did the line divisions bring up changes in the capital forecast cost for Bipole 3 through the internal channels up to its vice-president?"), his response was "I don't know whether it made its way to the vice-president or not. It never made its way to executive committee though".

Following a follow-up question by Board Counsel: "Does the Board understand your previous evidence to be that the document (the CPJ that identified a forecast cost of $3.9 billion for Bipole 3, signed by two vice-presidents)) … never made its way to Manitoba Hydro's executive committee?", and, Mr. Warden testified "Yes, that's right", and, subsequently, "… it's the first time I've seen this document, it's never, been presented to the executive committee … it has no signatures. It's not signed by the … vice-president of transmission and power supply … until those signatures are affixed, this document is just a preliminary estimate which is subject to change…".

And, in response to Board Counsel's follow-up question "… you're suggesting that Hydro was not aware that on August 18th (2009) that … Hydro's transmission planning and design division was recommending a revision to the capital expenditure budget for

Bipole 3?", Mr. Warden responded "...it's the first time I've seen this document, it's never been presented to the executive committee, you'll note … it has no signatures … it's not signed by the vice-president of transmission and power supply … until those signatures are affixed, this document is just a preliminary estimate which is subject to changes".

Board Counsel then asked two more questions of Mr. Warden with respect to the above references CPJ: "… you're saying that until I showed (the CPJ, an unsigned version) to you this morning, you've never seen the document before?", and "… (would you) have expected to see this document in your capacity as a member of the executive committee if it had come up through the line divisions through the vice-presidents?".

And, Mr. Warden responded: "That's right", and "… I note that the division has not signed off. The process would be for the division to forward it to the respective vice-president to allow him the opportunity to challenge the document and – when he's satisfied – he or she, in this case he, but when he's satisfied with the document then it's brought forward for a review by the executive committee. That hasn't happened."

Board Counsel also asked Mr. Warden "What you're telling the Board … is that in 2007 and 2008 Manitoba Hydro saw no need to check to see whether the cost of Bipole 3 was escalating even though the costs for Conawapa and Keeyask were?" Mr. Warden responded "The process is to come up with an in-service cost for all projects and unless there's a reason to revise that estimate, there's no addendum (CPJ) brought forward. So it's not unusual to have a project that is estimated and unchanged" and "I'm telling you that we have an approved estimate of $2.2 billion for Bipole 3, and until it's officially revised that is the approved estimate … this is no different from any other capital estimate at MH in that respect. Until we have a number that we are satisfied with … a number that we can have confidence in we don't revise that number …".

Board Counsel concluded his cross-examination of Mr. Warden on this topic with the request "Mr. Warden, can you tell the Board whether (MH's) Audit Committee was provided a copy of the … revised Bipole (3) calculation?" Mr. Warden responded "No, they were not … the Audit Committee would not typical receive these documents … they receive a very consolidated summary of all capital expenditure forecasts for … the twenty year financial document".

Two days following this series of exchanges between Board Counsel and MH's Senior Vice-President and Chief Financial Officer, MH tabled the CPJ referenced above in the dialogue between Board Counsel and Mr. Warden. The CPJ was signed by two vice-presidents, as Mr. Warden then stated:

"Mr. Tymofichuk, the Vice-President of Transmission, did in fact sign this document on September 10th of 2009 … and the Vice-President of Power Supply signed the document on the very same day … the CPJ would have been forwarded to Finance and Administration (the division for which Mr. Warden is responsible) for the preparation of an (executive committee) recommendation, which was done and was, in fact, forwarded to my office… I did not recall having seen the document, however I would have … been aware of the amount at that point in time … I would have consulted with Mr. Brennan as to how we would deal with it… of course, we were both concerned about the increase … and, therefore, did not move forward."

Further, Mr. Warden reported: "I consulted again with Mr. Brennan just to make sure my memory and his memory was somewhat aligned, and following September of 2009, there would have been a lot of internal discussion about the amount of the capital cost estimate, or the revision to that estimate and it took approximately twelve months before we referred that to an outside consulting firm to resolve this issue for us, or at least to come up with an estimate that … we would have more comfort with”.

Thus, MH, accepting that estimated cost of Bipole III may be subject to a dramatic revision higher, in January 2011, MH sought an independent review of Bipole III costs by Rashwan (and Associates), the principal being a former MH employee.

While Rashwan & Associates reviewed the design concept and costs for the converter station and collector lines, the firm did not review the cost estimates for the HVDC transmission line. The firm concluded that MH could reduce Bipole III costs by eliminating a provision (included in the $3.9 billion estimate rejected by senior management) of a contingency reserve in case synchronous converters were required and, also, eliminate the escalation cost provisions usually employed by MH. Incorporating the changes suggested by the consultant, MH provided a revised CPJ with a $3.2 billion overall total costs for Bipole III, which was “accepted” by MH’s Board of Directors.

3.5.3 Project Economics

When prior to 2009, MH was negotiating with Northern States Power (NSP) on an extension of export sales contracts beyond MH’s fiscal year 2014/15, and with Minnesota Power (MP) and Wisconsin Public Service (WPS) for new sales contracts beyond 2020, the average value of new energy projected to be realized from MH’s planned new Keeyask G.S. was in the range of 6 to 7¢/kW.h. However, subsequent to negotiations that resulted in term sheets being entered into in 2007 and 2008, ahead of the global credit crisis and recession and the recognition of a substantial increase in the projected cost of Bipole III, the capital cost estimate for the construction of Keeyask increased (first by 25% as identified in CEF-10, and, later by another 18% in CEF-11, together representing an aggregate compounded increase of 50%).

Similarly, the expected average value of new energy arising from the planned construction and operation of Conawapa G.S. was in the range of 7¢/KWh in 2009. However, the estimated construction cost for the Conawapa generation station has since increased (by 25% in CEF-10 and by a further 25% in CEF-11, an aggregate increase of 56%).

Indications from publicly available documents from American regulatory hearings suggest that the term sheet negotiations carried out in 2007 and 2008 resulted in contract prices with NSP/WPS/MP that, at best, have not been increased in the NSP Agreement.

The evidence of the recent proceeding suggests that the subsequent and major project cost escalations for MH's preferred development plan will not be "covered" (met) by increases in export revenues. In short, it would appear that any profitability that may have appeared present with respect to these sales when the initial term sheets were entered into in 2007 and 2008, before the global recession and lower natural gas prices and industrial load, shale deposits, have been, at minimun, significantly reduced if not totally offset as the result of the capital cost increases (which were also not projected at the time of the signing of the term sheets).

3.5.4 Development Partnership Agreements

Manitoba Hydro has entered into agreements with First Nations with respect to the almost completed Wuskwatim Generation Station and the planned Keeyask Generation Station. The agreements provided the First Nations with the opportunity to participate in the equity ownership of the new generating stations, and represented a “new way” of approaching developments on lands occupied by First Nations, a way which involved negotiations ahead of construction, a way that allowed for First Nation approval and cooperation.

In both cases, taking into account the increases in construction costs from the original estimates, Wuskwatim – which is expected to be in operation in this fiscal year - and Keeyask, which is planned, are expected to produce power at or about 10¢/kWh.

According to MH’s projected initial “Operating Statement”, which was prepared by MH from the perspective of the partnership rather than MH’s overall operation, Wuskwatim’s probable initial years’ revenue stream will be based on opportunity export prices.

MH’s projected initial “Operating Statement” for the partnership, as reflected in IFF 09-1, projects revenues based on average opportunity export sales prices of about 7¢/KWh. Unfortunately, the export sale estimate is significantly higher than the current average MH is receiving for export opportunity sales to American counterparties, which appear to have been in the range of 2 to 3¢/kWh (2009/10 and 2010/11).

Accordingly, in the case of Wuskwatim and, if the Keeyask project is undertaken and completed, Keeyask’s, revenue stream as well, at least initially, if based on current opportunity export prices or, in the case of Keeyask, an average of firm and opportunity export sales prices, may prove insufficient to fully meet costs.

Also, from the evidence available, it appears the allocation of expenditures to be incurred by MH favour the new partnerships, resulting in an even lower overall "economic" value of the new generation stations to MH overall (details discussed below under Board Findings).

3.6 Finance Expense

Finance expenses, as reported in MH's audited accounts, were $401 million in 2009, representing over 29% of total operating expenses, and were forecast (MH's IFF 09-1) to be $417 million in fiscal 2009/10. Actual finance expenses decreased to $373 million in fiscal 2009/10.

For the fiscal years 2007/08 through to and including 2009/10, actual finance expenses were approximately $76 million lower than that forecast in IFF 07-1, this the result of declining and relatively low interest rates during the period (largely the result of the global credit crisis and recession, and the slow recovery from the event), the rates particularly low for short term debt. MH forecast its overall finance expense at $413 million for fiscal 2010/11 and to increase to $468 million for fiscal 2011/12, representing approximately 25% of its annual operating expense.

The variation between actual and forecast is attributable to two factors, a growth in debt levels, more than offset by lower interest rates.

As it does with respect to certain OM&A expenses, MH capitalizes interest on all capital projects during construction, and only begins to record the costs as expenses once the project is complete and in service.

MH's finance expense for electric operation before capitalized interest is forecast to be \$509 million for fiscal 2009/10, \$417 million on a net basis after adjusting for capitalized interest of \$92 million. MH forecasts net finance expense of \$413 million in fiscal 2010/11 and \$468 million in fiscal 2011/12, after capitalizing \$131 million and \$137 million, respectively.

As the major new generation and transmission projects commence construction, MH expects to capitalize a greater proportion of its finance costs, with \$449 million or 43% of net interest expense being capitalized in its 2017/18 fiscal year.

MH's gross finance expense is forecasted to grow from \$605 million in fiscal 2011/12 to \$1,104 million by fiscal 2018/19; or, \$674 million on a net basis after adjusting for capitalized interest of \$430 million. Finance expense and capitalized interest for fiscal years 2009/10 through to fiscal 2018/19 are as follows:

Table 7

Finance Interest & Capitalized Interest

Finance Expense ($ millions)	IFF MH09-1									
For the years ended March 28/29	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Gross Finance Expense	$509	$544	$605	$635	$671	$752	$835	$953	$1,036	$1,104
(Less) Capitalized Interest	(92)	(131)	(137)	(110)	(144)	(208)	(306)	(408)	(449)	(430)
Total Finance Expense	$417	$413	$468	$525	$527	$544	$529	$545	$587	$674
% Capitalized	18%	24%	23%	17%	21%	28%	37%	43%	43%	39%

Based on MH's IFF 09-1, by its fiscal year 2028/29, MH forecasts to have capitalized, in aggregate, over $4.8 billion in interest costs to the in-service dates of the planned two new generation stations. When considering the estimated cost of MH's capital expenditure plans, it is important to consider financing costs, which are a significant element in capital intensive operations such as hydro-electric based utilities.

IFF 10-1 Update

MH provided a partially updated IFF MH 10-2 during the hearing, which reflects recently adopted increases in the capital costs of the Major Generation and Transmission projects in the order of $3.6 billion. In total, MH now projects an increase in its long-term debt from current levels by over $15 billion, to $23 billion, by 2029 ($5.3 billion higher than that forecast in IFF 09-1).

Given updated capital costs, capitalized finance expense will exceed $5 billion by 2029 (capitalized finance expense would be amortized over the expected service life of the assets).

Based on IFF 10-2, MH's forecast for finance expense was updated from $413 million to $393 million for fiscal 2010/11 and from $468 million to $411 million for fiscal 2011/12. The updated forecast reflects expected reduced interest rates in the near term, as rates have remained relatively low due to the slowness of the North American economic recovery. Finance expense is forecast to grow from an annual $411 million to over $1.5 billion by fiscal 2025/26, when the last of MH's planned major new Generation and Transmission projects, Conawapa, is expected to be in-service.

Based on the updated cost estimates in IFF 10-2, MH's debt is forecasted to grow from $8.7 billion as of March 31, 2011 to $22.9 billion as of March 31, 2030, an increase of $14.2 billion. The debt to equity ratio for 2029 has also changed, and, as indicated previously, MH now forecasts that implementation of its development plan (which includes the construction of new generation and transmission assets, from the 51:49 ratio projected in MH's IFF 09 forecast to 72:28 in its partially updated IFF–10 forecast, representing a material financial change from one forecast to the next. (The latest forecast includes the assumption of a series of 3.5% annual rate increases for a decade, to be followed by annual 2% rate increases.)

In MH's current forecast, the overall finance interest rate is projected to increase to 6.6% (excluding the 1% Provincial Debt Guarantee Fee) by fiscal 2016/17, and from then projected to remain constant at that rate through fiscal 2029/30. MH has not forecast any increase in long term interest rates beyond 2029/30.

4.0 Risk

4.1 Financial Forecasts

MH's initial Application, as indicated based on MH's IFF 09-1 forecast, is supported in part by 2008 export pricing forecasts, now at question, and capital expenditure estimates for Bipole III/Keeyask G.S./Conawapa G.S. totalling $13.1billion (CEF-09), those since updated to a current construction cost projection of $16.6 billion (IFF 10-2).

There has been a major increase in expected capital costs, which will be exacerbated by finance costs on the additional debt. Finance costs over the full term of the debt, can be expected to exceed the initial construction cost by a wide margin by the time the debt is fully repaid. MH's net export revenue assumptions have, essentially, remained unchanged from its IFF 09-1 forecast, this notwithstanding a 30-40% reduction in natural gas price forecasts that has developed since IFF 09-1 and MH's plans were established (reduced natural gas prices are a primary driver of lower spot prices on in the American electricity market, MISO, that MH operates in).

The now-forecast decrease in natural gas forecasts, which, if realized, would reduce CCCT natural gas generation costs by, say 25%, and affect, lower, at least spot and opportunity export sales prices, are not reflected in the financial forecasts placed by MH before the Board.

Again, the implication of the major reduction in actual and projected natural gas and spot and opportunity electricity prices in the MISO market is the suggestion of a significant pending drop from MH's currently forecast net export revenues. MH plans for firm export volumes to represent no more than 50% of overall export volumes, the other 50% to be represented by opportunity export sales - much of that at off-peak hours where pricing has been as low as 0.5 kWh over the last year and more.

While net income reduction scenarios are intended to illustrate the sensitivity of net income to changes in export and import pricing assumptions, MH declined to test, as requested by the Board, its export revenue forecast against assumptions of low opportunity export sales prices (related in part to lower natural gas prices, the current lack of indication of a price being placed on carbon and reduced industrial demand in the United States), both in response to Information Requests/Pre-Asked Questions from the Board or in MH's latest (IFF 10-2) financial forecasts (and despite ICF, a MH's expert witness, testimony on natural gas price decline and recent trends in the export market sales).

While MH's financial position as reflected in the partially updated IFF 10 reflects a marked decline from MH's projections of IFF 09-1 (covering a 20 year period), due to increased costs of Keeyask G.S., Conawapa G.S. and Bipole III, MH's current projection of its future financial position does not include the potential for lower overall export revenues.

As it is, MH's net income and retained earnings forecast as of fiscal 2028/29 – while subject to question and likely further adjustments, has changed, as follows:

Table 8
Changes in Net Income, Retained Earnings & Long Term Debt

	Net Income	**Retained Earnings**	**Long Term Debt**
IFF 09-1	$1,224M	$11.0B	$17.7B
IFF 10	$ 906M	$ 9.2B	$21.2B
OL 10-2	$ 741M	$ 7.7B	$23.0B

The changes that have been made by MH reflects revised and increased capital costs of over $2.3 billion for Keeyask G.S. and Conawapa G.S. (reflected in IFF 10-1) and an additional $0.9 billion increase in the capital cost of Bipole III (reflected in IFF 10-2). On a cumulative basis, the "accepted" increase in the capital cost of MH's capital expenditure plans amount to $3.5 billion and results in a $3.3 billion reduction in MH's IFF 10-2 projected retained earnings, and an increase in MH's projected long term debt of over $5.3 billion compared to IFF 09-1.

Again, the accepted "decline" in MH's forecast financial results does not take into account any implications that may be related to potential lower than forecast export prices.

4.2 Domestic Load Forecast

In MH's IFF 09-1, the Corporation identified a projected decline from its 2008 GRA forecast of domestic demand of about 800-1,000 GWh. in its 10-year forecast of total domestic base load. Subsequently, and taking into account the slow recovery of industry (in the United States in particular), the closure of a Manitoba pulp and paper plant and the announced future closure of a smelter and refinery in Thompson, it could be argued that MH's domestic load forecast should, or at least could, have been further reduced by 1,400-1,800 GWh./year.

As it is, MH's latest forecast suggests total domestic loads of 25,700 GWh. in fiscal 2015/16 (down 1,400 GWh from IFF 09-1), and 27,000 GWh. in fiscal 2025/26 (down 1,700 GWh from IFF 09-1).

Almost the entire projected decline in domestic load forecasts rests with the industrial sector (or "Top Consumers" category), for which MH has forecast loads being down by

1,300 GWh./year from MH's IFF 09-1 forecast for fiscal 2015/16 through fiscal 2025/26. The major pulp and paper plant closure and "Primary Metal" industrial "cutbacks" could account for about 600 GWh/per year of the above decline. That noted, relying on notices issued by existing industrial companies concerning operational closures could add another 500 GWh/year of industrial demand loss after fiscal 2014/15.

Overall, and based on the evidence of the proceeding, growth prospects for the industrial sector, which currently account for about 1/3rd of annual domestic demand, appear to be very limited. MH testified that it was unaware of any new industrial customer planning to come on line over the current projection period, i.e. to fiscal 2028/29, not to say that either a new large industrial operation could choose to locate in Manitoba or an existing industrial concern expand.

Overall, MH's IFF 10 forecast does not forecast any reduction in total domestic revenue from the projections of IFF 09-1; MH's assumption being that load growth from residential or other classes will "make up" load losses as a result of industrial slow-downs or cut-backs. (The Board notes the potential that may lie with "electric" cars, though there are technological and economic issues to resolve (battery and "cold weather" among them).

MISO Market Impacts

MH's current actual export revenues (since the onset of the economic downturn in the fall of 2008 and the advent of enhanced forecasts of shale gas production and natural gas price declines) have reflected steep opportunity export price declines, from in excess of a 5¢/kWh range, that of the pre-economic slowdown period, to the 2 to 3¢/kWh. range.

Despite high river flows and excellent hydraulic generation potential, MH's overall export revenues remain depressed (due to not only low prices but also less volume that had been anticipated).

Going forward, export prices, taking into account low opportunity sales prices, may remain lower, perhaps considerably lower, than what is currently forecast by MH. The advent of commercially extractable shale gas and the absence in the near term and delay in the evolution of CO_2 emission pricing is reflected in ICF's revised long-term natural prices being 30% to 40% lower than the firm forecast in 2008.

Because MH exports "compete" with CCCT natural gas generation in the peak and shoulder period, and MH's exports "compete" with incremental coal and wind generation in off-peak periods, the lower natural gas prices could, hypothetically, result in a substantial reduction from what MH currently forecasts as its expected future net export revenues.

With MH declining to provide additional lower export price scenarios, for which MH was asked, the Board can only impute what domestic revenue requirements could be in the next 20 years. Shortfalls from expected net export revenue will be reflected in domestic rates, if MH's financial targets (particularly debt to equity) remain as is.

4.3 Export Revenue Pricing Assumptions

MH sales into the U.S. MISO Market over the last decade can be summarized as follows:

Table 9

MH's Exports into MISO & Canadian Markets (GW.h)

Year	Dependable	Opportunity	Total	CDN Sales[1]	Total
2000/01	4,895	4,511	9,406	3,047	12,153
2001/02	4,767	5,083	9,850	2,449	12,299
2002/03	4,947	2,713	7,660	2,075	9,735
2003/04	5,245	507	5,752	1,214	6,966
2004/05	5,683	3,218	8,851	1,680	10,431
2005/06	4,044	8,879	12,923	1,424	14,347
2006/07	3,654	5,877	9,531	373	9,904
2008/09	3,921	7,332	11,053	682	11,735
2009/10	4,087	6,071	10,158	418	10,576
2010/11	2,613	6,218	8,831	336	9,167

[1]Non-merchant sales from MH's own resources.

Typically, MH has purchased wind and thermally generated energy to support its hydraulic generation in the range of 1,500 to 3,000 GWh: drought period exceptions occurred in fiscal 2002/03, at 3,800 GWh, and in 2003/04, at 10,500 GWh.

With only the existing transmission tie-lines to rely upon, MH is generally limited to, assuming adequate water levels, about 7,000 GWh./yr of peak energy sales. Except for fiscal 2008/09, peak firm and opportunity sales over the last 10 years have accounted for 2/3^{rds} of MH's export; meaning the other 1/3rd of total export sales serve off-peak markets (in both MISO and Canada).

During that period, MH achieved average annual export prices of about 5¢/kWh. From 2004/05 to 2008/09 firm contract prices were 5 to 6¢/kWh, opportunity peak prices were 6.5 to 7.0¢/kWh, and opportunity off-peak export sales came at prices in the range of 2.5 to 3.5¢/KWh.

Unfortunately, this situation changed in 2009/10 after MH's IFF 09-1 had been filed. In IFF 09-1 and IFF 10 MH assumed average export revenue rates as follows:

Table 10

Forecasted Average Expert Revenue Rates

Fiscal Year	IFF 09-1	IFF 10
	(¢/kWh)	(¢/kWh)
2010/11	4.10	3.26
2014/15	7.41	6.63
2015/16	9.09	8.11
2019/20	10.56	10.84
2020/21	10.66	11.12
2021/22	10.94	11.13
2025/26	12.25	12.20
2026/27	12.64	12.58
2028/29	13.45	13.45

MH's IFF 09-1 forecast of export prices reflect the input (which occurred in or before 2008) of a panel of external consultants engaged by MH. ICF, one member of the panel, provided evidence in this proceeding that the natural gas prices employed by ICF's forecast in 2008 are 30-40% higher than ICF's current forecasts, and that, as a result, MH's previously forecast spot and opportunity electricity prices for the MISO market could be lower.

A comparison of MH's IFF assumptions to more current data as to Single Cycle Combustion Turbine (SCCT) thermal generation costs confirms that MH did not alter its export energy price forecasts in its IFF 10 projection from those of its IFF 09-1 forecast.

The chart which follows largely results from the expected change in natural gas prices and provides a comparison of four various export price scenarios, namely:

- Scenario #1 – MH's IFF 09-1 Export Revenue Prices
- Scenario #2 – MH's IFF 10 Export Revenue Prices
- Scenario #3 – 0.75 x MH's IFF 09-1 Export Prices
- Scenario #4 – PUB/MH Pre-Ask #4 Export Price Scenario

The first two scenarios are extracted from MH's filed export revenue price assumptions for IFF 09-1 and IFF 10. Scenario #3 at 75% of IFF 09-1 prices is intended to reflect the 35 to 40% reduction in ICF's natural gas price forecasts as of 2008 and 2010. Scenario #4 is drawn from PUB/MH – Pre-ask #4 (which MH declined to respond to).

The export revenue rates illustrated for the 20 years of forecast show very little change between IFF 09-1 and IFF 10, particularly from 2019/20 on-ward. As expected a 25% revenue rate reduction in Scenario #3 would see 8 to 10¢kWh export electricity prices after 2019/20 to 2029/30. This could be considered a conservative position, relative to Scenario #4 which at about 65% of IFF 09-1 prices is more pessimistic.

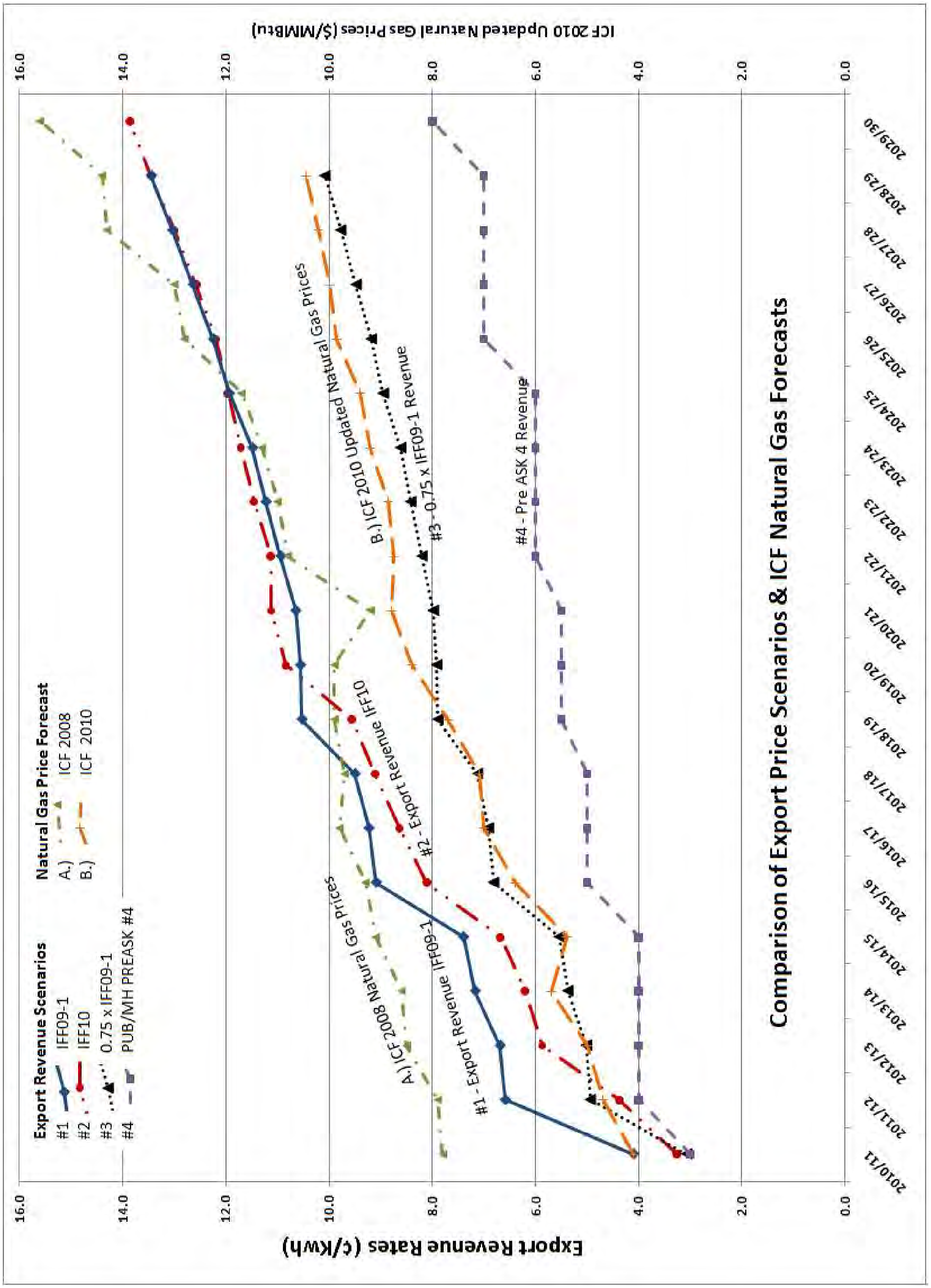
Also indicated as Scenarios A and B on the chart are the natural gas price forecast for 2008 and 2010 drawn from ICF presentations and subsequent exhibits.

ICF now expects natural gas prices to remain below $6/MMBtu until fiscal 2014/15, then remain below $8/MMBtu until 2018/19, and not achieve $10/MMBtu before 2026/27. (As a comparison, in the last decade natural gas prices have exceeded $10/MMBtu on at least two occasions – following hurricanes Katrina and Rita in 2005, natural gas prices soared to in excess of $15/MMBtu – these events precede the advent of shale gas production.)

In 2008, when MH developed its export price forecast for IFF 09-1, natural gas prices were upwards of $7/MMBtu, and were expected to progressively rise, achieving about $10/MMBtu (as CO_2 emissions factors kicked in circa 2015), and rising further to $15/MMBtu by 2028/29. CCCT thermal generation was then generally expected to dominate the peak period electricity generation market, and to a lesser extent compete for base load with coal generation. Other new energy resources for MISO, such as MH exports and northern states' wind farms would presumably be constrained price-wise by now expected lower CCCT operating costs.

Chart 1

Comparison of Export Price Scenarios & ICF Natural Gas Forecasts



According to the public record, MH expects to achieve on average at least 8.7¢/kWh for peak "firm" sales from its new export contracts, from 2015/16 onward. Even allowing for some escalation (MH advised of a formula within its new contracts that allow for price escalation related to a partial recognition of general inflation), this "expected" average price is at least 10% lower than MH's IFF 09-1 and IFF 10 assumptions for average export sales prices.

Intuitively this suggests that MH's spot and opportunity export sales (the average of peak and off-peak) may have to average about 1-2¢/kWh higher than the "firm" peak prices encapsulated in its contracts to meet the revenue forecasts made by MH. The historical record provides no evidence of such a past situation.

4.4 Export Contracts

4.4.1 Current Export Contracts

Currently, MH has firm long term obligations under Northern States Power (NSP) contract that extends from 2005-2015 and involves 500 MW. The contract requires MH to provide 500 MW to NSP or an annual supply of 2,100 GWh of "5x16" energy (five days a week, sixteen hours each day). The contract extends to 2015 with fixed pricing. Although this obligation could, theoretically and presumably, be reduced under drought conditions more severe than the worst case on record, the Board has not been in a position to review the contract.

Yet, according to NSP's public documents, as filed in the United States, MH has not, at least to the date of the filing of those documents, curtailed supply under this contract, and NSP has indicated to its regulator that it does not expect MH to ever curtail supply.

During the 2003/04 drought, MH continued to supply "firm" power to its American counterparties, despite the Board's understanding that the Corporation had the right to curtail supply in the event of a drought, but that it chose not to curtail to preserve the business arrangement and MH's reputation as a reliable supplier. In any case, if there was misunderstanding, that contention was corrected by MH in this proceeding, wherein MH indicated that the contract did not allow for the Corporation to curtail due to the drought, and that it had an obligation to supply that it could not set aside.

Additionally MH has entered into diversity agreements out to 2015 with NSP (and others) for about 350 MW of capacity. The arrangement, as reported, provides for a summer-winter exchange of capacity availability (variable energy as/when required to be supplied and billed at market prices). When MH imports power from the United States that power arises largely from thermal (coal primarily) generation, while MH exports hydro-electric power to the United States.

MH also annually enters into bilateral agreements with various parties in the MISO region to supply summer (5x16) firm energy. Typically these arrangements involve about 1,000 GWh./year of energy at prices that are annually adjusted.

As well, MH engages in day-ahead and real-time opportunity sales into the MISO market. These forays have, in above average flow years (since 2003/04), been in the 3,000 to 7,000 GWh/year range. Prices for such sales have dropped sharply since the fall of 2008, and now average about 3¢/KWh. (average includes both peak and off-peak sales).

4.4.2 Future Export Contracts

MH has recently announced that it has entered into new export contracts (subject to regulatory approval in both the United States and Canada and dependent on MH proceeding with its preferred capital development plan, pertaining to periods beyond 2015.

These include:

(i) Northern States Power (NSP)

NSP [2015 to 2025] - 375/325MW summer (5x16) winter (5x12) – fixed price/firm

- 350MW Diversity Exchange Agreement – market price based
- 125MW summer (5x16) winter (5x12) – fixed price/firm

(Defined energy obligation: 2100 GWh)

(ii) Minnesota Power (MP)

MP [2020 to 2035] - 250MW summer/winter (5x16) - fixed price/firm

- 250MW summer/winter weekend (2x16) - market price based

(Defined energy obligation: 1,400 GWh.)

(iii) Wisconsin Public Service (WPS)

WPS [2020 to 2035] – 100MW summer/winter (5x16) - fixed price/firm

- 100MW summer/winter weekend (2x16) – market price based

(Defined energy obligation: 600 GWh)

While individual contract specifics on pricing have been deemed confidential by MH, and have yet to be shared with the Board, ICF, an expert retained by MH, presented information at the proceeding suggesting MH's combined capacity and energy prices were in the range of about 8.7¢/kWh, on average, for firm (peak) energy.

When price escalation is factored in, the price suggested appears to represent about 90% of MH's IFF 09-1 export price assumptions. Consequently, if MH's forecast export prices for its IFF 09-1 are "reasonable", the required assumption appears to be that the average price of spot and opportunity export sales was expected to be higher than the contract values.

Without access to the unredacted contracts, it is not possible for the Board to either agree or disagree with either MH's views on pricing or that of its various consultants' on the adequacy of any curtailment or 'adverse water' clauses that may reside within the contracts.

However, and significantly, the evidence suggests that MH cannot reduce summer sales to its American counterparty under the 'adverse water' clause cited by MH at the proceeding. It is unclear at this time, and without present access to the contracts, as to what extent contract provisions mitigate against the likely or possible cost consequences associated with drought conditions.

From the evidence provided, MH's exports to NSP after 2015 come with environmental attributes included in the negotiated price – i.e. environmental attributes of power supplied by MH to its American counterparties are to be attributed to the American counterparties (the exact conditions of the Clean Energy Clause were redacted from the information placed on the record of the hearing).

What does appear clear is that there are no defined Clean Energy premiums to be paid MH by NSP. Rather, any future CO_2 premium costs would increase MH's import and thermal generation costs.

4.5 Drought

One of the major risks faced by MH is drought. Lack of available water during a drought severely limits MH's power supply.

Despite commitments made by MH to provide the Board, by April 1, 2011, a formal "written" Drought Preparedness Plan, nothing has been filed. Nonetheless, MH asserts that drought planning is a constant activity within the Corporation and is incorporated in its business processes. Both ICF and the Independent Experts recommended a formal written plan be prepared.

In 2003/04, MH experienced drought conditions that resulted in a net loss of $436 million. Despite the evident cost consequences of drought conditions for a utility relying on hydro-electric generation and involved in significant power exchanges with American utilities, with commitments and/or understandings with respect to supply involved, MH has suggested that a written Drought Preparations Plan would be redundant given MH's current practices, which were reported to have been employed in 2003/04.

Despite the Board having directed MH to engage an independent risk expert to conduct a post-audit of MH's actions through the drought, no such report was filed. And, no evidence was presented either at a prior or recent hearing indicating that MH undertook a detailed assessment of its water resource management and decisions employed in 2003/04.

MH's past planning position is that preparing for a five-year drought (as defined by the specific historical period from 1987/88 to 1991/93) provides an adequate drought risk stress test. It remains unclear as to what degree of shortage pricing, such as experienced in 2003/04, should be anticipated.

MH has projected that the financial consequences of a five-year drought to be in the range of $2.0 billion in reduced retained earnings ($2.4 billion when increased finance costs are considered). MH indicated that if shortage/ high import price situation coincided with a drought period this could increase the cost of a five year drought from $2.0 billion to $2.5 billion (with finance costs included, an even larger overall shortfall).

The Independent Experts also projected the cost of a five-year drought, and arrived at an estimate of $1.6 billion, with a $2.0 billion cost anticipated in the case of a seven-year drought. However, when an assumption of high import prices are incorporated and coincide, and are modelled as being sustained throughout the drought periods, the estimated cost of a drought may, in the view of the Board, be significantly higher.

The Independent Experts also recommended that MH not solely rely on retained earnings as the only buffer against a drought, but to also incorporate a reservoir storage buffer as a mitigation measure.

Evidence was presented at the hearing modelling varying duration of droughts, including efforts to ascertain the implications of droughts with durations longer than five years. During the period of 1928 to 1941, MH experienced low water flow conditions in 12 of the 14 years (this reflective of an extreme drought condition). While no estimate was provided as to the impact on MH if such a prolonged drought now occurred, it seems obvious that a repeat of such difficult conditions would have a significant financial impact on MH.

A similar situation occurred during the 1980/81 to 1991/92 period, with ten out of 12-years of drought, but the financial consequences at that time were much lower than would now be expected, particularly if the new export contracts were consummated. During that period, MH's exports to the United States were not a major factor.

On the issue of drought frequency, it may not be essential to define the return period of a 5-year or 7-year drought (by "return period", the concept is how many fiscal periods would be expected to have to occur before the losses were recovered). However, it is appropriate that MH's business strategies be tested against the entire historical drought experience, an experience that includes the 1928-1941 period, when 12 of 14 years were drought conditions.

Even after establishing the volumetric drought risk, the question that remains is what import prices should be expected in the case of an extended period of low hydraulic generation. The concept of shortage pricing is broadly acknowledged (when a shortage develops and the supplier seeks to meet demand through alternate sources, the price of obtaining the supply may be far higher than the normal cost of production for the supplier), but differences exist on whether volumetric shortfalls and shortage pricing are mutually exclusive and independently variable, or whether the two events are closely linked.

It could be postulated that for MH's export business shortage pricing is unlikely to occur and only be an issue in the absence of adverse or low water supply situations. In negotiating long term contracts, again yet to be shared with the Board, MH has advised that it has obtained 'price cap' clauses applying to the purchase costs of energy or buy-back costs that might be occasioned under 'adverse water' conditions. This suggests that shortage pricing could be a serious issue, otherwise why would MH simply not rely solely on the MISO market for imports as well as exports?

Droughts are expected to result in negative financial implications when MH's long term contracts are reliant only on hydraulic generation (and do not involve thermal and wind generation). In addition to being less profitable, dependable energy sales, and also peak opportunity sales, in volumes in excess of hydraulic generation can involve comparably priced energy purchases under the best of circumstances (while they can result in significantly greater financial losses for MH under adverse – low water flow - water conditions).

4.6 Financial Risks

Among the many and diverse high consequence risks faced by the Corporation (risks which include drought, the loss of export markets, and infrastructure – transmission or generation - failure), MH has also identified financial risks associated with interest rates and exchange rate volatility.

MH has indicated that a 1% upward change in interest rates can be expected to have a $170 million negative impact on its net income over an eleven year period. The analysis arriving at that forecast was based on using MH's IFF 07-1 as the base case and applying a 1% increase in interest rates to derive the interest rate risk scenario. MH compared the effect to its IFF 07-1 net income forecast for the fiscal period 2007/08 to 2017/18 (that being the base case employed to test the resultant total net income impact of a 1% upward and sustained movement in interest rates).

MH also provided an updated risk analysis for 2010, with an updated cost consequence related to a change in interest rates. The financial exposure risk was updated to approximately $430 million negative for a 1% increase in interest rates over a ten-year period, this up substantially from the previous estimate of $170 million.

The current higher estimate was likely based on MH's IFF 09–1 and, accordingly, has not reflected the more recent projection of higher capital costs for MH's planned major generation and transmission projects (the increase in projected capital costs being in the order of $3.5 billion).

Accordingly, the negative financial consequence of an increase in interest rates of 1% is likely to be even higher than the current estimate of $430 million over a 10-year period, and would have further negative financial implications over a 20-year term through to and including fiscal 2029/30.

Currently, MH has in excess of $7 billion in long term debt, the majority of which is locked in for terms as long as 30 years. As previously indicated, MH is planning, and acting currently on those plans – expending significant sums ahead of regulatory approvals, to undertake an ambitious capital expansion program requiring additional borrowings of $15 billion or so over the next fifteen years.)

With current interest rates, particularly short-term rates, being quite low, MH is forecasting long term interest rates to be 6.6% (excluding the provincial debt guarantee fee of 1%) by fiscal 2016/17, with that rate to remain constant to and including fiscal 2029/30.

MH is also at risk to economic losses due to unfavourable foreign exchange movements with respect to the Canadian dollar (CDN) vis a vis the United States dollar (USD).

Export sales to U.S. counterparties are denominated in USD, as is a component of MH's long term debt. MH's risk exposure to USD/CDN changes primarily arise through the sale and purchase of electricity and fuel into and from U.S. firms.

MH attempts to "manage"/offset the exchange risk through a long-term "natural hedge" involving USD cash inflows from export revenues and USD cash outflows for long-term debt interest and principal payments. MH's Exposure Management Program (EMP) is designed to match cash outflows for USD debt [principal and interest] with cash inflows from net exports sales (export sales net of U.S. fuel and power purchases).

To bridge the timing differences between the inflows and outflows of USD requirements, MH may utilize various financial instruments, including derivative foreign exchange contracts, debt, investments, swaps etc. Nonetheless, MH has estimated the potential negative financial impact of a reduction in the value of USD compared to CDN to be approximately $125 million over a ten-year period.

While presently CDN is valued above par with USD, MH is forecasting the US-CAD exchange rate to rise to 1.04 by 2012/13, 1.09 by 2014/15, and to 1.11 by 2015/16, with the 1.11 ratio to continue through to the end of MH's 20-year forecast. (In other words, MH's currency forecast has the Canadian dollar below par with the USD throughout the twenty year period.)

Currently, MH's accounts include within its equity component Accumulated Other Comprehensive Income (AOCI), that balance largely represented by "unrealized" gains on foreign exchange. MH borrowed funds in USD in the past at exchange rates much different than is currently the case, and the "current market value" ascribed to those debts is much lower expressed in CDN that it was when the debt was incurred. This situation also is assisting MH when it pays interest on American debt, converted to CDN the cost is less than the "coupon rate" of the debt.

As present unrealized gains on foreign exchange are realized through annual payments of principal and interest, the "gains" are expected to offset by the countervailing effect of exports to American counterparties being priced in USD. In short, it would appear that AOCI is but a temporary "credit" component of equity as its value will diminish and eventual be extinguished through lower values of export sales that would have been the case if the CDN/USD ratio had not changed.

And, going forward, while export sales to American counterparties will continue to be priced in USD, or so it appears, there is no guarantee that further downward movements in the USD ratio to the CDN to offset the loss of revenue will occur. As well, there is no guarantee that MH will continue to borrow in USD at the same rate as it has in the past.

A more detailed discussion and analysis of the financial risks, interest rates and currency, faced by MH will be provided in the second Order.

4.7 Power Resource Modelling

MH employs a fairly extensive array of models to define energy, energy demand and net revenue streams. MH models were the focus of much study and commentary ever since the 2003/04 drought event, and particularly in the recent proceeding.

There appears to be a reasonable consensus (among the various experts that testified in the hearing) that MH's models are more effective in defining and considering the effects of high flow circumstances than defining and considering the effects of low flow circumstances. Except for MH's 2003/04 fiscal year, the available data essentially reflects above average water flow situations. Prior to 2005/06, market price information did not readily provide peak and off-peak volume and price data, inhibiting the back-testing of drought events such as the drought of 2003/04.

A common theme in the various reviews was that the models lacked hydrologic predictive components and instead relied on antecedent forecasting. Lack of consistency in model assumptions was also a concern.

The use of the assumption of "perfect foresight" in MH's SPLASH modeling allows reservoirs to be drawn down to zero storage; a situation that would not be acceptable in MH's HERMES model. The result is that SPLASH-based IFF revenue projections may be overstated.

Unlike SPLASH, HERMES employs only "limited foresight": that is, hydrologic run-off predictions based on previous precipitation levels is not a direct factor in MH's forecasting of hydrologic generation. Evaporation losses are not actually determined on an ongoing basis, rather average conditions apparently are assumed for this and ungauged local stream flows.

It was noted by the Independent Experts that MH's various models (SPLASH/HERMES/PRISM, etc.) lack an integrated platform. The Independent Experts suggested that the lack of a common/integrated platform left uncertainty as to the consistency of the assumptions employed in the various models.

All of MH's recent external reviews (particularly KPMG, Independent Consultants and NYC) focused on the need for MH managing a more transparent operation, particularly as it relates to having an effective "middle office" function. The middle office is intended to operate as a check to the sales operation, to ensure that sale and purchase decisions from external counterparties are in MH's best interests. A strong middle office, with a defined mandate and a broader expertise in staffing, was seen as an essential step to assure appropriate MH Power Resource Management, Drought Mitigation and the derivation of other risk element evaluations.

Again, in the second Order more will be said on this topic.

4.8 Interveners and Positions on Rates

CAC/MSOS submitted that the Board eliminate the 2% interim rate increase for 2011/12, or at least cut the increase in half. CAC/MSOS asserts that the evidence does not support the increase.

MIPUG submitted that the Board should given final approval to the 2010 – 2.9% and 2011- 2.0% interim increases as granted, but with proposed rate adjustments between customer classes incorporated to reflect MIPUG's position respecting required rebalancing based on differences in revenue to cost coverage ratios.

RCM/TREE submitted that the Board should give final approval to the 2010 – 2.9% and 2011 – 2% interim increases as granted, and requested by MH, and the Board should add a further 0.9 of 1% from the date of the Board's order for a rate increase of 2.9% forward for the balance of the 2011/12 year. RCM/TREE also proposed rate structure changes for the residential class.

The City of Winnipeg submitted, in agreement with the position of MH, that no increase in rates be applied to its rate category of Area and Roadway Lighting; the City took no position on the general issue of rate increases.

SCO submitted that if the Board approves the interim rate increases for 2010/11 and 2011/12, those revenues arising from the increases should be set aside and earmarked for all Manitoba First Nations, to be used as a compensation fund. MKO made no submissions.

It is fair to say that, in general, all participants await the outcome of MH's pending Cost of Service Study (COSS), and all interveners see the need to have further input on rate design/rate class issues. MH seeks across the board increases at this time (as noted), excluding Area and Roadway Lighting, given that the COSS is not complete.

5.0 Board Findings

Two Rate Orders

As previously indicated, on December 1, 2009, MH filed its 2010/11 and 2011/12 GRA.

The proceeding that followed included a detailed review of MH's risks and risk management as practised by MH, and spanned a period of 19 months and involved 41 hearing dates (not including pre-hearing conferences and three days of closing statements) and the filing of 27 binders of information (including over 5,300 filed interrogatory responses, over 200 exhibits, and testimony from several expert witnesses), all providing an extensive record of the proceeding for the Board to evaluate.

While the record of the hearing is extensive, it is, unfortunately, not complete. MH has failed to provide export contracts, financial projections, alternative development scenarios and other information requested by the Board, despite the Board's need for the information to allow for a finalization of various interim decisions, and the Board's commitment to maintain commercially sensitive information confidential.

During the course of the proceeding, and particularly concerned with the risks faced by the Corporation in difficult and uncertain economic conditions, the Board granted MH interim rate increases of 2.9% effective April 1, 2010 and 2% (rather than the 2.9% applied for) effective April 1, 2011, both of which Orders MH now requests be finalized.

In addition, MH has requested a further 0.9% rate increase; in seeking the additional 0.9% MH requested that the additional rate increase be approved effective August 1, 2011.

To respond to MH's requests, the Board will issue two Rate Orders. This first Order addresses issues on certain rate and risk related issues, with the second Order to provide a much more detailed and comprehensive review of the issues before the Board (the issuance date and comprehensiveness of the second Order cannot be assured at this time, dependent in part on whether the Board receives information it deems necessary and within its jurisdiction to receive).

Rates

Particularly since the 2003/04 drought, the Board, MH, along with certain Interveners, have recognized the importance of MH having an adequate and stable financial structure.

While the Board retains serious concerns with how MH calculates the equity component of its debt and equity ratio, the attainment of MH's target ratio of 75:25 (debt to equity) was not, at the 2008 GRA proceeding, envisioned to occur within the then 10-year planning horizon. And, at that time, the anticipated result of achieving the 75:25 target was the expectation of modest annual rate increases to follow, to reflect general inflationary pressures, no more.

While, with the filing of this GRA, MH asserts the achievement of the 75:25 debt-to-equity target, this coming four years in advance of the most previous target date, rather than annual "inflation level" rate increases to follow, MH is now seeking rate increases of 2.9% in both 2010/11 and 2011/12, and projects further rate increases of 3.5% per year for each year of the following decade, to be followed by annual rate increases of 2%, the 2% level coinciding with the target of the Bank of Canada for inflation.

The years of 2.9% and 3.5% projected annual rate increases coincide with the decade that MH would have marked by the construction of major new generation and transmission investments, advanced ahead of Manitoba demand requirements to meet expected and presumably profitable U.S. export contracts.

MH acknowledges that its operations involve risk in virtually every aspect of the Corporation's operations. As one and a major component of a plan to mitigate risks, the assumption has been to achieve the 75:25 debt to equity ratio and hold it there through inflation level annual increases thereafter.

However, as indicated above, MH's planned "decade of investment" (to involve major capital construction at a cost of $20 billion or more), despite larger annual rate increases than previously thought required, once the 75:25 debt to equity ratio was reached, is now projected by MH to deteriorate to 83:17, before fully recovering following several years after the in-service dates of the planned major construction.

In determining whether or not, particularly in the circumstances now in "play", MH's capital structure and rate proposals mitigate the various and serious risks faced by the Corporation, the Board reviewed MH's risks and risk management in this proceeding.

It has become very clear that a major risk is associated with MH's planned "decade of investment" (to be supported by sought-after long-term energy sales to American counterparties). The capital costs of the new generating stations, to be built well ahead of domestic load requirements, and transmission are very high, and while the planned new export contracts bring significant obligations they, perhaps, do not produce enough assured revenue to avoid higher domestic rate increases than may be acceptable.

Manitoba Hydro's historical record of having domestic rates that are the lowest or among the lowest in North America has been described as the *Manitoba Advantage*. And, despite these low rates, Manitoba's cold weather and the lack of province-wide availability of natural gas mean that some customers, particularly lower income households, receive electricity bills that they have difficulty paying (some 80,000 or so accounts are apparently delinquent following any billing date – being delinquent does not mean the account ends up written-down or off, but it does infer late payment fees).

In addition, large industrial consumers, represented by presenters at MH GRA hearings, have often cited the importance of Manitoba retaining low electricity rates to their operations remaining and expanding in the Province.

Rate increases above the rate of inflation are regularly opposed by consumer advocates, including an Intervener to this hearing. And, MH currently projects just that through its planned "decade of investment". It is far from clear whether the risk tolerance level of MH matches that of its customers, particularly its household and industrial customers.

It is also far from clear for the Board, which has yet to receive (in confidence) MH's export contracts, whether MH's proposed new export arrangements can be expected, if not assured, to generate enough additional revenue to fully meet the cost of advancing new generation ahead of domestic need, or whether, in the end, domestic customers will end up subsidizing exports to the U.S.

And, with respect to Bipole III, while the Board readily identifies with the vulnerability of southern Manitoba, in particular, to outages caused by the failure of Bipole I or II or both, and understands the Corporation's focus on reliability, the Board is, despite the hearing, still not assured that the costs of the new transmission will be met by net export profits and not have to be absorbed by domestic customers through rate increases higher than those now projected.

The Board notes that MH's plan (major construction and new export sales) preceded the negative economic events of the summer and fall of 2008, which involved a credit crisis and the beginning of a global recession that still "lingers". It also preceded changes in the American political landscape, where the focus has moved from "climate change" and efforts to reduce green house gas (GHG) emissions to pressing economic and budgetary challenges.

This said, the Board observes that American politics is a volatile environment and a resurgence of support for measures to reduce GHG emissions could reappear in the future. Currently, America is locked in a critical debate centered around its federal budget and an ongoing slow recovery from the recession.

However, it is the Board's understanding that MH's recent export contracts, conditional upon regulatory approval and the construction of new generation and transmission by MH and the construction of new transmission by the American utility counterparties, provide for the exporting of power for a considerable length of time with any “clean energy” credit that could develop to accrue to the benefit of the American counterparties, not MH.

To further complicate the situation, since MH entered into term sheets in 2007 and 2008 with American counterparties, new engineering methodology has allowed for the affordable extraction of natural gas from North American shale deposits, further depressing the price of natural gas (already depressed by the slow recovery from the recession), which affects the marginal cost of production of electricity within the American component of the MISO market.

(The Board notes that the production of shale gas from shale deposits has been associated with negative environmental consequences primarily associated with the use of water and the condition of such water after its employment in gas production. Accordingly, the Board cannot be “sure” that the shale gas “revolution”, described as a “game changer” by academics, producers and others, will be realized as now anticipated.)

Yet, despite all of the changes that have occurred since MH developed and put into action its preferred development plan, which counts on new export contracts, changes which also extend to the rise of the Canadian dollar to above par with the respect to the American dollar, and hyper-inflation with respect to major construction projects, MH has not changed its “game plan”.

The main question before this Board is whether MH’s “game plan” will require higher domestic rates than MH projects. At this point, and with the information that MH has provided the Board, while the “jury is still out” the Board has serious concerns.

Through this proceeding, the Board gained the understanding that the approximate cost of creating and supplying the energy to service the planned export contracts from major new generation projects is estimated to be in excess of $0.10/kW.h. However, the record of the proceeding also indicates that the expected export prices, which include not only firm energy obligations and opportunity export sales, may not, in aggregate, be sufficient to cover the cost of advancing the projects ahead of domestic demand, leaving a financial shortfall to be reflected in the rates of domestic ratepayers (that being in addition to the rate increases currently forecast by MH).

In order to appropriately assess the risks faced by domestic Manitoba customers. The Board first requested and later subpoenaed copies of MH's new export contracts, this to allow the Board to assess whether the prices and the terms in the contracts either mitigate or increase risks for domestic ratepayers. The obtaining of the export contracts is currently subject to procedural motions; to-date, the Board has not yet been provided with the specific information requested.

The appropriateness of the current 75:25 debt-to-equity target is predicated on the Board's understanding of MH's risk profile, and, as well, the Board's acceptance of MH's calculation of its equity. As to the terms of the new export contracts and the implications for the risks assumed and rates to be assessed domestic ratepayers, these have not been fully assessed by the Board, given the withholding of the subpoenaed contracts and the failure of MH to provide a fully updated IFF and additional development scenarios.

Thus, the Board is currently unable to determine whether the interim and the requested additional rates are just and reasonable.

Therefore the rate increases granted on an interim basis in this proceeding will remain interim, subject to finalization, amendment or further continuation as interim until such time as the Board has sufficient information to reach a further decision. As well, and for the same reason, the additional rate increase sought of 0.9% across all rate classes will not be granted at this time.

The capital expenditures and planned capital expenditures and the related export contracts have a direct financial bearing on domestic rates and speak to whether MH's projected rate increases through to fiscal 2028/29 are likely to be sufficient to meet the growing capital and other associated costs of the new generation and transmission projects required to service the export contracts.

MH has expended hundreds of millions already on its "preferred development plan", a plan yet to receive regulatory approval on either side of the Canadian-U.S. border. MH continues to spend to "protect" the in-service dates required to meet the obligations of its new export sales contracts.

Regardless of the "good faith" and "good intentions" likely attached to this pre-spending, expending massive funds ahead of final regulatory approval appears to represent speculation, and, given the hundreds of millions that have been spent and the ongoing spending, a degree of speculation rarely found with private utilities, let alone Crown Corporations.

If the plans do not work out, then the pre-spending may well have to be "written off", with implications for rates and the current generation of ratepayers.

These interim findings may be continued or otherwise varied in the Board's next Order.

Operating Results

The Board notes that MH has projected an improved financial position from that it reflected in its IFF 09–1, and accepts that, on the surface of the evidence before the Board, MH has reached its long-sought 75:25 debt to equity ratio. Assuming Board acceptance of the methodology employed by MH to derive its projected debt to equity ratio, a methodology the Board currently continues to question, the Board would have to question the need for any further rate increases other than that required to sustain the capital structure.

The planned major Generation and Transmission projects required to support the announced new export contracts reflect seemingly ever-escalating capital costs, which, pursuant to the filings made by MH, are expected to result in the debt to equity ratio forecast deteriorating from the current asserted 75:25 to 84:16 for fiscal 2020/21.

And that "weakened" projected capital structure is predicated on the Board providing consecutive annual rate increases that compound to reflect an overall increase of over 40% by 2021, and to almost 60% by fiscal 2027/28, required, according to MH's projections, just to return to the 75:25 ratio now claimed to have been achieved.

All considered, MH's business case is predicated on stepping up domestic rates by 60% from current levels to support the development of generation and transmission projects, the projects to be advanced for export ahead of domestic requirements, projects yet to receive regulatory approval.

Given the changing circumstances within the North American and MISO market, it is not clear whether the export contracts negotiated can be expected to provide sufficient revenue to avoid domestic ratepayers subsidizing export sales. A significant portion of the energy to be delivered under the export contracts will be based on spot and opportunity sale market rates, which may be depressed for some time due to reduced natural gas prices, that the result of seemingly abundant shale deposits which have and are expected to depress natural gas prices.

This in turn has and is presently expected to lower the incremental cost of generated electricity by American utilities in the MISO market, which may, as it has since 2008, depress the export prices MH realizes and may realize in the future. The Board has a serious concern as to current and potentially longer term MISO market conditions, which are outside the control of MH, and which may well have negative implications for domestic ratepayer rates.

If export revenues do not meet MH's currently forecast targets, and MH's currently planned major capital expenditures take place, MH will need to look towards domestic ratepayers to support much of the debt to be entered into to build the generation and transmission assets. Until, if possible, the risk of unacceptable future domestic rate increases can be reduced or eliminated (addressed to the Board's satisfaction), it seems quite possible that future rate increases, now forecast at 3.5% annually for ten years to be followed by 2% annually, may prove quite insufficient.

OM&A Expense

MH's forecast of its OM&A expenses assumes a productivity factor in the order of 0.5% to 1% annually (i.e. that costs will be lower by 1% in each future year due to ongoing productivity improvements – in the absence of achieving the annual productivity target, OM&A costs would, presumably, be 1% higher than MH's present forecast) in the setting of its business unit OM&A targets.

In Order 07/03, the Board stated:

> *"Corporate performance measures such as the operating and administration costs per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities."*

In Order 116/08 the Board stated:

> *"Although Hydro's operating and administrative expenses appear reasonable, the Board urges Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates of some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies. Corporate Performance measures such as operating and administration cost per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements of its operations as compared to other utilities."*

In that Order the Board directed:

> *"MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most current available data and including:*

a) *Primary key drivers of OM&A in each operational division [Board preferences to allow for a comparison with a greater number of other utilities].*
b) *Comparable other Canadian Utility data for each of the drivers.*
c) *Key comparison indicators including staffing levels.*
d) *A comparison with and discussion of industry best practices.*
e) *Potential improvement areas."*

The Board expects to be apprised of the scope of the expected study, and its advancement (in advance of receipt and review of the study, it is difficult to complete an assessment of the prudency of MH's OM&A expenditures), and anticipates being provided the opportunity to provide direction.

The Board is convinced that domestic ratepayers will benefit from the developments of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance of, if not particularly because of, the proposed major capital expansion program (that program "driving" OM&A expenses).

To-date, the Board's past and present concerns on the ongoing annual escalation of MH's OM&A expenses have not been addressed. MH has not undertaken Board-directed benchmarking studies and has deferred such studies until 2013 (when IFRS is expected to be fully implemented).

In the meantime, OM&A expenses, particularly before the capitalization and deferral of a significant percentage of such expenses, have escalated well above inflation, in part due to MH's Preferred Development Plan. The Board remains concerned with the escalation of operating expense, of which a large portion is being deferred (to be borne by future ratepayers). Such deferral has muted the OM&A increases reflected in MH's annual accounts, its GRA rate requests and domestic rates.

OM&A costs have increased in part due to MH engaging hundreds of new employees involved, in one capacity or another, in implementing – ahead of regulatory approval - the Utility's development plans. OM&A period costs are being accumulated and that accumulated amount, which grows by the day, faces the risk that it may have to be "written off" if the development plans now proposed by MH are either significantly amended or rejected.

The Board questions the sincerity of MH's commitment to rein in costs, without action rate increases above inflation remain a probable outcome. As previously indicated, MH continues to capitalize and defer a significant portion of its annual operating costs.

While this practice has been accepted by MH's external auditor and, accordingly, may be considered to be within the guidelines of what now represents GAAP, Canadian accounting standards, and leaving aside that those guidelines and GAAP are in flux as the transition to IFRS continues, the practice allows MH to report higher annual net income results than it otherwise could (if more of the now deferred and capitalized expenses were treated as period costs and charged directly, in the year of incurrence, against the net income of that year).

Though these capitalized and/or deferred costs are presently not charged against net income in the year of incurrence and do not affect either MH's retained earnings and debt to equity ratio, they do not "go away", but are simply "transferred" to future years, where the costs will be charged by way of gradual amortization against the net income of those future years, affecting the revenue requirement and rates of those years.

These issues will be discussed further in the Board's subsequent Order.

Partnerships and Wind Purchases

The contracts entered into by MH with respect to partnerships with First Nations (the partnership with respect to Wuskwatim Generation Station signed off on and with the generating station well on the way to completion; the partnership with respect to Keeyask Generation Station, being conditional on Keeyask proceeding and that requiring regulatory approvals on both sides of the border) and wind generators are based on factors that go beyond the economic.

There is an "accounting" and "business" aspect to these completed and/or pending arrangements that need to be understood. While MH "treats" the generation and direct payments to the wind farm owners as "purchased power" and intends to amalgamate the power to be generated from Wuskwatim and Keeyask within its consolidated accounts as if Wuskwatim and Keeyask were just another MH hydro-electric generation station, and will record any payments due the First Nations from future partnership net income as deductions from consolidated net income denoted as "minority interest", the accounting fails to identify nuances of some importance.

MH will incur costs that while associated with the First Nations-MH partnerships and the wind farms will neither be charged against the partnerships nor be allocated to its Manitoba wind generation purchases; those costs will simply "fall" to overall operations and so affect domestic rates. These "ignored" costs (ignored only as to recognition in respect to partnership and wind generation costs) include, at least, capital tax (which will be assessed on MH with respect to loan balances attributable to the partnerships and wind farms) and general operating and administration costs that could, fairly, be allocated to the partnerships and the wind purchases.

Power Resource Planning

The Board is not satisfied that MH has explored all reasonable power resource scenarios based on the following assumptions:

- Domestic customers and their rates are the priority;
- Domestic customers and exports share in both fixed and incremental costs; and
- Exports are an independent profit centre, separate from domestic customer classes.

In particular, the Board finds it troubling that MH has not explored in any depth natural gas (CCCT) thermal generation supply alternatives to the new major hydraulic generation and transmission projects now planned for by MH. Yet, MH chose to compare the Keeyask and Conawapa hydraulic generation options to a natural gas (SCCT) thermal generation base case scenario in 2004/05 (a time when natural gas prices were much higher than current prices).

MH's current reluctance or failure to consider CCCT thermal generation as a potentially viable option to its current development plans ignores the presently very competitive position of CCCT generation in the MISO market.

As well, to further "cloud" the present situation, MH's apparent decision to proceed with the Keeyask G.S. to serve the "announced" 125 MW (NSP)/250 MW (MP)/100 MW (WPS) export sales instead of proceeding first with the Conawapa G.S. is a significant departure from both MH's previously devised recommended development plan and, as well, the possible merits of an alternative development sequence.

MH's current plans, backed by expenditures in excess of $400 million on pre-construction Keeyask costs, appear to contemplate a power resource scenario without

Conawapa G.S. if the 400 MW (WPS) contract is not achieved. If this approach was actually taken, it seems the full benefits of Bipole III would not be realized.

With the considerable escalation of project costs for Keeyask G.S., Conawapa G.S. and Bipole III, the Board would prefer MH justify (on a Net Present Value basis) the need for and alternatives to each of these three projects.

Accordingly, the Board strongly believes a thorough 'Needs For and Alternative To' (NFAAT) process, presided over by a quasi judicial panel with independent adjudicative authority and evidence based process should address these issues far in advance of MH making final commitments to enter into its proposed export contracts, and as soon as possible to avoid further massive new investments in MH's preferred development plan ahead of a thorough NFAAT proceeding.

That proceeding should examine not only MH's preferred development plans, but also consider alternative development scenarios including the potential construction of a combined cycle natural gas generation plant, that to diversify supply, reduce drought risk and, potentially defer Keeyask, if not Bipole III.

As to the alternative of proceeding with Conawapa ahead of Keeyask, it also needs a thorough hearing.

Such a proceeding needs to have access to all needed information, including export contracts, and, as well, MH's IFF 20-year forecast needs to be fully updated, to take into account the reality of current and expected market prices in the MISO market.

The Independent Experts suggested to the Board that MH should be focused on 'least cost scenarios' in exploring future power resource and export initiatives. By this recommendation, the Board understands that the Independent Experts, as does the Board, place domestic ratepayers, reliable domestic service, and the rates domestic ratepayers are to pay in future years as the number one priority.

The Board is also concerned about MH's inability to achieve significant (if any) premiums for "clean energy" in its pending export contracts. When MH commits to providing substantially CO_2-free energy without a defined premium, it seems that there is a risk that future environment costs of importing thermally generated electricity could be expected to flow to MH's domestic customers and result in higher domestic rates.

Capital

The Board views with concern MH's infrequent updating of not only its capital cost estimates for major new generation and transmission assets but also its forecasts of spot and opportunity sales export prices. It seems inappropriate to make commitments on major projects and large export contracts when the capital expenditure forecast remains unchanged through three or four years of CEF submissions, and when issued financial forecasts do not reflect changing export market conditions.

There has been a material increase in the capital costs of MH's Major Generation and Transmission Projects, and this has implications, which include increased debt requirements and the related carrying costs (amortization of assets – the cost of which include pre-construction costs - and finance costs on assumed debt) when the projects are placed into service. These projects are being advanced to meet recently entered into export commitments.

Export contract negotiations that appear to use outdated costs of generation and transmission as a point of reference could, in the Board's opinion, seriously undervalue the total energy being sold. Belated capital cost updates will not, it appears, achieve any cost recovery from exports with respect to the additional capital costs.

The Board is unaware of any MH explicit policy or process for ensuring adequate capital investment recovery on facilities built or advanced for export purposes.

Finance Expense/ Financial Risks

Ultimately the total finance expense associated with MH's planned new major capital construction of generation and transmission will need to be recovered from future revenue as the major projects come on line and capitalization of interest ceases.

As it is, a significant percentage of MH's annual finance expense is currently being capitalized, and MH has forecast that over $5 billion will have been capitalized when all developments are complete. The Board remains concerned with the significant escalations in the capital cost for these major projects, which appear to be resulting in seemingly ever increasing borrowing requirements. Such capitalized amounts will form part of the capital base and will be need to be recovered from future revenue.

Once the major projects have been completed, the capitalization of finance expense will cease and will need to be recovered from revenue. If net export revenues are insufficient to meet all of the period costs that will begin to be recorded in MH's accounts following the in-service dates of the new assets, then domestic rate payers will be required to subsidize the investments through rates (if the debt to equity ratio target is to be maintained).

As the cost of the major programs escalate there will be, as demonstrated in the recent increase of over $3.6 billion from prior IFF 09-based estimates, both increased debt levels and ultimately higher finance costs (which may well have to be recovered solely from domestic ratepayers as the export sales prices were developed prior to the construction cost escalation).

There remains a real risk that interest rates may rise from what has been forecast by MH. Given the increases in Long Term Debt from the ever escalating cost of the Major Generation and Transmission projects, such a higher interest rate environment with the increased borrowing requirements, will further erode MH's financial strength to the detriment of domestic ratepayers. To the extent that export revenues do not materialize, interest costs do not disappear and will have to be met by domestic ratepayers.

As for foreign exchange rate risk, the Board notes that the Canadian dollar is currently above par with its USD counterpart, yet MH continues to project a weakening Canadian dollar relative to USD within MH's forecast period. In the Board's view, there is a real risk that the current exchange paradigm (with the Canadian dollar at or above par with its US dollar counterpart) may be sustained for a long period of time.

While the Board is not certain on how such an eventuality would impact MH's financial position, it is concerned that MH's current forecast of future export revenues may be overstated. As MH has experienced in the past couple years, a Canadian dollar at or above parity with its USD counterpart has resulted in lower realized export revenues.

MH's preferred Development Plan is predicated on export revenues derived from the new export contracts with US counterparties to support the costs incurred to build the Major Generation and Transmission Assets required to service them. A weakening USD would place further pressure on MH, which may then have to seek to recover any shortfall from domestic ratepayers.

The Board will require MH to provide a full analysis of the implications of a Canadian dollar at or above parity on its long-term Preferred Development Plan.

Domestic Load Forecast

With MH's forecast of domestic load being down by 1,400 to 1,800 GWh, the unit revenue (rate per kWh) would have to increase to retain MH's forecast of future annual electricity revenue. However, MH has not made any significant adjustment to its projection of domestic rates and MH's forecast of total residential and commercial load was identical in IFF 10 and IFF 09-1. MH has yet to explain how this is possible.

The Board is unable to reconcile MH's domestic load forecasts with domestic revenues and is concerned that MH's forecast domestic revenues may be overstated.

In MH's Recommended Development Plan, (IFF 09-1 assumptions) Keeyask G.S. had an in-service date of 2019/20; in the Board's view domestic load, only, would have required a 2021/22 in-service date, and now with the reduced domestic load forecasts a 2025/26 in-service date could be more appropriate.

It is the Board's view that MH's most recent domestic load forecasts for the longer term:

- Do not adequately recognize the longer term implications of the recent economic downturn;
- Are overly optimistic, given the stagnation (lack of growth) over the last five years in the load of the industrial sector - particularly when coupled with an actual major pulp and paper plant closure and imminent announced smelter and refinery closures; and

- Do not support the significantly advanced dates for new generation, but rather, in the absence the new export contracts, suggest a 2025/26 in-service date is required to meet domestic load.

The Board understands that the recent MP and WPS announced contracts essentially commit MH to building Keeyask G.S. by 2020/21. This is about five years earlier than domestic load requires.

Export Contracts

Without access to MH's new export contracts, the Board continues to see these ventures as potentially unfavourable risk issues. There is no certainty that the revenue streams from those announced contracts will cover the incremental revenue requirements of new generation and transmission.

The Board does not see that the volumetric drought risks are being reduced with the new export contracts. Cost consequences of a drought may well be greater with the contracts in place. As of now, the question is open for debate, as there are experts that say the consequences of a drought with the new export contracts should be lower.

However, these experts have all seen the export contracts and are, presumably, relying on MH's, and perhaps their own, interpretation of the Adverse Water clauses. Because the Board has not seen the contract to verify the salient terms, the Board advises that it may change its view after it receives and has reviewed the contracts.

Export Revenue Pricing

It is the Board's understanding that MH's IFF 09-1 forecast (particularly for electricity export revenues) was based on 2008 circumstances, and, presumably, employed ICF predicted natural gas prices. The forecast predated the advent of shale gas and lower natural gas prices, the collapse of CO_2 emissions charges and the severe economic downturn that has transpired in the U.S. economy.

With ICF's revised (October 20, 2010) natural gas prices being 30-40% lower than its 2008 forecast, projected electricity prices with respect to the fuel cost portion of CCCT generation may well be lower by a comparable amount. (If fixed costs were included in the IFF assumptions, the forecast electricity price would be about 25% lower, rather than 30-40% as projected by ICF).

While MH has declined to provide an IFF using the export electricity pricing assumptions advanced by the Board (PUB/MH/PREASK-4), MH has not refuted the proposed pricing scenario, which, at about 65% of IFF 09-1 pricing assumptions, are in the Board's view relatively consistent with ICF's revised natural price forecast when applied to CCCT generation fixed and variable prices.

In the absence of any significant MH downward revisions of export market electricity prices to reflect the drastic shift in the forecast cost of CCCT thermal generation, the Board has elected to address this issue by postulating two alternative electricity export pricing scenarios. These are not the only, or necessarily correct, views of MH's export market over the next 15 years.

And, at 75% and 65% of MH's IFF net export revenues assumptions, the Board's price forecast could be viewed as somewhat pessimistic if not very pessimistic as to a recovery of past and higher MISO Market electricity prices.

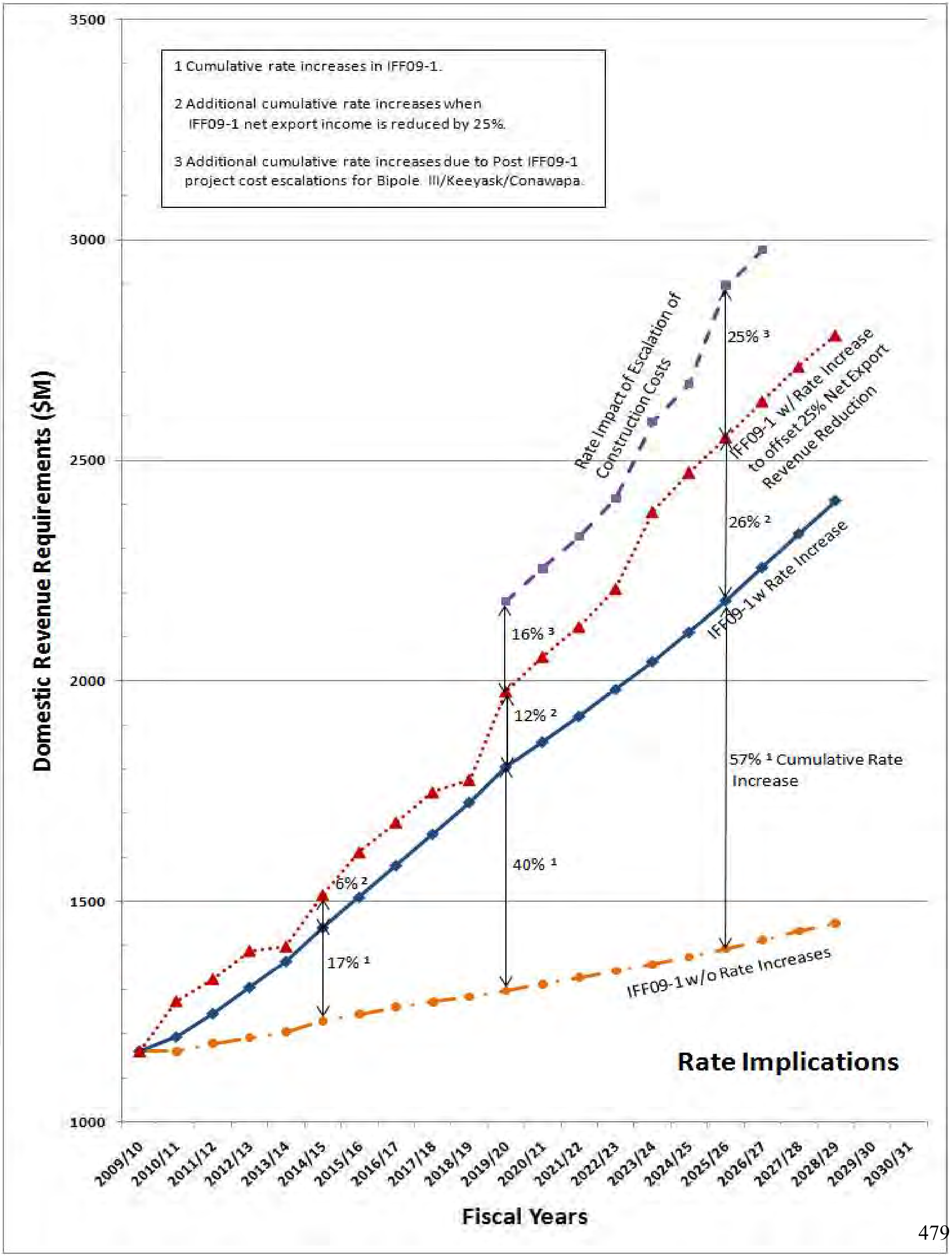
In Chart 2, which follows below, the lower line (red-dashed) projects MH's domestic revenue in the absence of any domestic rate increases over the next 20 years. The next line up (blue-solid) illustrates MH's IFF 09-1 based domestic revenues with MH's projected rate increases (2.9% to 3.5%/year, annually). In 2025/26, such an eventuality would be expected to result in overall domestic revenue of about $2.2 billion (57% of which would arise from rate increases).

If, as a result of ICF's projected lower natural gas price forecasts, MH's export revenue projections of IFF 09-01 were reduced by 25%, this would negatively affect IFF 09-1 projections for net income, retained earnings and MH's debt:equity ratio. Accordingly to meet MH's targets of its IFF 09-01, domestic revenue would have to be increased as shown in the 3rd line from the bottom (red–dotted). In 2025/26, such a scenario suggests that domestic revenue of about $2.25 billion would be required (which would represent another 26% increase from the 57% projected by MH in IFF 09-1).

This upper line (blue-dashed) models the required addition of domestic revenue that appears to arise from the major project price escalation that has developed since MH's IFF 09-1 forecast. In 2025/26, recognition of this factor suggests that the domestic revenue requirement would be approximately $2.85 billion (up a further 25% from that projected by MH).

Chart 2

Domestic Revenue Requirements and Rate Implications (75% of IFF 09 Export Revenue Rates)



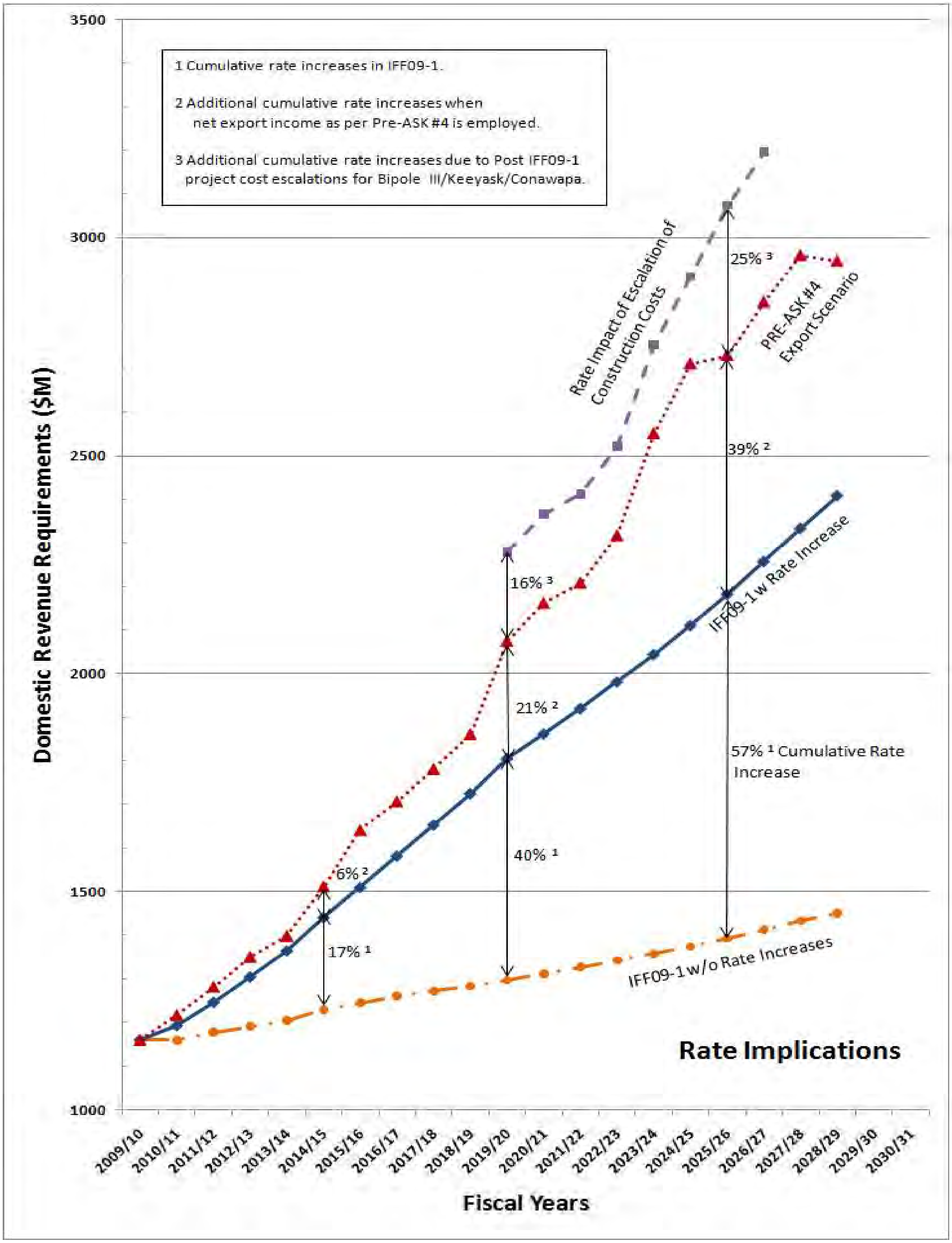
In Chart 3, which follows, the lower line (red-dashed) projects MH's domestic revenue in the absence of any rate increase over the next 20 years. The next line up (blue-solid) illustrates MH's IFF 09-1 projected domestic revenues with MH's projected rate increases (2.9% to 3.5%/year). In 2025/26, MH's assumptions project domestic revenue of about $2.2 billion (57% of which would come from rate increases).

The third line (red-dotted) on the chart illustrates the domestic revenue requirement if export revenues were consistent with the export/import price scenarios PUB requested MH provide in PUB/MH-Pre-ask #4, and if MH's IFF 09-1 targets for net income, retained earnings and debt-equity were to remain unchanged. In 2025/26, this assumption requires domestic revenue of $2.7 billion (up another 39% increase from the 57% projected by MH in its IFF 09-1).

The upper line (blue-dashed) indicates the additional domestic revenue requirement that would presumably result from meeting the major project cost escalation that has occurred since IFF 09-1 was developed by MH. In 2025/26, recognizing this development would require domestic revenue of about $3.1 billion (up a further 25% from the 57% modelled by MH's IFF 09-1 and the 39% projected by the presumed response to PUB/MH-Pre-ask #4).

Chart 3

Domestic Revenue Requirements and Rate Implications (PUB/MH Pre-Ask #4 Export Revenue Rates)



These charts suggest that MH's IFF 09-1's rate increase assumptions may prove significantly too low if ICF's lower natural gas prices "prevail" and MH's latest capital estimates are realistic. It is possible that actual domestic rates could be more than doubled over the next two decades if the Board's modelled assumptions were realized.

In the Board's view, MH's IFF 09-1 and IFF 10-2 export price assumptions are not reflective of the current and likely near-term energy market. As such, the suggested progression of rate increases for domestic customers may well not be adequate to cover, even after taking into account projected additional export revenues, the costs of MH's CEF 09 Major Capital Expenditure Program. And, when the latest major project cost escalation is considered, the potential revenue insufficiency appears to be substantially magnified.

Export Revenue Pricing

In Board Order 116/08, it was the Board's opinion that MH's export revenue pricing forecasts provided in the preceding 2008 GRA, and in MH's 2008 Energy Intensive Industry Rate (EIIR) application, were overly optimistic. Prior to 2008/09, MH's forecasts counted on future high natural gas supply prices (forecast to continue to rise and anticipated an early introduction of substantial CO_2 emissions pricing. These are no longer realistic expectations.

IFF 09-1 export revenue pricing (based on advice to MH from an external consultant panel, which, as previously indicated, included ICF) was prepared in 2008 and neither reflected the lower natural gas prices with shale gas availability now being experienced nor the evident major resistance to CO_2 emissions pricing in the U.S.

ICF testimony at this hearing provided a much lower future natural gas price outlook and suggested that a substantial deferral of CO_2 emission pricing would take place. Despite this, MH did not significantly alter its IFF 10 Export Revenue Assumptions from those MH employed in IFF 09-1. Notably both ICF and KPMG indicated that, pursuant to their terms of reference, which were provided by MH, they did not challenge MH's views on market energy prices. Apparently, neither ICF nor KPMG nor the Independent Experts had access to MH's IFF market price derivations.

The Board also notes that MH declined to provide any alternative IFF scenarios based on the now obviously lower natural gas prices and absence of CO_2 emissions regulations.

Overall, the Board does not accept MH's export revenue forecasts to-date as representing a realistic basis for determining the economic viability of MH's proposed new major generation and transmission facilities, to be supported by export sales in advance of domestic load requirements.

Implications for the Domestic Revenue Requirement

Based on the evidence in this proceeding, the Board suggests that the cumulated rate increase required of domestic customers would, by fiscal 2025/26, be significantly greater than the approximately 60% (57%) forecast in IFF 09-1, and, more probably, the cumulated rate increase in 2025/26 could be in the 100% to 120% range (roughly double MH's forecast).

In the next MH rate application, the Board will require MH to file a revised 20-year electric IFF, reflecting as of December 31, 2012:

- Updates to construction costs;

- Projected extra-provincial gross and net revenues;
- Projected domestic and export loads;
- Projected net income;
- Debt equity ratios;
- Projected retained earnings; and
- Projected future domestic rate increases (2012/13 to 2032/32).

Further to the above, the Board will also require MH to analyze and file the implications associated with limiting annual domestic rate increases to 2%, using a 7% discount rate net present value analysis of MH's Development Plan.

This should indicate the adjusted:

- Projected net income;
- Debt/equity ratios; and
- Projected retained earnings.

Drought

Without going into a detailed litany of the various critiques of MH's drought risk processes issued by various parties since 2003/04, the Board is convinced that there are many areas of MH's Drought Risk Management processes that could be improved upon.

These include a more open and transparent management of volumetric risks and price risks. As well, annual post-mortems (back-testing of decisions) should be normal practice. (The Board, in its 2004 GRA Order directed MH to provide such a post-mortem of its actions through the drought of 2003/04, that report was never filed.)

In the Board's view, and in the Board's present predicament of not being privy to MH's export contracts, MH's export business model does not appear to be the assured profit generator that it may have been in past decades. Specific concerns relate to what appears to be MH's misconception that export sales are always profitable when they exceed water rentals and transmission losses; subsequent repurchase costs and the need for export contributions to embedded costs seem to be ignored.

The Board cannot be sure that MH's drought management actions in the period 2002/03 to and including 2004/05 were optimal, when a $436 million net loss required a rate increase aggregating 9.5% to restore MH to its financial targets. That result cannot, in the absence of detailed post-mortem review, be considered ideal. MH should be looking to do better in the future than it did in 2003/04.

In a response to an interrogatory submitted by the Board, MH responded that it would file a written Drought Preparedness Plan by April 1, 2011; MH did not. In cross-examination, MH suggested that a written plan was not needed as MH reacts "everyday" on the basis that a drought could be starting, and it would be difficult to reduce all of MH's experiences into a written plan, when MH has to plan given an infinite number of variables. However, another MH executive appear to over-rule the other executive by indicating "…(it) would be a good idea to have a written drought preparedness plan… "

MH was disingenuous in its response to the Board's interrogatory and it remains to be seen if the Corporation will follow through on its written evidence and oral testimony by a Vice-President.

The Board recommends MH act to meet the urgent need for such a document.

There appears to have been a prodigious amount of study and analysis since 2003/04 (KMG, ICF, Independent Experts, 2008 and 2010 GRA) on MH's risk practices and management. Further work is still warranted. The severe consequences that can attend a drought or less than optimal decisions on major capital projects and export contracts require the attention now apparently being given to the risks.

Power Resource Modelling

The Board accepts that there have been valuable insights gained from the rather extensive number of experts involved on the broader risk issues since the 2003/04 drought event. Significant contributions were made by the following:

- Risk Advisory (engaged by MH);
- Manitoba Water Stewardship Expert Panel (Wuskwatim Hearings);
- NYC (initially engaged by MH);
- Dr. Bhattacharyya (engaged by MH);
- ICF and KPMG (engaged by MH); and
- Independent Experts (engaged by the Board).

The Board has been given to understand that MH has and will be acting on many of the recommendations made in these various reports. The Board sees a need to verify the status of those changes and to seek assurance as to further improvements to MH's modeling process.

Despite an extensive and protracted process that involved numerous experts, there is still no clear indication of the appropriate level of retained earnings required as a drought reserve. While MH does not formally target a specific level of retained earnings, or provide for a specific drought reserve, achieving and maintaining a debt-equity ratio of

75:25, debt to equity, is viewed by MH as the best way to financially position itself for a severe drought, such as has been experienced within the historical record.

The Board has heard recommendations and commentary about:

- Dedicated drought reserve;
- Greater energy-in-storage;
- Export contract value-at-risk reserves; and
- Domestic rate-riders to track export price volatility.

In the Board's view, none of these absolutely preclude the diversion to other purposes of reserves intended for drought recovery. However, the Board favours measures that may reduce the volumetric domestic and export load shortfalls and thus limit the cost impact of drought events. Such measures could include:

- More clearly defined curtailment opportunities within the long term export contracts;
- Stricter volume limits on summer bilateral agreements;
- Redefinition of dependable energy to reduce the non-hydraulic generation components that go to defining dependable surplus energy;
- Adding CCCT thermal generation units to MH's power sources to beef-up dependable generation (generation diversification, as practised by most North American electricity utilities);
- A minimum energy-in-storage policy, in effect a water reserve that cannot be tapped into except in below average flow years;
- Hydrologic predictions of potential spring runoff and potential summer evaporation losses; and

- Disclosure of annual back-testing of supply system operations and net export revenues achieved.

The Board is aware that ICF/KPMG/Independent Experts reports alluded to the ability to gain domestic rate increases (if approved by the Board) as a risk mitigation factor. This is not inconsistent with what happened after both 2003/04 drought and the 2006/07 mini-drought, where rate increases were provided to MH; increases that have provided ongoing revenues that, as a present value, has provided well in excess of the specific revenue shortfalls experienced. Ratepayers have not seen any subsequent rate relief.

Concluding Note

On a positive note, and recognizing that the in-depth risk assessment explored in this hearing (limited by MH's refusal to provide its export contracts, fully updated 20-year financial forecasts and alternative development scenarios, as requested by the Board) was partially stimulated by the dire predictions of bankruptcy and blackouts by NYC, the Board is satisfied by the unanimous evidence of all the experts heard from that such dire predictions are without merit.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

6.0 IT IS THEREFORE ORDERED THAT:

1. Manitoba Hydro's requests to finalize existing interim rates and for an additional 0.9% rate increase for all customer classes, effective August 1, 2011, BE AND IS HEREBY DENIED;

2. Existing interim rates and MH's request for a further 0.9% rate increase will be further considered and may be adjusted on a final basis in a subsequent Order of the Board;

3. This Order shall remain interim until a further Order of the Board.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE CA"
Chairman

"HOLLIS SINGH"
Secretary

Certified a true copy of Order No. 99/11 issued by The Public Utilities Board

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Secretary

Appendix A

Appearances

R. Peters A. Southall	Counsel for The Manitoba Public Utilities Board (Board)
M. Boyd P. Ramage	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams M Bowman	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./ Winnipeg Harvest (COALITION)
A. Hacault	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson (np)	Representing *Manitoba Keewatinook Ininew Okimowin*. (MKO)
W. Gange D. Rempel P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Pambrum	Counsel for the City of Winnipeg (CITY)
D. Coad (np)	Southern Chiefs Organization (SCO)
G. Wood	Independent Experts

(np)- not present at the hearing

Appendix B

Witnesses for Hydro

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Section Head, Generation System Studies, Resource Planning and Market Analysis
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
D. Cormie	Division Manager, Power Sale
L. J. Kuczek	Division Manager, Consumer Marketing and Sales
D. Rainkie	Corporate Controller, Corporate Controller Division
M. Schulz	Corporate Treasurer

KPMG Panel

W. Lipson	Partner
F. Chen	Director, Financial Risk Management
J. Erling	Managing Director, Toronto
A. Gupta	Senior Manager

ICF International Panel

J. Rose	Managing Director

Appendix C

Interveners of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors/Winnipeg Harvest (Coalition)

Manitoba Industrial Power Users Group (MIPUG)

Manitoba Keewatinook Ininew Okimowin (MKO)

Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)

City of Winnipeg (CITY)

Southern Chiefs Organization (SCO)

Independent Experts Panel

Dr. Atif Kubursi	Professor Emeritus, Department of Economics McMaster University
Dr. Lonnie Magee	Professor, Department of Economics, McMaster University

Appendix D

Intervener Witnesses

CAC/MSOS

W. Harper	Manager, Econalysis Consulting Services, Inc.
R. Colton	Fisher, Sheehan & Colton
G. Matwichuk	Stephen Johnson Chartered Accountants
J. McCormick	McCormick Financial Services Inc.
T. Carter	Professor, University of Winnipeg

MIPUG

A. McLaren	Consultants, InterGroup Consultants Ltd.
P. Bowman	

RCM/TREE

P. Chernick	President, Resource Insight Inc
J. Wallach	Vice-President, Resource Insight Inc.

Appendix E

Presenters

Mr. A. Ciekiewicz	Citizen
Mr. B. Turner	Chair, Manitoba Industrial Power Users Group
Mr. R. Rader (written only)	Managing Director, Koch Fertilizer Canada, Ltd.
Mr. John Gray	Citizen
Mr. Lynn Jones (written only)	Citizen
Mr. Norm Gruhn (written only)	Citizen
Mr. Mark Shirley (written only)	COO, Amsted Rail
Mr. Art Carriere (written only)	Citizen
Mr. Graham Starmer	Manitoba Chambers of Commerce

Tab 15

The Public Utilities Board

Report on the **N**eeds **F**or and **A**lternatives **T**o **(NFAT)**

Review of Manitoba Hydro's Preferred Development Plan

June 2014

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MESSAGE FROM THE PANEL

Manitobans have benefited from many decades of inexpensive electricity, in large part because of earlier decisions to develop the province's rich hydraulic resources. Manitobans will continue to be highly reliant on these resources for their power generation, and this Report addresses incremental additions to a hydro-dominant system.

At the same time, Manitoba's energy future is uncertain. Wind, solar and energy efficiency technologies, flattening load growth, volatile natural gas prices, climate change and the resulting impacts on water flows, and regulatory changes including the potential for carbon taxes are all creating upheaval in North American energy markets.

Faced with these uncertainties, and in light of the short time frame for the Panel to conduct the review, it would have been tempting to recommend deferring decisions. The Panel took a different route. This Report frames a new energy future for Manitoba.

The Panel expresses its appreciation and gratitude to all participants in the NFAT Review, especially the Public Utilities Board's Staff and Advisors. Any errors and omissions in this Report are solely the responsibility of the Panel.

Respectfully submitted, Winnipeg, June 20, 2014

Régis Gosselin, Chairperson

Richard Bel

Hugh Grant

Marilyn Kapitany

Larry Soldier

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Executive Summary

A. Mandate

By way of an Order in Council, on April 17, 2013, the Government of Manitoba asked a Panel of the Public Utilities Board of Manitoba (PUB) to conduct a review into the Needs For and Alternatives To (NFAT Review) Manitoba Hydro's Preferred Development Plan, and issue a Report to the Minister responsible for the administration of *The Public Utilities Board Act* by June 20, 2014. The Terms of Reference issued for the NFAT Review require the Panel's report to address the needs for Manitoba Hydro's Preferred Development Plan and to provide an overall assessment as to whether or not the Plan is in the best long-term interest of the Province of Manitoba when compared to other options and alternatives.

Manitoba Hydro's Preferred Development Plan consists of the following components:

- The 695 megawatt (MW) Keeyask Project ($6.5 billion), with a planned in-service date of 2019;
- The 1,485 MW Conawapa Project ($10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately $500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately $1 billion).

B. Key Panel Recommendations

As a result of its review, the Panel rejects Manitoba Hydro's Preferred Development Plan, as well as Manitoba Hydro's suggestion to consider pathways that map out a 78-year future, as the Panel sees Manitoba Hydro's long-term future projections as highly speculative and too uncertain.

The Panel recommends to the Government of Manitoba that:

- Spending on the Conawapa Project and the North-South Transmission Upgrade Project be discontinued immediately and the projects terminated;
- The Keeyask Project proceed with an in-service date of 2019;
- The 750 MW U.S. Transmission Interconnection Project proceed;

- Manitoba Hydro be divested of Demand Side Management (DSM) responsibilities and the Government of Manitoba establish an independent arm's length entity to deliver government-mandated DSM targets; and
- The Government of Manitoba not approve any further generation and transmission projects, or approve the commencement of spending on such projects, unless such projects have been examined through a comprehensive and regularly occurring integrated resource planning process.

In reaching its recommendation with respect to the Keeyask Project, the Panel concluded that natural gas generation does not present an acceptable alternative, as it is less economic than hydroelectric generation and relies on burning fossil fuel. Furthermore, any short-term capital cost advantages are offset by significant ongoing operating cost risk, primarily fuel costs. Similarly, wind generation does not currently represent a preferred alternative to Keeyask based on economics.

The Panel's full conclusions and recommendations are set out in Chapter 14 and described at the end of this Executive Summary.

C. The NFAT Review Process

The NFAT Review was governed by the NFAT Terms of Reference as well as the PUB's Rules of Practice and Procedure. As permitted by the Rules of Practice and Procedure, the Panel granted Intervener status to five organizations, namely the Consumers' Association of Canada (Manitoba) Inc. (CAC), the Green Action Centre (GAC), the Manitoba Industrial Power Users Group (MIPUG), the Manitoba Métis Federation (MMF) and Manitoba Keewatinowi Okimakanak Inc. (MKO).

The NFAT Terms of Reference also permitted the Panel to appoint Independent Expert Consultants (IECs) in different subject areas to examine the Preferred Development Plan, file expert reports on the record, and testify in the NFAT Review. The Panel appointed eight IECs to provide evidence at the hearing.

Manitoba Hydro filed its written NFAT Business Case on August 16, 2013 and was subject to two rounds of written Information Requests, which were in part answered through direct discussion between the NFAT Review participants and Manitoba Hydro. Evidence from Interveners and IECs was subject to one round of Information Requests.

The oral evidentiary portion of the NFAT Review started on March 3, 2014, and ended with Manitoba Hydro's closing submissions on May 26, 2014. Overall, the Panel heard 43 days of evidence.

In addition to hearing evidence, the Panel also heard from numerous Presenters, both in Winnipeg and in Thompson, Manitoba. Their Presentations are summarized in Appendix 6.

D. The Need for New Resources

The need for new electricity resources in Manitoba is determined by three things: the level of demand growth in the province projected through load forecasting, existing contractual export obligations, and any reductions in this anticipated demand that can be achieved through DSM initiatives.

Electrical demand is made up of two components: energy, which is the amount of electricity used over a period of time measured in gigawatt-hours (GWh); and capacity, which is the demand for energy at any given point in time measured in megawatts (MW).

Because Manitoba Hydro relies primarily on hydroelectricity, it is subject to water flow variations, which translate into variations in the amount of energy that can be produced in any given year. To meet Manitoba demand and firm export obligations, Manitoba Hydro relies only on dependable energy. Dependable energy is the amount of energy that can be produced during a year that mirrors the lowest-flow year in the last 100 years.

The year of need for new resources is the year in which Manitoba Hydro is first expected to experience a shortage of either dependable energy or capacity.

On its own accord and at the request of the Panel and Interveners, Manitoba Hydro analyzed the year of need based on several uncertainties:

- Whether a demand for 1,700 GWh as a result of oil and gas pipeline customers (pipeline load) would materialize;
- The magnitude of DSM initiatives and corresponding energy and capacity reductions; and
- The ability to serve export contracts, including the new Minnesota Power and Wisconsin Public Service contracts even if the Keeyask Project were deferred beyond 2019.

Based on these factors, the Panel concludes that new generation will likely be required no later than 2024. However, there are compelling economic, financial and commercial reasons to advance the Keeyask Project to 2019.

E. Manitoba Hydro's Load Forecast

Manitoba Hydro prepares a 20-year Load Forecast on an annual basis that projects demand in several customer classes, including Residential, General Service Commercial, General Service Industrial, and Top Consumers, the latter being the largest industrial consumers of electricity in the province. In its 2013 Load Forecast, Manitoba Hydro projects total demand for both energy and capacity to grow by 1.5% per year over the next 20 years. This represents a reduction from earlier planning assumptions.

Several parties criticized the methodologies used by Manitoba Hydro, but the Panel is satisfied that the load forecasting methodology is reasonable in the short term. The biggest short-term uncertainty is whether or not 1,700 GWh of new pipeline load will materialize in Manitoba. This could change the need date for new resources by a full seven years. There is sufficient evidence to assume that the pipeline load will materialize. Accordingly, it is prudent to plan for a need date on that basis.

The Panel has less confidence in Manitoba Hydro's Load Forecast over the long term, as the Load Forecast is unable to anticipate fundamental structural change that could greatly increase or decrease demand. An example of a structural change that could increase demand would be the widespread adoption of electric cars. An example of a structural change that could decrease demand would be alternative renewable technologies, such as domestic solar photovoltaic cells, which are rapidly becoming cost-competitive with traditional generation technologies. This concept is known as "grid parity."

Another long-term uncertainty is the effect of Demand Side Management (DSM), which has the potential to reduce the overall demand for electricity.

F. Demand Side Management (DSM)

DSM is the reduction of energy consumption through targeted energy efficiency and demand initiatives. DSM may also include the adoption of an alternative energy resource or technologies that may result in energy reductions (such as fuel switching to natural gas, domestic solar photovoltaic or heat pump technology). DSM is a powerful tool, as it can defer the need for new generation, and has the potential to be as economic, if not more economic, than new generation.

For consumers, DSM is attractive as it can lower their total consumption of energy, which mitigates the impact of higher rates. Consumers who fully avail themselves of DSM measures have the potential to lower their total energy bill even as rates increase.

Manitoba Hydro prepares a 3-year DSM plan, called Power Smart Plan, on an annual basis in consultation with the Province of Manitoba as required by *The Energy Savings Act*. Through DSM, Manitoba Hydro expects to offset 86% of the anticipated load growth to 2017.

In 2014, Manitoba Hydro also prepared a 15-year supplementary plan. In that plan, Manitoba Hydro expects to offset 66% of anticipated load growth to 2028/29, saving 1,136 MW of capacity and 3,978 GWh of dependable energy annually.

To place this into perspective, the capacity savings in the supplementary plan amount to more than 80% of the net system capacity addition from the proposed Conawapa Project. Similarly, the annual dependable energy savings from the Power Smart Plan exceed 85% of the dependable energy output from the proposed Conawapa Project. To achieve these electricity savings, Manitoba Hydro budgets $822 million, which is less than 8% of the $10.7 billion cost of building Conawapa.

While *The Energy Savings Act* requires consultation with respect to Manitoba Hydro, the Province of Manitoba does not currently set mandatory DSM targets.

Manitoba Hydro treats DSM as a reduction in load forecast demand, rather than as an alternative resource to meet demand projections. This approach was criticized by an independent expert and several Interveners. In their view, DSM should have the same status as generation sources, and be evaluated as such for planning purposes. The Panel shares that view.

Manitoba Hydro dramatically increased its projected DSM savings in the course of the NFAT Review. The Panel is uncertain that these projections can be achieved by Manitoba Hydro. However, this risk is mitigated by the Panel's recommendation to proceed with a 2019 in-service date for the Keeyask Project, which will provide sufficient energy and capacity to meet needs if projected savings do not fully materialize.

Manitoba Hydro's DSM targets appear to be overly aggressive in the short term, and overly conservative in the long term. While incremental DSM savings are projected to be significant in the first few years of the plan, they ultimately tail off. Other jurisdictions have reported that achieving sustainable annual incremental targets of 1.2-1.5% of forecast load is possible.

Manitoba Hydro, formerly a leader in DSM initiatives, has been surpassed by a number of other jurisdictions. Jurisdictions that are DSM leaders have separate DSM delivery entities with clear targets and accountability measures to achieve such targets. The Panel concludes that there is an inherent conflict in Manitoba Hydro being both a seller of electricity and a purveyor of energy efficiency measures. A separate externally regulated entity is required to develop and implement energy efficiency measures and monitor their effectiveness. Such an entity should be subject to regular external audits to confirm DSM savings. Examples of similar arrangements exist in other North American jurisdictions.

The electricity savings delivered through an independent arm's-length entity would constitute an additional resource available to Manitoba Hydro to meet energy needs.

G. Defining Manitoba Hydro's Preferred Development Plan

Manitoba Hydro's Preferred Development Plan consists of the following:

- The 695 MW Keeyask Project ($6.5 billion), with a planned in-service date of 2019;
- The 1,485 Conawapa Project ($10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately $500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately $1 billion).

Manitoba Hydro predicated its Preferred Development Plan on a series of executed new power purchase agreements with U.S. counterparties, specifically:

- A 125 MW system power sale agreement with Northern States Power to run from 2021-2025;
- A 100 MW system power sale agreement with Wisconsin Public Service to run from 2021-2027;
- A 250 MW system power sale agreement with Minnesota Power to run from 2020-2035; and
- A 308 MW system power sale agreement with Wisconsin Public Service to run from 2027-2036.

The 308 MW Wisconsin Public Service contract is premised on the construction of the Conawapa Project. Although the export commitments under the contract can be fulfilled with Keeyask alone, this would require a waiver by both parties of the contractual requirement that Conawapa be built for the sale contract to proceed. There is reason to believe that the contract will proceed if Manitoba Hydro can establish that sufficient firm energy will be available without Conawapa.

In addition to exports under contract, Manitoba Hydro also currently exports, and plans to continue to export, electricity into the Midcontinent Independent System Operator (MISO) market at prevailing spot market prices that vary on a day-ahead, real-time basis. Approximately 60% of Manitoba Hydro's projected export revenues are based on these opportunity sales. Manitoba Hydro's total energy exports into MISO represent less than two percent of the total energy in MISO, making Manitoba Hydro a price taker in that market.

Manitoba Hydro argued that a confluence of factors led by significant interest of U.S. counterparties in new imports from Manitoba Hydro and a strengthened interconnection created an opportunity to proceed with the Preferred Development Plan now. The Panel agrees with that argument as it relates to the Keeyask Project and the 750 MW Transmission Interconnection, but not as it relates to the Conawapa Project and the North-South Transmission Upgrade Project.

H. Pathways vs. Projects

In the course of the NFAT Review, Manitoba Hydro recognized that the economic prospects of the Conawapa Project in the near term were uncertain and encouraged the Panel to consider a "pathway" approach. This approach focuses on decisions that must be made in 2014 and acknowledges that there are other decisions that do not have to be made until a later date. Manitoba Hydro suggested that the two decisions that must be reached in 2014 are (1) whether to proceed with the Keeyask Project, and specifically, its planned 2019 in-service date, and (2) whether to proceed with the 750 MW interconnection.

Given the significant uncertainty involved in planning over a 78-year time frame, it is not feasible to approve a pathway with numerous future decision options.

I. Alternatives Evaluated

The Table below shows the 15 alternative development plans presented by Manitoba Hydro for analysis, listed in increasing order of required capital investment.

In the course of the NFAT, Manitoba Hydro took the position that several plans were no longer viable. Specifically, Manitoba Hydro indicated that any plans with a 250 MW interconnection are "hypothetical" as Minnesota Power has sought regulatory approval for a 750 MW line. This eliminates Plans 4, 11, and 13. Furthermore, Plans 5 and 14 were updated to reflect Wisconsin Public Service's unwillingness to invest in the U.S. segment of the transmission line.

Plans were analyzed through an initial economic screening. Manitoba Hydro conducted a full economic analysis on only 12 of the plans, and narrowed this down further to eight plans in its financial and rate impact analysis. In the course of the hearing, as updated assumptions became available, the list of plans was further narrowed.

Description of Manitoba Hydro's Development Plans

Plan	Short Name	Description
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW(WPS Sale & Inv)**	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW*	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan**	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

*Described as hypothetical due to Minnesota Power seeking regulatory approval for a 750 MW interconnection

**Adjusted to remove Wisconsin Public Service investment in the Great Northern Transmission Line

J. Economic Comparison of Alternatives

Manitoba Hydro has consistently taken the position that a "do nothing" approach is not an option, as new generation is eventually required to meet Manitoba demand for electricity. Accordingly, rather than analyze the 15 plans against a do-nothing scenario, Manitoba Hydro used the All Gas Plan as a baseline against which all other plans were evaluated.

Plans were subjected to different methods of economic analysis and compared to the All Gas Plan. The methods used included a determination of Net Present Value (NPV), internal rate of return and break-even year.

Over the course of the NFAT, Manitoba Hydro substantially and materially revised its assumptions, which caused the economics of the Preferred Development Plan to deteriorate. Whereas the NFAT Submission showed an incremental Net Present Value for the Preferred Development Plan of $1.7 billion compared to the All Gas Plan, the revised assumptions reduced this amount to only $45 million over 78 years. This was caused primarily by changes to the assumed capital cost of Keeyask and Conawapa as well as the assumed discount rate and increased DSM.

In contrast, a plan that involves the construction of Keeyask for a 2019 in-service date, the construction of the 750 MW interconnection, and a gas turbine in the later years of the plan, fared better. This plan compares favourably to both the All Gas Plan and the Preferred Development Plan. Deferring Keeyask to 2024 (the need for new supply in Manitoba) is less economic than to advance its in-service date to 2019. Furthermore, even if the 750 MW U.S. transmission interconnection should not receive regulatory approval in the United States, a plan that involves only Keeyask fares no worse than the All Gas Plan. As such, there is sufficient justification to proceed with a 2019 in-service date for the Keeyask Project.

There are realities of the Keeyask Project over which the Panel had no influence. Approximately $1.2 billion has already been spent on the Keeyask Project. The $3.2 billion Bipole III transmission line, which was not subject to the NFAT Review, has already received regulatory approval and will be constructed to carry northern electricity to southern Manitoba. Both of these were treated by Manitoba Hydro as "sunk costs", and therefore excluded from the economic analysis.

Conawapa's economic benefits have not been demonstrated. Furthermore, Manitoba Hydro has not put forward a business case that supports protecting Conawapa's 2026 in-service date.

Gas generation is not a preferred alternative to Keeyask, as it is at least $339 million less economic than the plan recommended by the Panel. While short-term capital costs may be lower, ongoing operating costs are higher, and the lifetime of gas turbines is only approximately one-third of that of a hydroelectric facility. This means a gas turbine of comparable size would have to be replaced twice during the lifetime of the Keeyask Project. The operating costs of a gas facility include the price of natural gas, which is volatile and forecast to increase from current decade-low prices. The burning of fossil fuels also creates significant greenhouse gas emissions, contradicting the Province's Clean Energy Strategy. Furthermore, the pursuit of the All Gas plan would not support the Minnesota Power export contract, which could lead to a loss of the 750 MW U.S. interconnection.

There are significant benefits associated with the 750 MW interconnection that go beyond the pure economics of the underlying export contract. Currently, Manitoba is interconnected with the MISO market through 1,950 MW of transmission capacity. An additional 750 MW interconnection provides increased electric reliability to Manitoba through additional capacity for imports in times of drought or infrastructure outages. The increased transmission capacity also opens new potential markets in the United States to Manitoba Hydro.

Similarly, wind power is not currently a preferred alternative to Keeyask. On its own, wind power is variable and requires backup capacity, either through a gas plant or hydraulic storage. While Manitoba Hydro's future cost projections for wind power are excessively conservative, wind power is currently less economic than other alternatives.

K. Financial Evaluation and Rate Impacts

All plans analyzed by Manitoba Hydro will require significant rate increases for a period of at least 20 years. Given the need to construct new generation by no later than 2024 and to repair or replace existing infrastructure, an approximate doubling of rates by 2032 is seen by Manitoba Hydro as inevitable. By 2032, Manitoba Hydro's projected increase in rates varies from 82% to 125% for different plans. This means that an average electricity bill in 2013 could double by 2032.

Manitoba Hydro's financial targets determine how rates are set. Targets include a self-imposed 75/25 debt-to-equity ratio. Manitoba Hydro's financial forecasts are premised on rates being increased sufficiently to allow the debt-to-equity ratio to recover to the target level over a 20-year time period, followed by lesser rate increases thereafter. During the NFAT Review, Manitoba Hydro also provided alternate suggested rate methodologies that would increase rates more gradually, with the result of pushing back the date at which financial targets will fully recover.

A doubling of rates will have a significant effect on all ratepayers. This includes not just residential customers, but also commercial and industrial ratepayers, the latter of which are sensitive to price increases as it can affect their competitive position. The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased.

While some ratepayers have the option of switching to gas heat if electricity gets too expensive, this option is not available to many other Manitobans to whom gas is not available. These customers will be especially affected by rising rates, as they are dependent on electricity to meet their heating needs.

The Panel is particularly concerned about the impact the projected rate increases will have on lower income consumers, as it heard a substantial amount of evidence about the impact of electricity rates on the lower income segment of the population. This includes customers living in First Nation communities. Manitoba Keewatinowi Okimakanak (MKO) advised that in its First Nations 86% of accounts are currently in arrears, which signals significant affordability issues. However, to a large extent, cost increases can be mitigated by aggressive DSM, which can lead to overall savings.

While ratepayers will shoulder a significant rate burden over the next 20 years, the Province of Manitoba will reap substantial incremental revenues through capital tax and water rental payments from Manitoba Hydro as a result of the Keeyask Project. The Province should give serious consideration to using some of these incremental revenues to fund energy affordability programs targeted to vulnerable consumers, particularly lower income consumers and customers residing in northern and First Nation communities. This could involve rate relief programs as well as targeted DSM programs.

L. Economic Risk Factors

i. Capital Cost Uncertainty

Manitoba Hydro prepares Capital Expenditure Forecasts (CEFs) on an annual basis. Since CEF08, prepared in 2008, the capital cost projections for the Keeyask Project and Conawapa Project have increased in successive annual forecasts. At the start of the NFAT, Manitoba Hydro's capital cost projection was $6.2 billion for the Keeyask Project and $10.2 billion for the Conawapa project. Manitoba Hydro's NFAT Business case was prepared based on these estimates.

The most recent capital cost estimates for the Keeyask Project and Conawapa Project are $6.5 billion and $10.7 billion respectively. This means that since Manitoba Hydro's NFAT evaluations were initially prepared, the projected cost for the Keeyask project has increased by $300 million and the projected cost for the Conawapa Project has increased by $500 million.

Manitoba Hydro executed the Keeyask general civil contract in early 2014. With that contract, approximately 80% of the Keeyask project has now been contracted. Manitoba Hydro assumes that this reduces cost uncertainty, but noted that the Wuskwatim hydroelectric project increased in cost by 10% from a similar project development stage as the Keeyask Project.

Manitoba Hydro's $6.5 billion cost estimate is based on a "P50" estimate, meaning there is a 50/50 chance of costs being either lower or higher. This creates a higher risk of cost overruns than a more conservative P80 estimate. The Panel is also concerned that Manitoba Hydro's assumed escalation rate for construction materials and labour may be too conservative.

The Keeyask general civil contract is a costs-reimbursable contract rather than a fixed-price contract. This means that if volumes of materials increase, Manitoba Hydro is responsible for that increase. The Panel had the opportunity to consider the contract *in camera* as Commercially Sensitive Information, and has concluded that Manitoba Hydro bears a significant cost risk. There is a realistic possibility that the capital cost for the Keeyask Project may reach Manitoba Hydro's "high" cost scenario of $7.2 billion, with a smaller possibility of total costs increasing beyond that amount.

With respect to Conawapa, which has a projected in-service date of 2026, there is significantly more cost uncertainty than for Keeyask, and the Panel has little confidence in the capital cost estimate for the Conawapa Project.

ii. Export Revenue Projections

Over the past decade, Manitoba Hydro has exported between 10,000-12,000 GWh of electricity annually. Its Preferred Development Plan is predicated on exports, and Manitoba Hydro currently predicts a cumulative $6.9 billion of contracted firm energy revenues between 2015 and 2036. In addition, Manitoba Hydro projects approximately $10.1 billion of opportunity sales into the spot market, for which prices fluctuate on a real-time basis. With respect to firm energy, the primary risk is that Manitoba Hydro will not be able to obtain new contracts in the future on equally favourable terms, or at all. With respect to opportunity sales, the primary risk is that energy prices will be lower than projected.

Opportunity sales projections rely on a carbon price eventually developing in the United States, making them highly speculative. There is currently no clear consensus among different commercial export price forecasters regarding the timing and magnitude of carbon pricing. The MISO market is undergoing a period of significant transition, which could have the effect of negating Manitoba Hydro's competitive advantages. This includes the replacement of coal with other, cleaner, technology, which would decrease the environmental premium U.S. utilities will be willing to pay. Furthermore, to the extent any contractual counterparties are currently paying an implicit "carbon premium" on the expectation that carbon pricing will materialize, the failure of a carbon regime to develop could reduce firm export prices in future contracts. Lastly, if load growth in MISO ends up being less than projected, as a result of the reduced demand for electricity, opportunity prices may not be as high as assumed by Manitoba Hydro.

While the Panel has confidence in Manitoba Hydro's projection of $6.9 billion of contract revenue, opportunity sale projections are optimistic, particularly if a carbon pricing regime does not materialize. In that case, domestic ratepayers are exposed to risk as they would have to make up any revenue shortfall.

M. Socio-Economic Evaluation

Manitoba Hydro conducted a Multiple Account Benefit/Cost Analysis for several plans, including the Preferred Development Plan. This analysis determines the net social benefits of each plan and how these benefits are distributed among Manitoba Hydro, ratepayers, the Government of Manitoba and provincial residents in general. Several non-monetary accounts are also considered. Two aspects of this analysis are noteworthy: the socio-economic benefits associated with each plan; and the implications for the Government of Manitoba's revenues.

In Manitoba Hydro's analysis, the Preferred Development Plan has the highest net social benefits. This is primarily due to the economic spin-offs associated with the construction phase of the Keeyask and Conawapa Projects. There would be significant leakages of spending out of the province, as only 45% of construction jobs are expected to be filled by Manitobans and major components such as turbines, cement and steel must be sourced from outside the province; nonetheless, the Preferred Development Plan has a larger impact on employment and income than the other plans.

The socio-economic benefits of the Keeyask Project are more tangible than those of the Conawapa Project. According to Manitoba Hydro's economic analysis, the Keeyask Project will create Manitoba labour income of over $500 million, and almost 7,000 person-years of employment. The project will be developed through a partnership between Manitoba Hydro and four First Nations. These are Tataskweyak, War Lake, Fox Lake and York Factory, collectively known as the Keeyask Cree Nations (KCNs). Pursuant to the partnership agreement, significant benefits will flow to the four First Nations through preferred dividend distributions, directly negotiated contracts, and an aboriginal training and employment initiative. To reap the long-term benefits of such training and employment, ongoing professional development opportunities are likely required after Keeyask is completed.

At the NFAT Review, the KCNs spoke in support of the project and indicated that if Keeyask were to be delayed, it would not be easy to regain the momentum and start over. While the NFAT Panel heard dissenting views from some members of the KCN communities, such views represent a minority opinion, as referenda were held in each community.

With respect to the Government of Manitoba, substantial government revenues accrue from hydroelectric development, primarily through water rental fees and capital taxes paid by Manitoba Hydro. At a 3.0% discount rate, the 78-year Net Present Value of water rentals and capital taxes is $6.1 billion for a plan that involves Keeyask and the 750 MW interconnection. This constitutes an additional benefit to the Province that is not captured in the results of Manitoba Hydro's economic evaluation, and dwarfs the incremental benefits flowing to Manitoba Hydro and its ratepayers.

N. Macro Environmental Evaluation

The Panel was asked to conduct a macro environmental evaluation of the Preferred Development Plan. The Panel interpreted and defined the term in accordance with the direction of the Province not to duplicate efforts undertaken by the Manitoba Clean Environment Commission, which, together with the federal Canadian Environmental Assessment Agency, has conducted an environmental assessment review of the Keeyask Project. No similar review has taken place for the Conawapa Project to date. The Clean Environment Commission recommended that a licence be issued for the Keeyask Project, with certain mitigation and monitoring conditions, including stocking of lake sturgeon for 50 years.

The Preferred Development Plan has significant Greenhouse Gas (GHG) benefits compared to alternatives, both in terms of avoided emissions and in terms of GHG displacement in the MISO market, which is still heavily reliant on coal. The Panel's recommended plan has lower total emissions than all other technologies except wind and nuclear energy.

Nonetheless, both the Keeyask Project and the Conawapa Project will have adverse impacts, with the impacts of the Keeyask Project better known due to the environmental assessment review having already been completed. The most significant adverse effect of the Keeyask Project is its impact on lake sturgeon due to the disappearance of Gull Rapids and a risk of turbine mortality for adult lake sturgeon. Other adverse effects include impact on caribou, flooding, and temporarily increased methyl mercury levels as a result of leaching from flooded soil. To the extent such effects have not been mitigated, Manitoba Hydro has agreed to compensate affected First Nations through Adverse Effects Agreements.

Manitoba Hydro's hydroelectric plans have the lowest overall macro environmental impact when GHG savings are taken into consideration, with wind power being competitive with hydroelectricity from a macro environmental perspective. Nonetheless, the Panel heard from several affected First Nations communities about the effects of past hydropower developments, and one Intervener strongly suggested the need for a regional Cumulative Effects Assessment to be completed.

While the Preferred Development Plan has the greatest GHG displacement potential, the Panel notes that if Keeyask proceeds and Manitoba Hydro renews its emphasis on DSM, Conawapa is not required. The Panel further notes that in the future, other renewable technologies are likely to become commercially feasible.

The Panel's recommendations are aligned with Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reductions Act*, and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*, and as such are consistent with the Province's goals for a clean energy future.

O. Integrated Resource Planning

The Terms of Reference required the Panel to consider "if preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound."

By failing to offer an analysis of conservation measures as a stand-alone energy resource competitive with other generation resources, Manitoba Hydro presented an analysis of conservation measures that was neither complete, accurate, thorough, reasonable nor sound.

Integrated resource planning is a regular practice in many jurisdictions. An integrated resource plan determines what supply side and demand side resource mix is in the best interest of electricity customers. The Panel heard evidence that the best practices for integrated resource planning involve placing every resource option on an equal footing and a public consultative planning process. In contrast, Manitoba Hydro prepares an annual Power Resource Plan that is not developed through a public integrated resource planning process.

The NFAT Review demonstrated that DSM measures were not equally weighted with other energy options as they would have been if Manitoba Hydro had used an integrated resource planning process framework.

The effectiveness of integrated resource planning in determining least-cost combinations of resources cannot be overestimated.

To satisfy anticipated load growth to 2028/29, the Preferred Development Plan delivers 2,025 MW of additional capacity at an estimated cost of $18.7 billion. If the supplementary 2014 Power Smart Plan DSM measures were treated as a stand-alone and equally weighted resource and added to the capacity from the Keeyask Project, the total capacity addition would be 1,766 MW at a projected cost, including transmission, of $8.3 billion. This is more than 85% of the net system capacity addition of the Preferred Development Plan.

It was only in the course of the NFAT hearing that it became clear that significantly higher levels of DSM than originally proposed by Manitoba Hydro were both achievable and economic. Proper integrated resource planning could have reached that determination years earlier.

P. Panel Conclusions and Recommendations

Manitoba Hydro has not justified the need for its Preferred Development Plan and has not shown it to be superior to alternatives.

There are good reasons to proceed with the Keeyask Project at this time in light of the need for new resources, construction expenditures undertaken to date, the socio-economic and environmental benefits of the project, and the important commercial relations that Manitoba Hydro has established both with First Nations and through its export contracts. Moreover, there are associated reliability benefits with the 750 MW Transmission Interconnection Project.

In contrast, Manitoba Hydro's business case did not demonstrate the need for Conawapa and the associated North-South Transmission Upgrade. The risks associated with the Conawapa Project are unacceptable. It is too speculative in light of rapidly changing conditions in North American electricity markets.

Manitoba's energy future no longer lies exclusively with hydroelectricity. In a time of rapid technological innovation in both the demand and supply side, openness to alternative resources and new technologies will be required. This may involve new methods of saving electricity as well as new methods of generating it, such as wind and solar power. Integrated resource planning provides the analytical framework to evaluate such options and, as such, should be required before any further generating facilities beyond the Keeyask Project are constructed.

The Panel recommends the following:

Manitoba Hydro's Preferred Development Plan

1. The Panel recommends that the Government of Manitoba not approve Manitoba Hydro's proposed Preferred Development Plan.

Keeyask Project

2. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date.

750 MW U.S. Transmission Interconnection Project

3. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date.

Conawapa Project

4. The Panel recommends that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project.

5. The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.

Creating New Demand Side Management Opportunities

6. The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.

7. The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.

8. The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.

9. The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.

10. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.

11. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.

Rates and Ratepayer Impacts

12. The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.

13. The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.

14. The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.

Actions in Support of a Clean Energy Future

15. The Panel recommends that integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba.

16. The Panel recommends that the Government of Manitoba not approve the construction of any generating facilities, nor approve the beginning of the

required infrastructure work for any generation facility, beyond the Keeyask Project, unless such facilities are justified through an integrated resource planning process. The integrated resource planning process must include public consultation.

1.0.0 The Needs For and Alternatives To Review

1.1.0 Background

Manitoba Hydro has identified a need for new electricity resources based on its forecasts of future electricity demand in Manitoba and electricity export sale commitments. To meet this need, Manitoba Hydro examined a number of resource options and identified a Preferred Development Plan, which it believes will provide significant benefits to Manitobans and is the best option when compared to alternatives. This Plan, which consists of building the Keeyask and Conawapa generating stations, as well as associated transmission facilities, and a 750 MW transmission interconnection to the United States, has been approved by the Manitoba Hydro Electric Board and submitted to the Government of Manitoba for approval.

Under *The Manitoba Hydro Act*, Manitoba Hydro must have the Lieutenant Governor in Council's approval to develop new power generation stations and to supply power to other jurisdictions. Before it makes a decision, the Government of Manitoba may have Manitoba Hydro's development plans undergo a public review.

On January 13, 2011, the Government of Manitoba advised Manitoba Hydro that it intended to have an independent body conduct a Needs For and Alternatives To (NFAT) review of the proposed Keeyask and Conawapa generation projects and related transmission facilities. This notification was followed in late 2012 by an announcement from the then Minister of Innovation, Energy and Mines that the Government had asked the Public Utilities Board (PUB) to conduct the NFAT Review.

1.2.0 The Nature and Role of the Public Utilities Board

The Public Utilities Board is an arm's length, provincial, quasi-judicial body established under *The Public Utilities Board Act*. The Lieutenant Governor in Council appoints the Board's members. One of the PUB's main functions is to set "just and reasonable rates" that utilities such as Manitoba Hydro may collect from ratepayers for electricity and natural gas services. In addition to its general jurisdiction, the Board may, from time to time, perform additional duties assigned to it, such as those assigned by order of the Lieutenant Governor in Council under clause 107(b) of *The Public Utilities Board Act*.

1.3.0 Formation of the Needs For and Alternatives To (NFAT) Review

1.3.1. Order in Council and Terms of Reference

The NFAT Review was officially constituted on April 17, 2013 by Order in Council 128/13, whereby the Lieutenant Governor in Council assigned to the PUB, the conduct of a Needs For and Alternatives To Review (NFAT Review) of Manitoba Hydro's proposed Preferred Development Plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternating current transmission facilities, and a new international transmission interconnection.

The Order in Council sets out detailed Terms of Reference for the conduct of the NFAT Review (see Appendix 1). The Terms of Reference establish the subject matter and scope of the NFAT Review. The first component of the Review is a "needs for" analysis. In this regard, the Terms of Reference direct the PUB to assess whether the needs for Manitoba Hydro's Preferred Development Plan are "thoroughly justified and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate."[1] The second element of the Terms of Reference directs the PUB to examine the "alternatives to" the Preferred Development Plan and "whether the Plan is justified as superior to potential alternatives that could fulfill the need."[2] The factors that must be considered in relation to both of these elements are outlined in the Terms of Reference.

1.3.2. Matters Not Within the Scope of the Review

There are a number of matters that the Government has decided to exclude from the scope of the NFAT Review. These matters are set out in the Terms of Reference and are listed below:

- The Bipole III transmission line and converter station project;
- The Pointe Du Bois project;
- Commercial arrangements between Hydro and its aboriginal partners for the development of the proposed hydro-electric generating stations (Keeyask and Conawapa);
- The environmental reviews of the proposed projects that are part of the Preferred Development Plan, including Environmental Impact Statements (subject to individual processes by the Manitoba Clean Environment Commission);

[1] Exhibit PUB-2, p. 2.
[2] Exhibit PUB-2, p. 2.

- Aboriginal consultation pursuant to section 35 of the *Constitution Act* (conducted as a separate Crown-Aboriginal consultation process);
- Past Manitoba Hydro development proposals or government assessments of past development proposals, including past NFATs; and
- Historic environmental costs.

1.3.3. Conduct of the NFAT Review

The Terms of Reference direct the Panel to conduct the NFAT Review in accordance with *The Public Utilities Board Act* and the Terms of Reference, and through "a transparent and public process." The public was encouraged to provide input and comment on the Preferred Development Plan. In an effort to provide the public with access to the public information filed in the course of the Review, the PUB maintained a dedicated NFAT Review portal within the PUB's website. All of the non-Commercially Sensitive Information, including documents, reports, filings, exhibits and testimony provided in the NFAT Review can be downloaded from the website of the Public Utilities Board at the following address: *http://www.pub.gov.mb.ca/nfat/index.html.*

1.3.4. Report to Government

The Order in Council directs the PUB to prepare a report on the matters outlined in the Terms of Reference and to present that report to the Minister responsible for the administration of *The Public Utilities Board Act* by June 20, 2014. The Report is to include recommendations to the Government of Manitoba on the needs for Manitoba Hydro's Preferred Development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.[3]

1.4.0 Review Parties and Participants

1.4.1. The PUB NFAT Review Panel

Under the Terms of Reference, the Chair of the PUB is to designate an NFAT Panel from PUB members to carry out the NFAT Review. The Panel formed to conduct the Review consisted of Régis Gosselin, (Chair of the Panel and of The Public Utilities Board), and Board members Richard Bel, Dr. Hugh Grant, Marilyn Kapitany, and Larry Soldier. Mr. Bel and Dr. Grant were appointed as members of the Public Utilities Board for the purpose of participating in the NFAT Review by Order in Council 472/2013 on December 18, 2013.

[3] Exhibit PUB-2, pp. 2-3.

1.4.2. Manitoba Hydro

As the proponent for the Preferred Development Plan, Manitoba Hydro had "applicant" status for the NFAT Review. It was Manitoba Hydro's business case that was analyzed by the Panel. Throughout this Report, the business case is referred to as Manitoba Hydro's NFAT Submission.

1.4.3. Interveners

Interveners are parties, usually umbrella organizations, which represent the perspectives of affected stakeholders. There is no right to Intervener status, but the Public Utilities Board has the discretion to permit Interveners. The function of Interveners is to assist the Board in a role akin to a "friend of the court." Interveners have the right to adduce their own evidence and test the evidence of other parties.
The Board granted Intervener status to the following five organizations: [4]

- Consumers' Association of Canada (Manitoba) Inc. (CAC)
- Green Action Centre (GAC)
- Manitoba Industrial Power Users Group (MIPUG)
- Manitoba Keewatinowi Okimakanak Inc. (MKO)
- Manitoba Métis Federation (MMF).

The Consumers' Association of Canada (Manitoba) Inc. is an independent, non-profit, volunteer-based organization dedicated to educating and informing consumers and to representing the interests of consumers to all levels of government and sectors of society. CAC notionally represents Manitoba Hydro's 456,130 residential customers. CAC has intervened in all rate applications before the PUB for electricity, natural gas, and auto insurance rates.

The Green Action Centre (formerly Resource Conservation Manitoba) is a non-profit, non-governmental organization, based in Winnipeg and serving Manitoba. GAC promotes greener living through environmental education and encourages practical green solutions for homeowners, workplaces, schools, and communities. Its primary areas of work are green commuting, composting and waste, sustainable living, resource conservation, and energy and climate change policy.

The Manitoba Industrial Power Users Group is an association of major industrial customers operating in Manitoba. Its members are: Amsted Rail - Griffin Wheel

[4] Exhibit PUB-6.

Company (Winnipeg); Canexus (Brandon); Enbridge Pipelines Inc. (Southern Manitoba); ERCO Worldwide (Virden); Gerdau Long Steel North America – Manitoba Mill (Selkirk); HudBay Minerals Inc. (Flin Flon); Koch Fertilizer Canada ULC (Brandon); Tolko Industries Ltd. (The Pas); TransCanada Keystone Pipeline (Southern Manitoba); and Vale (Thompson). These customers work together on issues of common concern related to electricity supply and rates in Manitoba. Members' concerns are reflective of the size of their investments in Manitoba, the long-term view essential for such investments, and the requirement for continued large-scale purchases from Manitoba Hydro. Members' concerns also reflect competitive market pressures from selling Manitoba industrial products to external markets, and the need to secure the lowest reasonable costs for power and other production inputs to offset disadvantages from operating in Manitoba, such as transportation.

Manitoba Keewatinowi Okimakanak Inc. represents more than 65,000 treaty First Nation citizens in northern Manitoba. MKO has been in existence for over 32 years, and is a non-profit advocacy organization governed by the elected Chiefs of the 30 First Nations in northern Manitoba.

The Manitoba Métis Federation represents over 100,000 Manitoba Métis citizens at the local, regional, and provincial levels. The history and early beginnings of trade and industrial development in Manitoba are interwoven with the history of the Manitoba Métis community as founders of Manitoba. The MMF supports development in Manitoba as long as the development is handled in a manner that promotes sustainability and economic prosperity for the Manitoba Métis community and for all Manitobans.

The PUB approved Intervener funding for all five Interveners as provided for in its Rules of Practice and Procedure. Interveners were represented by legal counsel and were approved by the PUB to engage experts to undertake research, prepare reports and assist them in participating in the NFAT Review. Please see Appendix 4 of this Report for a listing of the Interveners and the issues they considered in relation to the Terms of Reference.

1.4.4. Independent Expert Consultants

The Terms of Reference also provide for the Panel to engage independent expert consultants (IECs) to assist it in the NFAT Review. The Terms of Reference outline a number of subjects that the IECs are to examine.

The Panel used a Request for Qualifications (RFQ) process to engage the IECs. A detailed Request For Qualifications document was finalized in June 2013 and approved by the Panel. Fifteen firms responded to the RFQ and eight were chosen as IECs, along with another firm who was approved as a subcontractor to one of the chosen IECs. Detailed scopes of work were developed for each IEC in specific subject and issue areas. Independent legal counsel was also appointed for the IECs.

The following subject areas were addressed by IECs. Their detailed scopes of work can be found on the PUB website.

Table 1 List of Independent Expert Consultants

Independent Expert Consultant	Scope of Work (High-Level Description)
Elenchus Research Associates Inc.	Load forecasting, DSM, energy efficiency
La Capra Associates, Inc.	Power resource planning, economic evaluation, business case and risk analysis, transmission economics, export contracts, financial modelling
EnerNex (as a subcontractor to La Capra Associates, Inc.)	Wind matters
Knight Piésold Ltd.	Construction management, capital costs
MNP LLP	Macro-environmental issues
MPA Morrison Park Advisors Inc.	Commercial evaluation of Preferred Development Plan
Potomac Economics, Inc.	Midcontinent Independent System Operator (MISO), export markets, export prices and revenues
Power Engineers, Inc	Transmission line construction and management
TyPlan Consulting Ltd.	Socio-economic impacts and benefits

The IECs were engaged as independent arm's-length experts to provide an impartial, independent review of the matters assigned to them in their respective scopes of work and by the Terms of Reference. With a view to preserving that impartiality and independence, the PUB required all parties to the Review to follow a comprehensive communications protocol in relation to the IECs.[5] The communications protocol established parameters for IEC interaction with the NFAT Review Panel and other members of the PUB NFAT Review team, including PUB staff, legal counsel, technical advisors, and the NFAT project manager. The protocol ensured that the IECs did not receive direct instruction from the NFAT Review Panel, aside from additions to their scopes of work. Inquiries between the PUB team and the IECs, other than those of a purely administrative nature, were routed through the IECs' independent legal counsel.

Parameters were also established in relation to the preparation and filing of the IECs' reports. IECs were not to share draft reports with the PUB team and their final reports were to be filed in evidence in the NFAT proceeding on the public record even if the NFAT Review Panel disagreed with their findings and conclusions. As required by the

[5] Exhibit PUB-20, Appendix A, pp. 16-18.

Terms of Reference, the IECs' reports were to contain their analysis of the submissions filed by Hydro and were not to draw conclusions about the needs for or alternatives to the Preferred Development Plan; this being the remit of the Panel.[6]

1.4.5. Presenters

The Panel also heard from Presenters. Presenters are organizations or individuals who are not intervening in the proceedings, but who nevertheless wish to make their views known to the Panel. Presenters were able to provide their views in writing to the Panel or could appear before the Panel at the NFAT public hearings. Presenters made their presentations throughout the hearing process, as well as at designated presenter days in Winnipeg and Thompson, Manitoba. Summaries of the Presenters' reports and presentations are found in Appendix 6.

1.5.0 Review Process and Hearing

1.5.1. The Hearing

Following the issuance of the NFAT Terms of Reference on April 17, 2013, the Panel issued a public Notice of Pre-Hearing Conference in major newspapers across Manitoba and required Manitoba Hydro to serve past Interveners before the Public Utilities Board and the Clean Environment Commission. A pre-hearing conference to hear submissions with respect to process as well as applications for Intervener status took place on May 16, 2013. A further pre-hearing conference to deal with procedural matters took place on September 4, 2013.

Prior to the filing of Manitoba Hydro's NFAT Submission on August 16, 2013, Manitoba Hydro held a two-day technical conference for the Panel, IECs and approved Interveners to provide an overview of how the NFAT Submission business case would be organized and what information it would contain. A second technical conference was held in September 2013.

The hearings began on February 27, 2014 with non-evidentiary presentations received from registered Presenters. Presentations were also heard throughout the proceedings in Winnipeg and on May 14, 2014 in Thompson, Manitoba. The evidentiary portion of the hearing commenced on March 3, 2014 and ended on May 14, 2015. Closing submissions from Interveners were held on May 20 and May 21, 2014. Closing submissions from Manitoba Hydro were received on May 26, 2014. With the exception

[6] Exhibit PUB-2, p. 4.

of the one-day session for Presenters in Thompson, Manitoba, all hearings were held in Winnipeg.

1.5.2. Filings and Records of the Hearing

Information Requests

The Board's Rules of Practice and Procedure allow the parties to make Information Requests of other parties. Following the filing of Manitoba Hydro's NFAT Submission on August 16, 2013, Interveners, IECs, and PUB Advisors submitted two rounds of written Information Requests. Manitoba Hydro challenged a number of Information Requests and questioned the volume of them. The Panel held a motions day on these issues on September 30, 2013, as a result of which it decided that certain Information Requests did not have to be answered. The Panel also encouraged all parties to obtain answers to Information Requests through informal discussion with Manitoba Hydro to the extent possible, thus reducing the number of formal written Information Requests to be answered.

The process also allowed for one round of Information Requests to IECs and Intervener experts, which was utilized by most parties to the hearing.

Filing of Evidence

Consistent with PUB practice, all documents relevant to the Review and within the scope of the Terms of Reference, except for Commercially Sensitive Information, were filed on the public record. These public documents were made available to the public on the PUB website. Commercially Sensitive Information was not publicly filed or made available on the website. In addition to the filing of Manitoba Hydro's NFAT Submission and responses to Information Requests, answers to undertakings and pre-asks were filed periodically throughout the oral evidentiary portion of the hearing.

1.5.3. Commercially Sensitive Information

The Panel obtained access to and considered Commercially Sensitive Information (CSI) to ensure that it was fully informed in reaching its conclusions and recommendations. CSI is described in the Terms of Reference as *"any information that may reasonably be expected to cause undue financial loss to Manitoba Hydro … or any of its contractual counterparties or to harm significantly Hydro's or its contractual counterparties' or domestic customers' competitive position"….* [7] This information included Manitoba Hydro's export contracts and term sheets for the purchase and sale of power and

[7] Exhibit PUB-2, p. 6.

energy entered into between Manitoba Hydro and its U.S. customers, export price forecasts, Manitoba Hydro's yearly internal, non-public load forecasts, construction contracts, and Manitoba Hydro's existing and future Power Resource Plans.

The Panel was aware of the importance of conducting a transparent and public process, but also of its obligation to respect the commercially sensitive nature of some of Manitoba Hydro's information. Throughout the hearings, the Panel, in discussions with Manitoba Hydro and legal counsel, endeavored to find ways to make as much information publicly available as possible. As a result of these discussions, some of the information initially redacted as CSI was made publicly available with Manitoba Hydro's consent.

The IECs had access to CSI in preparing their reports. However, CSI was redacted from public versions of IECs' reports. The Panel held *in camera* proceedings to consider evidence based on Commercially Sensitive Information.

While this report does not contain or make direct reference to specific Commercially Sensitive Information, the Panel's conclusions and recommendations are informed by CSI evidence adduced during the *in camera* portions of the hearing.

1.5.4. Weighing of Evidence

In Appendix 7 the Panel has listed the names of the witnesses, and others, who have appeared at the NFAT Review.

It was the Panel's intention to record the names of all who have contributed to the Panel's better understanding of the myriad of complex issues, and the Panel regrets any omissions that may have occurred.

As the list discloses, the Panel heard evidence from over 75 witnesses. Even if the witness' name is not cited in the body of the Report, each and every witness assisted the Panel in its understanding of the issues and in reaching its decisions and recommendations.

As can be expected in a hearing of this magnitude, different witnesses provided different and sometimes opposing evidence on the same issue. In such cases, the Panel carefully weighed the evidence from the competing perspectives before arriving at its conclusions and recommendations.

The Panel again thanks all witnesses and parties for their dedication and professionalism in the NFAT Review.

2.0.0 Manitoba Hydro's Preferred Development Plan

2.1.0 Preferred Development Plan Components

Manitoba Hydro's Preferred Development Plan involves a major investment in new generation, transmission, and export contracts. At its core, the Preferred Development Plan involves the following components:

- The 695 megawatt (MW) Keeyask Project ($6.5 billion), with a planned in-service date of 2019;
- The 1,485 MW Conawapa Project ($10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately $500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately $1 billion).

2.1.1. The Keeyask Project

The Keeyask Project includes the construction of a 695 MW hydropower generating station located in northern Manitoba at Gull Rapids, as well as the development of ancillary transmission facilities.

The Keeyask Project is expected to take seven years to construct at a total estimated in-service cost of $6.2 billion as of the time of Manitoba Hydro's NFAT Submission. This estimate has since been revised to $6.5 billion.[8] Construction of the preparatory support infrastructure began in 2012. Manitoba Hydro anticipates that construction of the generating station and transmission components will commence during the summer in 2014, after all necessary regulatory approvals have been received. Initial power production is anticipated for 2019, with all generating units in production by 2020. When fully operational, Keeyask is expected to produce an average of 4,400 gigawatt-hours (GWh) of electrical energy annually. Annual dependable energy production (the amount of energy that could be produced in the lowest-flow year on record) is projected to be 3,003 GWh.

[8] Exhibit MH-113.

The generating facility is being developed through the Keeyask Hydropower Limited Partnership (KHLP), a partnership between Manitoba Hydro and four First Nations, namely the Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. The commercial terms of the arrangement are set out in the Joint Keeyask Development Agreement (JKDA). A review of these terms was excluded from the scope of the NFAT Review.

The Partnership will contract the planning, construction, and operation of the generation and infrastructure projects to Manitoba Hydro. Manitoba Hydro will then subcontract most of the services and supplies required to build the project. In addition, Manitoba Hydro will be contracted to provide the required debt financing for the projects. KHLP will sell all the power produced at the generating station to Manitoba Hydro.

Manitoba Hydro will own and operate the transmission infrastructure required for the Keeyask generating station.

2.1.2. The Conawapa Project

The Conawapa Project includes the construction of a 1,485 MW hydroelectric generating station downstream of the Limestone generating station, as well as the development of ancillary transmission facilities.

The Conawapa Project is expected to take over 10 years to construct at a total estimated in-service cost of $10.2 billion as of the time of the filing of Manitoba Hydro's NFAT Submission. This estimate has since been revised to $10.7 billion.[9] In its August 2013 submission, Manitoba Hydro anticipates that construction of the generating station will commence in 2017. Initial power production is projected for May 2026; with all generation units in production by October 2027. Final decommissioning of temporary infrastructure and site rehabilitation is slated for completion in 2028. When fully operational, Conawapa is expected to produce an average of 7,000 gigawatt-hours (GWh) of electrical energy annually.

2.1.3. North-South Transmission System Upgrade Project

Manitoba Hydro's high-voltage direct current (HVDC) transmission system, which will include Bipole III, will be used to transmit the power to be produced at the Conawapa Generating Station. However, certain upgrades to the exiting northern alternating current and high-voltage direct current system are required to transmit the remaining power. These upgrades are described in Manitoba Hydro's NFAT Submission as the

[9] Exhibit MH-113.

North-South Transmission System Upgrade Project. The Upgrade Project consists of two main elements:

- Upgrades to the existing northern 230 kV alternating current (AC) transmission system; and
- Upgrades to the existing HVDC transmission system within or in the immediate vicinity of the Radisson Converter Station and Kettle Generating Station in the north and the Riel Converter Station in the south.

The proposed in-service date for the Project is to coincide with the in-service date of the last Conawapa generating units. The initial, estimated capital cost for the North-South Transmission System Upgrade Project is $340 million (in $2012).[10]

2.1.4. Manitoba-Minnesota Transmission Project

The proposed Manitoba-Minnesota Transmission Project is a single circuit 750 MW, 500 kV alternating current (AC) transmission line starting at the existing Dorsey Converter Station south of Winnipeg, and connecting at the Manitoba-Minnesota border to the Great Northern Transmission Line, a new transmission line proposed by Minnesota Power. The projected in-service cost for the Manitoba portion of the project is $350 million.

2.1.5. Great Northern Transmission Line

The Great Northern Transmission Line is a new 750 MW, 500 kV AC transmission line proposed by Minnesota Power, one of Manitoba Hydro's contractual counterparties, in Minnesota. In the north, it would join with the Manitoba-Minnesota Transmission Project described above. In the south, it would terminate in the Iron Range near Duluth, Minnesota.

While the Great Northern Transmission Line is proposed and being developed by Minnesota Power, Manitoba Hydro plans to have a 49% ownership stake in the line, effectively funding a portion of construction and operating expenses. Manitoba Hydro intends to fund 67% of the line, but has expressed hope that it will eventually be able to sell its ownership stake. The total projected construction cost is in the vicinity of US$700 million. Construction is anticipated to begin in 2016, for an in-service date of 2020.

[10] Exhibit MH-95, p. 85.

2.2.0 The Preferred Development Plan and its Alternatives

In its NFAT Submission, Manitoba Hydro presented 14 alternative plans in addition to the Preferred Development Plan. These alternatives had been prepared to help test the Preferred Plan, as well as illustrate other resource options. These alternatives are presented in the Table below.

The plans fall into three main categories:

- four plans with a 750 MW U.S. interconnection;
- three plans with a 250 MW U.S. interconnection; and
- seven plans that, starting in 2022/23, meet Manitoba Hydro's domestic load and existing firm export commitments with no new U.S. interconnection.

2.2.1. Pathways

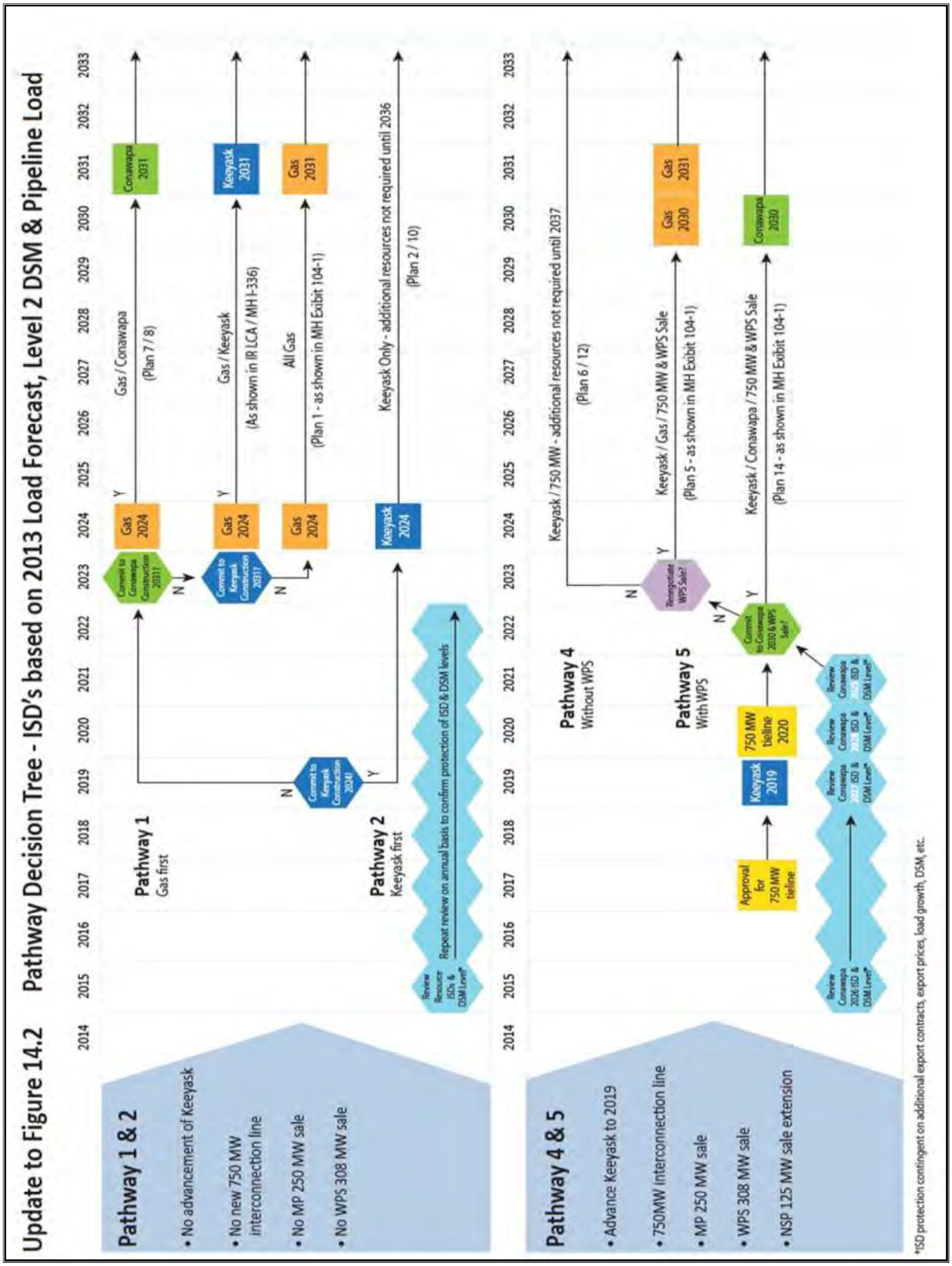
As a part of its planning, Manitoba Hydro prepared a number of pathways that would guide decisions on both the introduction of new generation, and their logical timing and order.[11] The Figure at the end of this chapter[12] presents the final version of the pathways that include the proposed actions associated with all of the new generation options and facilities: the construction of the Keeyask and Conawapa Projects, the construction of the transmission line, and the introduction of Demand Side Management (DSM) Level 2 initiatives.

[11] Manitoba Hydro NFAT Submission, Chapter 14, pp. 5-6.
[12] Exhibit MH-192 p.1.

Table 2 Description of Manitoba Hydro's Development Plans

Plan	Short Name	Description
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW(WPS Sale & Inv)	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

Figure 1 Pathways Identified by Manitoba Hydro



2.2.2. Developments During the NFAT Review

Manitoba Hydro made a number of changes that affected the economics of the Preferred Development Plan during the course of the NFAT hearing. On March 10, 2014, Manitoba Hydro updated its capital costs estimates for both Keeyask and Conawapa.[13] The update showed increases in the construction cost estimate for Keeyask from $6.2 billion to $6.5 billion and for Conawapa from $10.2 billion to $10.7 billion. Manitoba Hydro also explained that Wisconsin Public Service would not be investing in the proposed 750 MW transmission interconnection while still committing to purchase 308 MW of power from Manitoba Hydro. "

At that same time, Manitoba Hydro also provided information on the impact of increased Demand Side Management efforts and the potential for future pipeline industry load.[14] Its new Power Smart Plan envisions its customers switching from electricity to gas, where available, for space and water heating, conservation rates for domestic customers and self-generation by industrial customers.[15] The increased Demand Side Management will have the potential to delay the domestic need for new generation beyond 2022, which was the year Manitoba Hydro forecasted that new generation would be needed in its NFAT Submission.

[13] Exhibit MH- 95.
[14] Exhibit MH- 95.
[15] Exhibit MH-153.

3.0.0 Alignment with Applicable Legislative and Policy Documents

3.1.0 Introduction

In its Terms of Reference, the Panel was asked to consider the alignment of the Preferred Development Plan and its proposed alternatives to a number of acts and strategies. These were *The Manitoba Hydro Act*, the *Manitoba Clean Energy Strategy*, *The Change and Emissions Reductions Act*, and the sustainable development principles, as outlined in *The Sustainable Development Act*.

3.2.0 The Manitoba Hydro Act

The Terms of Reference specifically direct the Panel to consider the alignment of the proposed Preferred Development Plan with Manitoba Hydro's mandate as stated in section 2 of *The Manitoba Hydro Act.* That section states the following*:*

> ***Purposes and Objects of Act***
>
> *2. The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are*
>
> > *(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and*
> >
> > *(b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.*

In the Panel's interpretation, Manitoba Hydro's foremost purpose under section 2 of the *Act* is to ensure that Manitobans have adequate access to electrical power at all times. All plan alternatives presented by Manitoba Hydro are focused on meeting domestic load growth, providing reliable power, and anticipating load growth challenges.

The *Act* also directs Manitoba Hydro to seek economies and efficiencies in its development, generation, transmission, distribution, supply, and end-use of power. In the Panel's interpretation, this involves several things. First, while the *Act* does not mandate Manitoba Hydro to choose the lowest-cost generation source, it requires a careful analysis of the economic and financial impacts of alternative choices. Second, it involves an obligation on Manitoba Hydro to act efficiently and avoid unnecessary costs. Third, it requires a focus on energy efficiency and Demand Side Management, with a legitimate focus on end-use of power. In the Panel's view, while all alternative plans involving a significant focus on Demand Side Management are broadly aligned with these requirements, the focus on economics and efficiency mandated by the *Act* underlines the Panel's conclusions about new investments in generation.

The Manitoba Hydro Act further provides for the marketing of products, services and expertise, as well as direct export sales to external customers in Canadian provinces beyond Manitoba and in the United States. In the Panel's view, this section is permissive, that is, while it allows Manitoba Hydro to engage in these activities, it does not mandate the utility to do so. As such, Manitoba Hydro should only pursue them if it is in the economic interest of Manitoba ratepayers to do so.

In its Preferred Development Plan and corporate plans and documents, Manitoba Hydro points to the value and importance of export sales as a means of supporting new generation costs and moderating domestic rates. As was indicated in its Preferred Development Plan, Manitoba Hydro looks to "surplus by design" to take advantage of export sales opportunities. In fact, Manitoba Hydro sees a limited "window of opportunity" available to capitalize on the need of external customers to seek out renewable energy sources.

3.3.0 Manitoba's Clean Energy Strategy

Released in December 2012, the Manitoba Clean Energy Strategy outlines proposed goals and actions in five areas: (1) building a new Manitoba Hydro; (2) leading Canada in energy efficiency; (3) keeping rates low; (4) growing renewable alternatives; and (5) freedom from fossil fuels.

The Clean Energy Strategy suggests that "by advancing the construction of new hydro plants ahead of domestic needs, Manitoba can both earn additional export revenues and expand valuable interconnection transmission, while also building the plants it will need to meet its own future requirements."[16]

In addition, the Strategy envisages a new Manitoba Hydro having a clean energy portfolio which would add wind and other emerging, renewable energies, as well as energy efficiency initiatives, improved transmission, and the rehabilitation of older

[16] Exhibit PUB 58-5, p.337.

projects.[17] Notably, the Strategy does not require Manitoba Hydro to proceed with construction, but only requires the proposed new generating stations to proceed through environmental and economic review.[18]

The Strategy also describes Manitoba's energy efficiency efforts and achievements. It notes the Province's ability within a few years of becoming a leader in Canada. The Strategy proceeds to outline a number of priority actions for the future, including new programs and funding for residential energy efficiency improvements.[19]

The Clean Energy Strategy celebrates the fact that the cost of electricity in Manitoba has been among the lowest in Canada. It endeavours to maintain a "low utility rate advantage"[20] through predictable, modest rates increases for Manitoba Hydro over the coming years.[21]

The Strategy observes that there has been a growth in the range of renewable energy technologies, such as wind, heat pumps, and electric vehicles. It outlines efforts in a number of areas where new priorities will be given to new initiatives. These areas include wind, solar, geothermal heat pumps, and electric vehicles. In particular, the Strategy talks about the opportunities, advantages, and goals associated with wind power. It describes the expected economic benefits to come from the St. Leon and St. Joseph wind farms. The Strategy sets out the goal of an additional 1,000 MWs of economically developed new wind.[22]

Manitoba Hydro has taken the position that it is more economic to import wind energy from the United States. It has a wind exchange agreement beginning in 2020 with Minnesota Power pursuant to which U.S. wind power is stored in Manitoba Hydro's reservoirs. However, several Interveners criticized Manitoba Hydro's assumptions with respect to the cost of wind energy. The Panel is of the view that a decision to proceed with Keeyask will likely delay the development of any additional wind power in Manitoba, as Keeyask adds a significant amount of dependable energy to Manitoba Hydro's system, negating the need for new generation for at least a decade.

The Strategy concludes with a commitment to move away from fossil fuels as an energy source for Manitoba. In addition to highlighting a number of specific initiatives, the Strategy notes Manitoba Hydro's own action in this regard. The Panel would note that

[17] Exhibit PUB 58-5, p.341.
[18] Exhibit PUB 58-5, p.330.
[19] Exhibit PUB 58-5, pp.346-354.
[20] Exhibit PUB 58-5, p.354.
[21] Exhibit PUB 58-5, p.355.
[22] Exhibit PUB 58-5, p.375.

the Preferred Development Plan and many of its alternatives support this goal of the Clean Energy Strategy. Some alternatives do involve gas thermal generation, but in supporting roles to hydropower. However, one should not forget that during periods of off-peak imports, Manitoba Hydro is likely importing coal-generated energy from the United States.

3.4.0 The Climate Change and Emissions Reductions Act

The Climate Change and Emissions Reductions Act stipulates that Manitoba Hydro must not use coal to generate power, with the exception of emergencies.[23] The Panel notes that the Preferred Development Plan and its alternatives do not propose to use or develop coal to generate power. As such, all proposed plans are aligned with this statute.

3.5.0 Principles of Sustainable Development (as outlined in The Sustainable Development Act)

In 1998, the Province of Manitoba enacted *The Sustainable Development Act* to "create a framework through which sustainable development will be implemented in the provincial public sector and promoted in private industry and in society generally" (Government of Manitoba 1998). The principles and guidelines of sustainable development are appended to the statute. These principles are: integration of environmental and economic decisions, stewardship, shared responsibility and understanding, prevention, conservation and enhancement, rehabilitation, and global responsibility.

Manitoba Hydro provided the Panel with evidence as to how its plans and actions are aligned with these principles.[24] For example, Manitoba Hydro has integrated environmental factors into its economic decisions. Stewardship and defined, shared responsibilities are evident in its agreements with the Keeyask Cree Nations. Manitoba Hydro's environmental mitigation and adverse effects agreements address prevention and conservation considerations.

It is readily apparent to the Panel that both the Preferred Development Plan and the plan recommended by the Panel will yield some residual effects. This includes the environmental impact of flooding, erosion, and the destruction of sturgeon habitat, as well as long-term rate impacts on consumers.

[23] Exhibit PUB - 62, pp. 1-2.
[24] Manitoba Hydro NFAT Submission, Appendix 14.1, pp. 1-12.

3.6.0 Conclusions of the Panel

It is the Panel's view that the Preferred Development Plan and the proposed Alternative Plans are aligned with *The Manitoba Hydro Act*, the Manitoba Clean Energy Strategy, *The Climate Change and Emissions Reductions Act*, and the sustainable development principles outlined in *The Sustainable Development Act.*

The Panel finds that all alternative plans are broadly aligned with section 2 of *The Manitoba Hydro Act*, so long as the economic and financial repercussions of each plan are sound.

In particular, the Panel notes that the 2012 Clean Energy Strategy provides a basis for the Panel's thinking about what is needed to achieve a new energy future. The Panel shares the Strategy's conclusions as to the importance of Demand Side Management initiatives, the need for a greater portfolio of renewable resource options, and the need to keep rates low. In particular, the Panel agrees with the goal of making Manitoba a leader in energy efficiency initiatives.

4.0.0 Domestic Need and Load Forecast

4.1.0 Introduction

Manitoba Hydro's mandate under section 2 of *The Manitoba Hydro Act* includes "providing for the continuance of a supply of power adequate for the needs of the province." To ensure there is an adequate, reliable supply of power to meet demand, Manitoba Hydro must plan ahead by looking at current energy demand, future energy requirements, and the ability of existing power resources to meet those requirements. In carrying out its mandate, Manitoba Hydro annually forecasts the expected future electricity needs of Manitoba residences, commercial businesses, industries, and institutions as part of its power resource planning process.

The Terms of Reference direct the Panel to examine the "*reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied on to justify the needs. This should include Hydro's planning load forecast and future load scenarios, its demand and supply analysis, export expectations and commitments and demand side management and conservation forecasts*."[25]

4.2.0 The Components of Manitoba's Electricity Demand

4.2.1. Energy and Capacity Demands

There are two components to Manitoba's electricity demand, namely energy and capacity. Energy, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh), is the total quantity of power consumed over a certain timeframe. Capacity, measured in megawatts (MW), is the amount of electricity consumed at a point in time. Manitoba Hydro must be able to supply sufficient energy to meet its customers' needs over a period of time, such as a season or year, as well as sufficient generating capacity to meet the peak demands of its customers. Manitoba Hydro's 2013 Electric Load Forecast provides a forecast for Manitoba's Gross Firm Energy requirements in GWh and Gross Total Peak demand in MW assuming normal weather.

Gross Firm Energy is the total annual energy required for Manitoba Hydro's domestic customers on the integrated electricity grid. Gross Total Peak is the maximum amount of power needed to serve Manitoba Hydro's grid-based customers at any given time. Because Manitoba is a winter-peaking jurisdiction, peak domestic load occurs in winter, typically on a very cold weekday. For generation planning purposes, Manitoba Hydro reduces the Gross Firm Energy and Gross Peak Demand by forecasted DSM savings.

[25] Exhibit PUB-2, p. 2, Item 1.

The forecast of Gross Firm Energy is derived from the energy forecasts for the individual sectors that make up total domestic load. These sectors are comprised of major customer groups — Residential Basic, General Service - Mass Market, and General Service - Top Consumers — and other components such as Losses (losses associated with the transmission and distribution of electricity over power lines) and Station Service (energy used by power plants to generate power and service their own load), and miscellaneous customers such as seasonal customers, flat rate water heating customers, and area and roadway lighting.

Manitoba Hydro's analysis filed in its NFAT Submission was based largely on its 2012 Electric Load Forecast, which covers the 20-year period to 2031/32. Manitoba Hydro also included further analysis based on updated information from the 2013 Electric Load Forecast (2013 Load Forecast). The 2013 Load Forecast estimates Manitoba's energy needs and peak demand requirements for the 20-year period from 2012/13 to 2032/33. In the 2013 Load Forecast, Manitoba Hydro forecasts Gross Firm Energy to grow at the rate of 1.5% (413 GWh) per year over the next 20 years to 32,667 GWh by 2032/33. Gross Total Peak is expected to grow by 76 MW (1.5%) per year to reach 5,959 MW by 2032/33. Manitoba Hydro has not specifically provided load growth beyond 2033, but it can it be calculated as being 1.1% (with DSM Level 2 as explained in Chapter 5) out to 2049.[26]

Compared to the 2012 Load Forecast, the 2013 Load Forecast shows a 1,159 GWh (3.5%) reduction in Gross Firm Energy by 2031/32, which is equivalent to almost three years of annual load growth. Forecast Gross Total Peak in the 2013 Load Forecast shows a decline of 146 MW (2.4%) by 2031/32, amounting to a reduction of almost two years of load growth. Lower forecasted population growth and delays in the plans of two industrial power customers were largely responsible for the reductions in forecasted demand between the 2012 and 2013 Load Forecasts.

Manitoba Hydro stated that its 2014 Electric Load Forecast will not be ready in time for the Panel to consider it during the NFAT Review. However, Manitoba Hydro identified the following potential adjustments to its upcoming 2014 Load Forecast.[27]

[26] Exhibit MH-104-3, p.6.
[27] Exhibit MH-87, p. 12.

Table 3 Load Forecast Adjustments to Manitoba Hydro's 2014 Load Forecast

Change Item	Impact – GW.h	Date
Pipeline Sector	1700 GW.h*	2019/20
Codes and Standards	(300) GW.h	2027/28
Price Elasticity	(500-600) GW.h	2027/28
Fuel Choice	(100) GW.h	2027/28

4.2.2. Main Customer Components

The three main customer groups (Residential Basic, General Service – Mass Market, General Service – Top Consumers) are the most significant components of Manitoba Hydro's load and contribute most of Manitoba Hydro's revenue. Manitoba Hydro uses a different methodology for forecasting the energy requirements of each customer group and has made a number of changes to its forecasting methodologies over time. Manitoba Hydro is forecasting growth in consumption across all customer groups, resulting in overall load growth that is slightly higher than the Canadian average, and slightly lower than the U.S. average.[28]

Residential Basic

The Residential Basic sector consists mainly of single detached dwellings, multi-attached dwellings, and individually metered apartments. In 2012/13, there were 456,130 Residential Basic customers comprising 33.6% of domestic sales.

The primary drivers of growth in this sector are population increases (largely attributable to immigration) and greater reliance on electricity for space and water heating. Manitoba Hydro is forecasting increased use of electricity for space and water heating. Projections in the 2013 Load Forecast indicate that by 2032/33, approximately 40% of Residential Basic customers will be using electricity as a heating source, an increase of 3% from 2013 levels. The number of residential customers using electric water heating is expected to climb to nearly two-thirds by 2032/33. However, in its 2014 Power Smart Plan, Manitoba Hydro expects to achieve significant electricity savings through a fuel switching program and conservation rates, both of which could encourage electric space and water heat customers to switch to gas. If implemented, such measures may reverse this trend. Fuel switching is discussed in greater detail in Chapter 5.

[28] Exhibit MH-87, p. 8.

General Service - Mass Market

The General Service - Mass Market sector is comprised of commercial and industrial customers such as offices, retail and wholesale businesses, schools, hospitals, agriculture, apartment complexes, manufacturing, and industrial customers that do not fall within the Top Consumers sector. In 2012/13, there were 65,974 General Service - Mass Market customers accounting for approximately 39.3% of electricity sales. The main drivers for growth in the General Service – Mass Market sector are growth in the number of Residential Basic customers and the forecast Gross Domestic Product (GDP) for Manitoba, which Manitoba Hydro currently estimates will grow by 2% over the long term.[29]

General Service – Top Consumers

The General Service – Top Consumers category is comprised of 31 customers made up of 17 companies in sectors such as primary metals, chemicals, petrol/oil/natural gas, pulp/paper, food/beverage, and colleges/universities. This sector accounts for approximately 22.8% of load.

Energy consumption by Top Consumers grew by 91 GWh (2.0%) per year over the past 20 years. Growth over the past 10 years, however, was down considerably, at only 28 GWh per year (0.5%). The economic downturn from 2008 to 2011 and the loss of one major customer in this sector significantly reduced the 10-year growth rate. Manitoba Hydro is forecasting energy consumption to increase by 1.6% or 103 GWh per year over the next 20 years, similar to growth over the past 20 years despite the pending closure of the Vale smelter and refinery in Thompson circa 2016/17.

Manitoba Hydro uses a two-pronged approach to forecasting load in this sector comprised of shorter-term (3-5 years) individual forecasts for each member of the sector and a longer-term potential load calculation, "Potential Large Industrial Loads" or "PLIL." PLIL is used to represent the sector's overall growth, including major expansions, as well as the addition and loss of customers. Starting in 2016/17, 100 GWh a year is forecast for PLIL to account for unforeseen expansion, contraction, and growth.

In addition to PLIL, Manitoba Hydro also considers it likely that 1,700 GWh of additional load will arise by 2019/20[30] from upgrades to pipeline pumping stations within Manitoba. Enbridge's Alberta Clipper pipeline, Enbridge's planned upgrades to its Line 3 pipeline, and TransCanada Pipeline's Energy East pipeline project, which involves the conversion of a portion of TransCanada's Mainline gas pipeline to oil, will result in

[29] Manitoba Hydro NFAT Submission, Appendix G, p. 6.
[30] Exhibit MH-87, p.12.

1700 GWh of additional load. The Line 3 upgrade and the Energy East project are currently before the National Energy Board, while the remaining pipeline expansions, with their resulting electric load, have already received National Energy Board approval.[31] Four hundred GWh of that pipeline load are incorporated in Manitoba Hydro's 2013 Load Forecast as PLIL projections.[32]

4.3.0 Load Forecasts

4.3.1. Load Forecasting Methodology

Because the customer sector forecasts play such an important role in Manitoba Hydro's load forecast, there was a considerable amount of discussion before the Panel about the methodologies that Manitoba Hydro employs to develop these forecasts.

Manitoba Hydro employs an end-use model to forecast energy demand in the Residential Basic sector. The model determines electricity use based on assumptions about the numbers of customers, dwelling type, location within Manitoba, appliance age and saturation, and the number of customers who use electricity for space and water heating. These assumptions rely on information from Manitoba Hydro's 2009 Residential Survey.

With respect to the Residential Basic forecast, Elenchus identified a number of concerns, ranging from problems with the method of forecasting the residential customers' market share of electric heat and failing to account for potential changes in population growth, to reliance on a static person-per-household ratio and dated (2009) survey data that may not reflect current conditions.

Economic and Population Demand Scenarios

Experts testifying on behalf of CAC raised the issue of testing the effect of different economic and population scenarios on demand. The Residential Basic and General Service – Mass Market sectors' forecasts are heavily influenced by population and economic growth.[33] The Panel learned that the projected growth in Manitoba's population could be lower than the future growth projected in the 2013 Load Forecast, based on three of the five updated population forecasts relied upon by Manitoba Hydro.[34] Even with these concerns, Elenchus noted that there have not been significant errors in recent Residential Basic forecasts when compared to actual consumption.

[31] Transcript, pp. 1137-1140.
[32] Exhibit MH-104-3, pp. 59,83.
[33] Exhibit CAC-25, p. 8.
[34] Exhibit MH-93.

However, over the longer-term 20-year forecast period, the concerns identified could "cause more significant deviations."[35]

The Top Consumers sector was singled out as the source of the highest forecasting error. Elenchus pointed to consistent over-forecasting in recent years, as well as previous periods of both under-forecasting and over-forecasting. Elenchus maintained that the PLIL projection is particularly sensitive to economic conditions, as was evidenced by the economic downturn in the last decade, and would benefit from sensitivity testing against high, medium and low economic conditions.[36] Similarly, Patrick Bowman, an expert witness for the Manitoba Industrial Power Users Group (MIPUG) noted that "*the most significant weakness for the industrial load forecast, from the perspective of a long-term NFAT review, is the failure to explicitly consider scenarios that result in much higher or quicker developing future industrial load."*[37]

Manitoba Hydro acknowledges that it is more difficult to forecast load growth in the Top Consumers sector than it is in the Residential Basic or General Service - Mass Market sectors, where load typically increases (or decreases) gradually. Load growth (or contraction) in the Top Consumers sector, on the other hand, tends not to be gradual or linear because the addition of new customers or customer expansions can add large blocks of load and contractions or plant closings can reduce load significantly. Manitoba Hydro maintains that the PLIL calculation is a reasonable proxy for longer-term load growth forecasts based on average load growth over the past 20 years with the expectation of future periods of economic downturn and economic growth.[38]

Forecasting Methods

Manitoba Hydro uses a hybrid approach to forecasting load, employing different methodologies for the different sectors. CAC expert, Dr. Gotham, provided the Panel with a high-level description of load forecasting methodologies that MISO considers acceptable in some circumstances and unacceptable in other circumstances. He noted that econometric modelling would be useful in a number of sectors.[39] Dr. Gotham identified concerns with some of the methodologies employed by Manitoba Hydro. According to Dr. Gotham, load forecasts prepared in support of generation planning for MISO participants may not utilize certain approaches, such as trend analysis or survey-based forecasting techniques. Manitoba Hydro uses both in certain elements of its load

[35] Exhibit ERA-5, p. 16.
[36] Exhibit ERA-5, p. 25.
[37] Exhibit MIPUG-9, pp. 3-11.
[38] Exhibit MH-85, p.18.
[39] Transcript, pp. 8292-8293.

forecasting.[40] PLIL is an example of trend analysis, as is the use of a fixed ratio of population to households, which is used in the Residential Basic forecast. The Residential Basic forecast also makes use of survey-based techniques to forecast the market share of electric heat. As the General Service – Mass Market forecast relies on the Residential Basic customer forecast, it too relies on trend analysis forecasting techniques, according to Dr. Gotham.[41] Manitoba Hydro acknowledged that the PLIL calculation is a form of trend analysis, but argued that it has very little overall influence on the load forecast.[42]

Electricity Demand/Price Elasticity

Manitoba Hydro's load forecast does not factor in the effects of increasing electricity prices on electricity demand, a concept known as price elasticity. Drs. Simpson and Gotham described its absence as "the most disturbing omission from Manitoba Hydro's forecasting methodology" because it implies an upward bias into the forecast, leading to "inflated load forecasts and requirements for new system capacity.[43]

In a similar vein, Elenchus maintains that it is inconsistent with experience in other jurisdictions to assume there will be no impact on demand from rising electricity rates.[44] Given projected long-term annual rate increases associated with the Preferred Development Plan in the order of 2% more than expected annual increases in the Consumer Price Index, Dr. Simpson suggested that, with a long-run elasticity factor of -0.5 in the residential sector, loads could decline despite future population growth.[45] The reduced load growth could defer the need for new resources by one year and possibly up to three or four years if the General Service - Mass Market and Top Consumers sectors similarly responded to increasing electricity prices.[46]

Manitoba Hydro pointed out that electricity prices in Manitoba have increased slowly, at or close to the rate of inflation and, consequently, the effect of price changes on customers' use of electricity would not have demonstrated a measurable price elasticity.[47] Manitoba Hydro provided preliminary projections of price elasticity-related load reductions in the order of 500-600 GWh by 2027/28, which are expected to be incorporated into the 2014 Load Forecast.[48] Manitoba Hydro's calculation assumes an

[40] Exhibit CAC-65, p. 4, 6; Transcript, pp. 8542-8543.
[41] Transcript, p. 8641.
[42] Transcript, p. 8543.
[43] Exhibit CAC-25, p. 10.
[44] Exhibit ERA-5, p. 46.
[45] Exhibit CAC-65, p. 19.
[46] Exhibit CAC-25, pp. 8-9; Transcript, pp. 8304-8305.
[47] Exhibit MH-85, p, 19.
[48] Exhibit MH-87, p.12.

elasticity value of -0.05, which Dr. Gotham described as being on the low end of values used in other jurisdictions.[49]

Accuracy of Forecasts

Elenchus examined the accuracy of Manitoba Hydro's forecasts by looking at historical 5-year ahead, 10-year ahead and 15-year ahead forecast performance for both energy and peak demand. Elenchus' analysis revealed periods of under- and over-forecasting, much of which is attributable to forecasts in the Top Consumers sector,[50] while the 20-year ahead forecast accuracy levels compared favourably with some other longer-term forecasts in other jurisdictions prepared for system expansion purposes.[51]

As for the probability approach adopted by Manitoba Hydro, Elenchus argues that it: *"is less transparent and provides less insight than the multiple scenarios approach used in 2009."*[52] Furthermore, according to Elenchus, it is important to test "*the sensitivity of the forecast to changes in the economic and demographic assumptions used to derive it."*

MIPUG's expert witness, Mr. Bowman, cautioned that in the context of the NFAT analysis it is less important to achieve a high degree of accuracy in a single load forecast than it is to test a series of scenarios.[53]

Despite the concerns raised with respect to various aspects of Manitoba Hydro's load forecasting methodologies and assumptions, overall, Elenchus and MIPUG's expert found Manitoba Hydro's methodology appropriate for short-term forecasting and the load forecast reasonable.

4.4.0 Need for New Resources

The need for new generation resources arises when Manitoba Hydro expects to have a shortfall in energy or capacity. Manitoba Hydro's generation planning involves comparing the existing and proposed generating resources along with contracted and proposed imports against the firm domestic load and export obligations. The planning criteria for hydraulically generated energy are based on dependable generation, which means the generation available from the lowest water flow year recorded. The year when new resources, such as Keeyask or a gas turbine plant, are required is called the "need date", and it could be driven by either a shortfall in energy or capacity.

[49] Exhibit GAC-65, p. 34.
[50] Exhibit ERA-3, pp. 34-38.
[51] Exhibit ERA-3, p. 40.
[52] Transcript, p. 4841.
[53] Exhibit ERA-3; Exhibit MIPUG-9, p. 3.11.

The need date considers only the forecasted domestic load and existing export contracts. The need date does not include any future export obligations, such as the Minnesota Power 250 MW contract, except those that are already being served.

Manitoba Hydro presented several load growth scenarios to determine the domestic need date based on various levels of DSM and whether or not the pipeline load materializes.

Table 4 Need for New Resources Under Different Planning Assumptions

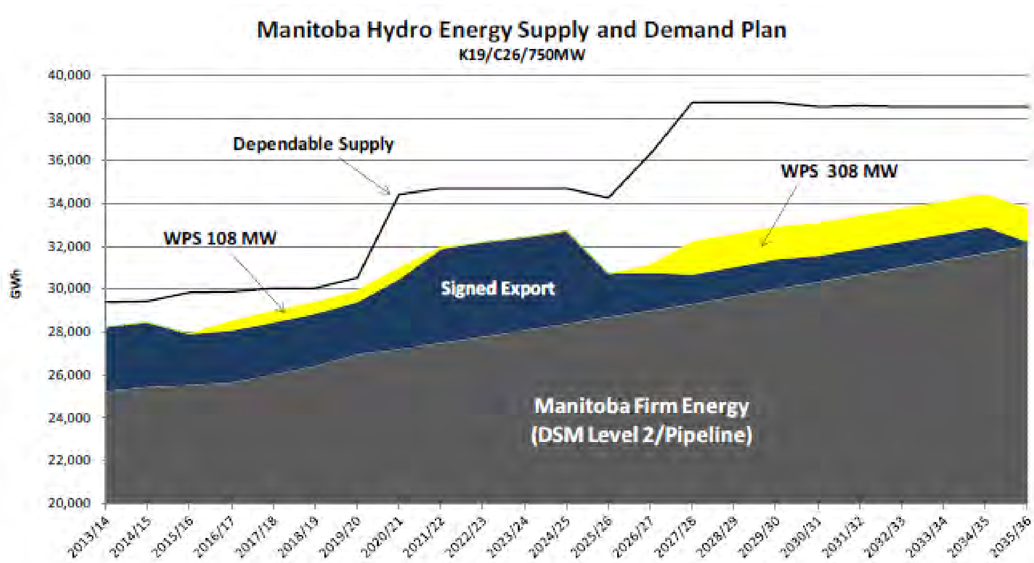
Estimated Need for New Resources		
Planning Assumptions	**Need for Dependable Energy**	**Need for Capacity**
2012 Planning Assumption	2022/23	2025/26
2013 Planning Assumption	2023/24	2026/27
NFAT DSM 1	2028/29	2030/31
NFAT DSM 2	2031/32	2031/32
NFAT DSM 2 + increased pipeline load	2024/25	2030/31
NFAT DSM 3	2033/34	2033/34
NFAT DSM 3 + increased pipeline load	2029/30	2030/31

The most plausible scenario draws on their 2013 Load Forecast, includes the pipeline load and DSM Level 2 initiatives, and assumes no new exports. Initially, Manitoba Hydro stated the domestic need date was 2027, neglecting a small (39 GWh) energy deficit in 2024 because of larger energy surpluses in 2025 and 2026. Later in the NFAT proceeding, Manitoba Hydro determined the domestic need date should be driven by the small deficit in 2024, and confirmed 2024 as the domestic need date.

In all cases with additional future export obligations, such as the Minnesota Power 250 MW contract, it is assumed that Keeyask is constructed for an in-service date of 2019. However, a scenario not considered by Manitoba Hydro but investigated by the Panel is the potential to defer Keeyask while still serving the Minnesota Power and other new export contracts. This potential to defer Keeyask arose with the additional DSM savings proposed by Manitoba Hydro, resulting in sufficient surplus power to serve the new export contracts with Manitoba Hydro's existing generating resources. With DSM Level 2, or with the DSM savings from the 2014 Power Smart Plan, Keeyask may not be needed until the mid- to late 2020s.

The exact date when Keeyask is needed depends on whether the pipeline load materializes, whether Manitoba Hydro extends its diversity exchange contract with Northern States Power, or whether other measures that increase capacity are included, such as the Curtailable Rate Program. The following Figure shows Manitoba Hydro's energy supply and demand, as well as surplus dependable energy.

Figure 2 Manitoba Hydro Energy Supply and Demand (K19/C26/750MW – Pipeline Load)



4.5.0 Transformative Change in Load Demand

4.5.1. Structural Changes to Forecast Fundamentals

The Panel heard evidence on two factors that over the longer term may have a significant impact on electricity demand: change in the fundamental factors underlying electricity demand, and distributed generation technologies achieving cost parity with grid-supplied electricity, otherwise known as "grid parity."

Elenchus contends that Manitoba Hydro's load forecasting methodology tacitly assumes that there will be no significant structural changes in the fundamentals underpinning the forecasts. Given that the analyses on which Manitoba Hydro's NFAT Submission is based extend out over a 78-year timeframe, Elenchus maintains *"that it is more reasonable to expect that there will be significant structural changes that will result in dramatically different domestic demand (and presumably export prices) in the coming decades than it is to assume that the past provides a realistic window on the future."*[54]

Elenchus offered two examples of transformative changes to illustrate the possible impacts. Improved battery storage for electric vehicles, which, combined with carbon pricing of transportation fuels, could transform the transportation market and increase

[54] Exhibit ERA-5, p. 41.

load dramatically. On the other hand, significant penetration of alternative distributed generation technologies, such as solar photovoltaic, could transform the market and reduce load as the cost of electricity from these technologies approaches parity with grid-supplied power.

4.5.2. Impact of Grid Parity

The Panel heard evidence from witnesses about the impact of grid parity on demand for grid-supplied electricity. Grid parity is the term used to describe the point at which the cost of producing electricity with a new technology, such as solar photovoltaic or distributed generation, equals the cost of electricity from traditional generating technologies used to provide grid-based power.

Dunsky Energy Consulting's pre-filed expert evidence on behalf of CAC and GAC, noted that the cost to produce electricity from solar panels, on a ¢/kWh basis, is now the same or cheaper than electricity rates in some U.S. states and could reach parity with Manitoba Hydro's domestic rates before the end of the current load forecast period. Furthermore, the cost of utility-scale solar photovoltaic applications is declining to the point where it will become competitive with the cost of other generating technologies.[55]

Grid parity has the potential to affect Manitoba Hydro in two ways: by reducing domestic demand for electricity; and by decreasing demand and suppressing prices in Manitoba Hydro's export markets. Manitoba Hydro advised that it has not carried out any modelling of the longer-term impact of grid parity or disruptive technologies on domestic load or analysed when parity will be reached in Manitoba, although it has done a high-level examination of solar photovoltaic technology as a DSM savings.[56]

If grid parity materializes in the export markets, it could depress load growth and put downward pressure on prices. Manitoba Hydro may not be able to realize the export revenues it is forecasting if this were to occur.

Elenchus noted that with grid parity, distributed generation will compete directly with grid-supplied power and constrain the prices Manitoba Hydro can charge. In this scenario, Manitoba Hydro will always be able to sell the full output of its dams, but not necessarily at a sufficiently high price to recover the cost to build them: "*Once built, high-capital-cost, low-operating-cost technologies such as large-scale hydro generation which the associated extensive transmission and distribution networks may always be*

[55] Exhibit CAC-62, p. 37.
[56] Transcript, p. 604.

able to under-price the alternatives, but that ability to compete does not ensure full recovery of sunk costs."[57]

Manitoba Hydro submitted that there is a great deal of uncertainty about the timeframe when grid parity may be reached, although it does not expect sufficient penetration of distributed generation, and specifically solar photovoltaic generation, to result in any significant demand savings until after 2020.[58] Manitoba Hydro anticipates than even after grid parity is achieved, there would be a gradual reduction in domestic load over a number of years rather than a step change in load because the adoption of new technology will be slow at first and build momentum over time.[59]

4.6.0 Reliability and Security of Manitoba's Electricity Supply

One of Manitoba Hydro's key responsibilities is to provide and maintain a reliable power system. Given this responsibility, Manitoba Hydro identified a need for new resources to meet persistent shortfalls in system capacity and energy and identified different development plans to meet that need. When considering reliability, the focus is on the ability of the power system to meet peak load. Manitoba Hydro designed the Preferred Development Plan and alternative plans evaluated for the purpose of its NFAT Submission to provide the required system reliability and to ensure that there are sufficient resources to meet peak and annual load.

Manitoba Hydro explained to the Panel that the degree of system reliability is typically measured by "loss of load expectation" – the average number of days per year that the load could not be fully met. A common industry standard is an inability to meet system load one day every 10 years. The lower the loss of load expectation, the greater is the system's reliability. This can equivalently be expressed in terms of the system's load-carrying capability. With greater reliability, the system can reliably carry or meet a greater amount of peak load.

Although all of the development plans that Manitoba Hydro considered ensure system reliability, some plans were found to offer more reliability than others. Plans with a 750 MW interconnection provide greater reliability because of the ability to import power from the U.S. For example, plans with a 750 MW transmission interconnection offer 500 to 1,000 MW of additional transmission capacity to carry domestic load from 2020 to 2040 than plans with no interconnection, and the Preferred Development Plan, with its

[57] ERA-3 p. 42.
[58] Transcript, p. 606.
[59] Transcript, p. 607.

two generating stations and the 750 MW transmission interconnection, offers the most reliability benefits of the plans with a 750 MW interconnection.[60]

Building Keeyask would add more capacity than is required for a considerable period of time and Conawapa would add even more. This additional capacity is far more than reliability-planning metrics suggest is needed. However, there are reliability benefits associated with these additions in terms of avoiding shorter- and longer-term power outages and supply constraints.

Manitoba Hydro's analysis indicates that development plans with a 750 MW interconnection are much more secure under extreme drought conditions than other plans because of the import room they provide – some 3,000 to 4,500 GWh/year more emergency energy for Manitoba domestic load from 2020 to 2040.[61] Although the Preferred Development Plan adds additional hydraulic generation that can be affected by drought, it will still add to Manitoba's energy security because Manitoba Hydro can curtail delivery of exports in order to satisfy Manitoba load.

4.7.0 Conclusions of the Panel

The Panel is satisfied that Manitoba Hydro's load forecast is reasonable for the short term. It is prudent to assume that the planned pipeline load will materialize, especially in light of the long lead time to construct Keeyask and Manitoba Hydro's obligation to serve domestic load. The Panel accepts the need date determined by Manitoba Hydro to be 2024, based on the 2013 Load Forecast, DSM Level 2, and the pipeline load.

Nonetheless, the methodological concerns raised by parties to the NFAT Review highlight the need for more robust forecasting. In future General Rate Applications, the Panel will expect Manitoba Hydro to provide a more robust forecast to better understand the factors that influence short-term load fluctuations.

That said, the Panel encourages Manitoba Hydro to consider the improvements to the load forecasting methodology recommended by Drs. Gotham and Simpson, as they could provide benefits to the forecasts considered at future rate proceedings.

The Panel has less confidence in Manitoba Hydro's forecast in the long term as it does not address the effects of potential structural change from new technologies or grid parity. The Panel recognizes that such factors are difficult to predict in both their magnitude and direction. While some structural change, such as the widespread adoption of electric vehicles, could significantly increase demand, other structural

[60] Exhibit MH-204, p.182
[61] Exhibit MH-95, p. 140.

change, such as grid parity for solar photovoltaic technology, could substantially decrease it. It is the Panel's view that Manitoba Hydro should, in the coming years, avail itself of external expertise to be a leader in the implementation of these technologies and prepare future integrated resource plans on that basis.

In light of the significant rate increases projected over the next 20 years, the Panel further concludes that Manitoba Hydro should more carefully scrutinize the potential for price elasticity impacts.

The Panel notes that Demand Side Management initiatives in the future will likely have a profound impact on Manitoba Hydro's load forecast. This issue is further discussed in Chapter 5. Manitoba Hydro did not consider the ability for DSM to increase Manitoba Hydro's exportable surplus, such that Keeyask may not be needed to serve the new export contracts until the mid- to late 2020s. The Panel views this as a weakness in the analysis. Despite this shortcoming, the Panel accepts that there are tangible reasons to proceed with the construction of Keeyask at this time, rather than to delay construction for five years and require a renegotiation of the general civil contract to construct the project and the numerous First Nation agreements already executed.

Should Manitoba Hydro's load forecast turn out to be too low, construction of the 750 MW U.S. transmission interconnection provides concrete reliability benefits, as it facilitates additional imports.

5.0.0 Demand Side Management (DSM)

5.1.0 Introduction

The Terms of Reference direct the Panel to consider the role of Manitoba Hydro's Demand Side Management (DSM) and conservation forecasts in Manitoba Hydro's Preferred Development Plan. This involves consideration of whether the DSM programs were adequately integrated into Manitoba Hydro's resource planning, and assessing the extent to which DSM could affect decisions on the timing of and need for new resources. For the purposes of this chapter, DSM includes energy efficiency and capacity savings.

The Panel heard of the importance of DSM in the course of the NFAT Review hearings. DSM can be a valuable and versatile asset in resource planning. It can help meet energy, as well as capacity needs. It can be targeted to specific end-users or technologies and solutions, and designed to meet the challenges and circumstances of each jurisdiction. DSM can be designed to offset or delay the need for new generation investments. Philippe Dunsky, an expert witness appearing on behalf of CAC, put forward the business case for DSM as a resource option, noting that at 2¢ to 4¢ per kWh, DSM costs two to eight times less than new power plant investments, produces from two to ten times more jobs per million dollars invested, reduces greenhouse gas (GHG) emissions, has economic benefits, and produces high levels of customer satisfaction.[62]

During the hearings, a significant change in DSM planning and strategy occurred. In early March 2014, Manitoba Hydro introduced the possibility of including a new set of DSM programs and measures in the Preferred Development Plan and the alternative development plans. Their effect would be to potentially delay the need for new generation resources and deal with increasing domestic need. Up to this point, Independent Expert Consultants and Interveners had been critical of the Preferred Development Plan and the absence of new DSM plans or efforts. This changed with Manitoba Hydro's new DSM plan, which promised an impact on the need for new resources and the nature of the required resource portfolio.

In its NFAT Submission in August 2013, Manitoba Hydro provided a DSM potential study prepared by EnerNOC, a U.S. consulting firm that identified the DSM potential that could be achieved. Manitoba Hydro retained EnerNOC in 2011.[63] Relying on EnerNOC's work, Manitoba Hydro developed three different levels of DSM savings,

[62] Exhibit CAC-62, p.9.
[63] Transcript, p.395.

identified as Level 1, Level 2, and Level 3, and concluded that DSM Level 2 was achievable and economic. Manitoba Hydro first provided this information in late February 2014. Manitoba Hydro then provided a number of economic analyses based on the assumption that DSM Level 2 would be implemented.

This Chapter focuses on the nature and impact of these new DSM Level 2 initiatives, their associated energy and capacity savings, their impact on the Preferred Development Plan and alternative development plans, and the requirements to ensure the successful implementation and long-term realization of DSM goals.

5.2.0 Manitoba Hydro's Power Smart Programs and DSM Proposal

5.2.1. Manitoba Hydro's Power Smart Programs

Manitoba Hydro engages in DSM initiatives to reduce electricity demand. Manitoba Hydro's DSM programs are outlined in its Power Smart Plans, and consist of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. Program measures include:

- Education initiatives and financial incentives to encourage energy savings;
- Supporting energy savings through the adoption of federal and provincial codes and standards;
- Load reduction by participating customers; and
- Encouraging customers to install load-displacement generation systems.

Manitoba Hydro views DSM programs as a way to reduce energy consumption and demand, and thus defer the need for new generating resources. Manitoba Hydro used to be a leader in DSM. In recent years, Manitoba Hydro's DSM spending has decreased. The energy savings reported by Manitoba Hydro on an annual basis as a percentage of total demand have declined to approximately 0.4%, well below the 1.5% to 2% levels achieved in many other jurisdictions.

Manitoba Hydro's 2013-2016 Power Smart Plan outlined a series of measures that Manitoba Hydro expected would produce energy savings of 570 GWh and demand reductions in the order of 280 MW over the Plan's three-year horizon. The three-year plan was prepared in consultation with the Government of Manitoba, as required under *The Energy Savings Act.* [64] Manitoba Hydro was forecasting that the DSM efforts in its

[64] Transcript, p. 9856.

2013-2016 Power Smart Plan would reduce annual load growth to 1.4% per year over the 20-year load forecast period.

Manitoba Hydro's new 2014-2017 Power Smart Plan, which became available in April 2014 during the NFAT Review hearings, outlines substantially increased spending on DSM and proposes a doubling of targeted electricity savings to be achieved over the next three years (2014/15-2016/17) relative to the 2013-2016 Power Smart Plan. These savings are projected to be 1064 GWh and 411 MW, or 4% of the estimated load forecast by 2016/17, thus offsetting 86% of projected load growth during this three-year period.[65] Manitoba Hydro prepared its 15-year Supplemental Report for integrated resource planning purposes.

5.2.2. Revised Manitoba Hydro DSM Proposals (March 2014)

Before the NFAT Review hearings began in early March, Manitoba Hydro filed new evidence on its DSM activities and projections, which Manitoba Hydro described as DSM Levels 1 through 3. Each level contains higher levels of DSM programming, as described below, and produces progressively higher levels of energy savings beyond the existing DSM portfolio used in the NFAT Submission.[66]

- DSM Level 1 is comprised of energy efficiency initiatives, which include extending some existing programs, technologies such as LED lights for applications in roadway, residential and commercial lighting, and modifying some existing programs with a more aggressive design and approach.
- DSM Level 2 includes the Level 1 initiatives plus measures such as conservation rates, load displacement measures, and fuel switching.
- DSM Level 3 encompasses all of the DSM Level 2 initiatives and modifies the energy efficiency programs to achieve greater energy savings, but at a higher cost. These higher cost programs would be considered uneconomic relative to the Level 2 programs when evaluated against the marginal costs but were included to test more fully the viability of a higher level of DSM.[67]

The three new programs Manitoba Hydro highlighted as part of DSM Level 2 were conservation rates, fuel switching, and load displacement. Conservation rates are electricity rates that are tailored to encourage conservation through pricing mechanisms and may involve inclining blocks where electricity consumed beyond a certain threshold costs more than the initial block. These rates would require approval by the Public

[65] Exhibit MH-153, p. 1.
[66] Exhibit MH-85, pp. 28-29.
[67] Exhibit MH- 85, p. 28.

Utilities Board. Fuel switching encourages customers to use natural gas instead of electricity for space and water heating. Load displacement programs encourage industrial customers to self-generate electricity.

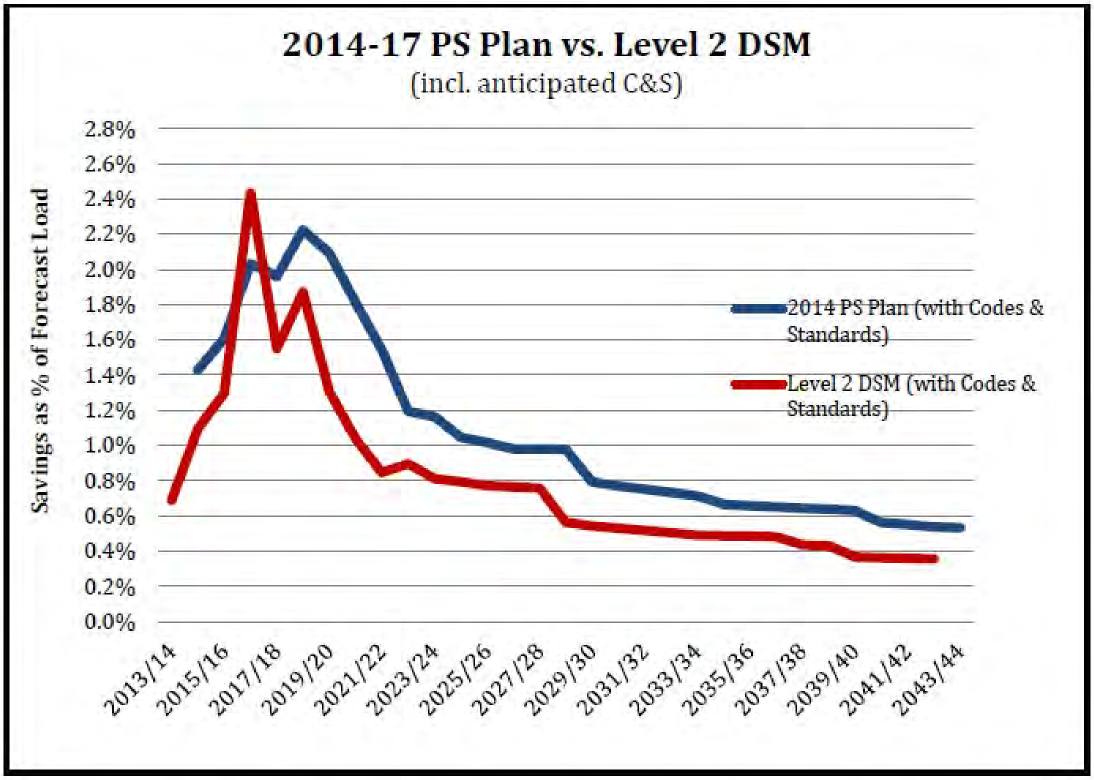
These increased levels of DSM represent substantial increases over the DSM program outlined in the 2013 Power Smart Plan; ranging from 2.2 to 4.6 times the program savings outlined in the 2013 Plan.[68] Manitoba Hydro considered the DSM Level 2 initiatives to be economic, but Level 3 to be uneconomic.

Manitoba Hydro confirmed that the DSM savings projected in the 2014-17 Power Smart Plan were similar to the savings projected for DSM Level 2. The Power Smart Plan program savings are slightly lower than the DSM Level 2 savings. However, the savings from codes and standards projected in the Power Smart Plan are higher, making the overall Power Smart Plan savings greater than DSM Level 2.

In assessing DSM savings, a distinction must be drawn between cumulative savings and incremental savings. Once a DSM measure is implemented, it usually provides cumulative savings. Incremental savings, on the other hand, are those savings achieved through new measures layered on top of existing measures. The Figure below illustrates the anticipated differences between the 2014-2017 Power Smart Plan and DSM Level 2 in terms of incremental DSM savings, expressed as a percentage of forecasted load, including codes and standards savings. [69]

[68] Exhibit MH-204, p. 20.
[69] Exhibit MH-202.

Figure 3 Manitoba Hydro 2014 Power Smart Plan vs. DSM Level 2 Savings



5.3.0 The Impact of New DSM on Load Growth

A number of witnesses talked about the impact of Manitoba Hydro's DSM Level 2 proposals on the forecasted load growth. All agreed that increased DSM could reduce load growth. Most suggested tht with successful implementation, Manitoba Hydro could achieve DSM savings greater than Manitoba Hydro's plans, which they characterized as conservative in the long term.

Several witnesses questioned the proposed incremental savings scenario for DSM Level 2, particularly the sudden increase followed by a tailing-off of incremental savings. As illustrated in the above Figure, Manitoba Hydro's scenario suggests a rapid increase in incremental savings to 2.4% in 2017/18, followed by an equally steep decline to 0.8% in 2021/22, and then a downward trend to 0.4% by 2043/44. Mr. Chernick, who testified on behalf of the Green Action Centre, suggested that it was unusual for a power utility to commit to an early DSM increase and then indicate that there were few achievable DSM savings afterwards.[70] He stated:

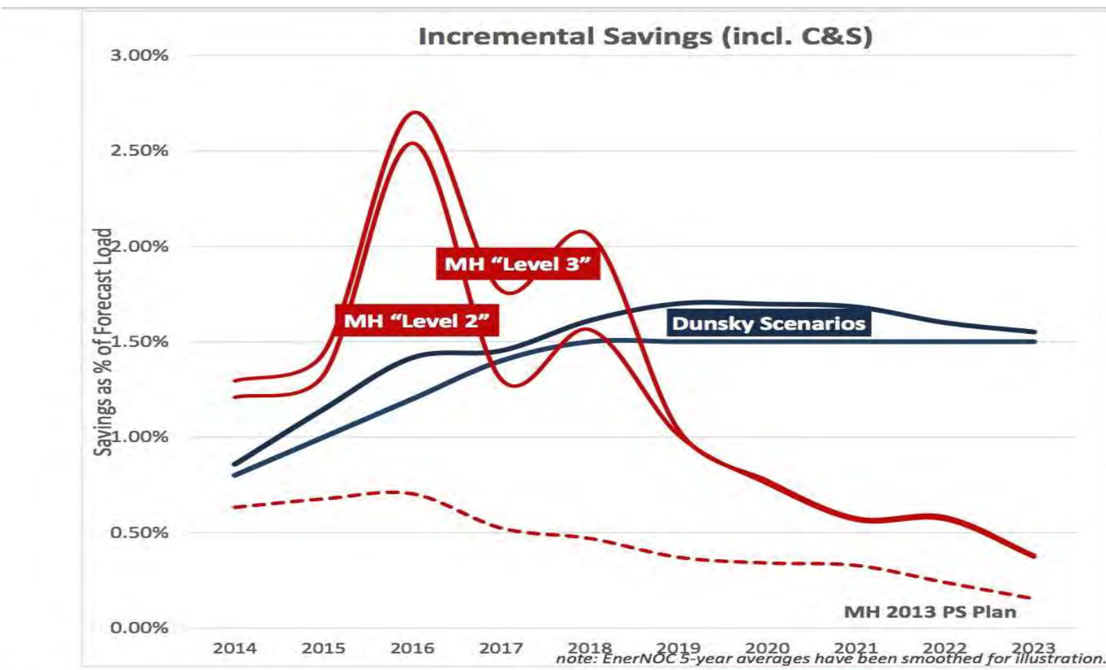
[70] Transcript, p. 9838.

> *I can't really think of another example that – that's quite so vivid in terms of a utility saying over and over again, we can do a lot in the next few years, but then nothing after that. And it – it looks like the Utility is – is willing and interested in doing some energy efficiency in the near term, but is reluctant to interfere with long-term construction plans by committing to a long-term energy efficiency program, so the numbers go down.*[71]

Mr. Dunsky submitted that Manitoba Hydro's DSM Level 2 plans represented a static view of the future: while they signified a dramatic and commendable change in DSM planning and target setting over the short term, they then reverted to previous assumptions, such that by 2023 and after, DSM savings would be 90% below the Level 2 peak.[72]

Mr. Dunsky provided the Panel with an alternative view for a DSM scenario that presents a more gradual growth to 1.5% incremental savings in 2016, followed by a stable DSM savings of 1.5% around 2019, as depicted in the Figure below. [73]

Figure 4 Incremental Savings - Manitoba Hydro DSM Levels 2 & 3 vs. Dunsky Scenarios

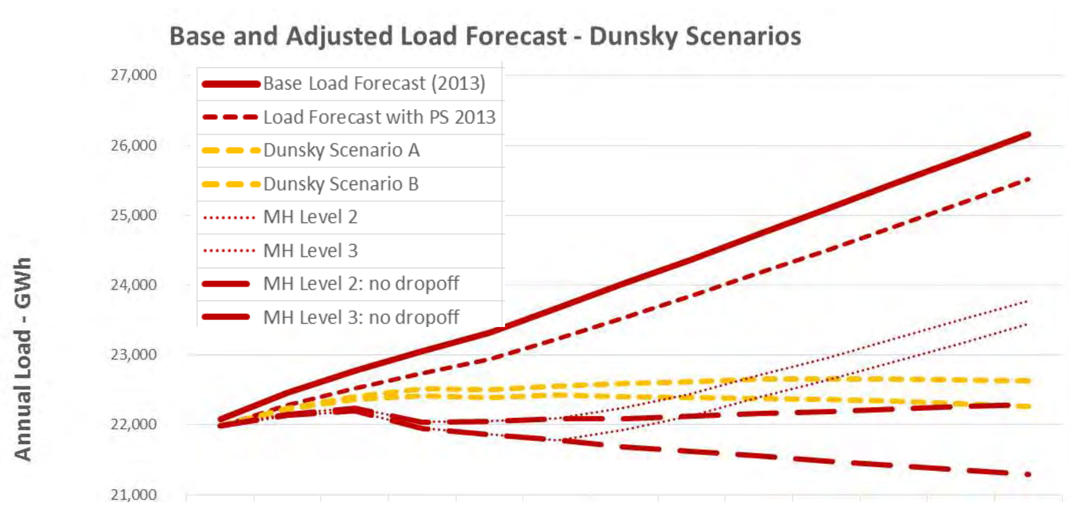


Mr. Dunsky felt that Manitoba Hydro could achieve annual average energy savings at a cost well below the cost of new generation or the price of power exports, and achieve

[71] Transcript, p. 9838.
[72] Exhibit CAC-62, p.15.
[73] Exhibit CAC-62, p.14.

annual average energy savings for the next 10 years (2014-2023) of 1.1% from utility programs (1.3% including codes and standards) under a "cautious" DSM scenario and 1.3% (1.5% including codes and standards) under a more aggressive approach to DSM.[74] These increased DSM levels, he maintained, could translate into cumulative savings over that 10-year period of 2,634 GWh/year (3,220 GWh/year including codes and standards) under the cautious scenario and 3,013 GWh/year (3,534 GWh/year including codes and standards) for the aggressive portfolio, the net effect of which is to virtually flatten domestic load growth, as shown by the dashed yellow lines in the following Figure.[75]

Figure 5 DSM Scenarios' Impact on Manitoba Hydro Load Forecast



Mr. Chernick also suggested that Manitoba Hydro could increase DSM savings from the current 0.4% of retail sales to 1.5% of sales annually through a combination of measures to discourage the use of electricity for heating, as well as codes and standards, and regulations.[76]

A number of witnesses were of the view that it was possible to flatten load growth with DSM. Dr. Gotham, an expert witness on behalf of the CAC, felt that DSM could not realistically achieve negative net load growth, because incentives change when load is shrinking there is no longer the benefit of avoided cost of new generation.[77] Mr. Dunsky argued that load growth could be flattened and new generation deferred until at least

[74] Exhibit, CAC-62, p.13.
[75] Exhibit CAC-19, p. 30; Transcript p.7876.
[76] Exhibit GAC-22, p. 25.
[77] Transcript, pp 8602-8603.

the mid-2020s.[78] Mr. Chernick and another CAC expert, Dr. Higgin, also agreed that flat load growth could be attained through DSM efforts.[79]

The original versions of Manitoba Hydro's proposed development plans provided in August 2013 assumed the 2012 load forecast projections, and a "base" level of DSM. The 2014 versions of the development plans assume the newer 2013 load forecast projections and substantially higher DSM spending to achieve DSM Level 2. This change in forecasted DSM savings caused dramatic changes in both the need date for new generation resources to meet Manitoba demand and in the economics of the development plans that Manitoba Hydro analyzed.

DSM Level 2 affected the Net Present Value of all development plans. The Net Present Value of the Preferred Development Plan relative to the All Gas Plan decreased by $329 million such that it is only $45 million better than the All Gas Plan. Plans with Keeyask but not Conawapa were not significantly affected by DSM Level 2 relative to All Gas, and, in fact, improved their Net Present Value.[80]

Chapter 8 of this Report discusses Manitoba Hydro's economic evaluation of the Preferred Development Plan and alternatives.

5.4.0 The Value Proposition of DSM

During the NFAT Review hearings, the Panel heard from a number of witnesses about the importance of DSM in Manitoba's energy future. Witnesses spoke to the Panel about successful DSM programs in other jurisdictions and the framework required to achieve stable long-term DSM savings. The Panel saw that DSM can have a profound impact on the date when new energy resources are needed. The Panel learned that DSM is a powerful resource that can bring value to resource planners, ratepayers, the economy, and the environment. The Panel, therefore, considered how DSM can bring that value. It looked at the role of DSM in resource planning.

The Panel found that treating the DSM savings from the Supplemental 2014 Power Smart Plan as a separate, independent energy resource, yields capacity savings that amount to more than 80% of the net system capacity addition from the proposed Conawapa Project. Similarly, the annual dependable energy savings from the Power Smart Plan exceed 85% of the dependable energy output from the proposed Conawapa

[78] Transcript, p.8182; Exhibit CAC-62, p. 57.
[79] Transcript, p.9536; Transcript, pp. 9661-2.
[80] Exhibit MH 104-15, p. 2.

Project. To achieve these electricity savings, Manitoba Hydro budgets to spend $822 million, which is less than 8% of the $10.7 billion cost of building Conawapa.[81]

5.4.1. Role of DSM in Resource Planning

A number of witnesses discussed how DSM savings should be treated for resource planning purposes.

Manitoba Hydro provided evidence on how its DSM initiatives fit into its power resource planning process. Referring to the interface as a "combined DSM integrated resource planning process", it begins with resource planning staff indicating a value that represents the value of energy to Manitoba Hydro (currently approximately 7.5 ¢/kWh). This marginal value represents the value of energy that is saved and then exported combined with the avoided cost of new transmission and distribution infrastructure. This value is used to update Manitoba Hydro's Power Smart Plan in relation to economic DSM opportunities based on a total resource cost metric. The revised plan is then provided back to Manitoba Hydro's resource planners for input into the resource planning process.[82]

Elenchus and Mr. Dunsky emphasized that Manitoba Hydro should treat DSM as a resource option from the outset, assessing it in the same manner as investments in traditional resource options such as hydro dams or investments in transmission and distribution. Both suggested that Manitoba Hydro pursue an Integrated Resource Planning (IRP) approach to evaluate supply- and demand-side resources on an equal footing.[83]

Mr. Dunsky further stated that an integrated process helps to ensure that least cost options are fully considered. He maintained that by not treating DSM as a resource option through an IRP approach in its analysis of the possible resource options to meet domestic power needs, Manitoba Hydro has *"de facto excluded the single lowest-cost and lowest-risk resource option available"*[84] and "*risks locking itself into a path of new supply that, as a result, will lock out the much less expensive option of more efficient demand.*"[85]

Manitoba Hydro maintains that it is undertaking integrated resource planning that combines supply and demand options, and that its Power Smart Plan is an integral

[81] Exhibit MH-180, p. 31.
[82] Transcript, pp. 431-434.
[83] Exhibit ERA-2.2, p. 1; Exhibit CAC-19, p. 6.
[84] Exhibit CAC-19, p. 12.
[85] Exhibit CAC-19, p. 16.

component of its resource plans. It asserted that the analysis of DSM options and supply options provided to the Panel after the hearing began was an integrated evaluation.[86]

There was also discussion about innovations that can sustain DSM savings over the long term. Mr. Dunsky stressed that DSM opportunities are constantly being renewed through innovation.[87] He further suggested that Manitoba Hydro was presenting an unrealistic view of the emerging opportunities for energy efficiencies, such as emerging innovations in efficiency standards, LED lighting, heat pumps, data-driven analytics, and solar photovoltaics.[88] In his view, "*New DSM opportunities abound – including several "game changers" that have already landed in market, with many more to come."*[89] He further stated that: *"Not accounting for these game changing future opportunities really exposes long-term investment plans to significant risk. And that's not to say it's not a risk worth taking, but there's a very real risk that needs to be accounted for, especially in long-term forecasts.*"[90]

Mr. Dunsky indicated that resource planners in a number of jurisdictions are now assuming that DSM opportunities will continue to improve and replenish themselves as opposed to reaching depletion. Those same system planners also consider DSM to be a dependable, low-risk resource.[91]

Manitoba Hydro has traditionally focused on DSM measures and opportunities that are known, commercially available, or very near commercialization.[92] On the issue of innovation and the focus of its DSM measures and opportunities, Manitoba Hydro stated the following:

> *"While it may only be a question of timing as to when the next innovation or evolution of energy efficient technology will become available and commercially viable, for the purposes of resource planning and meeting customers' energy needs, timing does matter. The Corporation must balance risks and the timing of technology evolution, and its adoption can have a significant impact on the Corporation's obligation to meet customers' energy requirements."*[93]

[86] Exhibit MH-204, pp. 38-39.
[87] Transcript, p. 8076; Exhibit CAC-62 pp.19-39.
[88] Exhibit CAC-62, pp. 32-38.
[89] Exhibit CAC-62, p. 39.
[90] Transcript, pp. 8034-8035.
[91] Exhibit CAC-62, p. 52.
[92] Exhibit MH-204, p. 25.
[93] Exhibit MH-204, p. 26.

The certainty of DSM savings was the subject of some discussion. While Manitoba Hydro includes DSM in its supply-demand analysis and considers DSM to be 100% dependable, it would appear to have some reservations about the certainty of DSM as a resource. In its NFAT Submission, Manitoba Hydro notes the following:

> *"… Without regulation or legislation, achieving energy reduction targets is strongly dependent upon market acceptance and voluntary action. Also, in addition to market availability and adoption forecasts, the savings potential is estimated based on a variety of assumptions that include natural technological development, anticipated customer energy usage/savings and market cost projections. As a result, expected energy savings from DSM do not have the same future certainty of supply as would the development of a physical resource."*[94]

Elenchus maintained that future DSM savings were not certain and suggested that DSM should be treated as a non-dispatchable resource subject to explicit dependability factors.[95] Mr. Dunsky, on the other hand, was of the opinion that all forecasted DSM savings could be counted on for planning purposes.[96] This view was supported by Mr. Chernick.[97]

5.4.2. Value of DSM to Ratepayers: Savings Potential

DSM program spending and benefits have different impacts on customers as some customers participate to varying degrees in the DSM programs while other customers do not participate at all. In particular, specific barriers to participating in DSM programs have been identified with respect to lower income customers.

DSM programs typically result in higher rates because total demand is reduced; the fixed costs of Manitoba Hydro's system, including DSM spending, do not fall with demand and have to be recovered over lower sales volumes. The result is that bills may go down for participating customers even as the electricity rates may go up. Customers who access DSM programs and choose to participate can benefit from reduced energy consumption and thus reduce their annual energy bills. Customers who do not participate in DSM programs and therefore do not reduce their energy consumption will potentially pay more for their electricity.[98]

[94] Manitoba Hydro NFAT Submission, Chapter 7, p. 13.
[95] Exhibit ERA-2-2, p. 35.
[96] Transcript, p. 8074.
[97] Transcript, p. 9822.
[98] Exhibit MPA–3-1, pp. 6-7.

In jurisdictions that export surplus energy and capacity, DSM savings may mitigate the rate increases associated with the cost of DSM measures. This mitigating effect comes from the ability of DSM measures to free up more energy and capacity for export, and thus increase revenues from export sales. If export prices are equal to or greater than the utility's costs of the DSM measures, these costs could be recovered from export revenues and ratepayers might not see a rate increase at all.

Residential customers can realize significant savings on their energy bills if they fully utilize the available DSM measures. Manitoba Hydro provided three example scenarios to illustrate such savings based on an average single detached home of approximately 1,300 square feet.[99] These examples show annual energy savings ranging from 7% to 42% depending on the measures employed.

- Example 1: For the customer heating both their home and their water with electricity, if they were to install energy efficient lighting, the free Water & Energy Saver kit, upgrade their attic insulation from R20 to R50 and their basement insulation from R0 to R24, and retire their second refrigerator, they could save approximately 42% on their annual electricity bill.
- Example 2: For the customer heating their home with natural gas and their water with electricity, if they were to install energy efficient lighting, the free Water & Energy Saver kit and retire their second refrigerator, they could save approximately 16% on their electricity costs or 7% on their overall energy bill (natural gas and electricity).
- Example 3: For the customer heating their home and their water with natural gas, if they were to install energy efficient lighting and retire their second refrigerator, they could save approximately 15% on their annual electricity costs or 5% on their overall energy bill (natural gas and electricity).

DSM programs are a direct way for residential, commercial, and industrial ratepayers to participate in their energy savings and contribute to their energy future. Since their implementation in 1989, Manitoba Hydro programs will have saved participating customers over $1 billion.[100]

Certain industrial customers have the greatest potential to benefit from DSM program energy savings as they are large consumers of electricity. The Manitoba Industrial Power Users Group (MIPUG) indicated that industry has been one of the largest and most committed participants in Manitoba Hydro's DSM programming.[101] However, as

[99] Exhibit MH-164.
[100] Exhibit MH-154, p.5.
[101] MIPUG-28, p. 91.

further set out below, MIPUG was critical of the perceived lack of availability of some DSM measures to industry, particularly the Curtailable Rate Program (CRP).[102]

In its updated analysis of ratepayer costs for the Panel, Morrison Park found that DSM Level 2 had a "powerful effect" on ratepayer costs in that it brought ratepayer costs down. They noted that DSM can not only help to reduce the electricity bills of ratepayers who take advantage of the programs, but also reduce Manitoba domestic load, and free up more capacity for export.[103]

5.4.3. Value to Lower Income Customers

Throughout the hearing, the Panel heard about how lower income customers would be negatively affected by the rate increases projected in Manitoba Hydro's development plans. The Panel also learned that lower income customers face barriers to participating in energy efficiency programs. CAC identified a number of barriers to lower income customer participation in Power Smart programs, including lack of access to financing, housing conditions that preclude energy efficiency improvements, and electricity bills being in arrears.[104] Witnesses noted the common problem of DSM programs in reaching lower income and vulnerable customers. In some cases, the challenge is getting information, services, and incentives to rural and remote communities.

Dr. Higgin stressed the importance of DSM programs reaching vulnerable customers. He concluded that bills, not rates were important.[105] Dr. Higgin was of the view that the impacts on ratepayer bills in the short term proposed for the Preferred Development Plan were not acceptable, particularly for vulnerable consumers,[106] whom he defines as customers whose household income is less than 125% of Statistics Canada's Lower Income Cut-Off measure.[107]

The ability of customers who are in arrears to participate in Power Smart Programs was identified as a particular concern. Manitoba Hydro does not permit these customers to participate in its Power Smart programs unless they have made payment arrangements designed to eliminate the arrears. The Panel was told that the exclusion of customers in arrears from Power Smart programs has a significant impact on many aboriginal communities where many residents are in arrears.[108] MKO submitted in its closing

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[102] Exhibit MIPUG-28, p. 91.
[103] Exhibit MPA-3-1, p. 14.
[104] Exhibit CAC-92 p. 63; Transcript p.11139.
[105] Exhibit CAC-76, p. 10; Transcript, p, 9458.
[106] Exhibit CAC-76, p. 10.
[107] Transcript, p. 9450.
[108] Exhibit MKO-11. p. 8.

argument that 86% of MKO First Nations accounts are currently in arrears and are therefore ineligible to participate in DSM measures.[109]

The Interveners agreed that specific actions should be taken to assist lower income and vulnerable customers. CAC suggested that bill support be considered.[110] MKO stressed the importance of Manitoba Hydro undertaking efforts to reduce electricity bills by ensuring the availability of DSM programs, particularly to lower income, fixed income, and remote residential customers, and to general service customers in First Nations communities. MKO also maintained that future rate increases should be conditional on Manitoba Hydro's DSM programs being universally available and practically accessible to First Nations customers. To achieve accessibility, MKO recommended that Manitoba Hydro act on Mr. Dunsky's ideas of providing DSM programs on a turn-key basis to First Nations customers. MKO also recommended that Manitoba Hydro measure and report on the availability and penetration of lower income DSM programs for First Nations customers, particularly to lower income First Nations customers, and on the success of DSM programs in reducing the bills of lower income First Nations customers.[111]

5.4.4. The Curtailable Rate Program (CRP)

Manitoba Hydro has had a Curtailable Rate Program in place for industrial customers since 1998. Customers who participate in the Curtailable Rate Program can have their power curtailed on short notice. This program is used to maintain operating and contingency reserves in order to minimize disruption to Manitoba Hydro's firm customers in the event of loss of generation or transmission. Curtailable load is particularly valuable to Manitoba Hydro in system emergencies. However, its greatest value is during times of peak power use.

Mr. Dunsky explained that there is considerable opportunity for Manitoba Hydro to achieve capacity savings through a combination of new demand response initiatives, energy-focused DSM initiatives, and Manitoba Hydro's current industrial Curtailable Rate Program (CRP).[112] The Panel learned that Manitoba Hydro has capped the CRP and is no longer accepting new entrants. MIPUG members appeared before the Panel and expressed an appetite for continued participation in the program, as well as for enhanced and new opportunities to participate in other demand response initiatives and customer self-generation measures. MIPUG offered the view that Manitoba Hydro had not captured the benefits of the CRP. In its view, the CRP provides capacity and helps

[109] Exhibit MKO-11, p. 8.
[110] Exhibit CAC – 91, p, 50.
[111] Exhibit MKO-11, pp. 6-7.
[112] Exhibit CAC-19, pp. 41-42.

with reliability. As such, participation in the CRP should not be capped and there should be options to allow for new participants.[113]

In response, Manitoba Hydro noted that only 16 industrial customers have made use of the CRP since its formation, and only three businesses currently use it. Accordingly, while Manitoba intends to ensure that existing CRP participants continue to receive its benefits, Manitoba Hydro indicated that to remove the cap would invite uneconomic DSM.[114]

5.4.5. DSM and Fuel Switching

GAC's expert witness, Mr. Chernick, raised a concern with the ongoing switching of Manitoba Hydro customers from gas-fired space and water heating to electric heat. In GAC's view, space and water heating with natural gas is preferable by every measure. Gas heating is a more efficient use of gas than to generate power (greater than 90% efficient for space heating versus 25 to 50% efficient in a power plant), saves customers money, is better for the environment because of reduced global emissions, and provides cash flow to Manitoba Hydro through additional exports. Since the electricity savings generated by relying on gas allow Manitoba Hydro to export more electricity into the heavily coal-based MISO market, relying on gas heat instead of electric heat actually reduces global greenhouse gas emissions. In light of these factors, GAC called the ongoing switch to electric space and water heat a "*serious market failure*."[115]

Manitoba Hydro's 2012 Fuel Switching Report provided findings similar to Mr. Chernick's analysis. The Report states that: "*From the customer, utility and provincial leakage perspectives, there are substantive benefits when customers use natural gas rather than electricity for space heating purposes... Using electricity for space heating in Manitoba as opposed to natural gas will reduce GHG emissions in Manitoba; however the global GHG emissions will be higher due to reduced electricity exports from Manitoba.*"[116]

Manitoba Hydro owns Centra Gas, the Province's only natural gas distributor. Because of this, Manitoba Hydro is in the position of being able to encourage its customers' fuel choices one way or the other. Rather than aggressively advocating one fuel over the other, Manitoba Hydro has developed a "Fuel Switching Initiative" consisting of an education and information campaign directed to homeowners, heating contractors, homebuilders, and land developers. The aim of the initiative is to increase awareness of

[113] Exhibit MIPUG-28, p. 68.
[114] Exhibit MH–204, p. 35.
[115] Exhibit GAC-27, pp. 12-13.
[116] Manitoba Hydro NFAT Submission, Appendix 15.4.

the lifetime costs of installing and operating electricity, natural gas, and geothermal heating systems in order to provide customers with information to make informed choices.

Mr. Chernick disagrees with this passive approach and suggests that the trend toward electric heat could be reversed through the vigorous promotion of gas heat by a combination of better information, appropriate incentives, Power Smart programs, and offering low-cost, on-bill, transferable financing.[117] Furthermore, Mr. Chernick suggested that Manitoba Hydro could do more to discourage electric heat by increasing the cost to land developers for electricity line extensions and reducing the cost of gas connections.[118] Elenchus further noted that because Manitoba Hydro controls both the distribution and sale of electricity and natural gas, and Manitoba Hydro's focus as a Crown corporation is on serving the customer as cost effectively as possible, it should help customers choose the least expensive fuel.[119]

The Manitoba Métis Federation noted its concern about the failure of Manitoba Hydro to consider biomass, such as wood, as a fuel switching or load displacement option. They observed that many northern and aboriginal communities have access to this fuel source and that considerable new technologies now exist to use biomass as a fuel.[120]

5.4.6. DSM Employment Potential

Manitoba Hydro indicated that it did not prepare a study of the employment impacts associated with DSM for the NFAT Review, in part, because fewer opportunities for DSM-related training and employment would exist in northern Manitoba. However, Mr. Dunsky suggested that DSM could create significant employment in comparison to new generation options. He noted that studies of the economic benefits of DSM show that for every million dollars spent on DSM, 15 to 35 person-years of employment were created, which is 2 to 10 times more than for new power plant construction. The high level of job creation associated with DSM was confirmed in a study Mr. Dunsky conducted in four Canadian provinces, and will, he suggests, be further supported by a national DSM study that has yet to be publicly released. Mr. Dunsky stated the DSM employment values for Manitoba will be toward the higher end of the range, based on the study's macroeconomic modelling.[121]

117 Exhibit GAC–12, pp. 2-13.
118 Exhibit GAC–12, pp. 2-15, 2-16.
119 Transcript, p. 5183.
120 Exhibit MMF-36, p. 6.
121 Transcript, pp. 8184-8186. Exhibit CAC-62 p.9.

One of the presentations to the Panel provided information on the job creation potential of DSM, indicating that the cost to create a Demand Side Management job could be about $80,000 per direct/indirect full-time equivalent (FTE) position.[122] The cost to create a hydropower development job could, in this Presenter's view, be several hundreds of thousands of dollars. He emphasized there were many advantages associated with DSM employment opportunities, such as more permanent jobs, additional transferable skills, and more local employment, as well as a better geographic distribution of jobs, including northern and aboriginal communities.[123]

5.4.7. Environmental Benefits of DSM

Reducing energy consumption has obvious environment benefits. Manitoba Hydro is projecting greenhouse gas (GHG) emission reductions of 780,000 tonnes as a result of its gas and electric DSM programs over the three-year period, 2014-2017.[124] Including GHG reductions achieved to date, Manitoba Hydro is forecasting GHG reductions in the order of 4.6 million tonnes by 2028/29.[125]

A long-time advocate of using natural gas as a heating fuel because it frees up electricity for export, GAC emphasized the importance of distinguishing between the GHG impacts of natural gas used for heating and natural gas used to generate electric power. Because of the difference in their efficiencies, (greater than 90% for a gas furnace versus 20-50% for gas turbine or coal power generation), heating with electricity causes significantly more GHGs to be produced by the North American energy system than heating with a high-efficiency gas furnace. GAC argues that converting to electric heat to achieve fossil fuel freedom increases the net environmental impacts associated with the heating choice.[126]

5.4.8. Implementing a Successful DSM Program

An inherent conflict of interest may exist when a utility that derives income from the power it sells also has the responsibility of promoting the use of less electricity through energy efficiency programs. If a utility can make more money from selling electricity than it can if electricity is saved, there can be a disincentive to encouraging customers to reduce their energy consumption. Reduced consumption means less income, unless the energy can be sold on the export market at prices that are higher than domestic electricity rates.

[122] Transcript, p.7930.
[123] Transcript, pp. 7927-7931.
[124] Exhibit MH-153, p. 5.
[125] Exhibit MH-180, p. 40.
[126] GAC-27, p. 32.

Witnesses outlined to the Panel their views on how best to achieve a successful DSM program. Based on their observations and experiences with other jurisdictions in Canada and the United States, they identified the following requirements:[127]

- The creation of DSM targets. Targets are mandated, clear, and measurable. While it is important to have a long-term perspective on desired outcomes, DSM programs need measurable targets to guide program design.
- Aggressive pursuit of DSM targets. The entity charged with delivering DSM programs must be committed to achieving the targets.
- Monitoring and reporting of performance relative to targets. Performance against goals is assessed through independent (third party) audits and evaluations, which is reported publicly.
- An effective body to track performance. Often times this body is the regulator, but it could also be another entity.

In his testimony, Mr. Dunsky explained:

> *"I've worked with organizations that have put DSM out there and hope that people will come. And often times they find that they don't, and then declare failure. Those organizations tend not to have the motivation to deliver, to sell. They tend not to have a solid reporting framework, where they have to actually report their results in a specific way. Those organizations that operate under a clear oversight framework with clear reporting requirements, and ideally performance requirements, they deliver and they systematically deliver."*[128]

Manitoba Hydro submitted that such a framework already exists in Manitoba by virtue of *The Energy Savings Act,* which requires Manitoba Hydro to consult with the Province of Manitoba in developing its DSM plans.[129]

In their Closing Submissions, both CAC and MIPUG supported efforts to implement and pursue enhanced DSM programs.[130]

MKO recommended in its closing submission that an entity independent of Manitoba Hydro be established with a mandate to deliver DSM programs in Manitoba.[131] Residential, business, and especially lower income customers often need to be "sold"

[127] Transcript, pp. 8143-8149; pp. 9420-25.
[128] Transcript, p. 8147.
[129] Exhibit MH-204 p. 37.
[130] Exhibit CAC-91, p. 52; Exhibit MIPUG - 28, p. 61.
[131] Exhibit MKO-11, p. 9.

on DSM. Programs and information need to be provided in a manner that speaks to them directly, and in a clear and convincing manner.

5.5.0 Conclusions of the Panel

In the course of the NFAT Review, the Panel heard much about the importance of DSM. Energy and capacity savings achieved through DSM measures provide a low-cost, reliable, dependable resource that has the added benefit of reducing customer energy bills. Furthermore, DSM measures can provide a hedge for the consumer against increasing energy costs and for the utility against grid parity. In the Panel's view, there are ample reasons for placing DSM measures on an equal footing with supply-side resource options.

Integrated Resource Planning

Integrated resource planning is a regular practice in many jurisdictions. The purpose of an integrated resource plan is to determine analytically what resource is in the best interest of consumers by examining a full spectrum of possible supply-side and demand-side options and measuring them against a collective set of objectives and criteria. This contrasts with traditional methods of utility resource planning, which emphasize supply-side options such as building new generation, transmission, and distribution facilities. Integrated resource planning also tends to be more transparent than traditional resource planning.

The Panel heard evidence that the best practices for integrated resource planning involve placing every conceivable resource option on an equal footing. Manitoba Hydro prepares an annual Power Resource Plan. However, this plan is not tested through an integrated resource planning process.

The Terms of Reference required the Panel to consider "if preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound."

By failing to offer an analysis of conservation measures as a stand-alone energy resource competitive with other generation resources, Manitoba Hydro presented an analysis of conservation measures that was neither complete, accurate, thorough, reasonable, nor sound.

The NFAT Review demonstrated that DSM measures were not equally weighted with other energy options. It was only in the course of the NFAT hearing that it became clear that significantly higher levels of DSM than originally proposed by Manitoba Hydro were both achievable and economic. The Panel agrees with the Consumers' Association of Canada (Manitoba) that Manitoba Hydro did not treat DSM as a stand-alone resource option competitive with other generation options in its resource planning and analyses.

In its resource planning, Manitoba Hydro added DSM to each alternative plan it examined. By doing this, Manitoba Hydro effectively screened out DSM as an independent resource to be evaluated against other generation resources.

Had Manitoba Hydro undertaken a best-practices integrated resource planning effort, DSM would have been incorporated in the NFAT analysis from the beginning.

Thus, to satisfy anticipated load growth to 2028/29, the Preferred Development Plan delivers 2,025 MW of additional capacity at an estimated cost of $18.7 billion. Had the Supplemental 2014 Power Smart Plan DSM measures been treated as a stand-alone and equally weighted resource, and added to the capacity from the Keeyask Project, the total capacity addition would be 1,766 MW at a projected cost, including transmission, of $8.3 billion. This is more than 85% of the net system capacity of the Preferred Development Plan, at a considerably lower cost.

It is clear: DSM must be evaluated as a stand-alone resource in an integrated resource planning process by Manitoba Hydro.

In a time of rapid technological innovation on both the demand and supply side, openness to alternative resources and new technologies will be required. This may involve new methods of saving electricity as well as new methods of generating it, such as wind and solar power. Integrated resource planning provides the analytical framework to evaluate all such energy resource options – hydropower, wind, solar, gas, DSM, or other technologies – on an equal footing. As such, it should be adopted by Manitoba Hydro before any further generating facilities beyond the Keeyask Project are constructed in the future.

DSM Targets

Annual average incremental energy savings in the order of 1.5% (including codes and standards) are achievable and economic. This target contrasts with Manitoba Hydro's 2014-17 Power Smart Plan which forecasts declining future DSM savings. In the Panel's view, it is prudent to assume that DSM savings will continue to be attained and technological advances will present new savings opportunities.

While reliance on on-going incremental DSM savings present a risk that the savings will not be realized, several other North American jurisdictions have successfully achieved ongoing annual savings at targeted levels. Mitigating this risk, the Panel's recommendation to proceed with a 2019 in-service date for Keeyask will provide sufficient capacity and dependable energy to create a safety margin in case DSM targets cannot be fully achieved in the short term.

While Manitoba Hydro currently consults with the Province of Manitoba as required under *The Energy Savings Act*, there are no clear DSM targets established by the Government. The Panel is of the view that clear, measurable DSM goals and targets are a key component of Manitoba's energy future.

Implementing DSM Programs

There is an inherent conflict of interest when a utility acts as both a seller of electricity and a purveyor of energy efficiency measures. Therefore, the Panel concludes that the planning and provision of DSM services should be divested from Manitoba Hydro.

Jurisdictions such as Vermont that have established independent arm's-length entities to deliver DSM programs have had considerable success in reducing energy consumption and maintaining program performance. The Panel notes that Manitoba Hydro has a long and for the most part successful history with DSM, but in recent years has seen DSM initiatives scaled back and spending reduced. While Manitoba Hydro is to be commended for the new DSM initiatives in its latest Power Smart program, the Panel believes from the evidence before it that the energy savings will not be sustained at levels it considers achievable over the long term. The Panel is also concerned that the utility's renewed focus on DSM may not be continued into the future, in the face of cost constraints and other corporate priorities.

Therefore, in addition to supporting the creation of long-term DSM targets, the Panel also sees great value in establishing an entity independent of Manitoba Hydro to implement DSM programs. The independent arm's-length model has been operating and proven successful in other jurisdictions; the Panel sees no reason why it could not be successfully implemented in Manitoba. The power savings delivered through an independent arm's-length entity would constitute an additional resource available to Manitoba Hydro to meet energy needs.

Monitoring DSM Performance

Monitoring performance against DSM targets was stressed by a number of witnesses as a hallmark of a successful DSM program. The Panel concurs with that view and strongly believes there should be accountability and performance measurement in terms of achieving DSM goals. The Panel also sees the importance of ensuring that performance evaluation is carried out by someone independent of the DSM provider. For these reasons, DSM savings should be independently audited on an annual basis.

Lower Income and Vulnerable Customers

A significant concern of the Panel is the impact of Manitoba Hydro's projected rate increases over the next 20 years on lower income and vulnerable customers, as discussed in Chapter 9. The Panel notes that DSM measures can help customers mitigate the impact of expected rate increases on their bills. The Panel is of the view that until a new independent arm's-length entity is established to implement DSM programs, Manitoba Hydro should continue to address barriers to lower income customer participation in Power Smart programs. The Panel suggests that a stakeholder consultation process that involves business, residents, and organizations may be able to provide assistance in reaching lower income and vulnerable customers.

Furthermore, the exclusion of customers in arrears from Power Smart programs precludes those that are most in need of these programs from receiving their benefits. Given the projected rate increases that customers will face in the decades ahead, the exclusion of these customers from participating in Power Smart programs needs to be addressed immediately.

The Curtailable Rate Program (CRP)

The Curtailable Rate Program has the potential to result in additional capacity savings. As such, the program merits further review.

Fuel Switching

The Panel supports efforts to reduce the number of customers switching from natural gas to electric heating, and to encourage natural gas use for space and water heating in new construction. Therefore, until a new independent arm's-length entity is established to implement DSM programs, Manitoba Hydro should continue to proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating. If warranted, fuel switching initiatives should include the provision of a fuel-switching option to biomass in areas where natural gas service is not available.

DSM Employment Potential

Long-term DSM provides enhanced long-term employment, which should be considered an additional socio-economic benefit of DSM programs.

6.0.0 Exports Markets and Contracts

6.1.0 Introduction

Since 1970, Manitoba Hydro has sought out customers and exported its electricity to markets in other Canadian provinces and into the United States. What has been a growing endeavour with increasing revenue is now an essential element of Manitoba Hydro's future plans and strategies.

Manitoba Hydro sees export sales as an opportunity to offset a portion of the costs of its proposed new resource needs, mitigate risks for ratepayers, and meet its commitment to sustain low electricity costs. As Manitoba Hydro has stated in its filing, under the title of Surplus by Design "Exports and transmission access to export markets have been and will continue to be critical for the effective and efficient operation of Manitoba Hydro's system and the development of Manitoba's hydropower resources."[132]

The Panel's Terms of Reference directed it to consider a number of issues related to exports and Manitoba Hydro's export contracts. In particular, the Panel was asked to examine the reasonableness, thoroughness, and soundness of Manitoba Hydro's export market forecast and its revenue projections.

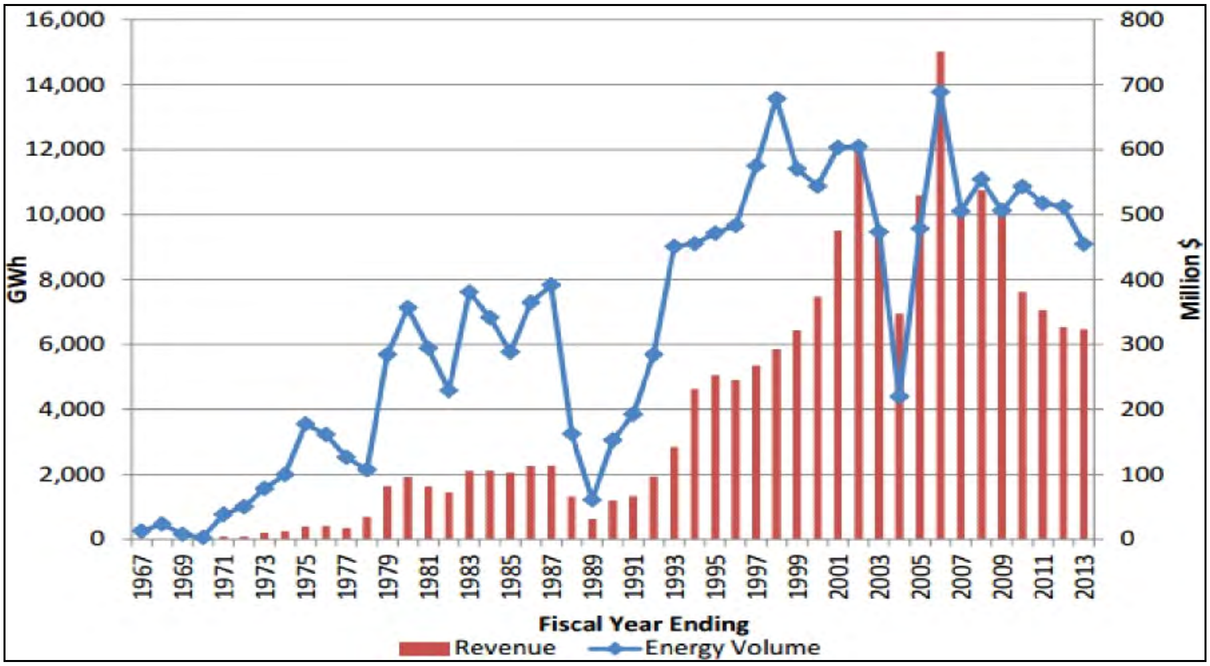
6.2.0 Background and Context

6.2.1. History of Manitoba Hydro's Exports

The annual history of Manitoba Hydro's energy exports (GWh) and gross revenues from those exports are presented in the Figure below:[133]

[132] Manitoba Hydro NFAT Submission, Chapter 5, p. 31.
[133] Manitoba Hydro NFAT Submission, Chapter 5, Figure 6.3, p. 20.

Figure 6 Manitoba Hydro's Gross Export Revenues and Volumes (1967-2013)



Over the past decade, Manitoba Hydro's exports have generally been between 10,000 and 12,000 GWh/year. Over the period of 2002/03 to 2011/12, about one-third of Manitoba Hydro's total electricity gross revenue has come from exports.[134]

6.2.2. Export Sales, Services and Products

Manitoba Hydro exports four services or commodities: electrical energy generated as measured in GWh, capacity as measured in MW, ancillary services, and environmental attributes. Environmental attributes provide additional value for energy from certain types of generation such as renewable or low-emission generation. These products can be sold in a direct contractual arrangement with another utility. This is often referred to as a bilateral transaction. Alternatively, they can be sold in an organized market where multiple sellers can offer these components to multiple buyers through a competitive market structure.

Manitoba Hydro sells its exports in durations of long-term firm products, medium-term products, and spot-market products. With regard to long-term firm sales, Manitoba Hydro determines its dependable surplus power availability and then seeks to make surplus firm energy available for sale under agreements with terms greater than one year. These sales are done on a bilateral basis directly with counterparties. These long-term sales include both system participation power sales and diversity exchange sales,

[134] Exhibit LCA-9, p. 6-4.

and are usually of 10- to 15-year durations with utility companies in the U.S. Medium-term arrangements are sales with terms longer than one day but less than one year. Spot market sales are defined as sales with timeframes of one day or less. They are done on a bilateral basis or through structured markets, and administered by regional transmission organizations, such as the Midcontinent Independent System Operator, Inc. (MISO).[135]

6.2.3. Surplus By Design

Manitoba Hydro's focus on exports and transmission access to export markets is a continuation of past practices. In its Preferred Development Plan and in many of the alternatives, exporting energy is an underpinning strategy and goal of Manitoba Hydro. Continued and increased exports are seen as the means to contribute to the financing of its new generation needs. By design, in all flow conditions other than the lowest flow period of the past 99 years, there will be hydro-generation capacity surplus to domestic load and committed firm export requirements. Furthermore, hydro developments result in large additions of capacity that produce surpluses of energy compared to what is needed for domestic load, especially in the early years of a new hydro development.[136]

During the hearings, this strategy was presented as the "opportunity" side of the ledger, or the "opportunity pathway." As Manitoba Hydro CEO Scott Thomson indicated on the first day of the hearings:

> *"… Our statutory mandate contemplates exports on appropriate terms. As I'll discuss later, exports have been a major reason why Manitoba Hydro's rates remain so low relative to many other jurisdictions. Revenues from exports help to offset costs for domestic customers."*[137]

Others had differing views as to this approach and its implications. In its closing submission, the Consumers' Association of Canada (Manitoba) Inc. (CAC) made note of the "merchant plant" concept (that is, building a generating station for the export market) underlying Manitoba Hydro's export plans and pathways. In CAC's view, this approach exposes ratepayers to substantial risks.[138]

This notion of the "merchant plant" and its implications was best articulated in the report and testimony of Morrison Park:

135 Exhibit LCA-9, p. 5-8.
136 Manitoba Hydro NFAT Submission, Chapter 5, pp. 31-32.
137 Transcript, p. 79.
138 Exhibit CAC-91, pp. 8-9.

> *"Considered more broadly, Manitoba is simply a price taker in the MISO market, whether it is taking prices in short-term markets, or in a longer-term market for bilateral arrangements with specific counterparties…. As a result, the longer-term firm contracts are not mitigating market risk or exposure for Manitoba Hydro, but merely apportioning the market risk accepted in pursuing the Preferred Development Plan.*
>
> *In this respect, Manitoba Hydro is acting as a "merchant" investor, taking substantial market risk based on expectations, or bets, about the future. While "probabilities" have been placed on different potential futures through the scenario modeling process, fundamental market risks are necessarily imbedded in some Resource Plans to a far greater extent than in others.*
>
> *Prices will either turn out to be high, and ratepayers will benefit, or they will turn out to be low, and ratepayers will have to shoulder more of the burden of Manitoba Hydro's costs. Either way, ratepayers can have no certainty in advance, and no choice in the matter."*[139]

6.3.0 Export Markets

6.3.1. Canadian Export Markets

In its planning, Manitoba Hydro examined the long-term potential and value of both its current markets and potential markets in Ontario and Saskatchewan. Manitoba Hydro currently has a relatively small, 200 MW, export capability into Northwestern Ontario. There is already ample generation and a relatively small load within Northwestern Ontario. The Ontario interconnection through east-west transmission lines is insufficient for a major new sale into southern Ontario. In the view of Manitoba Hydro, this makes the likelihood of increased future power sales to Ontario unrealistic.[140]

Manitoba and Saskatchewan have had ongoing discussions about future power sales. Over the last decade, SaskPower appears to have focused on natural gas-fired generation of electricity, with Saskatchewan being Canada's third-largest producer of natural gas. Recently Manitoba Hydro and SaskPower entered into a Memorandum of Understanding (MOU) dated October 7, 2011 regarding SaskPower's potential

[139] Exhibit MPA-3, pp. 68-69.
[140] Manitoba Hydro NFAT Submission, Chapter 5, pp. 49-51.

purchase of 25 MW from Manitoba Hydro, commencing in approximately 2015. That MOU was converted to a non-binding Term Sheet, dated September 13, 2013.[141]

6.3.2. United States/MISO

Manitoba Hydro has long sold power to public utilities in the MISO territory comprising 15 of the United States. Manitoba Hydro pursues U.S. exports through bilateral contract negotiations with MISO members, especially utilities in Minnesota. The primary reason for Manitoba Hydro's focus on U.S. exports and interconnections with the MISO market is the Minneapolis–Saint Paul metropolitan area of Minnesota, which represents the closest and largest population centre and electricity market to southern Manitoba. Minnesota is a significant net importer of electricity, providing a market for Manitoba Hydro's surplus power.[142] Given the existing U.S. interconnections and size of the Midwestern U.S. market, over 85% of Manitoba Hydro's exports have been sold into the MISO market in recent years. Manitoba Hydro continues to rely on the MISO energy market for the majority of its exports.

6.4.0 Export Market Forecast

6.4.1. Introduction

During the course of the NFAT Review, the Panel heard testimony about the transformation of the electricity marketplace. As a result of innovation, technology advances, concerns about climate change and impending regulations, power utilities are facing an uncertain world which makes planning and forecasting challenging. These factors include:

- The flattening of load growth throughout the U.S.;
- The cost of fuels, especially natural gas;
- The impact and timing of climate policies and regulations, especially as they pertain to carbon pricing;
- The retirement and other restrictions on power sources, such as coal-fired and nuclear generation;
- Public acceptance of new power options, especially shale gas hydraulic fracturing;

[141] Manitoba Hydro NFAT Submission, Related Documents, Export Contracts, Saskatchewan Power Corporation and Manitoba Hydro Term Sheet, September, 13, 2013.
[142] Manitoba Hydro NFAT Submission, Chapter 5, p. 38.

- The rate and adoption of new energy technologies, such as wind, solar photovoltaic, and ground source heating; and
- Changes in the generation sources that might come with grid parity (that is, distributed generating resources that achieve cost parity with grid supplied power).

The potential impacts of distributed generation achieving grid parity are discussed in Chapter 4. Proliferation of grid parity technologies in Manitoba Hydro's export markets could dramatically limit load growth in those markets and compete on price with grid power, effectively capping export prices.

6.4.2. The Nature of the MISO Market: Influences and Determinants

Overview of the Market Drivers

Electricity demand in both Canada and the U.S. is assumed by Manitoba Hydro to continue to increase over its 35-year planning horizon. The Energy Information Administration's (EIA) Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).[143]

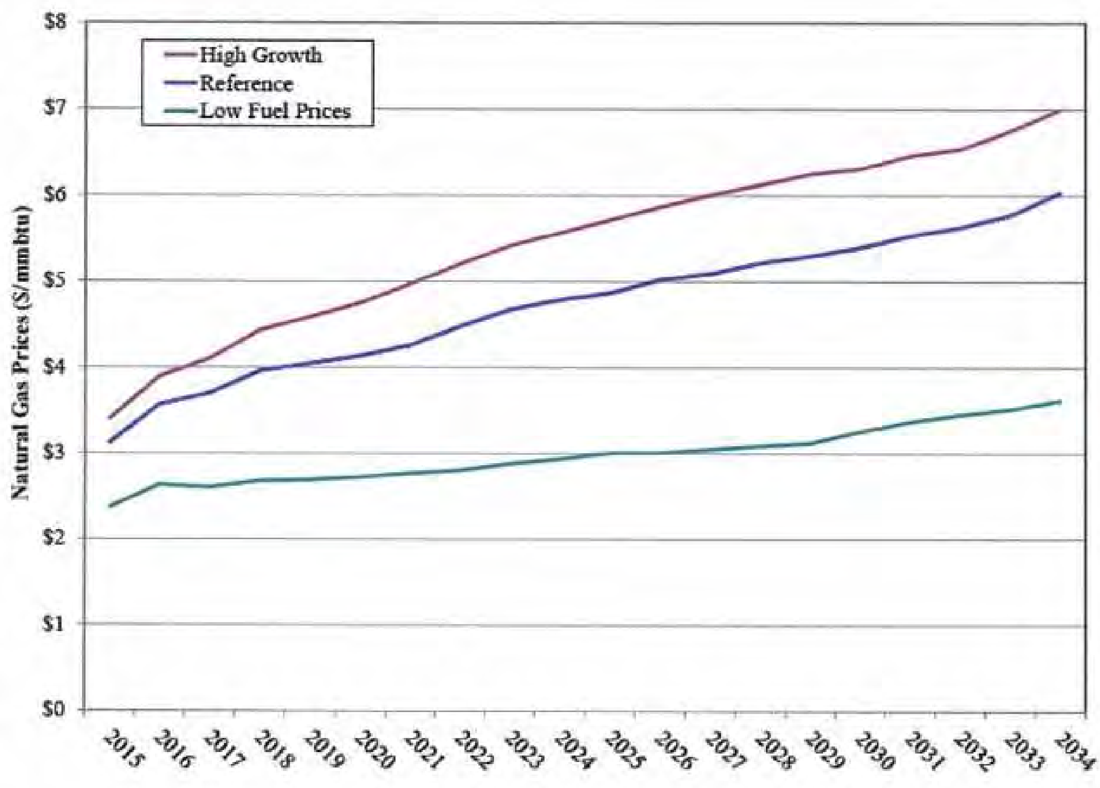
The electricity market is driven not just by the cost of generation but by environmental considerations and policies. For the foreseeable future, environmental considerations, including the anticipated effects of electric industry regulations on greenhouse gas emissions, will continue to influence the generation choices of utilities in MISO and the U.S. as a whole. Many market participants and observers, including Manitoba Hydro, anticipate legislation or regulation that will put a price on electricity generated with carbon-emitting resources such as coal and natural gas. Such policies, often referred to as "carbon taxes", ultimately favour non-greenhouse gas (GHG) emitting generation sources such as hydroelectricity generated by Manitoba Hydro.

Countering the purely environmental considerations of electricity generation are the recent developments in natural gas extraction that have increased natural gas supplies and reduced the cost of production. The combination of horizontal directional drilling and hydraulic fracturing of shale rock has resulted in abundant new supplies of natural gas. Since the highs of 2008, natural gas prices have declined. While future prices are, as always, the subject of prognostication and speculation, the expectation from industry analysts is that natural gas prices will moderately increase over the next decade.[144]

[143] Manitoba Hydro NFAT Submission, Chapter 3, p.1. See also, Manitoba Hydro NFAT Submission, Appendix 6.3.
[144] Manitoba Hydro NFAT Submission, Chapter 3, p.31.

While the Independent Expert Consultant, Potomac Economics, did not produce their own natural gas price forecast, they did provide the EIA's forecast, depicted in the following Figure: [145]

Figure 7 Energy Information Agency Natural Gas Price Forecasts (2013 Energy Outlook, real US$/mmBtu at Henry Hub)



Future MISO Generation Mix

Several factors are driving expected change in the electricity generation mix in MISO. Environmental policies are growing in importance for electricity generators and will increase the cost of refurbishing coal plants and accelerate the pace of coal plant retirements.

Investment decisions in new generation for MISO market participants will be driven by capital costs, fuel costs, financing costs, and regulatory considerations. Manitoba Hydro expects that constraints on new coal generation in the U.S. along with continued low natural gas prices will drive the choice toward new natural gas generation.[146] At the

[145] Exhibit POT-2-1, Appendix A-1 p.47.
[146] Manitoba Hydro NFAT Submission, Chapter 3, pp. 1-3.

same time, new renewable portfolio standards and lower capital costs could move investment towards wind and solar power.

As a part of the NFAT Review, the Independent Expert Consultant MNP reviewed the MISO generation mix. MNP concluded that by 2020 a number of factors will converge: coal plants grappling with compliance with carbon policy; new mercury policy; new water use regulations; and more stringent air pollutant regulations. These will all have the effect of retiring coal power plants. Although the rate at which it will occur is open to debate, MNP expects between 10 and 20 GW of coal generation to retire by 2025, representing a possible reduction in coal generation of at least 17%. Potomac Economics, on the other hand, expects only 6 GW of coal plant retirements in the MISO market based on the EIA's view of the expected retirements.[147]

MNP believes that new energy requirements will be met with a combination of natural gas combined cycle generators and wind investments over the period of 2015 to 2037. This may dampen the amount of coal that currently sets marginal prices in the MISO market, and move more gas to the marginal fuel.[148] MNP suggested the forecast changes might have the effect of supporting hydroelectricity development.[149]

Potomac Economics' view of the future MISO generation mix likewise foresees new combined cycle gas turbines and wind generation. Potomac agrees with the EIA's forecast of 6 GW of coal plant retirements which differs from the MISO Transmission Expansion Planning forecast of 12 GW of retirements.[150]

Impact of U.S. Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a U.S. regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. Hydro power is not always included in a particular state's RPS; hydro generating plants with a capacity less than 100 MW may be included in Minnesota's RPS, while any new hydro plant built after 2010 is eligible for Wisconsin's RPS.[151] The RPS mechanism generally places an obligation on load serving utilities to procure a specified fraction of their electricity from renewable energy sources.

[147] Exhibit POT-1, MH/POT-022a.
[148] Exhibit MNP-5, p.30.
[149] Exhibit MNP-5, p. 30.
[150] Exhibit POT-1, MH/POT-022a.
[151] Manitoba Hydro NFAT Submission, Chapter 5, p.54.

Independent Expert Consultant La Capra Associates concluded that neither Minnesota nor Wisconsin would be short of renewable supply under current policies.[152] This could reduce Manitoba Hydro's prospects for future 'clean' hydro electricity sales.

Impact of Carbon Pricing

Carbon pricing has the potential to greatly influence the market price for electricity. As a carbon price is implemented, the cost of fossil fuel-fired generation goes up in proportion to the level of carbon emissions associated with each individual resource. For example, the carbon price component for electricity generated from coal is approximately two times the carbon price component of electricity generated from a combined cycle gas turbine plant. Given that the MISO market is heavily coal-dominant and despite anticipated coal plant retirements, Manitoba Hydro's primary market will be highly susceptible to the presence or absence of carbon pricing. Manitoba Hydro noted that carbon pricing will be a major driver of future power prices.

The Panel also heard from a number of expert witnesses on this matter. MNP prepared a low, reference (or base), and high carbon price forecast. The low case assumed no cap-and-trade legislation until 2030 and a $10/tonne floor price. MNP's reference or base case assumed legislation in 2021 and a $13.14/tonne of carbon floor price. MNP's high case foresaw cap-and-trade legislation in effect in 2020 and a floor price of $15.80/tonne of carbon.[153]

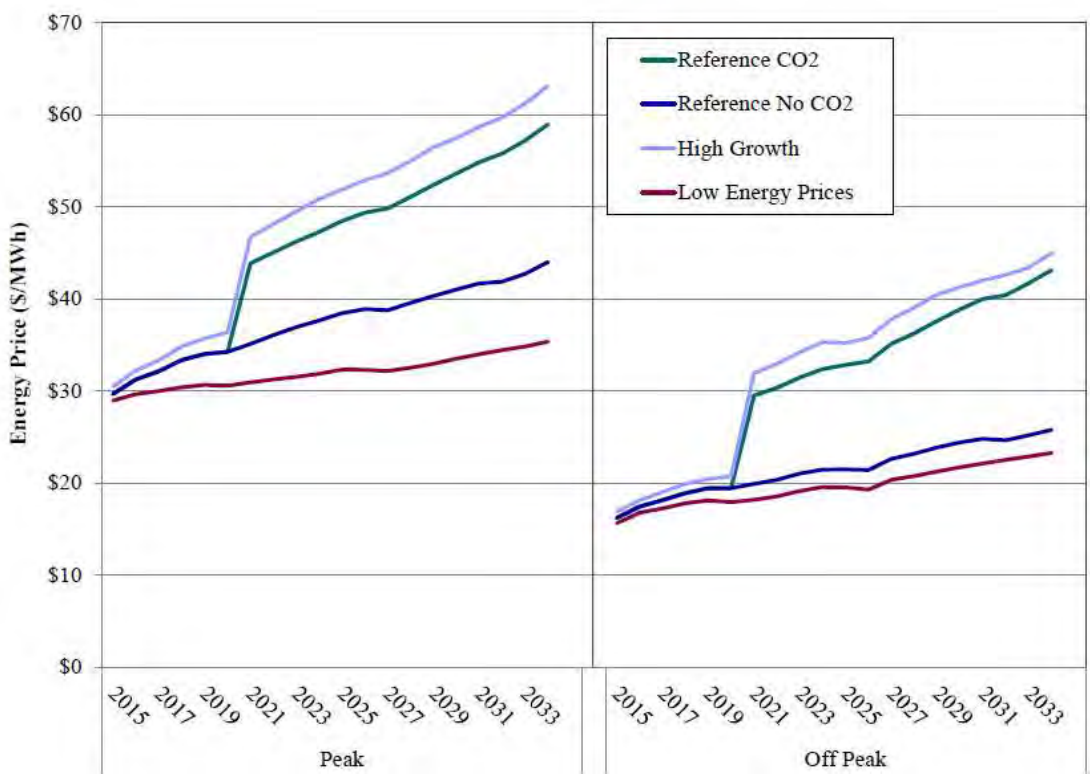
In his review of the carbon costs, Dr. Gotham indicated that there was considerable uncertainty with the use of carbon costs in the export price forecasts. He also concluded that the imposition of carbon restrictions could have a significant impact on projected export revenues. Referencing the public forecasts of the Brattle Group, moderate carbon costs could result in an increase of $13-14/MWh in the market price, while the absence of carbon costs could see Manitoba Hydro's export prices and revenues 20-25% lower, or a shortfall of $1.8 to $2.3 billion based on the expected present value of Manitoba Hydro's export revenues.[154]

Potomac viewed an equal probability of there being, or not being, a future carbon price. Potomac prepared price forecasts reflecting both scenarios, as shown in the graph below. The Reference and High Growth scenarios both anticipate a carbon price beginning at $13.14/tonne in 2021 as suggested by MNP, while the Reference No Carbon and High Resource cases assume no carbon price.[155] According to Potomac's

[152] Exhibit LCA 7-1, p. 4-18.
[153] Exhibit MNP-5, p. 31.
[154] Exhibit CAC 26-1, p. 7.
[155] Exhibit POT-4 p.27 and Exhibit POT-3 pp. 25-28.

graph, on-peak electricity export prices are increased by 25-30% by carbon pricing; off-peak export prices are increased by 50-65%.

Figure 8 Potomac Economics Export Price Forecasts



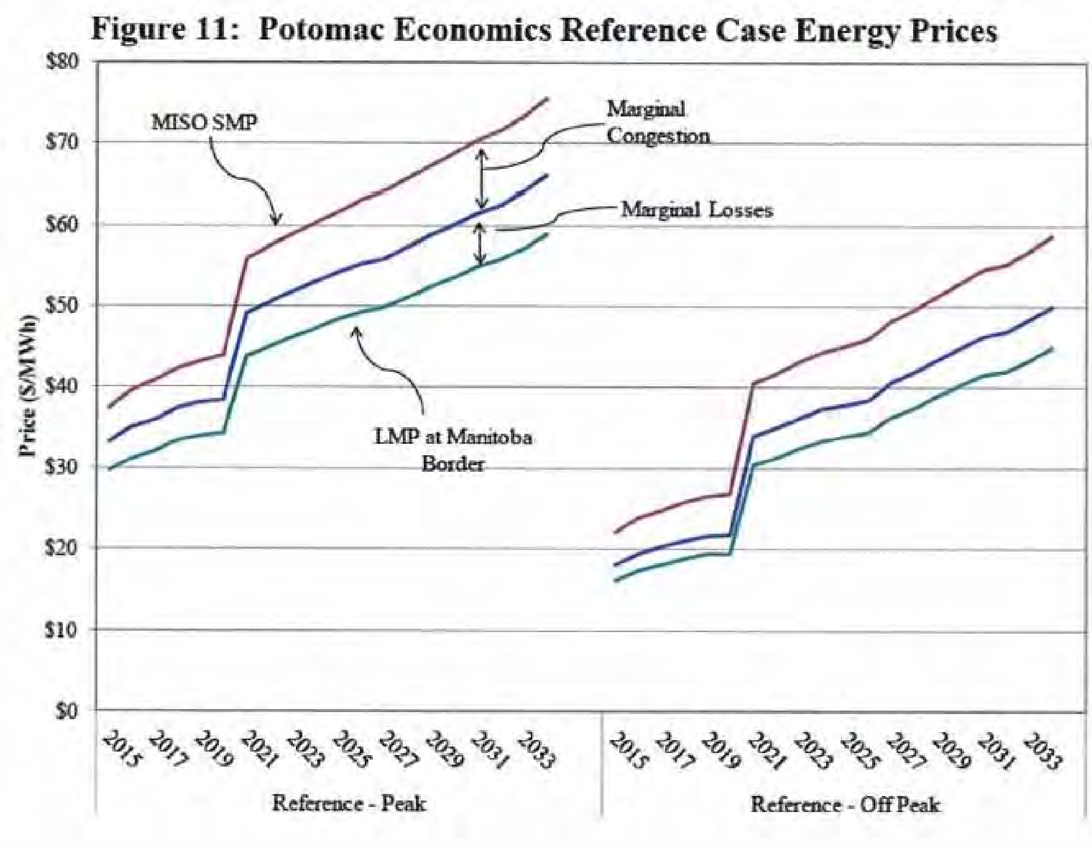
Transmission Congestion

Transmission congestion occurs on electric transmission grids when actual or scheduled flows of electricity over a line or piece of equipment are constrained below desired levels. Transmission congestion shrinks the size of the export market since it excludes participants from outside the congested area. In his analysis, Dr. Gotham concludes that transmission congestion will have an impact on export prices, and could reduce annual average prices by 3-12% at the Minnesota Hub, which is one of several price clearing locations within MISO.[156] In Dr. Gotham's view, there is substantial congestion between Minnesota and Wisconsin and the rest of the MISO market which serves to reduce the market prices in these locations, which in turn, will reduce Manitoba Hydro's export revenues.[157]

[156] Exhibit CAC 26-1, pp. 4-6.
[157] Exhibit CAC 26-1, p.9.

Potomac Economics also examined transmission congestion. They developed an econometric model to estimate how key factors that contribute to congestion, such as system marginal prices, market generation, ramp requirements and wind share of generation, affect market prices. Potomac Economics incorporated these congestion effects into its forecast of market prices. The graph below shows how congestion depresses the System Marginal Price, which in conjunction with transmission losses, results in a lower Locational Marginal Price at the Manitoba-Minnesota border where the prices for Manitoba Hydro's exports are settled.[158]

Figure 9 Potomac Economics Reference Case Energy Prices



6.4.3. Energy Price Forecasts

MISO market electricity prices consist of the market price for energy, which includes the variable cost of generation including fuel, and the price of capacity, which reflects the capital, financing, and fixed costs of investing in new generation. Energy and capacity prices incorporate the effects of supply and demand, economic conditions, commodity prices, and the impact of existing or potential energy and environmental policy. Based

[158] Exhibit POT 2-1, pp. 29-34.

on these factors, electricity prices are expected to increase in real terms. For purposes of its planning and the development of its alternatives, Manitoba Hydro used an export price forecast that is an average of six forecasts provided by independent consultants. With one exception (the Brattle Group), these forecasts were not available on the public record due to their proprietary and commercially sensitive nature. These forecasts were available to the Panel *in-camera*.

Potomac Economics is the Independent Market Monitor of MISO, a role that requires Potomac to closely monitor prices, investments, market structure, and market outcomes. Potomac formulated and developed their own MISO market price forecasts using publicly available information, which they compared to Manitoba Hydro's independent consultants' forecasts. Potomac created a forecast based on MISO supply and demand characteristics and recent market outcomes, along with input assumptions from the EIA. Potomac's models relied on lower natural gas price forecasts, lower rates of demand growth, and lower quantities of coal plant retirements than most of the six consultants.[159]

Each of Manitoba Hydro's consultants' forecasts was evaluated by Potomac, although Potomac was not provided access to the underlying assumptions behind the consultants' forecasts. Potomac forecasts lower prices than the Brattle Group, and generally lower prices than the other consultants. Potomac noted that the Brattle Group assumes carbon pricing beginning in 2020 at $15/tonne and increasing to $24/tonne by 2034. Potomac believes Brattle overstates the emissions and fuel costs of gas-fired and coal-fired generators and thus overstates forecast energy prices, while at the same time understating capacity prices. Potomac was not able to disentangle these conflicting effects and thus does not recommend the NFAT Panel use Brattle's forecast. For various reasons, contained in commercially sensitive information reviewed *in-camera*, Potomac was not able to recommend the use of any of the other Manitoba Hydro consultants' forecasts. Potomac recommended their own forecast be used by the NFAT Panel to evaluate Manitoba Hydro's Preferred Development Plan business case because Potomac does not find the Manitoba Hydro consultants' forecasts to be credible.[160]

Dr. Gotham commented that if carbon prices do not materialize, MISO market prices will be lower by 20-25%. Dr. Gotham quoted La Capra's finding that the impact of carbon prices on the Preferred Development Plan are significant, as the absence of a carbon

[159] Exhibit POT-2 p.5.
[160] Exhibit POT-2 p.41.

price lowers the NPV advantage of the Preferred Development Plan over the All Gas Plan by approximately $340 million.[161]

Dr. Gotham prepared and presented a review of export price forecasts using MISO's Transmission Expansion Plan, Brattle Group and Potomac Economics cases with the lowest carbon price assumptions.[162]

Table 5 Export Price Forecast Comparison: No Carbon/Low Carbon (US$/MWh)

	MTEP	Brattle	Potomac
2017	29.65	30.00	26.00
2022	32.54	33.00	29.00
2027	37.78	37.00	31.00

In Dr. Gotham's view: "*If the electricity price projections from The Brattle Group are indicative of Manitoba Hydro's forecast from the average of the vendor forecasts, it is reasonable. If the Manitoba Hydro forecast is higher than the Brattle forecast, there is cause for concern.*"[163]

6.4.4. "Window of Opportunity"

In support of its Preferred Development Plan, Manitoba Hydro argues that there is a window of opportunity to develop new hydroelectric generating resources. According to Manitoba Hydro, along with new transmission interconnections, new hydroelectric generating stations can take advantage of marketplace opportunities, if decisions are made now and proposed construction begins as planned. Manitoba Hydro identified the following factors as favoring new hydro development: expectations of MISO load growth; retirements of older, smaller coal plants in MISO; and additional carbon related costs and environmental restrictions for fossil-fired generation. Furthermore, Manitoba Hydro has negotiated transmission project agreements and Minnesota Power has undertaken to champion them to the U.S. regulatory authorities. Manitoba Hydro is concerned that it might miss out on improved transmission opportunities if it does not proceed with the U.S. interconnection.[164] Manitoba Hydro indicated that a number of the already negotiated, but conditional export contracts are linked to the power generated by Keeyask and/or Conawapa.[165]

[161] Transcript, p.8438.
[162] Exhibit CAC-26-1, pp. 7-9.
[163] Exhibit CAC-26, p. 9.
[164] Manitoba Hydro NFAT Submission, Chapter 6, p. 6.
[165] Manitoba Hydro NFAT Submission, Chapter 6, p. 28. Exhibit MH-99, See also Appendix 6.1.

As part of its analysis, La Capra examined Manitoba Hydro's reasoning for a "window of opportunity." La Capra noted that one of Manitoba Hydro's rationales for this window was the ability to respond to Renewable Portfolio Standards requirements. However, current U.S. RPS requirements are primarily focused on increasing U.S. wind generation capacity, not Canadian hydro capacity.[166]

When Manitoba Hydro agreed to a Term Sheet with WPS in 2008, Manitoba Hydro also placed firm transmission reservations in order to have the transmission capacity to export power from Minnesota to Wisconsin. These reservations placed Manitoba Hydro at the front of the queue for access to new transmission facilities from Minnesota to Wisconsin. When available, this transmission access opens up new markets for Manitoba Hydro's exports, in essence doubling its market size by being able to export beyond Minnesota into Wisconsin. In Manitoba Hydro's view, failure to take advantage of the window of opportunity by building the 750 MW interconnection and completing the WPS sale would result in the firm transmission reservations being lost. According to Manitoba Hydro, the 750 MW Great Northern Transmission Line is a once in a lifetime opportunity.[167]

6.4.5. Export Volume Assumptions

Manitoba Hydro assumes that all surplus electricity can be sold either as long-term firm energy or as on-peak and off-peak opportunity sales. Potomac Economics concludes that because Manitoba Hydro's exports are a small percentage (less than 2%) of the total MISO market volumes, Manitoba Hydro will be able to sell all of its surplus power into MISO, and Potomac's price forecasts account for these additional volumes.

Potomac disagreed with Manitoba Hydro's assumption that it can sell 100% of its dependable energy under long-term firm contracts at the premium prices that Manitoba Hydro assumes for those long-term firm contracts. Potomac Economics reviewed this assumption and suggested that Manitoba Hydro could export 91% of its surplus dependable energy under long-term firm contracts.[168] However, it has not been conclusively demonstrated that all of this surplus dependable energy will achieve capacity revenues in addition to energy revenues.

[166] Exhibit LCA-11, pp. 8-24.
[167] Exhibit MH-204 p.99.
[168] Exhibit POT-2-2, pp. 43-44; Transcript, p. 4686, Potomac Undertaking 86, Transcript, p. 4687.

6.5.0 Export Prices, Revenues Forecast and Contracts

6.5.1. Existing and Future Export Contracts

The following is a listing of the current and future signed export contracts:[169]

Table 6 List of Current and Future Manitoba Hydro Export Contracts

Customer	Contract Type	Term
Northern States Power	150 MW Seasonal Diversity (Summer)	May 1991 to April 2015
Northern States Power	200 MW Seasonal Diversity (Summer)	November 1996 to April 2015
Northern States Power	500 MW System Participation	May 2005 to April 2015
Minnesota Power	50 MW System Participation	May 2009 to April 2015
Minnesota Power	50 MW System Participation	May 2015 to May 2020
Minnesota Power	250 MW System Participation	June 2020 to May 2035
Minnesota Power	Energy Exchange	June 2020 to May 2035
Great River Energy	150 MW Seasonal Diversity	May 1995 to October 2014
Great River Energy	200 MW Seasonal Diversity	November 2014 to April 2030
Northern States Power	125 MW System Participation	May 2021 to April 2025
Northern States Power	375/325 MW System Participation	May 2015 to April 2025
Northern States Power	350 MW Seasonal Diversity	May 2015 to April 2025
Wisconsin Public Service (100 Product A)	100 MW System Participation	June 2021 to May 2025
Wisconsin Public Service (100 Product B)	Surplus Energy	June 2025 to May 2029
Wisconsin Public Service	308 MW System Participation	January 2027 to May 2036
Wisconsin Public Service	108 MW System Participation*	June 2016 to May 2021
Note: The Wisconsin Public Service contracts (Product A and B) will terminate if the 308-system power sale begins before May 31, 2029.		

[169] Exhibit PUB/MH 1-280R and Exhibit MH-99.

6.5.2. Impact of Exports on Selected Plans

Morrison Park examined the relationship of energy prices with ratepayer impacts. Their conclusion was that high energy prices would lead to lower Manitoba ratepayer costs in the Plans based on the Keeyask and Conawapa projects. In their recent work, Morrison Park compared the role of exports in the 2013 versions of the Plans with the role of exports in the 2014 updated versions (calculated from the 6% NPV figures):[170]

Table 7 Exports as % of Total Revenues : 2013 vs. Updated Plans

	Plan 1: All Gas	Plan 2: K22/Gas	Plan 4: K19/Gas 24/250	Plan 5: K19/Gas 25/750	Plan 6: K19/Gas 31/750	Plan 14 (PDP)
2013 Version	8.6%		14.2%		13.8%	17.3%
2014 Version	13.9%	16.1%	20.2%	21.4%	21.1%	27.5%
Change	+5.3%		+6.0%		+7.3%	+10.2%

The significant increases in revenues, from exports, for Manitoba Hydro across all of the updated Plans result from the much lower domestic demand in Manitoba due to increased DSM programs. The percentage of revenues from exports for the updated 2014 All Gas Plan 1 is similar to the percentage of revenues from exports for the 2013 versions of Plans 4 and 6. The updated versions of Plans 4 and 6 are now almost 50% more export oriented, and in fact are projected to generate a greater percentage of revenue from exports than the 2013 version of the Preferred Development Plan.

6.5.3. Assessing the Contract Terms and Conditions

Minnesota Power Contracts

In its NFAT Submission and during the hearings, Manitoba Hydro indicated that several of its signed export contracts were contingent on the construction of Keeyask and/or Conawapa. For the Minnesota Power 250 MW sale, it was noted that a condition precedent (in favour of Manitoba Hydro and which Manitoba Hydro could waive) existed related to Keeyask construction commencing by June 2016. A two-year delay for regulatory purposes is permitted. While the construction of Keeyask is a condition precedent, which Manitoba Hydro could choose to waive, Manitoba Hydro stated that it had always represented to Minnesota Power that Keeyask would be built to serve the MP 250 MW contract. In Manitoba Hydro's view, the Minnesota Power sale is uncertain without the start of Keeyask construction by June 2016.

[170] Exhibit MPA 3-1, pp. 22-23.

Manitoba Hydro expressed further concern that Minnesota Power may back away from its application to build the 750 MW Great Northern Transmission Line if Keeyask was not also built. Manitoba Hydro stated that Minnesota Power was counting on the wind storage benefits from new hydraulic generation, implying that Minnesota Power was counting on Keeyask. Manitoba Hydro had previously stated that Keeyask does not provide wind storage benefits because of the relatively small size of its forebay. However, significant wind storage exits in Manitoba Hydro's overall system.

Manitoba Hydro can control the level of Stephens Lake to increase or decrease flow through Kettle, Long Spruce, Limestone, and Conawapa, which makes the lake act as a storage battery for wind energy. Conawapa enhances the effective energy storage capacity of Stephens Lake by approximately 25%.[171]

Manitoba Hydro and Minnesota Power also have an agreement to exchange wind energy. Minnesota Power has the option of storing 250 GWh, or up to 383 GWh, of wind energy in Manitoba Hydro's water reservoirs. If Manitoba Hydro accepts the wind energy, it then has the obligation to return energy when requested by Minnesota Power.[172]

Wisconsin Public Service Contracts

According to Manitoba Hydro, the WPS 100 MW sale is contingent on Keeyask being in service.[173] However, construction and commissioning of Keeyask are not conditions precedent in favour of WPS in this contract. Manitoba Hydro's conditions precedent for this contract are considered trade secrets and thus commercially sensitive.[174] However even if construction or commissioning of Keeyask was a condition precedent in favour of Manitoba Hydro, Manitoba Hydro could waive the condition and serve the WPS 100 MW contract from its existing resources.

The WPS 308 MW contract has conditions precedent in favour of Manitoba Hydro that allow the contract to be canceled if either Keeyask or Conawapa do not enter service. WPS has no condition precedent requiring Keeyask and Conawapa to be built, however there is a termination clause that allows WPS to cancel the contract if the 4th unit of Conawapa does not enter service by June 2031. There was no evidence provided in the hearing that WPS would exercise this termination clause if Conawapa was not built.[175]

[171] Transcript, pp.1671-1672, 1683-1684.
[172] 250 MW Energy Exchange Agreement - MHEB and MP, May 19, 2011.
[173] Exhibit MH-99.
[174] Exhibit MH-31-3, p. 73.
[175] 308 MW System Power Agreement between MHEB and WPS, February 26, 2014. p. 114 to 120, 123

In their testimony, Morrison Park made mention of this situation, when contracts and commercial agreements must be terminated by one party. In Morrison Park's view, commercial transactions are ended all the time; there are consequences in terms of financial losses as well as lost reputation and commercial trust. These are difficult to measure, but are nevertheless real.[176]

6.5.4. Export Revenue Forecasts

Manitoba Hydro's Export Contract Revenues

Manitoba Hydro began the hearings by indicating that export sales revenues would be a significant aspect of their Preferred Development Plan. While initially, Manitoba Hydro estimated export revenues from firm contracts at $9 billion, this amount was subsequently revised to $6.9 billion.[177]

Table 8 Manitoba Hydro's Gross Export Revenues

Gross Export Revenues and Sales 2015-2037	$ Billions
Dependable Capacity and Energy[178]	5.88
Contracted Surplus Energy[179]	1.05
Total Contracted Sales (sub-total)	6.93
Opportunity Sales (non-contracted peak and off-peak)	10.08
Total Gross Extra-Provincial Revenues[180]	17.01

In addition to the contracted energy and capacity, Manitoba Hydro also forecasts that between 2015 and 2037, it will sell an additional $3.416 billion worth of 'Non-Contracted Surplus Energy Sales', which amounts are included in the Opportunity Sales in the above Table. Manitoba Hydro seeks to achieve firm (long term and short term) bilateral sales to its existing counterparties, for its presently 'non-contracted surplus'. Any of this surplus that is not contracted would then be sold as opportunity sales into the MISO market.

Based on La Capra's review of Manitoba Hydro's bilateral firm contracts, the Panel accepts the quantification of Manitoba Hydro's contracted dependable capacity and energy revenues as well as the contracted surplus energy revenues. However, the

[176] Transcript, p.7264.
[177] Transcript , pp. 97 and 140; Exhibit MH-100.
[178] Exhibit MH-100.
[179] Exhibit MH-100.
[180] Exhibit MH-104-12-7.

Panel notes that diversity revenues are not guaranteed revenues as the counterparty has no obligation to purchase any diversity energy.

Diversity Exchange Agreements[181] augment Manitoba Hydro's winter capacity by 350 MW with Northern States Power, and by an additional 200 MW with Great River Energy. In summer, Manitoba Hydro is obligated to dedicate 550 MW of capacity to Northern States Power and Great River Energy for all hours of the summer months. While there is no obligation for Northern States Power or Great River Energy to buy any energy from the dedicated capacity, Manitoba Hydro is prohibited from selling the dedicated capacity during the summer months under long-term or short-term contracts.[182] Furthermore, although diversity exchanges are served from Manitoba Hydro's dependable resources, the energy prices are transacted at market prices, not fixed contract prices.

Relationship of Export Contract Revenues to In-Service Costs

From an accounting and rate setting perspective, when a generating station or transmission line comes into service, Manitoba Hydro no longer capitalizes the related costs. Rather the accumulated costs, including the financing charges, depreciation expense and operating and maintenance expenses are charged through to domestic ratepayers by way of Manitoba Hydro's Operating Statement. Manitoba Hydro then proposes rates, at regular General Rate Applications before the Public Utilities Board, to recover the costs included in the Operating Statement. Manitoba Hydro contends that while some of the in-service costs of new capital assets are directly attributable to a particular asset, the benefits are not.[183] Manitoba Hydro submits that the appropriate approach to the evaluation of capital assets such as Keeyask and new transmission lines is through development plan comparisons.

In addition to development plan comparisons, the NFAT Terms of Reference direct the Panel to examine "[T]he impact on domestic electricity rates over time with and without the Plan and with alternatives."[184]

Manitoba Hydro provided an indication of the in-service costs for various capital projects that are included and/or required in its Preferred Development Plan. Bipole III will enhance reliability for domestic customers and will be used for transmission of Keeyask energy. In 2025, the annual in-service costs for Keeyask are $486 million; the costs for

[181] Exhibits MH-99, pp. 2-3 and MH-100, pp. 1-5.
[182] 350 MW Diversity Sale Agreement with NSP dated May 27, 2010 and 200 MW Diversity Exchange Agreement with GRE dated July 26, 2013.
[183] Exhibit MH-210 and MH-211.
[184] NFAT Terms of Reference, p. 3 of 8.

the 750 MW interconnection are $86 million and the costs of Bipole III are $259 million - totaling $831 million for that year.[185]

To partially offset those $831 million of 2025 in-service costs, Manitoba Hydro forecasts net export revenues (net of fuel and power purchases and incremental water rentals) of approximately $600 million.[186]

The resulting shortfall of $231 million is to be recovered from domestic ratepayers. Additionally, the costs of, and the resulting domestic revenue reductions due to enhanced DSM programs will become the responsibility of the domestic ratepayers.

On a cumulative basis from 2016 to 2037, (the years Manitoba Hydro has firm export contracts) the gross export revenues of $17.0 billion are reduced to $10.5 billion by the costs of exports (fuel and power purchases and incremental water rental fees). The cumulative costs of Keeyask, the 750 MW interconnection and Bipole III over the same period are approximately $14.4 billion. The resulting shortfall of $3.9 billion, together with costs for enhanced DSM and the related reduction in domestic revenues, will be added to ratepayer obligations.[187]

Morrison Park noted the relationship between Manitoba Hydro's capital and operating costs, and its export prices and revenues. They stated that the long-term fixed contract prices are not related to Manitoba Hydro's cost of production, but rather to what the counterparty's alternative cost of energy might be, which is typically gas or coal-fired generation. According to Morrison Park, Manitoba Hydro is producing a fundamentally different product with different risks than the gas-fired generation developers in MISO, but is obtaining prices that are structured to reimburse a gas-fired developer for the risks it is taking.[188]

6.6.0 Conclusions of the Panel

Long-Term Export Sales

Long-term export sales at premium prices underpin the business case of Manitoba Hydro's Preferred Development Plan and many of its alternatives. "Surplus by design" as a business strategy requires the assurance that Manitoba Hydro has access to markets and can sell its surplus capacity at favourable prices, for decades to come.

[185] Exhibit MH-211.
[186] Exhibit MH-104-12-7.
[187] Exhibit MH-211 and Exhibit MH-104-12-7.
[188] Transcript pp. 7379-81.

Manitoba Hydro's primary export market lies in MISO, particularly in Minnesota and Wisconsin. There does not appear to be a substantial Canadian market for Manitoba Hydro's exports. The reality is that Manitoba Hydro is reliant on a single market and dependent on the circumstances of that market, in which it is a price taker.

Based on the Panel's and La Capra's review of Manitoba Hydro's bilateral firm contracts, the Panel accepts the quantification of Manitoba Hydro's contracted dependable capacity and energy revenues as well as the contracted surplus energy revenues as $6.9 billion. However, the Panel notes that diversity revenues are not guaranteed revenues as the counterparty has no obligation to purchase any diversity energy.

The Panel is concerned that Manitoba Hydro only has export contracts with terms of 10 to 15 years, and no contracts extend past 2036. This is less of a concern if only Keeyask is built, since domestic load and the existing signed contracts are expected to consume Keeyask' s dependable output prior to 2036. The Panel is concerned with the risk that future export contracts may not attract the premium pricing that Manitoba Hydro assumes. These premium prices are also assumed in the economic and financial analyses of the Conawapa Project.

Export Price Forecasts

Manitoba Hydro's electricity export price forecast is optimistic. Manitoba Hydro bases its forecast of opportunity sales and future long-term firm contracted sales on its electricity price forecast. If the export price forecast is too high, then Manitoba Hydro will not realize the anticipated export revenues and domestic ratepayers will be required to pay higher rates to make up the shortfall.

Carbon pricing may have a significant impact on the North American energy sector including MISO market prices. To the extent Manitoba Hydro's export price forecast includes a 'carbon premium', those export revenue forecasts will be overly optimistic if such a carbon premium does not materialize when forecasted. If a more robust carbon regime materializes, the results would be more favourable to Manitoba Hydro. The uncertainty as to carbon pricing adds to the risk facing Manitoba Hydro and its ratepayers.

Dependable vs. Opportunity Sales

The Panel does not share Manitoba Hydro's view that it can sell all of its surplus dependable energy and capacity as long-term firm contracted sales at premium prices. In the absence of long-term firm U.S. MISO bi-lateral sales, Manitoba Hydro will have to rely on opportunity sales, at market prices. Accordingly, the Panel considers Manitoba Hydro's forecast of future firm export revenues to be optimistic.

New Generation and Transmission

The Panel evaluated the in-service costs (financing, depreciation, operating and maintenance) of Keeyask, Conawapa, Bipole III and the 750 MW interconnection. The Panel concludes that the firm and opportunity revenues from Keeyask are not sufficient to pay all of the in-service costs of Keeyask, the 750 MW interconnection, and Bipole III. As a result, domestic customers are required to make up the shortfall through rates. Keeyask is required by domestic customers after 2024. Until then, the export revenues will continue to defray some of the in-service costs and mitigate some of the risk associated with the project.

The Panel considered the new export contract with Minnesota Power. The Panel notes that there is no contractual obligation on the part of Manitoba Hydro to construct Keeyask in order to serve the Minnesota Power 250 MW contract. Furthermore, with its enhanced DSM measures, Manitoba Hydro may not need the power from Keeyask to serve this contract until the mid- to late-2020s. However, as the Panel concludes in the Economic Evaluation Chapter, it is still more economic to construct Keeyask for a 2019 in-service date than to defer construction.

Manitoba Hydro stated that Minnesota Power is justifying the 750 MW interconnection to its regulator by highlighting the benefits of the additional wind storage that will result from new hydraulic generation being constructed by Manitoba Hydro. The Panel sees little risk in Minnesota Power backing away from the 750 MW interconnection because the Energy Exchange Agreement provides significant wind storage benefits in Manitoba Hydro's system. While the Panel does not expect Minnesota Power to back away from its application to build the 750 MW transmission line, the Panel notes there is risk that the Minnesota Public Utilities Commission may not approve the project. This risk is discussed in Chapter 10.

Manitoba Hydro asserted that the other significant export contract, the WPS 308 MW sale, is "tied to Conawapa." There is a termination clause that allows WPS and/or Manitoba Hydro to cancel the contract if the 4th unit of Conawapa is not commissioned by 2031. With Manitoba Hydro's enhanced DSM measures, the WPS contract could be served from Keeyask and existing hydraulic resources. While the Panel recognizes that WPS could terminate the 308 MW sale contract if Conawapa is not constructed, it also expects WPS would want to avail itself of Manitoba Hydro's exported energy, regardless of whether it is generated by Conawapa or Manitoba Hydro's other hydroelectric stations.

Summary Observations

The Panel observes that:

- MISO market price forecasts may be too high;
- Carbon prices may not materialize, lowering the forecast market price by 20-25%. Alternatively, if the carbon market exceeds forecasts, the value of Manitoba Hydro's exports may be enhanced;
- With decreased MISO market prices, both opportunity and future firm contract prices and revenue will be lower;
- Manitoba Hydro is unlikely to be able to sell 100% of its dependable energy under long-term firm contracts at premium pricing; and
- Other technology risks such as distributed generation achieving grid parity could result in dramatic decreases in market prices.

If export revenues are less than Manitoba Hydro forecasts, domestic customers will be expected to make up the shortfall. While Manitoba Hydro forecasts rate increases for the next twenty years, export revenues short of those expectations may force the rate increases to be greater. Since more of the output of Keeyask is sold under firm contract, including the WPS 308 MW contract, the Panel sees less risk of disappointing export revenues from Keeyask compared to Conawapa.

Considering the uncertainty of future export revenues, specifically those that flow from Conawapa, all of these factors add up to heightened and unacceptable risk associated with the Preferred Development Plan.

The Panel considers it critical that Manitoba Hydro achieve firm bilateral sales, at premium prices, for its non-contracted surplus energy. Failure to do so exposes the domestic ratepayer to additional rate increases.

7.0.0 Cost of New Generation and Transmission

7.1.0 Introduction

The need to develop and construct new generation resources underpins all of Manitoba Hydro's plans and strategies. To meet that need, Manitoba Hydro considered a range of alternative resource options, including hydroelectric generating stations, natural gas-fired generation stations and wind farms. All alternatives rely on new transmission infrastructure. The hydroelectric alternatives rely on the northern HVDC corridor and interconnection to the United States.

The alternatives differ in the magnitude of their capital costs, and expected useful life. The magnitude of the required capital investments creates risks of a nature and extent that will have a significant impact on Manitoba Hydro, Manitoba ratepayers, and the Government of Manitoba.

Given the importance associated with the costs and risks in constructing new generation, the Terms of Reference directed the Panel to consider a number of specific questions. In particular, the Panel was asked to assess the reasonableness of construction costs. This chapter examines Manitoba Hydro's construction cost projections and management.

This chapter begins with a consideration of the construction requirements and costs associated with the Keeyask and Conawapa Projects. It examines the estimated costs, the contracting procedures and the construction management requirements and risks. The chapter then proceeds to look at the transmission elements to the Preferred Development Plan. Finally, the chapter considers the construction costs and roles of gas, wind and solar generation in Manitoba Hydro's future.

7.2.0 Alternative Plans and New Generation Requirements

Each of the proposed alternative plans has different combinations of generation supply components, including hydropower, thermal gas-fired generation (both simple cycle gas turbines and combined cycle gas turbines), and wind power. In addition, different plans have different transmission requirements and components. These requirements and options are summarized in the Table below. They include the 15 plans as originally filed by Manitoba Hydro, along with two additional plans prepared and presented by La Capra Associates.[189]

[189] Manitoba Hydro NFAT Submission, Chapter 9, p. 12. Exhibit LCA-45, pp. 29-39.

Table 9 List of New Resource Components by Development Plan

#	Plan Name	New Resource Components							
		Keeyask	Conawapa	SCGT	CCGT	Wind	Solar	750MW	250MW
1	All Gas			x	x				
2	K22/Gas	x		x	x				
3	Wind/Gas			x	x	x			
4	K19/Gas24/250MW	x		x	x				x
5	K19/Gas25/750MW	x		x	x			x	
6	K19/Gas31/750MW	x		x	x			x	
7	SCGT/C26		x	x					
9	CCGT/C26		x		x				
9	Wind/C29		x			x			
10	K22/C29	x	x						
11	K19/C31/250MW	x	x						x
12	K19/C31/750MW	x	x					x	
13	K19/C25/250MW	x	x						x
14	K19/C25/750MW (WPS Sale and Inv.)	x	x					x	
15	K19/C25/750MW	x	x					x	
16	LCA All CCGT				x				
17	LCA No New Generation			x	x			x	

7.3.0 Hydropower Projects: Keeyask and Conawapa

Manitoba Hydro's Preferred Development Plan and its alternatives include two hydropower projects (Keeyask and Conawapa), a new 750 MW U.S. transmission interconnection, and upgrades to Manitoba Hydro's northern alternating current (AC) transmission system. Each consists of a number of components, which are further described below.

7.3.1. Overview of the Keeyask and Conawapa Projects

The Keeyask Project has three components: the 695 MW generation station, the related Keeyask infrastructure project, which is currently nearing completion, and the Keeyask transmission project. Collectively, the Keeyask Project is expected to take 8 years to construct. The infrastructure work began in 2012 and the generation stations and transmission element are scheduled to begin in July 2014 depending on decisions and approvals by the Government of Manitoba and the Government of Canada.

The first generation units are planned to be in-service in 2019, and all units in operation in 2020. Keeyask will add 3,000 GWh of dependable energy to Manitoba Hydro's system.

The Conawapa Project consists of two elements: the 1,495 MW generation station and related Conawapa transmission outlet project. Additionally, Manitoba Hydro will undertake a north-south transmission system upgrade to the existing northern 230 kV alternating current (AC) system and the existing HVDC transmission system. This upgrade is only required if Conawapa is developed.

The generation component is expected to take 9 years to complete from a planned start in 2019. In the NFAT Submission, Manitoba Hydro indicated a 2026/27 in-service goal with the first of 10 generating units for service in 2026 and the remaining units in production in 2027.

The north-south transmission upgrades will be completed coinciding with the in-service date of the last Conawapa units. Conawapa will add 4,650 GWh of dependable energy to Manitoba Hydro's system.

7.3.2. Construction Costs of Keeyask and Conawapa Projects

In the course of the hearing, Manitoba Hydro advised the NFAT Panel of capital cost estimate updates for Keeyask and Conawapa. As illustrated below, the capital cost estimates were increased on March 10, 2014 to $6.5 billion from $6.2 billion for the Keeyask Project and to $10.7 billion from $10.2 billion for the Conawapa Project.[190]

[190] Exhibit MH-95, pp. 101, 103. See also 2009 Estimate: CEF09-1, November 2009.

Table 10 Keeyask and Conawapa Construction Budget Updates, 2009-2014

Project	Capital Cost Updates	Base Costs (includes sunk costs)	Interest + Escalation	Total Costs
Keeyask	**2009 Estimate (2019 ISD)**	n/a	n/a	3.7
	NFAT Submission (2019 ISD)	4.63	1.59	6.2
	March 2014 Update (2019 ISD)	4.84	1.65	6.5
Conawapa	**2009 Estimate (2022 ISD)**	n/a	n/a	4.9
	NFAT Submission (2025 ISD)	6.39	3.90	10.2
	NFAT Submission Update (2026 ISD)	6.39	4.05	10.4
	March 10, 2014 Update (2026 ISD)	6.44	4.22	10.7

Since 2009, the capital costs of Keeyask and Conawapa have increased materially, with the Keeyask capital cost projection having increased by 75% and the Conawapa capital cost projection by over 100%.

Manitoba Hydro's current "high" capital cost estimate is $7.2 billion for the Keeyask Project (15% above its current cost estimate) and $12.5 billion for the Conawapa project (17% above its current cost estimate).[191] The Panel notes that, in March 2014, Manitoba Hydro estimated sunk costs by June 2014 for the Keeyask Project of $1.2 billion and $.4 billion for Conawapa. However, Manitoba Hydro's witness Dr. Borison cautioned against assuming that past increases were a predictor of future cost increases. In response to concerns that Keeyask may experience similar cost increases as Wuskwatim, Manitoba Hydro noted that Wuskwatim costs only increased by 10% from the point in time where Wuskwatim had reached a similar stage of development, project definition, and contracting as Keeyask.[192]

In their review of similar dam construction projects, Knight Piésold found that large hydropower plants such as Keeyask and Conawapa typically range from $2 Million/MW installed to $10 Million/MW installed. The proposed installed costs of the Keeyask Project is $9.9 Million MW, which is at the upper level of project norms.

7.3.3. Construction Contingencies and Reserves

Manitoba Hydro's "reference" capital cost estimates are based on a P50 contingency level, meaning there is an equal probability of costs being lower or higher. Manitoba Hydro's "high" capital cost estimates are determined by adding a Management Reserve to the contingency. The Management Reserve consists of a labour reserve, which is

[191] Exhibit MH-161, pp. 2-3.
[192] Exhibit MH-204, p. 69.

designed to account for labour productivity problems, as well as an escalation reserve, which is designed to account for annual escalation costs being higher than the 2.5% budgeted by Manitoba Hydro.[193]

Knight Piésold reviewed Manitoba Hydro's approach to contracting and risk management. It found that Manitoba Hydro was following best practices. However, Knight Piésold also suggested that a more risk-averse decision maker would use a P80 cost estimate, rather than a P50 cost estimate[194], as well as apply a composite hydropower escalation rate of 3.1% to 3.4% rather than the 2.5% applied by Manitoba Hydro.[195] A P80 cost estimate means that there is only a 20% chance of the project being over budget and, according to Manitoba Hydro's estimate, would increase the required contingency for Keeyask by $321 million.[196]

Based on their knowledge of similar projects, Knight Piésold expressed concerns about the risks associated with labour shortages, construction delays given terrain and northern climate, and concrete work productivity. As a result, Knight Piésold concluded that the "amount of contingency carried for the two generation projects (Keeyask and Conawapa) could be considered insufficient depending on the use made of the capital cost estimates."[197] A worst-case capital cost scenario might see costs higher than the $7.2 billion for Keeyask currently forecast by Manitoba Hydro for its "high" scenario.

7.3.4. Keeyask Construction Contract

In its scope of work, Knight Piésold was asked to review the cost estimates, contracting practices, and the contract provisions. They undertook to determine the extent practices were appropriate, costs were reasonable, and measures were in effect to address changes or increases in construction costs. The Panel focused on Keeyask-related contracting given the immediate nature of decisions on whether to proceed with construction in July 2014, and the fact that Conawapa construction contracts had not yet been entered into.

Knight Piésold assessed Manitoba Hydro's costs estimates and contracts. They discussed questions about documentation and procedures with Manitoba Hydro staff. They then used their experience and past work to assess these practices against industry best practices and similar hydropower construction projects. Knight Piésold reported to the Panel that many of Manitoba Hydro's practices and procedures were

193 Manitoba Hydro NFAT Submission, Chapter 15, p. 39.
194 Exhibit KP-4, p.57.
195 Transcript, p. 6904.
196 KP/MH II-26(a).
197 Exhibit KP 3-1, p. i.

reasonable and appropriate, relative to industry best practice. Knight Piésold supported Manitoba Hydro using an Early Contractor Involvement process to obtain input from the chosen contractor in order to refine the design, construction techniques, schedule, and risk sharing.[198] Knight Piésold told the Panel that Manitoba Hydro had made the appropriate choices in the various Keeyask Project contracting efforts. The contracting choices were designed to secure the most cost effective contracts.[199]

Manitoba Hydro submitted that the risk associated with the Keeyask construction is somewhat addressed given that 80% of the construction contracts have now been negotiated. However, this only partially mitigates cost risk. The Keeyask general civil contract is a cost-reimbursable contract, not a fixed price contract. This leaves the contract vulnerable to cost escalations as a result of: quantity risk, especially in areas where quantities may have been underestimated; escalation to the contractor's cost factors due to labour productivity or labour costs; escalation in the cost of supply and equipment; and challenges related to adverse weather conditions.

No similar contracts exist with respect to the Conawapa Project.

7.4.0 Transmission

7.4.1. Overview of Transmission Components

Manitoba Hydro's transmission system consists of numerous transmission lines that assist in delivering power to its Manitoba customers, as well as supporting both exports and imports to and from neighbouring power systems in Saskatchewan, Ontario and the United States.

The system has two major components: the Alternating Current ("AC") transmission system and the High Voltage Direct Current ("HVDC") system. The existing HVDC system consists of Bipoles I and II and connects to the Northern Collector System, which consists of several short transmission lines connected to the northern hydro dams.

The AC transmission system forms the bulk of the length of the transmission lines in Manitoba, consisting of 7,200 km of lines. This system brings power from generating stations to dozens of electrical stations around the province.

With regard to other provinces and the United States, Manitoba Hydro currently has five cross-border transmission interconnections with Saskatchewan, three interconnections

[198] Exhibit KP-4 p.14.
[199] Exhibit KP-4 p. 14.

with Ontario and four interconnections with the U.S. The current interconnection capacity is:[200]

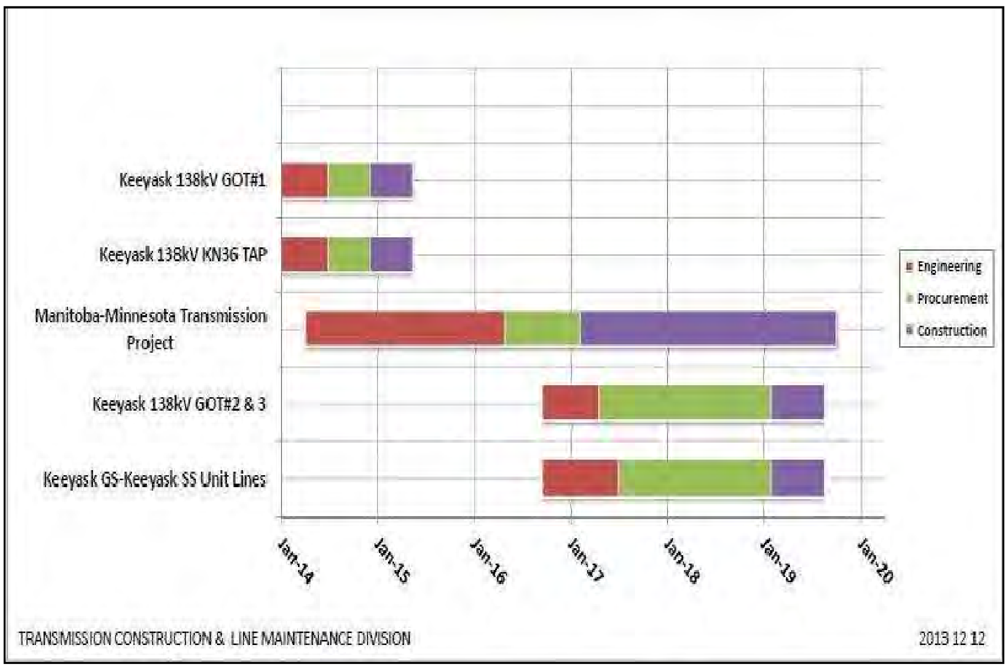
Table 11 Manitoba Hydro Interconnection Limit and Capacities

Interconnections	Firm Export Schedule Limit	Firm Import Transfer Capacity
United States	1,950 MW	700 MW
Ontario	200 MW	0 MW
Saskatchewan	150 MW	0 MW
Total	2,300 MW	700 MW

7.4.2. Proposed Transmission Connections

In its Preferred Development Plan, Manitoba Hydro identified the following transmission components: Keeyask Transmission Project; Conawapa Transmission Project; North-South Transmission System Upgrade Project; and the Manitoba-Minnesota Transmission Project. These are to be constructed in accordance with the following Manitoba Hydro timetable:[201]

Figure 10 Transmission Engineering, Procurement and Construction Timetable, 2014-2020



200 Manitoba Hydro NFAT Submission, Chapter 5, p.16.
201 Exhibit KP-3-1, p. 79.

The Conawapa Transmission Project and North-South Transmission System Upgrade Project are scheduled to be completed by 2027.

Keeyask Transmission Project

The Keeyask Transmission Project will connect the Keeyask Generating Station to the existing Radisson Converter Station, and involves the construction of a new switching station as well as approximately 39 km of transmission line. The total cost estimate, in 2012 dollars, is projected at $156.7 million.[202] With escalation and interest, the in-service cost is estimated at $203 million.[203] Power Engineers examined the cost estimate and found it to be reasonable in light of several construction difficulties identified for the line.

Conawapa Transmission Outlet Project

The Conawapa Transmission Outlet Project will connect the Conawapa Generating Station to the newly constructed Keewatinow Converter Station by means of a 7 km transmission line. The total cost estimate, in 2012 dollars, is projected at $10 million.[204] With escalation and interest, the in-service cost is estimated at $14 million.[205]

North-South Transmission System Upgrade

Although all of Conawapa's power can be transmitted from northern Manitoba to southern customers on Manitoba Hydro's high-voltage direct-current (HVDC) transmission system (including Bipole III, which is expected to be constructed by the time Conawapa enters service), Manitoba Hydro has identified reliability issues with respect to such an arrangement. To improve reliability, Manitoba Hydro proposes to upgrade the existing northern 230 kV alternating current (AC) system and existing HVDC transmission system, including a split of the northern Bipole system and placing one or more units of the Kettle Generating Station from the HVDC system onto the AC system. This will see the overall system usage rebalanced.

Together, these upgrades are referred to as the North-South Transmission System Upgrade Project. The project would have an in-service date coinciding with that of the last Conawapa unit. It would only be constructed if Conawapa proceeds. The total cost, in 2012 dollars, is estimated at $340 million. With escalation, the total in-service cost is estimated at $498 million.[206] Power Engineers examined the cost estimate and found it to be reasonable. However, Power Engineers also identified a possible additional cost

[202] Exhibit MH-95, p. 78.
[203] Exhibit PE-3, p.3.
[204] Exhibit MH-95, p.84.
[205] Exhibit PE-3, p.5.
[206] Exhibit PE-3, p.6.

of $39 million to enhance Bipole III converters to increase Bipole III capacity by 300 MW.[207]

Manitoba-Minnesota Transmission Project

The proposed U.S. interconnection consists of a new single-circuit 500 kV AC transmission line originating from Dorsey Station, northwest of Winnipeg, running south around Winnipeg, connecting to the Riel Converter Station, and then continuing in a southeast direction toward the international border. The U.S. portion of this interconnection, called the Great Northern Transmission Line, will terminate at a new 500 kV substation adjacent to the existing Blackberry substation in Minnesota, located approximately 100 km northwest of Duluth, Minnesota. The approximate total length of the 500 kV transmission line between the Dorsey and Blackberry substations is 600 km. The Manitoba-Minnesota portion of the Transmission Project in-service cost is estimated to be $350 million.[208]

Great Northern Transmission Route

The Manitoba-Minnesota Transmission Line will connect at the U.S. border with Minnesota Power's proposed Great Northern Transmission Line with an in-service date of 2020. The total cost in 2013 U.S. dollars is estimated at $507 million.[209] Manitoba Hydro will be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the transmission line. During the hearings, Manitoba Hydro updated the Panel on the costs and cost sharing arrangements.

Minnesota Power will have funding responsibility (33%) for the transmission needed for the 250 MW Power Sale Agreement. Manitoba Hydro will fund the remaining 67% share for its 49% ownership position plus 18% scheduling fee. This is paid to Minnesota Power to cover increased revenue requirements associated with the additional 133 MW of capacity that it will own above the 250 MW Sales Agreement. Manitoba Hydro is in discussions to sell a portion of their 49% share.[210]

7.4.3. The Role and Value of Transmission Export and Import Capacity

In the course of the hearings, the Panel learned of the importance of new transmission to the United States with regard to enhancing system reliability and providing greater opportunities for both exporting and importing electricity.

[207] Exhibit PE-3, p.6.
[208] Manitoba Hydro NFAT Submission, Chapter 2, p. 59.
[209] Exhibit MH-95, p. 81.
[210] Exhibit MH-204, pp. 103-104.

In its Preferred Development Plan, Manitoba Hydro outlined the potential benefits realized by the addition of the new hydro resources and the new U.S. interconnection. In its view, the interconnections provide significant reliability benefits in terms of sharing of generation contingency reserves, sharing of capacity resources due to load diversity, importation of energy during drought conditions or extreme supply loss in Manitoba, and the ability to supply cross-border load when this load is isolated from its system.

Transmission has economic value. It provides the means to export surplus hydropower. There are times during the peak winter demand period when it may be economically beneficial to import lower-cost resources from outside of Manitoba rather than use Manitoba Hydro's own thermal resources.

Several individuals testified that the development of new transmission connections with the United States will be a strategic asset. They noted that transmission to facilitate imports could have the effect of changing the development plan options and pathways. Greater imports could defer the need for new resource development, especially hydropower facilities. For several interveners, such as the Green Action Centre, the construction of the 750 MW transmission line has demonstrated value.[211]

In its report on transmission, La Capra Associates identified that the addition of Keeyask in 2019, the new interconnection line in 2020, and Conawapa in 2026 all affect the total energy exported by Manitoba Hydro. They concluded that there is a 3.2% increase in total exports when Keeyask is placed in service and a 38% increase when the new line is completed. Lastly, there could be a 30% increase in total exports in 2026 when Conawapa enters operation.[212]

The new interconnection will, therefore, help in optimizing the new capacity from Keeyask and perhaps Conawapa in future years. The majority of the benefits will appear after the construction of Conawapa where the total exports will be around 14,000 GWh, almost 50% higher than the average over the 2009-2012 period. Still, the addition of the new interconnection results in a significant increase in total firm sales in 2020. The increase in firm sales is mostly associated with the initiation of the new Minnesota Power Sales Agreement and the Wisconsin Public Service Agreement.

7.5.0 Manitoba Hydro's Proposed Generation Alternatives

In its NFAT Submission, Manitoba Hydro outlined a number of generation options and opportunities. Some are described as long-term opportunities for future consideration.

[211] Exhibit GAC-27, p. 23.
[212] Exhibit LCA-11, pp. 65-66.

Others were assessed as being not effective or relevant to Manitoba's power requirements. Still others, such as the Keeyask Project, are presented in detail and require immediate decision-making, leading to impending development and construction. The following Table summarizes the capital and per unit energy costs as identified by Manitoba Hydro:[213]

Table 12 Comparison of Installed Capital Cost and Per Unit Costs Based on Utility Scale Generation in Manitoba

Technology	Installed Costs $/kW	Energy Cost $/MWh	Cost Trend
Energy Storage	300 – 11,000	10 – 360	**Decreasing**
Solar Photovoltaic	3,700 – 5,000	190 – 200	
Wind	1,600 – 7,600	60 – 210	
Biomass	2,000 – 5,800	100 – 150	**Stable**
Solar Thermal	3,500 – 7,500	140 – 190	
Enhanced Geothermal	25,000 – 37,500	290 – 440	**Increasing**
Hydroelectric	3,800 – 21,000	60 – 290	
Hydrokinetic	7,00 – 9,500	160 – 620	
Nuclear	3,500 – 7,000	90 – 120	

During the hearings, the Panel heard a great deal from its Independent Expert Consultants and the Interveners about the relative merits of gas turbines as a resource option, and the emerging importance of solar and wind power generation.

7.5.1. Thermal Gas Generation

Thermal gas generation options play a prominent role in Manitoba Hydro's planning options. An All Gas option was used as the reference case. All of the 15 Alternative Plans entail the construction on one type or other of gas turbines at some point in the future.[214] Manitoba Hydro examined both Simple Cycle Gas Turbines (SCGT) and Combined Cycle Gas Turbines (CCGT). While SCGTs are lower capital cost, they are less efficient than CCGTs, more at risk to fuel price changes, and emit more greenhouse gases. CCGTs are more efficient, use less fuel, emit fewer greenhouse gases, and are better suited to either intermediate or baseload service because of their higher capital cost.[215]

[213] Manitoba Hydro NFAT Submission, Appendix 7.1, p. 17.
[214] Manitoba Hydro NFAT Submission, Chapter 9, Table 9.3.
[215] Manitoba Hydro NFAT Submission, Appendix 7.2, pp. 26-30.

Knight Piésold examined the capital costs of gas turbines: SCGTs cost $0.77 million per MW of installed capacity and CCGT turbines cost $1.30 million per MW.[216] The various Plans required differing numbers of types of turbines over the 78-year period. The All Gas Plan requires eight SCGTs and CCGTs.[217]

La Capra Associates provided the Panel with two additional alternative plans, including one with an all-gas scenario. It involved only CCGTs rather than mix of CCGT and SCGTs. This additional option was seen to be similar to Manitoba Hydro's All Gas reference case. The No New Generation Plan included the 750 MW interconnection with the U.S., enhanced DSM, increased imports from the U.S., and new gas turbines as required once DSM and imports could no longer address domestic load growth. The No New Generation plan compared favourably to the All Gas Plan on economics, and had better expected values than the Preferred Development Plan.[218]

There are also socio-economic and environmental considerations of gas as a resource option. Gas generation might offer more distributed socio-economic benefits throughout Manitoba, and employment advantages might eventually equal those of northern hydropower projects. However, the benefits to northern and aboriginal communities associated with hydropower options would be lost. Moreover, there are serious environmental impacts: the Clean Environment Commission estimated that a comparably sized natural gas plant would produce as much greenhouse gas in 177 days as the Keeyask Generation Project will produce in 100 years.[219]

7.5.2. Solar Power Generation

Solar photovoltaic power, or solar PV, was once an expensive option, and unthinkable from a resource planning perspective. However, a combination of technological advances and economies of scale have dramatically altered the outlook for solar PV. Solar power is currently being supplied by some electrical utilities using large "solar farms," as well as through roof-top panels by individual residential and commercial users.

During the hearings, the Panel heard from several parties about the new promise of solar power, given its forecasted cost decline and its implications for grid parity. Grid parity is that point at which, from homeowner or business perspectives, the installed cost of rooftop solar PV becomes less expensive, on an annualized basis, than the cost of electricity supplied by the grid. In the view of Mr. Dunsky, solar PV costs have been

[216] Exhibit KP 3-1, p. 51.
[217] Manitoba Hydro NFAT Submission, Chapter 8, pp. 19-22.
[218] Exhibit LCA- 45, p. 24.
[219] Exhibit PUB-69, p. 61.

declining sharply (10% per year on average since 2006) and are expected to continue to do so in the near future. Because of these declines, solar PV has begun to achieve grid parity in several U.S. states. Various forecasts now expect grid parity to be reached for a large share of worldwide electricity demand by 2020.[220]

In its NFAT Submission, Manitoba Hydro identified the declining costs of solar PV through 2020 for residential and utility systems. Manitoba Hydro anticipates residential system costs declining to $1.12/watt by 2020.[221] Given Manitoba's annual sunshine (global solar radiation in Winnipeg based on Natural Resources Canada data), Mr. Dunsky estimates residential rooftop solar PV costing approximately 8¢/kWh by 2020.[222] According to Mr. Dunsky, if this cost forecast is correct, then given Manitoba Hydro's own projected rate increases, residential grid parity could be reached in Manitoba well before the end of the current planning period. Moreover, Mr. Dunsky states that Manitoba Hydro's own projections for utility-scale PV costs are even more dramatic and are forecast to cost $0.65/watt by 2020. If this is accurate, the cost of utility-scale solar in Manitoba would drop to approximately 5¢/kWh by 2020, well below the projected levelized cost of Conawapa.[223]

Knight Piésold also noted that capital costs for solar PV have reduced by a factor of 10 over the last three decades and have experienced a 22% reduction in the last three years. Manitoba Hydro will have to factor these price decreases into its future integrated resource plans.[224]

7.5.3. Wind Power

Manitoba Hydro currently purchases all of the output of the privately owned St. Leon and St. Joseph wind farms, which have a combined maximum hourly generation capacity of 258 MW[225]. Wind power generation was also part of two of Manitoba Hydro's alternative development plans. Under the Wind/Gas Plan, new wind capacity would come into service in 2022/23, supported by new gas capacity but no new hydro capacity. This Plan would encompass generic 65 MW wind farms: two built per year from 2022 through 2024, and one per year from 2027 through 2047 for a total of 1,755 MW. Under the Wind/C26 plan, new wind capacity would be installed in 2022/23, along with Conawapa coming into service in 2026/27. This Plan would involve a nominal wind capacity of 390 MW.[226]

[220] Exhibit CAC-19, pp. 35-39.
[221] Manitoba Hydro NFAT Submission, Appendix 7.1, pp. 43-44.
[222] Exhibit CAC-19, p. 39.
[223] Exhibit CAC-19, p. 39.
[224] Exhibit KP-3-1, p.57.
[225] Manitoba Hydro NFAT Submission, Chapter 5, p. 6.
[226] Manitoba Hydro NFAT Submission, Chapter 8, p. 19.

However, for purposes of its resource planning, Manitoba Hydro considers wind as an intermittent resource that is only available when the wind is blowing. Manitoba Hydro also assumed that wind power has a reliable winter peak capacity of zero, given its intermittent nature and the inability of wind generators to reliably function in temperatures below -30^{o}C.[227] Manitoba Hydro calculated that the Levelized Cost of Electricity[228] (LCOE) of wind was $82/MWh (2014$) as compared to $60/MWh for Keeyask and $67/MWh for Conawapa.[229]

Manitoba Hydro concluded that wind generation was significantly more expensive than its Preferred Development Plan. As a result, Manitoba Hydro stated that "wind generation as a major generation supply in Manitoba was determined to be un-economic at this time."[230] A number of the Independent Expert Consultants and the Interveners disagreed with Manitoba Hydro's conclusions based on the following three factors.

Wind Power Capital Costs and Trends

In its NFAT Submission, Manitoba Hydro identified a reference case capital cost of $2,100/kW for the wind turbines, with an additional $300/kW for transmission upgrades.[231] This assumption was also addressed by Knight Piésold, which suggested a base cost of $1,800/kW (excluding transmission).[232] La Capra Associates concluded that average capital costs were about $1,750/kW in 2012 including transmission interconnection costs.[233] In its assessment, Power Advisory recommended $1,940/kW as a reasonable estimate of wind capital costs in 2012 including transmission.[234]

Manitoba Hydro assumed that wind capital costs would neither increase nor decrease in real terms. To the contrary, Knight Piésold, La Capra Associates, and Power Advisory all reported that wind capital costs are expected to decline.

Construction Period and Operating Life

Manitoba Hydro's LCOE calculations suggest a three-year construction period, which Power Advisory's research suggested was reasonable. However, Manitoba Hydro assumed that 97% of the wind project construction costs will have been incurred by the second year. Power Advisory disagreed, suggesting that 5% of total costs are incurred

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227 Manitoba Hydro NFAT Submission, Chapter 5, p. 6.
228 Manitoba Hydro NFAT Submission, Appendix 7.1 p. 75.
229 Manitoba Hydro NFAT Submission, Chapter 7, p. 25, 34.
230 Manitoba Hydro NFAT Submission, Appendix 14.1, p. 24.
231 Exhibit KP-3-1, p. 47.
232 Exhibit KP-3-1, p. 49.
233 Exhibit LCA-45, p. 35.
234 Transcript, p.9668, 9829.

in the first year and 35% in the second year.[235] Manitoba Hydro's assumption increases the LCOE for wind because the costs are being evaluated on a net present value basis.

In its NFAT Submission, Manitoba Hydro assumed that new wind projects would have a useful life of 20 years.[236] La Capra Associates identified 25 years and Power Advisory found in discussions with wind power developers that 25 years is a common operating life for wind turbines.[237] Power Advisory noted that the St. Leon wind project has a contract term with Manitoba Hydro for 25 years, while the St. Joseph wind project has a 27 year contract term. Power Advisory also noted that new wind turbines have 25 year warranties. The shorter project life assumed by Manitoba Hydro negatively impacts the economics of wind projects.

Wind Capacity Factor

Manitoba Hydro assumed a wind capacity factor of 40%, "consistent with recent experience for wind generation resources in Manitoba having 80 metre hub heights."[238] La Capra Associates questioned this assumption. It noted recent projects in the region with an average capacity factor of 42% and assumed a 43% capacity factor in its sensitivity analysis.[239] Power Advisory agreed with Manitoba Hydro's assumption of a 40% capacity factor, while pointing out a higher capacity factor may be appropriate for new projects with larger towers.[240] Manitoba Hydro states that it assumes a Fixed O&M cost of $39.55/kW-year in 2012 dollars.[241] Power Associates reported that this was consistent with its experience, but also noted that Manitoba Hydro used a higher cost of $46/kW-year in its calculation of LCOE.[242]

7.6.0 Conclusions of the Panel

The actual construction cost of Keeyask will increase beyond Manitoba Hydro's currently projected capital cost of $6.5 billion. Budgeting at least for Manitoba Hydro's "high" estimate of $7.2 billion would be prudent.

This conclusion is not reached as a result of the history of past capital cost increases. The Panel accepts Manitoba Hydro's argument that the past is not necessarily a predictor of the future. Rather, the Panel bases its conclusion on its review of the Keeyask general civil contract, which is a cost-reimbursable contract that leaves a

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[235] Stevens, May 1, 2014 Transcript p.9669.
[236] Exhibit GAC/MH, 1-010a.
[237] Exhibit GAC-13, pp. 4-7.
[238] Exhibit GAC/MH 1-004a.
[239] Exhibit LCA-5-1, p.10.
[240] Exhibit GAC-13, pp. 4-8.
[241] Manitoba Hydro NFAT Submission, Appendix 7.2, p. 327.
[242] Exhibit GAC-13, pp.4-9.

significant portion of cost risk with Manitoba Hydro. It would be a fallacy to assume that the contract provides anywhere near the same level of cost certainty as a fixed-price contract, which would be more expensive.

This is not a criticism of the Keeyask general civil contract or Manitoba Hydro's approach to contracting. The Panel is satisfied that Manitoba Hydro's approach to developing and negotiating the contract, as well as its approach to managing risk, has been appropriate to date. Rather, it reflects the general nature of a large infrastructure project with inherent risks that can be mitigated, but not avoided.

Since no similar contract exists for the Conawapa Project to date, and Conawapa's proposed in-service date is a full 12 years away, the Panel has little confidence in Manitoba Hydro's current control budget. While the Panel is satisfied that Manitoba Hydro followed proper cost estimating procedures, in the Panel's view the significant uncertainties associated with Conawapa make any current estimate a rough guess at best and a high risk at most.

The history of capital cost increases over numerous successive forecasts is of concern to the Panel. It therefore sees a need for greater cost accountability in the form of an annual accounting of construction costs to the Province of Manitoba, which would explain the reason for such increases, rather than simply filing a new Capital Expenditure Forecast.

With respect to Manitoba Hydro's construction cost estimates for transmission facilities, the Panel concludes that such estimates are reasonable and recommends that Manitoba Hydro be given approval to proceed with the construction of a 750 MW transmission interconnection to the United States for a 2020 in-service date.

This interconnection provides increased firm transmission access extending into Minnesota, provides important, increased reliability, and supports import and export of electricity. However, the Panel encourages Manitoba Hydro to sell a portion of its 49% stake in the Great Northern Transmission Line.

Given the Panel's recommendation to discontinue spending on Conawapa, the North-South Transmission System Upgrade will not be required.

The Panel does not believe that thermal gas generation provides a reasonable alternative, especially when considered against the future potential of solar and wind power. The Panel is very concerned about the environmental implications of gas generation as a baseload resource, especially with respect to Simple Cycle Gas Turbines that do not achieve the same efficiency as Combined Cycle Gas Turbines.

While future integrated resource planning will have to consider all resource options, the adverse environmental effects of gas generation will have to be thoroughly considered.

With respect to alternative generation technologies, the Panel concludes that Manitoba Hydro's cost estimates for wind are likely overstated. Given the rapid changes in pricing with respect to alternative generation technologies, especially wind and solar PV, Manitoba Hydro should include greater consideration of such technologies in its integrated resource planning. This analysis and planning must include consideration of potential future grid parity with respect to solar technology, and the likely impacts of such a scenario on load forecasts and expected revenues.

8.0.0 Economic Evaluation

8.1.0 Introduction

8.1.1. Types of Evaluations

Manitoba Hydro's NFAT Submission provides an economic and a financial evaluation of the Preferred Development Plan and the alternative development plans that Manitoba Hydro considered as future resource options. Both types of evaluations are ways to compare the different plans and provide information to aid decision making in choosing a plan. The economic evaluation compares the benefits and costs of the different plans from Manitoba Hydro's perspective in order to determine which plan provides the greatest economic benefit to the utility. The financial evaluation compares the costs and revenues associated with each plan to determine the impact on future customer rates and Manitoba Hydro's exposure to financial risk. In Manitoba Hydro's Multiple Account Benefit-Cost Analysis (MA-BCA) discussed in Chapter 11, the total social benefits and costs, as well as their distribution, are considered.

The Terms of Reference task the Panel with assessing "whether the Preferred Development Plan is justified as superior to potential alternatives that could fulfill the need." In doing so, the Panel is to consider "the reasonableness of the scope and evaluation of risks and benefits proposed to arise from the development" and the "economic risks of the Plan … and alternative development strategies." The Terms of Reference further state that the Independent Expert Consultants engaged by the Panel must "critically examine whether the high level summaries filed by Hydro of Net Present Values and Internal Rates of Return which are derived from Commercially Sensitive Information reflect sound assumptions and calculations."[243]

This chapter examines Manitoba Hydro's economic evaluation of the Preferred Development Plan and alternatives. It also presents other economic evaluation metrics that the Independent Expert Consultants have used in their respective economic analyses.

8.1.2. Metrics

This chapter makes reference to different metrics in relation to the economic analysis: Net Present Value (NPV), Cumulative Present Value (CPV), Break Even/Payback, Internal Rate of Return (IRR), Ref-Ref-Ref, and Expected Value. Each of these metrics has a different meaning and provides a different view of the various development plans.

[243] Exhibit PUB-2, pp. 2-4.

In its analysis, Manitoba Hydro compares the net benefits of alternative development plans to Plan 1 (the All Gas Plan).

Net Present Value (NPV) is a standard economic analysis tool representing the present value of the future stream of annual revenues and costs. Because people tend to place a higher value on income today compared to income in the future, the stream of net benefits over time must be "discounted" at an appropriate rate to reflect this time preference. Net Present Value thus allows for alternatives with different costs and revenues that occur at different times to be compared on an equivalent basis at a single point in time.[244]

Cumulative Present Value (CPV) examines how beneficial a plan is compared to a base case from the start of a study period to a certain point in time during the period. The Cumulative Present Value is the Net Present Value at a given time (and thus ignores the incremental value of a plan over future dates). The final year's Cumulative Present Value matches the 78-year Net Present Value metric used by Manitoba Hydro.

A Cumulative Present Value Analysis is useful because it provides an understanding of the path towards reaching the Net Present Value and the year when a plan breaks even on a present value basis when compared to the base case and other plans being evaluated, or the **Break Even/Payback**. It complements a Net Present Value analysis by providing information on how quickly an upfront investment pays off as it is discounted over time.[245]

Manitoba Hydro did not calculate the Cumulative Present Value for the various development plans. La Capra Associates, Inc. provided these calculations in its analysis for the Panel.

Internal Rate of Return (IRR) is another metric typically used to evaluate investments or development plans. The Internal Rate of Return of a plan is the interest rate at which the Net Present Value of the costs associated with a development plan equals the net present value of the plan's benefits. It calculates the average annual return earned over the length of the study period. Another way of describing the Internal Rate of Return is the discount rate that brings the Net Present Value to zero. In relation to the evaluation of the development plans, if a plan has a positive incremental Net Present Value compared to the base case, then the Internal Rate of Return will be greater than the discount rate that Manitoba Hydro used in the economic evaluation. Manitoba Hydro provided Internal Rates of Return in response to an Information request from the

[244] NFAT Review, Manitoba Hydro Application, Chapter 9 p.3
[245] Exhibit LCA-12, p. 9A-36.

Panel[246], but did not perform an Internal Rate of Return analysis in the main NFAT Submission. La Capra developed the Internal Rates of Return for the alternative development plans by using the annual cash flows incremental to the All Gas Plan. The annual cash flows are the annual values that resulted from Manitoba Hydro's modeling results.

In Manitoba Hydro's economic analysis, Ref-Ref-Ref refers to reference, or most likely, conditions. Manitoba Hydro also provided analyses for varying conditions for high and low export and natural gas prices, capital costs, and interest or discount rates. The weighted average of all of the ranges of those factors is known as the Expected Value (EV). Expected Value is an alternative metric to the Ref-Ref-Ref metric.

8.2.0 Manitoba Hydro's Economic Evaluation

8.2.1. Economic Evaluation Parameters

In Chapter 9 of the NFAT submission, Manitoba Hydro conducted an economic evaluation of the Preferred Development Plan and its 14 alternative plans using the following parameters:

- A 78-year study period. The study period used in Manitoba Hydro's NPV analysis is 78 years in order to include the end of the service life of the longest-lived asset, the Keeyask and Conawapa generating stations., The first 35 years of analysis are based on a detailed evaluation of each plan while, for some plans, the results are extrapolated over the remaining 43 years.
- Revenue sources used to calculate each incremental NPV include revenues from electricity export sales contracts and forecast revenues from surplus power exports. Costs were comprised of capital cost estimates; fuel costs, consisting of the water rental rate under *The Water Power Act* and Manitoba Hydro's natural gas price forecast; estimated operating and maintenance costs, including capital maintenance; estimated cost of electricity imports; capital tax; Manitoba's carbon tax on coal; and the forecast of future carbon costs for Manitoba-based generation.
- The discount rate applied to convert the cash flow streams to a net present value. The discount rate was based on Manitoba Hydro's real weighted average cost of capital (WACC). The WACC is calculated using Manitoba Hydro's target debt-to-equity ratio of 75/25, its forecast cost of borrowing of 3.65% plus the 1% debt guarantee fee Manitoba Hydro pays to the Government of Manitoba, and an

[246] NFAT Review, PUB/MH1-079(c).

added premium of 3% to set the return for the equity component.[247] The initial real discount rate used was 5.05%. [248]This was updated for 2013 to 5.40%.[249]

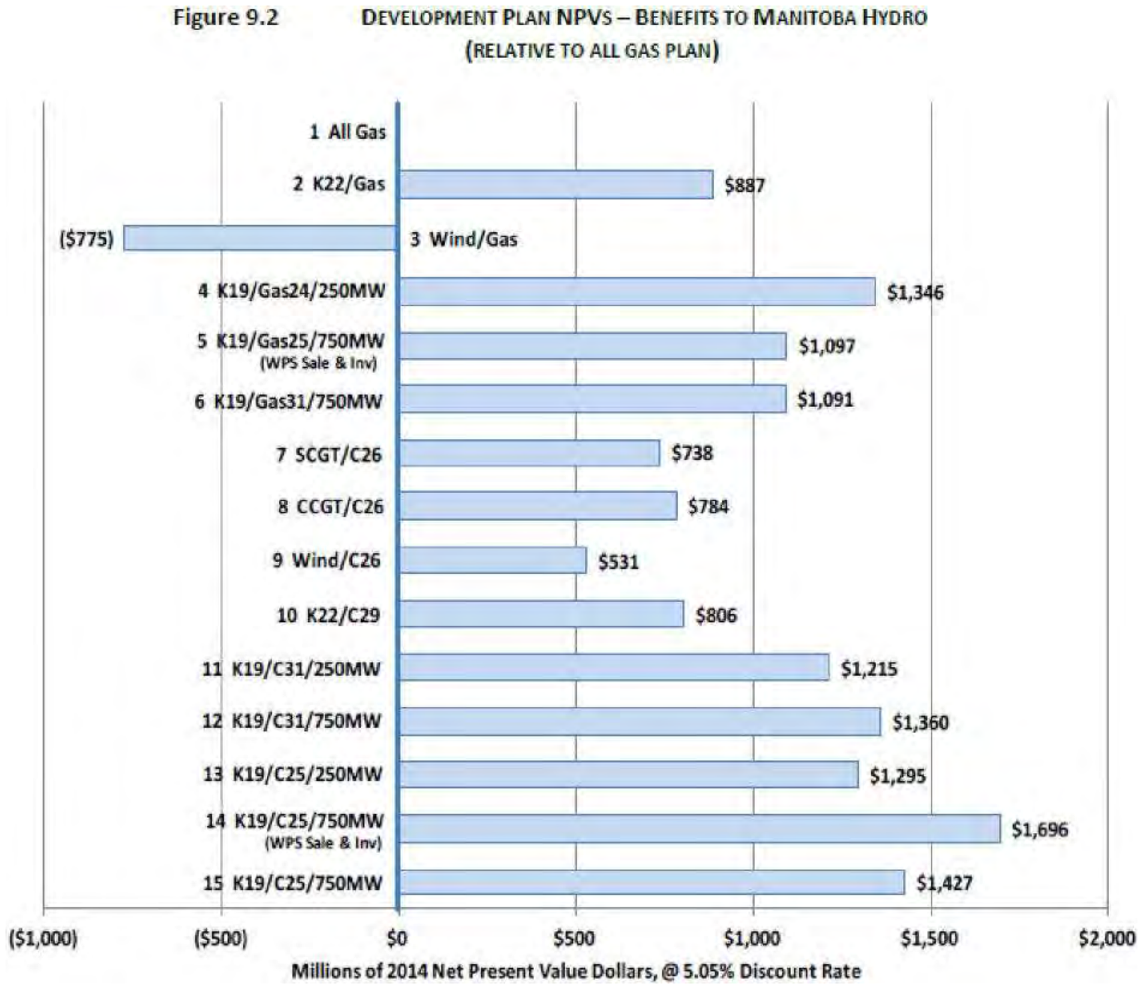
- Manitoba Hydro used the All Gas Plan with the lowest capital costs as a proxy for the do-nothing option against which the other development plans were compared.
- The various development plans were evaluated relative to the All Gas Plan for their benefits to Manitoba Hydro.
- A "reference case" known as "Ref-Ref-Ref" was used for each alternative development plan. The reference case is based on what Manitoba Hydro considered to be the "most likely" costs and benefits.
- All costs to be incurred prior to June 2014 related to preserving the in-service dates of Keeyask and Conawapa (estimated at $1.6 billion) were considered to be "sunk costs" and common to all plans and were excluded from the economic analysis.

8.2.2. Manitoba Hydro's Initial Evaluation Results

The results of the economic evaluation for each Plan's Reference Case based on Manitoba Hydro's 2012 planning assumptions are provided below. (Note that the value for the All Gas Plan is zero, as it is the base case.)[250]

[247] NFAT Review, NFAT Application Chapter 9 pp. 6-7.
[248] NFAT Review, NFAT Application Appendix 9.3 p. 7.
[249] NFAT Review, PUB/MH I-068(c).
[250] Manitoba Hydro NFAT Submission, Chapter 9, p. 15.

Figure 11 Results of Manitoba Hydro's Initial Incremental NPV Evaluation



The initial economic evaluation showed that Plan 14 (Preferred Development Plan) provides significantly better economic benefits ($1.7billion) compared to Plan 1 (All Gas) and the other development plans. Plans with a 750 MW transmission interconnection and gas generation (rather than Conawapa) following Keeyask (Plans 5 and 6) were virtually identical in overall benefits, but substantially below Plan 14. Manitoba Hydro indicated that given the levels of costs and revenues involved, differences of more than $100 million would be required to determine conclusively that one Plan was more attractive than another.[251] The results of the NPV analysis materially changed when Manitoba Hydro updated its plan on March 10, 2014.

[251] LCA/MH 1-349.

8.2.3. Updated Evaluation During NFAT Review Hearing

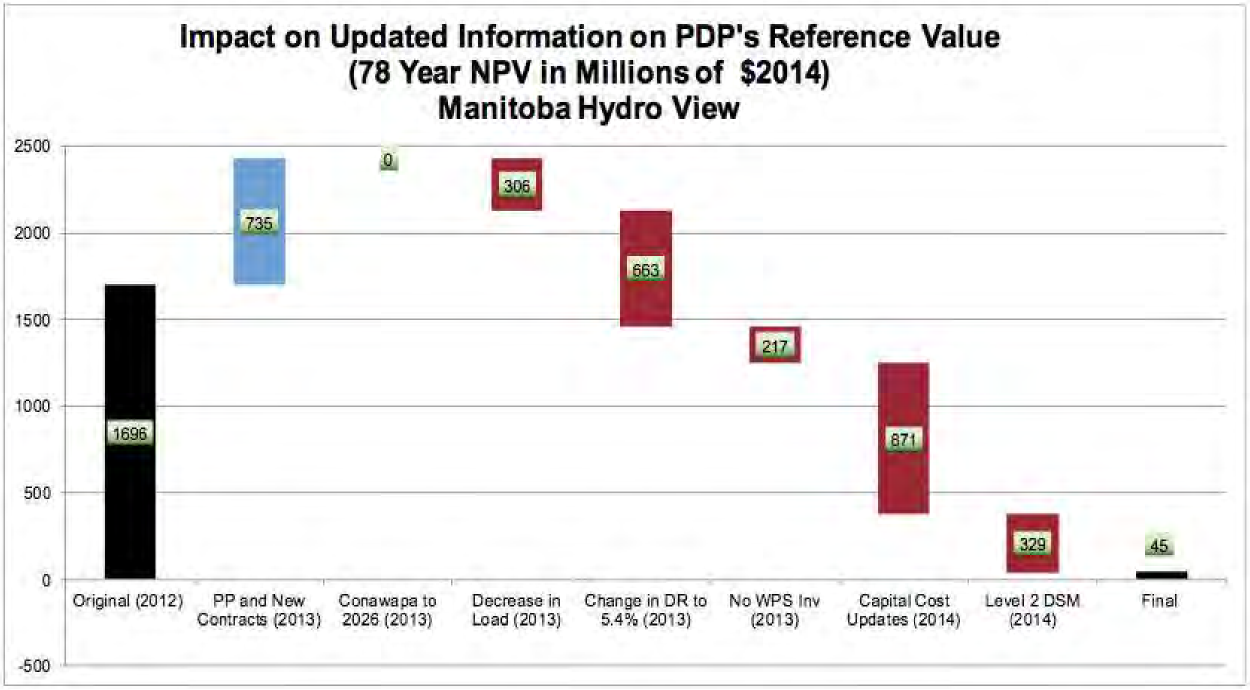
On March 10, 2014, Manitoba Hydro provided the Panel with new information that had a material impact on the economics of various development plans:

- the capital cost estimates for Keeyask increased by approximately $300 million and Conawapa increased by about $500 million between Capital Expenditure Forecast CEF12 and the March 2014 update;[252]
- Wisconsin Public Service (WPS) would not be investing in the 750 MW transmission interconnection, thus changing the costs of Plans that included a WPS investment, including the Preferred Development Plan;
- New Demand Side Management scenarios (DSM Levels 1 – 3), of which initiatives approximating DSM Level 2 will be pursued through the Power Smart program; and
- the possibility of increased domestic load associated with the expansion of the pipeline transportation sector.[253]

As a result of the updates, the incremental Net Present Value of the Preferred Development Plan was reduced from $1.7 billion to $45 million. La Capra depicted the decline in the Net Present Value of the Preferred Development Plan relative to All Gas in the waterfall diagram below.[254]

[252] NFAT Review, Exhibit MH-95, pp. 123-124.
[253] Exhibit MH-95 pp. 103,128.
[254] Exhibit LCA-53.

Figure 12 La Capra Associates "Waterfall" Chart Showing Impact of Updated Information on the Economics of the Preferred Development Plan



The largest contributor to the deterioration in the economics of the Preferred Development Plan was the increase in capital costs for Keeyask and Conawapa, which lowered the Net Present Value by $871 million, while an increase in the discount rate of 35 basis points reduced the Net Present Value by $663 million. Other factors such as DSM Level 2 and the absence of WPS investment in the 750 MW transmission interconnection also played a material role in reducing the Net Present Value.

Under the updated assumptions, plans that include Keeyask, Gas and the 750 MW transmission line such as Plan 5 provide significantly more economic benefits than the Preferred Development Plan, and Plan 4 (Keeyask19/Gas/250 MW) has the best ranking overall. Manitoba Hydro, however, advised that it no longer considers Plan 4 a viable option because Minnesota Power has applied for regulatory approval to construct to a 750 MW transmission line. These changes are outlined in the Table below.[255]

At the request of the Panel, Manitoba Hydro analyzed two alternate scenarios under which the Keeyask Project would be deferred to 2026. Both are based on DSM Level 2 and the pipeline load materializing.

[255] Exhibit MH-104-15 (Revision 3).

The first Keeyask deferral scenario is based on 2013 planning assumptions and 2014 capital costs. It assumes that Keeyask is deferred to 2026, the Northern States Power 125 MW Sale does not proceed, the coal-fired Brandon Unit 5 is kept operational for drought emergencies until December 2025, the 750 MW U.S. interconnection is built for a 2019/20 in-service date, and the existing Great River Energy 200 MW and NSP 350 MW diversity agreements are extended to 2035. The in-service date for a post-Keeyask gas-fired generation facility does not change. The incremental NPV of such a scenario is $259 million. This is $80 million less than the incremental NPV of Plan 5, which has a Keeyask in-service date of 2019.[256]

Manitoba Hydro's second Keeyask deferral scenario is based on the same set of assumptions as the one above, with the exception that the in-service date of a post-Keeyask gas turbine is deferred based on the extension of the diversity sales. This pushes the assumed in-service date for new gas-fired generation back from 2031 to 2035 and beyond. Manitoba Hydro's analysis indicated that this scenario is marginally more economic than Plan 5, at $345 million compared to $339 million for Plan 5. However, this amounts to only a $6 million difference over 78 years.[257] Given the inherent imprecision in this type of analysis, that difference is not material.

Overall, these two deferral scenarios indicate that deferring Keeyask does not improve the economics of a Keeyask-based plan.

Manitoba Hydro also analyzed a scenario in which the Keeyask Project proceeds with a 2019 in-service date, but the 750 MW U.S. transmission interconnection does not get built. This scenario approximates a situation in which Minnesota Power cannot obtain regulatory approval for the Great Northern Transmission Line. The plan, denoted as "Plan 2 Modified" on the Table below, shows that without the interconnection, a Keeyask-based plan has essentially the same 78-year Net Present Value as the All Gas Plan, at an incremental NPV of $1 million.[258]

[256] May 28, 2014 PUB/MH Pre-Ask
[257] May 28, 2014 PUB/MH Pre-Ask
[258] May 28, 2014 PUB/MH Pre-Ask

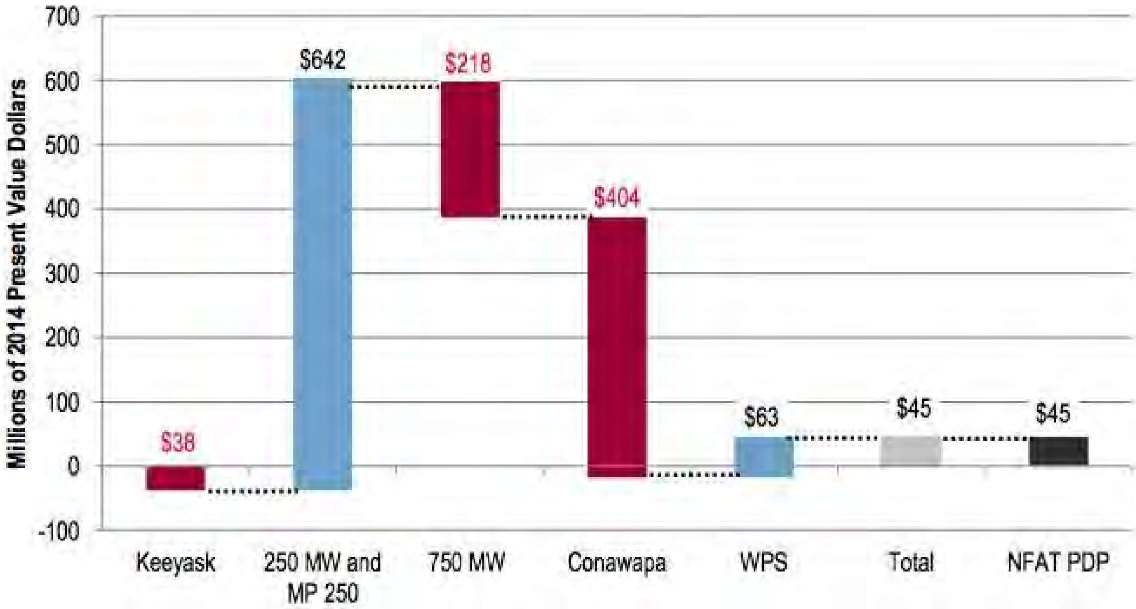
Table 13 Incremental Net Present Values of Alternative Plans Compared to All Gas Plan under Ref-Ref-Ref Assumptions, With In-Service Dates for Subsequent New Generation

	Incremental Net Present Value, (Millions of $(2014)) Relative to All Gas at Specified Level of DSM			
	Base DSM	**DSM Level 1**	**DSM Level 2**	**DSM Level 3**
Plan 2 (K23/Gas)	164 Gas 2029		-38 K 2031	
Plan 2 Modified (K19/Gas)			1 Gas 40	
Plan 4 – Hypothetical (K19/Gas/250MW)			604 Gas 2040	
Plan 5 (K19/Gas/750MW)	377 Gas 2026	339 Gas 2030	410 Gas 2031	373 Gas 2033
Plan 5 (K19/Gas/750MW) – With Pipeline			339 Gas 2030	361 Gas 2030
Plan 5 Keeyask Deferral Scenario 1 (K26/Gas/750MW19) – With Pipeline			259 Gas 2030	
Plan 5 Keeyask Deferral Scenario 2 (K26/Gas/750MW19) – With Pipeline			345 Gas 2030	
Plan 6 (K19/Gas/750MW)			386 Gas 2040	
Plan 12 (K19/C40/750MW)			-18 Conawapa 2040	
Plan 14 (K19/C/750MW) – With Pipeline	374 Conawapa 2026	124 Conawapa 2030	45 Conawapa 2031	-7 Conawapa 2033

The waterfall diagram below from La Capra's analysis depicts the incremental Net Present Value of each of the components of the Preferred Development Plan. This depiction shows that adding Keeyask would increase the costs by $38 million relative to the All Gas Plan over the 78-year period based on which NPV is calculated. The value of adding the 250 MW transmission interconnection and the Minnesota Power sale is $642 million. Moving from a 250 MW to a 750 MW interconnection and adding Conawapa increase the costs by $218 million and $404 million, respectively, while the addition of the Wisconsin Public Service sale provides a benefit of $63 million. As this figure indicates, the Net Present Value reduction associated with Conawapa virtually negates the value of the transmission interconnection. The WPS contract, on the other hand, improves the NPV by $63 million.[259]

[259] Exhibit LCA-3-3, p. 9S-6, Figure 9-99S.

Figure 13 La Capra Associates Chart Showing the 78-Year Incremental NPV of Preferred Development Plan Components



La Capra stated that alternative metrics, such as Internal Rate of Return and Break-Even Year, do not show the Preferred Development Plan to be the lowest cost development plan.

Another way of looking at the economics of the various plans is to determine the Cumulative Present Value relative to the All Gas Plan (Plan 1) at various points over the 78-year timeframe. Cumulative Present Value provides an understanding of the timing of the costs and benefits over a study period. The Table below shows that Plan 14 (Preferred Development Plan) does not achieve a positive Cumulative Present Value relative to the All Gas Plan until 2089. Plan 5, on the other hand, moves into positive range by 2062, twenty-seven years before the Preferred Development Plan. Plan 4, with the 250 MW line, ranks best overall, but Manitoba Hydro now considers this plan to be hypothetical because of its commercial arrangements with Minnesota Power.

All of the breakeven years for development plans that include Keeyask or Keeyask and Conawapa are beyond the detailed analysis period of 35 years and therefore rely on the extrapolation of assumptions to determine the benefits. Plans with Keeyask and excluding Conawapa break even at 40-50 years compared to All Gas and are therefore less reliant on forecast extrapolation than Conawapa-related plans.[260]

[260] Exhibit, LCA-3-3, p. 9S-8, Figure 9-21S.

Table 14 Summary – CPVs as compared to All Gas Plan at the End of Various Periods, Break-Even Year, 78 year IRR and 78 Year CPV of Total Capital ($millions in 2014 Present Value Dollars)

Plans	78 Year CPV of Total Capital	78 NPV	50 CPV	35 CPV	20 CPV	78 Year IRR	Break Even Year (All Gas) Base Case
1 All Gas	$2,764	$0	$0	$0	$0	N/A	N/A
2 K31/Gas29	$4,429	($38)	($349)	($798)	($1,781)	5.28%	N/A
4 K19/Gas40/250MW	$5,774	$604	$239	($284)	($1,541)	6.26%	2055
5 K19/Gas31/750MW (WPS	$6,215	$410	$10	($523)	($1,899)	5.92%	2062
6 K19/Gas40/750MW	$6,175	$386	($5)	($555)	($1,876)	5.90%	2063
12 K19/C40/750MW	$8,421	($18)	($954)	($2,261)	($2,395)	5.36%	N/A
14 K19/C31/750 (WPS)	$9,528	$45	($863)	($2,173)	($5,298)	5.42%	2089

The Preferred Development Plan (Plan 14) economics have eroded to essentially break-even with the All Gas Plan, even over the 78-year study period.

Several resource development plans (Plans 4, 5 and 6) that do not include Conawapa have economic benefits over a 78-year Net Present Value basis of about $400 to $600 million as compared to the Preferred Development Plan.

The Table above also shows that the net gain on the Net Present Value of the Preferred Development Plan is a miniscule percentage of the incremental investment costs of the plan. For example, the 78-year Net Present Value of the Preferred Development Plan is $45 million. To carry out the Plan, the incremental investment on a present value basis is over $9.5 billion. Plans 5 and 6 perform better than the Preferred Development Plan on this metric at just over $6 billion for $400 million in benefits. The All Gas Plan represents the lowest investment at $2.7 billion.

As for the Internal Rate of Return metric, over 78 years the IRR of the Preferred Development Plan is slightly higher than the 5.40% hurdle discount rate; Plans 5 and 6 posted better IRR values, at 5.92% and 5.90% respectively.

8.3.0 La Capra's Alternative Plans

In addition to the various development plans presented in Manitoba Hydro's NFAT Submission, La Capra provided two additional alternative plans – an All Gas plan involving only combined cycle gas turbines (CCGT) rather than mix of CCGT and simple cycle gas turbines (SCGT) relied on by Manitoba Hydro, and a No New Generation Plan relying on increased imports. The economic evaluation of La Capra's CCGT Plan and No New Generation Plan revealed that the CCGT Plan was similar to Manitoba Hydro's All Gas reference case. The No New Generation Plan compared favorably to the All Gas Plan and had better Expected Values than the Preferred Development Plan.

The No New Generation Plan is considered by La Capra to be a hypothetical plan, the results of which point to the potential for added elements such as DSM, import limit capabilities which may have promise either by themselves or in some combination. [261]

Manitoba Hydro suggested that a new transmission line in the U.S. to provide imports to rather than exports from Manitoba is unrealistic.[262] Manitoba Hydro saw no value in the hypothetical No New Generation plan, as it is of the view that it has captured the benefits of various elements of the No New Generation Plan through incorporating higher DSM levels, and the 750 MW Manitoba-Minnesota transmission interconnection.[263]

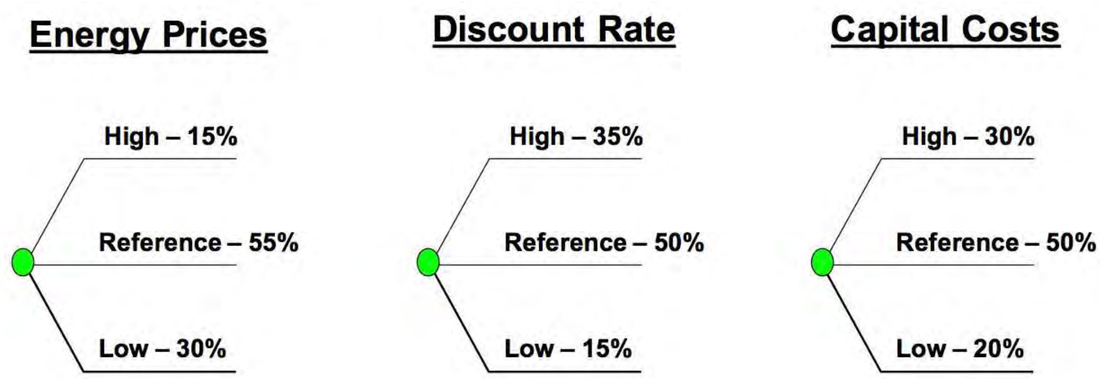
8.4.0 Uncertainty Analysis

Manitoba Hydro's economic evaluation also provided an economic uncertainty analysis. This branch of the analysis included a probabilistic analysis, which examined the range of uncertainty around energy prices, the discount rate and capital costs, three factors that Manitoba Hydro asserts have the greatest impact on the economic and financial outcomes of the development plans. Each of those factors is a grouping of several underlying factors. For example energy prices are influenced by export prices, carbon prices and natural gas prices. The discount rate includes the nominal interest rate, inflation and exchange rates. Capital costs include the capital costs of hydro, wind and natural gas generation, transmission costs and certain escalation.

A range consisting of low, reference and high was developed for each of the three factors. Based on its own judgment, Manitoba Hydro determined probability weightings for the high impact factors as follows: [264]

[261] Transcript p. 5826.
[262] Exhibit MH-204, p. 168.
[263] Exhibit MH-204, p. 169.
[264] Manitoba Hydro NFAT Submission, Chapter 10 –p.8, Figure 10.4.

Figure 14 Probability Weightings for Energy Prices, Discount Rate and Capital Cost



The combination of these three groupings and three sets of assumptions in each grouping combined to produce 27 scenarios that were modeled in the initial analysis for 12 of the 15 development plans.

Manitoba Hydro determined both a reference Net Present Value and the Expected Net Present Value which reflected the probability distribution of all outcomes. The use of the Expected Value methodology was recommended by Dr. Borison of Navigant Consulting,[265] which assisted Manitoba Hydro in undertaking the uncertainty analysis. Navigant opined that in uncertainty analyses, the single most important output is typically the Expected Value or mean. The Expected Value is the sum of each scenario Net Present Value by the probability of its occurrence. Accordingly, Manitoba Hydro determined the Expected Value of each of the development plans by taking the sum of the Net Present Values multiplied by the appropriate scenario probabilities listed in the column on the far right on the following Table, known as a Probabilistic Analysis Quilt:[266]

[265] Exhibit MH-95 pp. 60-61.
[266] Manitoba Hydro NFAT Submission, Chapter 10, Table 10.5, p. 17.

Table 15 Manitoba Hydro's Initial Incremental Economics – All Scenarios

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14	
			All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW	
													WPS Sale & Investment		
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												Probabilities
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841	1.35%
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410	2.25%
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292	0.90%
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155	4.50%
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929	7.50%
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20	3.00%
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810	3.15%
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698	5.25%
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157	2.10%
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853	2.48%
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284	4.13%
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402	1.65%
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470	8.25%
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696	13.75%
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645	5.50%
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268	5.78%
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380	9.63%
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235	3.85%
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940	2.25%
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166	3.75%
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115	1.50%
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203	1.58%
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315	2.63%
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170	1.05%

Colour Legend: < -3000 | 0 | > 3000

The above Probabilistic Analysis Quilt is based on the incremental difference of the Net Present Value against the least capital cost option, which is the All Gas Plan (Plan 1). Green cells indicate an incremental positive Net Present Value relative to the Net Present Value of the All Gas Plan, while red cells indicate a negative incremental Net Present Value.

Manitoba Hydro determined a single un-weighted scenario (representing the reference value for the three risk factors) with the resulting incremental Net Present Value of $1.7 billion for Plan 14 (Preferred Development Plan) as compared to the All Gas Plan. Based on the Expected Value economics, the relative Expected Value NPV was $1.085 billion based on the original NFAT Submission.[267]

Table 16 Manitoba Hydro Initial Expected Value Calculation

Development Plan	1	3	7	2	4	13	11	6	15	12	5	14
	All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
											WPS Sale & Investment	
	Millions of 2014 NPV dollars											
10th Percentile - "Risk"	-3502	-4599	-1217	-1249	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429
25th Percentile	-560	-2200	-297	-248	115	-650	-363	-183	-904	-361	139	-204
75th Percentile	1481	383	1363	1636	2092	1854	2074	1832	2008	2009	1726	2255
90th Percentile - "Reward"	1905	1209	1956	2007	2479	3180	2953	2215	3360	3220	2256	3377
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

267 Manitoba Hydro NFAT Submission, Chapter 10, Table 10.6, p. 17.

This analysis showed that the incremental Expected Value for the Preferred Development Plan was higher than the Expected Value for all other development plans.

On March 10, 2014, Manitoba Hydro updated the capital cost estimates for Keeyask and Conawapa, and adjusted for Wisconsin Public Service's decision not to invest in the 750 MW U.S. Great Northern Transmission Line. Manitoba Hydro also updated for 2013 planning assumptions, which included enhanced levels of DSM and potential new pipeline load. With that information, Manitoba Hydro also updated the probability weightings as follows:[268]

Figure 15 March 10, 2014 Updated Probability Weightings for Energy Prices, Discount Rate, and Capital Costs

Based on this updated information, the incremental Net Present Value on a reference case basis for the Preferred Development Plan declined to $45 million relative to All Gas Plan from the $1.7 billion in the original business case. On the basis of reference case comparisons, the Preferred Development Plan was no longer the most economic plan, where other alternatives such as Plan 5, which excludes Conawapa, had materially higher economic value on an incremental NPV basis.

On March 27, 2014, Manitoba Hydro provided an incomplete update of Expected Values of eight plans based on the updated capital cost assumptions, as well as the removal of the originally anticipated investment of Wisconsin Public Service in the Great Northern Transmission Line. This update was still based on 2012 planning assumptions, without enhanced DSM and without the anticipated new pipeline load. In this update, Manitoba Hydro also lowered the probability weightings for 'high' capital costs from 30% to 20% based on Manitoba Hydro's view that there would be increased cost certainty from the recently received Keeyask general civil contract.

[268] Exhibit MH-104-8.

The update was provided for 7 of the 12 plans originally analyzed, as well as for Plan 8, as reflected in the following Table.[269]

Table 17 March 10, 2014 Updated Expected Values

Development Plan	1	2	4	8	6	12	5	14
	All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & no WPS Inv	
	Millions of 2014 NPV Dollars							
10th Percentile -"Risk"	-953	-862	-727	-1457	-1007	-2512	-909	-2946
25th Percentile	-244	-622	-290	-980	-556	-1482	-367	-1760
75th Percentile	483	1026	1339	916	1099	1232	824	1105
90th Percentile - "Reward"	738	1448	2019	1898	1749	3239	1475	3653
Expected Value	-9	268	651	143	386	115	268	120
Ref-Ref-Ref NPV	0	489	917	403	662	536	484	614

Most significantly, the update reduced the Expected Value for the incremental Net Present Value of the Preferred Development Plan to $120 million. This is over $900 million less than the $1.085 billion Expected Value forecast in the original business case. Furthermore, the revised analysis indicates that those plans that exclude Conawapa have higher Expected Values than those that include it. The updated analysis reveals that Plan 4 has the highest Expected Value (Manitoba Hydro now considers Plan 4 to be hypothetical). Excluding Plan 4, Plan 6 (K19/Gas32/750 MW) has the highest Expected Value ($386 million) followed by Plan 5 at $268 million. Plan 14 has the most downside risk:[270]

[269] Exhibit MH-104-8.
[270] Exhibit MH-104-8.

Table 18 March 10, 2014 Updated Probabilistic Quilt

		Development Plan	1	2	4	8	6	12	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
									WPS Sale & no WPS Inv	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars							
Low	Low	H	-1062	-1401	-851	-1501	-1079	-2143	-758	-1825
		Ref	-68	16	646	106	392	-53	698	424
		L	734	1205	1898	1449	1613	1750	1906	2359
	Ref	H	-463	-1751	-1512	-2398	-1793	-3717	-1546	-3969
		Ref	208	-677	-334	-1085	-614	-1977	-355	-2010
		L	750	232	658	15	369	-476	637	-325
	High	H	-88	-1782	-1761	-2625	-2060	-4202	-1872	-4838
		Ref	416	-891	-748	-1480	-1033	-2668	-820	-3044
		L	823	-133	110	-519	-172	-1345	61	-1500
Ref	Low	H	-2033	-120	543	325	298	1410	-7	1869
		Ref	-1039	1296	2040	1932	1770	3501	1449	4118
		L	-237	2486	3292	3275	2991	5304	2658	6053
	Ref	H	-671	-585	-260	-910	-517	-1204	-707	-1345
		Ref	0	489	917	403	662	536	484	614
		L	542	1397	1910	1503	1645	2037	1477	2300
	High	H	17	-716	-620	-1343	-880	-2214	-1034	-2759
		Ref	520	175	393	-198	148	-680	18	-966
		L	927	933	1251	762	1008	643	899	578
High	Low	H	-3454	892	1647	2005	1333	4820	402	5388
		Ref	-2460	2309	3143	3612	2804	6911	1858	7638
		L	-1658	3498	4396	4955	4025	8714	3066	9573
	Ref	H	-1158	402	797	469	526	1178	-103	1125
		Ref	-487	1476	1974	1782	1704	2918	1088	3084
		L	55	2384	2967	2882	2687	4418	2081	4770
	High	H	-82	210	368	-156	115	-352	-384	-824
		Ref	422	1101	1381	989	1143	1182	669	969
		L	828	1859	2239	1949	2003	2505	1549	2513

The uncertainty analysis also reveals that the upside potential for Plans that include Conawapa comes with scenarios that include high export prices, low capital costs and/or low interest rates. These scenarios are uncertain at best.

The above quilt reflects a reference Net Present Value for the Preferred Development Plan of $614 million. This led to an Expected Value of $120 million. The above quilt does not fully reflect the updated economic information, which indicates that the Preferred Development Plan has a Reference Net Present Value of $45 million. Accordingly, it is possible that the Expected Value remains overstated at $120 million. Manitoba Hydro did not provide any further updates to the Expected Value analysis, nor a probability quilt on the Preferred Development Plan or alternatives based on 2013 planning assumptions with enhanced DSM and potential Pipeline load due to timing restrictions to run the full analysis.

Many witnesses described the Expected Value as a key risk output and more informative than the Ref-Ref-Ref value. The Panel was not in a position to comment on how the Preferred Development Plan would have performed relative to other plans based on the risk-adjusted basis.

La Capra also performed an uncertainty analysis, but instead of referencing every Net Present Value to the All Gas Plan Ref-Ref-Ref scenario, it provides a comparative analysis across plans using consistent assumptions of uncertain parameters based on the same probabilities used by Manitoba Hydro. For example, the Preferred Development Plan's Hi-Low-Ref scenario was compared to the All Gas Hi-Low-Ref scenario. What La Capra determined was that when interim period economic analysis results are used to develop metrics for 20, 35, and 50 year study periods, the Preferred Development Plan does not appear to be the lowest-cost resource plan alternative even when a probabilistic scenario analysis covering 27 scenarios is included. Plans with Keeyask but without Conawapa have more favorable economic uncertainty profiles than the Preferred Development Plan.[271]

La Capra also conducted a sensitivity analysis of changing the discount rates, capital costs and export prices and their impact on the Preferred Development Plan. La Capra concluded the following:[272]

- A modest increase in discount rates or the elimination from consideration of the low discount rate scenarios postulated by Manitoba Hydro would make the Preferred Development Plan have the same present values of costs over 78 years as the All Gas Plan on an Expected Value basis.
- Several Plans have lower costs than the Preferred Development Plan, even over 78 years, when higher discount rates are assumed.
- Modest increases in capital cost assumptions for the Keeyask and Conawapa projects would also result in other development plans having lower costs than the Preferred Development Plan, even over 78 years.
- A slightly lower view of export market prices substantially erodes Manitoba Hydro's expected economic benefits of the Preferred Development Plan.

CAC's expert, Dr. Wayne Simpson, plotted the risk against expected return to determine that Plan 4 was the superior plan, followed by Plan 6, Plan 5, and then Plan 2. Dr. Simpson was of the view that Manitoba Hydro's evaluation was not robust to changing costs and other updates.[273] Another CAC expert, Mr. Harper, also provided a probabilistic analysis and determined that the Preferred Development Plan was not preferred from an economic perspective.[274]

[271] Exhibit LCA-12 p. 80.
[272] Exhibit LCA-12. p.129.
[273] Exhibit CAC-69, pp. 14-15.
[274] Exhibit CAC-68 pp. 47-48.

La Capra's view was supported following the updates to the Keeyask and Conawapa capital costs that showed plans with Keeyask and the interconnection as being superior to plans containing both Keeyask and Conawapa.

The Panel received comments from several witnesses about the limitations of Manitoba Hydro's updated analysis, particularly the fact that it was not updated to reflect new DSM levels. Many felt that their analysis was hampered by the absence of revised Expected Values that would factor in the new levels of DSM. The rapidly changing economic analysis constituted a significant problem to both the Panel and Interveners in analyzing the Preferred Development Plan and alternatives.

8.5.0 Specific Risk factors

Manitoba Hydro also evaluated the sensitivity of selected development plans to factors such as drought, long-term climate change, Manitoba load growth and Demand Side Management. These risk factors are discussed in Chapter 10.

8.6.0 Selected Issues Relating to Manitoba Hydro's Analytical Approach

8.6.1. Treatment of Cash Transfers to the Province

Manitoba Hydro's economic analysis (not its MA-BCA analysis) includes payments to government as a benefit, which is discounted at the same rate as benefits to Manitoba Hydro. CAC's expert witness, Mr. Harper, raised two concerns with this approach. First, the inclusion of cash transfers to the Government clouds the perspective of the economic analysis in that it no longer represents only Manitoba Hydro's perspective. Second, this inclusion does not adequately portray the broader societal perspective because the discount rate applied is the same discount rate used to determine the NPVs from Manitoba Hydro's perspective.

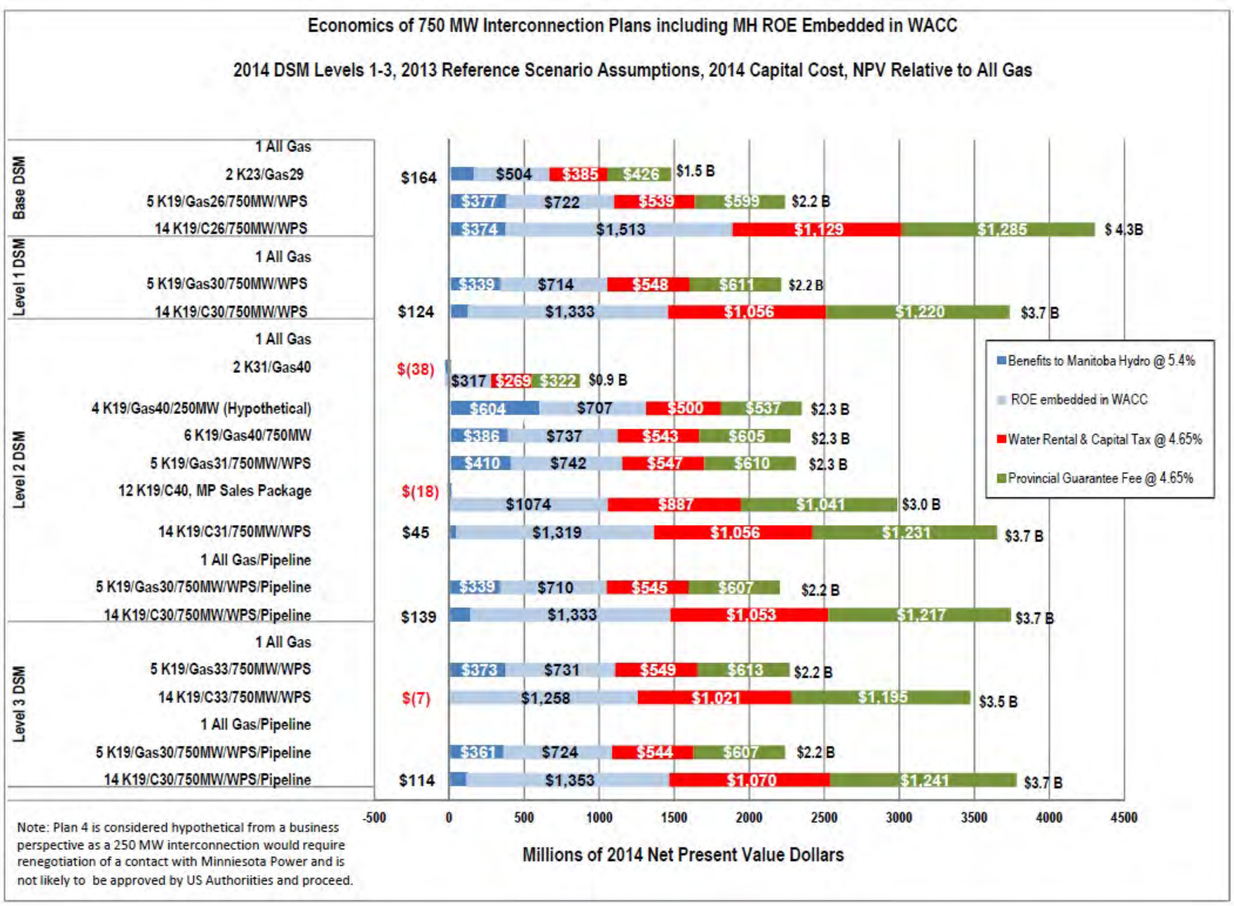
Mr. Harper pointed out that in the MA-BCA analysis (see Chapter 11), Manitoba Hydro used a 6% discount rate for government benefits, which is intended to reflect the social opportunity cost of capital from the taxpayers' point of view. Furthermore, Mr. Harper is of the view that the MA-BCA analysis properly recognizes that the debt guarantee fee payable by Manitoba Hydro to the Province of Manitoba is a cost associated with compensating the province for the increased risk the province assumes for guaranteeing Manitoba Hydro's debt.[275]

[275] Exhibit CAC-30, pp. 25-26.

8.6.2. Embedded Return on Equity

In concert with its March 10, 2014 update, Manitoba Hydro introduced into its economic evaluation the concept of the Return on Equity embedded in its Weighted Average Cost of Capital (WACC). Based on this change in methodology, Manitoba Hydro continues to include transfers to the Government, including the debt guarantee fee, in its updated Net Present Value analysis, but now uses a lower discount rate of 4.65%, rather than the 5.40% WACC used to calculate the benefits to Manitoba Hydro. The net effect of this was to nullify the application of a WACC to the analysis of provincial benefits and return to an analysis based on Manitoba Hydro's cost of borrowing plus the 1.0% debt guarantee fee. The impact of lowering the discount rate in this manner was to increase the indicated level of benefits to be derived by the Province. The diagram below depicts this approach:[276]

Figure 16 Manitoba Hydro Embedded Return on Equity



[276] Exhibit MH-171 (Revision 4).

Based on this new approach, the total NPV of provincial benefits calculated by Manitoba Hydro is $3.7 billion for the Preferred Development Plan for DSM Level 2 including the derived $1.3 billion in embedded equity. The analysis was provided for illustrative purposes and was not suggested to replace the WACC being used for corporate economic purposes[277].

Morrison Park questioned the significance of the calculation, noting that it was not directly relevant to ratepayers or the government, but simply represented Manitoba Hydro's view.[278] MIPUG's expert witness indicated that it could be informative, but should not be the primary consideration.[279]

In its final argument, MIPUG noted that one of the main concerns with the embedded return on equity methodology is that it is calculating the Net Present Value by looking only at the need to finance the underlying debt. MIPUG stated:

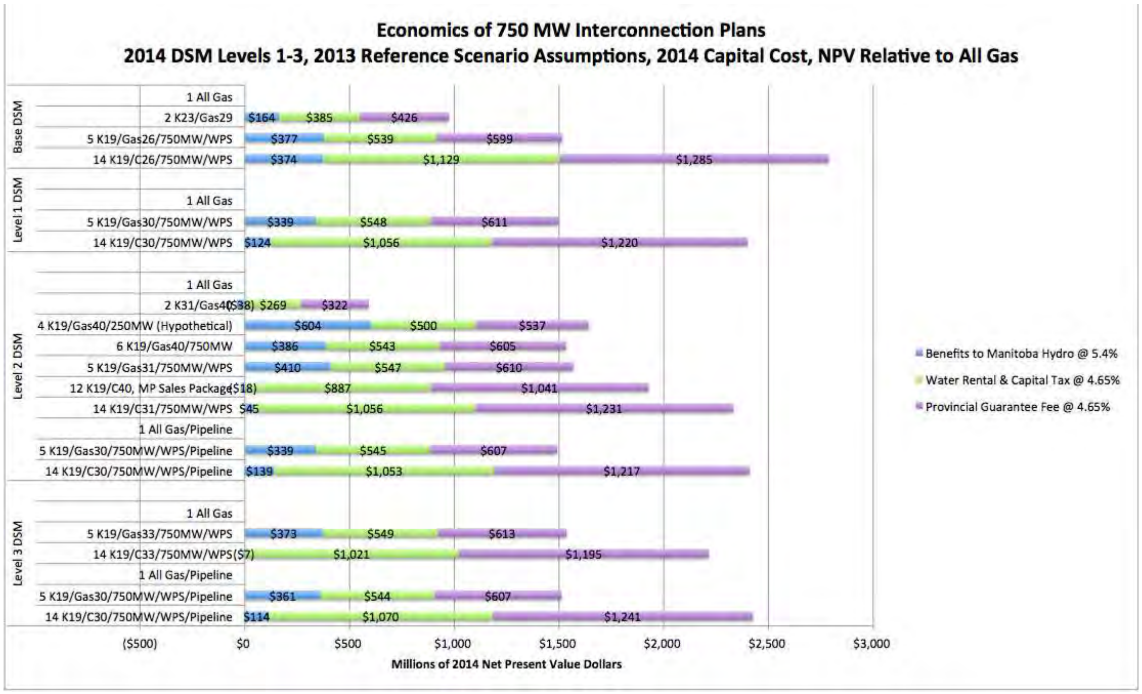
> *Conceptually, we know that larger plans require other levels of returns – whether that is for First Nation benefit sharing, setting aside reserves, or helping build to a debt:equity target. All of those other considerations cannot be achieved with a plan that is solely (barely) able to repay its debt over its life, which is what a 4.65% discount rate effectively represents.*[280]

CAC's witness, Mr. Harper, questioned whether embedded equity could be viewed as a benefit. The Preferred Development Plan involves more capital and that requires additional equity in order to sustain Manitoba Hydro's financial integrity.[281]

The following Table shows the comparable economics excluding the embedded return on equity:[282]

[277] Exhibit MH-95 p. 131.
[278] Transcript, p. 7406.
[279] Transcript, p. 10129.
[280] Exhibit MIPUG-28, p. 30.
[281] Transcript, p. 8542.
[282] Derived from Exhibit MH-171, excluding embedded equity.

Figure 17 Manitoba Hydro Exhibit #171 Excluding Embedded Equity



8.6.3. How Determinative is the NPV Analysis?

Manitoba Hydro maintains that Net Present Value is the best metric for economic analysis when comparing mutually exclusive plans, while Internal Rate of Return (IRR) is useful when analyzing incremental cash flows.[283] Dr. Borison, Manitoba Hydro's expert, indicated that the Net Present Value metric is the primary decision making tool used to evaluate such major capital investments."[284]

La Capra stressed that the Net Present Value metric, while important, did not reveal everything that one might need to know about the economic benefits of a plan. Manitoba Hydro's singular focus on the 78-year Net Present Value metric as the basis for comparing alternative development plans is too limited in scope for a decision of this magnitude. Manitoba Hydro does not offer any comparative metrics that capture important differences in the plans through the study period that bear on the timing of costs and benefits and the associated risks.[285] For example, the Internal Rate of Return demonstrates how large an investment is needed to obtain the benefit shown. Similarly, Cumulative Present Value provides a snapshot of the economics at a particular time

[283] Transcript, p. 1686, p.1878.
[284] Transcript, p. 1686.
[285] Exhibit LCA-12 p. 9A-151.

and will provide important information on the time required for proposed investments to provide benefits and on assessing implications of forecast risk.[286]

Morrison Park stated that for a typical investor, the discount rate could either represent the investor's hurdle rate, or the total cost of capital for the project if calculating Internal Rate of Return rather than total return. However, Morrison Park noted that neither of these uses appears to be appropriate in the current case. Since minimizing cost to ratepayers is a priority, use of the discount rate seems better focused on the comparison of ratepayer costs over time.[287]

8.6.4. Timeframe of the Analysis

As mentioned earlier in this chapter, Manitoba Hydro used a 78-year time period in its economic evaluation, comprised of a 35-year detailed evaluation and an extension of the 35-year period by 43 years to the end of the service life of the longest-lived asset, a hydro-electric generating station. The values for the 43-year period are an extrapolation of those used in the detailed analysis representing a residual value of a long-lived project. Some witnesses were of the view that the study period was too long and exposed the economic evaluation to too much uncertainty. Manitoba Hydro maintains that for the purpose of an economic analysis, it is appropriate for the timeframe to extend to the end of the life of the longest-lived asset.

The MMF's expert witness, Whitfield Russell Associates, indicated that the 78-year period exceeds Manitoba Hydro's 20-year financial forecast and its 35-year Power Resource Plan period. It was noted that there could be many changes over that period which could affect how revenues and costs were treated.[288]

Both Morrison Park and La Capra cautioned that there was much uncertainty and unpredictability associated with a long timeframe used in Manitoba Hydro's analysis.

Morrison Park indicated that there is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. For example, technological advances could render the underlying assumptions obsolete even in relatively short periods of time.[289] The technology development of hydraulic fracturing in the natural gas industry over the past decade is only a recent example of expectations about future market conditions being totally undermined: widespread expectations a decade ago

[286] Exhibit LCA -3, p. LCA-9.
[287] PUB/MPA 32(a)
[288] Exhibit MMF-31, pp. 5-6; Transcript, p. 10591.
[289] Exhibit MPA-3, p. 16.

were that North America would by now be supply-constrained and increasingly reliant on expensive imports of natural gas.

La Capra expressed concern that a 78-year study period is unusual in evaluating utility investments and indicated there are risks inherent in forecasting over such a long period of time, and the estimates of benefits over that period of time are subject to much uncertainty.[290]

La Capra further states that it is common for decision makers to place much less weight on long-term forecasts of long-term benefits in conjunction with plans with high front-end costs. This means it is valuable to consider intertemporal issues, payback, Internal Rate of Return and other metrics that better articulate the temporal relationship between investments and the associated benefits expected from those investments.[291]

By contrast MIPUG considered the 78-year evaluation appropriate for purposes of considering which plans should be pursued, but stated that to analyze ratepayer impacts, time horizons from the very short-term to the full forecast period is required.[292]

8.6.5. Treatment of Sunk Costs

The treatment of the $1.6 billion in sunk costs was also raised as an issue. In the Net Present Value analysis, the expenditures to preserve the in-service dates of Keeyask ($1.2 billion) and Conawapa ($400 million) were treated as common costs to all plans, rather than as costs applied to the Preferred Development Plan or to plans that include Keeyask or Conawapa. Some witnesses maintained that this treatment biases the analysis in favour of the Preferred Development Plan.

Whitfield Russell identified the treatment of costs associated with Bipole III as a particular concern. This witness was of the view that the costs of Bipole III were not sunk costs because the facility is yet to be built. Whitfield Russell further suggested that including Bipole III's costs as a common cost biases the economic analysis in favour of the hydro-based plans. In this witness's opinion, Bipole III should not be treated as a neutral factor in assessing all of the development plans because not all of the plans require its construction. Consequently, Bipole III's costs should be considered as a cost attributable to the hydro-based plans rather than to the system as a whole.[293]

[290] Exhibit LCA-12, p. 9A-24.
[291] Exhibit LCA-12, p. 9A-24.
[292] Exhibit MIPUG-28, p. 28.
[293] Exhibit MMF-31, pp. 23-24.

8.6.6. Discount Rate

Selection of the appropriate discount rate to apply over a 78-year time period is open to debate. Justification of a high discount rate can be based on the social cost of capital; an intermediate rate based on the current cost of borrowing; and a low rate based on views of inter-generational equity such as has arisen in treatments of the future impacts of climate change. The issue is magnified in the case of the Preferred Development Plan, which entails large expenditures in the near future with the expected net benefit accruing many years in the future.

The discount rate that Manitoba Hydro used in the economic evaluation accordingly drew comment. The discount rate in the economic evaluation context is designed to reflect the return that markets require from the type of investment in question.

CAC's expert Mr. William Harper was of the view that Manitoba Hydro understated the cost of equity, resulting in a lower discount rate than what should be applied in the analysis. Mr. Harper indicated that the allowed return on equity was higher in other jurisdictions than the amount assumed by Manitoba Hydro, which was notionally based on 300 basis points over the cost of debt, including the debt guarantee fee. Calculating the Net Present Value at the rate that Mr. Harper felt was appropriate (5.2%,[294] subsequently updated to 5.55%[295]) results in in lower NPV values for all plans.

Furthermore, CAC and MIPUG's experts argued that it was not appropriate to include the discount rate as an uncertainty because it challenges the ability to compare the alternatives and makes the discount rates and interest rates difficult to separate. Manitoba Hydro's expert acknowledged that the explicit treatment of the discount rate as an uncertainty is challenging, but stated that it is an accepted practice.

8.7.0 Conclusions of the Panel

The Panel accepts that Net Present Value (NPV) is an appropriate metric and a useful guide to decision-making. However, other metrics such as the Internal Rate of Return (IRR) and Cumulative Present Value (CPV) complement the Net Present Value analysis and have been considered by the Panel in assessing the economics of the plans.

Based on the March 27, 2014 updated information (which reflects only increases in the capital costs of Keeyask and Conawapa based on 2012 assumptions and the lack of Wisconsin Public Service investment, but does not reflect enhanced DSM or the new pipeline load), plans with Conawapa have a lower expected Net Present Value than

[294] Exhibit CAC-30 pp. 20-21.
[295] Exhibit CAC-69, p. 26.

plans without Conawapa. This means that on a risk-adjusted basis, it is not economic to pursue Conawapa.

Furthermore, the comparative economic benefits of the Preferred Development Plan at reference conditions have deteriorated significantly since Manitoba Hydro's NFAT Submission was filed in August 2013. In August 2013, Manitoba Hydro suggested that the Preferred Development Plan would have an incremental Net Present Value of $1.7 billion compared to the All Gas Plan. Since then, based on changed assumptions this advantage has disappeared virtually completely. The incremental Net Present Value is now only $45 million. Accordingly, it is clear that the economic analysis does not support proceeding with the Preferred Development Plan. Given the current economics, the plan does not break even until 2089, which is at the end of the 78-year planning horizon.

The Panel further agrees with Manitoba Hydro's expert witness, Dr. Borison, that Expected Values are one of the most important risk analysis outputs in comparing the economics of plans. Manitoba Hydro was not able to provide the Panel with fully updated Expected Value calculations before the completion of the hearings. Manitoba Hydro only provided non-risk-adjusted "reference" Net Present Value based on complete updated 2013 assumptions. This is unfortunate, as it left the Panel without one of the important decision-making tools at its disposal. The Panel has no choice but to extrapolate. In the last full economic analysis, which had a non-risk-adjusted reference Net Present Value of $614 million, the relative Expected Value was only $120 million. Since the non-risk-adjusted Net Present Value has now further deteriorated from $614 million to $45 million, the Expected Value compared to the All Gas Plan is now likely negative.

The plans that include Keeyask and the 750 MW transmission interconnection, on the other hand, break even compared to the All Gas Plan after approximately 50 years. While they are still a long-term proposition, they fare significantly better than the Preferred Development Plan.

The Panel notes that the economic analysis supports the building of a 750 MW transmission interconnection to the United States. There are measurable economic benefits associated with the transmission line relative to the All Gas Plan without an interconnection. Leaving the economics aside, there are also tangible reliability benefits associated with the transmission intertie, including the ability to import additional power in times of drought and during emergencies.

Manitoba Hydro was not able to provide the Panel with fully updated Expected Value calculations before the completion of the hearings. Manitoba Hydro only provided non-risk-adjusted "reference" Net Present Value based on complete updated 2013 assumptions. This is unfortunate, as it left the Panel without one of the important decision-making tools at its disposal. However, the Panel is prepared to extrapolate. In the last full economic analysis, the Preferred Development Plan had a non-risk-adjusted reference Net Present Value of $614 million, and the relative Expected Value was only $120 million. Since the non-risk-adjusted Net Present Value has now further deteriorated from $614 million to $45 million, it stands to reason that the Expected Value compared to the All-Gas Plan is now likely negative.

The various iterations of economic analysis from the August 2013 NFAT Submission until the end of the NFAT Review hearing have shown a narrowing of the gap between the various development plans and the All Gas Plan. But plans with Keeyask and a transmission interconnection to the U.S. have all outperformed the All Gas Plan by margins that are materially better. On the basis of the results of the economic analysis, the Panel can see no reason to support the All Gas Plan.

The Panel does not consider the Embedded Return on Equity to be a particularly useful metric in reaching its conclusions.

9.0.0 The Rate Impacts of the Preferred and Alternative Development Plans

9.1.0 Introduction

Proceeding with any of the development plans that Manitoba Hydro considered to meet electricity demand will have an impact on the rates that customers pay for electricity, as well as an impact on Manitoba Hydro's overall financial position. All plans require Manitoba Hydro to make significant expenditures, although the nature and timing of the expenditures vary. Some plans, particularly those that include hydroelectric generating stations, require large up-front capital expenditures and involve comparatively low operating expenses, while others, such as those that rely on gas-fired generators as the principal generating option, have relatively lower up-front capital costs and higher operating and maintenance costs over time. Customer rates will increase materially under all plans.

Rate increases above the rate of inflation will also be required over the coming decade even if Manitoba Hydro were not to proceed with developing new generation resources. Manitoba Hydro informed the Panel that the need to refurbish aging infrastructure and pay for Bipole III would be significant drivers of these increases.

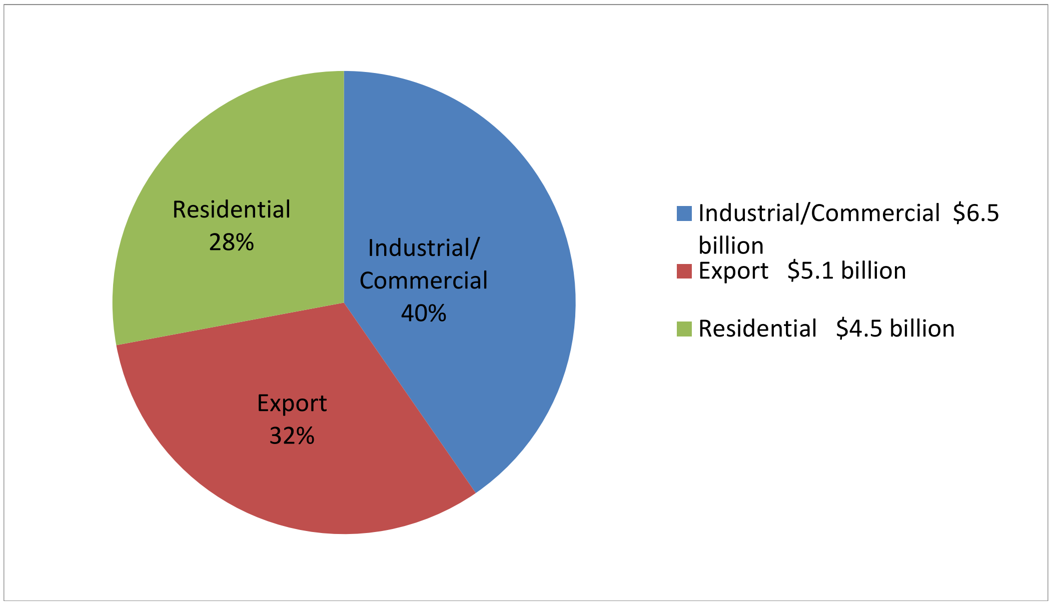
As Manitoba Hydro is obliged to recover its costs from its domestic customers, ratepayers are ultimately responsible for paying for the Preferred Development Plan or any other power resource option that may be pursued. The Terms of Reference address the issue of rates by requiring the Panel to consider the impact on domestic electricity rates over time with and without the Plan and with alternatives.

9.2.0 Manitoba Hydro's Current Revenue Base

Manitoba Hydro's revenue base from electric operations is derived from domestic rates and export revenues. Domestic electricity revenues accounted for just over two-thirds of Manitoba Hydro's revenue in the past 10 years. This share has been increasing as domestic consumption and rates have risen and export revenues and volumes have declined, largely due to lower opportunity export prices and the drop in U.S. consumption associated with a continued downturn in economic activity in Manitoba Hydro's U.S. export markets.

Manitoba Hydro is regulated on a cost of service basis and recovers its costs from domestic customers through PUB-approved rates. Ratepayers are divided into different customer classes; for example, residential, and general service, small, medium and large. Each class has a different rate structure. The Figure below depicts Manitoba Hydro's electricity revenues by customer type over the period 2003/04 – 2012/13.[296]

Figure 18 Electricity Revenue Sources, 2003/04 to 2012/13



Over the past decade, Manitoba Hydro has generally exported between 10,000 to 12,000 GWh of energy annually, which approximates 40% to 50% of the energy sold to domestic customers during the period.[297] Exports have contributed about 32% of Manitoba Hydro's revenue[298] and aided in keeping Manitoba Hydro's domestic electricity rates among the lowest in Canada and North America. Export revenues have declined in recent years from 2009 levels of over $600 million to about $350 million to $400 million annually because of the weakening in wholesale market prices resulting from the recession and lower natural gas prices.

Generally, export revenues come from two different sources: opportunity export sales and longer-term sales under export contracts. Opportunity sales are classified as on-peak and off-peak and may be priced above or at market prices at the time of the sale, Sales under export contracts are at the price agreed to in the contract, which is typically higher than the opportunity price. The types of export products Manitoba Hydro sells and the expected revenues are discussed in Chapter 6. For the purpose of the financial analysis, Manitoba Hydro assumes that all surplus dependable energy (dependable

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[296] Exhibit MH-111, p. 8.
[297] Exhibit LCA-9, p. 6-2.
[298] Over the past 10-years, export revenues totaling some $5.6 billion have accounted for nearly one-third of Manitoba Hydro's revenues for electricity sales. See https://www.hydro.mb.ca/corporate/electricity_exports.shtml, accessed May 17, 2014.

energy that is not currently subject to long-term contracts) can be sold at long-term firm prices.[299]

9.3.0 Manitoba Hydro's Financial Targets

Manitoba Hydro has three self-imposed key financial targets:

1. A minimum debt-to-equity ratio of 75/25;
2. An interest coverage ratio of greater than 1.20; and
3. A capital coverage ratio of greater than 1.20.

These targets are important because they provide a way to measure Manitoba Hydro's overall financial strength and guide proposed rate increases. The targets are imposed by Manitoba Hydro's Board of Directors and are monitored by credit rating agencies.

Manitoba Hydro's plan to construct new generating facilities and make capital expenditures to renew the existing infrastructure, as well as the costs involved with reliability improvements such as Bipole III, will put pressure on meeting these financial ratios over the next decade.

9.3.1. Debt-to-Equity Ratio

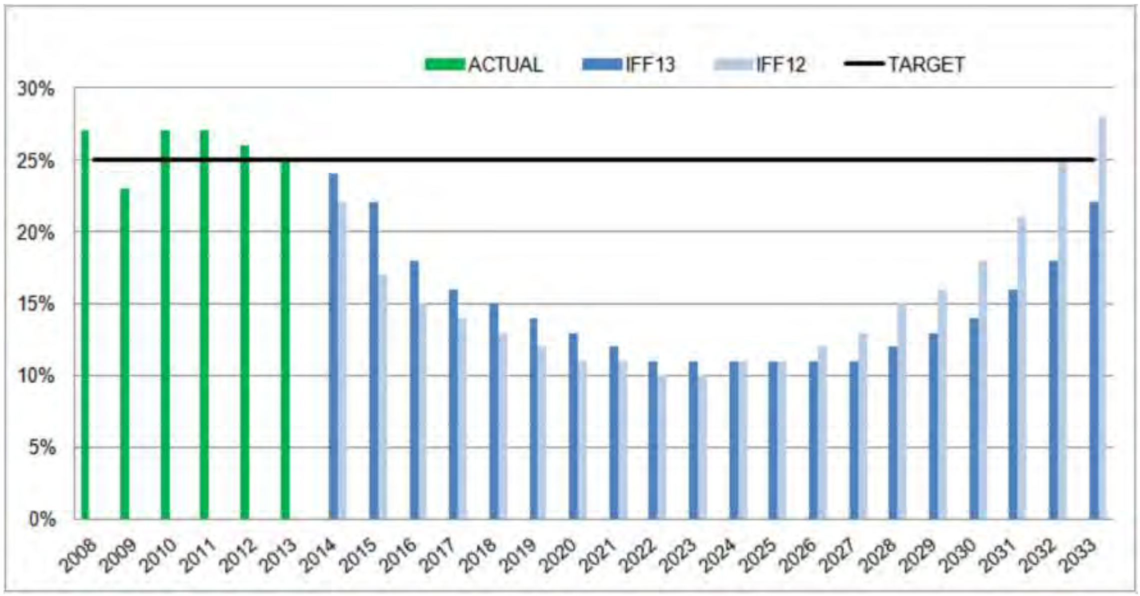
The debt-to-equity ratio indicates the portion of Manitoba Hydro's assets that are financed through long-term and short-term debt, and through funds from operations from customer rates and export revenues. This ratio is a measure of the overall financial risk to Manitoba Hydro. Attaining a debt-to-equity ratio of 75/25 means that 25% of Manitoba Hydro's assets would be financed through internally generated funds (domestic rates and export revenues) rather than through debt.

The debt-to-equity ratio is a long-term target, which serves as a financial guideline only, not an annual requirement. In 2013 it stood at 75/25.[300] Manitoba Hydro expects a significant deterioration in this ratio over the next 20 years to about 90/10 in the 2020s as debt levels increase because of Bipole III and the Preferred Development Plan. The Figure below depicts Manitoba Hydro's forecasted debt-to-equity ratio to 2033 (assuming development of the Preferred Development Plan) as compared between Integrated Financial Forecast IFF13 and with Integrated Financial Forecast IFF12.[301]

[299] 5x16 peak sales are sales that take place five days per week (Monday to Friday) when market load is typically higher. Off-peak periods are hours during the week when load is normally lower; for example overnight and over certain hours on the weekends.
[300] Exhibit MPA-3, p. 18.
[301] Exhibit MH-111, p. 6.

The 2014 updated Keeyask and Conawapa capital costs are not reflected in the debt-to-equity ratios shown in the following Figure.

Figure 19 Manitoba Hydro's Debt-to-Equity Ratio, 2008 to 2033



9.3.2. Interest Coverage Ratio

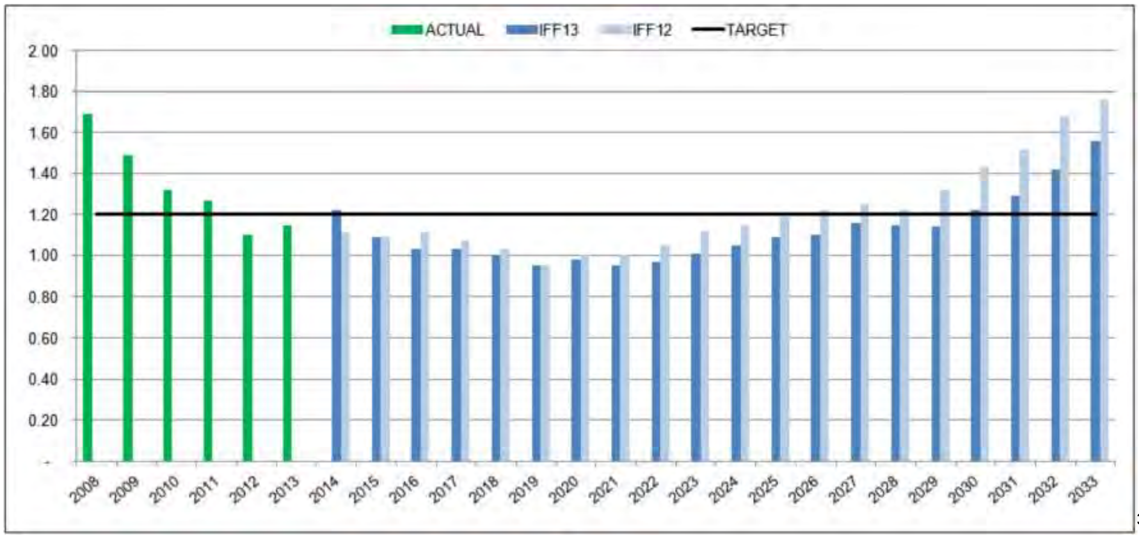
The Interest Coverage Ratio signals Manitoba Hydro's ability to meet its interest payment obligations from its net income. Manitoba Hydro seeks to maintain an interest coverage ratio of greater than 1.20, which gives it a 20% cushion of annual cash available over expected interest costs. An interest coverage ratio below 1.0 indicates that Manitoba Hydro may need to borrow to meet its interest obligations. Manitoba Hydro has indicated that it can maintain its interest payment obligations if the interest coverage ratio is greater than 0.8.[302]

In 2013, the interest coverage ratio stood at 1.15. Manitoba Hydro is projecting the Interest Coverage Ratio to fall below the target level for a period of 15 years because of higher debt levels and related borrowings associated with Bipole III and the Preferred Development Plan.

The Figure below depicts Manitoba Hydro's Interest Coverage Ratio forecast to 2033 (assuming the development of the Preferred Development Plan) as compared between 2013 and 2012 Integrated Financial Forecasts.[303]

[302] Transcript p. 2915.
[303] Exhibit MH-111, p.17.

Figure 20 Interest Coverage Ratio, 2008 to 2033



[304]

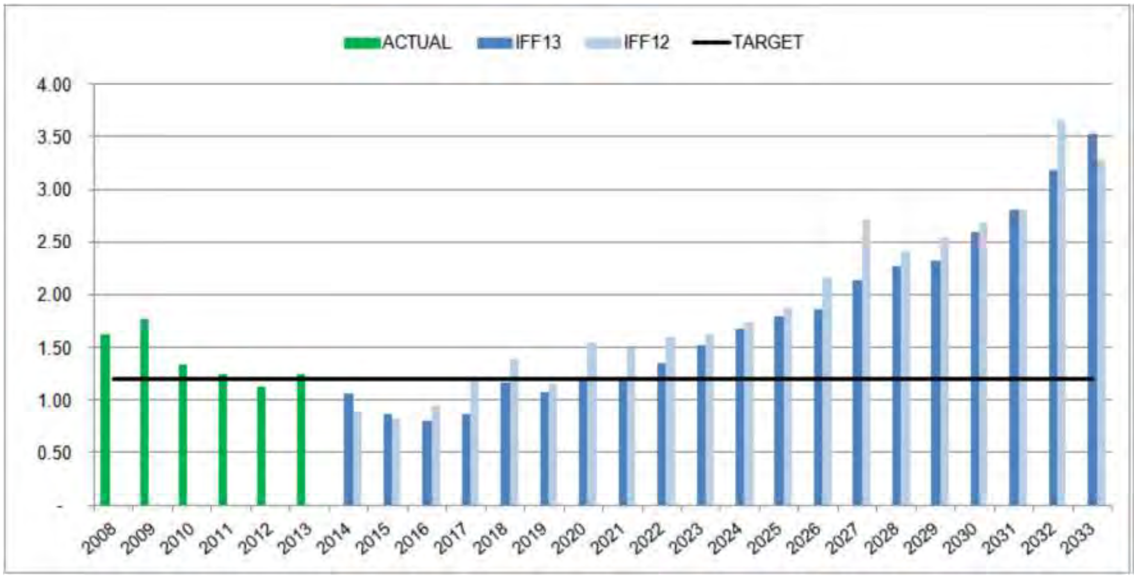
9.3.3. Capital Coverage Ratio

The Capital Coverage Ratio measures Manitoba Hydro's ability to fund sustaining base capital expenditures, excluding major new generation projects and transmission facilities, out of current cash flow from operations. Base capital expenditures are capital investment required to renew Manitoba Hydro's existing assets. Manitoba Hydro's target Capital Coverage Ratio is greater than 1.20. A capital coverage ratio of less than 1.0 indicates that Manitoba Hydro must borrow to fund its annual base capital requirements.

Manitoba Hydro expects its Capital Coverage Ratio to dip below the 1.20 target from 2014 to 2021, and even below 1.0 for much of that period. The Figure below depicts Manitoba Hydro's 2013 forecast for the Capital Coverage Ratio (assuming the development of the Preferred Development Plan) to 2033 as compared to its 2012 forecast.[305]

[304] Exhibit MH-11, p. 17.
[305] Exhibit MH-111, p.18.

Figure 21 Capital Coverage Ratio, 2008 to 2033



[306]

9.4.0 Manitoba Hydro's NFAT Financial Evaluation

Manitoba Hydro provided a financial evaluation of eight of the 15 different development plans it had considered in the economic evaluation. The financial evaluation compared the impact of each development plan on electricity rates and Manitoba Hydro's financial position.

The financial evaluation featured the same uncertainty analysis framework that was applied to the economic analysis, namely three values (reference, high, and low) for three variables (energy prices, economic indicators, and capital costs). A distinct difference was that $1.4 billion in sunk costs that were excluded from the economic analysis were included in the financial analysis for alternatives that did not include either or both Keeyask or Conawapa, as they represent real costs that will have to be recovered through rates.

The following eight plans were the subject of the financial analysis based on 2012 planning assumptions:[307]

[306] Exhibit MH-111, p. 18.
[307] Manitoba Hydro NFAT Submission, Chapter 11, p. 3.

Table 19 Evaluated Plans: Financial Analysis Based on 2012 Planning Assumptions

Interconnection	Plan #	Development Plan
No New Interconnection	1	All Gas
	2	K22/Gas
	7	Gas/C26
250 MW Interconnection	4	K19/Gas/250 MW
	13	K19/C25/250 MW
750 MW Interconnection	12	K19/C31/750 MW
	6	K19/Gas/750 MW
	14	K19/C25/750 MW (Preferred Development Plan)

Of the eight plans evaluated, the Plan 1 (All Gas) and Plan 14 (Preferred Development Plan) presented the most significant contrasts in overall resource strategy, as they have two different resource components (gas vs. electric) and two distinct orientations (domestic need vs. export). Manitoba Hydro did not provide a financial analysis of a Wind/Gas scenario, as it was screened out due to its economic performance against other plans.

Manitoba Hydro prepares a 20-year financial forecast annually. The NFAT financial analysis was based on a 50-year forecast of electric operations to 2062. Manitoba Hydro selected a 50-year study period "in order to be consistent with the long-term nature of hydro-electricity assets and to provide a sufficient time frame to analyze the benefits and costs of each development plan."[308] The financial analysis used a 35-year time period (coinciding with the period for which Manitoba Hydro's SPLASH[309] computer model simulates system operations) with additional extrapolation to extend the analysis to 50 years. All the financial analysis was performed in nominal dollars, which contrasts with the economic evaluation results that were provided in real dollars, excluding the impact of general inflation.

During the NFAT Review hearings, Manitoba Hydro filed an updated financial analysis for Plan 1 (All Gas) and Plan 14 (Preferred Development Plan), as well as a new financial analysis for Plan 5 (K19/Gas/750 MW).[310] Following this initial tranche of evaluations, financial evaluations were provided for Plans 2, 4, 6 and 12, and then for Plans 1, 5, and 14 with DSM Level 2 and the pipeline load.[311]

[308] Manitoba Hydro NFAT Submission, Chapter 11. p. 3.
[309] SPLASH is the acronym for Manitoba Hydro's computer model, Simulation Program for Long-term Analysis of System Hydraulics.
[310] Exhibits MH-104-12-1 to 104-12-4.
[311] Exhibits MH-104-12-5 to 104-12-7.

The plans were updated as follows:

- Plan 1 (All Gas), Plan 5 (K19/Gas/750 MW) and Plan 14 (Preferred Development Plan, K/19/C26-33/750 MW) were updated for Base and DSM Levels 1 – 3, 2014 updated reference Keeyask and Conawapa capital costs, and the 2013 Electric Load Forecast and discount rate, as well as for DSM Level 2 and the pipeline load.
- Plans 5 and 14 were updated for the various DSM levels, the 2013 Electric Load Forecast and discount rate, and the 2014 updated high capital cost scenario for Keeyask and Conawapa.
- Plan 2, (K31/Gas), Plan 4 (K19/Gas/ 250 MW), Plan 6 (K19/Gas/750 MW) and Plan 12 (K19/C40/750 MW) were updated for DSM Level 2, 2014 updated reference capital costs for Keeyask and Conawapa, and the 2013 Electric Load Forecast and discount rate.[312]

The updates were made to the IFF12 forecast model used for the NFAT Submission evaluation, as the IFF13 forecast was not extended to 50 years. Consequently, the base capital expenditures are based on IFF12 assumptions.[313]

Manitoba Hydro conducted its financial evaluation of the development plans on the basis of applying even annual rate increases over an 18-year period to achieve a debt-to-equity ratio of 75/25 by 2031/32. For years beyond 2031/32, Manitoba Hydro set annual rates to maintain a 1.20 interest coverage ratio to the end of the 50-year study period.

The financial modeling provides comparative metrics in order to assess the proposed development plans rather than a definite rate path. Manitoba Hydro told the Panel that it has a longstanding strategy of smoothing rates over a period of time in developing its rate proposals. This essentially involves pre-funding of major generation and transmission projects. Accordingly, actual rate increases may be higher or lower than projected. The Public Utilities Board must approve Manitoba Hydro's electricity rates. Proposed rate increases will depend on Manitoba Hydro's future revenue requirements and will be the subject matter of General Rate Applications before the Public Utilities Board.

[312] Exhibit MH-104-12-5.
[313] Exhibit MH-204, p. 188.

9.5.0 Impact of Development Plans on Electricity Rates

Manitoba Hydro's initial evaluation showed that the Preferred Development Plan would result in equal annual rate increases of 3.95% through 2031/32. Other development Plans ranged from 3.43% for Plan 1 (All Gas) to 3.86% for Plan 7 (Gas/Conawapa 26). The magnitude of rate increases under all options was significantly higher than the forecast level of inflation. Over a 78-year time frame, the Preferred Development Plan had the lowest overall cumulative nominal annual rate increases compared to other plans at 106% versus 176% for Plan 1 and 134% for Plan 7.[314]

The financial evaluations based on Manitoba Hydro's March 10, 2014 update project higher even annual rate increases to 2031/32 for plans that include Keeyask and/or Conawapa. The new analyses, which assumed implementation of DSM Level 2, Manitoba Hydro's new higher reference capital costs for Keeyask and Conawapa, and the 2013 Electric Load Forecast scenario, projected even annual rate increases from 2015/16 through 2031/32 as shown in the Table below.[315]

The financial evaluation reveals significant rate increases for all plans. Over the entire 50-year evaluation period to 2061/62, the hydro-based plans (with no gas) have the lowest rate increases, but over the medium term (through 2031/32), plans that include gas have the advantage over hydro-based plans.

Starting in 2015/16 and continuing to 2031/32, the Preferred Development Plan would see projected even annual increases of 4.38% (with DSM Level 2 with reference assumptions and reference costs and pipeline load), rather than 3.95%, as Manitoba Hydro first projected. This increase stems largely from higher capital costs estimates for Keeyask and Conawapa, lower forecast domestic load and Wisconsin Public Service (WPS) declining to invest in the U.S. transmission line. As reflected in the Table below, if capital costs increase to Manitoba Hydro's new high capital cost scenario upper limit, annual rate increases associated with the Preferred Development Plan are projected to be 4.63% over the period to 2031/32.

[314] PUB/MH I-0149a, Revised, p. 7.
[315] Exhibit MH-104-12-6, p. 1.

Table 20 Projected Even Annual and Cumulative Rate Increases by Development Plan, 2013 Assumptions/DSM 2/Reference & High Capital Costs (Main Submission Rate Methodology)

Plan #	Even Rate Increases 2015/16 to 2031/32	Even Rate Increases 2015/16 to 2061/62	Cumulative Nominal Rate Increases at 2031/32	Cumulative Nominal Rate Increases at 2061/62
Plan 1 (All Gas)	3.36%	2.02%	82%	161%
Plan 1 (All Gas) (Pipeline Load)	3.52%	2.05%	87%	165%
Plan 2 (K31/Gas)	3.55%	1.85%	88%	141%
Plan 5 (K19/Gas25/750MW)	3.74%	1.72%	94%	126%
Plan 5 (K19/Gas/750MW) (MP & WPS Sales) (High capital costs)	3.99%	1.72%	102%	127%
Plan 5 (K19/Gas/750MW) (MP & WPS Sales) (Pipeline Load)	3.86%	1.79%	98%	135%
Plan 6 (K19/Gas/750MW) (MP Sale)	3.75%	1.70%	95%	125%
Plan 12 (K19/C40/750MW) (MP Sale)	3.76%	1.55%	95%	109%
Plan 14 Preferred Development Plan (K/19/C31/750MW) (MP & WPS Sales)	4.27%	1.30%	112%	86%
Plan 14 Preferred Development Plan (K/19/C26/750MW) (MP & WPS Sales) (Pipeline Load)	4.38%	1.37%	115%	92%
Plan 14 Preferred Development Plan (K/19/C26/750MW) (MP & WPS Sales) (High capital costs)	4.63%	1.35%	125%	91%

9.6.0 Impact of Demand Side Management Programs on Rates

Manitoba Hydro's DSM programs and plans were discussed earlier in this report.

In preparing its financial evaluation updates, Manitoba Hydro assumes that it will be implementing higher levels of DSM, and determined that DSM Level 2 adds the most value to Manitoba Hydro and customers who take advantage of the DSM programs.

Manitoba Hydro is forecasting expenditures totaling $822 million from 2014/15 to 2028/29 for Electric Power Smart programs and initiatives.[316] Annual expenditures on DSM programs are amortized over ten years and included in rates. Furthermore, the reduction in domestic load from DSM programs will create an increasing revenue shortfall that must be offset by increased rates, unless the energy saved can be sold on the export market at prices that fully offset the loss of domestic revenues from DSM.

While all customers bear the impact of the costs of DSM programs, customers who take advantage of available programs have an opportunity to mitigate the rate impacts by reducing their energy consumption and lowering their energy bills, as further discussed below.

9.7.0 Impact of Sunk Costs on the Projected Rate Increases

The rate impact of the sunk costs of the Keeyask and Conawapa projects was identified as an important issue in relation to the financial evaluation of the projects. Sunk costs, which are currently estimated at $1.6 billion,[317] are the estimated expenditures that will have been incurred by June 2014 to protect the respective in-service dates for Keeyask and Conawapa.

Manitoba Hydro's financial evaluation assumes that these sunk costs need to be included in the revenue requirement for the purpose of rates. For plans that include Keeyask or Conawapa, sunk costs form part of the asset costs and are amortized over the life of the asset. For plans that exclude Keeyask or Conawapa, Manitoba Hydro has chosen to amortize the sunk costs over an 18-year period to 2031/32,[318] which would require approximately $90 million in annual revenue requirements associated with those plans over 18 years.[319]

[316] Exhibit MH-180, p. 31.
[317] Transcript, p. 2883. See also, Exhibit MH -111, p. 38.
[318] Manitoba Hydro NFAT Submission, Chapter 11, p. 5.
[319] MIPUG/MH I-003c.

The Panel was told that one of the reasons there is less of a distinction in the rate implications of the various plans than one might otherwise expect is that the sunk costs of the Keeyask and Conawapa projects will be applied to plans that do not include those assets because of the need to recover those costs.

Morrison Park noted before the Panel that sunk costs represent money spent that will have to be accounted for in some way.

> *"However, the reality is if you don't go forward with the Keeyask project, you still have to pay the $1.4 billion. So that $1.4 billion loss, if you will, in certain circumstances has to be addressed and taken into account. So is that in some sense unfair to other options? Well, I suppose. If an alternative option only costs $4 1/2 billion and Keeyask all-in costs 5 1/2, once you add the sunk costs of Keeyask onto the other option, suddenly it doesn't look so attractive. Fair or not, that's reality. … And that's how you have to address the attractiveness of the different options, because it's what ratepayers have to pay."*[320]

La Capra Associates provided the Panel with an analysis of the impact of sunk costs on various development plans. The Table below, based on 2012 assumptions, illustrates these impacts. It is clear from this analysis that Plan 1 (All Gas) bears the brunt of sunk costs, followed by Plan 7 (Gas/C26). Plans that include Keeyask but not Conawapa are less affected by sunk costs because the expenditures associated with Conawapa ($400 million to date) are less than the money spent to date on Keeyask ($1.2 billion). [321]

Table 21 Rate Increases by Development Plan under Reference Conditions With and Without Sunk Costs

Plan #	Plan Short Name	Even-Annual Rate Increases (2012/13 to 2031/32)		Cumulative Nominal Rate Increases at 2031/32	
		With Sunk Costs	Without Sunk Costs	With Sunk Costs	Without Sunk Costs
1	**All Gas**	3.43%	3.05%	90%	78%
7	**Gas/C26**	3.86%	3.58%	105%	95%
2	**K22/Gas**	3.49%	3.40%	92%	89%
4	**K19/Gas/250**	3.42%	3.33%	90%	87%
6	**K19/Gas/750**	3.50%	3.41%	92%	89%

Evidence was provided that the sunk costs may not have to be recovered through rates in the early years if either Keeyask or Conawapa remain in Manitoba Hydro's planning

[320] Transcript, p. 7283.
[321] Exhibit LCA-13, p.10A-31.

horizon.[322] Furthermore, the Panel was told that even if the sunk costs are written off, a one-time charge could be taken or the amount of costs found to not have a future value could be written off over different time frames. Any rate proposal related to a write-off of sunk costs would have to be approved by the PUB.

9.8.0 Impact of Bipole III on Rates

The Panel also heard evidence about the rate implications of the Bipole III transmission project, currently projected to cost $3.3 billion dollars. The last capital cost update for Bipole III was in 2010. In addition to Bipole III, the Riel Converter Station is required to deliver the power from Bipole III. When the project is completed and in service by 2017/18, Manitoba Hydro has determined approximately $280 million will have to be recovered annually through rates.[323] This would require a one-time rate increase of about 20%.

9.9.0 Export Revenue Forecasts

Manitoba Hydro indicated to the Panel that export revenues would continue to be an important source of revenue to help offset the costs of the Preferred Development Plan. To this end, Manitoba Hydro has negotiated a number of contracts with other parties as part of the development of the Preferred Development Plan, the most notable being the contracts with Minnesota Power (MP) and Wisconsin Public Service (WPS). These contracts, which all expire by 2036, take up a portion of the dependable output of Manitoba Hydro's system, leaving some room for Manitoba Hydro to negotiate more firm dependable contracts and sell a substantial amount of other surplus power in the opportunity export market. The terms of all of Manitoba Hydro's export contracts are relatively short (10 to 15 years) compared to the expected 100-year life of the proposed new generating stations. Consequently, Manitoba Hydro will be looking to renew contracts with existing counterparties or find new contract purchasers to sustain its export revenue stream.

The indicative rate increases associated with the various development plans are based on projections of operating results to meet a 75/25 debt-to-equity ratio by 2031/32. A key factor influencing the operating results is how much revenue Manitoba Hydro will be able to realize from export sales as opposed to domestic rates.

The level of export revenue is affected by the assumptions underlying export sales, including the volume of future exports and future export prices. Export prices, in turn are

[322] Transcript, pp. 2883-2884.
[323] Exhibit MH-211.

affected by the prices of natural gas and other fuels used to generate power in the export markets, mainly the U.S. MISO market. The implementation of a carbon tax premium is a crucial factor in Manitoba Hydro meeting its forecast export revenue assumptions. Manitoba Hydro's export sales assumptions and revenues are discussed more fully in Chapter 6 of this Report.

The following Table shows Manitoba Hydro's projected revenues from domestic and extra-provincial sources for selected years from 2015 to 2033.[324]

Table 22 Projected Domestic and Extra-Province Revenues, DSM Level 2 + Pipeline Load $ million

Plan 14 (Preferred Development Plan)	2015	2019	2022	2026	2029	2033
Domestic Customers	1,456	1,798	2,124	2,624	3,075	3,610
Gross Export Revenue	383	460	871	835	858	1,351
Plan 5 (K19/Gas/750 MW)	**2015**	**2019**	**2022**	**2026**	**2029**	**2033**
Domestic Revenue		1,762	2,052	2,485	2,869	3,319
Gross Export Revenue		460	871	836	873	906

By 2033, Manitoba Hydro is projecting that domestic revenue will more than double and export revenues will more than triple from current levels. These domestic revenue assumptions are based on even annual rate increases of 4.38% until 2032. The DSM Level 2 scenario assumes Conawapa coming into service in 2031. If Plan 5 (No Conawapa) were implemented, even annual rate increases to 2032 would be 3.86%, or over 0.53% (53 basis points) lower.

To the extent that export revenues fall short of Manitoba Hydro's forecasts, additional rate increases will be required to cover Manitoba Hydro's costs. Conversely, if export revenues exceed forecasted levels, ratepayers will benefit.

Morrison Park provided an updated analysis of the role of exports in the 2013 versions of the plans, as noted in the Table below.[325]

[324] Exhibit MH-104-12-7, p. 25, 31.
[325] Exhibit MPA 3-1, p. 22.

Table 23 Exports as % of Total Revenues: 2013 vs. Updated Plans

	Plan 1 All Gas	Plan 2 K22/Gas	Plan 4 K19/Gas/250MW	Plan 5 K19/Gas/750MW	Plan 6 K19/Gas/750MW	Plan 14 (Preferred Development Plan)
2013 Version	8.6%		14.2%		13.8%	17.3%
2014 Version	13.9%	16.1%	20.2%	21.4%	21.1%	27.5%
Change	+ 5.3%		+ 6.0%		+ 7.3%	+ 10.2%

Morrison Park concluded that the increases in revenues from exports for Manitoba Hydro across all of the updated plans result from lower domestic demand because of DSM Level 2 programs. The updated All Gas Plan is now as reliant on exports as the 2013 versions of Plans 4 and 6 were, while the updated versions of Plans 4 and 6 are now almost 50% more export-oriented, and projected to generate more revenue from exports than the 2013 version of the Preferred Development Plan. This indicates that ratepayer costs in all of the updated plans are inversely proportional to energy prices, and likely quite strongly inversely proportional.[326]

Commenting on the relationship between export risk and ratepayers, Morrison Park noted that "*structuring the Preferred Development Plan to be exposed to export price risks and export volume risks is not a traditional or typical way of constructing the economic relationship of a ratepayer to a monopoly utility provider*."[327]

9.10.0 Other Metrics for Examining Rates and Revenues

9.10.1. Net Present Value Analysis

La Capra Associates reviewed the financial evaluation presented in Manitoba Hydro's 2013 NFAT Submission and calculated the Net Present Value of the projected annual rate increases, assuming a 7.05% nominal discount rate. The Net Present Value calculation provides a comparison of future rate increases to present rate increases. Manitoba Hydro did not provide this calculation in its financial analysis.

La Capra's Net Present Value analysis indicated that the Preferred Development Plan was not a clear winner in terms of having the lowest rate increases over the entire 50-year study period. Plan 4 (K19/Gas/250 MW) had lower rate increases and Plan 6 (K19/Gas/750 MW) showed lower rate increases over 35- and 40-year time periods. It was not until year 50 that the Preferred Development Plan moved into second place

[326] Exhibit MPA 3-1, p. 22.
[327] Transcript, p. 7392.

behind Plan 4. La Capra's findings were also consistent with another metric it calculated, namely the levelized cost of energy supplied.[328]

9.10.2. Impact of Rate Increases on Ratepayers

Manitoba Hydro's rate projections call for sustained even annual rate increases for at least 20 years. In its evidence before the Panel, Manitoba Hydro emphasized the intergenerational considerations associated with these increases. Manitoba Hydro's argument is essentially a "pay-it-forward" approach: today's generation of ratepayers enjoy low electricity rates and benefit from the investments of past generations in the hydro-electric system; therefore, it is now this generation's turn to pay higher rates so that future generations will reap the benefits of lower electricity rates.

The Preferred Development Plan and the All Gas Plan provide a good example of the intergenerational differences among the plans: with the Preferred Development Plan, today's ratepayers would pay higher rates, while the next generation would presumably benefit from lower rates; with the All Gas Plan, today's ratepayers would face rate increases that are less prolonged and severe than those of the Preferred Development Plan, but the next generation of ratepayers would face higher rates.

It is Manitoba Hydro's view that even with the proposed doubling of electricity rates over the next 20 years, Manitobans will still experience lower rates than many other Canadian jurisdictions, as electricity rates in those jurisdictions are increasing as well.[329]

Manitoba Hydro also told the Panel that rate increases in the order of 3.95% annually for the next seven to ten years would be required even if no new generation options were undertaken. The need to refurbish existing infrastructure and pay for Bipole III will drive these increases.[330]

9.10.3. Present Value of Customers' Revenues

The Panel was told that two critical elements for ratepayers are: (1) what the rates are expected to be over time; and (2) the expected total rate revenue that will be generated over time from domestic customers. Under Manitoba Hydro's current rate proposals, rates will more than double from current values.

Morrison Park constructed a financial model of Manitoba Hydro's electrical operations to assess the overall costs, benefits, and risks to ratepayers and other stakeholders in

[328] Exhibit LCA-13, p. 10A-60.
[329] Transcript, pp. 246-248.
[330] Transcript, p. 3031.

relation to Plan 1 (All Gas), Plan 4 (K19/Gas24/250 MW), Plan 6 (K19/Gas25/750 MW, WPS investment in transmission), Plan 12 (K19/C31/750 MW) and Plan 14 (Preferred Development Plan). Morrison Park's financial model calculates the annual payment that Manitoba ratepayers are presumed to make in the future under various assumptions and hydrological patterns using two different discount rates (6% and 10%) in order to compare streams of cash flow that fluctuate over time. Morrison Park applied Manitoba Hydro's probability weightings to each set of future conditions and blended the results based on these weightings to provide a calculation of average probability-weighted present value of domestic revenue.

With respect to the present value of ratepayer costs, the model demonstrated the sensitivity of the various plans to changes in the discount rate. The All Gas Plan and the Preferred Development Plan represent different rate patterns, with the All Gas Plan showing rate increases for the "first generation" of ratepayers that are less prolonged and not as high as those projected for the Preferred Development Plan. For the "second generation" of ratepayers the pattern reverses. According to Morrison Park, this is where the discount rate and the time value of money become apparent: if ratepayers would prefer to save now and pay later, they would have a high discount rate such as 10% or more and choose Plan 1 (All Gas). Conversely, if they were to focus on long-term benefits, they would have a low discount rate of 6% or less and choose the Plan 14 (Preferred Development Plan). Plans 4 and 6 fall in between Plan 1 and Plan 14.[331]

Overall, Morrison Park concluded, among other things, that Plans 4 and 6, which include Keeyask, a transmission interconnection, and natural gas plants, appear to rank better than the other plans, while Plans 14 and 12, which include Conawapa, are more costly to ratepayers than Plans 4 and 6, which include Keeyask but not Conawapa. Furthermore, Plan 4, with a 250 MW interconnection, outranks Plan 6, with a 750 MW interconnection. However, there is never more than a 1% variation between them.

Morrison Park updated its Net Present Value (ratepayer costs) analysis for the Panel. Ratepayers costs associated with various development plans were calculated at 6% and 10% discount rates over 20-, 30-, and 48-year periods. This analysis showed that the Preferred Development Plan had the highest ratepayer costs for all periods, although the gap narrowed significantly over time.

Morrison Park provided the total cost to ratepayers based on each 2013-updated plan, assuming annual rate increases of 3.8%. The Net Present Value total cost to ratepayers by plan is as follows[332]:

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[331] Exhibit MPA-3, p. 46.
[332] Exhibit MPA 3-1, p.11.

Table 24 Morrison Park's Calculation of Total Cost to Ratepayers at 3.8% Maximum Annual Rate Changes

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
Maximum	$40,915	$41,569	$40,561	$40,671	$40,816	$43,854
Minimum	$38,596	$39,282	$38,274	$38,571	$38,642	$40,815
Standard Deviation	$486	$485	$494	$465	$492	$708
Present Value						
NPV @ 10.00%						
Average	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322
Maximum	$22,406	$22,720	$22,561	$22,666	$22,736	$23,886
Minimum	$21,583	$21,787	$21,737	$21,864	$21,895	$22,961
Standard Deviation	$201	$257	$183	$168	$172	$225
Nominal Value						
Average	$161,316	$162,570	$151,161	$151,791	$151,794	$158,555
Maximum	$172,403	$176,999	$161,403	$164,331	$162,887	$172,101
Minimum	$153,275	$154,896	$141,117	$142,701	$142,824	$149,689
Standard Deviation	$4,568	$4,059	$4,278	$4,212	$4,449	$4,950

Morrison Park made the following observations from the above analysis:[333]

- The results for Plans 4, 5, and 6 (all of which include Keeyask and exclude Conawapa) are within 1% of each other across all cases (based on 6%, 10% discount rates and nominal dollars and also across maximum, minimum, and average values).
- Plan 2, which includes Keeyask but no transmission interconnection, and is therefore a domestically focused Plan, is slightly inferior to Plans 4, 5, and 6 at a discount rate of both 6% and 10%. In nominal dollar terms, however, it is significantly inferior, which indicates that its costs to ratepayers are higher farther out in the future.
- The All Gas Plan is competitive with Plans 4, 5, and 6 at a discount rate of 6%, but slightly superior (by approximately 1%) when the discount rate is 10%. But in nominal dollar terms, the All Gas Plan has the highest ratepayer cost of all Plans modeled, which indicates that its costs to ratepayers are significantly higher farther out in the future.

[333] Exhibit MPA 3-1, pp.11-12.

- The Preferred Development Plan is approximately 5% inferior to Plans 4, 5, and 6 across all cases. It is the worst performing plan in terms of Net Present Value calculated at both 6% and 10%, but is superior to the All Gas Plan and Plan 2 in nominal dollar terms.
- The Preferred Development Plan also has the highest standard deviation, which suggests that it is the most sensitive to hydrology. Notably, there is no discount rate at which the Preferred Development Plan is superior to Plans 4, 5, and 6: they are superior to the Preferred Development Plan regardless of discount rate assumptions (note that nominal dollars are equivalent to a discount rate of 0%).

Morrison Park also provided a comparison between 2013 and 2014 ratepayer costs based on the updated 2013 information on a reference case basis. Morrison Park noted a significant change in the original 2013 analysis resulting in noteworthy changes in the costs to ratepayers.[334]

Table 25 Morrison Park's Calculation of Ratepayer Cost Impacts of 2014 Update of Planning Assumptions

Present Value of Domestic Revenue
Reference Economics, Energy and Capital
2013 Plans vs. 2014 Plans
(2015 - 2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
2013 Average	$43,791		$42,878		$43,301	$44,230
2014 Average	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
Difference	-$4,132		-$3,438		-$3,605	-$2,231
%	-9.4%		-8.0%		-8.3%	-5.0%
NPV @ 10.00%	$23,623		$23,476		$23,633	$24,148
2013 Average	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322
2014 Average	-$1,624		-$1,251		-$1,288	-$826
Difference	-6.9%		-5.3%		-5.4%	-3.4%
%						

Morrison Park noted that across all Plans, projected total costs for Manitoba ratepayers have declined. It was notable that the decline occurred despite the fact that expected interest rates have increased, capital costs for projects have increased, and inflation rates have increased slightly. According to Morrison Park, the declines in the total ratepayer costs "*speak to the powerful impact of dramatically expanded DSM programs (4x the spending contemplated in the 2013 Business Case), which are expected to*

[334] Exhibit MPA 3-1, p.14.

dramatically reduce Manitoba domestic load, and free up more capacity for export."[335] Furthermore, the plans now contemplate a reduced level of capital spending on generation projects (and generally later in time), although spending on enhanced DSM programs will begin almost immediately.

As for the specific plans, the gap between All Gas and the Keeyask-based plans has lessened. The All Gas Plan is now marginally superior to Plans 4, 5 and 6 at a 10% discount rate, and essentially identical at a 6% discount rate. Based on the 2013 Plans, Plans 4 and 6 were superior to All Gas at 6%, and Plan 4 was also superior at 10%. When it comes to the Preferred Development Plan, however, that gap between that Plan and the other Plans increased.[336]

9.10.4. Plan 5 (K19/Gas/750 MW) Rate Pathway vs. Plan 14 (Preferred Development Plan)

Morrison Park mapped the rate increases based on 99 hydrological conditions and determined that based on an annual 3.8% or 4.0% maximum allowable rate increase scenario, Plan 5 (K19/Gas/750 MW) rate requirements are radically different from Plan 14 (Preferred Development Plan). Rate increases under Plan 5 peak in early 2030s then fall for approximately 10 years while under the Preferred Development Plan the rate increases do not peak until between 2038 and 2040.[337]

9.10.5. Intergenerational Impacts

Morrison Park's analysis also considered the intergenerational impacts of the projected rate increases. Morrison Park noted that irrespective of the plan chosen, ratepayers would face the maximum allowable rate increases for the next 15 years under all plans. After approximately 2030, however, the plans separate fairly dramatically and continue to do so for many decades. Morrison Park calculated ratepayer impacts at different timeframes, as shown in the Figure below.[338]

[335] Exhibit MPA 3-1, p.14.
[336] Exhibit MPA 3-1, p.14.
[337] Exhibit MPA 3-1, pp.16-17.
[338] Exhibit MPA 3-1, p. 23.

Table 26 Morrison Park's Calculation of Ratepayer Costs for Alternative Periods

Present Value of Domestic Revenue
Reference Economics, Energy and Capital
20 year, 30 year and 48 year periods
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
2015 - 34	$24,244	$24,094	$24,911	$24,965	$24,993	$25,212
2015 - 44	$31,014	$31,728	$32,111	$32,314	$32,407	$34,694
2015 - 62	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
NPV @ 10.00%						
2015 - 34	$17,224	$17,133	$17,572	$17,599	$17,612	$17,721
2015 - 44	$19,900	$20,149	$20,440	$20,526	$20,566	$21,488
2015 - 62	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322

Morrison Park's analysis indicates that in the first 20-year period, Plan 2 (Keeyask/Gas) is the least costly for ratepayers, likely because it does not require Keeyask's sunk costs to be written off (as the All Gas Plan does), while new spending on Keeyask occurs relatively late in the period. When the examined period is 48 years, Plans 4 (K19/Gas/250 MW), 5 (K19/Gas/750MW, with WPS sale), and 6 (K19/Gas/750MW) have caught up to or surpassed the All Gas Plan, which suggests that ratepayers in that final 18-year period are dramatically better off under Keeyask-based plans.[339]

The Preferred Development Plan has the highest ratepayer costs in all periods, but the gap narrows considerably over time. Morrison Park noted that if its model were to progress beyond 48 years, the ranking of the Preferred Development Plan likely would continue to improve in nominal dollar terms. However, depending on the discount rate selected, the Preferred Development Plan might never catch up to Plans 4, 5, and 6, as higher discount rates dramatically reduce the present value effect of results so far in the future.[340]

When considering ratepayer costs from an intergenerational perspective, Morrison Park concluded that the choice of plans is essentially immaterial to anyone who is likely to be a ratepayer only for the next 15 years. This would include older ratepayers or businesses that do not foresee a long-term future in the province as rates will increase under all plans. Past that point, however, the choice of plans can have a very significant impact, as ratepayer costs diverge.[341] Morrison Park's analysis reveals that "*the*

[339] Exhibit MPA 3-1, p.24.
[340] Exhibit MPA 3-1, p.24.
[341] Exhibit MPA 3-1, p.24.

generational burdens, and the likely competitiveness of Manitoba electricity rates, will be very different depending on the choices made."[342]

In its Final Argument, Manitoba Hydro commented on Morrison Park's model, noting that while there may be some benefit in using third party models for indicative long-term planning purposes, the models were not sufficiently robust to be considered reliable for short-term decision-making or rate-setting purposes. Manitoba Hydro was of the view that Morrison Park's model was sophisticated but had shortcomings that would limit its use.[343]

9.11.0 Bill Impacts

The Panel heard that customers' electricity bills matter more than rates. Each month, customers are focused on how much they have to pay rather than their electricity rate. The following Table provided by La Capra Associates shows the projected monthly bills for a residential customer using 750kWh of electricity at the estimated rate increases for the different plans. [344]

[342] Exhibit MPA 3-1, p.24.
[343] Exhibit MH-204, p. 197.
[344] Exhibit LCA-3-3, p. 9S-10.

Table 27 La Capra Associates - Projected Monthly Residential Electricity Bill (Non-Electric Heat, 750 kWh/month)

	2013	2032	2042	2052	2062	NPV 2013-2062
Plan 1 (All Gas) – Original 2013 Analysis	$60.96	$115.72	$119.21	$143.32	$168.50	$1,218
Plan 7 (Gas/C26) – Original 2013 Analysis	$60.96	$124.69	$109.96	$128.65	$142.89	$1,222
Plan 2 (K22/Gas) – Original 2013 Analysis	$60.96	$117.05	$115.46	$134.58	$146.44	$1,209
Plan 4 (K19/Gas/250MW) – Original 2013 Analysis	$60.96	$115.58	$112.42	$131.55	$148.33	$1,196
Plan 13 (K19/C25/250MW) – Original 2013 Analysis	$60.96	$127.28	$106.89	$120.03	$128.65	$1,217
Plan 12 (K19/C31/750MW) – Original 2013 Analysis	$60.96	$123.43	$110.55	$121.69	$128.94	$1,214
Plan 6 (K19/Gas/750MW) – Original 2013 Analysis	$60.96	$117.16	$112.24	$131.86	$148.10	$1,202
Plan 14 (PDP – K19/C25/750) – Original 2013 Analysis	$60.96	$126.65	$104.92	$118.28	$125.59	$1,208
Plan 14 – 2014 Update - With DSM Level 2 – Main Rate Submission	$60.96	$129.00	$104.93	$110.16	$113.28	$1,196
Plan 5 – 2014 Update - With DSM Level 2 – Main Rate Submission	$60.96	$118.31	$104.61	$123.35	$137.80	$1,168
Plan 1 – 2014 Update - With DSM Level 2 – Main Rate Submission	$60.96	$111.11	$110.78	$137.97	$158.89	$1,171
Plan 14 – 2014 Update - With DSM Level 2 and High Capital Cost – Main Rate Submission	$60.96	$136.88	$111.89	$114.52	$116.21	$1,237

The above Table shows that by 2032, the various development plans all significantly impact customer bills.

9.11.1. Impact on Lower Income and Vulnerable Consumers

Many witnesses and presenters expressed concern about the proposed rate increases. Dr. Higgin, an expert witness on behalf of CAC, noted that there was considerable "intergenerational inequity" associated with the proposed increases since ratepayers would have to wait a long time to benefit from more modest rate increases while paying much higher electricity bills in the short term (2015 to 2025). He described the short-term impact on ratepayers' bills as "not acceptable", particularly for lower income and vulnerable consumers.[345] Dr. Higgin determined that vulnerable consumers[346] who use electricity to heat their dwellings would see a 46.5% increase in their electricity bills over 10 years (2013 to 2023) under the Preferred Development Plan compared to 39.9% under the All Gas plan, as depicted in the following Table.[347] Dr. Higgin defines

[345] Exhibit CAC-76, p. 10.
[346] Exhibit CAC-27, p. 55.
[347] Exhibit, CAC-27, p. 55.

vulnerable consumers as families (1-7 persons) with an income that meets the Statistics Canada After Tax LICO (2011 data).[348]

Table 28 Dr. Higgin (CAC) Calculation - Bill Increases for Electric Heat, 2013 to 2023

Plan	2013 Base yr.	2013	2013 – 2023 Increase
K19ExpC25 750 MW	$1831	$2683	46.5% ($852)
All Gas	$1831	$2561	39.9% ($730)

In their analysis of the impact of rate increases on low and non-low income households in Manitoba, two other CAC experts, Harvey Stevens and Dr. Wayne Simpson, concluded that rate increases of the scale proposed by Manitoba Hydro over the 2015 to 2032 period worsen the deficit already experienced by low income households and could move many near low income households into a deficit position.[349] Dr. Simpson noted that government transfers are one way to address the affordability of electricity rates.[350]

One witness from the joint CAC/MMF ratepayer panel told that Panel that electricity currently comprises 12% to 15% of her family's annual income.[351] CAC argued that the proposed rate increases would only further erode the already scarce dollars of lower income consumers and force them to cut back on other basic necessities.

9.11.2. Impact on Northern and Aboriginal Customers

Another concern brought to the Panel's attention was the large electricity bills paid by northern and aboriginal customers.

At one time, electricity customers paid different rates depending on where they lived in Manitoba. Northern customers were charged higher electricity rates than residents in the larger population centres such as Winnipeg and Brandon. This rate structure was abandoned several years ago when *The Manitoba Hydro Act* was amended to ensure that all customers in a specific rate class, including residential customers on the interconnected grid, paid the same electricity rates regardless of where they live in the province.[352]

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[348] The Low income cut-off (LICO) represents a household income threshold where a family is likely to spend 20% or more of its income on food, shelter and clothing than the average family, leaving less income available for other expenses such as health, education, transportation and recreation. LICOs are calculated for families and communities of different sizes
[349] Exhibit CAC- 31, p. 3.
[350] Transcript, pp. 7865, 7867.
[351] Transcript, p. 7646.
[352] *The Manitoba Hydro Act*, C.C.S.M., c. H190. ss. 39(2.1), 39(2.2).

The Panel heard that residents of northern Manitoba face higher electricity bills because of the particularly harsh climate and their reliance on electricity as a heating source. It was pointed out to the Panel that customers in northern Manitoba do not have the range of heating fuels available to them that many customers in southern Manitoba do. Natural gas is not available in the north, leaving electricity or wood as the primary heating fuel options.

One northern resident described the sense of inequity felt upon seeing the homes of Manitoba Hydro employees in Gillam equipped with two electricity meters, one for heat and one for regular electricity use, and knowing that these employees do not have the same costs for electric heat. Some northern residents believe that Manitoba Hydro's northern employees receive free heat.[353] While these employees do not receive free electric heat, the Panel learned that they do pay a much-reduced charge for this service. Manitoba Hydro confirmed that corporate homes for employees are fitted with two meters in order to separately meter electricity used for home heating. Employees pay a flat rate for heat based on the lowest average heating costs in Winnipeg, adjusted annually, and regular rates for electricity used for non-heating purposes.[354] The Panel recognizes that this is an irritant for northern ratepayers, but Manitoba Hydro reported that this is a taxable benefit for its employees.

The Panel learned that affordability of electricity was a major concern for residential and general service customers in MKO First Nation communities. Most citizens of MKO First Nation communities fall into the low-income category and, like other lower income Manitobans, spend a greater percentage of their income on electricity than customers in higher-income categories. The Panel was told that rate increases would only exacerbate the lack of affordability demonstrated by the high levels of delinquent accounts in First Nations communities. Furthermore, these communities have no evidence that the federal government will raise its level of support to offset the projected rate increases.

In its presentation in Thompson on May 14, 2014, MKO indicated that 86% of MKO First Nation electricity accounts are currently in arrears. MKO called for greater access to DSM programs to help MKO customers to reduce their electricity bills and for the impact of future rate increases to be mitigated to the fullest extent possible. Of particular concern was the potential ineligibility of customers in arrears for Power Smart DSM programs.

[353] Transcript, p. 8244.
[354] Exhibit MH-181, p. 1.

MKO told the Panel that a significant number of customers in MKO First Nations continue to be affected by the projects and operations of Manitoba Hydro in the north. Manitoba Hydro makes mitigation payments to certain First Nations customers to compensate for these effects. The Panel heard that because Manitoba Hydro must recover the costs of mitigation payments through rates, the recipients of these payments are, in effect, paying for a portion of the mitigation payments they receive. To address this issue, MKO suggested that mitigation costs be removed from the rates that hydro-affected customers pay.

9.11.3. Impact on Commercial and Industrial Customers

Industrial and commercial (general service) customers provide 56% of Manitoba Hydro's domestic revenue from rates. The 17 largest industrial customers contribute some 22% of total domestic electricity revenue.[355] Overall, industry pays up to 10% more in rates than it costs Manitoba Hydro to provide them with power.[356]

MIPUG presenters identified their main concerns with respect to electricity costs as stability of rates, ongoing transparent regulation of Manitoba Hydro's rates and major capital spending, and ensuring that rates for all customer classes reflect the cost of serving the class. One MIPUG presenter underlined that industry could expect to pay some $400 million more over the next 20 years for the Preferred Development Plan compared to other viable alternatives. MIPUG also noted that rate increases of the magnitude and length proposed under Manitoba Hydro's Preferred Development Plan will be important considerations in future investment decisions, especially in deciding whether to expand and where expansions will take place, given competitive power rates in other jurisdictions.

The Panel was told that industrial customers have more flexibility than residential customers in their ability to respond to rate increases since, ultimately, they can take their business to jurisdictions with more competitive rates. The result would be a loss of these businesses in Manitoba.

9.12.0 Manitoba Hydro's Alternative Rate Methodologies

Manitoba Hydro's rate methodology for the NFAT analysis proposes even annual rate increases on the basis of reaching the 75/25 debt-to-equity target by 2031/32. After the debt-to-equity target is reached, the 1.20 interest coverage ratio would become the relevant target and rates increases would decline significantly.

[355] Manitoba Hydro, Annual Report for the year ended March 31, 2013, pp. 48-49.
[356] Exhibit MIPUG -28, p. 13.

Manitoba Hydro filed two alternative rate-setting methodologies with the Panel that would moderate the projected rate increases. According to Manitoba Hydro, these methodologies were provided as information for the Panel and do not indicate a policy change or yielding on its financial targets, but rather are a means of providing additional flexibility[357] in relation to the amount of rate increases and the timing of reaching the financial targets.[358]

The alternative rate methodologies, which propose rate increases based on the interest coverage ratio, are described below:

Alternative Methodology One would maintain annual 3.95% rate increases for each development plan until the 1.20 interest coverage ratio was achieved followed by subsequent rates increases to maintain the 1.20 ratio. This alternative yields significantly on the debt-to-equity target, and only achieves debt-to-equity ratios in the order of 82% for the All Gas Plan (1) and 88% for the Preferred Development Plan (14) by 2031/32.[359]

Alternative Methodology Two is similar to Alternative Methodology One, with rate increases adjusted from 2016 to 2022 to minimize losses, followed by 3.95% annual rate increases until the 1.20 interest coverage ratio was achieved, and subsequently by rate increases to maintain the 1.20 ratio. Similar to Alternative One, Alternative Methodology Two represents financial scenarios that materially miss Manitoba Hydro's debt-to-equity target, and only achieve ratios in the order of 78% for the All Gas Plan and 86% for the Preferred Development Plan by 2031/32.[360]

The following Table shows the cumulative rate increases using Alternative Methodologies One and Two.[361]

[357] Exhibit MH-204, p. 188.
[358] Exhibit MH-204, p. 188.
[359] Exhibit MH-104-12-6, p. 2.
[360] Exhibit MH-104-12-6, p. 3.
[361] Exhibit MH-104-12-6, pp. 1-3.\\MH-104-12

Table 29 Cumulative Rate Increases at DSM Level 2, Using Alternative Methodologies and Reference Capital Cost

Manitoba Hydro Plans	2031/32		
	Base Methodology	Alternative Methodology One	Alternative Methodology Two
ALL GAS (1)	82%	54%	51%
K31/GAS (2)	88%	56%	53%
K19/GAS/750 MW (5)	94%	56%	53%
K19/GAS/750 MW (6)	95%	57%	53%
K19/C40/750 MW (12)	95%	57%	54%
Preferred Development Plan (14)	115%	70%	69%
Preferred Development Plan (14) (Pipeline Load)	115%	78%	76%

Under Alternative Methodology Two, in the medium term, most of the plans have cumulative rate increases in the range of 51%-54%, as compared to the Preferred Development Plan's 69%. This is significantly lower than the expected cumulative rate increases under Manitoba Hydro's base methodology.

9.13.0 Mitigating the Impact of Rate Increases

About 15% of Manitoba Hydro's annual gross revenue is paid to the Government of Manitoba for water rentals, debt guarantee fees, and capital tax. These direct payments are currently in the order of $250 million annually and will double to over $500 million for the Preferred Development Plan.[362] In addition, the Panel estimates that Bipole III in-service will result in incremental government revenue of over $40 million annually. On an incremental Net Present Value basis, the total benefits to the Province are almost $2.3 billion for the Preferred Plan compared to the All Gas Plan.[363]

Several witnesses commented on the scale of the relatively risk-free government benefits in relation to the rate increases and risks that ratepayers will face with export-oriented development plans. The Panel was told that the provincial government would see significant increases in payments from Manitoba Hydro under export-oriented development plans compared to plans designed to serve domestic need at a time when customers face the burden of rate increases and added risk.

[362] PUB/MH I-073a
[363] Exhibit MH-171, p. 1.

A number of Interveners suggested ways for Manitoba Hydro or the Government of Manitoba to mitigate the impact of higher rates and the associated risks. MIPUG suggested that if Keeyask and the 750 MW transmission interconnection were to be pursued, Manitoba Hydro could adopt, for rate-setting purposes, lower debt-to-equity and interest coverage targets rather than adhering to a 75/25 debt to equity ratio target for at least the next two decades in order to bring rates for plans involving new hydro generation closer to the rate increases expected from the All Gas plan. MIPUG also called for the Government of Manitoba to reduce the impact on ratepayers by foregoing incremental government charges on the new projects for 15 years after their in-service dates.

MIPUG's expert witness provided an illustrative example of foregone government benefits that would make the Preferred Development Plan more beneficial for ratepayers than the All Gas Plan based on the 2012 estimates provided in the original NFAT Submission. In MIPUG's example, the present value of the foregone government benefits over the period to 2040 is $1.398 billion (with no relief after that date), which amounts to approximately 60% of the benefit from water rentals, capital taxes and debt guarantee fees under Plan 14 (not including the other government benefits from higher taxes from the construction and other economic development arising from construction and operation.)[364]

Morrison Park provided the Panel with a recent example of risk sharing where the Government of Newfoundland and Labrador is absorbing a portion of the risk associated with the development of the Muskrat Falls generating station, which is being proposed to serve domestic and export markets.[365]

CAC recommended that the government create a Green Energy Benefit to mitigate the costs and risks associated with the export-oriented plants.

MKO suggested that the Government of Manitoba should consider broadening its current water rental sharing arrangements to include other MKO First Nations. It also suggested that additional consideration should be given to exempting hydro affected First Nations from water rental fees and mitigation costs. MKO also proposed a sharing of export revenues with affected communities.

[364] Exhibit MIPUG-127, pp.1-3.
[365] Transcript pp. 7392-7393.

9.14.0 Conclusions of the Panel

There is a requirement for Manitoba Hydro to provide safe and reliable electricity service, and that this includes investments in new generation, as well as replacement of aging infrastructure. As a result, all proposed development plans would require increases in electricity rates above the rate of inflation. In that regard, Manitoba is no different than other Canadian jurisdictions, which project substantial rate increases in the imminent future.

All development plans presented could lead to higher-than-projected rate increases under several scenarios, including (1) capital costs higher than forecast, (2) interest rates rising above forecast levels, (3) export prices being lower than what is forecast, or (4) drought conditions which limit export quantities. All other things being equal, any single one of these risk factors would result in higher rate increases than projected. Ratepayers are shouldering each of these risks. In comparison, the capital tax and water rental fees realized by the Government of Manitoba are relatively risk-free.

It would be reasonable for the Government of Manitoba to give serious consideration to a reduction of increment provincial benefits from the Keeyask Project. This should involve the Government directing a portion of its incremental capital taxes and water rental fees to be used to mitigate the impact of rate increases on lower-income customers, as well as northern and aboriginal communities.

Manitoba Hydro can contribute to the impact of rate increases in two ways. It can relax is 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases. Manitoba Hydro should also mitigate rate increases by seeking to reduce its own expenditures through operational savings.

The development of the Conawapa Project would result in even higher ratepayer commitments to 50 years, after which the rate increases are not as great as other options. Based on current circumstances, the risks related to Conawapa's development far exceed any rewards to ratepayers over the next 50 years. It would not be prudent to continue spending money on Conawapa. The Panel also notes the importance of sunk costs and their impact on rates, particularly when those costs have to be written off.

10.0.0 Risk and Uncertainty

10.1.0 Introduction

Manitoba Hydro identified a number of risks inherent in the Preferred Development Plan and alternative plans. In estimating the expected Net Present Value of different plans, it is necessary to make assumptions about the likely future values of critical economic variables (the reference case) and then conduct a sensitivity analysis in order to test the vulnerability of the reference case outcomes to different risk factors. For example, Manitoba Hydro's load forecast is based on a number of assumptions about population and economic growth in the province. If this forecast growth is not realized, new generation assets will be oversized for actual load. Similarly, if energy prices are lower than forecast by Manitoba Hydro, then electricity export revenues will be less than expected and will result in higher domestic rates to make up for the shortfall.

There are a number of risk factors facing Manitoba Hydro and its ratepayers:

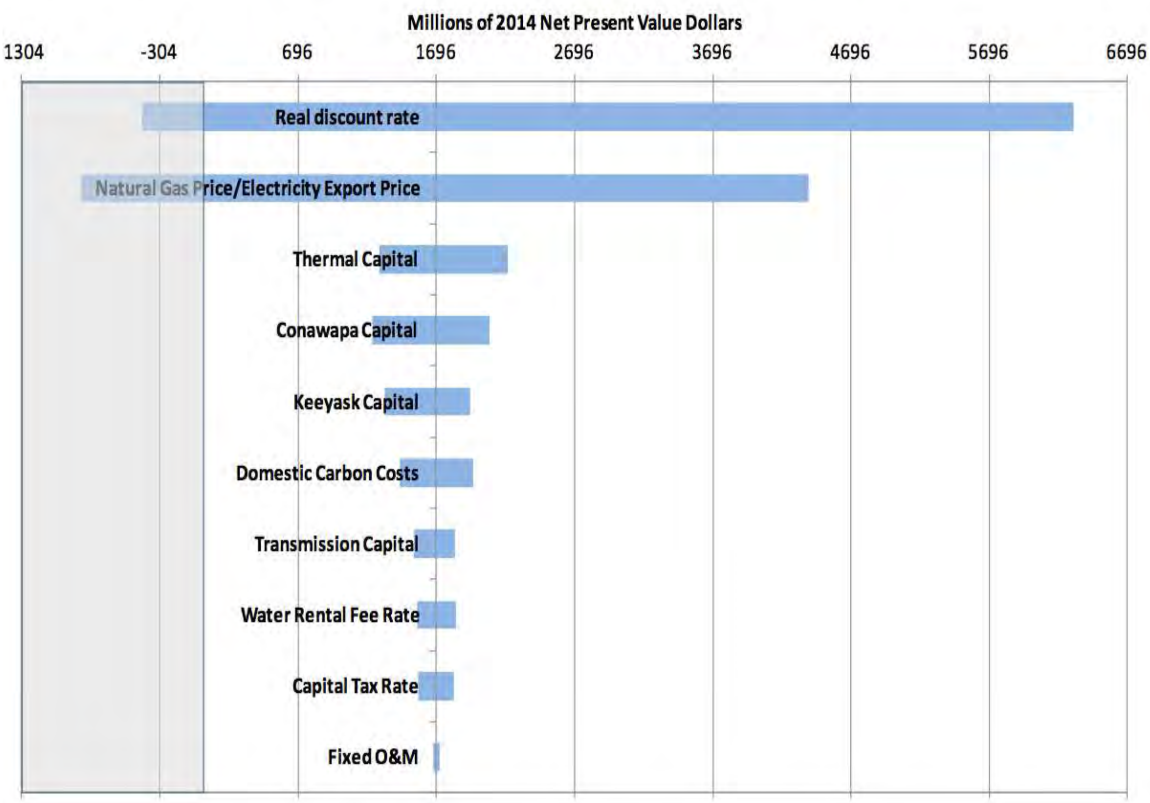
- Energy prices;
- Assumptions for a recovery of U.S. demand to pre-2008 levels;
- The future price of natural gas;
- The development of a carbon price regime in the U.S.;
- Assumptions regarding coal retirements;
- Discount rate and interest rates;
- Load forecast and Demand Side Management;
- Construction costs;
- Climate change and drought;
- Drought impacts and mitigation;
- U.S. transmission interconnection approval;
- Financial impact to the Province of Manitoba; and
- Risk impact on ratepayers compared to risk impacts on the Province.

Any planning process must consider the risk that the assumptions regarding key economic variables may not be accurate. This problem is magnified by the lengthy planning horizon over which Manitoba Hydro conducted its economic analysis and financial analysis (78 years and 50 years, respectively). As the time period lengthens, forecasting future trends in such factors as load growth, energy prices, interest rates and capital costs becomes more difficult and the results more uncertain. As a result, the Preferred Development Plan and alternative plans are subject to a significant level of risk and uncertainty in meeting their expected economic and financial outcomes.

10.2.0 Identification and Ranking of Risk Factors

With respect to the Preferred Development Plan, Manitoba Hydro identified the ten risk factors and their range of uncertainty from low to high. For the purpose of its uncertainty analysis, Manitoba Hydro grouped the high impact factors into three categories: (1) economic indicators (primarily the discount rate), (2) energy prices (both electricity export and natural gas prices), and (3) capital costs. The following Tornado diagram lists the factors from highest to lowest impacts.[366]

Figure 22 Tornado Diagram Showing Sensitivity of the Preferred Development Plan to Different Risk Factors



Source: Manitoba Hydro NFAT Submission, Chapter 10, Figure 10.1, p, 4

[366] Manitoba Hydro NFAT Submission, Chapter 10, p, 4.

Other factors were identified, but not separately analyzed, as they did not appear to have a material impact on the relative benefits of evaluated alternative plans. Manitoba Hydro determined that certain plans were affected differently by the three identified factors.

In addressing risk, Manitoba Hydro performed an assessment to determine which risk factors had the highest impact on the economic and financial outcomes. After identifying the most critical risk factors, Manitoba Hydro undertook an uncertainty analysis, defined by "reference" values as well as "low" and "high" values for these factors. They were then formulated into 27 different scenarios, each of which was analyzed for its probability.

For the All Gas Plan, the discount rate was the foremost factor affecting its Net Present Value. At a low discount rate, there is a significant negative impact on its incremental Net Present Value, while a high discount rate would give it a comparative advantage over more capital-intensive plans. The All Gas plan is also exposed to future gas prices, as the commodity cost of gas is an input into the generation cost.

For the Preferred Development Plan, the opposite effect is the case. It is a capital-intensive hydro project with a large upfront capital cost and attendant revenue requirement to recover these costs over the long-term. The Preferred Development Plan is, therefore, affected more negatively by higher discount rates, which would dilute the long-term benefits from the Plan that occur fairly late in the 78-year study period. Conversely, a lower discount rate improves the benefits associated with the Plan.

Manitoba Hydro indicated that overall, the Preferred Development Plan is most affected by energy prices, but has significant exposure to both discount rate and capital cost escalations. In plans with a mix of new gas and hydro resources, such as Plan 5, the impact of the three factors is moderated. The diversity provided by the mix of hydroelectric and natural gas-fired resources balances the effect of the factors and limits the significance of their effect on incremental Net Present Value.[367]

10.2.1. Energy Prices

Manitoba Hydro's Preferred Development Plan relies on exports of power surplus to domestic needs through firm long-term contracts, shorter-term firm sales, and opportunity sales of surplus energy on the spot market. The primary market for Manitoba Hydro's exports is the MISO market. The greatest uncertainty in modeling export markets is the level of forecasted export market prices. These prices are subject

[367] Manitoba Hydro NFAT Submission, Chapter 10, p. 7.

to a number of different factors, including U.S. demand for electricity, the prices of competing generation sources, and whether or not a carbon tax will materialize in the U.S. Potomac Economics performed an analysis of the Midcontinent Independent System Operator (MISO) market and a review of Manitoba Hydro's export market price projections, which is discussed in further detail in Chapter 6.

Manitoba Hydro has included capacity pricing premiums in its export price forecast. Independent Expert Consultant, Potomac Economics, has suggested that this represents a substantial risk to Manitoba Hydro and that its capacity revenues may be much lower than expected. When there are capacity surpluses in the MISO region, the capacity market pricing may be much lower than expected.

In modelling the uncertainty around energy prices, Manitoba Hydro utilized six independent commercially available forecasts for electricity, natural gas, and carbon prices. Natural gas prices and carbon prices were assumed to be independently uncertain. Electricity prices were assumed to be deterministically dependent on the natural gas and carbon prices.

Export prices in the U.S. MISO market are influenced by the least costly generation alternative. Currently, electricity prices in MISO are set by the cost of coal-fired generation over 90% of the time and during virtually all of the off-peak hours. The rest of the time, the MISO market price is set by a combination of the cost of Combined Cycle Gas Turbine (CCGT) and Simple Cycle Gas Turbine (SCGT) natural gas-fired generation.[368]

Overall, Manitoba Hydro's energy price assumptions are directly influenced by four factors: (1) a recovery in the export market demand to pre-2008 levels (before the financial crisis); (2) trends in the future price of natural gas, especially shale gas; (3) the near-term development of a carbon price regime in the U.S.; and (4) retirements of coal-fired generating stations in the MISO area.

10.2.2. Assumptions for a Recovery of U.S. Demand to Pre-2008 Levels

The 2008 financial crisis in the U.S. resulted in electricity demand being significantly depressed, compared to pre-2008 levels. While the economy has since recovered, an issue that was raised repeatedly before the Panel was whether there has been a structural shift that has permanently altered the nature of the relationship between economic growth and load growth in the U.S. economy. CAC's witness, Dr. Gotham,

[368] Manitoba Hydro NFAT Submission, Chapter 5, pp. 45-46.

noted that there was significant unresolved uncertainty regarding this issue.[369] Notably, despite the recovery in the U.S. economy, Manitoba Hydro has experienced five years of average export prices in the MISO region in the 3¢/kWh to 3.5¢/kWh range, with no apparent upward trend in market prices.[370]

Elenchus noted the potential for structural change to the electricity market as a result of new technology, suggesting that forecasting, by its very nature, does not assume or account for such structural change. Potential issues of concern would be the widespread adoption of electric vehicles, which would increase demand, or alternatively grid parity of alternative generation sources such as solar power that would lower demand. In Elenchus' view, the uncertainty is not whether such change will happen, but when.[371] If (or when) the cost of distributed and/or micro-generation and storage declines to the point of grid parity, there could be a tipping point where industrial, commercial, and even residential customers switch en masse from grid power to self-generation.[372] This would allow consumers to price-competitively generate a portion or all of their electricity and reduce their reliance on the grid.[373]

Morrison Park and other witnesses also noted that while the timing and impact of changes would likely be gradual, long-lived assets, such as those included in the Preferred Development Plan, may become locked in. This means the utility would forego the possibility of adopting new, more inexpensive technology.[374] CAC further quoted Mr. Campbell, the CEO of Ontario's Independent Electricity System Operator, who spoke to the potential for fundamental change across the electricity sector, stating that:

> *Take these four points together: cheaper solar power, cheaper energy storage, more internet-connected devices, and low voltage DC power-networks offering alternative ways to distribute your home-grown energy sources to devices in your home. Somehow this is all starting to feel like very fundamental change across our sector.*[375]

For Manitoba Hydro, the risk of structural change is two-fold. First, it could reduce demand in Manitoba, resulting in decreased revenues from Manitoba customers. Second, it could depress export prices or complicate the renewal of export contracts,

369 Transcript, p. 8429.
370 Exhibit PUB-58-1, pp. 45, 63.
371 Exhibit ERA-3, p. ii, 42.
372 Exhibit ERA-3, p. 41.
373 Exhibit ERA-3, p. i.
374 Exhibit MPA-3, p. 74.
375 Exhibit CAC-91, p.19.

thus reducing export revenues. In the Panel's view, the worst-case scenario could lead to so-called stranded assets for which Manitoba Hydro cannot recover all of its costs through domestic and export revenues.

10.2.3. The Future Price of Natural Gas

Less than 10 years ago, natural gas prices were at all-time highs. Since then, prices have dropped by approximately 50% due to the advent of shale gas economically produced through hydraulic fracturing, or "fracking" technology. CAC noted the transformative effects of shale gas upon the U.S. marketplace and called it a "game changer."[376]

Natural gas prices are a significant cost input into gas-fired generation that sets the price point in MISO during on-peak periods. Continuation of low gas prices has the potential to significantly lower Manitoba Hydro's export revenues. Continued low gas prices may also affect domestic electricity demand for space-heating purposes if customers realize they can drastically reduce their heating bills by switching to gas furnaces and water heaters. This could reduce domestic demand for electricity.

10.2.4. The Development of a Carbon Price Regime in the U.S.

Hydroelectric energy does not result in any significant carbon dioxide (CO_2) emissions. Conversely, coal-fired generation and, to a lesser extent, gas-fired generation, results in significant emissions. According to the U.S. Environmental Protection Agency, average CO_2 emissions for coal are 1.02 tonnes/MWh, while emissions for gas are around 0.5 tonnes/MWh.

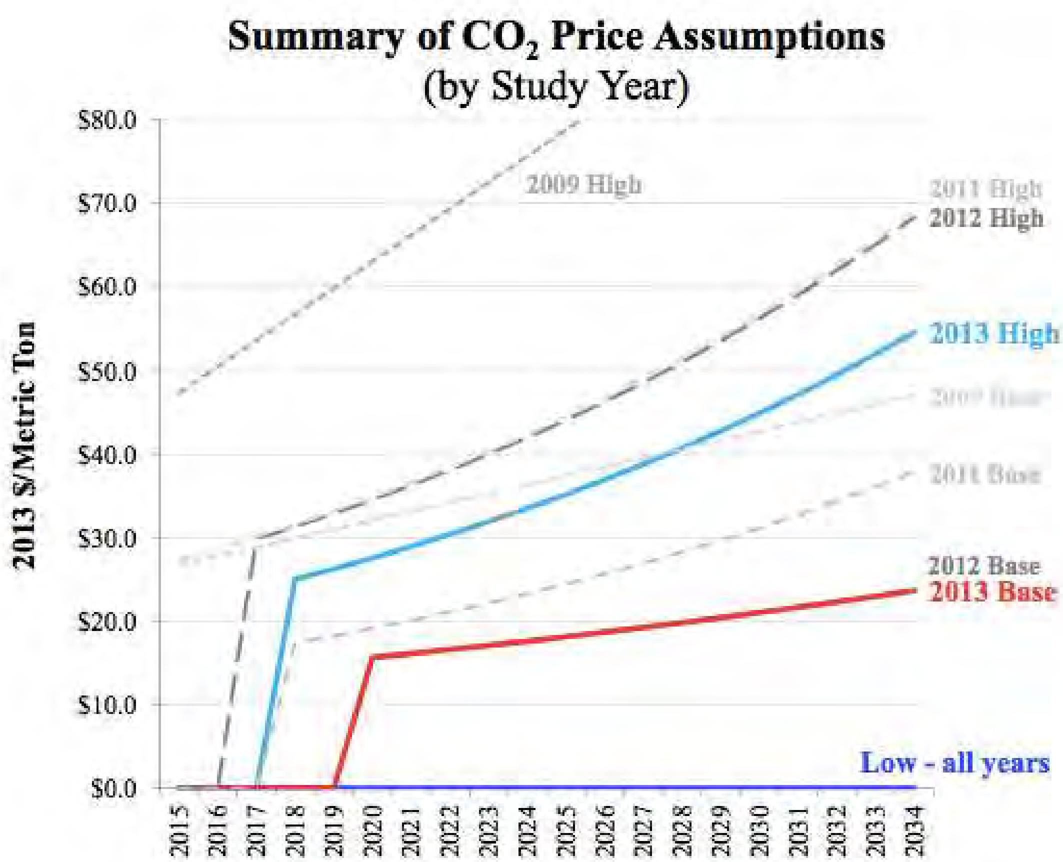
To date, the U.S. does not have a carbon tax or cap-and-trade mechanism. However, there is a widespread expectation that the U.S. will eventually implement legislation, although both the timing and magnitude of any tax or emissions restrictions is uncertain. Should such a regime be eventually introduced, the economic competitiveness of low-emission hydroelectricity will increase vis-à-vis coal- and gas-generated electricity, as the latter two would become more expensive due to the cost of emissions.

Dr. Murphy of the Brattle Group indicated that while less than a decade ago there was an expectation for a carbon regime in the relatively near term, the global recession "knocked that train off the rails."[377]

[376] Exhibit CAC-91, p. 11.
[377] Transcript, p. 2247.

Manitoba Hydro filed on the public record the Brattle Group's forecast, which assumes carbon prices starting at $15/ton (U.S.) in 2020, growing to $21/ton in 2030, and reaching $24/ton by 2034.[378] The Brattle Group also observed that over the past several years, carbon price assumptions have both pushed back the expected implementation date and reduced the expected carbon price. This is illustrated in the following diagram by the Brattle Group, which highlights the importance of both the level and timing of carbon pricing to export price forecasts:

Figure 23 Brattle Group Summary of Current and Historic Carbon Price Assumptions



In an in-camera session, the Panel had the opportunity to examine the various carbon price assumptions made by Manitoba Hydro's commercial forecasters. In addition, MNP provided evidence regarding its own pricing assumptions. Overall, it became clear that there is significant uncertainty about the development and nature of a carbon regime. In the Panel's view, there is no clear consensus on what level (if any) of carbon pricing should be employed.

[378] Exhibit POT-2-1, p. 10.

MNP assigned a 50/50 probability that a carbon tax regime would develop. Potomac Economics provided a reference forecast with a carbon tax commencing in 2021 and one reference forecast without a carbon tax regime. Potomac indicated both outcomes are equally as likely but will ultimately depend on the direction of future policy in the U.S.[379] CAC's witness, Dr. Gotham, stated that the development of a carbon regime is a binary proposition and essentially a "yes" or "no" question, with a significant difference in electricity market pricing between the two.[380]

Since Manitoba Hydro's export revenue forecast is premised on the development of a U.S. carbon regime, the failure of such a regime to develop could, in the Panel's view, significantly lower actual export revenues realized by Manitoba Hydro, and as such represents a significant risk in its assumptions. The uncertainty surrounding this forecast is significant, as La Capra Associates indicated that a slightly lower view of export market prices substantially erodes the economic benefits of the Preferred Development Plan.[381]

10.2.5. Assumptions Regarding Coal Retirements

As set out above, coal-fired generation sets the MISO market price, especially during off-peak hours. A retirement of coal-fired generating stations would likely lead to the replacement with higher-cost sources, such as natural gas generation. This could result in rising MISO electricity prices, and hence increased revenues achieved by Manitoba Hydro.

The Brattle Group forecasts from 11 to 16 GW of MISO coal plant retirements in the coming years. This level of MISO coal plant retirements is substantially above the level assumed by Potomac Economics in its reference case. Potomac assumes 6 GW of coal plant retirements in the MISO region. Potomac opined that the emissions and fuel cost assumptions along with the high level of coal plant retirements assumed by the Brattle Group overstate energy prices.[382]

10.2.6. Discount Rate & Interest Rates

The discount rate in the economic evaluation context is designed to reflect the return that markets require on the type of investment in question. Discount rates and interest rates are linked, as interest rates influence Manitoba Hydro's cost of borrowing. To the extent that interest rates increase the future the cost of borrowing, it will be reflected in a

[379] Exhibit POT-2-1, p. 45.
[380] Transcript, p. 8562.
[381] Exhibit LCA-3, p. LCA-27.
[382] Exhibit POT-2-1, p.11.

higher discount rate. Such circumstances would increase both the cost of borrowing incurred by Manitoba Hydro, as well as the discount rate used to evaluate the development plans. Higher discount rates have a negative impact on the finances and economics of capital-intensive plans with high up-front costs such as the Preferred Development Plan, because the long-term benefits are highly discounted.

Manitoba Hydro used a "weighted average cost of capital" (WACC) approach. This approach is premised on Manitoba Hydro's target 75/25 debt-to-equity ratio. The debt portion is based on Manitoba Hydro's cost of borrowing, including the debt guarantee fee it pays to the Province of Manitoba. For the equity component, which constitutes 25%, Manitoba Hydro added a 3.00% return on equity. In its original filing Manitoba Hydro's WACC discount rate was 5.05%. In its 2013 update, the WACC discount rate increased to 5.40% as a result of increased borrowing costs.

Manitoba Hydro assumed long-term interest rates of 4.50% for 2014, rising to 6.75% for 2019 onwards. Changing these interest rate assumptions will raise or lower the projected interest costs to be incurred by Manitoba Hydro, and will have a strong impact on its finances.

Morrison Park conducted an interest rate sensitivity analysis of the impact on the total costs to Manitoba ratepayers.[383]They indicated that interest rates have some clear impacts on total cost to Manitoba ratepayers. For Plan 5, a 1% increase in interest rates causes the Net Present Value (at a 6% discount rate) of Manitoba ratepayer costs to rise by approximately 6.5%. For the All Gas Plan, this sensitivity is only 4.5%, while for the Preferred Development Plan the sensitivity is 9.5%.

Changes in interest rates have the greatest impact on the Preferred Development Plan, which employs the greatest amount of debt. Conversely, interest rates have the least impact on the All Gas Plan, which employs the least amount of debt.[384]

La Capra Associates also measured the impact on the economics of the Preferred Development Plan of the increase from Manitoba Hydro's 2012-assumed WACC of 5.05% to the 2013-assumed WACC of 5.40%. According to La Capra, the change in discount rate reduced the $1.7 billion Net Present Value of the Preferred Development Plan by $663 million.[385] Given that this was a relatively minor change in the assumed discount rate, it is clear that the Preferred Development Plan is highly sensitive to

[383] Exhibit MPA 3-1, p. 20.
[384] Exhibit MPA 3-1, p. 19.
[385] Exhibit LCA-45, p.16.

discount rates. Plans involving only the Keeyask Project are still affected, but are less susceptible to discount rate risk due to less capital being committed.

10.2.7. Load Forecast and Demand Side Management

The Panel heard evidence of potential new industrial load in the pipeline sector, which can add approximately 1,300 GW of incremental energy load that is currently not included in the 2013 base load forecast. If the pipeline load materializes, this will increase pressure on Manitoba Hydro to achieve its Demand Side Management targets, as it will reduce the available generation surplus. However, advancing the construction of the Keeyask Project to 2019 mitigates this risk by providing additional surplus capacity.

Manitoba Hydro's latest load forecast assumes that enhanced DSM based on the 2014 Power Smart Plan will achieve over 3,900 GWh of energy savings, as well as over 1,100 MW in capacity savings.[386] This level of DSM is greater than the dependable energy output of the Keeyask Project. If the savings are not realized, this will have financial implications for Manitoba Hydro and will affect the timing requirement for other new generation.

In the long term, Manitoba Hydro's load forecast is significantly more uncertain, as it does not account for the development of new technologies that could either significantly increase or decrease electricity consumption. This could include the development of grid parity with respect to technologies such as solar photovoltaic cells or the proliferation of electric vehicles.

10.2.8. Construction Costs

Higher construction costs for Keeyask and Conawapa are a major risk facing the Preferred Development Plan. La Capra Associates stated that modest increases in capital cost assumptions for these projects would result in other development plans having lower costs than the Preferred Development Plan even over the 78-year evaluation period.[387] This was highlighted by the effect of a relatively modest capital cost increase noted in 2014. During the NFAT Review, Manitoba Hydro filed updated costs for Keeyask and Conawapa that increased the cost of Keeyask by close to $300 million and the cost of Conawapa by nearly $500 million from 2012 levels.[388] La Capra Associates determined a reduction in incremental Net Present Value of the Preferred

[386] Exhibit MH-180, pp.55-56.
[387] Exhibit LCA-3, p. LCA-27.
[388] Exhibit MH-113.

Development Plan by $871 million or over 50% of its benefit compared to the All Gas Plan.[389]

Morrison Park prepared a domestic revenue sensitivity analysis showing the Net Present Value (2015-2062) impact on ratepayers of a $1 billion increase in the capital cost of each of Keeyask and Conawapa. Morrison Park noted that the results of a $1 billion increase in capital costs were very similar to the impact of higher interest rates. Adding $1 billion to the construction costs of Keeyask causes Plan 5's Net Present Value (at 6%) of ratepayer costs to rise by slightly less than 3%. At this level, the All Gas Plan is approximately 2% superior to Plan 5 (or the other plans including Keeyask in 2019). Morrison Park also indicated that the analysis showed that the Preferred Development Plan was inferior, requiring higher domestic revenues compared to all other plans if both Keeyask and Conawapa construction costs are increased.[390]

10.2.9. Climate Change and Drought

Manitoba Hydro's primarily hydraulic generating facilities rely on adequate water flows being available. Plans that rely on either Keeyask or Conawapa are therefore subject to a greater risk of climate change and droughts.

Manitoba Hydro conducted an economic sensitivity analysis to see how various potential hydrological changes due to the effects of climate change would affect the economic analysis of some representative portfolios. However, Manitoba Hydro did not indicate any directional impacts of climate change.

La Capra Associates and MNP were critical of Manitoba Hydro's climate modeling and Manitoba Hydro's failure to quantify the impact of climate change on the severity of droughts.[391] According to La Capra Associates, Manitoba Hydro's Global Climate Model only models long-term average stream flows rather than dealing with specific annual flows. As a result, in a severe drought the long-term flows are "hardwired" into this analysis without being adjusted.[392] In La Capra Associates' view, this means that the impact of climate change is essential "assumed away" in the analysis.

Manitoba Hydro engaged the Ouranos Consortium on Regional Climatology and Adaption to Climate Change (Ouranos)[393] to assist with modeling the impact of climate

[389] Exhibit LCA-45, p. 16
[390] Exhibit MPA-3-1, p. 21.
[391] Exhibit LCA-7, p. 4-11.
[392] Exhibit LCA-7, p. 4-12.
[393] Ouranos was created in 2001 as a joint initiative of the Quebec Government, Hydro-Quebec and Environment Canada. The consortium brings together 450 scientists and professionals that have considerable experience in climate change impacts and adaptation including a focus on energy supply and water resources.

change on the Manitoba hydrology. Dr. Roy of Ouranos testified that he did not agree with the concerns raised by the Independent Expert Consultants. He indicated the state of knowledge on climate change and drought remains inconclusive, since there is no consensus in the scientific community with respect to quantitative impacts of climate change on droughts. Dr. Roy further noted that given the current state, Manitoba Hydro's consideration of the worst drought in its historical record was the best approach to be used at this time.[394]

However, Manitoba Hydro did not utilize the worst drought on record, choosing instead to use the 5-year historical drought from 1987/88 to 1991/92. Manitoba Hydro indicated that this was an appropriate drought to be utilized, as it is representative of a post-Lake Winnipeg Regulation scenario. Lake Winnipeg Regulation, which came into effect in the 1970s, requires Manitoba Hydro to keep the level of Lake Winnipeg between a certain minimum and maximum, subject to conditions.

Manitoba Hydro has experienced at least four multi-year drought situations in the last 99 years, namely:

Table 30 Historical Droughts Experienced in Manitoba

Historical Period	Duration of Drought
1929 -1933	5 Years
1935 - 1942	7 Years
1981 - 1985	5 Years
1988 - 1992	5 Years

Morrison Park illustrated that a prolonged drought such as the worst on record, which occurred from 1929 to 1942, when Manitoba Hydro experienced an extended period of below-average flows for 12 of 14 years, would have a large impact on retained earnings, and require a lengthy recovery period.[395] The recovery period would be much greater for the Preferred Development Plan versus the All Gas Plan.

Morrison Park did an analysis of the 1929 to 1942 period, superimposed on lower water flows based on 90% of the long-term average flows. While the long-term implications of a drought were similar for the Preferred Development Plan and the alternative plans, over the term of the drought, the Preferred Development Plan would require larger rate increases.

[394] Transcript, pp.1907-1908.
[395] PUB/MPA 027(a)-(c).

10.2.10. Drought Impacts and Mitigation

The biggest risk with respect to a prolonged drought is not that Manitoba's electrical demand cannot be met, but that Manitoba Hydro could suffer significant, adverse financial consequences in meeting both domestic and export contract obligations. Manitoba Hydro measured its drought risk based on the impact of a 5-year drought. The timing of a potential drought could directly affect Manitoba Hydro's retained earnings. For the Preferred Development Plan, a 5-year drought commencing in 2014/15 would reduce retained earnings by $1.2 billion. For a drought commencing in 2021/22 (when Keeyask is in service) the impact increases to $2.1 billion, and for one commencing in 2027/28 (when both Keeyask and Conawapa would be in-service), the impact would increase to $2.3 billion. The magnitude of the impact of droughts is similar for alternative plans including the All Gas Plan or one without Conawapa because Manitoba Hydro's system is predominantly hydro based.[396]

According to Morrison Park, in a prolonged 20-year period of low water flows similar to the 20-year period of high water flows Manitoba Hydro has just experienced, there is a risk that a portion of Manitoba Hydro's debt could become "stranded." This means that Manitoba Hydro would no longer be able to make full debt payments.[397] Since Manitoba's electricity system is virtually completely hydro-based, this risk exists regardless of whether the Keeyask Project or a gas facility is chosen.[398] If the Province of Manitoba had to start servicing this debt pursuant to its guarantee, this could be seen as a government subsidy of Manitoba Hydro.[399] However, because the Conawapa Project would increase Manitoba Hydro's debt by an additional $10 billion, it would increase the sensitivity to a prolonged drought.[400] In Morrison Park's assessment, the upper boundary of potentially stranded debt would be approximately $10 billion, and having the Province of Manitoba service such debt could be seen as a tax-supported subsidy of Manitoba Hydro.[401]

Manitoba Hydro took issue with Morrison Park's financial model used to determine financial distress. Manitoba Hydro suggested that Morrison Park's calculations would tend to overstate gross interest expense, understate net income, and understate the gross interest coverage ratio in some years. That would overstate the amount of stranded debt in some years.[402]

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[396] PUB/MH I-205 (Revised).
[397] Transcript, pp. 7289-7292.
[398] Transcript, p. 7292.
[399] PUB/MPA 27(c), p. 23.
[400] Transcript, p. 7292.
[401] PUB/MPA 27(c), p. 23.
[402] Exhibit MH-204, p. 198.

Aside from the possibility of rate increases greater than currently budgeted for by Manitoba Hydro, there are other drought mitigation options. Morrison Park suggested that the establishment of a drought contingency fund of sufficient size to offset all water rental fees and capital taxes for three years in the event of a severe drought would provide insurance against a significant level of financial distress.[403]

As experienced by Manitoba Hydro in 2004, droughts can lead to significant year-over-year rate increases both during and immediately following the drought. These rate increases become imbedded in Manitoba Hydro's future revenues.

10.2.11. U.S. Transmission Interconnection Approval

The Great Northern Transmission Line, in which Manitoba Hydro has an ownership and a financial stake, is a project being advanced by Minnesota Power. In order to proceed, this project requires a Certificate of Need from the Minnesota Public Utilities Commission (MPUC). If the transmission line is not approved by the MPUC and Manitoba Hydro has committed to the construction of Keeyask for an in-service date of 2019, Manitoba Hydro would have to rely on existing transmission to deliver Keeyask generated power to market. If the line receives permitting and is built, it will allow for expanded exports and have the added benefit of reducing drought risk by increasing import capabilities.

10.2.12. Financial Impact to the Province of Manitoba

The preceding risk issues all have the potential for reducing Manitoba Hydro's net income in the post-Keeyask construction time frame. A combination of downside risks, which involve higher capital cost, coupled with lower export prices and below average flow years, could result in consecutive annual net losses for Manitoba Hydro. Because the Province must show Manitoba Hydro's losses on its financial statements, and will experience lower water rental revenues during a drought, it is likely that Manitoba Hydro would seek higher rate increases to ensure positive net income.

10.2.13. Risk Impact on Ratepayers Compared to Risk Impacts to the Province

Depending on the direction of the risks set out above, ratepayers can either lose or benefit, since Manitoba Hydro's rates are set on a cost-of-service basis. To the extent that Manitoba Hydro's costs cannot be recovered from export revenues, they must be recovered through domestic rates. Ratepayers accordingly would face the risk of higher-

[403] PUB/MPA 27(c), p. 26.

than-expected rate increases under certain conditions, such as higher capital costs, higher interest rates or lower exports revenues.

It is important to note that the risks borne by ratepayers differ significantly from risks borne by the Province. The Province receives relatively steady revenue flows from Manitoba Hydro by virtue primarily of the capital tax, water rentals, and the debt guarantee fee. As a result, the Province is not exposed to the downside risk faced by ratepayers.

MIPUG compared and contrasted the respective upside and downside faced by ratepayers and the Province of Manitoba under a P10 scenario (approximating the worst case) and a P90 scenario (approximating the best case), as compared to the reference scenario of the All Gas Plan:[404]

Table 31 Incremental Benefit to Ratepayers and Government After 30 Years (Net Present Value Basis - $ millions)

	Plan 1 (All Gas)		**Plan 2 (K22/Gas)**		**Plan 6 (K19/Gas/750MW)**		**Plan 14 (K19/C26/750MW)**	
	Ratepayer Benefit	Government Benefit	Ratepayer Benefit	Government Benefit	Ratepayer Benefit	Government Benefit	Ratepayer Benefit	Government Benefit
Max (P90)	+593	+344	+1,083	+1,996	+1,204	+1,989	+1,074	+4,089
Reference	**0**	**0**	**-164**	**+1,666**	**-138**	**+1,572**	**-1,031**	**+3,598**
Min (P10)	-586	-384	-1,376	+1,300	-1,524	+ 1,100	-3,277	+3,093

The Table shows that for all plans, after 30 years, ratepayers will receive a negative incremental benefit compared to the All Gas Plan at a reference scenario, while the Province of Manitoba will realize a positive benefit. Furthermore, at a P10 probability level, which approximates a worst-case scenario, incremental ratepayer benefits will be significantly negative, while the Province of Manitoba has no negative downside risk whatsoever. In MIPUG's view, there should be a rebalancing of the benefits realized by the Province from the new developments to offset the large increases in rates being sought from ratepayers and the exposure to risks borne by ratepayers.

10.3.0 Conclusions

All plans have risks that will have to be ultimately borne by ratepayers. The Preferred Development Plan has both the highest upside potential and greatest downside potential of all of the plans evaluated. However, the rate implications of the downside risks are material to ratepayers. The downside risk of Plan 6, which excludes

[404] Exhibit MIPUG-9, p. C-46.

Conawapa, is half that of Plan 14, which includes Conawapa. In light of this risk, adding Conawapa to Manitoba Hydro's generation fleet is not justified. Further spending on Conawapa should be terminated immediately.

The Panel recognizes that there is uncertainty associated with Manitoba Hydro achieving its forecast electricity export prices, owing to uncertainty with respect to the development of a carbon tax regime and projected demand in the MISO market. Manitoba Hydro's export pricing forecasts include a carbon premium at a future date, which is dependent on pending U.S. Federal and State mandates on clean energy. Whether these mandates will materialize remains uncertain.

Manitoba Hydro is currently experiencing historically low interest rates. However, there is a risk that higher, future interest rates when Keeyask and Conawapa come into service will result in higher annual debt servicing costs. These costs will ultimately have to be borne by ratepayers.

Manitoba Hydro's load forecast is subject to several short-term uncertainties, primarily whether the expected pipeline load will materialize. In the long term, the load forecast is subject to the risk of new technologies developing that will either significantly increase or decrease the demand for electricity. Manitoba Hydro has yet to address the potential risk and impacts of competing technologies and the implications of grid parity on its load forecast. There is further risk related to Manitoba Hydro's Demand Side Management efforts. Manitoba Hydro's Power Smart Plan target is new and untested. The Plan has yet to be formalized and executed. If Manitoba Hydro does not meet its targets, then capacity implications may arise with the arrival of new pipeline load requirements. However, advancing the Keeyask Project to 2019 mitigates this risk by providing additional surplus capacity in advance of domestic need.

Manitoba Hydro's capital cost estimates for its major generation and transmission projects could experience further increases, which could challenge Manitoba Hydro's financial well-being. It is the Panel's view that there remains a high degree of uncertainty as to whether the capital cost estimates for Keeyask and, in particular, Conawapa will escalate further. Should costs escalate to even higher levels, the economics of Manitoba Hydro's Preferred Development Plan would further deteriorate.

Manitoba Hydro continues to be subject to drought risk, specifically in the face of prolonged low water flows. The primary risk is not that Manitoba Hydro could not meet domestic demand, but rather that its financial situation would erode. This could require rate increases beyond what is currently budgeted. In the absence of such rate increases, there is a risk that the Province of Manitoba might have to step in to assume a portion of Manitoba Hydro's debt. From a reliability perspective, the 750 MW U.S. transmission interconnection would mitigate drought risk by providing enhanced import capacity.

However, the Panel recognizes that ratepayers will face significant rate increases in the early years as a result of these projects even without any downside risk materializing, while the Province of Manitoba will stand to benefit.

11.0.0 Socio-Economic Impacts

11.1.0 Introduction and Background

The Economic Evaluation, outlined in Chapter 8, considers only the net economic benefits of various development plans, and does so only from the perspective of Manitoba Hydro. The Panel's Terms of Reference also directed it to consider a broader range of social and economic effects and to determine whether the Preferred Development Plan provides the highest level of overall socio-economic benefit to Manitobans.

Recognizing the broad nature of socio-economic impacts and benefits, the Panel first sought to define the scope of its inquiry. In consultation with Manitoba Hydro and the Interveners, the following definition was developed:

> *"A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal, family and community life; and resource use."*[405]

Manitoba Hydro's examination of these issues was limited in scope, largely restricted to four considerations:

- A qualitative assessment of the environmental and socio-economic benefits of a limited set of different resource technology options, including hydro, wind, Demand Side Management (DSM) and natural gas;
- An economic impact analysis of the Preferred Development Plan;
- A more detailed analysis of expected socio-economic benefits of the Keeyask Project; and
- A Multiple Account Benefit Cost Analysis (MA-BCA) to determine the net benefits accruing to various stakeholders (accounts), including Manitoba Hydro, the Government of Manitoba, ratepayers, aboriginal communities and the Manitoba economy in general.[406] The MA-BCA analysis was limited to a comparison of the Preferred Development Plan to three other plans: Plan 1/All Gas; Plan2/K22/Gas; and Plan 4/K19/Gas24/250MW.

[405] Exhibit PUB-10, p.14.
[406] Manitoba Hydro NFAT Submission, Chapter 13, p. 2.

This chapter reviews each of these four components of Manitoba Hydro's socio-economic evaluation and the limitations of the analysis presented during the NFAT Review. The Panel heard concerns that Manitoba Hydro's approach and the small number of plans that it considered did not provide a thorough socio-economic evaluation. Specifically, while there is an in-depth analysis of the Keeyask Project and its impact on aboriginal and northern communities, there is much less assessment of the benefits and impacts of other alternatives or other generation sources.[407]

11.2.0 Qualitative Assessment of Resource Technology Options

11.2.1. Manitoba Hydro's Screening of Resource Technology Options

In developing the Preferred Development Plan and alternative plans, Manitoba Hydro began by considering 16 utility-scale resource technology options to meet anticipated load growth. These included DSM, hydro, natural gas, coal, nuclear, wind, solar, geothermal, biomass, and imports. The viability of different resource options were then assessed according to: a) technical characteristics, including the intermittency and seasonality of supply; b) environmental characteristics, such as greenhouse gas emissions and other potential environmental harm; c) social and policy characteristics, such as regulatory constraints and "social acceptability"; and d) economic characteristics.

On this basis, Manitoba Hydro ruled out geothermal, biomass, nuclear, and solar as viable resource options and limited its consideration to resource plans that included DSM, hydro, wind, natural gas, and imports.

For the purposes of its socio-economic analysis, Manitoba Hydro prepared the following overview of a specific set of socioeconomic considerations associated with six resource options: DSM, the Keeyask Project, the Conawapa Project, on-shore wind, simple cycle gas turbines, and combined cycle gas turbines.[408]

[407] Exhibit MMF-26, pp. 7-8.
[408] Manitoba Hydro NFAT Submission, Chapter 7, p. 39.

Table 32 Socioeconomic Screening of Generation Technologies

	DSM	Keeyask	Conawapa	Wind	Heavy Duty CCGT	Heavy Duty SCGT
Health Concerns	-	Very Low	Very Low	Low	Low	Low
Safety Concerns	-	Medium	Medium	Very Low	High	High
MB Business Opportunities (% of capital spent in MB)	100%	53%	46%	18%	30%	17%
Employment Direct Construction	Program Dependent	4480 Person-Years	6650 Person-Years	35 to 80 Person-Years	329 Person-Years	116 Person-Years
At Northern Work Sites	Program Dependent	94%	94%	0%	0%	0%
Permanent O&M	Minimal	58 FTE	61 FTE	4 to 8 FTE	94 FTE (for 1 to 2 plants at site)	52 FTE (for 1 to 4 plants at site)
At Northern Work Sites	0%	100%	100%	0%	0%	0%
Royalties / Taxes (2014$) Water Rentals	-	$9.0 M/year	$12.8 M/year	-	-	-
Capital Taxes	Program Dependent	$17.3 M/year	$28.6 M/year	$0.8 M/year	$2.0 M/year	$0.8 M/year
Guarantee Fees	Program Dependent	$27.7 M/year	$45.8 M/year	Potential for $1.3 M/year	$3.2 M/year	$1.3 M/year

Aside from this very general qualitative overview, no aspects of the socio-economic impacts and benefits of DSM or wind options received further attention. Instead, Manitoba Hydro's analysis focussed on the socio-economic impacts on the Preferred Development Plan and a MA-BCA analysis restricted to four development plans that included only hydro and gas resource options.

11.2.2. Considering the Employment Benefits of Other Options: Wind and Demand Side Management

There was limited analysis of the employment opportunities and benefits associated with components of the Preferred Development Plan. This includes options that might involve generation located in central and southern Manitoba. In particular, there was little assessment of the employment impacts associated with wind generation and increased Demand Side Management programs.

Manitoba Hydro indicated that Demand Side Management had not been assessed because, in part, fewer opportunities for Demand Side Management-related training and employment would exist in northern Manitoba. However, Intervener witnesses suggested that Demand Side Management create significant employment in comparison to other capital projects. Mr. Dunsky who appeared on behalf of CAC, told the Panel in his presentation that Demand Side Management can result in two to ten times more jobs per $ million investment.[409]

Mr. Klassen provided information on the job creation potential of Demand Side Management. He indicated that the cost to create a Demand Side Management job could be about $80,000 per direct/indirect full-time equivalent (FTE) position.[410] The cost to create a hydropower development job could be several hundreds of thousands of dollars. In addition, Demand Side Management jobs provide ongoing employment for a wide range of skills and individuals associated with efficiency programs and trades throughout Manitoba, including northern and aboriginal communities.

In his analysis of wind power generation options, Mr. Hendriks, a witness for MMF, provided the Panel with additional information on employment benefits, especially for communities located in southern and central Manitoba. In its filing, Manitoba Hydro attributed 35 to 80 person-years to the direct construction of wind generation resources (4-8 FTEs); and a combined 120 to 240 person years, including O&M positions.[411] Using data from British Columbia wind energy construction and operations employment, Mr. Hendriks suggested that actual employment could be significantly higher.[412]

11.3.0 The Socio-Economic Impacts of the Preferred Development Plan

Manitoba Hydro estimated the economic impacts of the Preferred Development Plan that would accrue to Manitoba and the Rest-of-Canada (ROC). The Manitoba Bureau of Statistics' input-output model was used to estimate the direct, indirect and induced effects associated with project spending and the jurisdiction in which the effects accrue.

The impacts considered include a wide range of components, including the direct effects on employment and the production of goods or services delivered to Manitoba construction sites (such as cement), taxes and other indirect effects, (such as the spending on fuel and vehicle repair services associated with vehicles used on construction sites) and induced effects (where the employment income on construction sites can lead to spending on food, housing, entertainment, transportation).

For the Preferred Development Plan as a whole, which includes Keeyask, Conawapa, the North-South transmission upgrades, and the 750 MW interconnection, total

409 Exhibit CAC-62, p. 9.
410 Transcript, p. 7930.
411 Manitoba Hydro NFAT Submission, Chapter 7, p. 39.
412 Exhibit MMF-13-1, p. 31.

expected impacts would be significant. According to Manitoba Hydro's estimates, the total economic impact of the Preferred Development Plan would be significant. For the Manitoba economy, there would be over 17,000 person-years of employment created; roughly $1.4 billion in labour income; and just under $1 billion on government tax revenue. The distribution of impacts between Manitoba and the rest of Canada attributable to each component of the Preferred Development Plan are provided in the following Table:[413]

[413] Manitoba Hydro NFAT Submission, Appendix 2.3, p. 4.

Table 33 Economic Impact Analysis of the Preferred Development Plan Based on the Manitoba Bureau of Statistics Model

($100,000)

Manitoba - Economic Impacts of the Preferred Development Plan[1,2]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	2,436	39	3,238	42	171	119	1
Other Direct	2,175	2	1,831	2	164	124	0
Indirect and Induced	3,736	29	4,234	33	251	255	1
Total Employment (person-years)	8,347	70	9,303	77	586	498	2
Labour Income	$ 635,169	$ 5,921	$ 761,233	$ 6,597	$ 48,627	$ 35,195	$ 123
GDP ($millions)	$ 843,908	$ 6,872	$ 983,334	$ 7,676	$ 67,189	$ 50,209	$ 149
Tax Revenues ($ millions)							
Provincial	204,340	831	$ 256,096	$ 931	$ 13,954	$ 16,069	22
Local	40,915	162	$ 45,807	$ 182	$ 2,186	$ 2,478	$ 5
Federal	161,059	988	195,872	1,099	12,538	10,714	23
Total Tax Revenue ($ millions)	$ 406,314	$ 1,981	$ 497,776	$ 2,212	$ 28,679	$ 29,261	$ 51

Rest of Canada - Economic Impacts of the Preferred Development Plan[1]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	2,532	-	3,915	-	-	0	-
Other Direct	3,198	1	3,448	1	219	144	0
Indirect and Induced	10,414	16	13,601	18	386	444	1
Total Employment (person-years)	16,144	17	20,964	19	605	588	1
Labour Income	$ 1,021,350	$ 648	$ 1,402,932	$ 734	$ 30,606	$ 24,977	$ 23
GDP ($millions)	$ 1,440,223	$ 1,054	$ 1,997,461	$ 1,184	$ 54,676	$ 39,642	$ 37
Tax Revenues ($ millions)							
Provincial	$ 251,927	$ 117	$ 342,663	$ 132	$ 7,546	$ 7,146	$ 5
Local	$ 66,289	$ 31	$ 90,164	$ 35	$ 1,986	$ 1,880	$ 1
Federal	$ 307,444	$ 128	$ 426,252	$ 144	$ 10,935	$ 12,437	$ 5
Total Tax Revenue ($ millions)	$ 625,660	$ 276	$ 859,080	$ 311	$ 20,467	$ 21,463	$ 12

All of Canada - Economic Impacts of the Preferred Development Plan[1]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	4,967	39	7,154	42	171	119	1
Other Direct	5,374	3	5,279	4	383	268	0
Indirect and Induced	14,151	45	17,834	50	637	700	1
Total Employment (person-years)	24,491	87	30,267	96	1,191	1,086	2
Labour Income	$ 1,656,519	$ 6,569	$ 2,164,166	$ 7,331	$ 79,233	$ 60,173	$ 145
GDP ($millions)	$ 2,284,131	$ 7,926	$ 2,980,795	$ 8,860	$ 121,865	$ 89,851	$ 186
Tax Revenues ($ millions)							
Provincial	$ 456,268	$ 948	$ 598,759	$ 1,063	$ 21,501	$ 23,215	$ 27
Local	$ 107,204	$ 193	$ 135,972	$ 217	$ 4,172	$ 4,358	$ 7
Federal	$ 468,502	$ 1,116	$ 622,124	$ 1,243	$ 23,474	$ 23,150	$ 29
Total Tax Revenue ($ millions)	$ 1,031,974	$ 2,257	$ 1,356,855	$ 2,523	$ 49,146	$ 50,724	$ 62

[1] 2014 dollars
[2] Total may not add, due to rounding
[3] Average annual expenditures

11.3.1. Manitoba Economic Impacts

Manitoba Hydro's Preferred Development Plan and the alternative plans affect the Manitoba economy in terms of employment, needs and opportunities for new skills and training and demands for goods and services. In particular, the demand for labour has the greatest potential for economic impacts. The following Table provides the estimated Manitoba-specific economic impacts related to developing Keeyask and the 750 MW transmission line.[414]

Table 34 Manitoba Economic Impacts of the Keeyask Project and 750 MW Transmission Interconnection

	Construction			O&M			Total Impact on Manitoba		
	Keeyask	750 MW Transmission	Total	Keeyask	750 MW Transmission	Total	Keeyask	750 MW Transmission	Total
Employment (person years)									
Project Direct	2,436	119	2,555	39	1	40	2,475	120	2,595
Other Direct	2,175	124	2,299	2	-	2	2,177	124	2,301
Indirect and Induced	3,736	255	3,991	29	1	30	3,765	256	4,021
Total Employment (person-years)	8,347	498	8,845	70	2	72	8,417	588	8,917
Labour Income	635,169	35,195	670,364	5,921	123	6,044	641,090	35,318	676,408
GDP ($millions)	843,908	50,209	894,117	6,872	149	7,021	850,780	50,358	901,138
Tax Revenues ($millions)									
Provincial	204,340	16,069	220,409	831	22	853	205,171	16,091	221,262
Local	40,915	2,478	43,393	162	5	167	41,077	2,483	43,560
Federal	161,059	10,714	171,773	988	23	1,011	162,047	10,737	172,784
Total Tax Revenue ($millions)	406,314	29,261	435,575	1,981	50	2,031	408,295	21,463	437,606

One of the challenges with the economic impact analysis is to determine to what extent economic benefits accrue in Manitoba as opposed to elsewhere. If direct jobs are filled by non-Manitoba residents or if the procurement of materials is sourced outside of the province, there is a leakage of benefits to other parts of Canada or to other countries. Manitoba Hydro estimates that approximately 60% of labour income and 55% of GDP impact will be incurred in Manitoba.

TyPlan, an Independent Expert Consultant, largely confirmed the magnitude of the total economic impacts, but estimated that a greater proportion of the employment and income created would be captured within Manitoba.[415]

In comparison, Plan 1/All Gas has the least amount of capital spending in the first part of the planning period, with only small amounts invested for thermal power plants starting in the 2020s.[416] Because of the smaller scale of the construction involved, the

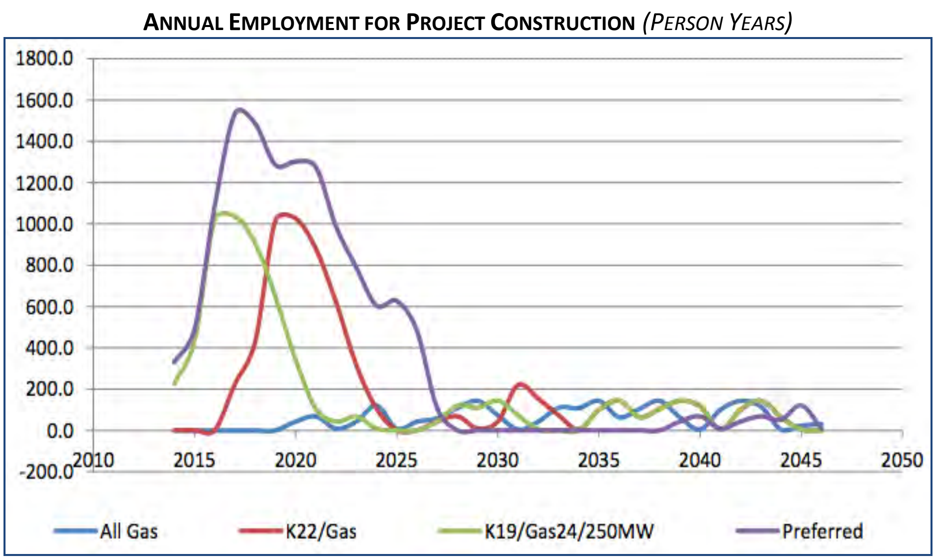
[414] Manitoba Hydro NFAT Submission, Appendix 2.3, p. 4.
[415] Exhibit TyP-1, p. 26.
[416] Manitoba Hydro NFAT Submission, Chapter 13, p. 34.

economic impacts are fewer. Employment would occur in primarily southern Manitoba construction, development and operation with more ongoing operational job requirements. In contrast, plans associated with the Keeyask and Conawapa dam construction have primarily northern Manitoba impacts.

11.3.2. Employment Benefits

These differences in capital spending carry over into the demand for labour. The total annual employment directly required for the construction of the generating and transmission projects varies between different plans. As noted in the chart below, the Preferred Development Plan, again followed by the two plans that include Keeyask, is expected to generate the largest amount of construction employment.[417]

Figure 24 Annual Employment Estimate for Project Construction



The following Table shows estimated and predicated present value of the gross wages generated by the direct employment in project construction and O&M in the preferred and alternative plans. The wages are shown separately for the employment that takes place in northern versus southern Manitoba.[418]

[417] Manitoba Hydro NFAT Submission, Chapter 13, p. 35.
[418] Manitoba Hydro NFAT Submission, Chapter 13, p. 37.

Table 35 Anticipated Gross Wages for Construction and O&M

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Construction – N. Man.	1,317.4	599.9	503.9	--
Construction – S. Man.	142.0	95.0	72.0	62.6
Total Construction	1,459.4	694.9	575.9	62.6
O&M – N. Man.	85.0	49.6	40.5	--
O&M – S. Man.	4.2	47.4	37.3	71.5
Total O&M	89.2	97.0	77.8	71.5
Total Gross Wages	1,548.6	791.9	653.7	134.1
Difference from Preferred Development Plan	0.0	(756.7)	(894.9)	(1,414.5)

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS 2014$)

In terms of net benefits, Manitoba Hydro assumed that 15% of the gross wages would be paid to Manitobans. However, the net benefit for northern aboriginal employment, supported by training, recruitment and retention policies and programs is estimated to be in the order of 50% of the gross wages paid.

At the time of the NFAT Submission, Manitoba Hydro assumed that Manitobans would fill 70% of construction jobs. In February 2014, Manitoba Hydro revised this estimate downwards to 40-45%, suggesting a significant employment leakage. Of these Manitobans, 50% would be northern aboriginal people.[419] With respect to the southern construction jobs, Manitoba Hydro indicated that Manitobans would fill just over 50% of the gas plant related employment and almost all of the tie-line and head office related employment.[420]

The net benefits derived from the employment on Manitoba Hydro's projects are not measured by the gross wage impact, but rather by the incremental income or other benefits Manitobans would realize. The incremental wage benefits during construction and ongoing operations of various plans were estimated as follows:[421]

[419] Manitoba Hydro NFAT Submission, Chapter 13, p. 38.
[420] Manitoba Hydro NFAT Submission, Chapter 13, p. 40.
[421] Manitoba Hydro NFAT Submission, Chapter 13, p. 41

Table 36 Anticipated Employment Net Benefits for Project Construction and O&M

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Construction – N. Man.	234.4	113.2	95.1	0.0
Construction – S. Man.	6.1	12.7	10.6	9.0
Total Construction	**240.5**	**125.8**	**105.7**	**9.0**
O&M – N. Man.	39.2	23.6	18.9	0.0
O&M – S. Man.	.5	7.1	5.6	10.9
Total O&M	**39.7**	**30.7**	**24.5**	**10.9**
Total Net Benefits	**280.2**	**156.5**	**130.2**	**19.8**
Difference from Preferred Development Plan	**0**	**[123.7]**	**(150.0)**	**[260.3]**

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS 2014$)

Manitoba Hydro assumes that Manitobans will fill all Operations & Maintenance (O&M) jobs. Manitoba Hydro has also assumed that at least 45% of northern O&M jobs would be filled by northern aboriginal people based on current shares of northern operations employment and targeted measures expected with the Keeyask Project.

Manitoba Hydro estimated the net benefits of construction employment in the North would equal 12.2 to 12.4% of the total gross wages paid. The net benefits of O&M employment in the north would be 30.8% of the total gross wages paid; for O&M employment in the South net benefits would be 15% of total gross wages paid.[422]

11.4.0 The Keeyask Project and Northern Aboriginal Communities

11.4.1. Joint Keeyask Development Partnership

Following years of discussion and negotiation, Manitoba Hydro and four Manitoba First Nations (Tataskweyak and War Lake acting as the Cree Nation Partners, York Factory, and Fox Lake) established the Keeyask Hydropower Limited Partnership (KHLP) and negotiated the Joint Keeyask Development Agreement with Manitoba Hydro. The agreement sets out how the Keeyask Project will be developed and identifies potential income opportunities, training, employment, business opportunities, and other related matters. In addition, individual Adverse Effects Agreements were signed to identify

[422] Manitoba Hydro NFAT Submission, Chapter 13, p. 39.

potential negative impacts of the Keeyask Project, and outline measures to prevent or reduce these effects.[423]

An important feature of the Agreement is the ability of the four Keeyask Cree Nations (KCNs) to purchase equity ownership shares. The KCNs have two investment options: a common equity option, which allows the community to obtain a proportionate share of cash distributions from the Project based on the Partnership financial performance, and a preferred equity option, which involves a guaranteed return of approximately $5 million per year.[424] At the time of this report, the choice of option has not been made, and Manitoba Hydro advised that its partners would have until 2019 to exercise the option.[425]

In the hearings, the Panel heard differing and often passionate views about the importance of the Partnership and the construction of the Keeyask Project. Some questioned the consultations leading to the Partnership Agreement.

Members of the KCNs told the Panel that they had been actively involved in negotiations and development of the Keeyask Project. They saw many positive advantages that had come from their involvement from the beginnings of the project development, the extensive community consultations and the respect shown to their Aboriginal Traditional Knowledge. These views and advantages were summarized during Manitoba Hydro's closing submission in remarks made by the Keeyask partner First Nations.[426]

The Panel notes that the commercial arrangements between the partners are outside the scope of the NFAT Terms of Reference. Accordingly, the Panel will not comment on the merit of these submissions.

11.4.2. Employment and Training

Manitoba Hydro has assumed that northern aboriginal people will fill approximately half of the construction positions filled by Manitobans. To the end of March 2013, there already had been 1,118 aboriginal hires for the Keeyask Project, representing 61% of total hires to date.[427] The Project will create jobs in three categories: designated trades, non-designated trades and support occupations. More specifically, Manitoba Hydro identified the following distribution of estimated employment:[428]

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[423] Manitoba Hydro NFAT Submission, Appendix 2.2, pp 1-4.
[424] Transcript, p. 3581.
[425] Transcript, p. 3797. See also PUB/MH 1-064.
[426] Exhibit MH-209, p. 3.
[427] Exhibit MH-143, p.1.
[428] Exhibit MH-159, pp. 1-3 (Excerpts).

Table 37 Keeyask Project Summary of Socio-Economic Benefits for Northern Manitobans

Direct Employment	Keeyask Cree Nations	Northern Aboriginal Residents
Construction	Infrastructure: up to 110 person years; Generation: 235 to 600 person years Other: 35-40 person years	Infrastructure: up to 138 person years, including KCNs Generation: 550-1700 person years (315-1100 persons excluding KCNs)
Operations	45% of 50 estimated positions to be aboriginal Minimum 182 positions	45% of 50 estimated positions to be aboriginal

Dr. Buckland and Dr. O'Gorman provided an estimate of the income associated with the 182 ongoing operational jobs. Each job was assumed to have an annual salary of $60,000 and inflated 2% annually. The high estimate of 182 jobs would result in total earnings of $13.408 Million and a low estimate of 91 jobs would equate to $7.204 Million.[429] As was noted in the hearings, all employment is conditional on applicants having the required qualifications.

The Panel also heard about the importance of addressing the need for qualifications through adequate, long-term training and skills development programs. Several presenters noted the outcomes of the Wuskwatim Training and Employment Initiative and the Hydro Northern Training and Employment Initiative (HNTEI). The Clean Environment Commission (CEC) report on the Keeyask Project expressed its concern about HNTEI's inability to train an aboriginal workforce of a size and skill set able to successfully compete for Manitoba Hydro jobs. The CEC recommended that the Keeyask Partnership support ongoing education and training initiatives.[430]

11.4.3. Business and Economic Impacts

The construction of the Keeyask project is estimated to bring business, investment and employment opportunities to the KCNs through the Partnership Agreement and Direct Negotiated Contract (DNC) provisions. To the end of March 2014, $393.6 million in purchase orders have been directly negotiated with the KCNs. These include construction camp services, worksite development, access road construction, and emergency services.[431]

As set out above, the KCNs also have investment options arising from the Keeyask project. The first option involves holding their investment in the form of Common Units.

[429] Exhibit, CAC-83, p. 1.
[430] Exhibit PUB-69, p. 104.
[431] Exhibit MH-137, p. 1.

The second option is the Preferred Unit option. The return on KCN investment for this option will be the higher of the Preferred Minimum Distribution and the Preferred Participating Distribution. In response to questions during the testimony, these estimates were updated to the following for high and low estimates of benefit:[432]

Table 38 Estimated Benefits to the Keeyask Cree Nations

Period	Total/Per Capita	Annual Estimated Range of Benefits	
		Low Estimate	High Estimate
Construction	**Total ($ million)**	$10.26	$20.67
	Per capita ($)	$1,616	$3,255
Post Construction	**Total Benefits ($ million)**	$9.58	$19.92
@ 1.9% equity ownership/6 years post construction	**Per capita ($)**	$1,509	$3,137
Post Construction	**Total Benefits ($ million)**	$9.58	$21.36
@ 2.5% equity ownership/6 years post construction	**Per capita ($)**	$1,509	$3,363

Under the Agreement, investment income can be used for such measures as support for the viability of resource harvesting, cultural and social development, business and employment development, construction, infrastructure, and housing.[433]

In addition, with this employment growth and these business opportunities, Keeyask Cree Nations members should have incomes to spend on goods and services. Construction workers will increase demand for all goods and services in the Keeyask Cree Nations. This may lead to further employment and spending, which could drive business growth.

The Panel learned that these effects would also see economic benefits for northern Manitoba communities, especially Gillam and Thompson. Other economic benefits would come from increased housing construction, local roads, or water infrastructure, especially in the Keeyask Cree Nation communities.

In closing arguments, the Panel heard of the efforts underway to create joint ventures as the communities prepare to capitalize on these economic and business opportunities. Counsel for the partners argued forcefully that these cannot be delayed or

[432] Exhibit CAC-85-1, p. 2.
[433] Exhibit PUB-69, p.100.

postponed with the expectation that they can be easily restarted later should there be a delay in developing Keeyask.[434]

11.4.4. Impacts on Communities, Culture, and Health

It is the nature of large hydropower projects to fundamentally alter the social and economic landscape of the local region. An initial period of construction, involving employment and other economic opportunities, may be followed by decades of adverse community, cultural, social, and health consequences.

Habitat Health Impact Consulting examined the health issues faced by northern Manitoba communities. Population health outcomes in the Burntwood Regional Health Authority (where over two-thirds of the residents are aboriginal), rank poorly when compared to Manitoba averages: pre-term births are greater; life expectancy is lower; mortality is higher; the rates of asthma, arthritis, diabetes, obesity, and heart disease are all higher; injuries are more common; and mental health issues are found in greater numbers.

These problems are likely to grow given the boom-and-bust nature of the hydroelectric investment projects. The period of construction creates social, economic, and cultural stress through the rapid influx of outside workers, rising living costs, and housing pressures. After the construction ends, problems of adjustment may continue for years as incomes are lost, and traditional diets and ways-of-life have been altered. These pressures imposed on communities occur in a region with an already inadequate and challenged health care system.[435]

In its filing, Manitoba Hydro recognized the potential for a wide range of community impacts, from pressures on housing, health services, and social programs to adverse impacts on traditional hunting, trapping, and fishing ways of life. For these reasons, it has worked with the KCNs to develop plans, strategies, and programs to address public safety and worker interactions, heritage resources, traditional ways-of-life, and community health.

In its Preferred Development Plan, Manitoba Hydro has undertaken to put into place a community impact and risk mitigation strategy. Under Adverse Effect Agreements, each KCN is responsible for managing, implementing and operating adverse effects programs. The Agreements include funding and compensation measures. The Adverse Effects Agreements include offsetting programs that encompass a wide range of

[434] Exhibit MH-204, p. 3-4.
[435] Exhibit CAC- 47, pp. 3-4.

projects and initiatives, such as transportation to access off-system lakes and rivers to fish; cultural sustainability efforts to support learning of the Cree language and culture; an alternative justice program; funding for a crisis centre and wellness counseling program; and support for a traditional lifestyle experience, and traditional knowledge learning programs.[436] Interveners in the NFAT hearings supported these efforts so long as there was effective monitoring and support for their implementation and success.

Several parties to the hearing were critical about benefits flowing only to the KCNs, leaving out other aboriginal groups. It was noted that the KCNs only make up 20% of northern affected aboriginal people. The Manitoba Métis Federation noted that there is no benefit sharing with the Métis.[437] Dr. Buckland and Dr. O'Gorman urged the Panel to support efforts to extend the benefit sharing to others.[438]

11.5.0 Multiple Account Benefit-Cost Analysis

Manitoba Hydro undertook a Multiple Account Benefit Cost Analysis (MA-BCA) to determine the net benefits accruing to different stakeholders (accounts), including Manitoba Hydro, the Government of Manitoba, ratepayers, aboriginal communities and the Manitoba economy in general.[439] In addition, the net environmental effects were considered. Where such costs and benefits could be expressed in monetary terms, the sum of each individual account provides the net benefits from a total or societal perspective.

The MA-BCA analysis was limited to a comparison of the Preferred Development Plan to three other plans: Plan 1/All Gas; Plan 2/K22/Gas; and Plan 4/K19/Gas24/250MW. It is summarized in the following Table.[440]

436 Exhibit MH-145. See also Transcript, p. 3892.
437 Exhibit MMF-16, pp. 4-5.
438 Exhibit CAC-48, p. 63.
439 Manitoba Hydro NFAT Submission, Chapter 13 (Updated), pp. 1-74.
440 Manitoba Hydro NFAT Submission, Chapter 13 (Updated), p. 67.

Table 39 Manitoba Hydro Multiple Account Benefit-Cost Analysis Summary

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Market Valuation Net revenues (cost) to MH and partners	--	17.0	(270.5)	(654.1)
Customer Account Cumulative rate increase	Preferred Development Plan has highest rate increases in first 20 years (cumulatively 16 to 18 percentage points more than the alternative plans) but has lowest rate increases over long term (cumulatively by year 50 approximately 34 to 37 percentage points less than the two alternatives with Keeyask G.S. and 70 percentage points less than the all gas plan).			
Reliability	Preferred Development Plan and to lesser extent the alternative with the smaller interconnection provides greater load carrying capability, lower expected loss of unserved energy and greater ability to manage extreme drought			
Government Incremental revenues net of costs/risk	--	(353.5)	(395.9)	(674.2)
Manitoba Economy Employment net benefits	--	(100.7)	(120.1)	(192.7)
Environment Manitoba GHG external cost	--	(208.6)	(174.3)	(320.3)
Global GHG impact	Preferred Development Plan and to lesser extent the two plans with Keeyask G.S. would contribute to a reduction in global emissions by displacing thermal generation in US.			
Manitoba CAC damage cost	--	(8.6)	(7.1)	(13.3)
Residual biophysical	Aquatic and terrestrial impacts with hydro projects in Preferred Development Plan and plans with Keeyask G.S.; subject to detailed environmental hearings, residual effects and local external cost expected to be relatively small with initial design, extensive mitigation, monitoring, compensation and benefit-sharing arrangements.			
Social Partner net return	Significant net returns from up to 25% interest in Keeyask G.S. and income benefits from Conawapa G.S. in Preferred Development Plan; significant benefits from up to 25% interest in two alternatives with Keeyask G.S., greater with new sales and interconnection.			
Community impacts	Wide range of potential impacts on local employment and business; population, infrastructure and service; social and community well-being; owners of land needed for rights of way and easements; major commitments and plans to minimize adverse residual effects with extensive mitigation, monitoring, compensation and partnership arrangements.			
Other Manitoba	Potentially significant bequest value from the hydro assets remaining at end of planning period; greatest with Preferred Development Plan and to a lesser extent in the alternatives with Keeyask G.S.			
Overall Monetized Net Benefit (Cost)	--	(654.4)	(967.5)	(1,854.6)

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS OF 2014$)

11.6.0 Government of Manitoba Benefits

Manitoba Hydro in the course of its operations pays to the Government of Manitoba fees and taxes, which currently total $262 million annually representing 16% of Manitoba Hydro's revenues. Payments to the Province are forecast to double to $516 million by 2032. These charges include water rental fees, payroll and capital taxes, a provincial debt guarantee fee of 1% on Manitoba Hydro's outstanding debt as well as a sinking fund administration fee. Manitoba Hydro also makes Municipal Grants in Lieu of Taxes (GILTs), which total $22 million and are forecast to grow to $35 million by 2032.[441]

Morrison Park estimated the Net Present Value of future payments to the Province for different plans based on 2013 planning assumptions. The estimates were provided at a 6% discount rate, a 3% discount rate (which approximates the provincial government's own cost of borrowing), and in nominal dollars.[442]

Table 40 Morrison Park – Average Present Value of Revenue to the Province of Manitoba

Average Present Value of Revenue to the Province of Manitoba
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015-2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Revenue						
NPV @ 6.00%						
Water Rental	$1,606	$1,669	$1,768	$1,771	$1,769	$1,887
Capital Tax	$1,510	$1,756	$1,830	$1,856	$1,855	$2,247
subtotal	*$3,116*	*$3,425*	*$3,599*	*$3,627*	*$3,623*	*$4,133*
Debt Guarantee Fee	$2,370	$2,692	$2,838	$2,918	$2,908	$3,486
Total	*$5,486*	*$6,117*	*$6,437*	*$6,545*	*$6,531*	*$7,619*
NPV @ 3.00%						
Water Rental	$2,628	$2,780	$2,928	$2,931	$2,928	$3,207
Capital Tax	$2,635	$3,147	$3,166	$3,209	$3,207	$4,021
subtotal	*$5,263*	*$5,927*	*$6,094*	*$6,139*	*$6,135*	*$7,228*
Debt Guarantee Fee	$3,987	$4,642	$4,565	$4,701	$4,671	$5,646
Total	*$9,250*	*$10,569*	*$10,659*	*$10,840*	*$10,807*	*$12,874*
Nominal Dollars						
Water Rental	$5,103	$5,506	$5,745	$5,749	$5,744	$6,472
Capital Tax	$5,490	$6,679	$6,494	$6,572	$6,573	$8,440
Subtotal	*$10,593*	*$12,185*	*$12,239*	*$12,320*	*$12,317*	*$14,912*
Debt Guarantee Fee	$7,998	$9,430	$8,561	$8,813	$8,727	$10,278
Total	*$18,591*	*$21,615*	*$20,800*	*$21,133*	*$21,045*	*$25,190*

[441] PUB/MH 1-073a.
[442] Exhibit MPA-3-1, p. 38.

Manitoba Hydro, La Capra and Morrison Park identified that not all of these payments constitute net benefits or incremental revenues to the Government of Manitoba. While the debt guarantee fees are substantial, the amount of debt that government would be guaranteeing is also significant. Given that the provincial debt guarantee fee is provided in exchange for this guarantee, it could be considered a fee for service rather than a net benefit to the Manitoba government.

According to Morrison Park's analysis above, the incremental Net Present Value of water rentals and capital taxes to the Province of Plan 5 (K19/750MW) compared the All Gas Plan is approximately $876 million. Morrison Park also noted that the Preferred Development Plan provides the Province of Manitoba with the most revenue under all scenarios: across each revenue source individually, in total, and regardless of the discount rate calculation. This should be expected since the Preferred Development Plan uses the most water, the most capital, and the most debt of all the Plans.[443]

The benefits of additional revenue from Manitoba Hydro must be balanced against the higher costs to ratepayers that result from the Preferred Development Plan. It must also be balanced against the potential economic drag that may result from those higher rates (higher costs for a staple such as electricity is roughly the equivalent of a reduction in disposable income for individuals and businesses, which could result in lower tax revenue to the Government from sources other than Manitoba Hydro).[444] MIPUG, in its closing submission, agreed with this analysis.[445]

The nature and extent of benefits to the Government of Manitoba drew the attention of MIPUG. In MIPUG's view, the benefits from the Preferred Development Plan and other opportunity-based, export focused plans were "extraordinary." Mr. Turner, who provided a presentation on behalf of MIPUG, indicated that Industry would be paying $400 million more in rates over the next 20 years for the Preferred Development Plan compared to viable alternatives. He stated that this amount would not be available for Manitoba companies to invest in expansion, employees, community support, and other actions that would help the companies' competitiveness.[446]

11.7.0 Conclusions of the Panel

The Preferred Development Plan provides significant socio-economic benefits to the province, though not as high as originally stated. Manitoba Hydro initially assumed that Manitobans would fill 70% of construction jobs; however, in February 2014, Manitoba

[443] Exhibit MPA 3-1, pp. 28-29.
[444] Exhibit MPA 3-1, p. 28.
[445] Exhibit MIPUG-28, p. 5. See also Transcript, pp. 7529-7530.
[446] Transcript, p. 7208.

Hydro revised this figure down to 45%. The limited analysis undertaken by Manitoba Hydro of other Development Plans supports the view that the socio-economic benefits of hydro-based plans compare favourably with those based primarily on natural-gas thermal generation, largely due to the scale of the construction expenditures involved.

At this point in time, the Keeyask Project is associated with tangible socio-economic benefits that have been assured through the Joint Keeyask Development Agreement, already executed directly negotiated contracts, and a significant training effort that has been undertaken to date. While there will be some adverse effects in the communities, the Adverse Effects Agreements negotiated between each Keeyask Cree Nation and Manitoba Hydro largely address such effects. The Panel concludes that plans involving the Keeyask Project have higher benefits than plans in which Keeyask is not included. In contrast, Conawapa benefits are primarily speculative, as no agreements have been negotiated.

From an employment perspective, there is a legitimate concern that employment is subject to the cyclical nature of construction work. Compared to fossil-fueled generation, hydroelectric dams require fewer operating personnel. However, the overall benefits associated with the Keeyask Project significantly exceed the benefits of an All Gas Plan, and are to a large extent directed to northern Manitoba, in particular to affected First Nations communities. This is clear from the fact that despite dissenting voices in the community, the Keeyask Cree Nations have unequivocally stated that they support Keeyask being built.

The Panel is concerned that the full value of the socio-economic benefits of construction of Keeyask will not be realized without due attention to long-term training and further skills development for local workers, especially First Nations. Manitoba Hydro, together with the Keeyask Cree Nations, should facilitate ongoing professional development opportunities even after Keeyask construction has been completed.

The Panel is also of the view that Demand Side Management has the potential to provide significant employment benefits, which were not analyzed in the course of the NFAT Review. Chapter 5 notes the employment potential of DSM. DSM can and will play an important role in the creation of jobs in the future.

The Panel notes that under all scenarios, the Province of Manitoba will realize significant benefits from the development of the Keeyask Project through water rental fees and capital tax payments as further discussed in Chapter 8. The Government of Manitoba could use a portion of the incremental capital tax and water rental fees from the development of the Keeyask Project to mitigate the impact of rate increases on lower income, northern and aboriginal communities.

12.0.0 Macro Environmental Considerations

12.1.0 Introduction

The Panel examined the risks and benefits associated with the Preferred Development Plan and its alternatives from a "macro environmental perspective."[447] While this term was not defined, the Panel assessed the Plan from a broad comparative perspective, including Greenhouse Gas (GHG) and the impact on select valued ecosystem components (VECs). Since the Panel was specifically directed not to duplicate the environmental impact assessment for Keeyask recently completed by the Clean Environment Commission (CEC), the NFAT environmental review took place at a higher level than would be expected for an environmental review. The Panel was further directed not to consider historic environmental costs.[448]

12.2.0 Background and Context

12.2.1. Defining the Term "Macro Environmental"

The Panel consulted with Manitoba Hydro and the Interveners, and decided on the following definition to guide its work:

> *"A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, land, water, flora, and fauna, including the potential significance of these changes, and their equitable distribution within and between present and future generations."*[449]

12.2.2. The Environmental Regulatory Process

It is important to understand the overall regulatory process given that there have been two reviews of the Keeyask Project: the recently completed environmental assessment hearing by the Manitoba Clean Environment Commission (CEC) and the comprehensive study by the Canadian Environmental Assessment Agency (CEAA). The Panel expects that both of the agencies heard significantly more detailed evidence on the environmental effects of Keeyask than the Panel did, and thus defers to the findings of these agencies on several environmental issues.

[447] Exhibit PUB-2, p. 3.
[448] Exhibit PUB-2, pp. 7-8.
[449] Exhibit PUB-10, p. 12.

Since no environmental assessment process has taken place with respect to Conawapa to date, the Panel's evidence as to the macro environmental effects of Conawapa is limited. While the greenhouse gas (GHG) implications of Conawapa were well developed in the evidence, impacts on valued environmental components (as described below) were not.

Canadian Environmental Assessment Agency Report on the Keeyask Project

The Canadian Environmental Assessment Agency completed its work and issued its report with respect to the Keeyask Project in April 2013.[450] The Agency concluded the Keeyask Project is not likely to cause significant adverse environmental effects when its proposed mitigation measures were put into place.[451] It recommended a follow-up program should be established to verify the accuracy of the environmental assessment and to determine the effectiveness of the proposed mitigation measures. This follow-up program will focus on country foods and human health, fresh-water fish and fish habitat, water resources, birds and wildlife, wetlands, rare plants, and archaeological and heritage resources.

Manitoba Clean Environment Commission Report on the Keeyask Project

The Manitoba Clean Environment Commission has recently completed its public hearings and issued its report on the Keeyask Project.[452] After considering its evidence, the Commission recommended that the Keeyask Project be approved for a license with certain conditions.[453] These conditions included finding specific ways of mitigating impacts on the environment, including reducing the level of disturbance or replacing habitat. Other recommendations focused on the need for additional monitoring so that adverse effects can be identified and environmental management measures developed. The Commission's report has the status of an advisory document to the provincial government. Accordingly, discretion will lie with the provincial government as to whether to incorporate these suggestions if it decides to issue an environmental permit with respect to Keeyask.

In its report, the Commission has also made several non-licensing recommendations to the Province of Manitoba, including that the Province provide guidelines for cumulative effects assessment best practices and include specific direction for proponents in

[450] Exhibit PUB-70.
[451] Exhibit PUB- 70, pp. iii-iv.
[452] Exhibit PUB-69.
[453] Exhibit PUB-69, pp. 165-167.

project guidelines. The Commission also noted that a regional cumulative effects assessment is currently being prepared and is expected to be released in 2015.

12.3.0 Manitoba Hydro's Environmental Assessment Approach

In lieu of providing an actual environmental impact assessment in the NFAT process, Manitoba Hydro provided a comparative overview of environmental effects through a Multiple Accounts – Benefits/Cost Analysis (MA-BCA), as well as a matrix comparison between different technologies.

12.3.1. Environment Account of Multiple Account Benefit/Cost Analysis

Manitoba Hydro evaluated its planning options using a multiple account benefit cost analysis (MA-BCA). In their filing, Manitoba Hydro addressed the consequences of the different plans though an "environment account." This account attempted to provide a monetized social benefit of avoided greenhouse gas emissions, along with air contaminant and biophysical effects associated with the construction and operation of the projects in the different plans.[454] Manitoba Hydro concluded that the Preferred Development Plan has the lowest overall social cost of GHG emissions at $150.2 million, compared to $470.5 million for the All Gas Plan and $358.8 million for a plan involving Keeyask and a 250 MW interconnection.[455] Manitoba Hydro did not provide a separate analysis for a plan involving only Keeyask and a 750 MW interconnection.

12.3.2. Matrix Comparison of Different Technologies

In addition to being analyzed as one of the accounts in the MA-BCA framework, Manitoba Hydro provided a matrix analysis focused on specific Valued Ecosystem Components (VECs) and compared these VECs across different technologies.[456] The concept of a VEC forms part of the federal environmental assessment regime and was also applied in the environmental impact statement that formed the basis of the CEC's hearing into Keeyask.

The NFAT Panel heard evidence with respect to certain key VECs, which are described in greater detail below.

[454] Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 47.
[455] Exhibit MH-185 p. 2.
[456] CAC/MH 231(a).

12.4.0 Climate Change: Greenhouse Gases and Air Pollutants

12.4.1. Introduction

Manitoba Hydro's status as an exporter of hydroelectricity means that Manitoba Hydro's hydro-electric generation has GHG implications not only in Manitoba, but also in the United States. The MISO market into which Manitoba Hydro exports relies, to a large extent, on coal and gas generation, which means that exports from Manitoba have the potential to displace GHG emissions in MISO.[457] Conversely, night-time imports from MISO can increase GHG emissions.

12.4.2. Assessment by Resource Option

To compare the relative GHG emissions of the Keeyask and Conawapa Projects, six comparison generation technologies were researched: supercritical pulverized coal combustion, coal with carbon capture and storage, natural gas-fired combined cycle, natural gas-fired simple cycle combustion turbines, wind and nuclear.[458]

Keeyask and Conawapa Project Life Cycle GHG Results

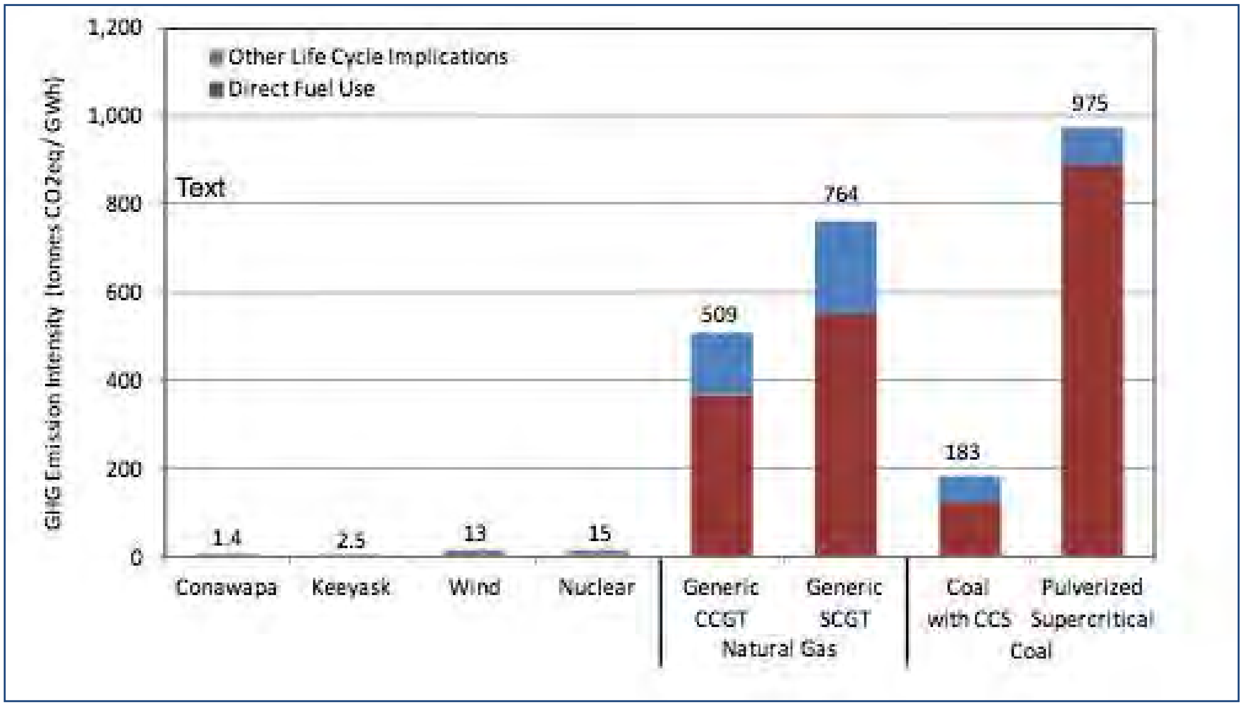
Over a 100-year life, the Keeyask Project is estimated to produce approximately 980,000 tonnes of CO_2 equivalent. Of this amount, GHG emissions associated with the construction phase of the project account for approximately 46% of life-cycle GHG emissions.[459] The Conawapa Project is estimated to produce approximately 900,000 tonnes of CO_2 equivalent with 86% of that amount related to construction.[460]

Comparison with Other Power Generation Technologies

As shown in the Figure below, lifetime GHG emissions for the two proposed hydro projects are significantly lower than for alternative technologies:[461]

[457] Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 67.
[458] Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 4.
[459] Manitoba Hydro NFAT Submission, Appendix 7.3, pp. 7-8.
[460] Manitoba Hydro NFAT Submission, Appendix 7.3, p. 9.
[461] Manitoba Hydro NFAT Submission, Appendix 7.3, p.12.

Figure 25 Comparison of Life Cycle Greenhouse Gas Emissions for Different Sources of Electricity



This is further borne out by an examination of the intensity-based GHG emissions for different technologies. The All Gas Plan would create 28.4 tonnes of CO_2e/GWh, compared to 13.1 tonnes of CO_2 equivalent/GWh for the Keeyask/Gas/750 plan and 5.5 tonnes of CO_2e/GWh for the Preferred Development Plan.[462] In terms of generating technologies, only wind and nuclear technology are competitive with hydroelectricity.

Unfortunately, no separate GHG emissions analysis was provided for Demand Side Management (DSM). However, it stands to reason that avoided generation would be at least as favourable as hydroelectric generation.

Greenhouse Gas Displacement

The energy produced by Keeyask and Conawapa Projects (less transmission losses) will displace a variety of fossil-fuelled generation in the interconnected U.S. export markets. Manitoba Hydro's analysis of the electricity market estimates the avoided GHG emissions due to energy being injected into the regional energy markets from Manitoba. Conventional coal generation is typically in the order of 900 to 1,100 tonnes CO_2 e/GWh, while natural gas can range from about 300 to 800 tonnes CO_2e/GWh

[462] Exhibit MH-148, p. 2.

depending on the specific technology and its efficiency.[463] Combined-cycle gas turbines (CCGT) tend to be significantly more efficient than simple cycle gas turbines (SCGT).[464]

Manitoba Hydro currently assumes that its net exports displace 750 tonnes CO_2 equivalent/GWh.[465] This reflects a marginal generation mix of various fossil fuels and technologies. Given that the current marginal generation, other than in peak periods, remains primarily coal; the 750 tonnes of CO_2 equivalent/GWh factor used by Manitoba Hydro is considered to underestimate the emissions displaced by exports. The net positive effect of the Keeyask and Conawapa Projects on climate change reflects the small life cycle GHG emissions of the proposed projects versus the much more significant emission reductions that will result from the displacement of high GHG intensity sources of generation.[466] MNP determined the following displacement potential:[467]

Table 41 Cumulative Greenhouse Gas Emissions and Cumulative Greenhouse Gas Displacement Potential of Alternative Development Plans

MNP LLP

Selected Plans' Air Impacts

Air Impacts*	Preferred Plan #14: K19/C25/ 750MW (WPS Sale & Investment)	Plan #1: All Gas	Plan #4: K19/Gas24/ 250MW	Plan #5: K19/Gas25/ 750MW (WPS Sale & Investment)	Plan #7: SGCT/C26
Cumulative GHG Operating Emissions	7.5 Mt CO2e	33.2 Mt CO2e	25.4 Mt CO2e	16.3 Mt CO2e	13.0 Mt CO2e
Cumulative Regional GHG Displacement Potential	191.6 Mt CO2e	22.5 Mt CO2e	107.7 Mt CO2e	94.4 Mt CO2e	102.1 Mt CO2e

**All values were taken from MH NFAT filing, Appendix 9.1 – High Level Development Plan Comparison Table*

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[463] Manitoba Hydro NFAT Submission, Appendix 7.3, p. 12.
[464] Manitoba Hydro NFAT Submission, Appendix 7.2, p. 6.
[465] Manitoba Hydro NFAT Submission, Appendix 7.2, p. 12.
[466] Manitoba Hydro NFAT Submission, Appendix 7.3, pp. 12-13.
[467] Exhibit MNP-8, p. 14.

12.5.0 Comparing Environmental Effects for Competing Technologies

12.5.1. Introduction

As part of its review, the Panel received evidence regarding the high-level impacts to be expected from different technologies. These are summarized in this section.

12.5.2. Hydropower Generation

While large hydropower projects can have significant global GHG benefits, they can also have a profound environmental impact on the land and water. Localized impacts include flooding, shoreline erosion and water quality impacts. In the context of a heavily developed river system like the Lower Nelson, the cumulative impacts must be considered together with the incremental impacts of a new dam.

Keeyask Project

The Keeyask Project will require about 125 km^2 of land in the boreal forest, of which 50 km^2 will be land that is flooded for the reservoir and dam.[468] This ecosystem and its water regime have already been altered considerably by previous hydroelectric developments and are therefore vulnerable to further change.[469]

According to Manitoba Hydro's NFAT Submission, the water regime changes include flooding and increased water levels at Keeyask downstream of Lake Winnipeg on the Upper Nelson River. The reservoir will stretch from the generating station approximately 93 km^2 in area and it will extend 42 km upstream to the outlet of Clark Lake. The reservoir will consist of approximately 48 km^2 of existing waterways, 45 km^2 of newly submerged lands and 264 km of shoreline.[470] Water quality in the newly flooded areas with be affected during the initial 10 to 15 years, but impacts are expected to diminish thereafter.[471]

In their report, MNP noted the following impacts: complete loss of Gull Rapids; slower, deeper water through Gull Lake, Birthday Rapids, and as far upstream as the outlet of Clark Lake; changes in erosion patterns and water quality downstream of Keeyask, but not upstream in Split Lake; and flooding of several Caribou calving islands in Gull Lake.[472]

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[468] CAC/MH I-231(a), p. 8.
[469] Exhibit MNP-6, p. 37.
[470] Exhibit MNP-6, p. 37.
[471] CAC/MH I-232(a), p 10.
[472] Exhibit MNP-6, pp. 39-40.

Conawapa Project

Preliminary information exists on the water impacts associated with the Conawapa Project. It will require over 20 km^2 of land, of which 10 km^2 is needed for construction and only 5 km^2 will be flooded for reservoir requirements.[473] Since no environmental impact statement has been prepared for Conawapa to date, the environmental impacts of Conawapa are significantly less well known than those of Keeyask. Similarly, any potential changes to the overall water flow regime and regulation of Lake Winnipeg to maximize exports have not been examined in detail.

Hydropower Mitigation Strategies

Manitoba Hydro plans to mitigate, manage and monitor environmental effects, primarily for the Keeyask Project. This includes environmental protection, management and monitoring plans. The program will cover erosion control from the shoreline, roads, stream crossings, earth dams and dykes, and will guide compliance with relevant legislation.[474]

In their review, MNP advised the Panel that these measures are "commensurate with expectations of a project this size. There is always risk that mitigation features are not as effective as expected, but we do not believe that Manitoba Hydro is missing any important elements in their mitigation strategies."[475] MNP's report was filed prior to the CEC releasing its report.

12.5.3. Natural Gas Thermal Generation

While GHG emissions from gas-fired power plants are less than emissions from coal-fired power plants, they are still significant, and the CEC noted that a comparably sized natural gas plant would produce as much greenhouse gas in 177 days as the Keeyask Generation Project will produce in 100 years.[476] Concerns over the impact of hydraulic fracturing and the considerable risks it poses to potable water supplies and human health as well as its significant contribution to global warming, must also be considered.[477]

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[473] CAC/MH I-232(a), p. 8.
[474] Exhibit MNP-6, p. 45.
[475] Exhibit MNP-6, p. 47.
[476] Exhibit PUB-69, p. 61.
[477] Exhibit CAC-29, p.22.

12.5.4. Wind Power

According to CAC's expert witness Dr. Gunn, much of the research on the environmental impacts of wind energy production has focused on the potential adverse effects of multiple rotor blades on birds and landscapes. Other studies suggest that no serious unusual interference with wildlife is associated with wind energy development. Aside from those associated with equipment production, wind energy CO_2 emissions are extremely low. Human health impacts include visual disturbance and shadow flicker.[478]

12.5.5. Solar Photovoltaic Power

There are two types of solar photovoltaic generation technologies – roof-based and ground-based. While GHG-emissions are created upon production, emissions are extremely low during the operating phase. However, while roof-based systems require little landmass, ground-based solar farms can have significant land requirements.[479]

12.5.6. Demand Side Management

Reducing energy consumption has obvious environment benefits, relative to new generation construction and development. The concept of Demand Side Management is not new and has been applied for decades not only to energy supplies but also to other public utilities such as water and gas. By reducing the need for new generation, Demand Side Management has the potential to avoid the adverse effects of other technologies. However, the environmental impact of DSM is dependent on the specific measure used.[480]

12.6.0 Valued Ecosystem Components (VECs)

12.6.1. Introduction and Scope

The Canadian Environmental Assessment Agency defines Valued Ecosystem Components (VECs) as environmental elements of the ecosystem that are identified as having unique, scientific, social, cultural economic and aesthetic importance. In the environmental impact statement filed before the CEC, a total of 38 VECs were discussed.[481]

Aside from GHGs, which are discussed above, the analysis before the NFAT Panel focused on three key VECs, namely lake sturgeon, caribou, and public health and

[478] Exhibit CAC-29, pp. 26-27.
[479] Exhibit CAC-29, pp.31-32.
[480] Exhibit CAC-29, pp. 34-36.
[481] Exhibit PUB-69, p. xv.

community safety. The Panel notes that virtually all of the evidence it heard with respect to specific VECs related to the Keeyask Project, with little information being provided as to the environmental effects of the Conawapa Project, other than high-level evidence with respect to GHG and flooding impacts.

12.6.2. Lake Sturgeon

Lake sturgeon are a culturally and spiritually important species to the Cree. Lake sturgeon are a Manitoba heritage species and have been designed as endangered by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC).[482] The federal government is also currently considering whether to list lake sturgeon as an endangered species under the *Species at Risk Act* (SARA).[483] In addition, lake sturgeon are particularly vulnerable due to a number of unique characteristics: they have a late sexual maturity, infrequent spawning patterns, slow to maturity growth rates, and 60-year plus longevity.[484] Manitoba Hydro identified lake sturgeon as the number one regulatory risk with respect to the Keeyask Project.[485]

In its filing, Manitoba Hydro notes that the Keeyask Project will affect sturgeon spawning habitat. In assessing the potential impacts, MNP determined that a number of the anticipated impacts have the potential for significant, adverse effects. Construction will impede fish migration and affect spawning. Sturgeon require a large turbulent rapids habitat. Construction will result in the permanent loss of Gull Rapids. Fish movement will be altered as a result of the presence of the generating station and increased access might encourage more fishing and overharvesting.[486]

To mitigate these effects, Manitoba Hydro indicated that the Keeyask Partnership will develop new sturgeon habitat; undertake an experimental, up-stream fish passage study; install turbines that enable a large percentage of fish to successfully pass downstream; and implement a regional sturgeon stocking program.[487] The Panel heard concerns that stocking programs have not been proven effective at hydroelectric projects; habitat required to fulfill life cycles may not be available; and large sturgeon may not be able to move past the generating station.[488]

MNP examined plans to install a temporary, experimental catch and transport system and conduct studies of fish habitat and behavior. While they concluded that this was a

[482] Transcript, p. 3870.
[483] Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 54.
[484] Exhibit MNP-6, p. 56.
[485] Transcript, p. 3869.
[486] Exhibit MNP-6, pp. 56-57.
[487] CAC/MH I-231(a), p. 13.
[488] CAC/MH I-231(a), p. 14.

"sensible approach," there is equally the cost to build and operate it.[489] Other testimony and the findings of the Clean Environment Commission questioned this approach. The CEC and CEAA environmental reports into the Keeyask Project both concluded that a permanent fish passage was not necessary. The Panel notes that, the Clean Environment Commission expressed its concerns about the mitigation strategies, and recommended that the Keeyask Partnership stock lake sturgeon for at least 50 years.[490]

The Panel notes that there remains a risk to lake sturgeon, and that the CEC recommendations will impose ongoing operational costs if imposed, as a term of Manitoba Hydro's environmental licence for Keeyask.

12.6.3. Caribou

Caribou are important to the northern ecology and to northern aboriginal people. Boreal woodland caribou are protected under the federal *Species at Risk Act (SARA)* and *The Endangered Species Act* (Manitoba). Some local Cree identify woodland caribou in the Keeyask region, but federal and provincial regulators have not determined that the caribou resident in the area are protected boreal woodland caribou.[491]

In their filing, Manitoba Hydro has identified a number of potential impacts on caribou. They include the habitat losses and fragmentation, increased predator access, and sensory disturbances from heavy machinery and construction activities. Among strategies identified to mitigate these potential effects, Manitoba Hydro and Keeyask Partnership have listed adjusted roads, borrow areas and excavated placement areas to avoid sensitive caribou habitat; limits of some construction activities such as blasting to the extent practicable during the calving season; and blocking access trails once they are no longer required (i.e., post-construction). New calving habitat is also expected to be created on new islands in the new reservoir.[492]

In their analysis, MNP determined that these impacts had a medium to low consequence: construction will not lead to a reduction of food sources; increased predator and hunters' access will be a concern; there will be minimal loss of habitat for calving; and caribou are shown not to abandon habitat.[493]

In their report, the Clean Environment Commission came to the conclusion that additional research was required given insufficient data on woodland caribou

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[489] Exhibit MNP-6, p. 64.
[490] Exhibit PUB-69, p. 78.
[491] CAC/MH I-231(a), p. 14.
[492] CAC/MH I-231(a), pp. 13-15.
[493] Exhibit MNP-6, pp. 49-50.

populations and recommended that a three- to five-year telemetry study be put into place.[494]

12.6.4. Mercury

Methyl mercury exposure and contamination of fish can be caused by mineral bank erosion and peat land disintegration.[495] Since mercury bio-accumulates in fish, this can cause a health risk from eating fish caught in the Nelson River. Predictions are that the maximum mean mercury concentrations for lake whitefish, northern pike, and walleye from the Keeyask reservoir and Stephens Lake could be reached within three to seven years post-construction, and return to pre-project levels at least 30 years post-impoundment.[496]

In its report, the Clean Environment Commission noted that this is an understandable concern, but concluded that methyl mercury would be a temporary effect that would occur over two to three decades. The Commission recommended continued monitoring.[497]

12.7.0 Adverse Effects Agreements

To compensate for any residual effects not addressed through mitigation, Manitoba Hydro negotiated adverse effects agreements with each of the Keeyask Cree Nations. Pursuant to these agreements, Manitoba Hydro provides a series of "offsetting programs" in each of the communities, as well as a residual monetary payment. The offsetting programs are primarily cultural in nature, such as the provision of gathering centres and counselling programs, but also include a healthy food fish program in each community, which facilitates access to fish not affected by increased mercury levels in the Nelson River.[498] The residual monetary payments provide ongoing payments for the duration of the Keeyask project in the case of three of the communities, and payments until 2025 for the fourth.[499]

12.8.0 Need for Regional Cumulative Environmental Assessment

In the course of conducting the NFAT Review, the Panel heard from several affected communities who commented on the effect of past hydroelectric developments on their lives. In addition, Dr. Gunn, who appeared on behalf of CAC, testified that a macro

[494] Exhibit PUB-69, p. 96.
[495] Exhibit MNP-6, p. 69.
[496] Exhibit MNP 6, pp. 69-70.
[497] Exhibit PUB-69, pp. 112-113.
[498] Exhibit MH-145.
[499] Exhibit PUB-58-5, Tab 9.

environmental review should be cumulative in nature. This means that it should consider not merely the incremental effect of one project, but the collective effect of the project when added to impacts that have already happened.[500]

The Panel notes that the CEC recommended a regional cumulative effects assessment for the area in its report into the Bipole III project, and commented in its report on the Keeyask Project that it expected such an assessment to be available by 2015, yet did not recommend withholding a licence for the Keeyask Project pending the availability of the document. The NFAT Panel supports the preparation of a regional Cumulative Effects Assessment and is heartened by the fact that on May 27, 2014, the Province and Manitoba Hydro agreed to Terms of Reference for a regional Cumulative Effects Assessment of hydro-electric developments that includes the Nelson, Burntwood, and Churchill River systems.

12.9.0 Conclusions of the Panel

In the Panel's view, all plans presented by Manitoba Hydro will have an impact on the local, regional and global environment. To some extent, such effects can be avoided through a focus on demand reduction through DSM efforts that avoid the need for new generation sources being constructed. However, if one accepts that new generation will be required in Manitoba within the next decade, DSM does not represent a freestanding solution.

Hydroelectricity emits minimal greenhouse gases and does not rely on fossil fuels. While wind and solar power are environmentally friendly technologies with similarly low GHG emissions, they are intermittent power sources that do not provide capacity and as such must be backed by either hydroelectricity or gas-fired generation.

These alternative generation options should be analyzed further as part of any future integrated resource plan, to assess their economics and study how they could be integrated into Manitoba Hydro's system. Manitoba Hydro expended substantial efforts to mitigate adverse environmental effects from Keeyask. The Panel received little substantive evidence on efforts to mitigate the impact of Conawapa, which has yet to be subject to environmental proceedings.

Overall, the Panel is of the view that while a plan involving Keeyask is environmentally favourable from an avoided GHG emissions basis, Keeyask creates an ongoing risk to lake sturgeon and will have a significant effect on its sustainability on the Nelson River. Nonetheless, the effects have been mitigated to the extent possible and have been

[500] Exhibit CAC-29, p. 12.

found to be acceptable by the Clean Environment Commission and the most affected First Nations.

To that extent, the Panel concurs with the Clean Environment Commission that a regional cumulative effects assessment for the area is required to determine the cumulative effects of hydroelectric developments to date. To date, insufficient information has been collected and better assessment methods are needed.

In addition, the Panel support the actions now needed as a result of the Clean Environment Commission recommendations. In particular, it notes the importance of the CEC's findings with regard to caribou and lake sturgeon.

13.0.0 The Commercial Perspective

13.1.0 Introduction

The Preferred Development Plan and suggested alternative development plans bring together all of the costs, risks and benefits that affect stakeholders such as ratepayers, the Government of Manitoba, Manitoba taxpayers, First Nations commercial partners and others. The Panel considered Manitoba Hydro's Plans from a number of perspectives, including financial, socio-economic and environmental. It assessed the costs of construction and the realities of expenditures and anticipated revenues.

In this chapter, the Panel considers the Preferred Development Plan and the alternatives from a commercial perspective. The Panel treats the Plan and alternatives as investments, and ratepayers as shareholders. In fact and as Morrison Park told the Panel, Manitoba ratepayers are in a disadvantaged position. They have no certainty in advance. They cannot choose another supplier of electricity, and they must shoulder the risk burden.[501]

13.2.0 The "Positional View"

In their analysis of Manitoba Hydro's plans, Morrison Park briefed the Panel on the realities of its "positional view." In many regards, the Panel and the NFAT Review was caught between decisions and actions already taken and the uncertainty of a long-term planning horizon. Uncertainties underlay many of the projections and forecasts, and they extend out not only years, but also many decades.

In this regard, the analytical tools and planning methods can be a limiting factor. The search for precision can disguise the reality that such tools are often based on assumptions that fail to consider future possibilities. In this context, the Panel was persuaded by the guidance provided by Morrison Park when they stated:

> *There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.*

[501] Exhibit MPA-3, p. 69.

> *It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. . . . However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these cases, decisions still must be made, but they must be rendered on the basis of judgement. Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.*[502]

Useful forecasts are typically based on assuming incremental changes to the practices of the past. Over extended time horizons, the practices and assumptions of the past have less value as a forecasting tool. Incremental change can be pushed aside by transformative events. As Morrison Park stated, "*what may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck*."[503]

The NFAT Panel had to consider this positional view. The NFAT Review took place in the midst of actions already taken, immediate decisions to be taken, and long-term uncertainties. Manitoba Hydro chose which plans to present and analyze, without input from the NFAT Panel or Interveners. Significant costs associated with Keeyask have been expended, and export contracts signed.

Commercial decisions, especially long-term decisions, are ultimately about judgment. As this report has already indicated, the economic and financial analyses have been useful tools to determine whether the Preferred Development Plan is in the best interests of Manitoba, and superior to others. However, the Panel is called on to consider a wide range of factors, including socio-economic and environmental factors, risks associated with droughts, and ratepayer risks. In the final analysis, the Panel has been asked to consider all the evidence and use its judgement to balance risk and opportunity, cost and benefit.

[502] Exhibit MPA-3, p. 16.
[503] Exhibit MPA-3, p. 16.

13.3.0 The Situation Today

Analyzing the reasonableness of Manitoba Hydro's Preferred Development Plan and alternatives from a commercial perspective involves looking at the options from the position that one is in today. Because of the circumstances and the timing of the NFAT Review, the Panel was not provided with a blank canvas.

The information before the Panel with respect to the Keeyask Project and the 750 MW transmission interconnection provides evidence of a tangible set of initiatives. The following bullets describe key aspects of the current commercial realities the Panel weighed in coming to its conclusions:

- Approximately $1.4 billion will have been spent on Keeyask by end of June 2014. If the project proceeds, these expenditures will be part of the project costs to be recovered when in-service. If the project does not proceed, these sunk costs will have to be absorbed into rates and paid by ratepayers over a much shorter period.
- Manitoba Hydro has signed the general civil contract for the Keeyask Project and authorized the general civil contractor to commence marshalling resources. Manitoba Hydro wishes to begin construction of the Keeyask project during summer 2014 in order for the first of the generating turbines to be in service in 2019.
- The Manitoba Clean Environment Commission has recommended that an environmental licence be issued for Keeyask.
- The federal environmental licensing process for the Keeyask Project is complete.
- Bipole III will be available to transmit Keeyask's power to the south.
- New export contracts have been negotiated and signed with counterparties in the United States to purchase hydro-electric power. Part of the output of Keeyask has been sold under firm export contracts. Manitoba Hydro continues to actively market Keeyask power to potential extra-provincial customers.
- A 750 MW transmission interconnection between Manitoba and Minnesota is being pursued for a projected in-service date of 2020. Minnesota Power has a 51% ownership stake in and is championing the interconnection before the Minnesota Public Utilities Commission.
- Manitoba Hydro will own the Manitoba portion of the interconnection and is taking a 49% ownership stake in the U.S. portion. Manitoba Hydro has agreed to pay 67% of the costs of the construction and operations of the new line. Manitoba

Hydro told the Panel it is seeking to divest its ownership position in the U.S. intertie and is actively negotiating to do so.

- The 750 MW transmission interconnection will enable Manitoba Hydro to deliver power under export agreements with Minnesota Power and Wisconsin Public Service, and may open up new market opportunities to sell Keeyask energy to other potential customers.
- Four First Nations communities have partnered with Manitoba Hydro to develop the Keeyask generation project. Agreements detailing the commercial arrangements among the parties have been negotiated and signed.

With respect to the Conawapa Project, Manitoba Hydro has spent $400 million to date, and wishes to spend an additional $323 million to preserve its in-service date.[504] However, despite the sunk costs, Manitoba Hydro has not made a viable business case for the Conawapa Project:

- Manitoba Hydro's own projections for DSM savings set out in the 2014 15-year Power Smart Plan supplant more than 85% of the net capacity addition that Conawapa was to provide by its in-service date.
- The Conawapa Project has yet to proceed to final design.
- No environmental assessment hearings have taken place to date.
- One export contract with Wisconsin Public Service is considered to be conditional upon Conawapa being in service by 2031. If Conawapa does not proceed, the contract would have to be amended to remove that condition. There are no guarantees such amendment negotiations would be successful, without Conawapa. Manitoba Hydro has the capacity to fulfill the power requirements called for in the contract from existing system resources, including Keeyask.
- Unless firm export contracts are negotiated for Conawapa's power, the output would have to be sold at the market prices of the day.

13.4.0 The Parameters of the Commercial Perspective

Morrison Park was of the view given that Keeyask and the 750 MW transmission interconnection are "immediate, real and actionable projects"[505] there would have to be a very persuasive case to terminate, change course, or choose another alternative.

Mr. Pelino Colaiacovo from Morrison Park put it this way:

[504] PUB/MH-1-238(c).
[505] Exhibit MPA 3-1, p. 43.

> *... our point was that given all of the money that's been spent on Keeyask, given the commercial arrangements that have been made for Keeyask, a decision to not proceed … could only occur if there was very, very strong evidence that not proceeding would be advantageous to the ratepayer and to other stakeholders. That it's not sufficient to say that financial modeling, or economic modeling suggests that All Gas is preferable to -- to going ahead with Keeyask on some narrow basis.*
>
> *That the burden of proof, frankly, lies on people who question the decision to go forward with Keeyask, to demonstrate that other options are conclusively better. If they can't demonstrate that … their other options are conclusively better, then Keeyask is the real option that -- that is before the Government of Manitoba, is before the NFAT process. There has been some new information. The cost of Keeyask has gone up. It's legitimate to recalculate numbers to ensure that … new information doesn't change all of the analysis that's happened so far to date.*[506]

The view with respect to Conawapa was quite different. Morrison Park described Conawapa as a "development opportunity", competing with other potentially superior alternatives; hence continued expenditures to develop Conawapa should have to be justified from that perspective.[507]

13.5.0 Conclusions of the Panel

It is clear to the Panel that from a commercial perspective much more is at stake with Keeyask and the 750 MW transmission line than there is with Conawapa. Cancelling the Keeyask Project now would result in material consequences for ratepayers, because Manitoba Hydro would have to recover the $1.4 billion spent on the Project to date. The arrangements with First Nations would have to be terminated and significant economic opportunities lost. Manitoba Hydro's commercial reputation may suffer. The Keeyask general civil contract would have to be renegotiated and cancellation fees may be payable.

Even changing the timing of the Keeyask development could present challenges and commercial consequences. Agreements and understandings either embedded or underlying export contracts would be affected. This could lead to future negotiation consequences. Commercial reputation concerns, reliability benefits and the possibility of future export opportunities are all tied to the 750 MW transmission interconnection.

[506] Transcript, p. 7614.
[507] Exhibit MPA-4, p. 6.

The Panel finds persuasive Morrison Park's arguments with respect to the high burden required to demonstrate other alternatives as being preferable to Keeyask and the 750 MW transmission interconnection. Keeyask and the 750 MW transmission line represent a tangible commercial opportunity. Therefore, it would be prudent to proceed with the development of Keeyask and the 750 MW transmission line.

The Panel concurs with Morrison Park's view that Conawapa is simply a development opportunity. It was therefore incumbent on Manitoba Hydro to justify why Conawapa is superior to other alternatives, either those that might exist now or be present in the future. Manitoba Hydro has not established that justification.

Conawapa's economic benefits have not been demonstrated. The risks to and burden on ratepayers are too high. Nor has Manitoba Hydro put forward a business case that supports protecting Conawapa's 2026 in-service date. Should the need for new generation resources of the magnitude of Conawapa arise in the future, consideration of Conawapa as a generating option must be justified through a full and thorough integrated resource planning process. Continuing to spend money on Conawapa would unduly advantage Conawapa in any future analysis and disadvantage other contending alternatives. The Panel strongly believes that, within a proper integrated resource planning process, there must be a level playing field with respect to the consideration of future alternatives.

14.0.0 Recommendations

In accordance with the Terms of Reference and based on the evidence presented by Manitoba Hydro, Interveners and the Independent Expert Consultants, the Panel makes the following recommendations.

Manitoba Hydro's Preferred Development Plan

The Panel was requested to assess whether the needs for Manitoba Hydro's Preferred Development Plan are thoroughly justified and sound, its timing is warranted and the factors that Manitoba Hydro relied on to prove its needs are complete, reasonable and accurate. The Terms of Reference also asked the Panel to assess whether the Preferred Development Plan is justified as superior to potential alternatives and is in the best long-term interest of the province of Manitoba. The factors that the Panel considered in reaching its conclusions and recommendations were defined by the Terms of Reference and have been discussed throughout this Report.

The Panel concludes that new generation resources will likely be required no later than 2024. However, Manitoba Hydro has not established that the Preferred Development Plan is the best alternative to meet this need, or has been justified as being in the best long-term interest of the province of Manitoba.

1. ***The Panel recommends that the Government of Manitoba not approve Manitoba Hydro's proposed Preferred Development Plan.***

However, the Panel recommends alternative actions that are better justified in terms of meeting the need for new resources and export opportunities, while addressing the risks to ratepayers and the requirement for a new approach in planning future generation resources. These actions are presented in the recommendations below.

Keeyask Project

The Panel concludes that the Keeyask Project is justified in terms of resource needs for domestic and export requirements. The Panel considered the impending domestic load requirements, and determined that even with the successful implementation of Demand Side Management programs, Manitoba requires new, long-term energy supply based on the hydropower from the Keeyask Project. The Panel was persuaded by the commercial realities of the Keeyask Project, including some $1.2 billion already spent on the Project, as well as the supporting export contracts and the socio-economic benefits from partnership agreements with First Nations.

The Panel considered the question of the in-service date and, in light of the potential impacts of Demand Side Management initiatives, whether to recommend deferral of the start of Keeyask's construction. The Panel notes the need for new capacity as a result of load demands associated with expected new pipeline construction. Agreements also have been signed with the Keeyask Cree Nations that could be adversely affected by delay. As a result, the Panel found no convincing reason to delay the in-service date of 2019 for the Keeyask Project.

2. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date.

750 MW Transmission Interconnection Project

Manitoba Hydro has demonstrated the value of constructing the proposed 750 MW Transmission Interconnection to the United States. Financial and economic analysis indicates that this Transmission Interconnection adds value to Manitoba Hydro's future plans. The Transmission Interconnection is equally justified in terms of its contribution to system reliability, and to address export and import needs during periods of drought or system emergencies.

3. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date.

Conawapa Project

The Panel concludes that Manitoba Hydro has not justified the construction of the Conawapa Project as part of the Preferred Development Plan, or any future plan. In light of the Panel's recommendations on Keeyask, the 750 MW Transmission Interconnection and expected impacts of future Demand Side Management efforts, Conawapa is not needed for either domestic or export needs. It makes no positive contribution to the financial value of the Preferred Development Plan or any alternative resource plans.

4. *The Panel recommends that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project*.

Given the Panel's view that the Conawapa Project has no place in future plans or strategies, there is no need to continue any activity to protect a future in-service date. Nor should existing sunk costs become a future justification for Conawapa.

5. ***The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.***

Demand Side Management Plans and Programs

During the NFAT Review hearings, the Panel heard that Demand Side Management initiatives were "game changers." The Panel learned that Demand Side Management can have a profound impact on the need for, and timing of, new energy resources. According to its 2014 Supplementary Power Smart Plan, Manitoba Hydro can achieve 1,136 MW and 3,978 GWh of electricity savings by 2028/29. This would amount to more than 80% of the net system capacity addition from the proposed Conawapa Project.

Successful Demand Side Management initiatives are based on ambitious and achievable targets. In recent years and on an annual basis as a percentage of total demand, Manitoba Hydro's DSM savings have declined to approximately 0.4%, well below the 1.5% to 2% levels seen in many other jurisdictions. Demand Side Management savings in the order of 1.5% (including codes and standards) are achievable and economic.

Manitoba Hydro was formerly recognized as a leader in DSM but has since been surpassed by a number of jurisdictions. The Panel is concerned that the full potential for Demand Side Management will not be realized if the responsibility for Demand Side Management remains within Manitoba Hydro. Commitment, independent action and external monitoring of performance are the demonstrated and proven ingredients of successful DSM programs. Interveners encouraged the Panel to take these steps.

6. ***The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.***

7. ***The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.***

8. ***The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.***

9. ***The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.***

10. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.

11. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.

Rates and Ratepayer Impacts

Manitoba Hydro will have to invest in replacing aging infrastructure and in building Bipole III. This will result in increasing electricity rates over the coming decade. The construction of new generation and associated transmission facilities will add to and prolong these rate increases. Furthermore, construction costs will most likely grow and revenue projections may not be achieved. This gap between rising costs and unrealized revenues will be borne by ratepayers.

Given the length of time projected for these rate increases and their magnitude, especially in the early years, the Panel is concerned about intergenerational fairness and the impact on vulnerable residents and communities. Lower income consumers, particularly those in northern and aboriginal communities where energy choices are limited or non-existent, will especially feel this impact.

The Government of Manitoba will receive significant revenues from incremental capital taxes and water rental fees from the development of the Keeyask Project. It would be reasonable for the Government of Manitoba to use some or all of the incremental revenue it will realize from the Keeyask Project to mitigate adverse rate impacts on vulnerable consumers. Furthermore, Manitoba Hydro should take internal actions to moderate rate increases.

12. The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.

13. The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.

14. The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.

Actions in Support of a Clean Energy Future

As a result of the NFAT Review, the Panel concludes that Manitoba requires a new commitment to a clean energy future. The recommendation to proceed with the Keeyask Project and the 750 MW Transmission Interconnection augments Manitoba's hydropower foundation. It is now time to determine and build a more diversified resource portfolio. To achieve this future, Manitoba must invest in new planning tools. Integrated resource planning is a best practice in many jurisdictions. The Panel concludes that an integrated resource planning process is required to determine what supply and demand side resource mix is in the best interests of Manitobans.

15. The Panel recommends that integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba.

16. The Panel recommends that the Government of Manitoba not approve the construction of any generating facilities, nor approve the beginning of the required infrastructure work for any generation facility, beyond the Keeyask Project, unless such facilities are justified through an integrated resource planning process. The integrated resource planning process must include public consultation.

APPENDIX 1 Order in Council and Terms of Reference

No. 128/2013

ORDER IN COUNCIL

Healthy Living, Seniors and Consumer Affairs
Initiating Department/Agency

Authorized Officer

APPROVED BY:

Civil Service Commission

Finance

APPROVED AS TO FORM: April 16/2013
IRIS C. ALLEN
Name
Civil Legal Services Initials

BILINGUAL: ☐ Yes ☒ No

ORDER

1. The Public Utilities Board (the "PUB") is assigned the conduct of a Needs For and Alternatives To review (an "NFAT review") of Manitoba Hydro's proposed preferred development plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternative current ("AC") transmission facilities, and a new Canada-United States of America ("USA") transmission interconnection.
2. Arthur Mauro and Mel Lazareck are appointed as members of the PUB, for the purpose of participating in the NFAT review, with terms to expire on such date as the PUB has fully completed its assigned duties in respect of the NFAT review, unless their appointments are revoked before that date by the Lieutenant Governor in Council.
3. The NFAT review will be conducted in accordance with the attached Terms of Reference.
4. This Order is effective on the date it is made.

AUTHORITY

The Public Utilities Board Act, C.C.S.M. c. P280, states:

Membership of board
4 The board shall be composed of such number of members, not less than three, as the Lieutenant Governor in Council may determine.

Appointment of members
7 The members shall be appointed by the Lieutenant Governor in Council, and shall be paid such remunerations as determined by the Lieutenant Governor in Council.

Term of office
9 Each member shall hold office during pleasure of the Lieutenant Governor in Council.

Power of board to perform assigned duties
107 The board may perform duties assigned to it

...

(b) by order of the Lieutenant Governor in Council; or

...

and Part I, in so far as it is applicable, applies to the carrying out of duties so assigned.

BACKGROUND

1. The Government of Manitoba wishes to have the PUB conduct an NFAT review of Manitoba Hydro's proposed preferred development plan for meeting a growing provincial demand for electricity and for taking advantage of export opportunities, which includes the Keeyask and Conawapa Generating Stations, their associated AC transmission facilities, and a new Canada-USA transmission interconnection, in accordance with the attached Terms of Reference.
2. Arthur Mauro and Mel Lazareck are being appointed to provide the PUB with the necessary capacity and expertise for the NFAT review. Manitoba has requested the chair of PUB to designate these new members, under subsection 15(6) of *The Public Utilities Board Act*, as the members who will conduct the NFAT review, together with any other members of PUB as he deems necessary for purposes of the review.

RECOMMENDED:
Minister of Healthy Living, Seniors and Consumer Affairs

APPROVED BY EXECUTIVE COUNCIL:
Presiding Member

ORDERED:
Lieutenant Governor

Date April 17, 2013

PSF 40 – 29040
November 2009

Page 1 of 1

No. 472/2013

ORDER IN COUNCIL

Tourism, Culture, Heritage, Sport and Consumer Protection
Initiating Department/Agency

Authorized Officer

APPROVED BY

Civil Service Commission

Finance

APPROVED AS TO FORM:
GAIL E. MILDREN
Name Dec 17, 2013
Civil Legal Services Initials

BILINGUAL: ☐ YES ☑ NO

ORDER

1. Hugh Grant and Richard Bell, both of Winnipeg, are appointed as members of The Public Utilities Board (the "PUB"), for the purpose of participating in The Needs For and Alternatives To review of Manitoba Hydro's proposed preferred development plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternative current ("AC") transmission facilities, and a new Canada-United States of America ("USA") transmission interconnection, assigned to the PUB by Order in Council 128/2013 (the "NFAT Review").
2. The terms of office of Hugh Grant and Richard Bell expire on the date the PUB has fully completed the duties assigned to the PUB in respect of the NFAT Review in accordance with Order in Council 128/2013, unless their appointments are revoked before that date by the Lieutenant Governor in Council.
3. The remuneration to be paid to members of the Board is $146.00 per meeting or $255.00 per day, plus out-of-pocket expenses.
4. The appointments of Arthur Mauro and Mel Lazareck as members of the PUB for the purposes of the NFAT Review are revoked.
5. This Order comes into effect on the date it is made.

AUTHORITY

The Public Utilities Board Act, C.C.S.M. c. P280 states:

Membership of board
4 The board shall be composed of such number of members, not less than three, as the Lieutenant Governor in Council may determine.

Appointment of members
7 The members shall be appointed by the Lieutenant Governor in Council, and shall be paid such remunerations as determined by the Lieutenant Governor in Council.

Term of office
9 Each member shall hold office during pleasure of the Lieutenant Governor in Council.

Power of board to perform assigned duties
107 The board may perform duties assigned to it

...

(b) by order of the Lieutenant Governor in Council; ....

...

and Part I, in so far as it is applicable, applies to the carrying out of duties so assigned.

BACKGROUND

1. Under clause 107(b) of *The Public Utilities Board Act*, the Lieutenant Governor in Council, by Order in Council 128/2013, assigned to the PUB the conduct of the NFAT review.
2. Arthur Mauro and Mel Lazareck were appointed as members of the PUB for the purpose of participating in the NFAT review by Order in Council 128/2013, and they have resigned.
3. Hugh Grant and Richard Bell are being appointed to the PUB to provide it with the necessary capacity and expertise for the NFAT review. Manitoba has requested the chair of the PUB to designate Hugh Grant and Richard Bell, under subsection 15(6) of *The Public Utilities Board Act*, as the members of the PUB who will conduct the NFAT review, together with any other members of PUB the chair considers necessary for purposes of the NFAT review.

RECOMMENDED:

Minister of Tourism, Culture, Heritage, Sport and Consumer Protection

APPROVED BY EXECUTIVE COUNCIL:

Presiding Member

ORDERED:

Lieutenant Governor

December 18, 2013
Date

Terms of Reference - Needs For and Alternatives To (NFAT) Review

NFAT review for Manitoba Hydro's proposed preferred development plan for the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection

INTRODUCTION

On January 13, 2011, the Government of Manitoba notified Manitoba Hydro (Hydro) of its intention to carry out a public Needs For and Alternatives To (NFAT) review and assessment of the corporation's proposed preferred development plan (Plan) for major new hydro-electric generation and Canada-USA interconnection facilities using an independent body.

On November 15, 2012 the Minister of Innovation, Energy and Mines announced that the Government of Manitoba had asked the Manitoba Public Utilities Board (PUB) to conduct the NFAT for the Keeyask and Conawapa Generating Stations and their associated transmission facilities. This document, including Appendix A, outlines the Terms of Reference for the NFAT.

THE PLAN

Hydro's Plan is intended to meet a growing provincial demand for electricity and take advantage of opportunities to export power to US customer utilities. The Plan includes the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection. Hydro has stated that its Plan is being brought forward now to take advantage of the proposed Canada-USA interconnection and long-term firm export sale opportunities that occur rather infrequently. Hydro's Plan is dependent upon developing a new transmission interconnection into the USA and entering into long-term firm export sales with US-based electric utilities Minnesota Power and Wisconsin Public Service.

Hydro asserts that the Plan will provide significant benefits to Manitobans. Hydro also asserts that the value proposition of its Plan is justified on a very broad basis, taking into consideration inherent uncertainties that exist over a reasonable range of future possible critical inputs into its business case, and that it is the best development option when compared to alternatives.

MANDATE

The NFAT will be conducted under the authority of section 107 of *The Public Utilities Board Act* ("The PUB Act"). PUB members designated by the Chair to conduct the NFAT under section 15(6) of The PUB Act will constitute the NFAT Panel (the "Panel"). Panel members will exercise their duty to conduct the assigned NFAT in accordance with The PUB Act and these Terms of Reference.

For greater certainty, in conducting the NFAT, the Panel members who are designated by the Chair to conduct the review:

(a) may hear evidence *in camera* for the purpose of protecting Commercially Sensitive Information as defined in Appendix A, which forms a part of these Terms of Reference;

(b) may exercise discretion over the access of any person to Commercially Sensitive Information; and

(c) shall follow the Rules of Practice and Procedure of the PUB, as amended from time to time, if not otherwise dealt with under these Terms of Reference.

At the completion of its review, the Panel will provide a report to the Minister responsible for the administration of *The Public Utilities Board Act* (currently the Minister of Healthy Living, Seniors and Consumer Affairs) no later than June 20, 2014. The report will include recommendations to the Government of Manitoba on the needs for Hydro's preferred development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.

PUBLIC PARTICIPATION

The public will be encouraged to provide input and comment on the Plan as part of the NFAT.

SCOPE OF THE NFAT REVIEW

The Panel will review and assess the needs for and alternatives to Hydro's Plan. Its assessment will be based upon the evidence submitted by Hydro, intervenors and independent expert consultants used by PUB to assist in the NFAT. The Panel's report to the Minister will address the following items:

1. An assessment as to whether the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate. The assessment will take the following factors into consideration:

   (a) The alignment of the Plan to Hydro's mandate, as set out in Section 2 of *The Manitoba Hydro Act*.

   (b) The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*.

   (c) The extent to which the Plan is needed to address reliability and security requirements of Manitoba's electricity supply.

   (d) The reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied upon for its justification of its needs. This should include Hydro's planning load forecast and future load scenarios, its demand and supply analysis, export expectations and commitments, and demand side management and conservation forecasts.

2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need. The assessment will take the following factors into consideration:

   (a) If preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound;

   (b) The alignment of the Plan and alternatives to Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reductions Act* and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*;

   (c) The accuracy and reasonableness of the modeling of export contract sale prices, terms, conditions, scheduling provisions, export transmission costs, and the reasonableness of projected revenues;

   (d) The reasonableness of forecasted critical inputs including construction costs, opportunity export revenues, future fuel prices, electricity market price forecasts, the determinants of those values, and export volumes;

(e) The reasonableness of the scope and evaluation of risks and the benefits proposed to arise from the development and the reasonableness and the reliability of Hydro's interpretation of the most likely future outcomes as a result of climate changes, interest rate fluctuations, export market prices, domestic load fluctuations, droughts, competing technologies, fuel prices, carbon pricing, technology developments, economic conditions, Hydro's transmission positions and other relevant factors;

(f) The impact on domestic electricity rates over time with and without the Plan and with alternatives;

(g) The financial and economic risks of the Plan and export contracts and export opportunity revenues in relation to alternative development strategies;

(h) The socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities;

(i) The macro environmental impact of the Plan compared to alternatives;

(j) If the Plan has been justified to provide the highest level of overall socio-economic benefit to Manitobans, and is justified to be the preferable long-term electricity development option for Manitoba when compared to alternatives.

Independent Expert Consultants

The Panel shall establish a process for the thorough review of any information that the Panel determines to be relevant to the conduct of the NFAT, including relevant Commercially Sensitive Information, as defined in Appendix A, subject to these Terms of Reference.

The Panel may use one or more independent expert consultant(s) for the purpose of the NFAT. In addition to such other questions and issues as the Panel may determine they should examine, the independent expert consultant(s) shall be expected to critically examine the following:

(a) the high level forecasts of export revenues that are filed by Hydro and whether the forecasts appropriately and accurately reflect the export contracts, including Commercially Sensitive Information.

(b) the accuracy and reasonableness of Hydro's approach to producing an assessment of financial risks (including drought), the assessment of which is derived using Commercially Sensitive Information;

(c) the appropriateness and correct application of methodologies that cannot be publicly disclosed by Manitoba Hydro because they contain Commercially Sensitive Information, such as whether Hydro's approach to comparing generation sequences follows sound industry practice;

(d) whether high level summaries filed by Hydro of Net Present Values and Internal Rates of Return which are derived from Commercially Sensitive Information reflect sound assumptions and calculations; and

(e) the accuracy and soundness of Hydro's calculation of a consensus forecast of future market prices for electricity and fuels which is derived from Commercially Sensitive Information.

The PUB shall hire the independent expert consultant(s).

The independent expert consultant(s) shall provide a report(s) to be filed in evidence on the public record, which shall contain their analysis of the submissions filed by Hydro, with sufficient information to satisfy the Panel that the review was conducted with due diligence. The report(s) shall not draw conclusions as to the needs for or alternatives to the Plan, which is the role of the Panel.

The independent expert consultant(s) shall be available for cross-examination at the public hearing, and shall be available as a resource to legal counsel for registered intervenors as deemed necessary by the PUB to prepare for the cross-examination of Hydro witnesses on Commercially Sensitive Information.

The independent expert consultant(s) may also provide such advice to the Panel, and file such report(s) with the Panel *in camera*, that contain, reference, or analyse Commercially Sensitive Information in sufficient detail to satisfy the Panel. Cross-examination of the independent expert consultant(s) on such issues shall be permitted *in camera.*

The independent expert consultant(s) shall not quote in their publicly filed report(s) Commercially Sensitive Information or information that would enable a third party to reverse-engineer Commercially Sensitive Information ("reverse-engineer" means to discover, synthesize or otherwise recreate the Commercially Sensitive Information following a detailed examination). No public cross-examination of the independent expert consultant(s) shall take place with respect to Commercially Sensitive Information. The independent expert consultant(s) will be required to execute a non-disclosure agreement satisfactory to Hydro and the Panel.

NOT IN SCOPE

The following items are not in the scope of the NFAT:

- The Bipole III transmission line and converter station project;
- The Pointe Du Bois project;
- The commercial arrangements between Hydro and its aboriginal partners for the development of the proposed hydro-electric generating facilities (the impacts of these are included in the cost of the projects that are part of the Plan);
- The environmental reviews of the proposed projects that are part of the Plan, including Environmental Impact Statements (these will be conducted through individual processes by the Manitoba Clean Environment Commission ("CEC"), and where possible the impacts of the matters to be considered by the CEC are included in the costs of the projects that are part of the Plan);
- Aboriginal consultation pursuant to Section 35 of the *Constitution Act* (this is conducted as a separate Crown-Aboriginal consultation process);
- Any past Hydro development proposals or government assessments of past development proposals, including past NFATs;
- Historic environmental costs.

APPENDIX A
PROVISIONS FOR THE PROTECTION OF COMMERCIALLY SENSITIVE INFORMATION:

Transparency

The Panel is directed to conduct the NFAT in a transparent and public process. However, in conducting the NFAT, the Panel is to ensure adequate protection of any information the disclosure of which may reasonably be expected to cause undue financial loss to Manitoba Hydro ("Hydro") or any of its contractual counterparties or to harm significantly Hydro's or its contractual counterparties' or domestic customers' competitive position, including, but not limited to, any sections of the following documents containing such information (collectively, "Commercially Sensitive Information"):

(a) any and all export contracts and term sheets now or hereafter in existence for the purchase and sale of power and energy entered into between Hydro and its customers in the United States of America, including but not limited to the export contracts and term sheets commonly described as follows: Minnesota Power 250 MW Energy Exchange Agreement; Minnesota Power 250 MW Power Sale Agreement; Wisconsin Public Service 100 MW Power Sale Agreement; Wisconsin Public Service 108 MW Energy Sale Agreement; Wisconsin Public Service Term Sheet, Northern States Power 375/325 MW System Power Sale Agreement; Northern States Power 125 MW System Power Sale Agreement, and Northern States Power 350 MW Seasonal Diversity Agreement (collectively, "Export Contracts");

(b) the internal, non-public load forecast prepared by Hydro on an annual basis (collectively, "Load Forecast"); and

(c) the Hydro document dated September 24, 2010 titled "THE 2010/11 POWER RESOURCE PLAN, Report PPD #10-07" and any further existing or future power resource plans hereinafter developed by Hydro (collectively, "Power Resource Plan")

Document Filings and Evidence

In conducting the NFAT, the Panel shall be able to require the production, from Hydro, of any documents and other such evidence as the Panel determines to be relevant to the conduct of the NFAT within the scope of the Terms of Reference from the Province of Manitoba. The procedures for filings and evidence shall be as set out below:

(a) Public Filings

Any documents that do not contain Commercially Sensitive Information are to be filed on the public record. As part of its NFAT submission Hydro shall file on the public record copies of its Export Contracts, Load Forecast and Power Resource Plan, with details considered by Hydro to be Commercially Sensitive Information redacted.

To the extent that information necessary for the conduct of the NFAT cannot be made public due to the presence of Commercially Sensitive Information, Hydro shall file on the public record high level summaries and reports that incorporate the relevant information, at a level of summary and aggregation which will not disclose Commercially Sensitive Information.

Any evidence before the Panel shall be public, other than evidence with respect to Commercially Sensitive Information, which testimony shall be received in camera as further described in (b) below. To the extent that it deems practical, the Panel shall limit the scope of *in camera* proceedings so that the major issues in the NFAT review can be canvassed and discussed in public.

(b) Confidential Filings

Any documents that the Panel determines to be relevant but that contain Commercially Sensitive Information are to be filed with the Panel in confidence in unredacted form, including unredacted copies of the Export Contracts, Load Forecast and Power Resource Plan.

On an *in camera* basis, the Panel may:

(i) ireview the complete, unredacted versions of Hydro documents that contain Commercially Sensitive Information; and

(ii) permit evidence with respect to Commercially Sensitive Information.

Access to *In Camera* Evidence

Based on the *in camera* review, the Panel may choose to publish findings and conclusions about export revenues, forecast market prices and the like, to inform the public discussion and serve as inputs to further analysis and review by participants at the public hearing, or it may choose to reserve comment until the conclusion of the hearing.

The documents filed and evidence adduced *in camera* shall not be made public, other than through the high-level summaries as described above, and shall only be disclosed to or shared with the following persons, on the terms and conditions as noted below:

1. Members of the Panel, the Board's Executive Director and Board staff may review Commercially Sensitive Information and participate in the *in camera* process for the purpose of carrying out their specific duties with respect to the NFAT without having to sign an undertaking or a non-disclosure agreement.

2. Legal counsel of record of the Board and counsel for registered interveners may review Commercially Sensitive Information and participate in the *in camera* process upon execution of an undertaking to the Panel in a form agreeable to the Panel and Hydro.

3. Any independent consultant(s) appointed by the Panel and any non-staff Panel advisors with a need to know, as determined by the Chair, may review Commercially Sensitive Information and participate in the *in camera* process upon execution of a non-disclosure agreement in a form agreeable to the Panel and Hydro.

Subject to the following dispute resolution provision, the Panel will not publish Commercially Sensitive Information in Orders or other public documents or include information that would enable a third party to reverse engineer Commercially Sensitive Information. The Panel will establish procedures to protect the documents and evidence from inadvertent disclosure and will instruct each individual who receives access to do the same. If the Panel so chooses, it may solicit Hydro's comments on particular documents that are in the process of being prepared in the interests of avoiding inadvertent disclosures.

Dispute Resolution Regarding Commercially Sensitive Information

If, during the in camera review, the Panel identifies any Commercially Sensitive Information, other than third party proprietary price forecasts, which the Panel considers would be beneficial to place on the public record at the NFAT, the Panel may refer those matters in dispute to a neutral third party to be agreed upon between the Panel and Hydro. The third party will receive written submissions and make a decision thereon, on an expedited basis, which decision will be given effect to in the proceedings before the Panel. In arriving at any such decision, the neutral third party shall specifically take into account the general undesirability of making disclosure of any Commercially Sensitive Information that may have been furnished to Hydro by third parties, in reliance upon contractual commitments by Hydro to maintain confidentiality, and the importance of maintaining such confidences.

APPENDIX 2 NFAT Panel Member Biographies

Régis Gosselin, B ès Arts, MBA, CGA, Chair

Appointed to Public Utilities Board April 2012

Former Director of Corporate Services for the Canadian Grain Commission, this member has worked for the Fédération des Caisses Populaires and also Entreprise Saint-Boniface, a community economic development organization. He is a past Chair of the Société d'assurances dépôts des caisses populaires du Manitoba, Caisse populaire de Saint-Boniface and Centre Youville.

Richard Bel, B.A., M.A. , M.Sc.

Appointed to Public Utilities Board December 2013

Co-owner and managing partner of the Fort Garry Hotel since 1994, this member is also the current Chair of the Forks North Portage Partnership. In addition to being a former owner of various Winnipeg restaurants, he was an Assistant Professor of Economics at Kobe University (Kobe, Japan) and the University of Manitoba. He has been appointed a member to examine Manitoba Hydro's Preferred Development Plan.

Hugh Grant, Ph.D. (Economics)

Appointed to Public Utilities Board December 2013

Professor of Economics at the University of Winnipeg, he teaches on indigenous economic development in the University's Masters of Development Practice program. He also currently serves as the President of the University of Winnipeg Faculty Association. He obtained his Ph.D. in Economics from the University of Toronto. In addition to his academic research on labour economics, health economics and Canadian economic development, he has engaged in policy work with a range of organizations including Industry Canada, the Law Commission of Canada, Manitoba Family Services and Consumer Affairs, the Public Interest Law Centre and the Canadian Royal Commission on Aboriginal Peoples. He also has previous experience as a consultant to aboriginal associations on comprehensive land claims. He was appointed a member to review Manitoba Hydro's Preferred Development Plan.

Marilyn Kapitany, BSc. Honours, MSc.

Appointed to Public Utilities Board July 2012

A former senior Federal Government executive responsible for Western Economic Diversification Canada. Former Regional Director General of Indian and Northern Affairs Canada (Manitoba) as well as Director of Industry Services at the Canadian Grain Commission.

Past Chair of the National Board of YM-YWCA of Canada and appointed as Canada's International Representative in 2014. Marilyn is a member of the Riverview Health Centre Board. Former Chair of the YM-YWCA of Winnipeg Board, and past member of Assiniboine Park Conservancy Board and Association of Professional Executives.

Larry Soldier

Appointed to Public Utilities Board July 2012

Former Chief of the Swan Lake First Nation.

Serves on the Board of Directors for Youville Centre. Former Vice-Chairman of the Dakota Ojibway Tribal Council and Dakota Ojibway Child and Family Services. Served on numerous committees which includes former Chairperson of the Small Business Management and Dev. Committee of Keewatin Community College and past member of Chiefs Committee on Treaties and Self-Determination. Former Chairman of the Regional Advisory Board, Alcoholism Foundation of Manitoba. Served as City Councillor for the City of Thompson. Proprietor since 2006.

APPENDIX 3 Chronology of Events

January 13, 2011 – The Government of Manitoba notifies the Manitoba Hydro-Electric Board (Manitoba Hydro) of its intention to carry out a public Needs For and Alternatives To (NFAT) Review and assessment of the Manitoba Hydro's proposed Preferred Development Plan (PDP) for major new hydro-electric generation and Canada-USA interconnection facilities using an independent body.

November 16, 2012 – The Minister of Innovation, Energy and Mines announces that the Government of Manitoba has asked the Manitoba Public Utilities Board (PUB) to conduct the NFAT Review for the Keeyask and Conawapa Generating Stations and their associated transmission facilities.

April 17, 2013 – By Order in Council 128/2013, the Government of Manitoba assigns to the PUB the conduct of a Needs For and Alternatives To (NFAT) Review Manitoba Hydro's Preferred Development Plan, which includes constructing the Keeyask and Conawapa Generating Stations, their associated domestic alternating current transmission facilities and a new Canada-United States transmission interconnection. The NFAT Review is to be conducted in accordance with the Terms of Reference for attached to the Order.

April 25, 2013 – The Government of Manitoba issues a news release respecting the NFAT Review.

May 16, 2013 – The NFAT Panel of the Public Utilities Board holds first Pre-Hearing Conference to determine Interveners for NFAT Review.

June 11, 2013 – The Panel issues Order 67/13 granting Intervener Status with respect to the NFAT Review to the following five applicants:

- Consumers' Association of Canada (Manitoba) Inc. (CAC);
- Green Action Centre (GAC);
- Manitoba Industrial Power Users Group (MIPUG);
- Manitoba Keewatinowi Okimakanak Inc. (MKO); and
- Manitoba Metis Federation (MMF).

The following four applicants were denied Intervener Status:

- Peguis First Nation;

- The Pimicikamak at Cross Lake;
- Kaweechiwasik Inninuwuk; and
- Manitoba Public Interest Research Group.

July 15, 17, 2013 – Manitoba Hydro holds first NFAT Technical Conference.

August 9, 2013 – The Panel issues Order 91/13 dismissing applications by Pimicikamak and the Manitoba Public Interest Research Group to review and vary Order 67/13, which dismissed applications by the respective applicants to obtain Intervener status in NFAT Review.

August 9, 2013 – The Panel issues Order 92/13, which addresses a number of procedural issues arising out of Order 67/13. The Order provides preliminary approval of Interveners' consultants and expert witnesses, and draft budgets.

This order also defines the terms ''macro environmental" and "'socio-economic" for the purposes of the Review.

> Macro environmental impact assessment is defined as*: A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, and, water, flora and fauna, including the potential significance of these changes, their equitable distribution within and between present and future generations.*
>
> Socio-economic impact and benefits is defined as*: A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use.*

August 16, 2013 – Manitoba Hydro files its NFAT Business Case Submission with the PUB.

August 2013 – The Panel engages Independent Expert Consultants to assist the Panel in the NFAT Review.

September 4, 2013 – The Panel holds second Pre-Hearing Conference.

September 5-6, 2013 – Manitoba Hydro holds second Technical Conference.

September 2013 – The Scopes of Work for the Independent Expert Consultants are established.

September 30, 2013 – The Panel holds a "motion day" hearing to deal with a motion made by Manitoba Hydro with respect to First Round Information Requests and issues raised by counsel for the independent expert consultants.

October 4, 2013 – The Panel issues procedural Order 119/13 in respect of matters raised at the September 30, 2013 "motion day" hearing. The Order establishes a process to deal with Information Requests directed to Manitoba Hydro and issues raised by the Independent Expert Consultants.

October 21, 2013 – The Panel issues Order 126/13, an Erratum order in respect of Order 119/13.

October 21, 2013 – The Panel issues Order 127/13, which relates to procedural matters arising from the September 4, 2013 Pre-Hearing Conference, including establishing a communications protocol for the Independent Expert Consultants.

December 18, 2013 – By Order in Council 472/2013, the Government of Manitoba appoints Dr. Hugh Grant and Mr. Richard Bel to the Public Utilities Board for the purpose of participating in the NFAT Review.

February 27, 2014 – The Panel holds a Presenters day in Winnipeg to hear a number of organizations and individuals who wished to make their views on the Preferred Development Plan known to the Panel.

March 3, 2014 – The oral evidentiary phase of the NFAT Review hearings begins.

March 4, 2014 – The Panel issues Order 22/14, which partially grants Manitoba Hydro's motion to strike portions of the evidence of Whitfield Russell Associates provided on behalf of the Manitoba Métis Federation (MMF) on that grounds that the evidence is outside scope of the Terms of Reference for the NFAT Review.

April 9, 2014 – The Panel issues Order 35/14 granting the MMF's motion to review and vary Order 22/14 and accepting the revised redactions proposed by MMF to the evidence of Whitfield Russell Associates.

May 13, 2014 – The evidentiary portion of the NFAT Review hearings concludes.

May 14, 2014 - The Panel holds a Presenters day in Thompson, Manitoba to hear from a number of organizations and individuals who wished to make their views on the Preferred Development Plan known to the Panel.

May 20-26, 2014 – The Panel hears closing submissions from Interveners and Manitoba Hydro.

June 20, 2014 – The NFAT Review report is submitted to the Minister responsible for the administration of *The Public Utilities Board Act,* as required by the Terms of Reference*.*

APPENDIX 4 Independent Expert Consultant Scope of Work

Independent Expert Consultant	Scope of Work (High-Level Description)
Elenchus Research Associates Inc.	Load forecasting; Demand side management (DSM); energy efficiency
La Capra Associates, Inc.	Power resource planning, economic evaluation, business case and risk analysis, transmission economics, export contracts, financial modelling
EnerNex (as a subcontractor to La Capra Associates, Inc.)	Wind matters
Knight Piésold Ltd.	Construction management, capital costs
MNP LLP	Macro-environmental issues
MPA Morrison Park Advisors Inc.	Commercial evaluation of Preferred Development Plan
Potomac Economics, Inc.	Midcontinent Independent System Operator (MISO); export markets, prices and revenues
Power Engineers, Inc.	Transmission line construction and management
TyPlan Consulting Ltd.	Socio-economic impacts and benefits

SCOPES OF WORK: The detailed Scopes of Work for the Independent Expert Consultants can be found on the PUB website.

http://www.pub.gov.mb.ca/nfat/index.html

REPORTS: The reports prepared by the Independent Expert Consultants can be found on the PUB website.

http://www.pub.gov.mb.ca/nfat/index.html

APPENDIX 5 Interveners

By Order 67/13, the Public Utilities Board granted Intervener status to the Intervener Applicants named below. Each Intervener was approved with respect to the issues listed for the respective Intervener.

Consumers' Association of Canada (Manitoba) Inc. (CAC)

- Reliability of Manitoba Hydro's forecast relating to load, capital costs, export revenues, and enhanced transmission capacity
- Risk Assessments as detailed in CAC's written Application for Intervener Status
- Analytical consideration of alternatives to Manitoba Hydro's Preferred Development Plan (PDP) including risk diversification, energy efficiency and non-hydroelectric options such as natural gas and wind
- Sustainability of Manitoba Hydro's PDP and comparison to alternatives
- Rate impacts on Manitoba Hydro's domestic ratepayers – including those on fixed and low incomes
- Macro-Environmental Impacts of the PDP and alternatives
- Socio-Economic impacts and benefits of Manitoba Hydro's PDP – compared to alternatives – in regard to northern and aboriginal communities as well as all Manitobans

Green Action Centre (GAC)

- Forecasts and risks associated with domestic load, export commitments and export pricing
- Use of Demand Side Management and alternative energy initiatives
- Marginal costs of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives including DSM
- Alternatives to Manitoba Hydro's PDP together with integration into a diversified portfolio and consideration of such contributions to Risk Management.

Manitoba Industrial Power Users Group (MIPUG)

- Impact on domestic rates, including long term impacts
- Risks to domestic customers through Manitoba Hydro's investment in subsidiaries, export ventures and new Programs

- Alternatives to Manitoba Hydro's Preferred Development Plan including demand side management programs
- Risks including long-term financial and economic risks and the financial liability of Manitoba Hydro

Manitoba Keewatinowi Okimakanak Inc. (MKO)

- The socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives in respect of the MKO First Nations
- The impact of domestic electricity rates over time, with and without the PDP and with alternatives

Manitoba Métis Federation (MMF)

- The impact on domestic rates
- Financial and economic risks
- Socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives to Northern and Aboriginal communities
- Macro-environmental Impacts of the PDP compared to alternatives
- Whether the PDP is the highest level of overall socio-economic benefit to Manitoba

REPORTS: The reports prepared by Intervener experts can be found on the PUB website.

http://www.pub.gov.mb.ca/nfat/index.html

APPENDIX 6 Summary of Intervener Closing Submissions

For the completeness of the record, this Appendix provides a summary of the closing submissions of each Intervener. The Panel regrets any errors or omissions that may have occurred in summarizing Intervener submissions. The full submissions can be accessed at http://www.pub.gov.mb.ca/nfat.

Consumers' Association of Canada (Manitoba) Inc. (CAC)

The Consumers' Association of Canada (Manitoba) Inc. (CAC) submitted that the Preferred Development Plan has suffered painful evidentiary blows, and that the most recent economics make it untenable. In CAC's view, the business case was premised on certain expected capital costs, a robust U.S. economy, and carbon prices developing in the United States. However, export price projections are now significantly lower than they used to be, while the capital cost of the Preferred Development Plan has gone up. CAC called the availability of shale gas a "game changer." In addition, CAC stated that carbon pricing is still uncertain, the U.S. economy has experienced a paradigm shift, grid parity is a risk during the planning horizon, and both wind and solar energy have become more feasible. CAC submitted that Manitoba Hydro is a price taker in the U.S., and thus is exposed to the cost of alternative technologies and market rates, being unable to obtain pricing based on its own cost structure. According to CAC, this confluence of factors eviscerated the "decade of returns" previously envisioned by Manitoba Hydro.

CAC was critical of the presence of sunk costs in Manitoba Hydro's analyses, which make non-hydro alternatives less competitive than they would otherwise be. CAC further stated that the inclusion of Bipole III costs and the Gillam expansion, both of which form part of Manitoba Hydro's northern strategy, further harm such alternative plans.

CAC further noted that the changes to a number of factors in Manitoba Hydro's analysis, including changed capital costs and economics, the revelation that the most economically competitive plan, which would have had a 250 MW interconnection, was not viable, and the exclusion of certain updates from new analyses all led to "resource planning on the fly."

CAC concluded that Manitoba Hydro's analysis did not constitute good integrated resource planning. According to CAC, Manitoba Hydro's plan suffers from an overstatement of demand, and the failure to include demand side management (DSM) as an integral element of resource planning constitutes a fatal flaw in Manitoba Hydro's business case. CAC noted that the rate of electricity demand growth in North America has been decreasing over the past decade and that there is the possibility of a zero-growth future. All of this creates risk when investing in a "merchant plant", i.e., a plant designed primarily for export.

CAC recommended that DSM Level 2 savings should be anticipated to extend beyond 2018, and that multi-year DSM targets should be imposed on Manitoba Hydro and reviewed by the Public Utilities Board on an annual basis.

CAC considered the impact of the Preferred Development Plan on ratepayers to be unacceptable, and states that electricity is an essential service and basic necessity for lower income consumers, who would have to pay an increasingly large percentage of their budget for electricity under the proposed rate increases. This issue is amplified for northern and aboriginal ratepayers who pay disproportionally large hydro bills. CAC stated that lower income customers face significant barriers in accessing DSM programs that could improve affordability, which means such programs should be straightforward for lower income ratepayers and, ideally, not involve a cost to the ratepayers. CAC recommended that a stakeholder consultation process be initiated to remove barriers, and Manitoba Hydro report on the issue in six months to one year.

CAC submitted that the Preferred Development Plan was not justified, and that no further funds should be spent on protecting a Conawapa in-service date without express authority of the Public Utilities Board following an updated consideration of the business case based on modern integrated resource practice. Otherwise, CAC submitted there were three feasible options:

1. Proceed with economic DSM; no build until domestic need date;

2. Proceed with economic DSM and have Manitoba Hydro return with updated information related to integrated resource planning, export opportunities, and a regional cumulative effects assessment; or

3. Proceed with economic DSM, Keeyask, and the 750 MW intertie with conditions.

Despite the fact that two of its expert witnesses spoke in favour of developing Keeyask, CAC submitted that the best option would be Option 2, which should be followed by a further review process. However, if the Panel approves Option 3, CAC recommended a phased approach, in which Manitoba Hydro, until 2018, would be required to expand its DSM program, provide annual cost reporting, and provide a rate impact mitigation strategy. In addition, CAC would like to see the regional cumulative effects assessment reviewed by the Clean Environment Commission. In Phase II, after the construction of Keeyask, CAC would like to see Manitoba Hydro file an updated business case for any further generation based on a comprehensive integrated resource planning framework.

If Keeyask proceeds, CAC further suggested the implementation of a Green Energy Benefit to compensate ratepayers for the disproportionate share of risk borne by them. This benefit could either be directed to persons of modest means or made available to a broader spectrum of ratepayers.

Green Action Centre (GAC)

The Green Action Centre (GAC) supported the target set out in *TomorrowNow: Manitoba's Green Plan* to make Manitoba one of the most sustainable places to live on earth. GAC noted that rate impacts are just one consideration among many others for the NFAT Panel to take into account. Specifically, GAC submitted that the NFAT Panel ought to consider broader societal issues such as jobs and economic benefits, revenue flows to the Province from water rentals, taxes and the debt guarantee fee, and the impact of the Preferred Development Plan on greenhouse gas emissions both within and outside Manitoba.

GAC submitted that Manitoba Hydro's evidence was deficient in failing to treat Demand Side Management (DSM) as an alternative to new generation and wind as an alternative to northern dams. GAC stated that the evidence of La Capra Associates, Mr. Chernick, Mr. Dunsky and Mr. Harper suggests that Manitoba Hydro can offset all currently projected load growth with DSM measures. According to GAC, DSM reduces line losses and emissions, creates jobs, and has proved to be a dependable resource for other utilities.

Of particular concern to GAC was fuel choice. GAC stated that Manitoba Hydro has insufficiently addressed this matter. GAC pointed to what it calls market failures with respect to the installation of electric space and water heat for the convenience of builders and contractors rather than homeowners. In GAC's view, the issue of fuel choice extends to the projected new pipeline load. GAC stated that if the pipeline companies had to pay export market rates for electricity, there would be little benefit for them in choosing electric pumping stations.

GAC is critical of Manitoba Hydro's DSM Level 2 program, stating that other utilities manage to achieve sustained savings of 1.3% per year. In contrast, Manitoba Hydro's proposed program ramps up to 2.1% in the short term, but then decreases gradually to only 0.2% by 2028/29, even including conservation rates and customer generation, neither of which are usually counted in DSM savings. According to GAC, Manitoba

Hydro's 41% probability of new supply being required in 2023 could be significantly reduced with increased DSM and fuel switching. GAC further stated that additional load will not appear overnight, and if growth turns out higher than expected, Manitoba Hydro could add wind resources within two years at a lower cost and at less risk than Keeyask.

According to GAC, the levelized cost of energy (LCOE) of wind would be lower than the LCOE for Keeyask and Conawapa. GAC suggested that for purposes of estimating the capital cost of wind, Manitoba Hydro should use the U.S. Department of Energy's market report as a starting point and determine cost differences specifically between average costs and those expected in Manitoba. Manitoba Hydro should further consult with wind developers as to expected project life and take into account technological and costing trends. GAC further suggested developing several wind sites to a preliminary level so that in the case of supply shortfalls, wind projects could be brought into commercial operation in approximately two years.

GAC recommended that Manitoba Hydro should pursue aggressive DSM, including conservation rates and fuel switching, but acknowledged that vulnerable persons with a high energy burden will require bill mitigation through targeted retrofit and efficiency programs, special rate design and, in some, cases, discounted bills. On the issue of rate design, GAC stated that stakeholder consultation could provide a valuable benefit.

GAC supported the approval of Keeyask and 750 MW intertie, noting that the intertie is the most important asset in Manitoba Hydro's plan and provides economic imports as well as firming capability for wind and solar power. GAC submitted that no case has been made to approve Conawapa, and argued forcefully against new gas generation, especially for baseload. GAC stated that while using gas for space and water heating leads to greenhouse gas reductions, the opposite is true if gas is used to generate electricity.

GAC further submitted that Manitoba Hydro should implement integrated resource planning, including an evaluation of wind integrated and the identification of trigger events to revive Conawapa.

Manitoba Industrial Power Users Group (MIPUG)

The Manitoba Industrial Power Users Group (MIPUG) noted that under Manitoba Hydro's initial numbers, industry could pay an additional $400 million in rates over the next 20 years compared to viable alternatives. MIPUG expressed frustration that the NFAT Review was made difficult by four factors, namely (1) the presence of over $1.4 billion of sunk costs which would have to be written off with all non-Keeyask plans, (2) the fact that the 250 MW transmission line option has effectively been dropped, (3) the absence of a broad resource planning review before the current project-specific review, and (4) the high rate impacts ratepayers are already bearing for Bipole III, a project without associated revenue benefits.

In MIPUG's view, plans that are focused on meeting domestic need rather than export opportunities remain credible, since with economic DSM the required in-service date for new generation could be pushed back to at least 2024. To that extent, MIPUG suggested a possible scenario in which a gas unit would be built before Keeyask, pushing Keeyask back to 2031 or later. MIPUG noted that all plans must consider that electric load forecasts may be reasonable over the short term, but significantly differ from the future reality over the medium to long term. It further observed that Manitoba Hydro's goal of a maximum 10% error over 10 years equates to approximately 3,000 GWh, which is similar to the output from Keeyask.

Nonetheless, MIPUG submitted that a K19/750 MW plan had significant benefits, among them cross-border transmission, the value of which had not been fully captured in the Manitoba Hydro's analysis. It suggested that K19/750 MW could in fact be the preferred plan, but only if mitigation measures were instituted. Specifically, MIPUG suggested that Manitoba Hydro should relax its financial standards such that it does not have to return to 75%/25% debt-to-equity and a 1.20 interest coverage ratio within the next 20 years. MIPUG pointed to several rate-design alternatives filed by Manitoba Hydro that would result in decreased retained earnings at the end of 20 years which, in MIPUG's view, would keep rate increases similar to the increases expected for an all-gas alternative, but would still allow Manitoba Hydro to absorb drought risk, which MIPUG noted does not exceed $3.568 billion even under a high-export price scenario. MIPUG also suggests that transfers to the provincial government through capital taxes and water rental fees should be reduced during the period in which customers face upward pressure on rates. MIPUG stated that under the current scenario, the risk for the K19/750 MW plan is borne by ratepayers, while the Province of Manitoba would reap significant benefits without any negative downside risk.

MIPUG was supportive of DSM Level 2if it is realistic and can be achieved without adverse rate impacts. In MIPUG's view, this would involve a focus on the Program Cost Administrator Test (PACT) and the Rate Impact Measure (RIM) test, and less reliance on the Total Resource Cost (TRC) test currently applied by Manitoba Hydro. The DSM program should also provide sufficient support for self-generation by industrial customers, as well as an encouragement of curtailable load to derive capacity benefits. MIPUG specifically took issue with Manitoba Hydro's cap on the Curtailable Service Program (CSP) and its closure to new entrants.

While MIPUG did not support a plan that involves Conawapa at this time, noting that it brings no benefits and substantial risks, MIPUG was supportive of "minimal" spending of $100-$150 million to protect a 2026 or 2031 Conawapa in-service date. MIPUG submitted that if Manitoba Hydro were to consider that the proposed U.S. 750 MW interconnection can be expanded to 1,100 MW in the future, the value of Conawapa energy could increase. Furthermore, Conawapa could provide a basis for Manitoba Hydro to be able to sell its stake in the 750 MW interconnection in the future.

MIPUG did not support a revision to Manitoba Hydro's import criteria without a detailed and thorough consideration of the risks from such a revision.

MMF

The Manitoba Métis Federation (MMF) submitted that while Manitoba Hydro consulted with Aboriginal communities and shared benefits with the Keeyask Cree Nations, Manitoba Hydro did not apply its proactive approach to partnership to the Métis community. For example, Manitoba Hydro's advisory group on employment only contained Aboriginal representation from the Keeyask Cree Nations despite Métis constituting a significant part of Manitoba Hydro's workforce. The MMF also criticized the fact that there are no adverse effects agreements with respect to transmission impacts, despite over $200 million having been paid for adverse transmission impacts associated with Wuskwatim. In that context, the MMF stated that the assumption in Manitoba Hydro's Multiple-Account Benefits-Cost Analysis that residual impacts would be minimized through mitigation and compensation does not apply to the Métis community, since no compensation was provided to the Métis and mitigation of transmission impacts was not included. The MMF also stated that the cost of Section 35 consultation should have been included in costs, even if such consultation was outside the scope of the NFAT Terms of Reference.

With respect to environmental issues, the MMF cautioned that findings from the Clean Environment Commission and the Canadian Environmental Assessment Agency apply only to Keeyask, but not to Conawapa or other alternatives, and that a regional cumulative effects assessment had not yet been provided. The MMF further stated that information provided by Manitoba Hydro in the course of the NFAT Review did not deal with the collective impact of the Preferred Development Plan.

With respect to rate impacts, the MMF submitted that Manitoba Hydro should diversify its DSM and fuel switching strategy and expand education programs targeted to northern and aboriginal communities. For example, in the MMF's view, not enough attention was paid to fuel switching to biomass, despite woodstoves being a viable source of heat for many aboriginal communities.

With respect to financial and economic risk, the MMF stated that the 78-year study period was too long and tends to favour high-risk hydro-centric plans requiring a large capital investment. The MMF submitted that lower rates in the long term at the cost of significant near-term rate increases would result in intergenerational inequity. In the MMF's view, the Preferred Development Plan was further dependent on the magnitude of future exports and future export prices, the latter of which have been declining over successive forecasts since 2009. The MMF also submitted that if the cost of Bipole III were to be added to the Preferred Development Plan, it would increase the in-service cost of Keeyask from approximately 10¢/kWh to 13¢/kWh, which would not recover the cost of Bipole III and Keeyask until the mid-2040s. The MMF further submitted that treating Bipole III as a sunk cost to be included in all development plans had the effect of biasing the analysis in favour of the Preferred Development Plan.

On the issue of transmission risk, the MMF stated that the deterministic standard applied by Manitoba Hydro to transmission risk could have been met by strengthening interconnections to the United States, and that any reliability benefits from Bipole III would drop with the addition of Keeyask and disappear completely with the addition of Conawapa. The MMF concluded that Manitoba Hydro is placing "too many eggs in one basket" by relying on the northern generation corridor and that greater emphasis should be placed on the need to improve import capability.

The MMF suggested that La Capra's No New Generation "Plan 17" remains an economic option, and that a U.S. 500 kV transmission line without further hydroelectric capacity would improve reliability and increase both the ability to export and import power. The MMF moreover argued that further consideration should be given to this plan, including pursuing additional diversity exchange agreements.

The MMF also submitted that wind could form part of an optimized plan to delay new hydro generation until 2030, which would delay the construction of any new hydro until after the completion of a regional cumulative effects assessment. In the MMF's view, wind as a resource not only provides for greater flexibility, but would allow communities to participate in small-scale renewable projects.

As a procedural recommendation, the MMF submitted that the NFAT Panel should recommend an amendment to existing legislation requiring Manitoba Hydro to undergo an NFAT before any major capital expenditure as a precondition to recovering its costs in rates.

Manitoba Keewatinowi Okimakanak Inc. (MKO)

Manitoba Keewatinowi Okimakanak Inc. (MKO) intervened on issues relating to the socio-economic impact of the Preferred Development Plan and alternatives on the MKO First Nations and the impact of domestic electricity rates over time. MKO's primary focus was the impact of rate increases on citizens of the MKO First Nations. MKO identified its member citizens as being Residential ratepayers and the First Nation governments to be General Service ratepayers, including the four communities receiving diesel-generated power.

In MKO's view, the planned rate increases tied to the Preferred Development Plan will have a disproportionate impact on the Residential and General Service ratepayers in the First Nations areas, as most citizens there are lower income customers and spend a higher proportion of their budget on electricity. Furthermore, for many, income to pay for electricity bills comes from the federal government. MKO noted that Aboriginal Affairs and Northern Development Canada (AANDC) funds electrical costs based on a cost reference manual and not based on actual costs. Of particular concern to MKO is the statistic that currently 86.3% of all Residential and General Service accounts in the MKO First Nations are in arrears, suggesting a significant existing issue with the ability of the MKO First Nations customers to pay the current electric rates. MKO cited several presenters who indicated in a presentation to the NFAT Panel that Manitoba Hydro will not deliver Power Smart programs to customers in arrears.

The MKO suggested that measures are required to mitigate the impact of rate increases on northern First Nations, including the establishment of objectives to make DSM programs available all First Nations customers. In that regard, the MKO sought a recommendation from the NFAT Panel that Manitoba Hydro be directed to regularly measure and report on the actual availability and penetration of Manitoba Hydro's lower income DSM programs to First Nation customers. No rate increase greater than the rate of inflation should apply to ratepayers in the MKO First Nations unless and until Manitoba Hydro or an independent DSM entity makes DSM and Power Smart universally accessible to all customers in the MKO First Nations, and universal penetration of these programs in the MKO First Nations can be confirmed.

The MKO also argued for several rate mitigation measures for MKO First Nations customers, submitting that while they currently pay the same level of rates as other customers, they do not share in the same level of provincial benefits as other ratepayers, with many of them having their income level determined by the Government of Canada. Furthermore, many of them could be classified as "Hydro Affected

Customers" since they reside in an area with significant existing hydro projects. MKO suggested six specific rate mitigation measures:

1. The removal of environmental mitigation costs from rates paid by Hydro Affected Customers, since these customers are directly affected by the environmental effects of the project;

2. An allocation of a greater share of net export revenue based on the recognition that a fundamental change in understanding has occurred since the time First Nations first entered into treaties and signed mitigation agreements, and the recognition that the generating stations located in the area are being used to create export revenue;

3. The creation of an "equivalent to gas" rate for the heat portion of the electricity bill, similarly to what is currently being provided to Manitoba Hydro employees working in the area, who pay a rate equivalent to the lowest average heating cost in Winnipeg. The MKO noted that natural gas service is not available to any of the MKO First Nations;

4. An allocation of net export revenue to reduce the cost of service in the four remaining Diesel communities that are not connected to the electric grid;

5. A removal of water rental fees from the bills of Hydro Affected Customers. In MKO's view, these represent an indirect provincial taxation from which First Nations should be exempt; and

6. The creation of a First Nation customer class, of which Hydro Affected Customers could be a sub-class.

Lastly, MKO noted that there is no reason why First Nations that have been affected by northern dams before the current benefit sharing model with the KCN was developed should not receive a portion of the benefits from past or current projects as well.

APPENDIX 7 Summary of Public Presentations

For the completeness of the record, this Appendix provides a summary public Presentations received by the Panel. The Panel regrets any errors or omissions that may have occurred in summarizing these Presentations. The full Presentations can be accessed at http://www.pub.gov.mb.ca/nfat.

Winnipeg Harvest

Donald Benham spoke to Winnipeg Harvest's perception on how Manitoba Hydro's plans are likely to affect lower income Manitobans. Mr. Benham noted Manitoba Hydro's current policy does not distinguish rates on ability to pay. It was also noted that the policy of cross-subsidization is already well-established in relation to urban-rural ratepayers. Based on this policy, rates are set to increase uniformly and lower income ratepayers are not able to absorb the increases. This results in more people taking money out of food budgets and greater reliance on food assistance from Winnipeg Harvest and its associated agencies.

Winnipeg Harvest then issued a proposal. The proposal recommends that the PUB raises rates by no more than one percent per year for lower income ratepayers. Ratepayers would apply to be designated as lower income ratepayers. Income levels for determining eligibility would be based on the 2012 Acceptable Living Level report. The Acceptable Living report produced by Winnipeg Harvest and the Social Planning Council of Winnipeg measures how much money is needed to buy basic necessities in Winnipeg.

It is also the position of Winnipeg Harvest that flooding and dams negatively affect the fishing, hunting and gathering of indigenous peoples in rural communities and their ability to provide their own food.

Bipole III Coalition

Dr. Garland Laliberte's presentation questioned Manitoba Hydro's load forecast upon which its preferred development plan relies. He stated that recent trends in both energy and peak load reveal a flattening of growth in Manitoba load that began in 2005/06, well before the 2008 recession. He further stated that this points to a similar flattening of demand in the region into which Manitoba seeks to export electricity and beyond. He proposed replacing Manitoba Hydro's load forecast with a moderate forecast that is more reflective of the trends outlined. The risk of proceeding with the preferred development is rates that escalate even more rapidly than projected. He raised the possibility of Manitoba Hydro becoming insolvent. He advocated a pause in the implementation of any plan, a pause which would allow the utility to take advantage of the extended timeline that a more moderate load forecast would permit. Further, domestic load should be continually monitored, and there should be further reviews based on more credible load forecasts.

Manitoba Industrial Power Users Group

Mr. Bill Turner stated that the recent change in available lower-cost natural-gas-produced power in the U.S. is making it more difficult for some major Manitoba companies to be competitive in the export of finished goods. Given the relative importance of electricity to industry, both the actual price and the predictability of electrical costs are extremely important. The Manitoba Industrial Power Users Group asked the Board to take a long-term view and allow them to retain a competitive position in Manitoba and in North America. The Manitoba Industrial Power Users Group indicated the importance of its associated businesses to the Manitoba economy.

Mr. Turner stated that although the Manitoba Industrial Power Users Group is supportive of continuing hydro development, it has concerns with the current preferred development plan. Mr. Turner indicated that industrial users are eager participants in Demand Side Managements programs. The Manitoba Industrial Power Users Group supports expansion and exports to other markets by Manitoba Hydro, but not at the sake of loss of domestic power loads.

Mr. David Forsythe relayed further concerns industrial users have with the Preferred Development Plan, specifically with the risk borne by ratepayers. He indicated that if the assumptions of Manitoba Hydro are incorrect, ratepayers will face rapidly increasing costs, contrary to the interests of industrial users.

Interchurch Council on Hydropower

Mr. Will Braun provided the Board with concerns relating to the Preferred Development Plan. He indicated that the faltering of Wuskwatim is a key indicator of issues with the overall plan. Wuskwatim highlights the risk and unpredictability of Manitoba Hydro's forecasts. He further stated that the resulting rate increase cannot be afforded by residents of northern Manitoba. He also outlined a number of environmental issues associated with the project, including the macro environmental impacts of the Preferred Development Plan fuel source in relation to the Churchill River Diversion. In his opinion, Manitoba Hydro failed to properly consider Demand Side Management as an alternative to the Preferred Development Plan. He argued that this planning error is so fundamental it should stop the process.

Canadian Wind Energy Association

Mr. Tom Levy provided a letter that presented CanWEA's belief that wind energy will continue to make a valuable contribution to Manitoba's future electricity needs. Further, he stated that wind energy is increasingly cost-competitive, provides important economic benefits to rural communities and can serve as a valuable complement to hydroelectricity.

Elton Energy Co-operative

Mr. Dan Mazier submitted a letter highlighting considerations for future energy production. It stated that the cost per kWh of non-hydro renewable energy continues to be economically competitive compared to non-renewables and non-hydro renewable energy can serve as a valuable complement to hydroelectricity.

The Lake on the Pembina Committee

Mr. David Melvin appeared on behalf of The Lake on the Pembina Committee, which represents five rural municipal governments and numerous village and town councils in the Pembina valley area of southern Manitoba that is not currently served by natural gas. He suggested that there would be significant benefits to expand gas service to the area, as with the phase-out of coal, businesses and industry would have to switch to expensive hydroelectricity, while in southwestern Manitoba, gas is being flared off. He further suggested that southeastern Manitoba would be an excellent location for a gas generating plant, since existing transmission already exists in the area due to the St. Leon windfarm.

GEOptimize

Mr. Ed Lohrenz stated that the use of geothermal energy is a more cost-effective alternative to hydroelectricity. He further stated that geothermal energy is established and proven in Manitoba, and less expensive to implement than the proposed projects as well as better for the environment. In this analysis, he compared the energy projections associated with the Preferred Development Plan to possible production from increased geothermal development. He presented information showing the increasing use of geothermal energy in Canada and the United States, citing increased accessibility and improved installment training that reduce risk in implementation.

50 by 30

Mr. Daniel Lepp Friesen spoke to 50 by 30's proposed goal to increase Manitoba's renewable energy use from 30% to 50% by the year 2030. In implementing this plan, he suggested utilizing renewable energy sources in combination with demand reduction programs. 50 by 30 would like to Panel to evaluate Manitoba Hydro's plan in the context of an overall energy policy in Manitoba, and suggests long-term, comprehensive planning prioritizing renewable energy sources.

Buller Center for Business

Mr. Bruce Duggan presented his concerns about Manitoba Hydro's Preferred Development Plan, in particular the capital expenditure forecast. He expressed concern with the debt financing approach the project would require and the fiscal stability of Manitoba Hydro and the province. He suggested delaying the project until Manitoba Hydro provides evidence that it has fully utilized Demand Side Management. He also suggested delaying the project until after Bipole III expenditures have peaked to reduce the pressure on Manitoba Hydro to raise debt.

Tim Sale

Mr. Sale expressed concern with Manitoba Hydro's Preferred Development Plan, and is of the opinion that the plan exposes Manitobans to unacceptable risks and major rate increases. He questioned Manitoba Hydro's past record of capital cost estimates. In his assessment he also considered the low cost of natural gas, the decreasing cost curve of alternative energy production methods, and unstable future interest rates. He advocated an assessment based on risk management. Mr. Sale believes Manitoba Hydro should prioritize its mandate to provide cost-effective power to Manitobans.

Prof. David G. Barber

Professor Barber of the Center for Earth Observation Science presented on climate change, including recent assessment reports, increasing global land-ocean temperatures, and reduction of sea ice caused by society's addiction to fossil fuels. He indicated that these changes could impact Manitoba infrastructure and agricultural crops and are already affecting the global economy through natural disasters. Professor Barber stated that climate change is a present issue that requires responsive planning.

Jackie Girardin

Ms. Girardin is concerned about electricity rate hikes proposed by Manitoba Hydro. She indicated that individuals who live in rural Manitoba only have the option of using electricity to heat their homes. She characterized the proposed rate increases as "outrageous" and states that increased electricity costs of this magnitude will put a significant financial strain on her and individuals in similar circumstances.

Ken Klassen

Mr. Klassen has over 30 years of experience focused on improving the energy and environmental performance of new and existing buildings and communities. He stated that the employment projections and comparisons of the Preferred Development Plan as compared to Demand Side Management are problematic. Mr. Klassen questioned the projected employment creation and the low number of permanent jobs created by the Preferred Plan. He indicated there were numerous employment advantages to using Demand Side Management.

Mr. Klassen indicated other benefits of using Demand Side Management. He stated energy efficiency was the lowest cost source of increased available electricity, and he believes that there has been a lack of consultation with local energy efficiency experts. He indicated there are a numerous energy efficiency measures that remain options.

Allan Ciekiewicz

Mr. Ciekiewicz presented his concerns with Manitoba Hydro's Preferred Development Plan, citing inaccuracies with its underlying predictions, projections and forecasts. He questioned the burden the Plan places on ratepayers for the purpose of supporting export markets. He questioned Manitoba Hydro's transparency. He argued that current production capabilities combined with Demand Side Management are sufficient to meet energy demands. He also addressed the possible risks associated with the Preferred Development Plan, specifically the possible repercussions of a severe drought. In addition, he questioned the planned rate increases in light of what he perceived to be Manitoba Hydro's excessive capital expenditures.

Dr. Peter Kulchyski

Dr. Kulchyski presented on hidden costs associated with the Keeyask and Conawapa projects. These hidden costs relate to potential aboriginal title and rights liabilities, and costs associated with continuing detrimental social impacts of these developments on local indigenous communities. He stated that outstanding or unfulfilled Treaty rights or claims can be considered contingent liabilities that have not been properly accounted for by Manitoba Hydro.

Dr. Kulchyski gave three examples of the liabilities potentially affecting the projects. They are a) the lack of signatures on Treaty 5 by Tataskweyak representatives; b) the non-surrender of water rights in Treaty 5; and c) the lack of constitutional amendments supporting the so-called implementation agreements associated with liabilities arising from obligations made in the Northern Flood Agreement. Dr. Kulchyski further stated that problems associated with these agreements could lead to substantial claims by indigenous communities, the notion of which is reinforced by the Supreme Court's strong position on protecting Aboriginal and Treaty rights. He argued that Manitoba Hydro's development plans will only benefit the small professional class, and will not alleviate poverty in those communities but create further disparity.

Solange Garson, Carol Kobliski & Janie Duncan

Ms. Garson, Ms. Kobliski and Ms. Duncan all expressed concerns with the transparency and accountability of Manitoba Hydro's expenditures and relations with First Nations communities. They feel that Manitoba Hydro has not utilized funds appropriately, causing unnecessary expenses to be passed on to ratepayers and communities affected by hydro development. There was particular concern with expenses relating to legal and consulting costs spent in planning and negotiations. They are concerned that business entities meant to accumulate economic benefits for first nations communities have failed to do so. Ms. Duncan argued that the Preferred Development Plan should not go forward.

Lorna Kopelaw

Ms. Kopelaw advocated for the communities along routes 201, 202, 203 and 204. Ms. Kopelaw argued that Manitoba Hydro's plan was severely flawed. She stated the plan will damage the heritage of these communities, have negative financial impacts, damage the ecosystem, and threaten the health of these communities. In her opinion, the plan unfairly exploits these communities.

Pimicikamak Okimawin

Mr. David Muswaggon expressed his community's concerns regarding the development plan. Mr. Muswaggon expressed his people were not in support of Manitoba Hydro's project, both due to the escalating costs of hydroelectricity for consumers and the destruction of their homeland and heritage. He expressed the opinion that the current infrastructure is sufficient to support Manitoba's energy needs. He expressed concerns that the ecological and cultural costs have not been adequately addressed in energy development and planning. He encourages an assessment of the legality and fairness of the projects that reflects indigenous peoples as a sovereign indigenous nation with their own values and legal systems.

Mr. Darwin Paupanekis presented a historical background of the Pimicikamak people, including specifics about their historical lifestyle and connection to the land. Further, Mr. Paupanekis described the impact he believed continued development by Manitoba

Hydro would have on the land and lifestyles previously stated. His people do not believe Manitoba Hydro has properly considered the needs of northern Manitobans, and has failed to properly mitigate ongoing environmental concerns. In addition, he stated that the Province of Manitoba and Manitoba Hydro have failed to meet their obligations related to the Northern Flood Agreement and other Treaties.

Ms. Flora Jane Ross spoke to the difficulties faced in their community. She discussed problems with basic amenities, sickness, and education. To address these problems, she stated that it is important to be able to access and utilize their land for traditional purposes.

Mr. Mervin Garrick expressed his concern with the Province's history of compliance with the Northern Flood Agreement. He believes the spirit of the agreement has not been fulfilled. He cites issues relating to continued poverty, unemployment and environmental damage in his community.

Mr. Tommy Monias expressed his belief that Manitoba Hydro has utilized an imbalance in bargaining power in its relations with aboriginal people. He encouraged alternatives to hydroelectricity, such as biomass and wind.

Mr. George Ross expressed concern regarding the relationship between Pimicikamak and the Province. He highlighted differences observed between pre- and post-development of hydroelectric dams proximate to their community. He further expressed concern about high electricity rates.

Mr. Jeremy Ross presented his objection to development of new dams. In his opinion, the current electricity production is sufficient, and any further development is not worth the resulting difficulties faced by surrounding communities. He also objected to any increased rates for people in his community due to the increased financial strain that would result.

Mr. Darrell Settee expressed disapproval with Manitoba Hydro's projects in their entire form. He is concerned with the environmental and ecological impacts of the projects. He questions the value of the projects. He is also concerned with the loss of land with important cultural, traditional and spiritual significance.

Ms. Shelly Paupanekis spoke against any further hydro developments in the area, due the negative impacts they have on the land, waters, resources and recreation for those living in Cross Lake.

Mr. Jack Osborne objected to any further hydro developments at this point in time. He requests further consultation with First Nations people before further developments take place.

York Factory First Nation – Gordon Wastesicoot

Mr. Wastesicoot presented the views of York Factory First Nation in support of the Keeyask Project. The community heavily analyzed the benefits and costs of the project and decided in its favour. He further stated that the financial and employment benefits from the project would not otherwise be available, and he expressed hope that the project will improve the socio-economic conditions of the community. The community is optimistic that it can navigate any obstacles faced to reach a mutually satisfying result. Mr. Wastesicoot expressed concern with increasing rates and the financial strain faced by his community.

Gerhard Randel

Mr. Randel presented an alternative to bury Manitoba Hydro's overhead high voltage transmission lines. He suggested that burying the lines will have the benefit of reducing lost electricity in transmission due to electromagnetic fields. By failing to pursue this alternative, Mr. Randel argued that Manitoba Hydro has failed to follow its mandate to produce electricity in a cost-efficient way. He further stated that burying the transmission lines also reduces health, environmental and economic costs. He cited studies showing increased incidents of cancer resulting from living close to transmission lines. He also explored risks associated with maintaining overhead transmission lines.

Jason Cook

Mr. Cook presented his experience on the effects hydro development has had on traditional aboriginal lifestyles. He described the destruction of his homeland and the environment. He indicated that navigational waterways are no longer safe to travel. He requested that future plans include a full socio-economic analysis that includes the costs previously stated. He also requested that that resource development should be planned and implemented in a transparent, accountable and equitable manner.

Leona Massan

Ms. Massan expressed concern with the cost of hydroelectricity in Gillam, Manitoba, and its effect on the strained financial budget of its residents. She questioned the underutilization of northern residents in project employment. She also cited examples of environmental and ecological damages caused by hydroelectrically development in her community.

Manitoba Keewatinowi Okimakanak

Elder Flora Beardy expressed thoughts and concerns of the community of York Landing. She indicated that the proposed rate increases would result in hardship for many residents. She indicated the nature of how residents of northern communities address budgetary concerns to attempt to address their basic needs. She requested that Manitoba Hydro come to the community to inform and advise residents on Power Smart and low income programs to help reduce electricity bills.

Mr. Roger Ross spoke on behalf of the Manto Sipi Cree Nation, which is concerned about the potential impacts of proposed rate increases at approximately double the rate of inflation. He calls on Manitoba Hydro to do everything possible to reduce electricity bills paid by First Nations people. He further recommended that the qualification requirements for the Home Insulation Program should not exclude individuals in arrears on their electricity bills. He does not want increased electricity costs to result in a reduction in the level of community programs and services in northern Manitoba.

Mr. Michael Anderson reiterated the difficulty faced by the community in affording hydro bills. He also addressed the problem previously addressed in the qualifications for the Power Smart program. He argued that the inability of these individual to access the Power Smart program inhibits them from reducing or paying off those debts. He also argued that First Nations people affected by hydro developments should be provided a portion of the revenue generated by such developments, and articulates a number of related options. The recommendations by Mr. Anderson in the presentation session mirrored the closing submissions of MKO.

Fox Lake Cree Nation

Mr. Ralph Beardy presented the impacts of the Preferred Development Plan in Fox Lake from the perspective of a business owner. One major issue with local hydroelectric development in the town of Gillam is a greater demand for land, contrary to Fox Lake's plans, historical claims, treaty and aboriginal rights. He referenced Fox Lake's support of the Keeyask project. Fox Lake is hoping to reach a mutually beneficial agreement with Manitoba Hydro regarding Conawapa. He suggested that a future goal for the community should be to work with Manitoba Hydro and the provincial government to create opportunities in Fox Lake.

Mr. Conway Arthurson spoke to the need for Fox Lake's First Nations community to be allotted more reserve land in Gillam. The Fox Lake First Nation requested the support of Manitoba Hydro as a third party interest holder in attempting to obtain more reserve land.

Fawn Morales

Ms. Morales suggested the possibility of creating a lock port on the Nelson River to allow safer navigation by boat. She discussed the negative impacts the dam had on marine life on which her people have relied. She expressed concern with the reduction of boreal forests and the destruction of ecosystems due to hydro development.

Alberteen Spence

Ms. Spence stated that she did not support the Keeyask dam with the current management and projections. She is not in favour of the major risk the project places on Manitobans, in particular First Nations people in northern Manitoba. She supports further analysis on alternative forms of energy.

Tataskweyak First Nation

Elder Eunice Beardy expressed concerns about the damages related to dam development. In her opinion although Manitoba has consulted with first nations people on certain issues, they have failed to show commitment to those groups in the implementation stages. She is concerned the land and environment will deteriorate further in future generations.

Ms. Charlotte Wastesicoot stated her belief that Manitoba Hydro should focus on stakeholders within its mandate, mainly provide sufficient power for the people of Manitoba.

South Indian Lake

Ms. Shirley Ducharme presented on the socio-economic impacts of past hydroelectric developments on their community. She indicated that the biggest impact has been on the fishing and trapping industry. There have been few employment opportunities provided to individuals in impacted communities. Due to hydro development the community have been unable to pursue traditional activities. The compensation for these losses has not been sufficient.

Ms. Hilda Dysart and Leslie Dysart spoke to the environmental impact of hydro development and the resulting impact on traditional aboriginal lifestyles. The cost to First Nations communities in surrounding areas is not worth the addition of the new dams.

Nisichawayasihk Cree Nation

Mr. Marcel Moody disputed information brought forward by previous presenters regarding the implementation of the Northern Flood Agreement. He stated that the Northern Flood Agreement has had success in spurring economic development in his community. He further stated that certain critiques of the agreement and Manitoba Hydro were uninformed and inaccurate on the actual compensatory measures being implemented. In his opinion, the partnership between Manitoba Hydro and his community has been working.

Elders Jimmy Hunter-Spence and Joe Moose reiterated the working relationship the community has with Manitoba Hydro. They stated that the two parties have worked together to form a relationship established on mutual respect and trust.

APPENDIX 8 Appearances

Manitoba Hydro Witnesses

Scott Thomson, President & CEO, Manitoba Hydro

Load Forecasting Panel

Ed Wojczynski, Division Manager, Portfolio Projects Management, Manitoba Hydro
Lloyd Kuczek, Vice President, Customer Care & Energy Conservation, Manitoba Hydro
Lois Morrison, Division Manager, Consumer Marketing and Sales, Manitoba Hydro
Dale Friesen, Division Manager, Industrial & Commercial Solutions, Manitoba Hydro
Ian Page, Division Manager, Corporate Planning & Strategic Review, Manitoba Hydro
Ingrid Rohmund, Director, Energy Analysis and Planning, EnerNOC Inc.

Needs and Alternatives Panel

Joanne Flynn, Division Manager, Power Planning, Manitoba Hydro
Terry Miles, Manager, Resource Planning & Market Analysis Department, Manitoba Hydro
Bill Hamlin, Manager, Energy Policy & Analysis Department, Manitoba Hydro
David Cormie, Division Manager, Power Sales and Operations, Manitoba Hydro
Dave Bowen, Manager, Project Services Department, New Generation and Construction Division, Manitoba Hydro
David Jacobsen, Section Head, Interconnections & Grid Supply, Manitoba Hydro
Adam Borison, Director, Navigant Consulting Inc.
Dean Murphy, Principal, Brattle Group
Eric Swanson, Attorney, Winthrop & Weinstine, P.A.
Rene Roy, Director, Scientific Programme, Ouranos Consortium
Kristina Koenig, Hydrologic Studies Section Head, Water Resources Engineering Department, Manitoba Hydro

Finance Panel

Darren Rainkie, Vice President, Finance & Regulatory, Manitoba Hydro
Manfred Schulz, Corporate Treasurer, Manitoba Hydro
Liz Carriere, Manager, Financial Planning Department, Manitoba Hydro
Greg Barnlund, Division Manager, Rates & Regulatory Affairs, Manitoba Hydro

Socio-Economic Panel

Shawna Pachal, Division Manager, Power Projects Development Division, Manitoba Hydro
Jane Kidd-Hantscher, Partnership Implementation Supervisor, Manitoba Hydro
Marvin Shaffer, Consultant, Marvin Shaffer & Associates Ltd.
Karen Anderson, Director of Operations, Fox Lake Cree Nation Negotiations Office
Ted Bland, Senior Negotiator, York Factory Future Development
Norman Brandson, Consultant, N2B Environmental, Resource & Governance Consultancy and EarthWise Environmental Governance
Martina Saunders, Negotiator, York Factory Future Development
Victor Spence, Manager of Future Development, Tataskweyak Cree Nation

Independent Expert Consultants

Robert Sinclair, Vice President, Potomac Economics, Ltd.
David Patton, President, Potomac Economics, Ltd.
John Todd, President, Elenchus Research Associates
Russ Houldin, Associate, Elenchus Research Associates
Craig Sabine, Senior Manager, Energy and Utilities, MNP
Sarah Keyes, Consultant, Energy and Utilities, MNP
Dan Peaco, President, La Capra Associates
John Athas, Principal Consultant and Treasurer, La Capra Associates
Mary Neal, Consultant, La Capra Associates
Glenn Davidson, Senior Project Manager, Power Engineers
Brian Furumasu, Senior Project Manager, Power Engineers
Paul Arnold, Senior Project Manager, Power Engineers
Michael Robertson, Specialist Engineer and Project Manager, Knight Piésold
Boris Fichot, Senior Engineer, Knight Piésold
Russell Tyson, President, TyPlan
Pelino Colaiacovo, Managing Director, Morrison Park Advisors
Benjamin Kinder, Vice President, Morrison Park Advisors

Intervener Panels

Affordability Panel

Gio Robson, Certified Energy Advisor and President, prairieHOUSE Performance Inc.
Gloria Hartley
Dave Mouland
Albertine Mason

Jacqueline Salamisan
Darrell Settee
Richard Genaille

Elders and Traditional Land Users

Noah Massan
Robert Spence
Flora Beardy
Ila Disbrowe
Christine Massan
Jack Massan
Ivan Moose

Intervener Experts

Phillipe Dunsky, President, Dunsky Consulting Inc.
William Harper, Associate, Econalysis Consulting Services
Douglas Gotham, Director, State Utility Forecasting Group, Purdue University
Wayne Simpson, Head, Department of Economics, University of Manitoba
Harvey Stevens, Consultant
Melanie O'Gorman, Associate Professor, Department of Economics, University of Winnipeg
Jerry Buckland, Professor of International Development Studies and Dean, Menno Simons College
Marla Orenstein, Senior Partner, Habitat Health Impact Consulting
Kyrke Gaudreau, Sustainability Manager, University of Northern British Columbia
Robert Gibson, Professor and Associate Chair, Department of Environment and Resource Studies, University of Waterloo
Jill Gunn, Assistant Professor, Department of Geography and Planning, University of Saskatchewan
Roger Higgin, Principal, Sustainable Planning Associates Inc.
Paul Chernick, President, Resource Insight, Inc.
Wesley Stevens, Senior Associate, Power Advisory LLC
Patrick Bowman, Principal and Consultant, InterGroup Consultants, Ltd.
Rick Hendricks, Director, Camerado Energy Consulting Inc.
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Meghan Menzies, Counsel, CAC
Aimée Craft, Counsel, CAC
Joëlle Pastora Sala, CAC
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Peter Miller, Advisor, GAC
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Diana Villegas, Administrative Assistant to the Public Utilities Board
Larry Buhr, Public Utilities Board Advisor
Roger Cathcart, Public Utilities Board Advisor
Brady Ryall, Public Utilities Board Advisor

APPENDIX 9 Glossary of Terms

2x16 Power: Power delivered two days a week (during weekends) for 16 hours per day, from 6:00am to 11:00pm.

5x16 Power: Power delivered five days a week (during weekdays) for 16 hours per day, from 6:00am to 11:00pm.

Alternating current (AC): Electric current that reverses its direction of flow at regular intervals. This occurs 60 times each second and is referred to as a frequency of 60 cycle (Hertz). All utilities in North America use 60 Hertz.

Average Energy: The energy Manitoba Hydro can produce in any given year based on average water flows.

Base Load: The basic demand for electricity that is expected during all times.

Bilateral Contract: A contractual agreement between two market participants for the purchase or sale of capacity and/or energy.

Board Counsel: Legal counsel to the Public Utilities Board, who acted as counsel to the NFAT Panel.

Canadian Environmental Assessment Agency: The federal Canadian environmental assessment body.

Capacity: The amount of power that a piece of equipment, or a group of pieces of equipment acting together, can generate or transmit. For example, a transmission line may have a transfer capacity of 750 megawatts or a generating station may have a capacity to produce 1200 megawatts.

Carbon Price: A tax or surcharge levied by the government on electricity generated from sources that emit carbon dioxide (CO2). The carbon price is specified in dollars per tonne of CO2. Different generating stations produce different amounts of carbon dioxide per MWh of electricity output, with coal producing the greatest amount of CO2 and combined cycle gas turbines producing about half of the emissions of coal per MWh.

Clean Environment Commission (CEC): Manitoba's environmental regulatory tribunal.

Combined Cycle Gas Turbine (CCGT): The combination of a gas turbine and a steam turbine in an electric generating plant. The waste heat from the gas turbine provides the heat energy for the steam turbine.

Conawapa Generating Station: A proposed new hydroelectric generating station with a capacity of 1,485 MW, producing 4,650 GWh of dependable energy per year and an average of 7,000 GWh per year.

Consumers' Association of Canada (Manitoba) Inc. (CAC): One of the five Interveners in the NFAT Review.

Congestion: Congestion occurs when there is inadequate transmission to deliver all of the lowest-cost power to the load.

Contingency or Operating Reserves: Available spare generation that must be kept available in the event of sudden generation or transmission outages.

Curtailable Load: A DSM load reduction program in which customers agree to a partial or complete power shut off for a limited period of time in exchange for lower electricity rates.

Demand Side Management (DSM): A targeted reduction in the demand for electricity through energy efficiency measures and updated codes and standards. DSM can reduce the requirement for new electricity generation and serve as a source of meeting demand in the same manner as new generation. Manitoba Hydro administers DSM through its Power Smart plan.

Dependable Energy: The energy that a generation station or electric system can produce under the lowest water flow conditions. Manitoba Hydro's total dependable energy is comprised of dependable energy from hydro generation, thermal generation, wind generation, and imports.

Discount Rate: A percentage rate by which a future revenue flow is discounted to derive the Net Present Value (NPV) of that flow of money.

Distributed Generation: Electricity generation located throughout the electrical distribution system, usually closer to load centres or downstream of the customer's meter. Distributed generation is usually comprised of smaller-scale generating facilities.

Diversity Agreements or Diversity Exchanges: Agreements that provide for the seasonal exchange of power between utilities during their respective peak load periods. When utilities have opposite peak load seasons, they can enter into diversity agreements to exchange power. For example, Manitoba's peak power load is in the winter, while Minnesota's peak power load is in the summer.

Energy: A quantity of power consumed over a period of time. Energy is expressed in kilowatt-hours (kWh), megawatt-hours (MWh) or gigawatt-hours (GWh). A 100-watt incandescent light bulb burning for 10 hours consumes one kWh (0.1 kW x 10 hrs).

Energy Information Agency (EIA): Part of the U.S. Department of Energy, the EIA creates forecasts for electricity and natural gas consumption, market prices, and supplies that are used by the electricity industry.

Expected Value: The probability-weighted NPV of the development plans calculated from the low, reference, and high estimates of energy prices, capital costs, and economic indicators/discount rates. Expected value is used in the economic analysis.

Firm Export: The guaranteed sale of a contracted amount of energy and/or capacity to utilities or customers located outside of Manitoba.

Firm Power: Capacity and energy that must be supplied to meet domestic demand or under certain export contracts. Firm power is guaranteed to be available when specified and can only be interrupted in emergencies or when the reliability of the power system is threatened.

Firm Transmission Service: Full path transmission service that has the highest priority and cannot be interrupted unless all lower priority levels of service have been interrupted.

Fracking or Hydraulic Fracturing: A technique for drilling and completing natural gas wells that, combined with horizontal drilling, produces greater amounts of gas from an individual well. Fracking has significantly increased the North American supply of natural gas.

Fuel Switching: The switch from one heating fuel source to another (e.g., gas to electricity or electricity to gas).

GHG: See Greenhouse Gas.

Gigawatt-Hour (GWh): A unit of electrical energy. A GWh is the amount of electrical energy produced by one gigawatt of power applied over one hour of time, or 1000 MW over one hour.

Green Action Centre (GAC): One of the five Interveners in the NFAT Review.

Greenhouse Gases (GHG): Gases that contribute to climate change because of they contribute to the greenhouse effect of the Earth's atmosphere by trapping thermal radiation from the sun. For electricity generation, the most common greenhouse gas - and the one of greatest concern - is carbon dioxide, which is a product of the combustion of fossil fuels such as coal and natural gas.

Grid Parity: The point where distributed generation technologies such as solar photovoltaics can generate electricity for the same cost as buying electricity from the utility using its distribution grid.

Gross Firm Energy: The total annual non-curtailable demand for energy in Manitoba.

Gross Total Peak: The highest demand for power to be expected in Manitoba in any specific year, measured at generation as opposed to at the meter. It typically occurs during the coldest winter day.

Hydraulic Fracturing: See Fracking.

Independent Export Consultant (IEC): Independent third-party experts retained by the NFAT Panel for purposes of the NFAT Review. IECs were represented by independent legal counsel and subject to cross-examination of their reports and testimony.

Integrated Financial Forecast (IFF): A 10- or 20-year financial forecast prepared by Manitoba Hydro on an annual basis that details expected revenues, expenses, financial ratios and rate increases.

Intervener: An organization with interest in the NFAT Review that was granted legal standing to appear and adduce evidence, cross-examine witnesses, and make closing submissions. The NFAT Panel granted Intervener status to five parties pursuant to the Public Utilities Board's Rules of Practice and Procedure.

Interconnections: Power lines that interconnect one electrical utility's power system with another. Interconnections facilitate the export and import of power.

Interruptible Energy: A supply of energy, which is subject to short- or long-term interruption with or without notice.

Keeyask General Civil Contract: The contract Manitoba Hydro awarded to construct the majority of the Keeyask generating station, including the rock excavation and concrete works.

Keeyask Generating Station: A proposed new hydroelectric generating station with a capacity of 695 MW, producing annual dependable energy of 3,000 GWh and average annual energy of 4,400 GWh. Manitoba Hydro plans to have Keeyask constructed for a 2019 in-service date.

Kilowatt (kW): The unit of electrical power equivalent to 1000 watts (W).

Kilowatt-Hour (kWh): A unit by which electrical energy is measured. A kilowatt-hour is a unit of energy equivalent to one kilowatt (1000 watts) of power applied over one hour of time. For example, 10, 100 W light bulbs switched on for one hour would use one kilowatt-hour (1000 W one hour). The electrical energy used in homes and small businesses is usually measured in kilowatt-hours.

LCOE: See Levelized Cost of Energy.

Levelized Cost of Energy (LCOE): The cost of constructing and operating a generating resource over its life, including capital cost, fuel cost, and operations and maintenance cost.

Load: The total amount of demand electricity.

Load Serving Utility: an electric utility that supplies electricity to end use customers. Manitoba Hydro, Minnesota Power, and Wisconsin Public Service are all load serving utilities.

Locational Marginal Price (LMP): The MISO market price for energy at a certain location, taking into account transmission losses and congestion effects that depress the price from the System Marginal Price.

Long-Term Firm Exports: The sale of electricity to parties outside Manitoba where the quantity and price of the electricity are fixed over a long-term period.

Manitoba Industrial Power Users Group (MIPUG): One of the five Interveners in the NFAT Review.

Manitoba Keewatinowi Okimakanak Inc. (MKO): One of the five Interveners in the NFAT Review.

Manitoba Métis Federation (MMF): One of the five Interveners in the NFAT Review.

Megawatt (MW): The unit of electrical power equivalent to 1,000,000 watts (W).

Megawatt -Hour (MWh): A unit by which electrical energy is measured. One MWh is a unit of energy equivalent to one million watts of power applied over one hour of time.

Midcontinent Independent System Operator, Inc. (MISO): MISO is a U.S.-based independent, not-for-profit regional transmission organization responsible for maintaining reliable transmission of power in 15 U.S. states and the Canadian province of Manitoba.

Minnesota Public Utilities Commission (MPUC): A regulatory body responsible for the regulation of natural gas and electric utilities in the state of Minnesota. MPUC has oversight over and approves the construction of natural gas and electricity facilities such as electric power plants, transmission lines, wind power generation plants, and large natural gas and petroleum pipelines. Manitoba Hydro's interconnection with the U.S. requires MPUC approval.

MISO: See Midcontinent Independent System Operator, Inc.

MPUC: See Minnesota Public Utilities Commission.

Net Present Value (NPV): The present value of a future revenue and cost stream. NPV is calculated by taking an assumed revenue in each future year and applying a discount rate to account for the time value of money (e.g., $100 ten years from now do not have the same value as $100 today). The applicable discount rate is a matter of judgment and was a subject of debate in the NFAT. Frequently in the NFAT the NPV of development plans is referenced to the NPV of the All Gas plan (i.e. the All Gas plan NPV is set to zero and the NPVs of the other plans are adjusted accordingly)

Nominal Dollars: Future year dollars that include the effect of inflation (CPI increases) as opposed to real dollars which have the effects of inflation removed.

Off-Peak Period: The overnight and weekend hours in a week during which load is usually lower that the average weekly load. Overnight the hours are 5 weekdays x 8 hours/day plus weekends which are 2 days x 24 hours/day.

On-Peak Period: The weekday daytime hours during which load is usually highest: from 6:00 am to 11:00 pm, otherwise known as "5x16."

Opportunity Energy: Available surplus energy that Manitoba Hydro sells into the MISO market at the prevailing spot market price, and for which it has not negotiated firm pricing arrangements through a bi-lateral contract.

Peak Load: Instantaneous maximum amount of electricity used. On an annual basis, peak load in MISO occurs during the summer air conditioning season, while peak load in Manitoba occurs during the winter heating season. On a daily basis, peak load varies with the business cycle.

Person-Year: A person-year of employment is the equivalent of one full time job for one year. The number of hours assigned to a person-year very. In the Keeyask environmental impact assessment, one person-year of employment is defined as 3,000 hours of work.508

Power: The flow of electricity at any given time. Power is expressed in watts (W), kilowatts (kW – 1,000 watts) or megawatts (MW – one million watts).

Real Dollars: Future year dollars that have the effects of inflation removed, as opposed to nominal dollars which include inflation effects.

Simple Cycle Gas Turbine (SCGT): A turbine powered by natural gas or fuel oil in an electric generation plant. The waste heat from the gas turbine is exhausted and not utilized.

Solar Photovoltaic Generation: The conversion of sunlight directly into electricity by incidence of sunlight on a semiconductor surface, also known as a solar panel. The amount of electricity generated is proportional to the size of the solar panel, and can range from roof-top units that generate electricity for a residential home to utility-scale arrays of solar panels that produce megawatts of electricity.

Surplus Energy: Energy not needed to meet Manitoba demand and which Manitoba Hydro is not contractually required to export.

System Marginal Price (SMP): The system-wide MISO market price for energy. SMPs do not take into losses or congestion that can depress the market prices at specific locations.

System Participation Sale: In the context of Manitoba Hydro, a contract through which Manitoba Hydro sells a defined amount of energy, from a defined portion of its installed generating capacity, to a named contractual counterparty. System Participation Sales do not include any generation reserve as required by counterparty's operating authority.

Terms of Reference: The terms of the Panel's mandate to conduct the NFAT Review, including definitions of items that are and are not in scope. The Terms of Reference were approved by Order in Council 128/2013 on April 17, 2013.

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[508] Transcript, p. 3898.

Voltage: The electric potential between two points in an electric connection, expressed in volts (V) or kilovolts (kV). A North American electrical outlet operates at 120 volts. High-voltage transmission usually operates at either 230 kV or 500 kV.

Water Flow: The flow of water through Manitoba Hydro's hydraulic basins and generating stations. It is expressed in cubic metres per second (m3/s).

Watt (W): The unit of measurement of electrical power.

Tab 16

NFAT Manitoba Hydro's Development Plan

A Review of Manitoba Hydro's Load Forecast

John Todd
Elenchus Research Associates
April 2, 2014

Overview

1. Purpose of Elenchus Load Forecast Evidence
2. Setting the Stage
3. Rebuttal Evidence of Manitoba Hydro
4. Key Messages: Concluding Remarks
5. Scope of Work (SOW) Responses

Purpose of evidence

- To address the issues in the MPUB Scope of Work (SOW) on Load Forecasting
- Within the context of the Terms of Reference

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Setting the Stage (1)

Load forecasting in the context of a GRA

vs.

Load forecasting for assessing a development plan

In the long run, structural change is a risk that is a "known unknown".
Relevant for NFAT; not for GRA.

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Setting the Stage (2)

Manitoba Hydro's load forecasting methodology:

- Incorporates known knowns reasonably well
- But ignores known unknowns (i.e., price elasticity and structural change)

At its core the NFAT is an analysis of the long term risks associated with the Preferred Development as compared to the alternatives.

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Setting the Stage (3)

Two missing "worst case" structural change scenarios:

1. **High demand** that result in supply inadequacy
2. **Low demand** that creates stranded assets

How tolerable are the extreme high-impact, low-probability (HILP) events?

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6

Setting the Stage (4)

1. The **high demand** structural change scenario:

- Perhaps, a "tipping point" for electric vehicles

Can MH respond to a worst case increase in demand?

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7

Setting the Stage (5)

2. The **low demand** structural change scenario:

- Disruptive innovation (e.g., grid parity/competitive options)
  - Declining cost of renewables + storage
  - Fuel cell technology
  - Result: low marginal cost and market price for power

The known unknown:
The market price for grid power in the long run (2+ decades).
Is stranded costs acceptable?

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8

Rebuttal Evidence of Manitoba Hydro

- Sect. 2.1, Overview of Forecast Growth
- Sect. 2.4, Price Elasticity
- Sect. 2.5, Adjusting for Weather
- Sect. 2.6, Forecast Variability and Accuracy
- Sect. 2.7, Scenarios and Probability
- Sect. 3.6, Solar and Grid Parity

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Key Messages: Concluding Remark #1

1. At the current time, the load forecast does not provide any alternative economic or population scenarios to test the sensitivity of the load forecast to changes in these assumptions. Elenchus believes that as an input for effective long-term resource planning, Manitoba Hydro should provide alternative economic and population growth scenarios and their associated effects. While Manitoba Hydro provides a simplified probabilistic confidence interval analysis, this does not test the sensitivity of load forecast parameters to changes in input assumptions on economic and population growth.

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Concluding Remark #2

2. Consideration should be given to the financial risks related to potential market transformation, such as grid parity, that could result in a disconnect between Manitoba Hydro's projection of (total domestic) demand and the future demand for grid power.

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Concluding Remark #3

3. Additional transparency about the choice of model and model accuracy needs to be provided. For example, methodological changes in the specification of econometric models have been made from one year to another without adequate explanation about why the changes were made and the effect of the changes. Model performance including within sample error and alternatives considered and rejected would also help increase transparency.

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Concluding Remark #4

4. An updated Residential Survey to reflect current conditions within the Residential market should be undertaken and integrated into the load forecast to verify assumptions about electric heat market share and the end-use model parameters.

Concluding Remark #5

5. Alternate models for projecting the number of Residential customers should be explored and reported on. Alternate population scenarios and the effect on the Residential and GS Mass Market forecasts should to be included.

Concluding Remark #6

6. Manitoba Hydro should explain the alternative models considered for the GS Mass market forecast.

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Concluding Remark #7

7. Alternative economic growth scenarios and additional transparency and analysis on the Top Consumers forecast would improve transparency.

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Concluding Remark #8

8. Elenchus believes the weather adjustment process applied by Manitoba Hydro should be treated with caution and may result in potentially spurious outcomes. Manitoba Hydro should investigate using time series longer than 2 years to estimate the weather sensitivity of its weather sensitive consumption sectors. A more thorough explanation of the weather adjustment process needs to be developed to allow stakeholders to understand the process more clearly.

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Scope of Work, #1

From an energy demand perspective, comment on the extent to which Manitoba's Preferred Development Plan addresses the reliability and security requirements of Manitoba's electricity supply.

- The Preferred Development Plan (and all alternatives) is designed to address the reliability and security requirements of Manitoba's electricity supply. While actual demand could exceed the forecast, the adequacy of supply would only be compromised in the most extreme circumstances.

SOW 1; Elenchus Load Forecast Report sections 3.1 and 3.2

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Scope of Work, #2

Review Manitoba Hydro's Load Forecast factors and comment on whether they are complete, reasonable and accurate.

- The load forecasting methodology is reasonable assuming there are no significant structural changes to the demand drivers that underpin the forecasting methodology. However, given the time frame of the NFAT analysis, it can be expected that there may be significant structural changes that could result in dramatically different domestic demand in the coming decades.

SOW 2; Elenchus Load Forecast Report sections 2.1

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Scope of Work, #3

Comment on the use of an econometric and end-use forecasting methodology.

- The methodology is generally reasonable although some refinements are suggested.

SOW 3; Elenchus Load Forecast Report sections 2.1.1 and 2.1.2

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Scope of Work, #4

Assess the reliability of Manitoba Hydro's short- and long-term domestic Load Forecast modelling.

- Manitoba Hydro's methodology is generally appropriate for short term forecasting (no structural changes). There is limited consideration of factors that could dramatically impact on demand in the long run (over the next decade and beyond).

SOW 4; Elenchus Load Forecast Report sections 3.1 and 3.2

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Scope of Work, #5

Review the extent to which Manitoba Hydro has used appropriate scenario planning to examine the potential impact of changes in the industry, the Manitoba and Canadian economies, available technology (generation and loads) and energy efficiency measures (costs and cost effectiveness).

- Rather than a specific point forecast associated only with a reference forecast, Elenchus believes an approach with a range of outcomes based on Low, Medium-Low, Reference, Medium-High and High economic scenarios should be paired with load forecast outcomes. Manitoba Hydro used this approach until 2009.

SOW 5; Elenchus Load Forecast Report sections 3.2

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Scope of Work, #6

Comment on the appropriate use of probability analysis in projected Load Forecasts.

- The probability approach used by Manitoba Hydro is less transparent and provides less insight than the multiple scenario approach used until 2009. See item 5 above.

SOW 6; Elenchus Load Forecast Report sections 2.1.1 and 2.1.2

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Scope of Work, #7

Comment on the extent to which retrospective load analysis provides confidence in the Load Forecast.

- Retrospective load analysis indicates that confidence in the load forecast is justified except for the Top Users. Top User loads can change significantly in unanticipated ways since their demands are driven by many idiosyncratic factors that cannot be known to Manitoba Hydro.

SOW 7; Elenchus Load Forecast Report sections 2.1 and 3.2

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Scope of Work, #8

Review Manitoba Hydro's 2012 in 2013 load forecasts.

- The review is captured by the other SOW items.

SOW 8; Elenchus Load Forecast Report section 2

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Scope of Work, #9 a)

Compare Manitoba Hydro's 2012 and 2013 Load Forecasts with Manitoba Hydro's historical load forecasts back to 2008 with specific reference to:

a) Population growth (birthrates/immigration)

Historical trends in population growth are reflected in the load forecast. Possible future changes in the historic trends are not specifically considered. See item 5 above.

SOW 9 a); Elenchus Load Forecast Report section 2.1.1

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Scope of Work, #9 b)

Compare Manitoba Hydro's 2012 and 2013 Load Forecasts with Manitoba Hydro's historical load forecasts back to 2008 with specific reference to:

b) Changes in number, size and occupancy of residential dwellings

Historical trends are reflected in the load forecast. Possible future changes in the historic trends are not specifically considered. See item 5 above.

SOW 9 b); Elenchus Load Forecast Report section 2.1.1

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Scope of Work, #9 c)

Compare Manitoba Hydro's 2012 and 2013 Load Forecasts with Manitoba Hydro's historical load forecasts back to 2008 with specific reference to:

c) A comparison of the Load Forecast with similar markets (i.e., are Manitoba Hydro's assumptions consistent with neighbouring jurisdictions)

- Manitoba Hydro's load forecasting methodology and accuracy are broadly consistent with load forecasting in other jurisdictions. For long term planning, however, increasing consideration is being given to the possibility of "game changers".

SOW 9 c); Elenchus Load Forecast Report section 3.2

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Scope of Work, #9 d)

Compare Manitoba Hydro's 2012 and 2013 Load Forecasts with Manitoba Hydro's historical load forecasts back to 2008 with specific reference to:

d) Peak demand and energy trends including seasonal variations in load forecasting

- Manitoba Hydro's methodology is based on the questionable assumption that past trends will continue for the full planning period.
- The load forecast does not address seasonal variations.

SOW 9 d); Elenchus Load Forecast Report section 3.1

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Scope of Work, #10

Review Manitoba Hydro's weather adjustment methodology, with specific reference to:

a) Non-heating load

b) Electric heating loads

c) Commercial or mass-market consumption

d) Distribution Losses

e) Transmission Losses

- Manitoba Hydro gives explicit and appropriate consideration to each factor identified in its weather adjustment methodology, subject to caveats noted elsewhere.

SOW 10; Elenchus Load Forecast Report section 2.1.4

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Scope of Work, #11

Assess the consistency of transmission and distribution losses under various loads and weather occurrences and the assignment of such losses to customer classes.

- The load forecast does not include this level of detail.

SOW 11; Elenchus Load Forecast Report – n.a.

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Scope of Work, #12

Assess the impacts on Load Forecasts resulting from potential fuel switching, particularly in light of recent trends in the cost of natural gas.

- Potential fuel switching is treated for load forecasting purposes as an independent customer decision. Since Manitoba Hydro controls both the electric and natural gas utilities, its decisions and marketing policies are likely to have significant influence on both the decisions made by developers for new buildings and fuel switching decisions (driven in part by the availability of natural gas as a result of system expansions). Over the longer term, the market penetration of natural gas for space heating could be significantly influenced by Manitoba Hydro.

SOW 12; Elenchus Load Forecast Report section 2.1.1

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Scope of Work, #13

Comment on the price elasticity and the impact of electricity rate changes in demand.

- Manitoba Hydro has not been able to quantify the price elasticity of demand for electricity empirically and it consequently excludes price elasticity from its load forecasting methodology. This result may be a reflection of the historically low price of electricity in Manitoba. It is not consistent with the experience of other jurisdictions to assume there will be no price response in the event of more significant electricity rate increases in the future.

SOW 13; Elenchus Load Forecast Report section 2.1.3

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Scope of Work, #14

Review and comment on Manitoba Hydro's historical and forecast growth in electric heating relative to natural gas heating in the context of electricity and natural gas pricing.

- See Slide 31 (SOW #12) above.

SOW 14; Elenchus Load Forecast Report section 2.1.1

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Scope of Work, #15

Review and comment on the extent to which Demand-Side Management and energy efficiency measures have been relied on as an alternative to generation.

- Manitoba Hydro has not utilized integrated resource planning as a basis for establishing the cost effective level of DSM in Manitoba. It has conducted sensitivity analysis with respect to the currently planned level of DSM.

SOW 15; Elenchus Load Forecast Report – n.a., See the Elenchus DSM Report

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Scope of Work, #16

Review and comment on the appropriateness of and uncertainty related to the timelines for future generation assets to meet domestic load requirements and export commitments.

- From a load forecasting perspective, the timelines appear adequate for meeting domestic load requirements and export commitments. The greatest risk relates to the ability to adjust to lower growth in demand in the event of market transformations such as grid parity in Manitoba and/or export jurisdictions.

SOW 16; Elenchus Load Forecast Report section 4

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Scope of Work, #17

Comment on the impact of global warming on the Load Forecast.

- The impact of climate change on the climate in specific areas is proving very difficult to predict. The primary impact appears to be increased uncertainty and more frequent extreme weather conditions. It is therefore difficult to build the impact of climate change into the Manitoba Hydro load forecast. The primary consideration is that longer term trends are more uncertain than ever, which suggests that flexibility in development plans may be of increased importance.

SOW 17; Elenchus Load Forecast Report section 3.2

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Scope of Work, #18

Comment on the Load Forecast for industrial and commercial consumers.

- The forecast for Top Consumers is the only component of the load forecast that has shown large variances. In recent years, there has been a tendency to over-forecast Top Consumer demand.
- There is a risk that Top Consumers could opt for self-generation in the future resulting in declining rather than decreasing demand. There is also a risk that closure in the coming decades could have a significant impact on Top Consumer demand given the small number of customers in this class.

SOW 18; Elenchus Load Forecast Report section 2.1.3

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Scope of Work, #19

Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

- Not applicable.

SOW 19; Elenchus Load Forecast Report – section ?

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Thank You!

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Tab 17

Manitoba Hydro
2017/18 & 2018/19
Electric General Rate Application

December 4, 2017

Kelvin Shepherd, P.Eng
President & Chief Executive Officer
Jamie McCallum
Chief Finance & Strategy Officer

Agenda

I. Overview of Manitoba Hydro
II. Highlights of Manitoba Hydro's Financial Plan
III. Manitoba Hydro Faces Large Risks
IV. Facts of this Rate Case
V. How Did We Get Here?
VI. Addressing Key Concerns
VII. Summary

Manitoba Hydro

Today's Presenters

- Kelvin Shepherd, P. Eng.
  - Appointed President and CEO December 2015
  - 36 years of progressive technical and management experience in large telecommunications companies
  - 9 years as President of MTS
  - Prior to that was Chief Operating Officer and Chief Technology Officer
  - Bachelor of Science, Electrical Engineering, University of Saskatchewan (1981)
- Jamie McCallum
  - Appointed Chief Finance and Strategy Officer February 2017
  - 22 years of experience in strategic and financial planning, corporate stewardship, capital management and capital markets
  - 2004 to 2016: Managing Director of Richardson Capital Limited
  - 1995 to 2004: Investment Banker at several leading global firms
  - Bachelor of Commerce (Hons), University of Manitoba (1995)
  - Former director of six corporations

A New Financial Plan for Hydro

- Old plans were not adequate and far too risky
- MH business outlook has deteriorated significantly
- MH will soon have an unsustainable level of debt
  - Not supportable with rate increases of old plan
- Current rates are not funding the ongoing costs of the current system
- Old financial plan has now **failed**

A New Financial Plan for Hydro

- A new plan is required to continue to keep providing safe, reliable and competitively priced power to Manitobans
  - MH has taken action to increase and accelerate internal cost reductions
  - Streamlined organization, reduced senior management and targeted 15% staff reduction
  - Rates need to be increased more in near term to help mitigate increase in debt levels
  - 10-year plan provides capacity to manage operational/business risks and keep rates lower over long term
- Appreciate the challenges associated with higher rates
  - But it will be worse not to act

I. Overview of Manitoba Hydro

Corporate Profile

Electric Residential Customers **503,000**	Electric Commercial /Industrial Customers **70,000**	Consolidated Assets(1) **$23.7 Billion**	Consolidated Debt(1) **$17.9 Billion**
2016/17 Consolidated Revenue **$2.3 Billion**	2016/17 Electric Segment Domestic Revenue **$1.4 Billion**	2016/17 Electric Export Revenue **$0.5 Billion**	2016/17 Natural Gas Revenue **$0.3 Billion**
2016/17 Consolidated Net Income(2) **$51 Million**	2016/17 Electric Segment Net Income(2) **$33 Million**	Leader in Indigenous Employment **≈1 in 5 Employees**	Equivalent Full Time Employees(3) **5,990**

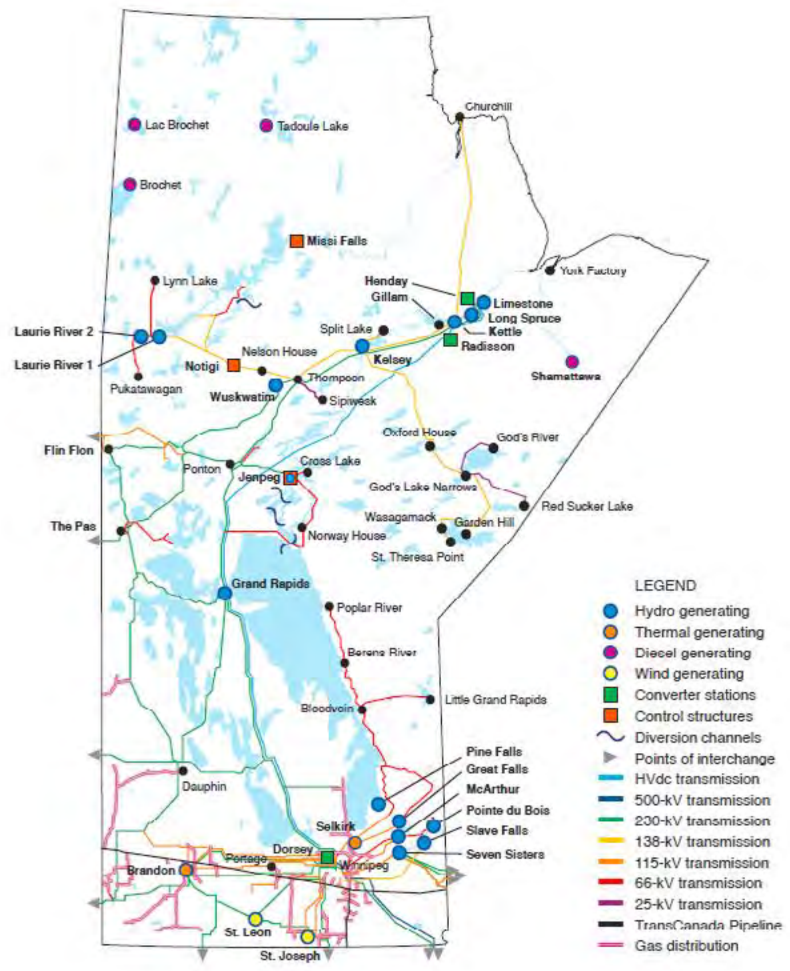
(1) As of September 30, 2017
(2) Excludes $20 million non-recurring gain
(3) As of October 2017 excluding subsidiaries

System Overview

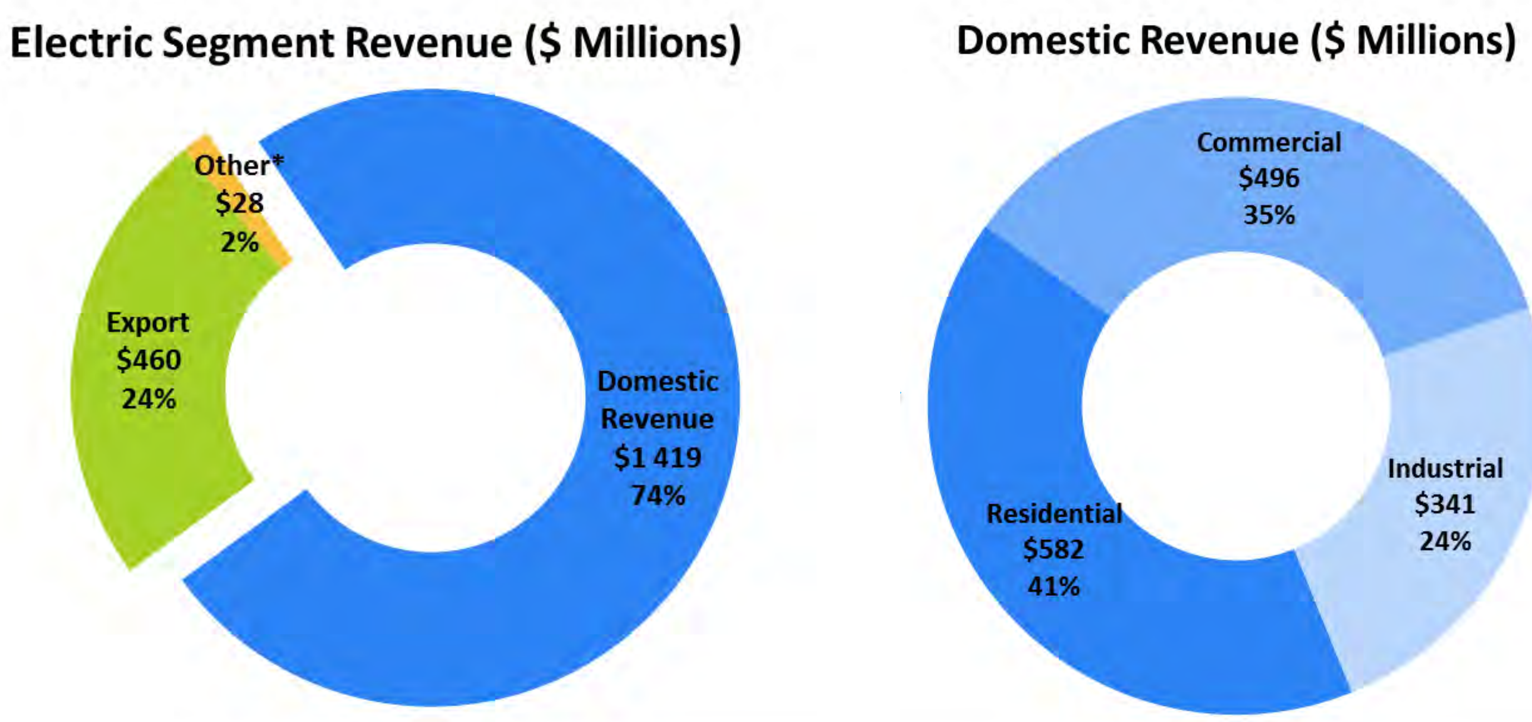
Total Customers	Hydro Generating Stations
573,000	**15**

Electricity Generating Capability	Distribution Lines
5,679 MW	**68,100 KM**

Transmission Lines	2016/17 Total Energy Supplied
18,500 KM	**36.4 TWh**



Revenue - Electric



*Excludes $20 million non-recurring gain

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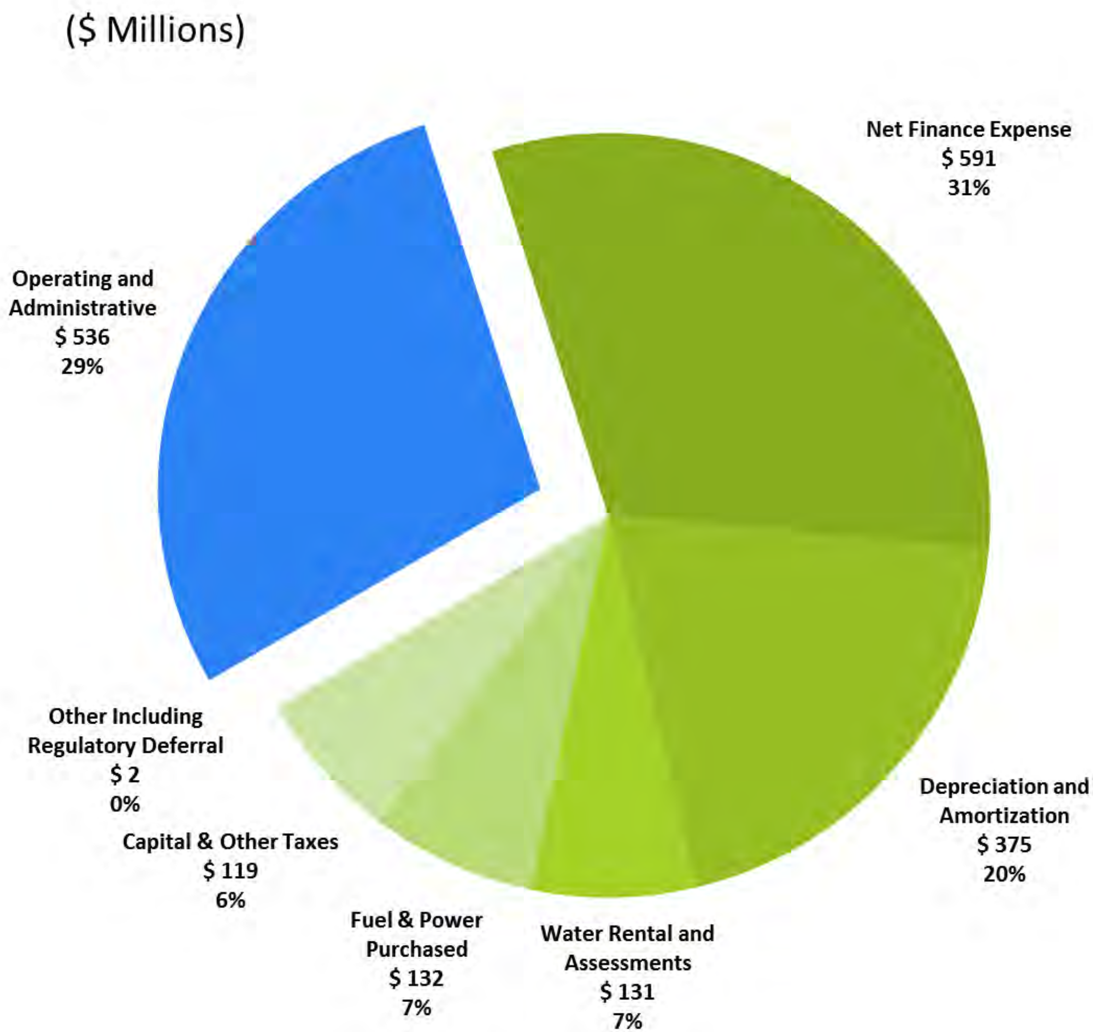
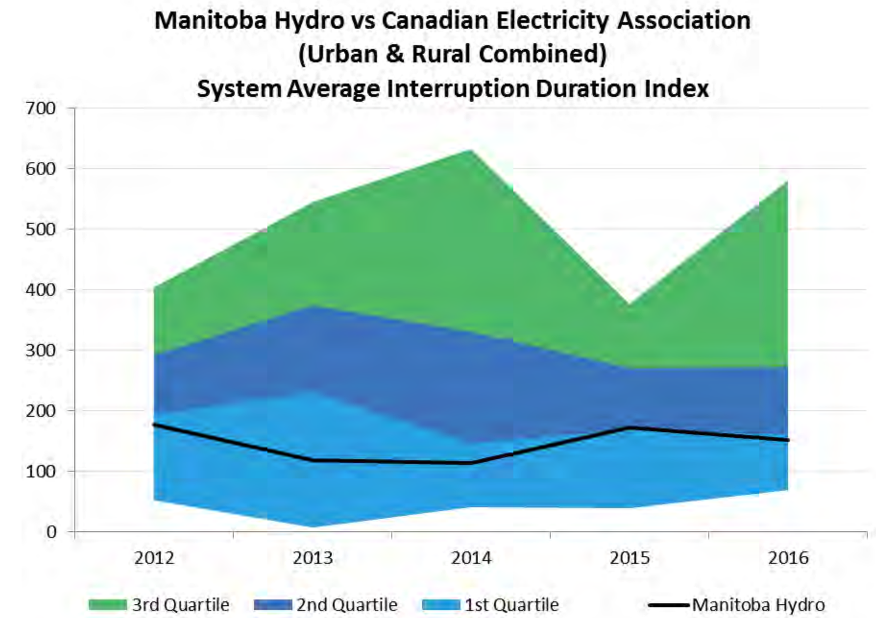
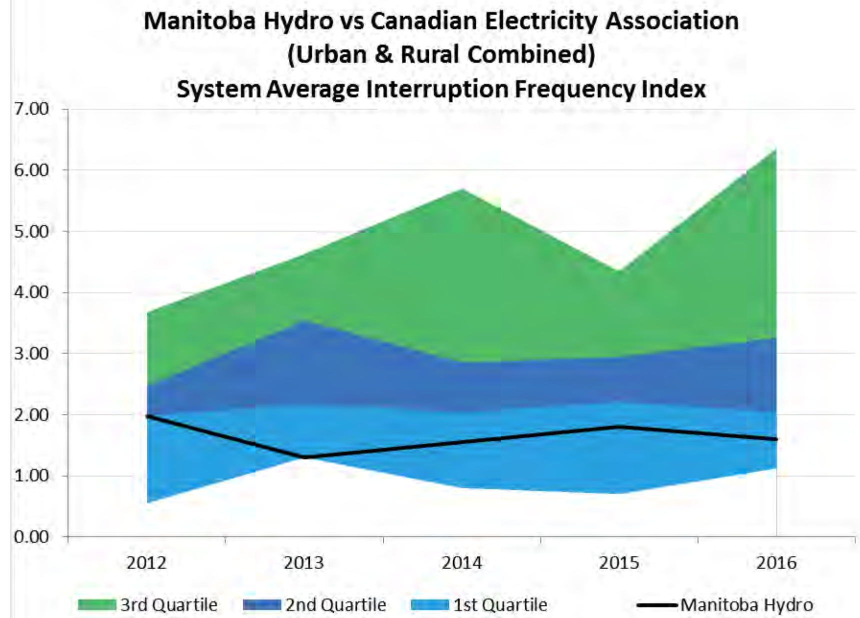
Cost Structure – Electric (2016/17)



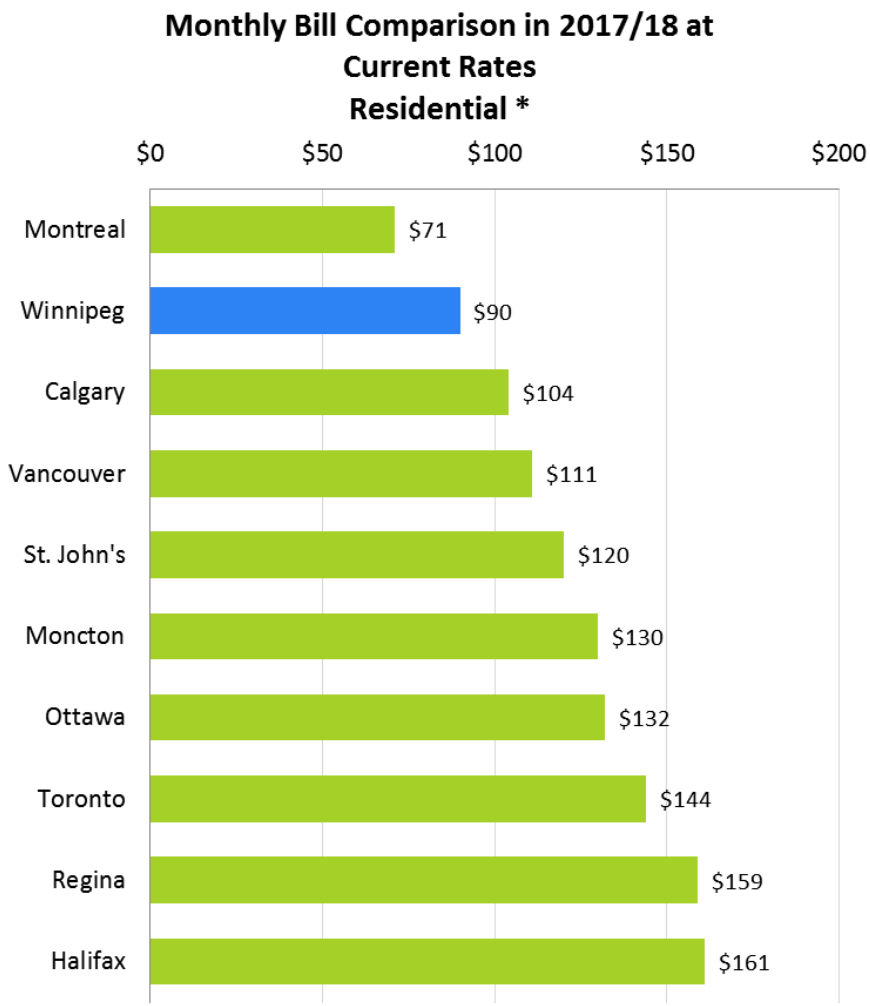
Reliability

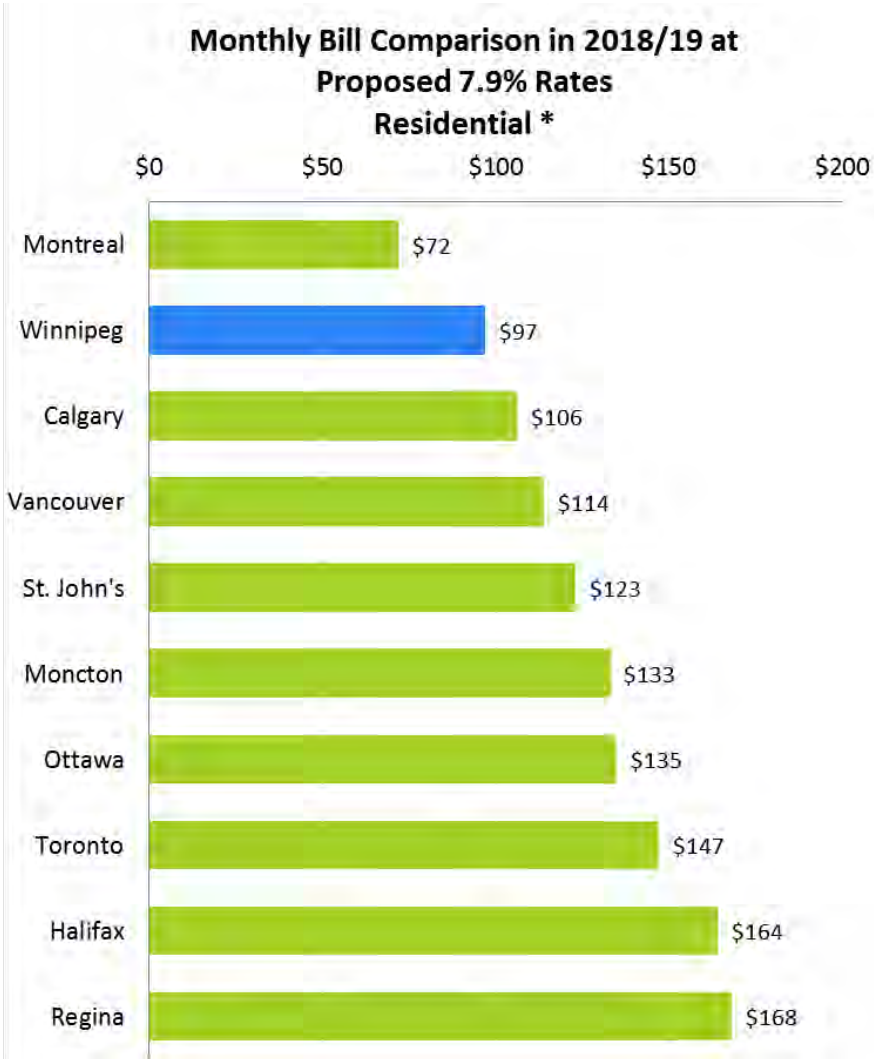
- Manitoba Hydro strives to maintain its reliability performance and looks to the performance of its peer group as one measure of its success





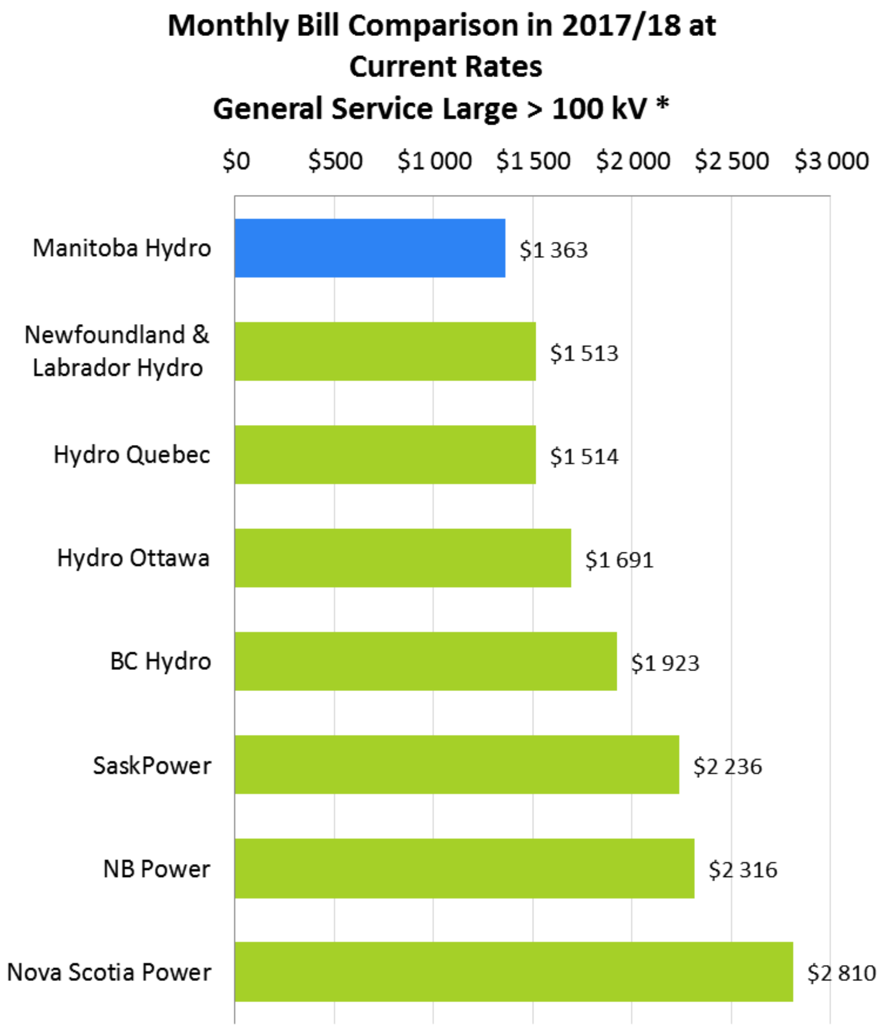
Rate Comparisons - Residential

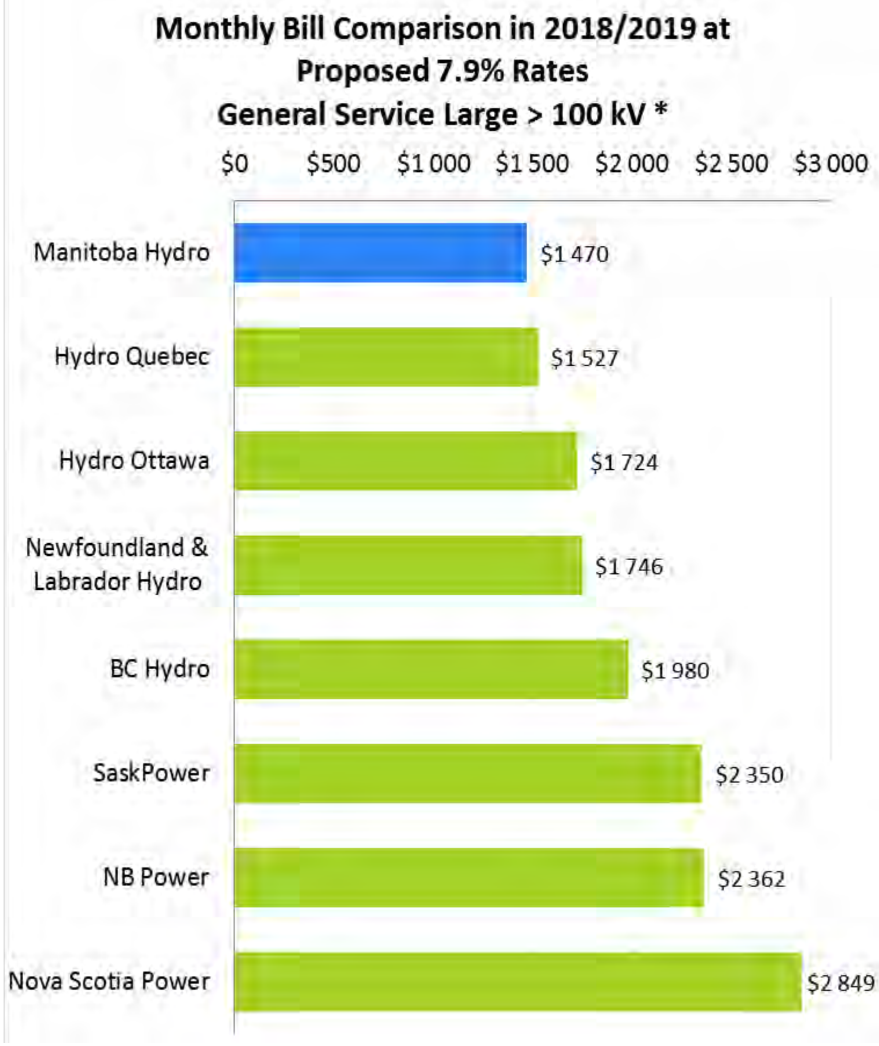




***Consumption: 1,000 kWh/Month**

Rate Comparisons - Industrial





Consumption: 31,000 MWh and 50 MW/Month; $ in 000's

Strategic Imperatives

Manitoba Hydro

OUR MISSION

We create value for Manitobans by meeting our customers' expectations for the delivery of safe, reliable energy services at a fair price

STRATEGIC PRIORITIES

Restore Financial Sustainability	Deliver an Excellent Customer Experience	Engage Employees in our Transformation	Respect & Support Indigenous Peoples in all Aspects of our Business

FOUNDATIONAL PRINCIPLES

Safety	Environmental Leadership
Respectful Engagement with Communities and Stakeholders	Respect for Each Other

II. Manitoba Hydro's New Financial Plan

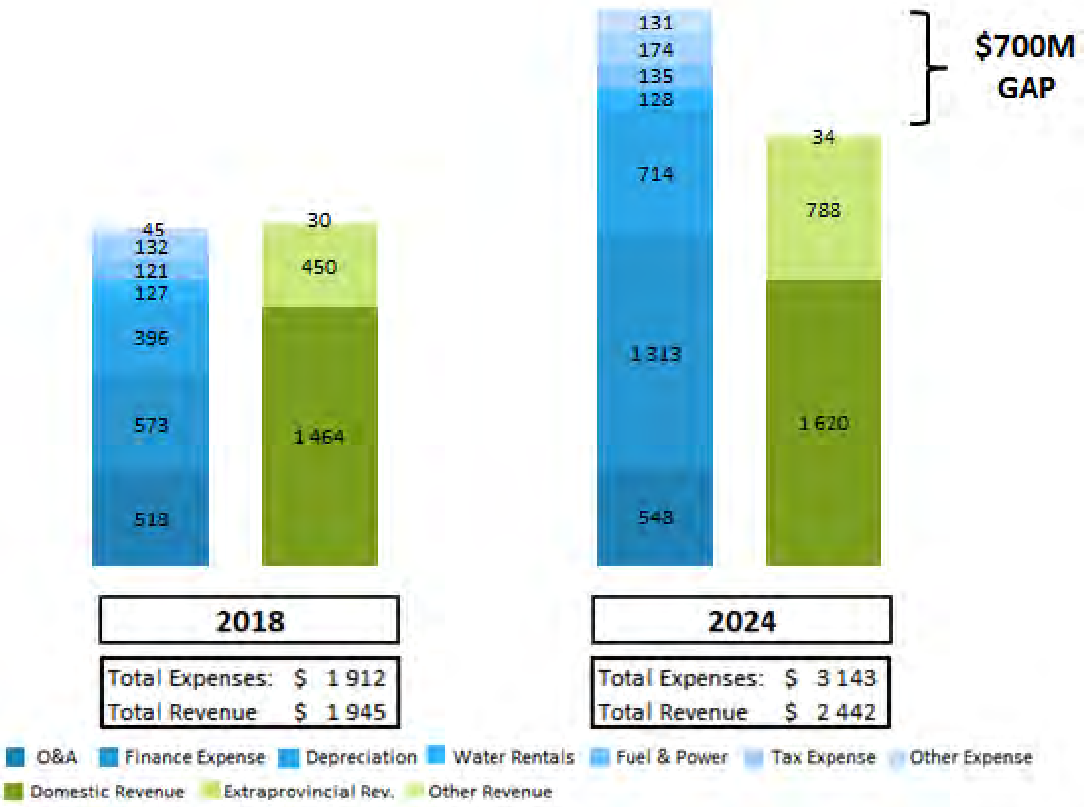
What Our Plan Had to Address

- Substantial deterioration in business outlook and growth expectations since last GRA/NFAT
- Current and future rate insufficiency
  - Negative net income: no cushion for scale of business and inherent risks
  - Borrowing money to fund core, continuing operations
- Growth in debt not sustainable
  - Not supported by 3.95% rate plan
- Risk of unpredictable and higher long term rate increases
- Inadequate financial strength for Manitoba Hydro to continue to meet its mandate
  - Need to invest in aging infrastructure
  - Potential industry and technology change threatening traditional utility model

Near-Term Income Shortfall

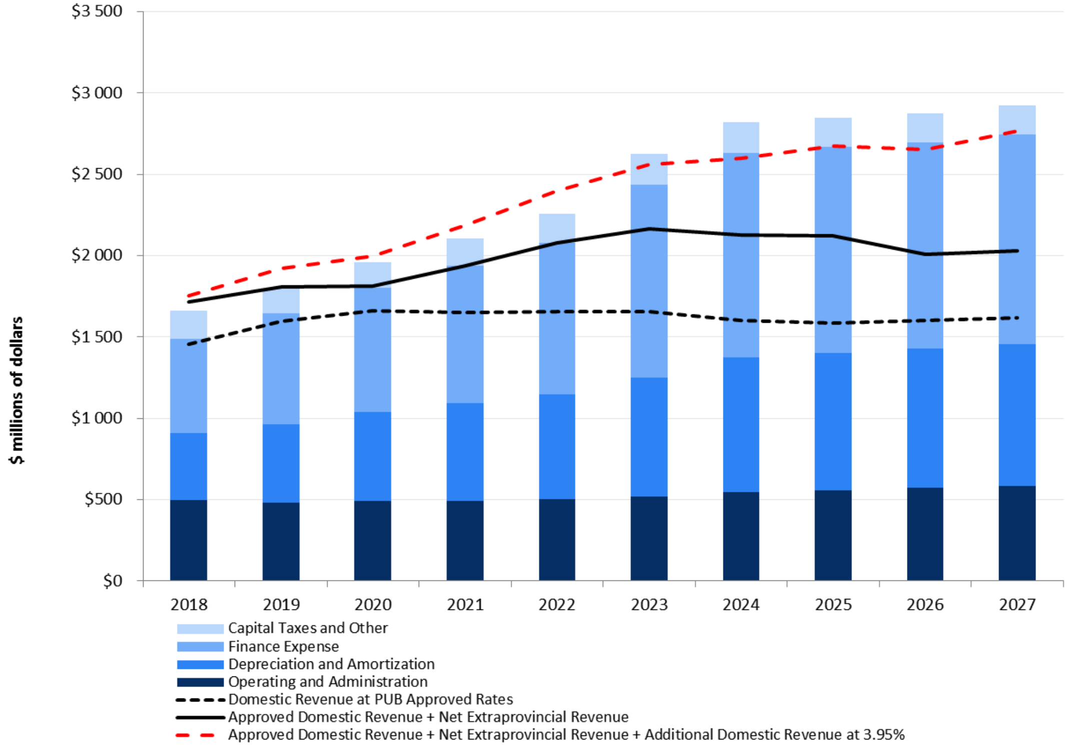
- Without rate increases, Manitoba Hydro will have a $700 million per year revenue shortfall in the first year Keeyask is fully in service
  - $700 million gap represents a 43% increase over 2017/18 domestic revenues
  - 3.95% rate increase would only address $480 million leaving a $220 million gap

- Breakeven income on $30 billion in assets cannot be the goal in any event



Old Financial Plan Does Not Work

- MH15 rate path (3.95% until 2029) fails to generate sufficient revenue to address inescapable growth in carrying costs
  - Cumulative net loss until 2031/32 (15 years); Debt >$25 billion



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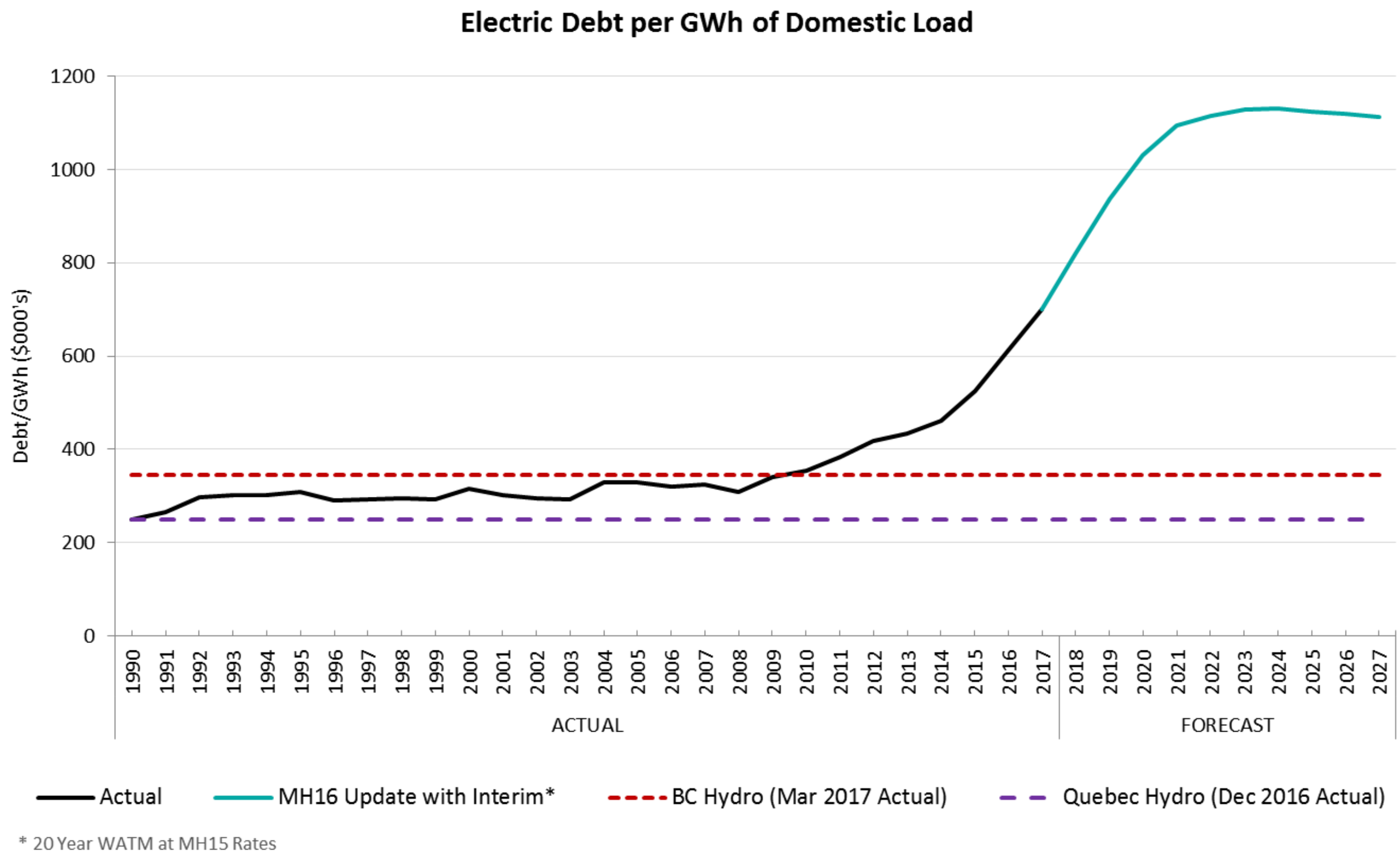
Cash Deficit on Current Operations

(In Millions of Dollars)	2015/16 Actual	2016/17 Actual	2017/18 Forecast (1)
Receipts from Customers	1 907	1 997	2 152
Payments to Suppliers and Employees	(736)	(933)	(892)
Interest Paid (2)	(575)	(580)	(550)
Business Operations Capital Expenditures	(616)	(578)	(586)
Demand Side Management	(54)	(50)	(55)
Mitigation and Other Deferred Expenditures	(22)	(5)	(27)
Ineligible Overhead	(20)	(20)	(20)
Cash From Operations Less Capex (2)	**(116)**	**(169)**	**22**
Mitigation, Major Development & Other Liability Payments	(26)	(13)	(59)
City of Winnipeg Payments	(16)	(16)	(16)
Adjusted Cash Deficit	**(158)**	**(198)**	**(53)**
Interest on Bipole III Reliability Project (2)	(52)	(98)	(174)
Contribution from Water Conditions (3)	(62)	(87)	(91)
Cash Flow (Deficiency)/Surplus	**(272)**	**(383)**	**(318)**
Shortfall vs. Domestic Revenue (Gross of BPIII Deferral)	**19%**	**25%**	**20%**

(1) MH16 Update with Interim not adjusted downward for revised outlook for 2017/18 per the MHEB Quarterly Report ended September 30, 2017
(2) For presentation purposes above, MH has separated out interest paid and capitalized to the Bipole III for further clarity
(3) From Figure 15 of Supplement to Tab 3

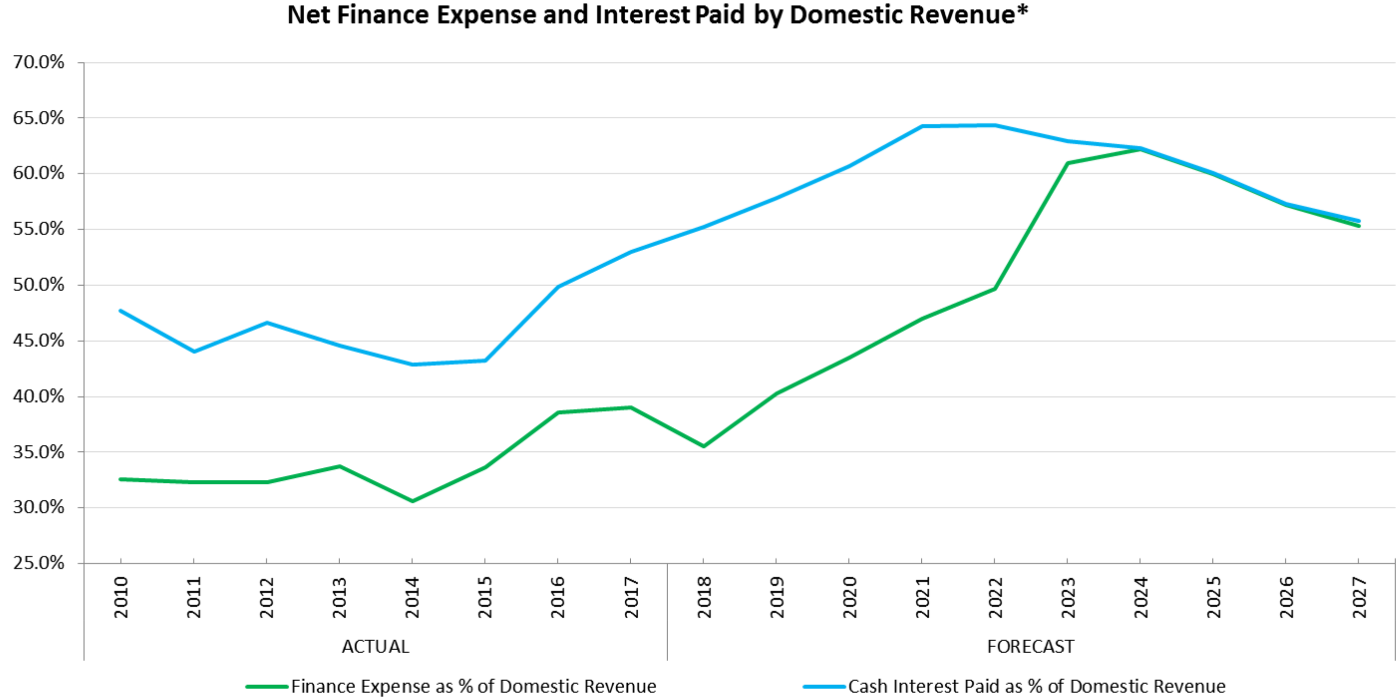
The Debt Problem

- Rates are insufficient – while debt is growing out of all historical proportion



The Debt Problem

- Without stronger rate action, interest costs will consume an ever larger share of domestic revenue
  - Fewer dollars left over to manage interest rate (or any other) volatility – which is entirely on the shoulders of domestic ratepayer



*20 Year WATM at MH15 Rates
Interest Paid is presented gross of capitalized interest

MH16 – A New Plan

- A 10-year plan to restore Manitoba Hydro to a minimum level of financial health
- Substantially accelerated operating cost reductions
- Acceleration of rate increases
  - Enabling lower and more stable rates in the long run vs. 3.95% plan
- Positive cash flow after Keeyask comes into service
  - Enabling more aggressive debt management strategy
  - Save interest costs and mitigate rate increases

Cost Reductions

- **$0.8 billion improvement in Operating & Administrative costs in 2017/18 - 2026/27 period as compared to MH15**
- New financial plan includes 900 person headcount reduction (15%)
  - On top of 429 operational position reduction from 2013/14 to 2016/17
  - 30% reduction in executive and 25% reduction in management
  - Voluntary Departure Program has identified 821 individuals to leave with the majority by February 1, 2018
  - Approximate savings of $90 million annually inclusive of salaries and benefits
    - It is estimated $70 million will come from O&A
- New initiatives expected to yield Supply Chain / Purchasing efficiencies of approximately $50 million per year by 2020/21
  - Approximately 30% of savings come from O&A

Rate Increase Profile

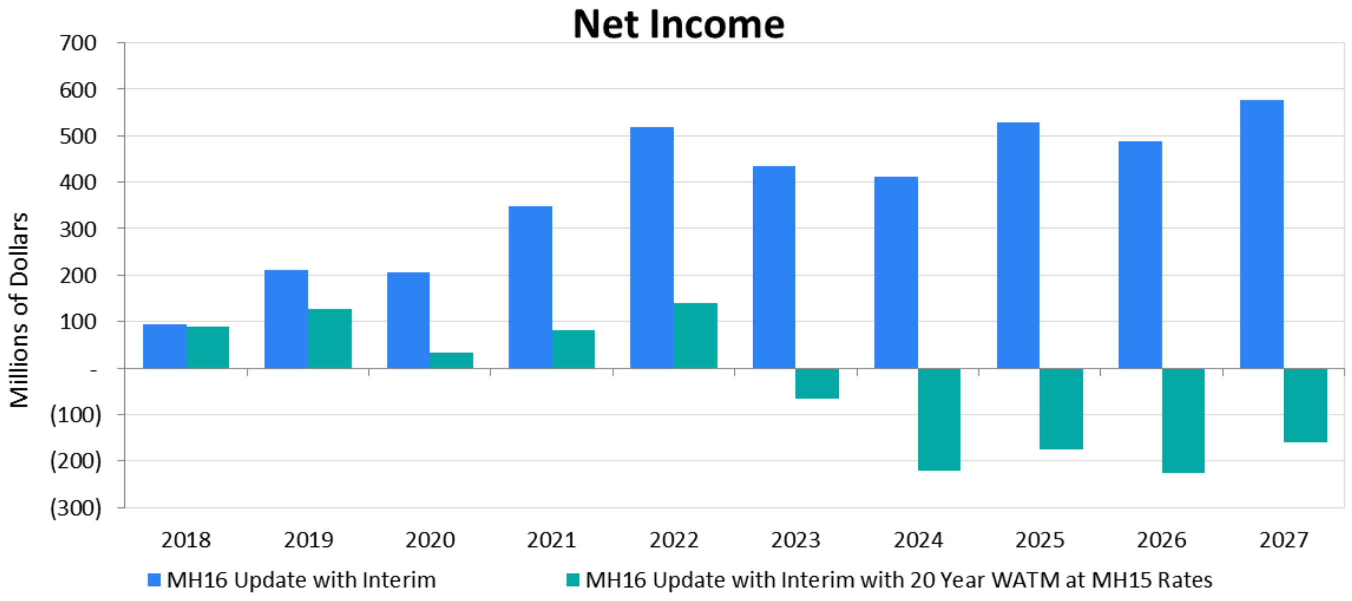
Year	Effective Date	"Old" Plans (3.95% Rate Increases)	MH16 (As Filed)	MH16 Update with Interim
2016/17	August 1, 2016	**3.36%**	**3.36%**	**3.36%**
2017/18	August 1, 2017	**3.36%**	**7.90%**	**3.36%**
2018/19	April 1, 2018	**3.95%**	**7.90%**	**7.90%**
2019/20	April 1, 2019	3.95%	7.90%	7.90%
2020/21	April 1, 2020	3.95%	7.90%	7.90%
2021/22	April 1, 2021	3.95%	7.90%	7.90%
2022/23	April 1, 2022	3.95%	2.00%	7.90%
2023/24	April 1, 2023	3.95%	2.00%	7.90%
2024/25	April 1, 2024	3.95%	2.00%	4.54%
2025/26	April 1, 2025	3.95%	2.00%	2.00%
2026/27	April 1, 2026	3.95%	2.00%	2.00%
	After 2027	3.95% for 9 more years to reach 25% equity by 2035/36	TBD	TBD

Debt Terming Strategy

- $500 million **potential** savings opportunity over 10 years is a benefit enabled by taking necessary rate action to address unsustainable debt
- Without expectation of any free cash flow – which is only possible through enhanced rate action – Manitoba Hydro’s customers would be exacerbating near-term refinancing risk
- **Not a “no risk” strategy** – insofar as cash flows don’t materialize for whatever reason, refinancing risk remains
- Even under past practice, MH will have substantial ($6 billion) refinancing risk in the 2022/23 - 2026/27 time period

Net Income Comparison

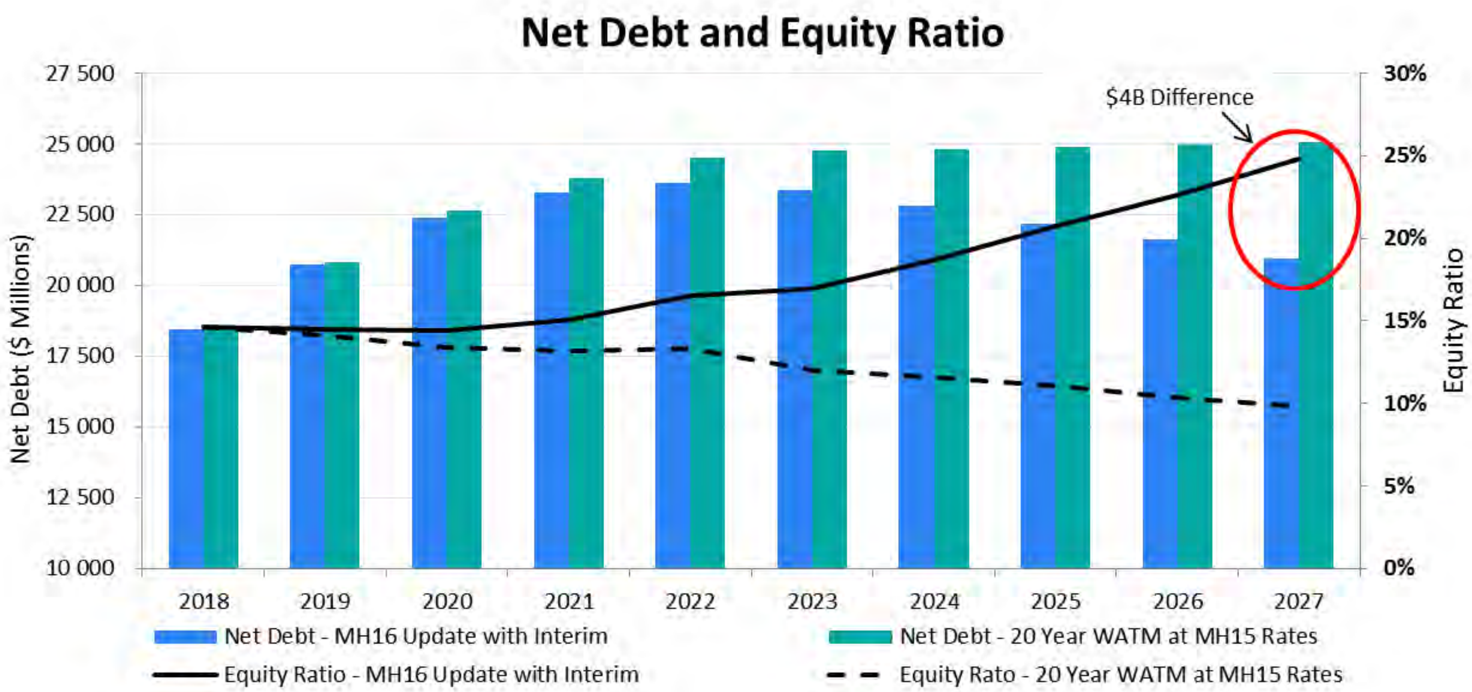
- 3.95% rate strategy leads to $850 million of net losses over the next 10 years to 2026/27
- Net income levels under the MH Plan are essential:
  - "Shock absorber" in **plan** to absorb forecast variability and adverse events
  - Creates cash flow needed to bring debt down to sustainable level



Manitoba Hydro

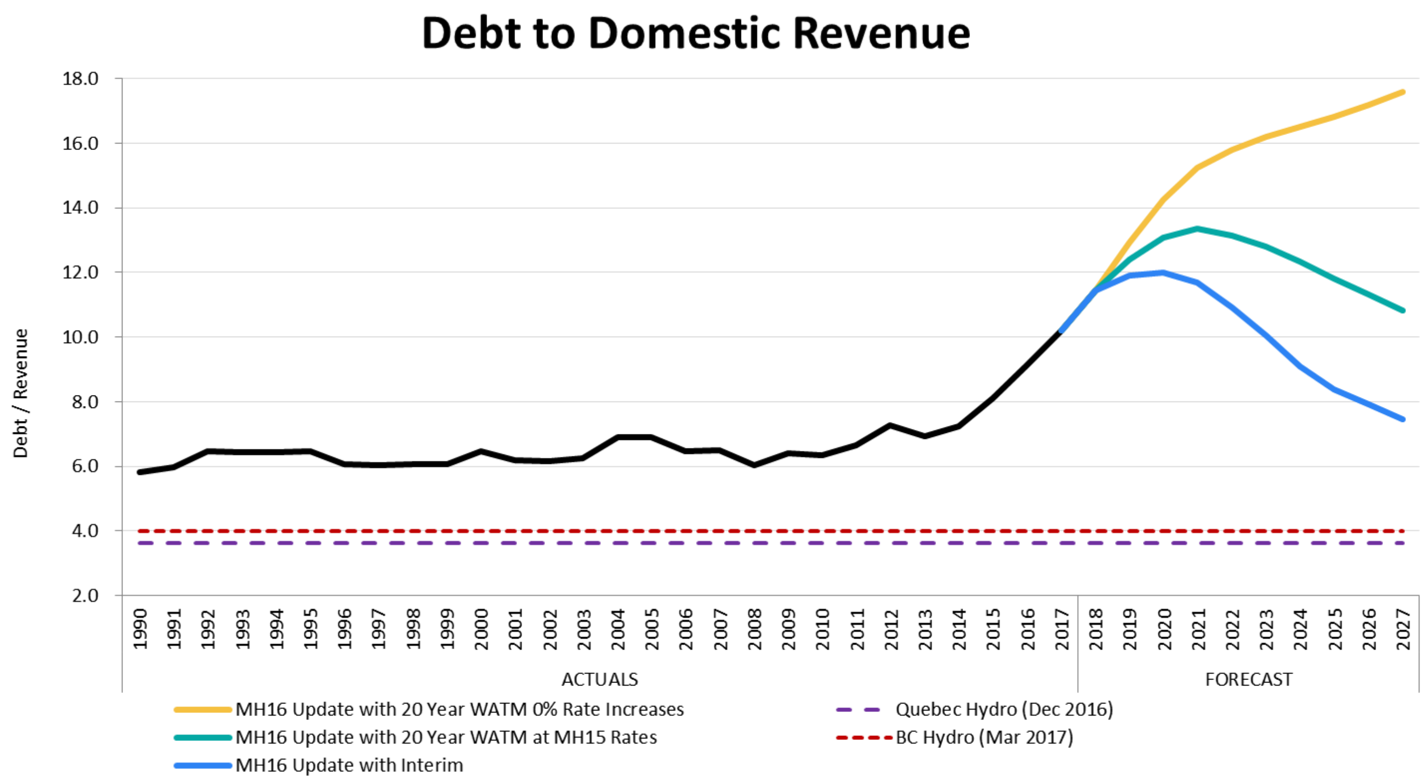
Debt Levels and Equity Ratios

- Higher net income is essential to creating cash flow
  - In short term rate increases are necessary just to ensure ratepayers are funding full current and future cost of operating the business
  - Important to maintain income at sufficient level to bring debt down to a sustainable level to achieve rate impact benefits for long term



Bringing Debt Partly Back to Scale

- The rate increases proposed reduce Manitoba Hydro to historical debt still 30% above relative levels before the major projects began
- And still well in excess of peers



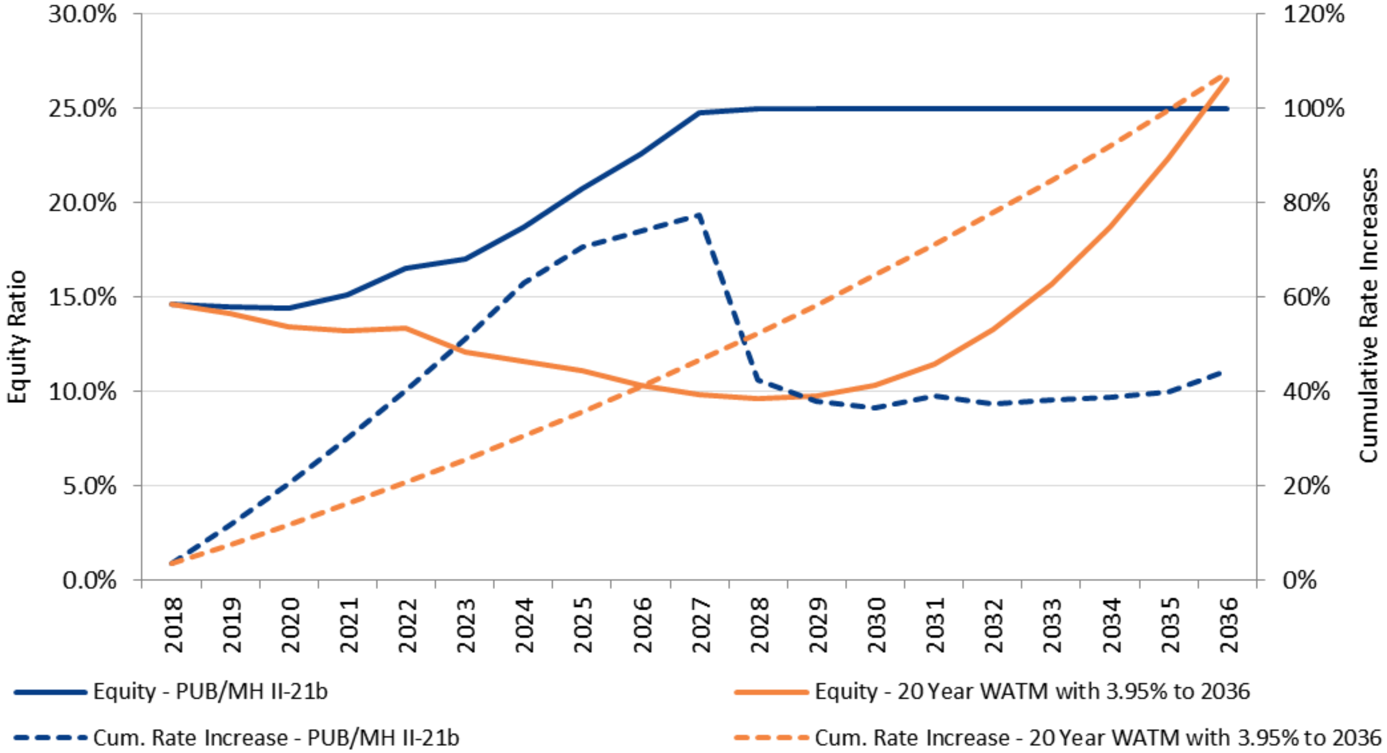
Note: excludes non-cash amortization of Bipole III Reserve Account

What Does MH16 Achieve?

- Proactive action to bring debt, while **still very high vs. relative historical levels**, to more sustainable levels
- Path of rate changes beyond 2026/27 can not be easily forecast today
- What is assured?
  - Interest rate exposure (and therefore rate volatility) lessened by removing $4 billion of debt
  - Regardless of future conditions, addressing debt problem enables lower cumulative rate increases over long term
- Near term potential economic impacts far outweighed by longer term benefit of lower cumulative rate increases and sharply reduced likelihood of contagion impacts on Province of Manitoba

Why Are We Doing This?

- Ensuring service, reliability, preparedness
- Managing risk
- Rate stability with potential for lower rates and bills in the long run



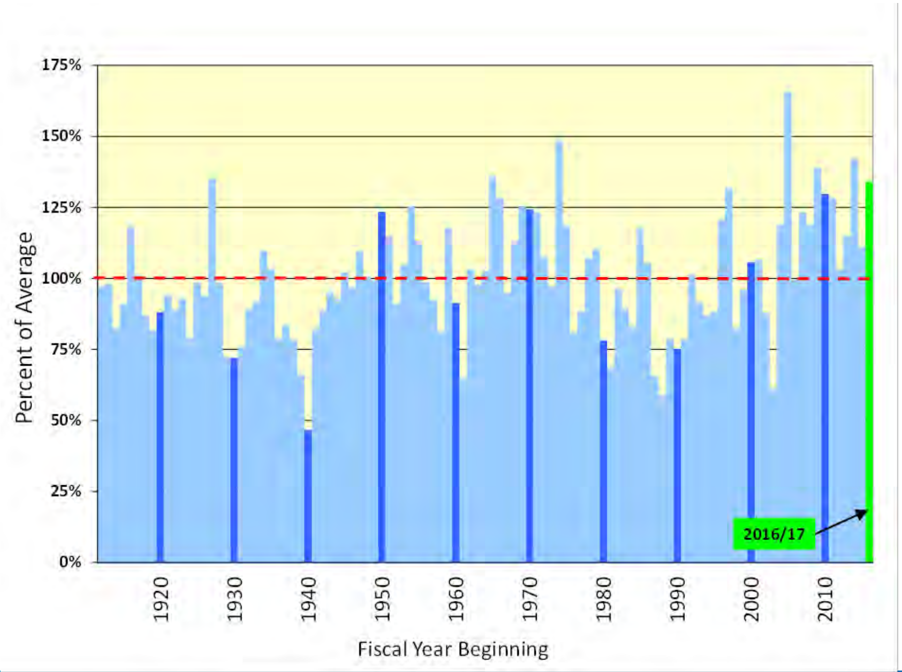
III. Manitoba Hydro Faces Large Risks

Manitoba Hydro Risks

- Manitoba Hydro presents a unique set of risks that together reinforce importance of adequate reserves:
  - **Hydrology** – no hydro-based utility has the volatility in water conditions and relative small reservoir size Manitoba Hydro must manage
  - **Debt** – Manitoba Hydro debt is, and will continue to be, more leveraged relative to the size of its operations than it has ever been creating far more exposure to interest rate volatility
  - **Export Revenue** – export sales represent a much larger share of total revenue (particularly after Keeyask) than peers creating more exposure to fluctuating export prices
  - **Major Projects** – each $500 million increase in capital costs is a $30 to $35 million annual addition to revenue requirement

Hydrologic Risk

- Manitoba Hydro's water conditions are subject to a great deal of volatility
- **Manitoba Hydro has enjoyed 14 consecutive years of greater than average system inflows**
  - Previous "wet" record was 5 years
  - Above average water has contributed $215 million to equity (or approximately 8%) since NFAT (2014/15 - 2016/17) representing virtually all of retained earnings growth in that time frame



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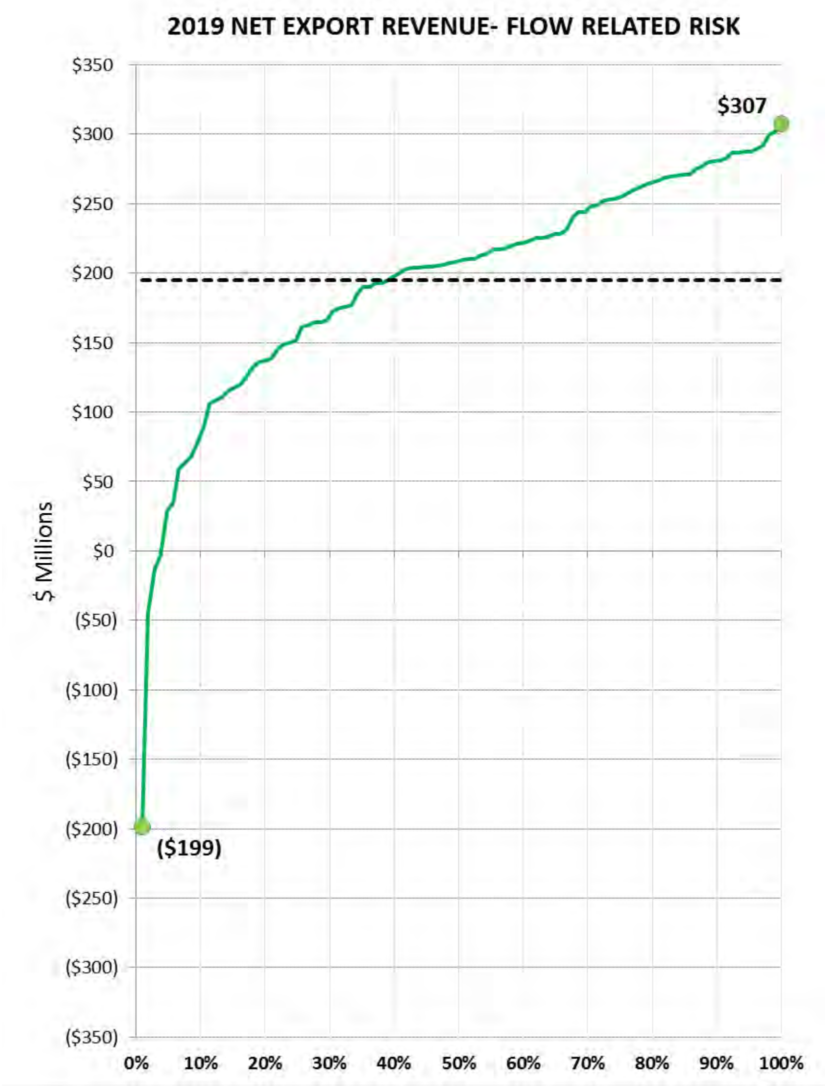
Hydrologic & Export Risk

- $58 million or 22% drop in net export revenue in 2017/18 between MH16 Update (prepared in May/June) and outlook in September
  - 68% decrease to 2017/18 forecast net income
- $20 million decrease to 2018/19 outlook
- Charts to follow highlight the potential variability in net export revenue due to water conditions for 2018/19 (which begins in four months)

Hydrologic & Export Risk

- While drought can impair next year's net income by up to $400 million, even below average (1 in 5 to 10 year) water conditions can compromise $60 to $120 million of earnings
- While tempered from past export price forecasts, Manitoba Hydro is still projecting appreciating opportunity export prices over the next 10 years
  - Opportunity price appreciation is contributing $45 million to 2022/23 net income and $90 million to 2026/27 net income
  - Combined with hydrologic risk, net export revenue is subject to **significant and asymmetrical** volatility in potential outcomes each year



No Room for Interest Rate Increases

- Manitoba Hydro's forecast assumes rates stay near all-time lows
  - Historical experience shows rates can often move up or down +/- 5% in a decade
- A comparison of borrowing requirements:

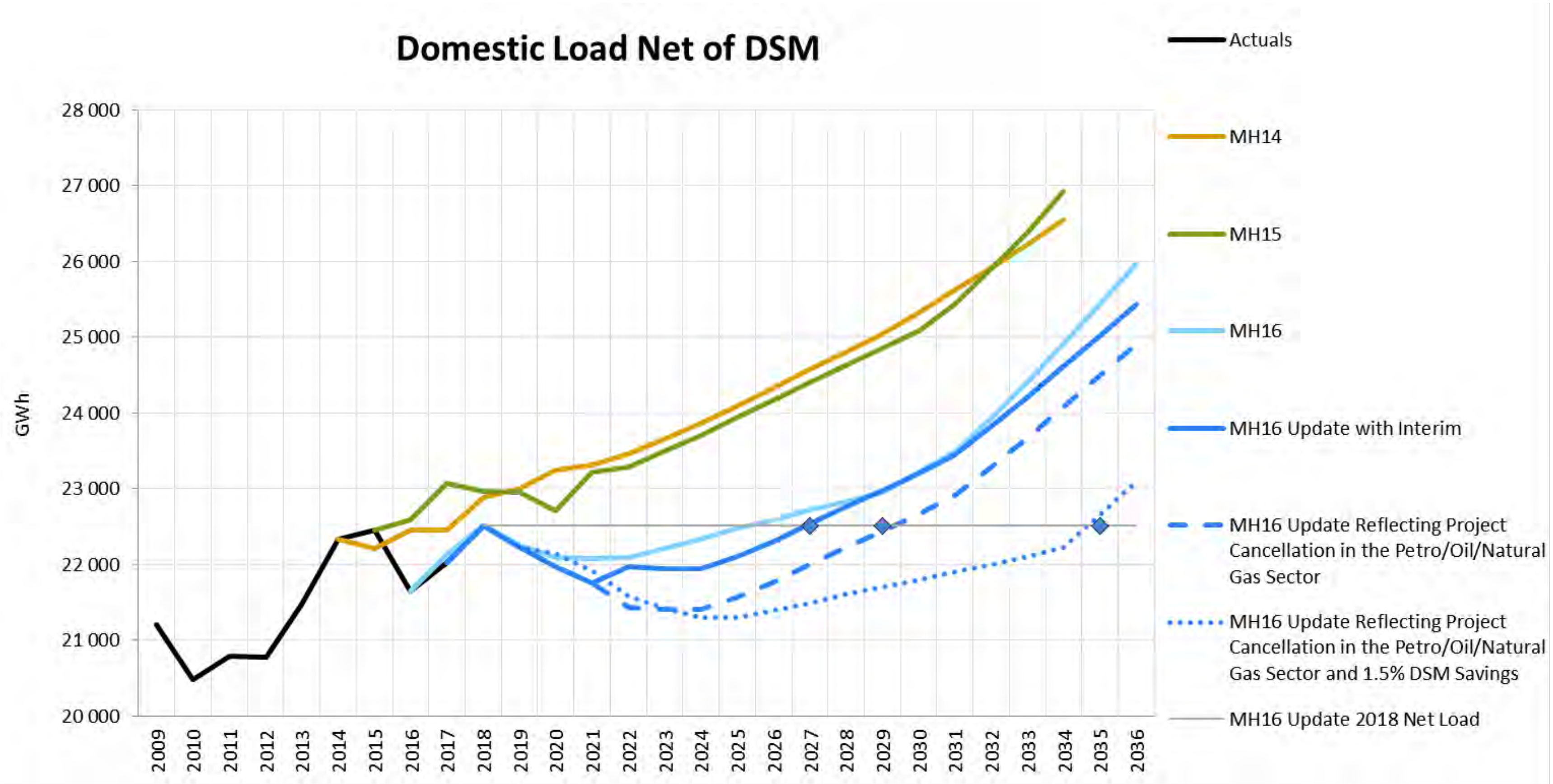
In Billions of Dollars	MH Plan	3.95% / 12 Year WATM
2017/18 - 2021/22 Borrowing	$13.5	$14.1
2022/23 - 2026/27 Borrowing	$8.8	$9.7
2022/23 - 2026/27 Cash Flow	($3.1)	($0.4)
Total 10-Year Borrowing	$19.2	$23.4

- Each 1% move upward in interest rates, depending on timing, could cost Manitoba Hydro upwards of $200 million **per year** by the end of the forecast period

IV. Key Facts of This Rate Case

MH Outlook Has Deteriorated

- Now facing 10 years or more of **no net load growth**
- Loss of unit volume amplifies the rate increase needed to maintain the same revenue dollars – the 3.95% plan assumed far more load



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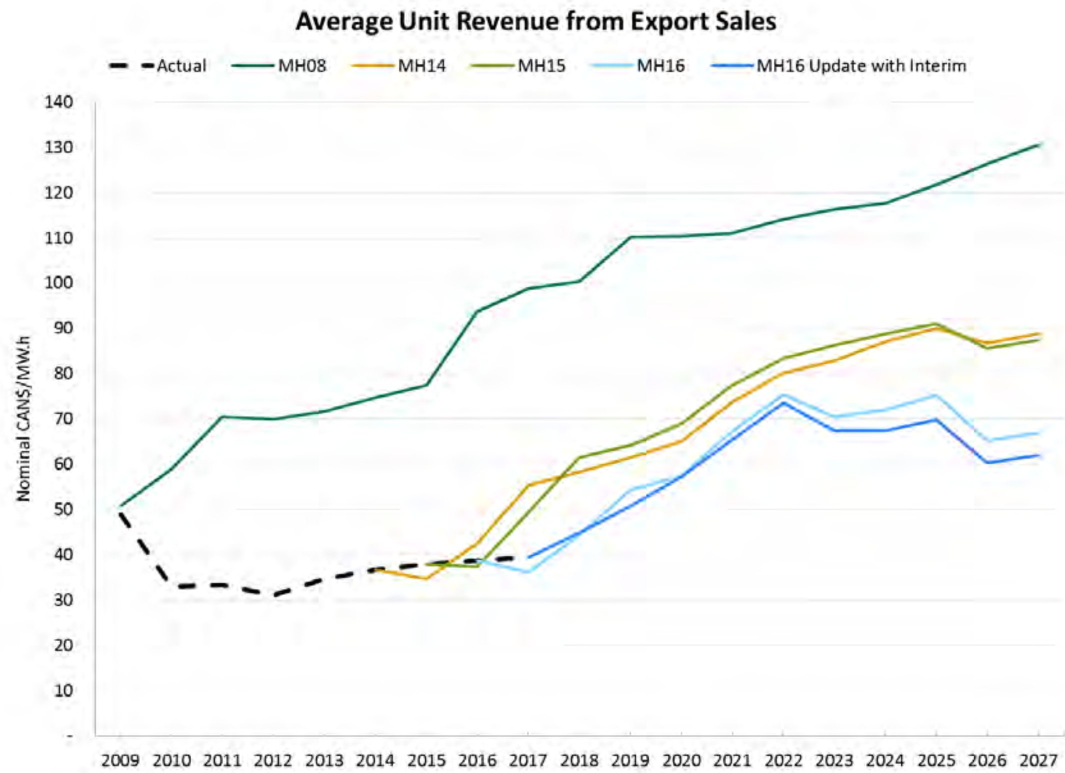
MH Outlook Has Deteriorated

- Export price outlook continues downward trend – decline in outlook for spot prices since MH15 impacting post-Keeyask revenue by ~$170 million
- Approximately $90 million/year in opportunity revenues at risk by 2026/27 if prices do not rebound



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MH Outlook Has Deteriorated

- Keeyask Generating Station “P50” control budget has increased $2.2 billion to $8.7 billion and in-service date has been delayed 21 months to August 2021

MH Outlook Has Deteriorated

- Bipole III Reliability Project control budget has increased $0.4 billion to $5.0 billion

MH Outlook Has Deteriorated

- Revenue down $3 billion
- Net income down $1 billion
- Debt increased $3.2 billion

	2017-2027		
	Increase/(Decrease) In Millions of Dollars		
NET INCOME	**MH16 Update***	**MH15**	**Variance**
Domestic Revenues (at MH15 Rate Increases)	20 865	22 265	(1 400)
Extraprovincial & Other	7 193	8 746	(1 554)
Total Revenues	**28 058**	**31 011**	**(2 954)**
Total Expenses including Net Movement	**28 378**	**30 407**	**(2 028)**
Non-Recurring Gain	20	-	20
Net Revenue Lost due to Current Water Flow Projections	(78)	-	(78)
Net Income	**(379)**	**604**	**(983)**
Net Income (at MH15 Rate Increases) Attributable to:			
Manitoba Hydro	**(403)**	**607**	**(1 010)**
Non-controlling Interest	25	(2)	27
	(379)	**604**	**(983)**
Equity Ratio in 2027	**10%**	**14%**	
Net Debt in 2027	**25 060**	**21 838**	**3 221**

*MH16 Update with Interim with 20 Year WATM at MH15 Rates

MH Outlook Has Deteriorated

- Comparison understates the forecast erosion
  - Keeyask 21 month delay **adds** $750 million to MH16 Update with Interim net income in form of net cost avoidance
  - 2016/17 under MH16 includes $87 million of additional net income from high water conditions
  - MH16 Update with Interim overstates current expectations by $78 million in test years due to dry 2017 summer and persistently low opportunity export prices
- **There is no basis whatsoever for intervener evidence of no deterioration**
- Very limited ability for interest rate reductions and O&A cuts to offset foregone revenue outlook
- **Manitoba Hydro is not going to grow its way into managing its debt – debt load needs to be reduced**

Net Income Is Not Full Picture

- On a normalized basis, Manitoba Hydro has had *minimal to negative* net income for each of the last three years and is forecast to again in 2017/18

(In Millions of Dollars)	2014/15	2015/16	2016/17	2017/18
Net Income Attributable to MH	111	37	53	93*
Non-Recurring Gain	-	-	(20)	-
Income Impact of Bipole III Capitalization	(8)	(15)	(32)	(54)
Above Average Water	(70)	(62)	(87)	(35)
Adjustment to Current Outlook	-	-	-	(63)
Restructuring Expenses	-	-	4	50
Adjusted Net Income/(Loss)	**33**	**(40)**	**(82)**	**(9)**

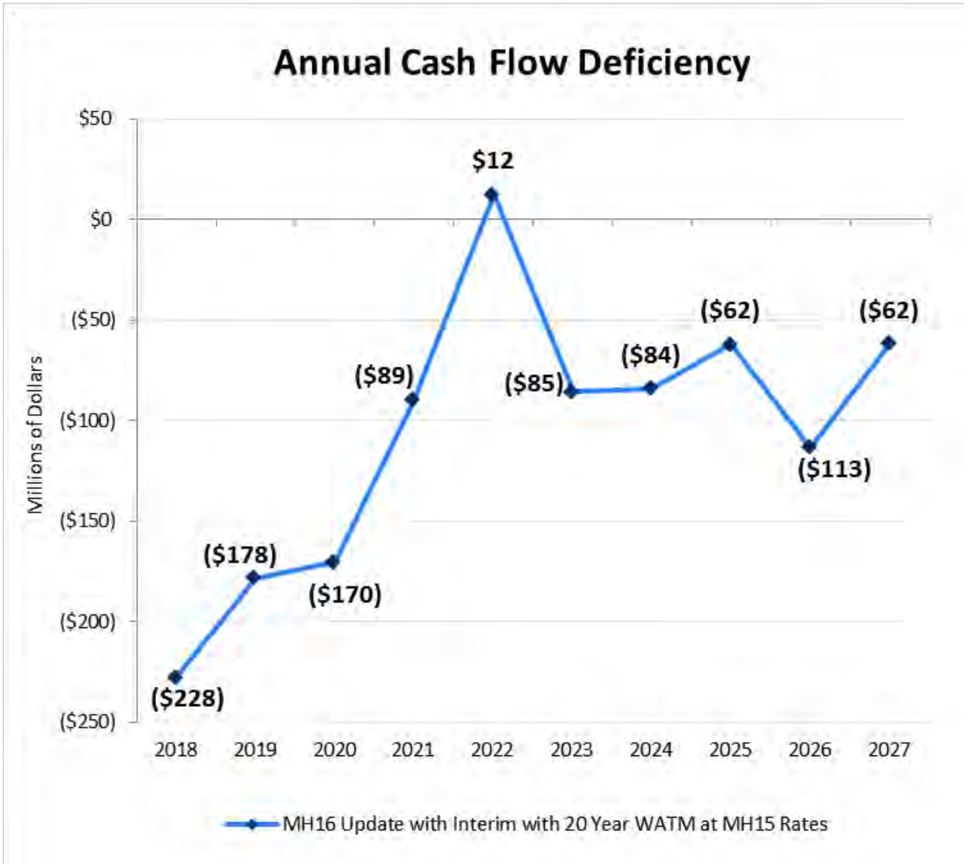
*MH16 Update with Interim

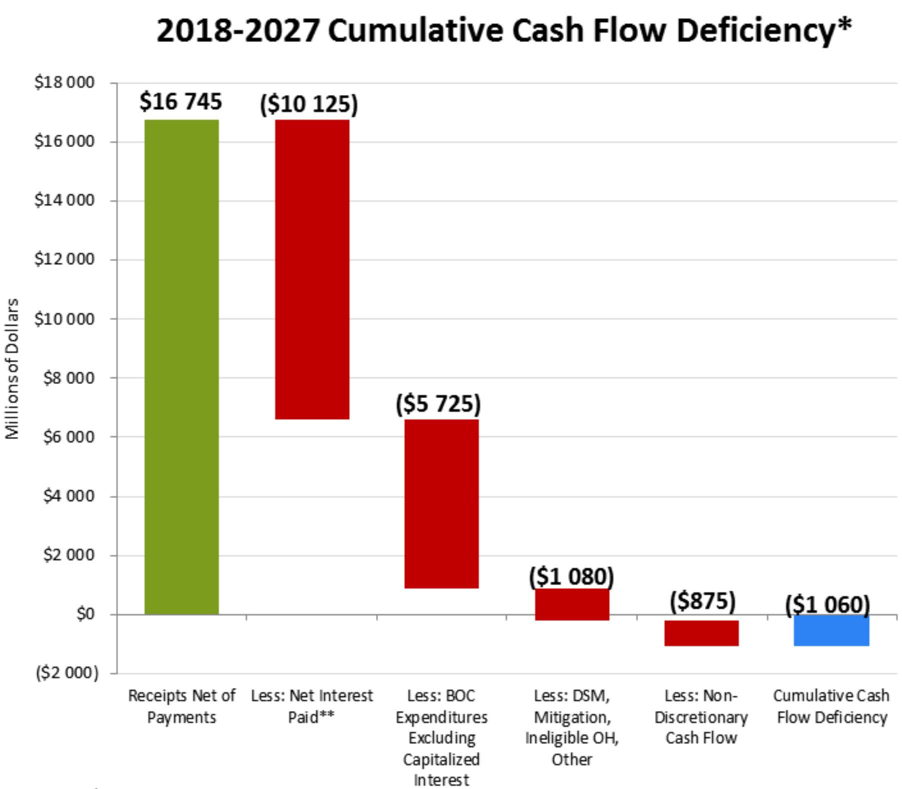
Net Income Is Not Full Picture

- Net income, even if positive, gives an incomplete picture of financial health
- Depreciation determines revenue requirement but is based on **historical cost**
  - Large part of the system was built more than 25-30 years ago
  - Costing significantly more to sustain
  - Business Operations Capital is $150-200 million more than amount being recovered through depreciation
- MH has significant other ongoing cash expenditures which only minimally impact revenue requirement / net income
  - Annual payments to City of Winnipeg
  - Payment commitments on mitigation and past development liabilities
  - Demand Side Management
- Must now take into account the current cash burden and imminent expense burden from Bipole III

MH Has a Cash Flow Problem

- The 3.95% rate path generates an annual cash flow deficiency in all years but one (2021/22) and a $1 billion cumulative deficit by 2026/27





*20 Year WATM at MH15 Rates

**Interest Paid net of Interest Received and gross of capitalized interest excluding Keeyask, MMTP & GNTL

Equity Ratio Is Important

- Equity ratio is the best of Manitoba Hydro's traditional financial targets
- Capital Coverage and Interest Coverage are incomplete
  - Do not capture all of the recurring, non-discretionary cash demands on Manitoba Hydro
  - Therefore provide no picture of whether MH is increasing or decreasing reserves and/or debt
- Equity ratio should also be thought of in inverse: Debt Ratio
  - **Equity is not a cash reserve – on its own, and without income, does nothing for MH when adverse events occur**
  - For MH, equity represents **debt avoided**
  - Focus of MH16 Financial Plan is to curb unsustainable growth in debt

Equity Ratio Is Important

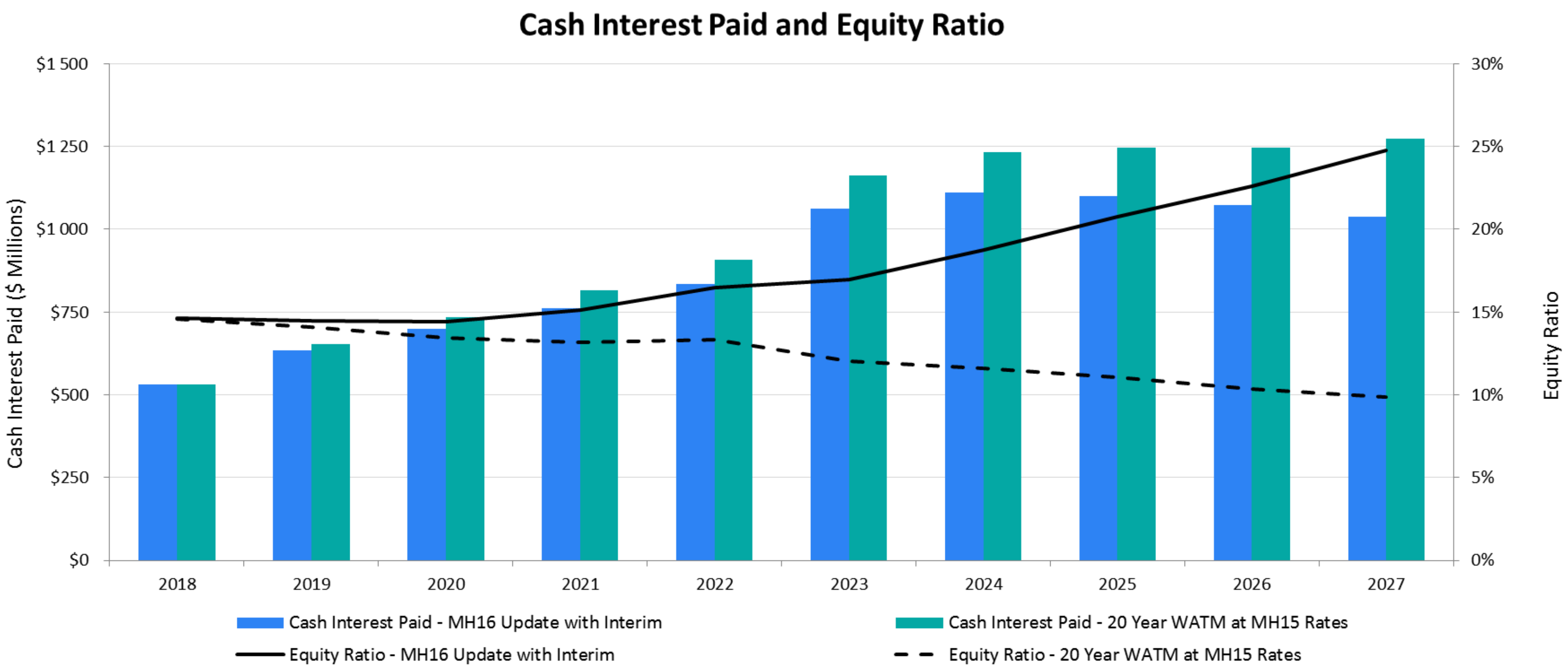
- Debt level is inextricably linked to the cash flow of any business
- For MH, interest expense will be, by far, the largest cost/cash flow burden on revenues
- Targeting equity can and does achieve **forecast** income and cash flow adequacy that leads to:
  - Reserves or “cushion” against the unforeseen **and forecast variability**
  - Debt reduction
  - Predictable rates which are lower in long run
- Achievement of equity ratio is perfectly aligned with meeting minimum cash flow based metrics advocated by intervener experts

Equity Ratio Is Important

- Numerous rating agency reports on Province of Manitoba cite rising debt levels at MH as a significant concern
- Debt:Equity is a proxy for overall debt levels which debt markets care about very much
- Regardless of the capital markets or credit rating agencies, Manitoba Hydro, its customers and the PUB should focus on and be concerned with debt levels
- Credit ratios are inextricably linked: Debt determines interest payments; interest payments determine cash flow and therefore cash flow adequacy

Equity Ratio is Important

- Interest will be **by far** the largest cash burden on Manitoba Hydro
- Therefore amount of debt is the most significant driver of the cash flow and financial condition of the Corporation



Other Ratios Have Shortcomings

- **Capital Coverage Ratio** has important weaknesses
- Numerator (Cash from Operations) **omits all capitalized interest** which can understate the current and pending burden on the company for **non-revenue generating** in flight projects (e.g. Bipole III)
- Denominator (Business Operations Capital) has numerous weaknesses which understate the annual cash burdens on Manitoba Hydro:
  - Business Operations Capital arbitrarily excludes large sustainment projects
  - DSM, City of Winnipeg, Mitigation and Past Development liability payments are entirely excluded **but are real costs**

Other Ratios Have Shortcomings

- **Interest Coverage** (EBITDA to Interest) Ratio provides no indication of whether cash flow is sufficient to meet interest obligations **and** the ongoing reinvestment and other commitments of the utility
  – For a utility, ongoing capital expenditures are, generally, not discretionary – investments are required to maintain system, meet mandate **and enable the revenue which the EBITDA forecast assumes**
  – Other payments (Mitigation, Winnipeg Hydro) represent contractual commitments

Other Ratios Have Shortcomings

- 3.95% rate path does not come close to meeting targets in any event

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x

Other Metrics:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	$ 18 473	$ 20 743	$ 22 407	$ 23 296	$ 23 609	$ 23 388	$ 22 831	$ 22 201	$ 21 613	$ 20 947
MH15 Rates	$ 18 474	$ 20 825	$ 22 657	$ 23 809	$ 24 496	$ 24 761	$ 24 811	$ 24 877	$ 24 994	$ 25 060

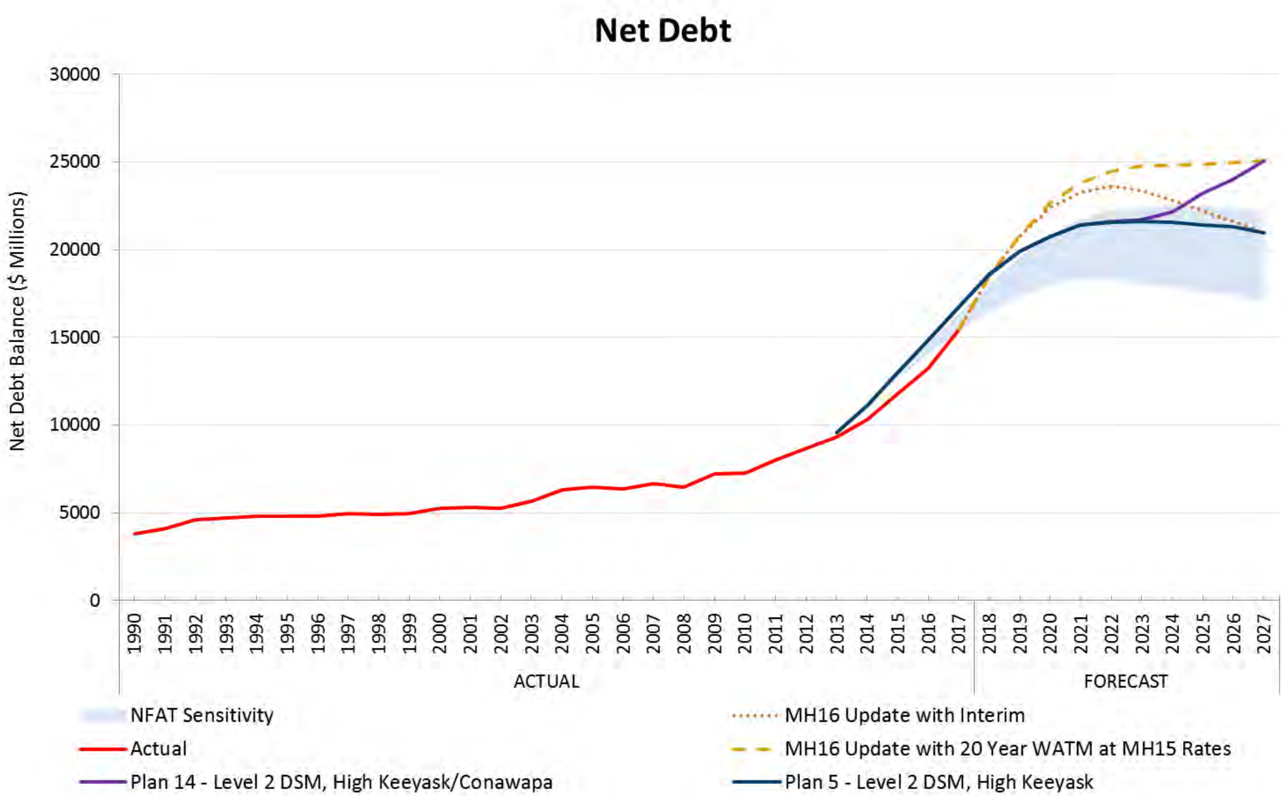
Other Ratios Have Shortcomings

- Adding other ongoing annual cash charges of Manitoba Hydro makes clear the alignment of equity ratio targets and that the proposed rate plan is minimally sufficient

(In Millions of Dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
MH16 Update with Interim:										
EBITDA (Numerator)	**1439**	**1676**	**1795**	**2068**	**2307**	**2308**	**2384**	**2495**	**2435**	**2508**
Interest	936	982	1041	1121	1145	1138	1148	1125	1089	1060
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	**1700**	**1754**	**1782**	**1890**	**1911**	**1880**	**1871**	**1908**	**1888**	**1882**
EBITDA / Ongoing Cash Burdens	**0.85** x	**0.96** x	**1.01** x	**1.09** x	**1.21** x	**1.23** x	**1.27** x	**1.31** x	**1.29** x	**1.33** x
Equity Ratio	**15%**	**14%**	**14%**	**15%**	**17%**	**17%**	**19%**	**21%**	**23%**	**25%**
At MH15 Rates:										
EBITDA / Ongoing Cash Burdens	**0.85** x	**0.91** x	**0.91** x	**0.95** x	**1.01** x	**0.96** x	**0.94** x	**0.94** x	**0.92** x	**0.95** x
Equity Ratio	**15%**	**14%**	**13%**	**13%**	**13%**	**12%**	**12%**	**11%**	**10%**	**10%**

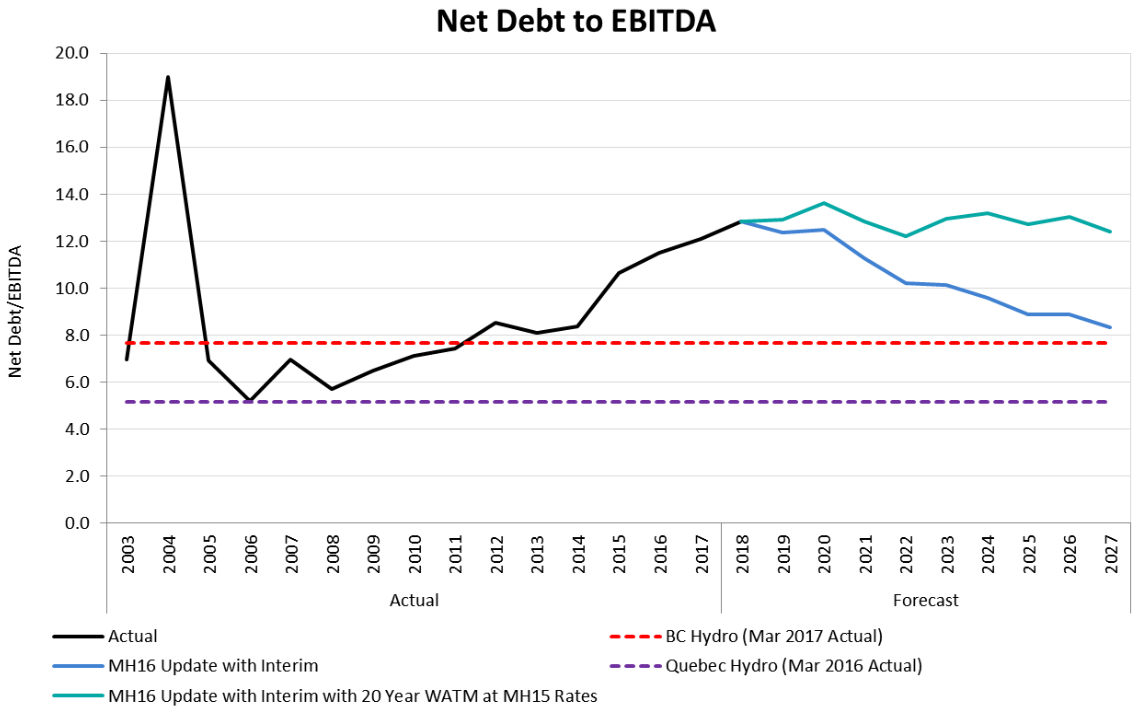
Debt Continues to Escalate

- Figure 5-3 from Mr. Bowman's evidence shows forecast net debt levels now substantially **exceed** high end of sensitivity range of NFAT
  - On a smaller than anticipated domestic business due to lower load growth outlook
  - Notwithstanding high water contributions of 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19…
  - …and in spite of now lower interest rate forecast



EBITDA and Leverage

- Debt / EBITDA is a common measure of relative debt level
- Manitoba Hydro's leverage ratio has steadily increased
  - Forecast to peak at nearly 14x and, without more aggressive rate action, not abate
  - Comparable leverage level to 2003/04 drought when MH lost >$400 million



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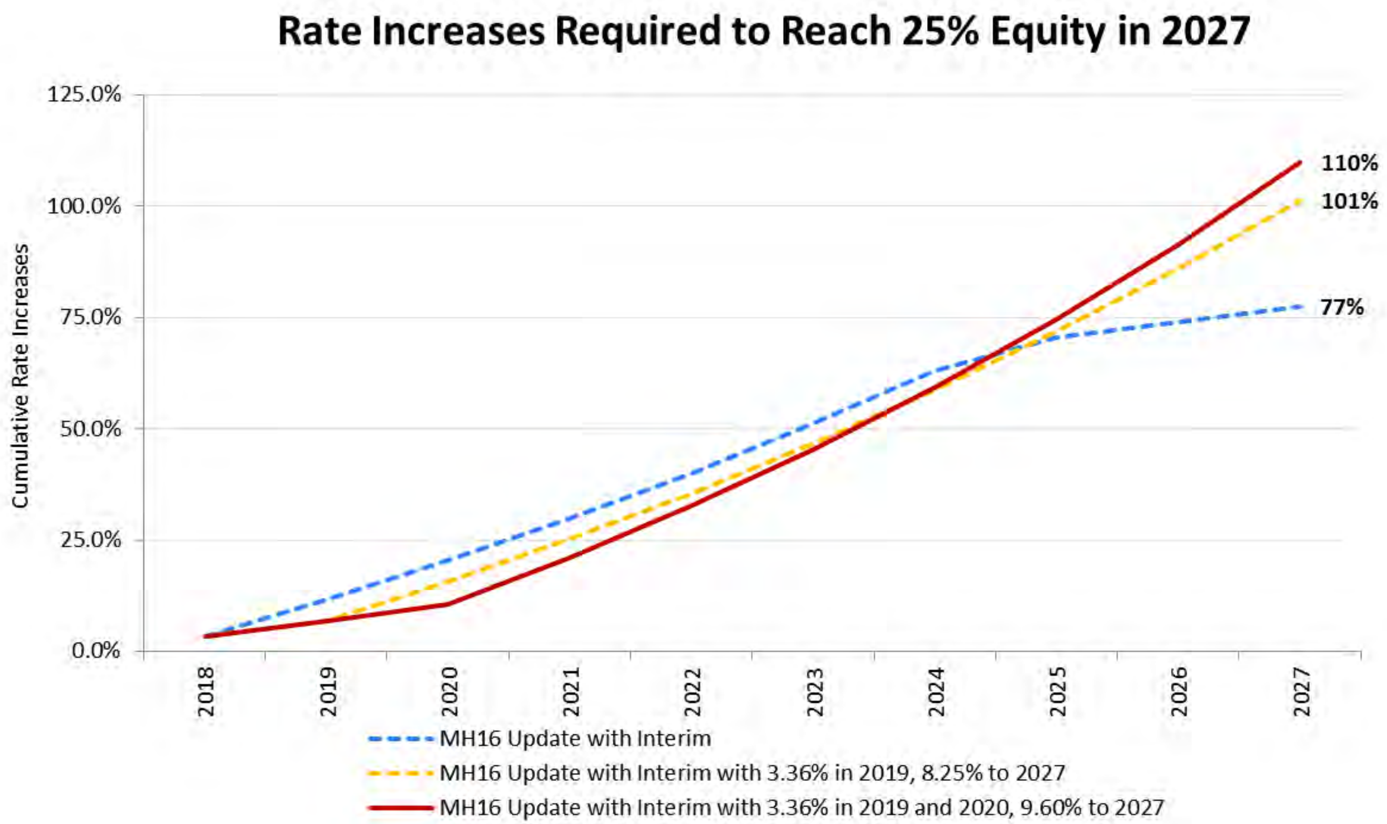
Province of MB is a Stakeholder

- Manitoba Hydro customers bear the **full cost** of operating the system
- MH should not be permitted to threaten or impair the credit standing of the Province of Manitoba
- Manitoba Hydro customers also have vested interest – Provincial borrowing cost is passed on to MH
- Not appropriate to inflate debt until **inevitable** corrective rate action is too politically or economically infeasible therefore forcing taxpayers to fund relief
- Provincial Guarantee Fee is **not** compensation for increasing Province's borrowing costs

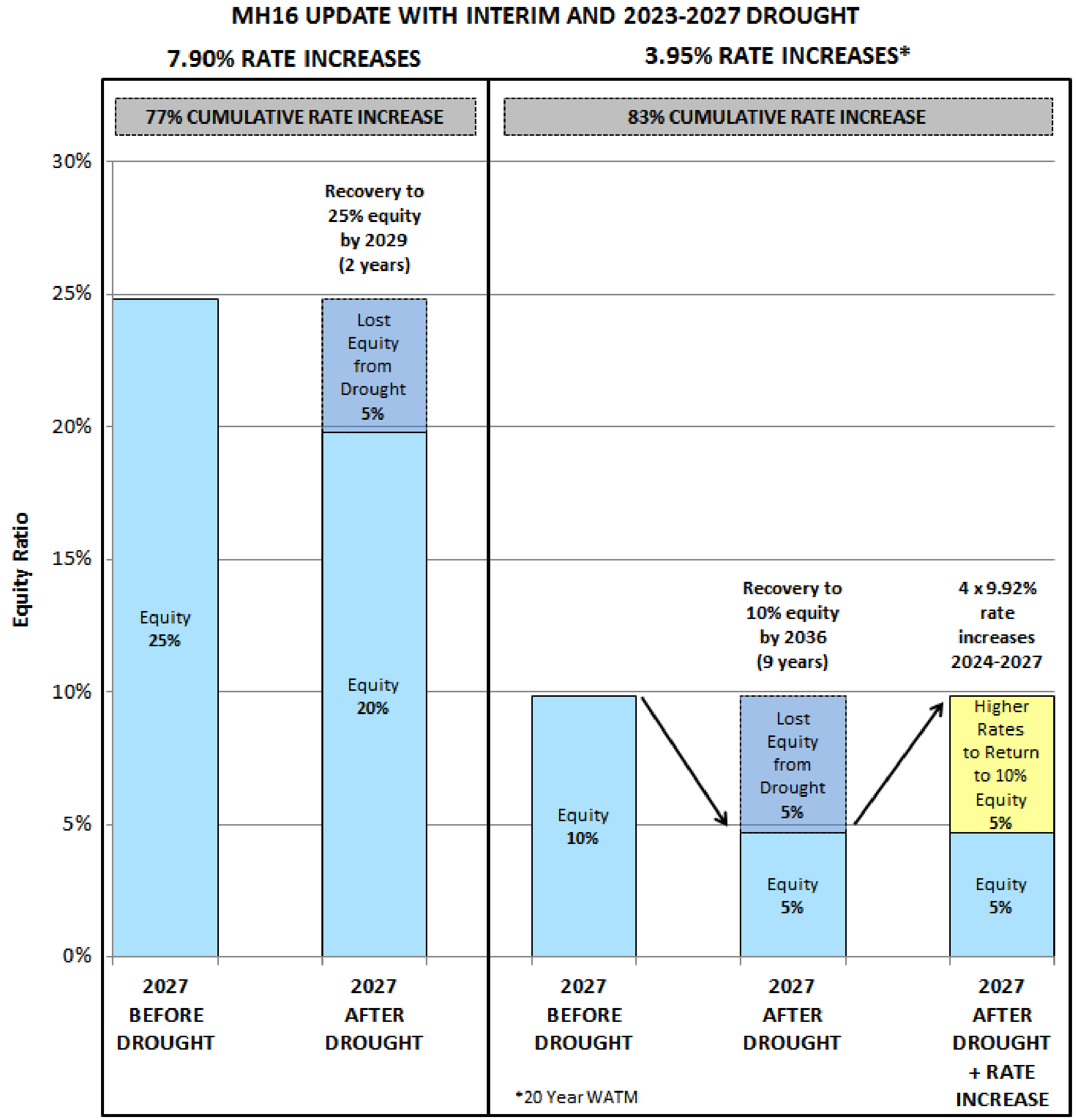
Important to Act Now

- Multi-year and compounding impacts of first year(s) rate increases are essential
- Must get on right trajectory - very difficult to “catch up”



Important to Act Now

- In the event of a five-year drought from 2022/23 - 2026/27:
  - Under the proposed plan, no significant rate action is required. Attainment of the 25% equity ratio is delayed by ***two years***
  - Under 3.95% rate increases, recovery to pre-drought equity of **only** 10% is delayed by ***nine years to 2035/36***
    - Or requires four 9.92% rate increases just to maintain **10% equity**
    - Which would leave rates in 2027 6% **higher** than under MH plan



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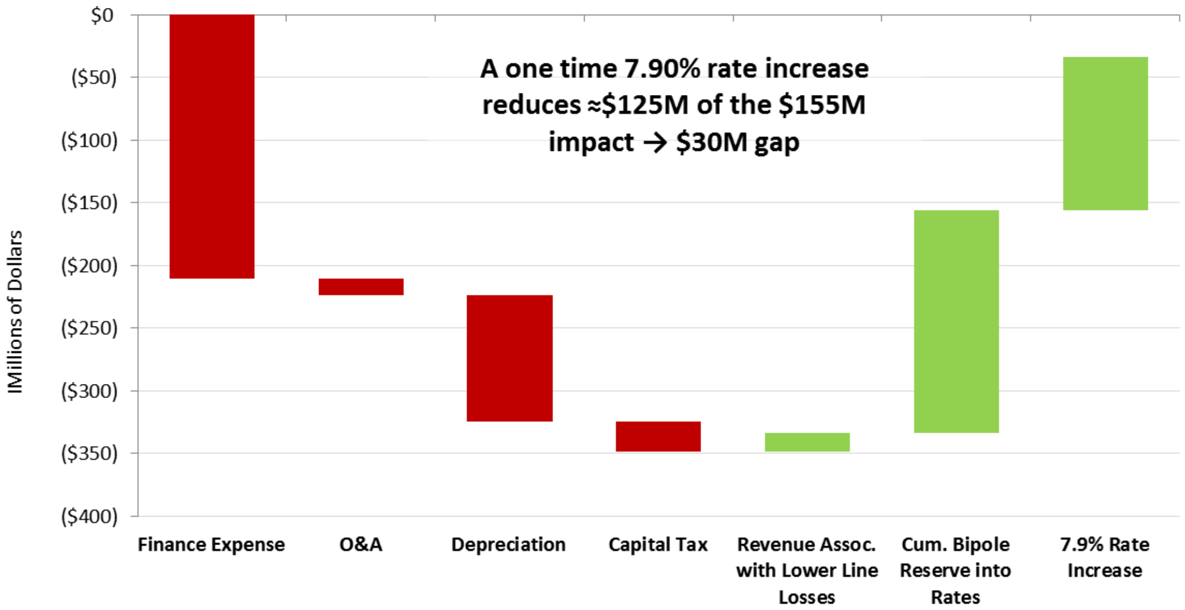
Important to Act Now

- April 1, 2018 (proposed) is the last rate increase before Bipole III comes in service in **less than 9 months**
- Current rates are not adequate
  - Already not funding full costs of operating the business
  - Bipole III is significantly underfunded through rates



April 1, 2018 Rate

- Rate request is 7.9% for April 1, 2018
- Comfortably supported by:
  - Will address only 60% of 2019 cash flow deficiency
  - Current rates too low by up to 20%
  - Still insufficient to address imminent revenue requirement of Bipole III
- Essential and necessary first step in proactively addressing
  - Lack of contribution to reserves in current rates
  - Debt continuing to grow to unsustainable levels
  - Need to ensure Manitoba Hydro is financially positioned to address aging infrastructure and a changing utility model

Reserves are Essential

- Equity – in and of itself – does not create the buffer that cushions rate impacts when things go wrong
  - It is not a cash “rainy day fund”
  - Accumulated net profit of years ago is of no use during adverse events with no current income / cash flow
- Instead, for Manitoba Hydro, equity (or reserves) represents **debt not borrowed**
- Only path available to MH to create useful reserves is to build a financial plan and rate strategy that has positive net income and positive cash flow
  - 3.95% does not come close to achieving

Reserves Must Be Funded In Rates

- Positive net income and cash flow represents a **planned** contribution to reserves each year through rates
- Value is the ability to manage and absorb **foreseeable** risks (e.g. below average water conditions, rising interest rates), without necessitating immediate rate action
- Insofar as risks don't present, income and cash flow will build reserves through the reduction of debt
  - Contribute to returning Manitoba Hydro debt to a sustainable level for the size of its operation
  - Increase probability of lower, more stable rates

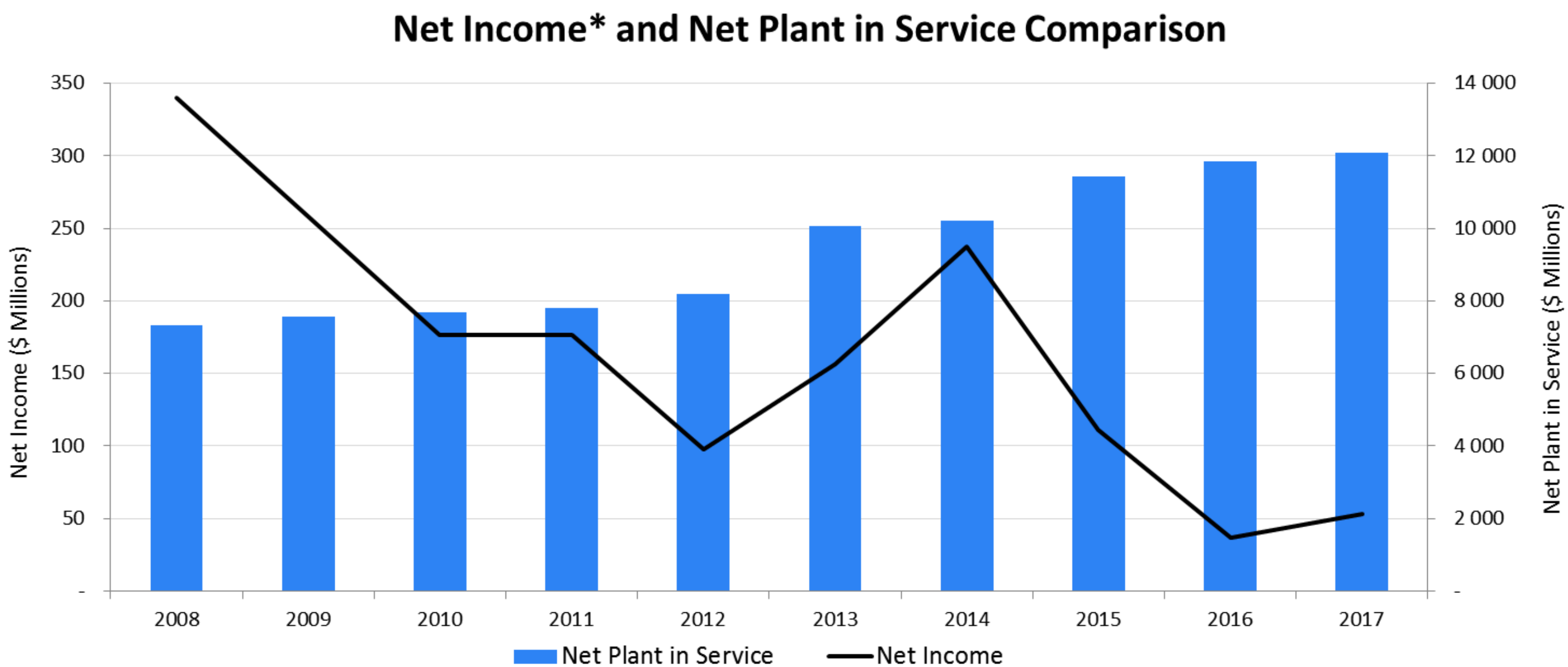
V. How Did We Get Here?

What Happened?

- Export prices collapsed, without domestic rates compensating
- Domestic load growth has slowed – substantially
- Costs of being in the electricity business have been rising faster than inflation
- Did not take advantage of high water conditions by making contributions to reserves – in fact, the opposite
- Keeyask business case has eroded
- Bipole III, while necessary, compounded the challenges
- Undertook what has become almost $14 billion of capital projects with too risky a plan to pay for them

Rates Are Too Low

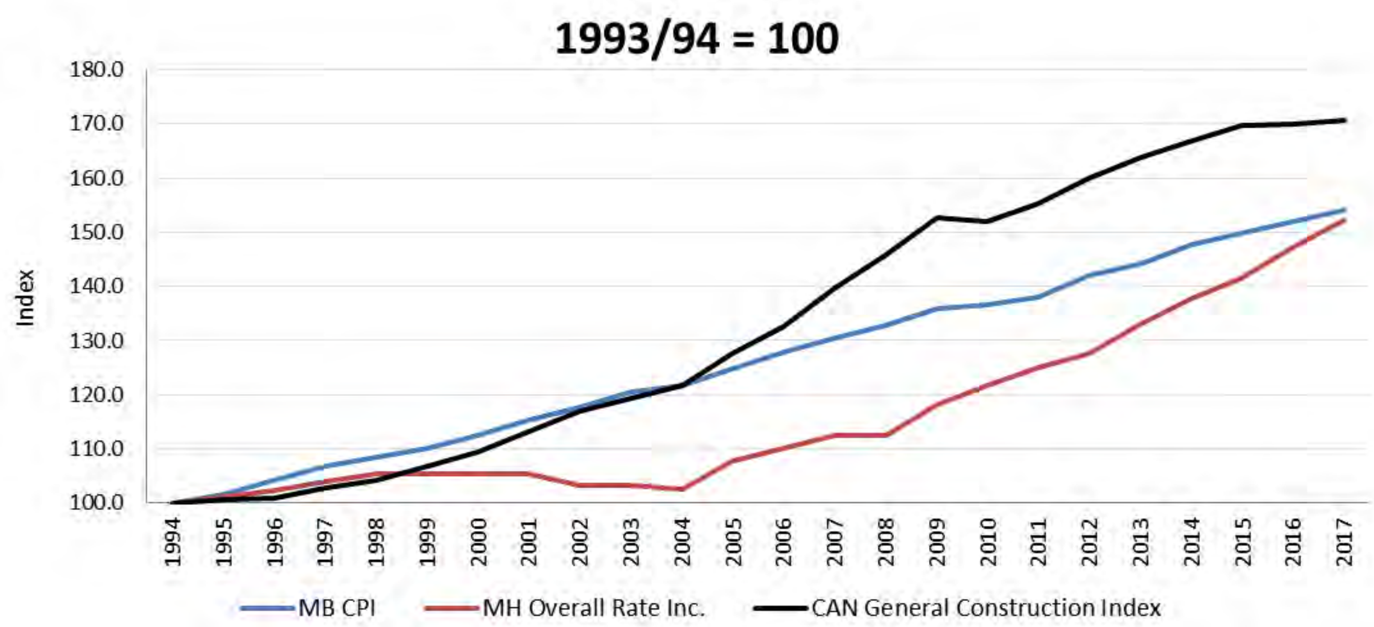
- Manitoba Hydro has not been asking for the right rates
  - As the business has grown, net income has been systemically falling
  - In spite of 14 years of above average water conditions
  - In spite of declining to multi-generational low interest rates
  - Inadequate or no contribution to reserves being made for size of this business



*2010-2014 net income adjusted to add back accounting changes from Figure 2.3 of Rebuttal Evidence

Rates vs. Inflation

- Until recently, rate increases have stayed well beneath inflation on a cumulative basis
- Meanwhile, construction costs – an important factor for Manitoba Hydro – have significantly outpaced inflation



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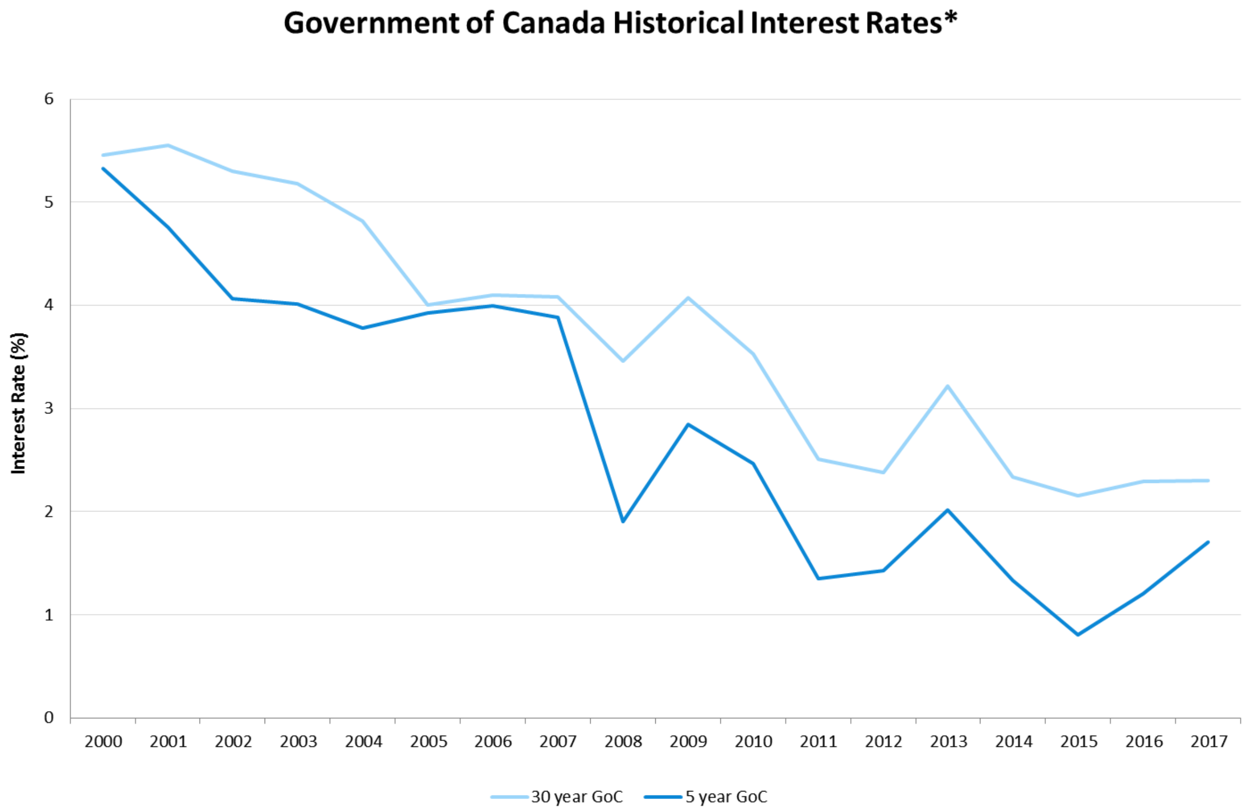
Interest Rates Have Cooperated

- Without declining interest rates this would have been a financial / rate catastrophe



* Reflects data at calendar year end

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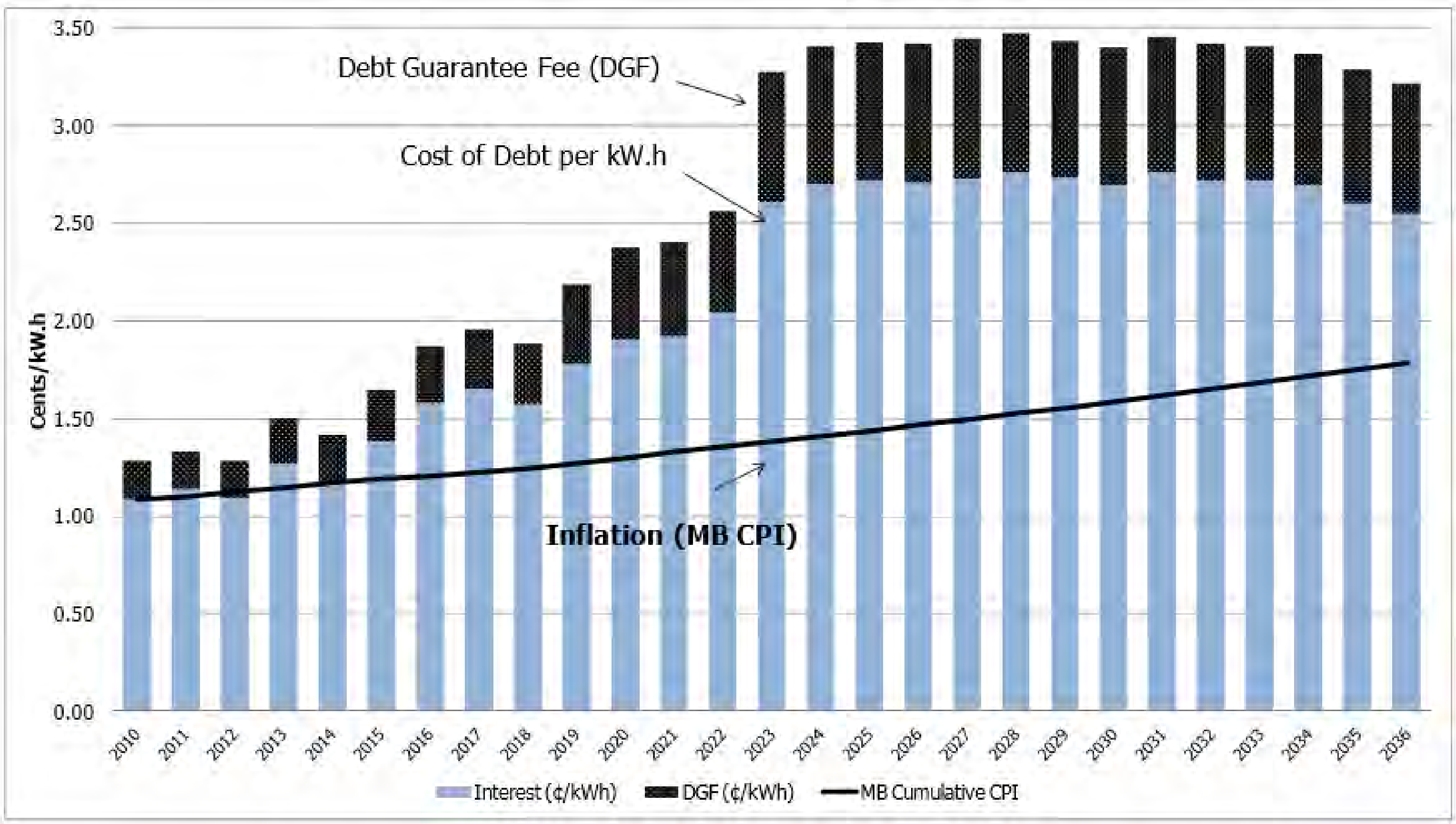
Manitoba Hydro

But Interest Burden Growing Rapidly

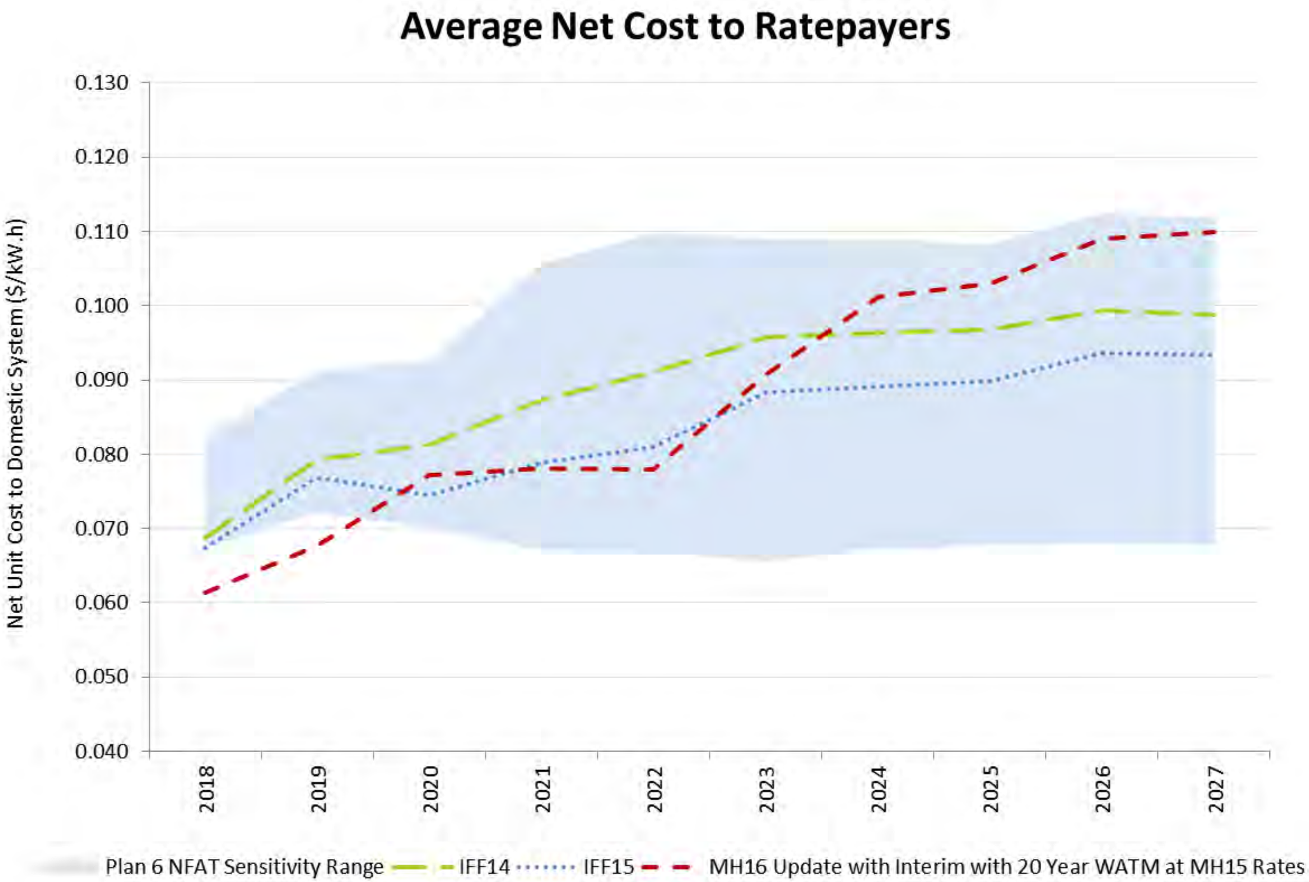
- Per MH-MIPUG (Bowman)-23, Figure 2*:



*based on MH16 Update with Interim at MH15 Rates from PUB/MH I-34 (Updated Appendix 3.4)

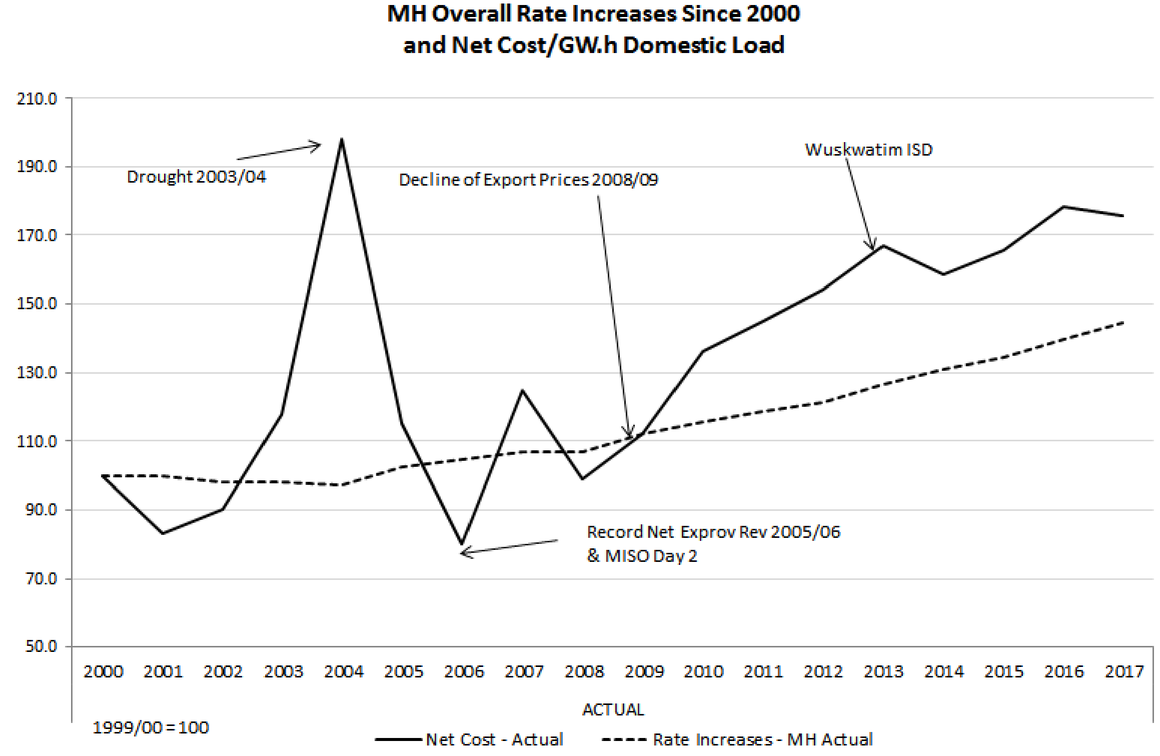
Net Costs vs. NFAT

- Net costs are now forecast to be at the high end of the NFAT sensitivity range (in spite of lower interest rates)



Net Costs vs. Rates

- After 2008, opportunity export prices collapsed
- Coupled with escalating costs and below CPI rate increases have led to net costs increasing substantially faster than rates



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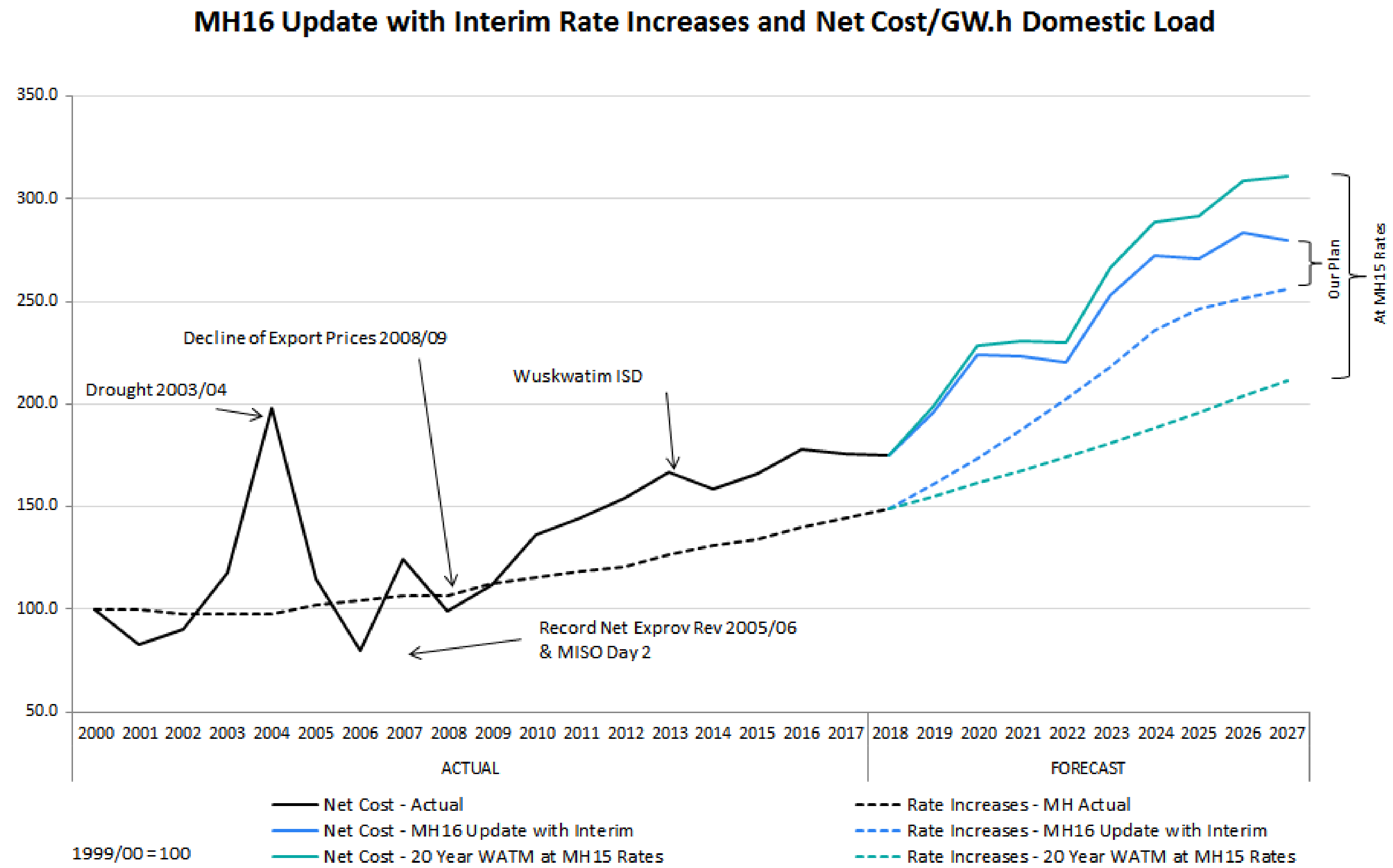
3.95% Path Does Not Work

- A 65% increase in net cost per unit between now and 2023/24 cannot be met with a 30% increase in rates



VI. Addressing Key Concerns

What You May Hear

Argument	Reality
MH has net income – things are fine	• Net income and cash flow are different and we are in a cash deficit • Today’s rate levels aren’t sufficient to absorb Bipole III and then Keeyask • $30 million of net income (with exceptional water conditions) is not adequate
These rate increases will damage the economy / industrial customers will leave	• 3.95% plan amounts to a doubling of rates over 18 years • Unplanned “rate shock” is worse • In longer term, competitiveness is enhanced through lower, more stable rates having lowered our debt
Stop Bipole III and Keeyask	• Far more damaging to customer rates – upwards of $450 million of annual interest cost without a functioning asset or any revenue to show for it

What You May Hear

Argument	Reality
Hydro should just cut more costs instead of raising rates	• O&A is <20% of costs post Keeyask; issue cannot be addressed without rate action • To plug gap in 2018/19 revenues from Order 80/17 (3.36%) vs. 7.9% would require reduction of ≈700 operational employees excluding restructuring costs beyond the 700 underway
Spread the rate increases over 20 years	• First 10+ years remain highly susceptible to risk • Greater potential for long term rate escalation…even if our forecasts are right and interest rates stay low • Continuing to build debt vs. make contributions to reserves for 6 years after Keeyask is in service
Low income customers can't afford this	• Important issue that MH does not have the tools/mandate to address • Relates directly to customers' ability to pay; issue requires many parties/organizations working together

What You May Hear

Argument	Reality
Change the Projections to Justify Lower Rate Increases	• Hope is not a plan • Depreciation and regulatory accounting policies make no material difference • Less risky to adjust rates later for good news
Markets are unperturbed and there is no threat to the Province of Manitoba credit rating or MH's borrowing costs	• Taking pressure off the Manitoba credit rating is a collateral benefit • The issue is that Manitoba Hydro has an unsustainable level of debt and therefore too much vulnerability to overall interest rate increases regardless of cause
Cut maintenance capital expenditures	• Short-term perspective; aging infrastructure needs to be addressed • Makes negligible difference to revenue needs in any event
Punish Manitoba Hydro by Withholding Rate Increases	• To what end? • Will only exacerbate the issue for our customers

What You May Hear

Argument	Reality
Take on shorter term debt to save on interest costs and keep rates lower	• Enormous risk to rate stability in next 10 years • Would leave almost the entirety of Hydro's projected peak debt subject to interest rate risk between now and 2026/27
Our forecasts are too conservative and overstate need for rate increases	• Load forecast is already looking too optimistic • Efficiency Manitoba is a wildcard • Export prices thus far in 2017 tracking well below projections • Short-term interest rates already ≥ 2018 forecast • Hope is not a plan – rates can be adjusted if things go better; much harder the other way
Not Fair to Current Ratepayers	• Rates have not kept up with costs of the system and are too low today • Rates have not made a contribution to reserves in almost 10 years • Not fair to park unsustainable debt burden on the next generation

VII. Summary

Key Messages

- Manitoba Hydro's business outlook has deteriorated significantly since the last GRA
- Financial condition is not sustainable
  - Debt levels are far too high and are growing massively out of proportion to the scale of MH business
  - Cash flow negative
- 3.95% rate plan is grossly insufficient and puts MH and its customers at far too much risk
- Taking strong action now is essential
  - April 1/18 rate request does not fully address Bipole III and current cash deficiency
  - Enables much higher likelihood of stable and overall lower rates in the long run

Tab 18

MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *Order in Council 128/2013 and attached Terms of Reference Needs For and Alternatives (NFAT) Review*

AND IN THE MATTER OF *Manitoba Hydro's Filing with Respect to the Need For and Alternatives to Manitoba Hydro's Preferred Development Plan*

FINAL ARGUMENT

OF MANITOBA HYDRO

May 26, 2014

Manitoba Hydro

TABLE OF CONTENTS

1.0 INTRODUCTION

The NFAT Terms of Reference provided by the Provincial Government to the PUB specify that the PUB's report is to "include recommendations to the Government of Manitoba on the needs for Hydro's Preferred Development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives."

As delineated in the Submission (e.g. Executive Summary Pages 1:2), the Preferred Development Plan contains two key components that require immediate commitment:

- Start construction immediately in 2014 of the Keeyask Generating Station (G.S) for a 2019 in-service date (ISD)
- Proceed with a 750 MW US transmission interconnection for a 2020 ISD

The Preferred Development plan also includes the 1485 MW Conawapa Generating Station, with an In Service Date not earlier than 2026. A decision regarding construction of Conawapa is not required immediately, however in order to protect an In Service Date for Conawapa as early as 2026 certain actions and investments are required in the near term, recognizing that conditions will be continually monitored to determine if such continued investments are warranted and, ultimately, to determine if Conawapa should be constructed and for what ISD. A final decision on construction of Conawapa for an ISD of 2026 must be made by 2018.

The resources in the Preferred Development Plan are supported by a number of export agreements, notably the 250MW sale to Minnesota Power, the 100 MW sale to Wisconsin Public Service (WPS) and the 308 MW sale to WPS. The Government of Manitoba authorized Manitoba Hydro to enter into both the Minnesota Power 250 MW and Wisconsin Public Service 100 MW sales agreements in Order In Council 304/2011 which issued August 17, 2011. Order In Council 308/2011 notes that the construction of new power generation facilities in the Province of Manitoba are necessary to fulfill these contracts. These agreements do not require further confirmation from the Government of Manitoba. However, if these agreements are to proceed, the generation and transmission facilities upon which they are contingent, that is the Keeyask Generating Station and the 750 MW transmission interconnection, require immediate approval.

The Preferred Development Plan includes continued substantial investment in DSM/Power Smart and efficiency improvements to existing generation. During the course of the NFAT process, MH filed new analysis which indicated that it would be economic to quadruple its DSM plan to target 3978 GWh and 1136 MW (including savings from codes and standards) by 2028/2029. DSM plans will also be continually monitored and updated.

The Preferred Development Plan is not a rigid plan with fixed ISDs and resource selection for the next 20 years. Mr. Thomson indicated on March 3rd (Tr. p. 76-77), "And I do want to underscore that the Preferred Development Plan is not without flexibility. While construction on the Keeyask generating station and other aspects of the Preferred Plan must begin shortly, Manitoba Hydro will always maintain the flexibility to respond to future circumstances when it comes to future resources identified as part of the path. Conawapa, for instance, will only get built if the business case remains sound."

The Preferred Development Plan has the necessary flexibility and optionality to permit Manitoba Hydro to respond to changing circumstances over the next number of years. The NFAT process outcome is not a long term plan with future decisions pre-established but a pathway. The pathway involves a combination of immediate decisions and commitments followed by longer term components which are responsive and adapt as the future unfolds. Future decisions on the longer term components will be influenced by a wide range of evolving factors such as load growth, natural gas prices, GHG emission restrictions, export prices, future export contract negotiations, capital cost forecasts, technological innovation, inflation and interest rates. Mr. Bowman strongly supports the concept of pathways and the importance of considering the optionality benefits associated with these pathways (Tr. p. 10040-10050). The Preferred Development Plan pathway involves front end decisions and commitments which provide early and immediate benefit while also providing options and flexibility in the long term to reduce risks and maximize benefits as opportunities arise.

While there are a number of fundamental possibilities for PUB to consider, the NFAT process has evolved such that the primary PUB recommendation to be considered is: Should Keeyask be constructed and advanced to have an ISD of 2019 in order to provide for both a range of possible need dates for domestic load and to take advantage of the Minnesota Power (MP) 250 MW export sale contract with the associated commitment by MP to develop a 500 kV interconnection? Recommending for or against this pathway will facilitate or put to an end a number of other critical options that will affect electricity supply in Manitoba for decades to come.

MH Exhibit #192 presented by Mr. Wojczynski on May 1 (Tr. p. 9848-9853) depicts the choice to be made concerning the long term electrical energy future of Manitoba. Advancing Keeyask to 2019 is integral to Pathway 4 & 5. This allows the MP 250 MW sale to proceed and the 750 MW interconnection be developed in concert with Manitoba Hydro's US partners. The WPS 100MW sale and the NSP 125 MW export extension would also proceed.

Proceeding with Keeyask and the interconnection in 2019/20 also provides for the opportunity in the future to take advantage of the WPS 308 MW export sale and to develop Conawapa, should circumstances be favorable. This would also facilitate pursuing other export contracts with counterparties such as with Great River Energy (GRE), SaskPower, NSP 500 MW and others. However, no decision is required for a number of years whether and when to construct Conawapa.

The other choice depicted in MH Exhibit #192 is to pursue Pathways 1 & 2. If these pathways are adopted, Keeyask will not be advanced to an early In Service Date, nor will the MP 250 MW, WPS 100 MW or WPS 308 MW export sales proceed and no new interconnection will be developed in the foreseeable future. At some later date a choice is made to proceed with Keeyask (Pathway 1) or with natural gas generation (Pathway 2).

In both sets of Pathways (1 & 2 and 4 & 5), there is an annual review of resource choices and timing (e.g. continuing commitment to DSM based on achievements and newly identified opportunities, potential new generation ISDs and options).

In deciding whether to recommend Pathway 1 & 2 or 4 & 5, there are a number of associated considerations which will help to illuminate the main recommendation:

- Is development of the 750 MW interconnection advantageous for Manitobans?
- Is it advantageous to advance Keeyask to 2019 from a date when it is needed strictly for domestic needs?
- Is the overall package of developing Keeyask in 2019 and proceeding with the MP 250 MW sale and 750 MW interconnection a preferred option for Manitoba compared to plans based on development of natural gas or other options?

The NFAT Terms of Reference specify the perspectives which were used to evaluate and compare the plans and pathways to demonstrate that the Preferred Plan and its associated pathway are in the best long term interest of the Province of Manitoba and Manitobans.

These perspectives are listed in Table 1 which is drawn from slides 7 and 8 from Manitoba Hydro Exhibit #86 and which were presented on the first day of the hearing.

These perspectives are addressed in the remainder of the MH Final Argument.

Table 1: NFAT Multiple Perspectives

Market Valuation Economics

- NPV net benefit to MH (domestic customers & project partners)

MH Domestic customer

- Reliability (minimum required by planning criteria & amount above criteria)
- Energy security (minimum required by planning criteria & amount above criteria)
- Rate increases (annual & cumulative)
- Financial targets (debt/equity, interest coverage, capital coverage)
- Retained earnings, fixed asset & debt levels

Socio-economic

- Manitoba Economy – employment & income
- Training & business opportunities
- Infrastructure, services, personal & family & community life, resource use, heritage resources
- Special focus on Northern & Aboriginal communities

Macro-environmental impacts & benefits

- Air, land, water, flora, fauna
- Greenhouse gases & key environmental functions
-

Manitoba Government

- Financial transfers to provincial government
- Capital tax, water rentals, debt guarantee fee
- Alignment to Manitoba Hydro Act, Sustainable Development Act, Climate Change Act, Clean Energy Strategy

Risk

- Deal with uncertainties, mitigation, flexibility

2.0 LOAD FORECAST

2.1 Manitoba Hydro's Position: the Forecast Is Reasonable for NFAT purposes

Manitoba Hydro's Load Forecast is updated annually to include current information about Manitoba Hydro customer groups in order that the best estimate of future load can be produced. The base forecast is intended to predict what would happen in an average growth case, where there is an equally likely (50:50) chance of the actual load being higher than the forecast as there is of it being lower than the forecast. If the future brings faster than expected population or economic growth, then the actual loads will exceed the forecast. If the future brings slower than expected population or economic growth, then the actual loads will be less than the forecast.

This position is supported by other experts. The conclusion of Mr. Todd (Elenchus) is that the forecast is reasonable, except for possible structural change.[1] However, as Mr. Todd also testified, structural change cannot be predicted or built into the forecast.[2]

The Elenchus report stated: "Elenchus is of the opinion that the 2012 and 2013 Electric Load Forecasts prepared by Manitoba Hydro are reasonable projections of future domestic electricity demand assuming there are no significant structural changes to the demand drivers that underpin the forecasting methodology." [Elenchus Review of Manitoba Hydro's Load Forecast, page i]

> "Unfortunately, it is not possible to build structural changes in the market into a load forecast. The most important potential changes are inherently unpredictable. We cannot even predict with confidence whether future structural changes will dramatically escalate demand or cause demand and sustainable prices to collapse." [Elenchus Review of Manitoba Hydro's Load Forecast, page 41]

This difficultly in determining the impact of structural change is further emphasized by Mr. Todd in his testimony at Transcript Page 5125, lines 14-17:

> "It would be harder to predict what the long-term structural impact would be in Manitoba than it would be for Canada as a whole. And economists –

[1] Transcript page 4788, line 7.
[2] Transcript page 4795, line 3.

analysts are still trying to figure that out and are guessing in both directions for Canada as a whole."

Manitoba Hydro's load forecast was also endorsed by MIPUG, wherein the pre-filed testimony of Mr. Bowman of InterGroup Consulting, states: "The load forecast used for Hydro's NFAT filing was tested for reasonableness (Appendix D), and found to be reasonable for the purposes of long-term planning. The P10 and P90 bounds provide a wide range of conditions that are appropriate for scenario analysis." [Pre-filed Testimony of P. Bowman for NFAT, page 1-10].

2.2 Handling Structural Change - Scenarios versus Probability

In 2009, Manitoba Hydro moved from scenario analysis to the use of a probabilistic approach for projecting potential variations to the load forecast. As part of Manitoba Hydro's Electric 2010/11 & 2011/12 General Rate Application, the Public Utilities Board issued Order No. 30/10 on March 26, 2010 appointing Drs. Kubursi and Magee to provide an independent assessment of Manitoba Hydro risks. The Load Forecast was part of this review, and Drs. Kubursi and Magee supported the probabilistic approach for risk assessment for long term planning.

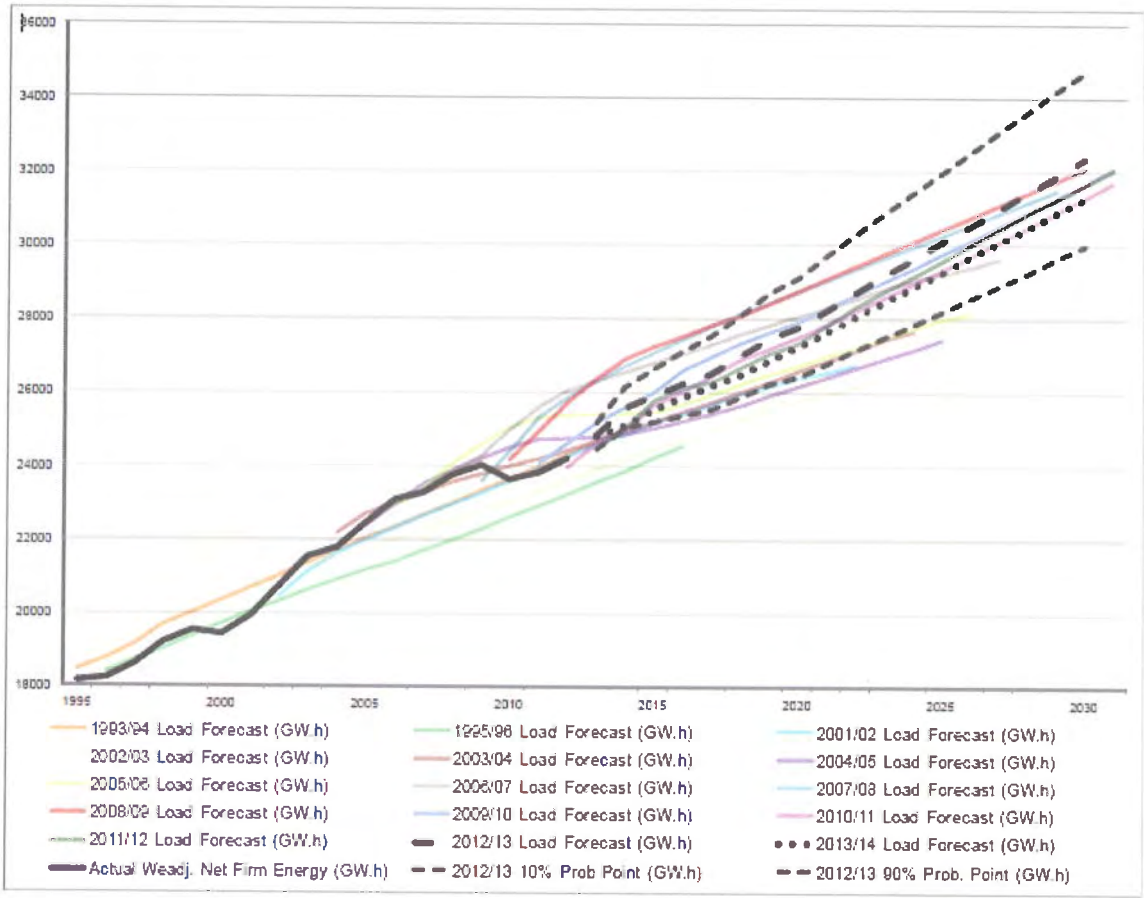
Scenario analysis requires the development of inputs for various cases or scenarios that are analyzed to establish their impact on future load growth. This process involves changing population forecasts, and/or economic input variables, and/or the inclusion of specific assumptions. This requires subjective decisions as to how to forecast each of the inputs. Even after the arbitrary decision is made as to what a scenario consists of, especially one of structural change, estimates must be based on relationships that occurred in the past. These relationships are often assumed to continue into the future. Otherwise, another set of assumptions are required in order to model future relationships. The selection of any scenario requires judgment and the possible combinations are limitless.

Probability analysis provides an analytical solution that avoids the problems of scenario analysis. Instead of attempting to manufacture a scenario, the distribution of load variation from the past is used to develop a probability distribution for future load variation, and statistics is used to produce probability bands. For specific purposes, a set of probability points can be selected to represent high and low scenarios.

Scenarios do not in and of themselves indicate the likelihood of the scenario occurring. In contrast, probability analysis provides a likelihood of what the load will be. Using probability points, any desired level of risk can be analyzed and assessed. The net benefit or cost of this level of risk can be determined and the results can be combined as a full risk analysis.

For the purposes of the NFAT analyses, Manitoba Hydro examined 90% and 10% confidence intervals of the load forecast. As Mr. Wojczynski testified, in setting up these sensitivities for analysis, Manitoba Hydro sought values which were not exceedingly extreme, but which had a medium level of occurrence (Tr. p. 1135, lines 14-18). In his pre-filed testimony, Mr. Bowman agreed that the use of this probability analysis can provide good bounds and presented the following figure:

Figure 6: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 10th and 90th Percentile Forecasts (2012/13 Load Forecast)[12]



"Figure 6 above shows the addition of Manitoba Hydro's sensitivity load forecasts. This includes the 10th and 90th percentiles. This figure serves to illustrate the wide range of sensitivities that arise when these load cases are tested against the NFAT Plans and why they provide what is generally a reasonable outer band of expected experience." (MIPUG Exhibit #9, Appendix D, p. D-9)

This is not to say that an assessment of individual possible events is not useful. Such analysis provides information as to the potential implications of specific events and their relative impacts. This type of information is provided in the Possible Events section of Manitoba Hydro's Load Forecast (Appendix D page 50).

Elenchus prefers the use of scenario analyses. Elenchus is of the opinion that Manitoba Hydro did not address structural change to future energy demand in its NFAT analyses, presenting grid parity as an example of a structural change that could cause a major reduction in the load forecast, and electric vehicles as a structural change that could cause a major increase in future load requirements.

As part of these proceedings, Manitoba Hydro did address structural changes that could cause a major reduction in load growth. Additional analyses were undertaken examining a "no new load growth" case (Manitoba Hydro Exhibit #156) and enhanced levels of DSM (MH Exhibit #95, page 129). In these analyses, Manitoba Hydro determined that if no load growth is assumed beyond 2022/23 and surplus energy is valued using the 2013 long-term price forecast, building Keeyask and a new interconnection results in an incremental net present value of $395M (at real WACC of 5.4%) relative to building no new generation, and that pursuing enhanced DSM up to Level 2 is beneficial under the All Gas, K19/Gas/750 MW and K19/C/750MW plans with incremental net present values ranging from $737 million to $887 million.

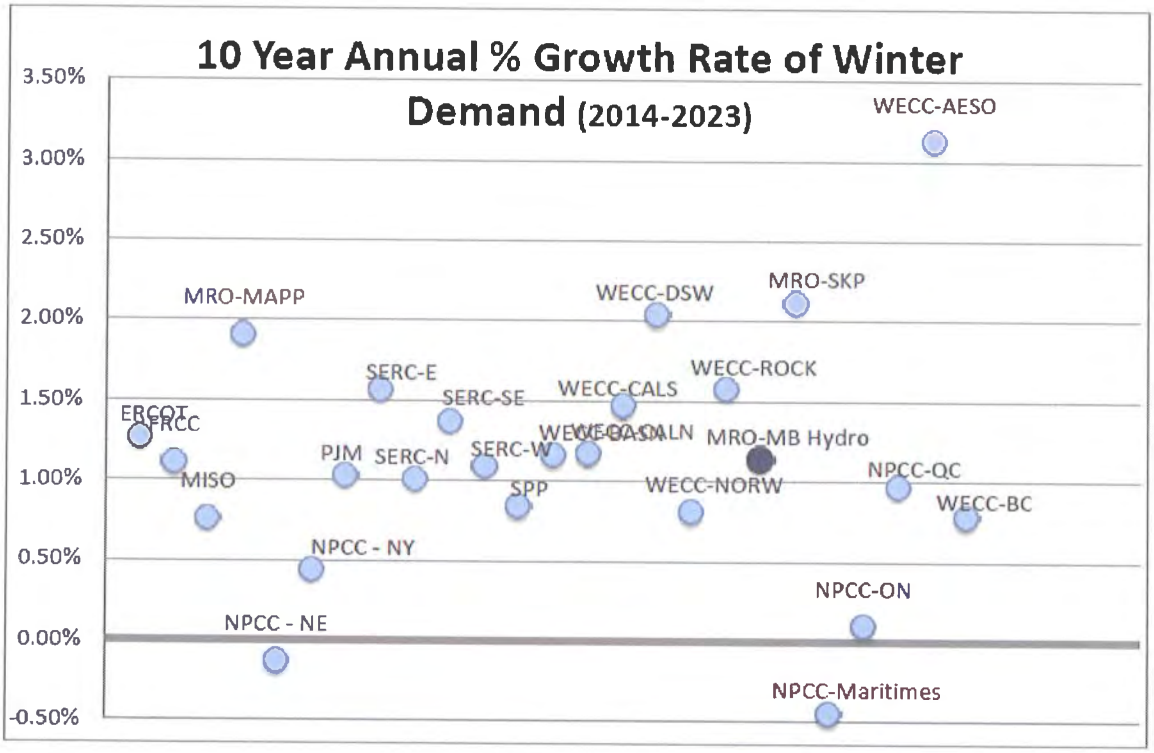
2.3 The Historical Accuracy is Within Reasonable Bounds.

The historical accuracy of the forecast is limited by the year to year variability in the actual growth. The base forecast assumes normal growth. Short term economic conditions may cause the short term load to be higher or lower than forecast, but in the long term, these conditions generally average out.

MIPUG's evidence noted that "Within the reasonable bounds of long-term forecast expectations, Manitoba Hydro's load forecasts appear to have generally tracked trends in power usage well. Each individual forecast can be off by a certain degree, but the forecasting process has been largely self-correcting over a series of years." [Pre-filed Testimony of P. Bowman for NFAT, page D-3]

2.4 Neither Over-Forecast nor Under-Forecast

Manitoba Hydro notes that in comparing its forecast load growth to other jurisdictions, on an equivalent basis, Manitoba's forecast rate of load growth is in line with other jurisdictions. Manitoba Hydro cautions that such comparisons between jurisdictions must be undertaken with care. Jurisdictions do not define their load the same way and comparisons must be done on an equivalent basis. In its Rebuttal Evidence, Manitoba Hydro presented the data assembled from utilities by the North American Electric Reliability Corporation (NERC) as an appropriate comparator [MH Exhibit #85, page 5]. NERC reports Summer and Winter peak demand excluding Station Service and including DSM programs and specific system improvements. This information was updated in MH Exhibit #94 (Transcript Page #810) and continues to demonstrate that Manitoba's forecast rate of load growth remains in line with other jurisdictions.



Manitoba Hydro also notes the evidence on behalf of MIPUG that "Over the past few decades, there has been substantial criticism of Canadian Crown utilities producing overly optimistic load forecasts supporting construction of new baseload plants. While it is important to test whether Manitoba Hydro has exhibited a tendency to over-forecast growth, the evidence in this Appendix suggests this is not the case." [Pre-filed Testimony of P. Bowman for NFAT, Appendix D-1]

Given this comparison, Manitoba Hydro submits that its forecast growth is not overstated, is reasonable and is in line with the majority of regions.

2.5 The Forecast Methodology is Reasonable

Manitoba Hydro's Load Forecast is updated annually to include the latest information about customer groups so that the best estimate of future load can be produced. The methods used for forecasting are reasonable, with Manitoba Hydro's position being supported by others.

> "Hydro's load forecast reflects relative consistency with past practice, and a reasonable approach to analysis. The Hydro load forecast also reflects a reasonable approach to assessing the NFAT Plans." [Pre-filed Testimony of P. Bowman for NFAT, page 3-11].

Manitoba Hydro uses econometric and end-use forecasting for its Residential and General Service Mass Market sectors. In reviewing Manitoba Hydro's use of econometric and end-use forecasting methodology, John Todd of Elenchus noted: "In our view the methodology is generally reasonable, although, some refinements are suggested. Again, we're talking about tweaking, judgment of experts." (Tr. p. 4839).

Manitoba Hydro submits that the refinements suggested by Mr. Todd do not impact the reliability of the load forecast for the purposes of considering the issues before this Board. Mr. Todd also admitted this when he testified: "…as a load forecast it's very difficult to criticize it and say there's a different set of numbers that's better… what we did not do from the beginning was to say, We're going to develop our own load forecast with a different set of numbers. If we did that, we wouldn't come up with anything much different." (Tr. p. 4855).

As such, using a different methodology than what Manitoba Hydro used would not produce a substantially different forecast.

2.6 Top Consumers and Potential Large Industrial Loads (PLIL)

Manitoba Hydro's Top Consumer segment is comprised of a limited number of customers spread across a broad grouping of differing industry sectors. The number of customers within each of those sectors is relatively small with no one sector having an overwhelmingly larger concentration of customers than other sectors. Variables related to facility age and technologies employed within industrial facilities located in Manitoba reflect different levels of competitiveness within a global industrial landscape. They contribute to an industrial landscape where the competitiveness and applicable market influence for a particular customer does not necessarily align with forecasting techniques that are based on high level sector-based trends[3]. The fortune of a few companies and their desire to situate in Manitoba, or need to expand or contract their Manitoba operations, as well as the nature of their specific industry that may force them to expand or reduce operations or close shop entirely is inherently unpredictable. Patrick Bowman testified that "Industrial Load Forecasting in particular is notoriously difficult when there are a limited number of customers." [Pre-filed Testimony of P. Bowman for NFAT, page 3-11]

In these circumstances, Econometric and End Use forecasts do not work well because they must rely on the generalized forecasts of the industries and levels of production expected which are at least as difficult to predict, if not more so, and may not be representative of the companies in Manitoba given their small number and specific circumstances. Manitoba Hydro also believes the use of available "Manitoba specific" GDP forecasts is not suitable as there is not a demonstrated strong relationship as noted in the response to PUB/MH II-457(a). Mr. Todd acknowledged these difficulties in his direct evidence, which includes the statement that "Top User loads can change significantly in unanticipated ways since their demands are driven by many idiosyncratic factors that cannot be known to Manitoba Hydro." [Elenchus presentation ERA Exhibit #5, slide 24] In addition, after review of the performance of Indiana's econometric-based load forecast for industrial customers, Dr. Gotham agreed that some events cannot be predicted with any methodology. (Tr. p. 8628)

Recognizing the limitations associated with econometric and end use forecasts for Top Consumers in Manitoba, Manitoba Hydro undertakes forecasting of short-term energy use for Top Consumers on a per-company basis in order to include their respective committed plans in its forecast. Manitoba Hydro has established a good working relationship with these customers, and is able to gain first-hand information regarding customers' short term energy requirements based on their knowledge of their operations, markets and opportunities. To

[3] Transcript page 8642, lines 10-22.

estimate the longer-term growth for the Top Consumer sector, the sector is forecast as a whole based upon average growth over a period of 20 years. Given the high degree of year over year variability in industrial growth (i.e. load is added or removed in large blocks), industrial growth and decline should be examined on a longer-term basis. This 20 year period includes periods of growth and recession, including the recent loss of one Top Consumer. This approach is endorsed by MIPUG in the response to Information Request MH/MIPUG I-4 which states: "It is reasonable to portray the ongoing load growth using an equal annual PLIL approach over the long-term with an acknowledgement that the intent is not to precisely predict the load in any given year, but simply the range of reasonable longer-term trends." [MH/MIPUG I-4, Page 4] MIPUG concludes by stating "Elenchus' conclusion that Hydro industrial load forecasts are overstated, and that 'the Top Consumer sales forecast appears to be a major source of forecast error' is not borne out over the periods relevant for the analysis of resource planning." [MH/MIPUG I-4, Page 5]

Manitoba Hydro is confident its approach to forecasting for the Top Consumers sector is reasonable and appropriate for long term forecasting purposes.

We cannot leave the discussion of Top Consumers without speaking to the pipeline sector. There has been significant discussion during this proceeding regarding projected growth in the pipeline sector. Mr. Friesen spoke at length about the projects driving growth in this sector (Tr. p. 1136 – 1142). He noted that the projects included upgrades in pumping capacity or enhancements to existing pipelines to increase flows; National Energy Board (NEB) approvals have been received for these projects with some components awaiting provincial approvals. In addition, TransCanada Pipeline Inc has filed the Energy East Pipeline proposal with the National Energy Board. Mr. Gange expressed in closing argument for GAC that the anticipated new pipeline load may not choose electricity over natural gas for compression and pumping (GAC Exhibit #27, page 13). To assist the Board and the stakeholders of this proceeding, we would remind the Board of Mr. Friesen's evidence that due to the viscosity and incompressibility of oil, it is difficult to provide the pumping force required through natural gas compression and therefore all discussions have been regarding electrically driven pumps (CSI Tr. p. 29 – 30, PUB/MH II-358b). Mr. Friesen also explained that for this sector it is not a matter of Manitoba actively attracting these customers to the region, but that Manitoba is simply "in the path" as they seek to serve customers in other locations (Tr. p. 587 – 588). Given the market indications, Manitoba Hydro is of the opinion that these projects will proceed.

2.7 Price Elasticity in Manitoba

Consideration of the impact of price elasticity in Manitoba has been an issue of interest in this proceeding. Manitoba Hydro agrees with the observation of Dr. Gotham that "having a -- a history of low, stable electricity prices makes determining a -- from a mathematical standpoint, determining a price elasticity from the historical data difficult, if not impossible". (Tr. p. 8643). Manitoba Hydro expects that higher real prices of electricity will lead to reductions in electricity use; however the analysis of the magnitude of this price effect is not a simple task.

The regression equations that determine price effect must not be so simplistic that all coincidental change in load is assigned to the price variable, or the price elasticity will be greatly over-estimated. This would result in a much larger price effect than would be realized and lower the forecast more than appropriate, risking Manitoba Hydro's ability to effectively meet future need.

Studies from other jurisdictions are not necessarily applicable to Manitoba, and it is not prudent to adopt a price elasticity found on the internet [Simpson/Gotham report, CAC Exhibit #65, page 9] without understanding the conditions and drivers underpinning that value. Differences between Manitoba and the other jurisdictions in factors such as starting price, rate structure, average versus marginal pricing and cross price effect with other fuels must be considered. All non-price effects must be accounted for to minimize the potential for double counting of effects, such as the effects of an economic downturn, codes and standards, conservation rate programs and DSM programming.

In contrast to the information from US jurisdictions referenced by Dr. Simpson in support of his suggestion of a -0.5 factor, BC Hydro in 2008 adopted an own price elasticity of -0.05 , one-tenth of that recommended by Dr. Simpson, for their load forecast which has been reviewed and accepted by the BC Utilities Commission. BC Hydro accounted for DSM programs, influence of codes & standards, and assumed a lower elasticity to compute the conservation effect of a rate level change under a flat rate design (-0.05) compared to that under an inclining rate design (-0.10). [CAC Exhibit #45-01, Subject: Load Forecast & DSM, Pages 144 to 145]

Manitoba Hydro intends to reflect the price effect in future forecasts. However, Manitoba Hydro seeks to ensure the price elasticity used appropriately represents Manitoba's situation with regards to rate structure, existing low prices, effects of DSM programs along with Codes and Standards. (Tr. p. 882 – 883).

3.0 FUEL SWITCHING

3.1 Manitoba Hydro's Heating Fuel Choice Initiative continues to evolve and will be effective in reducing electric heat market share

The electricity use of Manitoba Hydro's Residential Basic sector has grown 121 GWh per year (1.8%) for the past ten years. During this time, the number of Residential Basic customers has grown by 1.0% per year with average use growing 0.8% per year (MH Rebuttal page 10, lines 3-7). Although some jurisdictions are projecting lower growth rates, the average use per customer is projected to continue to grow in Manitoba, albeit more slowly, at a rate of 0.3% per year over the next 20 years (MH Rebuttal page 10, lines 13-14). Increasing saturations of electric space and water heating have been and are expected to continue to contribute to this increase in average use in Manitoba.

Manitoba Hydro recognizes the economic benefit to the customer, the utility and Province when customers with access to natural gas choose to heat with natural gas. This was outlined in Manitoba Hydro's August 2012 "Economic, Load and Environmental Impacts of Fuel Switching in Manitoba" report. Manitoba Hydro's Heating Fuel Choice Initiative, introduced to address this trend, is a multi-faceted approach to educate all stakeholders involved in the fuel choice decision including homeowners, heating contractors, homebuilders and land developers. Economic comparisons, technical information and a variety of convenient on-bill financing options are promoted to customers to assist them in making the optimal heating fuel choice, particularly in the new home market (PUB/MH I-253b).

Under the 2013 Load Forecast, Manitoba Hydro identified a projected reduction of 366 GWh by 2032/33 arising from this initiative and Mr. Kuczek testified to plans for increased educational efforts and an additional 100 GWh adjustment anticipated for the 2014 Load Forecast (Tr. p. 394, lines 2-6). This represents achieving over 50% of the potential energy impacts assuming the campaign was 100% successful. (MH Exhibit #122). Manitoba Hydro continues to monitor the market and adjust its approach and is exploring additional strategies to ensure these market objectives are achieved. Manitoba Hydro will look at other intervention strategies including the possibility of service extensions and allowances in the event that the targets set out for the Heating Fuel Choice initiative are not achieved (Tr. p. 547, lines 12-19).

Both Mr. Todd and Mr. Chernick addressed the potential to use service extension policies and/or incentives to reduce the number of homes with electric heat in natural gas available areas. While Mr. Chernick in his written report questioned the effectiveness of Manitoba Hydro's education campaign, it became apparent on cross-examination, that these conclusions were based on a cursory review of Manitoba Hydro's overall initiative, which did not take into account the targeted strategy, and financial and technical supports available to customers noted in the response to PUB/MH I-253b. Manitoba Hydro has indicated at both this and the recent past General Rate and Cost of Service proceedings that expanded strategies, such as service policies, are being explored and will be undertaken to ensure customers understand their heating fuel options and make the optimal choice.

3.2 Reducing Growth in Electric Space and Water Heating Market Share

Manitoba Hydro submits that its projections for influencing market share of electric space and water heating are realistic given Manitoba's market conditions combined with existing and emerging Federal and Provincial regulations.

3.2.1 Space Heating

Manitoba Hydro believes there are significant economic benefits for the customer, the utility and the Province when customers who have access to natural gas service, choose natural gas equipment for their space heating (MH Exhibit #189 – Tab 6 – Page 38). In setting targets for future market share of natural gas space heating in Winnipeg and the South Gas Available area, Manitoba Hydro acknowledges two key considerations:

- Customer choice – even with full information, some customers may choose electric space heat for reasons other than economic or global environmental impact such as perceptions related to renewability, or safety and support of the local economy (GAC/MH I-077).
- Economic access to natural gas in the South Gas Available area – In Winnipeg, most customers have natural gas service near to their homes, in both existing and new developments. However, not all customers in the South Gas Available area have natural gas service adjacent to their home or to a proposed new development and therefore the cost of extending the natural gas main must be considered. As Ms. Morrison noted at Transcript page 939, the analysis of economic access to natural gas is based upon the assumption that the customer has access to a natural gas line in front of their house, or already connected to the home.

Under the 2013 Load Forecast, Manitoba Hydro projects nearly 100% of new single detached homes in Winnipeg will choose natural gas space heat and that in the South Gas Available Area the trend towards electric space heating will reverse such that less than 1/3 of new single detached homes will heat with electricity by 2020/21, reducing further to less than ¼ of new single detached homes in the years beyond 2020/21 (PUB/MH I-253a).

3.2.2 Water Heating

Manitoba Hydro recognizes that water heating fuel choice may represent an opportunity to manage increasing electricity demand. However, the Corporation also recognizes that there are other considerations for customers when examining the economics of fuel choice for water heating. Where customers have an existing natural gas service and currently use a conventional natural gas water heater, there are economic benefits to the customer to "stay with natural gas". However, as outlined in MH Exhibit #189 – Tab 6 – Page 45, the economics differ where the customer's choices are between a side-vent natural gas water heater and an electric water heater such as in new homes.

> "Customers are better positioned economically when using electricity for water heating due to the high upfront capital cost of the side-vent natural gas tank (which the customer would be saving if they switched to electric). This is common in new home construction where chimneys are no longer required for venting high efficiency natural gas furnaces, thereby limiting natural gas water heater options to the higher capital cost side-vent options."

Manitoba Hydro also outlined in its response to GAC/MH I-071, circumstances where the economics for a customer with an existing natural gas water heater may see choosing an electric water heater as more attractive. As noted in this response, the customer will assess their choices based upon their individual circumstances, including the age and condition of their existing water heater. For example if a customer's existing natural gas water heater is relatively new and the venting requirements can be met by sleeving the chimney, the customer saves $450 by choosing to sleeve the chimney instead of installing a new electric water heater. However, if the existing natural gas water heater is near end of life and venting adjustments are required, installing a new conventional natural gas water heater and sleeving the chimney costs $450 more than installing an electric water heater.

The upfront capital cost difference between natural gas and electric water heating options is expected to become even greater in the future as the Federal Government pursues increased efficiency regulations for natural gas water heaters. (MH Exhibit #189 – Tab 6 – Page 50)

> "NRCan is proposing a minimum efficiency factor (EF) of 0.67 for residential natural gas water heaters effective April 1, 2016, and a minimum EF of 0.8 effective January 1, 2020. This regulation is aggressive considering most residential water heaters currently available on the market have an EF between 0.57 and 0.60."

Higher efficiency natural gas water heaters come at a much higher price than even the side-vent natural gas water heaters, where:

> "A preliminary market review indicated that water heaters with an EF of 0.67 can cost approximately $800 more than a side vent natural gas hot water tank… water heaters currently available in Manitoba that offer an EF of 0.80 are condensing natural gas water heaters which can cost up to an additional $3000 compared to a side vent natural gas water tank."

> "The large incremental product costs … are anticipated to further accelerate the market conversion to electric water heating"

These regulations will apply to all natural gas water heaters, for both existing and new homes. As a result, and notwithstanding Manitoba Hydro's pursuit of increased marketing efforts in an attempt to reduce the projected market share of electric water heating, Manitoba Hydro believes its projections for electric and natural gas water heating are reasonable.

3.3 Conclusion

Based upon these emerging market factors and Manitoba Hydro's accelerating efforts under its Heating Fuel Choice Initiative, Manitoba Hydro is confident in the projected reduction of 366 GWh by 2032/33 as outlined in the 2013 Load Forecast, and the further 100 GWh identified by Mr. Kuczek in his presentation of March 4, 2014 (MH Exhibit #87, slide 12). However, even with these efforts, the average use per customer is projected to continue to grow in Manitoba over the next 20 years.

4.0 DSM

4.1 Manitoba Hydro is aggressively pursuing DSM opportunities under the recently released 2014 PS plan

Manitoba Hydro has a long history of aggressively pursuing economic DSM opportunities through a broad and comprehensive strategy. This was acknowledged by GAC in its final argument, and by Mr. Dunsky in his evidence who testified:

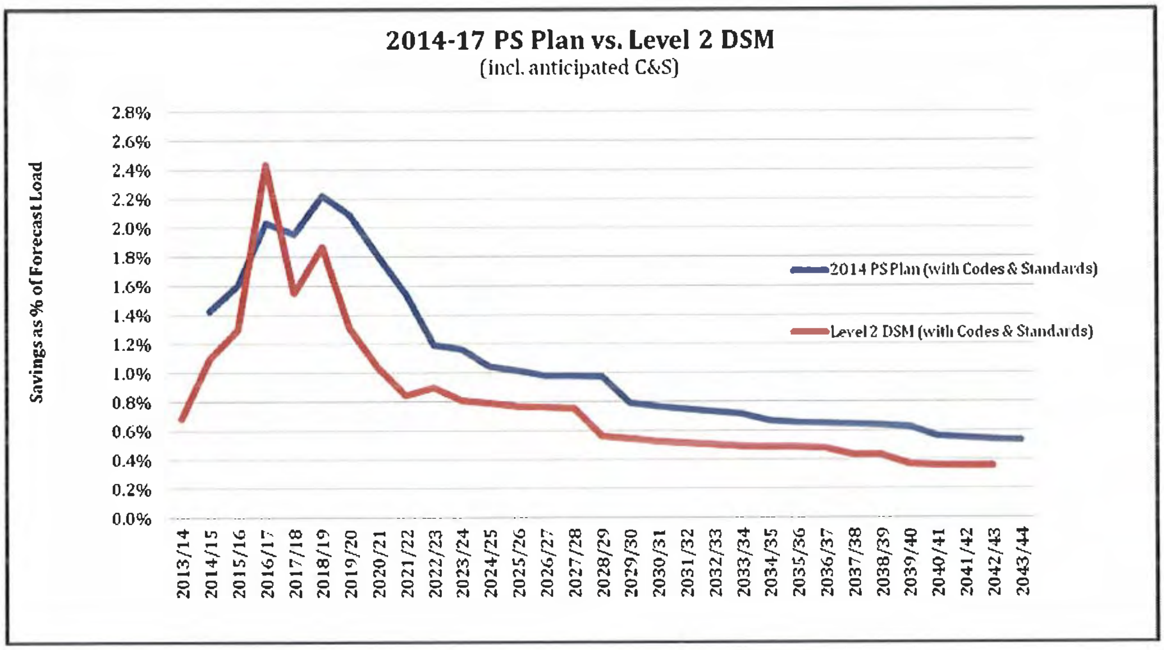
> "...Manitoba Hydro has a very strong history with -- with energy efficiency, dating back a fairly long time. It had, in previous years, received very strong ratings, several awards." (Tr. p. 7977-7988)

This success is demonstrated through the energy savings achieved to date of 2,269 GWh (MH Exhibit #203) which has allowed participating customers to save $660 million cumulatively on their electricity bills since launching its first program in 1989. Manitoba Hydro is committed to continuing its aggressive pursuit of all economic DSM opportunities in its overall efforts to meet Manitoba's future electricity demand in the most economic manner and to assist customers with managing their energy bills. As outlined in Manitoba Hydro's Rebuttal Evidence (MH Exhibit #85, pages 27-28), Manitoba Hydro has identified additional DSM opportunities and subsequent to the filing of the NFAT submission has analyzed three increased levels of DSM beyond the existing DSM portfolio included in the original submission. These increased levels of DSM represent significant increases over the program as outlined in the 2013 Power Smart Plan; with enhanced scenarios ranging from 2.2 to 4.6 times the program savings outlined in the 2013 Power Smart Plan (MH Exhibit #85, page 29).

Following the development of the higher levels of DSM for the scenario analysis, and as pursuant to the Energy Savings Act, Manitoba Hydro consulted with the Province of Manitoba (Tr. p. 9855, lines 18-22) in the creation of the 3-year 2014-2017 Power Smart Plan (MH Exhibit #153) which involves DSM savings of 411 MW and 1064 GWh over the three year period. This represents Manitoba Hydro's current Corporate approved DSM plan which Manitoba Hydro will be pursuing over the next three years. The energy savings to be achieved in the 2014-2017 Plan represent 4% of the forecast load by 2016/17, offsetting 86% of projected load growth during the period. One of the new initiatives contributing to increased program savings is a load displacement program involving economic customer-sited generation where low-cost or no-cost energy streams may be converted into heat and electricity, displacing energy that customers would otherwise purchase from Manitoba Hydro (MH Exhibit #153, p. 40). Incentives provided under the load displacement program will be determined with consideration of all related benefit streams, both energy and non-energy. Incentives may be structured as one-time payments to reduce capital costs, ongoing payments to reduce operating and fuel-related costs, or a combination of the two. The 2014 – 2017 Power Smart Plan does not contemplate a feed-in tariff arrangement.

Subsequent to the release of the 3-year plan, Manitoba Hydro developed the 2014 - 2017 Power Smart Plan 15-Year Supplemental Report (MH Exhibit #180). This Supplemental 15 year report is used for internal resource planning purposes and involves energy savings of 1,136 MW and 3,978 GWh by 2028/29. The energy savings represent 13% of the load forecast by 2028/29, offsetting 66% of projected load growth during the period.

The Figure below, which was filed as Manitoba Hydro Exhibit # 202 provides a comparison of the Level 2 DSM included in the NFAT analysis and the 2014 – 2017 Power Smart Plan.



MH Exhibit # 202

The energy savings to be achieved through the 2014 – 2017 Power Smart Plan (15-Year Supplemental Report) is similar to the Level 2 DSM analysis presented during the course of this hearing. Manitoba Hydro Exhibit # 202 provides a comparison of the projected energy savings (GWh) under the 2014 – 2017 Power Smart Plan (15-Year Supplemental Report) and the Level 2 DSM analysis as a percent of forecast load. This comparison reflects the forecast for energy savings expected to be achieved through both programming and codes & standards investments and efforts. The 2014 – 2017 Power Smart Plan (15-Year Supplemental Report) differs from the Level 2 DSM analysis as the latter was developed at a high level and for analysis purposes during the NFAT process. DSM Level 2 was analyzed based upon the 2013 Load Forecast and associated Codes & Standards projections. The 2014 -2017 Power Smart Plan (15-Year Supplemental Report) reflects more detailed analysis resulting in programming refinements (Tr. p. 8899 - 9900) and updated codes and standards adjustments (Tr. p. 393) as noted by Mr. Kuczek. The 2014 – 2017 Power Smart Plan (15-Year Supplemental Report) reflects more detailed analysis resulting in programming refinements (Tr. p. 8899-9900) and updated codes and standards adjustments (Tr. p. 393) as noted by Mr. Kuczek.

The Curtailable Rates Program is included within the 2014 – 2017 Power Smart Plan, with projected capacity savings re-earned each year (one year life). However, as outlined in Manitoba Hydro's Rebuttal Evidence (MH Exhibit # 85, p. 47), Manitoba Hydro does not include the demand benefits available from the Curtailable Rates Program in the assessment and development of its Resources Plan. There are no energy savings forecast to be achieved through the Curtailable Rates Program.

The 2014 – 2017 Power Smart Plan (15-Year Supplemental Report) includes forecast energy and demand savings from approved and potential programs (e.g. conservation rates and fuel switching). As noted by Mr. Kuczek during the hearing, the fuel switching and conservation rates programs are not approved internally at this time. These programs require further analysis and discussion both internally and externally. The plan includes the programs as placeholders and represents Manitoba Hydro's forecast of the timing, cost and energy savings which will be achieved through these initiatives (Tr. p. 9902, lines 14-25).

Manitoba Hydro is well positioned to aggressively pursue the higher levels of DSM outlined in the 2014-2017 Power Smart Plan. As Mr. Kuczek testified, (Tr. p. 9866, lines 15-18, 23-25) the funding to deliver the programs outlined in the 2014-2017 Plan is approved and additional staffing will be required. Manitoba Hydro's Executive and Board are committed to pursuing all economic DSM opportunities and the strategies outlined with the Corporation's approved 2014 – 2017 Power Smart plan are currently being executed. As Mr. Kuczek indicated, Manitoba Hydro will leverage the use of external resources such as the AKI Energy Organization, or contract services such as those supporting the existing Water & Energy Saver and Refrigerator Retirement Programs (Tr. p. 9866-9867) where appropriate to implement and deliver the programs. Individual programs will continue to be modified to address the unique market barriers to increase market penetration of the energy efficient measures/technologies being promoted (Tr. p. 9868). Manitoba Hydro has demonstrated an ongoing commitment to finding appropriate resources and effective means to deliver the programs and savings. It is also recognized that Manitoba Hydro's DSM staff is highly skilled as noted by Mr. Dunsky (CAC Exhibit #19, page 33). Having significant experience in pursuing DSM opportunities, Manitoba Hydro is well positioned to achieve the energy savings outlined within the 2014-2017 Power Smart Plan. Barriers to achieving the energy savings outlined with the 2014 – 2017 Power Smart Plan are external, including customer participation, government concurrence (i.e. in accordance with the Energy Saving Act) and regulatory approvals (e.g. Conservation rates are subject to the approval of the Public Utilities Board). With regard to the risks associated with customer participation rates, Manitoba Hydro is confident in achieving the energy savings projected within the 2014 – 2017 Power Smart Plan based on its extensive experience delivering DSM programming and given its flexibility to modify program designs (e.g. higher incentives, modified marketing strategies, etc.) as the programs move forward and markets respond.

4.2 Power Smart –Helping Customers Manage for Future Rate Increases

Manitoba Hydro recognizes the importance of providing options for customers to manage their energy bills, particularly in an environment with projected annual rate increases of 3.95% for the future. The portfolio of programs outlined in the 2014 - 2017 Power Smart Plan offers customers a variety of options for reducing their energy bills. Each customer's ability to reduce their energy bill depends upon the opportunities present in their homes and businesses. As outlined in the examples presented in MH Exhibit #164, an electrically-heated customer can save 42% on their annual energy bill by installing energy efficient lighting and the free Water & Energy Saver kit, upgrading their attic insulation from R20 to R50 and their basement insulation from R0 to R24, and "retiring" their second refrigerator. A customer using natural gas for space and water heating can save approximately 15% on their annual electricity costs or 5% on their overall energy bill (natural gas and electricity) by installing energy efficient lighting and retiring their second refrigerator. Manitoba Hydro promotes a number of no cost/low cost actions which can also help reduce customers' energy bills, such as lowering your thermostat by 3 degrees during the night or when you will be away during the day. All of these initiatives and programs are in place to aid customers in managing future energy bills and as Ms. Morrison testified (Tr.p.9919 and Tr. p. 9924 and 9925) Manitoba Hydro expects to have an even stronger message targeted to customers on how Manitoba Hydro can help them to reduce their energy use and thereby reduce the impact on their overall energy bill.

4.3 Comparing DSM Targets Across Jurisdictions

A focus of discussion by Intervenors during the course of these proceedings was a comparison of Manitoba Hydro's DSM targets and projections to those of other jurisdictions. Manitoba Hydro cautions that it is dangerous, and potentially misleading to compare among various jurisdictions using a metric such as "savings as a % of sales", as this will not recognize differences among regions in load characteristics and marginal cost considerations. It must also be recognized that utilities and energy efficiency agencies report savings differently, and treat the impact of interactive effects differently which will also impact upon comparisons between jurisdictions. (MH Exhibit #85 page 36)

Manitoba Hydro highlighted the differences in energy savings targets reported using gross methodology versus using net methodology in its Rebuttal Evidence (MH Exhibit #85, page 34 lines 27-33). That evidence includes a quote from a report produced by ACEEE, which

Mr. Dunsky describes as *"the premiere organization in DSM"* (Tr. p. 8148,lines 20-21), as follows;

> "..these substantial discrepancies between states in the use of net vs. gross savings (and the approaches used to calculate net savings) clearly underscore the difficulty of making "apples to apples" comparisons…" (Manitoba Hydro Rebuttal Evidence, MH Exhibit #85, page 34 line 34 to page 35 lines 1-2).

The report concludes with a recommendation on the issue of net vs. gross that;

> "…whichever approach a state uses, its methodologies and assumptions on this issue should be fully disclosed, so that others seeking to interpret reported results will have that understanding, and be able take that into consideration when comparing results across states." (Manitoba Hydro Rebuttal Evidence, MH Exhibit #85 page 35, lines 3-6).

Manitoba Hydro recognizes that all metrics, not just the % of sales metric discussed at length in these proceedings, must be viewed with caution recognizing the differences noted. The Corporation has concluded that a more relevant and useful approach to assessing its efforts relative to other regions is best accomplished by comparing its specific DSM programming, and its comprehensiveness, against DSM programming in other comparable regions.

4.4 DSM for the Long Term –Treatment of Technological Innovation

Manitoba Hydro's long-term commitment to DSM has been demonstrated in its active engagement in DSM programming for over more than 20 years, even during the uncertainty that arose in the restructuring of the electricity markets in the 1990's. This commitment to DSM will continue into the future. During these proceedings, there has been significant discussion around Manitoba Hydro's longer term projections for DSM savings. In preparing the projections of energy reductions under the 3 levels of enhanced DSM analysis and in the preparation of the 2014 -2017 Power Smart Plan – 15 Year Supplemental Report, Manitoba Hydro focused on known opportunities over the next 15 years. Most jurisdictions, as noted by Mr. Dunsky at page 8039 of the Transcript, plan for shorter horizons. As the DSM projections are included within Manitoba Hydro's resource planning process as a means of meeting future energy requirements where scale and timing are important considerations, Manitoba Hydro has traditionally focused on measures and opportunities that are known, commercially-available or very near commercialization. This practice is similar to most jurisdictions as noted by EnerNOC in Manitoba Hydro's Rebuttal Evidence (MH Exhibit #85, page 38, lines 34-35) and Mr. Dunsky (Tr. p. 8035, lines 21-22 and Tr. p. 8036, lines 1-6); although as Mr. Dunsky notes in his testimony beginning at Tr. p. 8036 (CAC Exhibit #62, slide 41) three jurisdictions are beginning to explore other approaches. It is important to note that even for those jurisdictions; the time horizon projected is shorter, using 10 year forecasts (CAC Exhibit #62, slides 43, 48 and 49; Tr. p. 8039, lines 18 – 24).

As Mr. Dunsky notes DSM is driven through innovation (Tr. p. 8001, lines 5-12). While it may only be a question of timing as to when the next innovation or evolution of energy efficient technology will become available and commercially viable, for the purposes of resource planning and meeting customers' energy needs, timing does matter. The Corporation must balance risks and the timing of technology evolution, and its adoption can have a significant impact on the Corporations obligation to meet customers' energy requirements. As a result, the Corporation has adopted the prudent practice of focusing on measures and opportunities that are known, commercially-available, or very near commercialization.

Manitoba Hydro monitors the market for emerging opportunities and incorporates these opportunities in the forecast of DSM savings when appropriate. As Mr. Kuczek testified, disruptive technology events are very difficult to forecast. Manitoba Hydro does not want to count on such technologies happening. As a result, Manitoba Hydro monitors energy technologies and incorporates them into its Plan as the risks become lower. Mr. Kuczek also suggested that Manitoba Hydro was more conservative in the past than we likely will be in the future (Tr. p. 9870, lines 5-15).

Mr. Todd acknowledged in his testimony that forecasting the "what" and the "when" of these innovations is difficult:

> "And the other side of it is that there's all of these promising technologies. I approach them with -- with caution. You know, fuel cells are something which were going to be ready for cars next year for about the last thirty (30) years. So, you know, many of the technologic innovations that are anticipated in being around the corner are not realized, and that's what makes the predictions very hard. But there's so much happening that it's hard not to believe that there will be breakthroughs on some of the efforts being made." (Tr. p. 4960, lines 6-17)

It is important to recognize that not all technological innovations reduce load. Some will in fact increase load. A prime example is the growth experienced due to technological changes in the home electronics sector (Manitoba Hydro Exhibit #85, p. 38). It is reasonable to expect that the future will also see innovations which may lead to increased electric load. Dr. Gotham in his discussion of load forecasting spoke of the electric vehicles and their impact on future load when he testified:

> "There are potential game-changing technologies that would go in the other direction, and I'm thinking in terms of, say, plug-in vehicles." (Tr. p. 8424, lines 19-22)

In his evidence, Mr. Dunsky at slide 21 (CAC Exhibit #62) presents five areas of "known" innovation that will support continuance of future DSM savings targets. Manitoba Hydro is aware of these opportunities, and has or will incorporate them as appropriate targets based on their particular relevance to Manitoba load and market.

1. New Efficiency Standards – Mr. Dunsky speaks to new efficiency standards and regulation of higher minimum performance standards as being regulatory innovations that will fundamentally affect our future energy requirements (Tr. p. 8003, lines 18-19). Substantial efficiency regulation for appliances and equipment has already been introduced over the last 20 years, which will continue to impact the market in future years, even if no further improvements are incorporated. Past savings are reflected in load growth to-date and future savings from current regulations are included in Manitoba Hydro's load forecast projections.

   As we look forward, Manitoba Hydro expects to continue realizing further savings through the introduction of new codes and standards incorporated into federal and provincial energy efficiency regulations, many of which are considered in the enhanced targets presented during these proceedings. However as Mr. Friesen stated

   > "that phenomena that Ms. Morrison spoke to, about the slice getting smaller, affects Codes and Standards as well. So I'll give you an example. If your refrigerator or other device went from 90 to 92 percent efficiency, the next time you only have [8] percent losses. If you go from ninety-two (92) to ninety-five (95), next time you only have 5 percent losses. You can't take away more than your losses essentially. That's your limiting factor. It's the law of science. 'Cause I

> think we can all agree that we're not going to get greater than 100 percent efficiency. And as we approach that threshold, the challenge becomes progressively larger from both a cost perspective and a technical perspective." (Tr. p. 9958, lines 20-25 and Tr. p. 9959, lines 1-10)

Manitoba Hydro continues to be heavily engaged at both the Federal and Provincial level, working to establish ongoing enhancements and updates to minimum energy performance standards for a broad array of energy-consuming technologies and to determine the appropriateness of their adoption into an energy efficiency code or regulation. As stated by Mr. Friesen:

> "Manitoba Hydro invests quite heavily in codes and standards development. I think if you would speak nationally, we are considered to be one (1) of the leaders with NRCan, BC Hydro, the Ontario Ministry of Energy, as funders of activities to develop new standards that are implemented in the future within federal and provincial regulations, energy efficiency regulations. So Manitoba Hydro does have a considerable investment in codes and standards. We work closely with provincial authorities. We work with federal authorities on many levels to achieve those." (Tr. p. 1128, lines 7-18).

2. LED Lighting – Manitoba Hydro has been pursuing energy efficient opportunities in the area of lighting for over 20 years through its Commercial Lighting Program and its past Roadway Lighting Conversion, Residential Compact Fluorescent Lighting and Seasonal LED lighting programs. Manitoba Hydro continues to monitor this market for emerging cost effective opportunities, including an LED Roadway Lighting Conversion Program and Residential LED Lighting program which were introduced under the recently approved 2014 -2017 Power Smart Plan.

As Ms. Morrison testified at pages 9957 – 9958, when looking at efficiency opportunities each efficiency innovation results in a "smaller slice" of energy reduction. The initial transition from incandescent lighting to compact fluorescent lighting yielded savings of 60 - 80 percent (e.g. 60 watt incandescent to 13 watt compact fluorescent). The introduction of current generation LEDs over CFLs provided incremental savings of about 5 to 10 percent when compared against the original incandescent lamp (e.g. 13 watt compact fluorescent to 8 watt LED). Now, despite a nearly 40 percent improvement in efficiency over the compact fluorescent technology , current generation LED's provide incremental savings that amount to approximately 1/10th of that provided from the earlier transition to compact fluorescent lamps. Mr. Dunsky (CAC Exhibit #62, slide 24) submits that further incremental savings of 50 percent are anticipated from LED technology is currently being projected for later in the decade as efficacy (lumens per watt) increases by 2.0 to 2.5 times. If this next stage of innovation is realized at the level suggested, incremental energy savings will be substantially smaller than those achieved through earlier innovations. Although 50% sounds like a significant improvement, it is important to consider the base on which that it being calculated to understand what it actually means in terms of energy savings.

3. Air Source/Ductless Heat Pumps – The efficiency and cost effectiveness of air source heat pump technology in Manitoba is largely dependent on the ability of the heat pump's to efficiently extract heat (energy) from a highly variable energy supply (outside ambient air) that is at its absolute lowest when Manitoba's heating requirement is at its absolute highest (cold winter temperatures). Pursuing air-source heat pump technology becomes progressively more challenging and expensive as the outside air temperatures decline, lowering the coefficient of performance and effectively increasing the amount of electrical energy required to upgrade heat extracted from progressively colder outside air, decreasing the economic benefit over ground-source heat pumps and other non-electric heating options (CAC_GAC/MH I-003b and GAC_CAC/MH II-011b). As Mr. Robson testifies in oral testimony;

> "...as the temperature drops, it takes more and more energy to pull energy -- the heat out of that air and transfer it to the house. So as it gets colder and colder, the efficiency drops and drops and drops till eventually it's just working like an electric furnace. So electric back-up resistance heat takes over." (Tr. p. 7770, lines 9-16)

In his testimony, Mr. Dunsky (Transcript Page 8018) indicates that his analysis of cost effectiveness for air source heat pumps is based on a design that meets 30 to 60 percent of the heating requirement for a residential home, thereby reducing installation costs. While this approach may lead to lower overall capital costs for installation of air source/ductless heat pumps, it is clear that such an installation will also yields lower benefits to the customer as the remainder of the home will continue to require heat, which Mr. Dunsky suggests be supplied by electric base board heat

(Tr. p 8018, lines 9-11). The reduced benefits, along with the continued requirement for auxiliary or supplemental electric heat during colder periods are not anticipated to significantly enhance the economics of air source/ductless heat pumps for residential heating in Manitoba.

In Manitoba's lowest temperatures, air source heat pumps require supplemental heat (typically electric resistance) which offsets the potential benefits that other heating options can provide during periods of peak system demand. As such, air source heat pumps are not presently economic in Manitoba (NFAT Application, Chapter 4, page 26, lines 18-19) and will require considerable advancement in performance and reductions in cost to achieve levels necessary for wide-spread market adoption.

4. Data Driven Analytics – Data-driven analytics continue to be reviewed by Manitoba Hydro as a tool to enhance engagement with customers and support greater understanding of how customer behavior impacts consumption. The technologies and platforms through which consumers can assess their energy consumption data is evolving at a pace that is consistent with information technology and smart home communication systems. Manitoba Hydro assessed this type of energy efficiency measure for the residential market in the DSM Potential Study under Home Energy Management Systems with a result of 34 GWh of Achievable savings potential as of 2031/32 (Appendix 4.3, page 6-10). The adoption of data analytics is supported by plans to enhance Manitoba Hydro's industrial and commercial programs under the 2014 - 2017 Power Smart Plan. As Ms. Morrison testified (Tr. p. 9970-9972), Manitoba Hydro has also had numerous discussions with OPower on their energy bill comparison product for the Manitoba market. The concern raised is that under these initiatives the savings must be re-earned each year in order to maintain energy savings into the future. Also as more DSM initiatives are pursued to "send the right message" to customers, such as through conservation rates, Manitoba Hydro must ensure that projected energy savings are not counted in more than once in multiple initiatives. Manitoba Hydro continues to investigate these opportunities.

5. Solar PV - Where the promotion of customer-sited generation displaces energy that would otherwise be purchased from the utility grid, it is important to recognize the competing economics of grid power and customer-sited generation along with other drivers that may encourage customers to abandon the security and reliability of the utility grid. The phenomenon of grid parity, where the delivered cost of energy from customer-sited generation becomes equal to that of energy provided from centralized

generation supporting the utility grid, was a topic of significant discussion during these proceedings, with numerous witnesses speaking to the subject in the context of structural change that may potentially strand utility assets built in anticipation of future load growth that might not materialize if customers choose to self-generate. In his testimony, Mr Colaiacovo cited the potential for such changes in the utility sector:

> "… and in higher cost jurisdictions, I think it's a very real and significant possibility. You know, where in a place like Ontario, the pure electicity commodity separated from transmission and distribution is an average of seven(7) to eight(8) cents, and during daytime peaks, will be substantially higher than that. Grid parity starts to look like a real issue, because if the cost of distributed generation of whatever sort it happens to be is cheaper, well, you know, then – then it makes sense, as long as you continue to have access to the grid for backup.." (Tr. p 7319, lines 10-21)

Mr. Colaiacovo's last point is particularly important as it clearly illustrates that the union between distributed generation and the centralized utility cannot be easily separated. The variability of solar energy, particularly during peak winter months when the peak generally occurs after dark, will not eliminate the need for generation, transmission and distribution system connectivity and support. Integrating distributed generation sources such as solar will become progressively more complicated as penetration of solar installations increase. Mr. Colaiacovo points to this challenge in his testimony:

> "…One(1) of the things that's likely to happen as a result of that is changes to rate structures, changes to cost responsibility, because the reality is, there's enormous investments in iron in the ground, whether those are distribution or transmission, and – or – or generation, and people benefit from those things. And you know, you can't just put solar panels on your roof, use them for six(6) hours a day, and not have any cost consequences, which is the way it is working today, because it's a cottage industry..." (Tr. p. 7320, lines 6-16)

Mr. Colaiacovo also testified that the utility industry will have to adapt its rate structures to accommodate integration:

> "… But if it becomes a real competitive threat to utilities, will there be changes in the market to compensate for that, to – to react to that? I think there has to be. It's the number 1 issue in the United States amongst utilities, is: How do we deal with the distorted incentives of distributed generation and sol – solar panels on the roof, because it is changing the utility business and its having consequences? By building a long-term, effectively merchant facility, are you exposing yourself to that risk? Absolutely, you are exposing yourself to that risk. However, there are billions and billions of dollars of utility shareholders in the United States who are exposed to that risk and are planning to do something about it. So in – in some measure, you have to try and put it in that broader context." (Tr. p. 7320, lines 17-25 and Tr. p. 7321, lines 1-8).

"Grid parity" represents a point in time when a customer may reasonably be expected to begin considering self-generation. As Mr. Dunsky (CAC Exhibit#19, Figure 15) indicated in his written evidence, it is anticipated that adoption of self-generation technologies such as solar photovoltaic will be highly variable from jurisdiction to jurisdiction based on the anticipated onset of grid parity alone, with differences dependent on current utility rates and projected rate increases, incentive structures, regional carbon taxes and emission regulations (fossil fuel-based generation), mandated renewable portfolios, opportunities for obtaining renewable energy supply at the utility scale, and very significantly, on the relative costs and benefits provided by technologies used for self-generation.

Several of these factors have supported the successful introduction of customer-sited solar photovoltaic technologies in other jurisdictions where mandated renewable energy portfolios, high utility rates and substantive financial incentives, have accelerated the onset of grid parity. Manitoba Hydro has already achieved extremely high levels of renewable generation without the introduction of solar technologies and maintained comparably low rates, and is therefore in a somewhat different position than utilities in jurisdictions with more limited options for renewable supply.

As Mr. Friesen indicated in his testimony (Tr. p. 606-607) the rate of technology adoption after grid parity is achieved will be highly variable and is anticipated to be gradual as competing technologies improve and become more cost-effective relative to other supply options. Mr. Dunsky supports this position in his written evidence

(CAC Exhibit #19, Page 15) and provides further comment in oral testimony with respect to grid parity in Minnesota and the rate that adoption would impact the demand for grid power.

> "... the sorts of changes that we're talking about are not going to dramatically change the -- the picture on the ground when we talk about solar, for example. If we have solar parity in Minnesota today, that doesn't mean that tomorrow morning everyone runs out and puts solar panels on the roofs for the very same reason that energy efficiency is very cheap for people to do today, and they are still not doing it on their own. These things take time. You know, there's -- there's an adoption curve. " (Tr. p. 8188, lines 3-14)

The rate of cost decline for solar photovoltaic technologies and the anticipated rate of adoption by residential and commercial customers have significant uncertainty associated with them, which uncertainty is extenuated by Manitoba Hydro's low utility rates and northern latitude (low day light hours) during critical peak periods of winter consumption.

Testimony by Mr. Dunsky and others points towards grid parity for residential solar starting in Manitoba at some point around 2020, and starting potentially as late as 2025 and beyond, depending on the rate of cost decline for solar photovoltaic equipment and projections for utility rate increases (CAC Exhibit #62, Slide 37). It is therefore reasonable to expect, based on the anticipation of a gradual adoption rate as cited by Mr. Dunsky and Elenchus (Tr. p. 5132 - 5133), that customer-sited solar photovoltaic will not substantively impact the grid requirement for power in Manitoba until some period after 2030, which is on the outer fringes for targeting future DSM savings.

The competitiveness of solar photovoltaic energy nearly 15 to 20 years into the future is uncertain, especially given the uncertainty with respect to the future solar PV, distribution integration and power system back-up costs, and future changes to the utility rate structure.

Mr. Friesen also points to considerations about the suitability of solar in his testimony that highlight the importance of recognizing the intermittency in supply;

> "If the you look at the consumption characteristic of a top consumer, a top consumer has a very high load factor. So their - generally, their load factor is point eight (.8) or higher, often as high as point nine (.9). So they have a fairly continuous requirement for energy at or near their peak capacity requirements on an almost twenty-four (24) hour basis. Solar's a very intermittent supply. As a result, I would not expect that a top consumer would choose solar as their first option in supplying their needs due to it -- due to its intermittency" (Tr. p. 610, lines 9-20)

In preparation for future grid parity Manitoba Hydro's DSM plan allows for continued monitoring, testing and demonstration of solar installations in Manitoba's harsh climate, backed by current programming that supports the installation of solar and other self-generation technology when they are economic. Where opportunities emerge and clarity is obtained, they will be included in future DSM target setting.

4.5 Curtailable Rates Program

Mr. Hacault notes in his final argument (TR. 11249 – lines 17-22) that the amount of load made available through the Curtailable Rate Program (CRP) from just one customer equates to the amount of load generated by Wuskwatim. He further points out (Tr. p. 11322, lines 1-4) that by curtailing this load it frees up a good part of a small dam. His implication therefore is that MH should be doing more to encourage these types of DSM Industrial programs, and not placing caps on the CRP.

Mr. Friesen, in his testimony (Tr. p. 1146, lines 18-22) explained that "dependable energy from Wuskwatim is very different than the amount of energy that we would be able to release through the Curtailable Rates Program". Wuskwatim is both a dependable energy and capacity resource, whereas the CRP only provides capacity. This makes Mr. Hacault's comparison to Wuskwatim only partially correct. From a capacity perspective this is correct. However, Mr. Hacault fails to note that the CRP only permits curtailment for a limited period, and for a limited number of curtailments. Contrast this with a generating station, over which Manitoba Hydro has complete and unlimited control.

Mr. Friesen noted (Tr. p. 1151-1152) that only certain industries are capable of curtailing their load on short notice, and that it is difficult for some industries to restore their load after a curtailment within a reasonable amount of time. This perhaps explains why there are only three customers on the program.

MH has had a permanent Curtailable Rate Program (CRP) in place since 1998. Over these 16 years, only a total of five industrial customers have ever participated in the program, even when there was no cap limitations. Today there are only three customers on the program. Although some have shown interest over the last few years, a review of the impact on their operations have prevented them from signing on, even though there was still available room for uptake on the program. MH therefore chose to make changes to the Terms and Conditions of the CRP, as proposed in its 2012/13 and 2013/14 GRA filing, to ensure that existing CRP customers could continue to obtain value from the program while continuing to provide reliability benefits for Manitoba Hydro. Manitoba Hydro agrees with MIPUG's assertion that DSM ought to be economic. The Curtailable Rate Program is no different. To remove the cap on the CRP would be to invite uneconomic DSM.

4.6 *The Energy Savings Act*

During this proceeding, there has been substantial discussion around target setting and where these responsibilities lie in other jurisdictions. Ms. Rohmund spoke to target setting in the United States, particularly that 25 of the US states have adopted energy efficiency resource standards (EERS) through regulation or legislation. The specific form or framework of these requirements can vary significantly from state to state (Tr. p. 419, lines 15-25, MH Exhibit #87, page 42). In Canada, the Province of British Columbia has set conservation objectives through its *Clean Energy Act* and Ontario has done so through its *Green Energy Act*. In Manitoba, those objectives are set out in *The Energy Savings Act*. This Act, enacted in June, 2012, guides Manitoba Hydro's DSM targets and activity and outlines the Province of Manitoba's expectations for the Manitoba Hydro Board with respect to the setting of energy efficiency targets.

> 7(1) **The board must, in consultation with the minister,**
> (a) prepare an energy efficiency plan by March 31, 2013; and
> (b) prepare an update to the plan annually after that.
>
> 7(2) The energy efficiency plan must set out
> (a) energy efficiency targets in relation to the projected use of power and natural gas by the corporation's customers in Manitoba;
> (b) a strategy for achieving the energy efficiency targets;
> (c) the programs, services and projects that the corporation will support to implement the strategy, which may include programs, services and projects that

(i) replace or improve equipment and materials related to the use of power and natural gas and the production of greenhouse gas emissions,

(ii) enhance space heat retention and heating efficiency, and

(iii) change customer behaviour relating to the use of power and natural gas and the production of greenhouse gas emissions; and

(d) the estimated annual cost of implementing the strategy and indicate how the costs will be funded.

(Transcript Page 9854 Line 18)

Section 8 of the Act also outlines how the Corporation is to report on performance to these DSM targets:

> 8(1) For each fiscal year beginning after March 31, 2013, the board must report, in writing, on the outcomes achieved under the energy efficiency plan during the fiscal year. The report must be given to the minister within 12 months of the end of the fiscal year.
>
> 8(2) The minister must table a copy of the corporation's report in the Assembly within 15 days after receiving it if the Assembly is sitting or, if it is not, within 15 days after the next sitting begins.

Mr. Kuczek confirmed that the recently released 2014 – 2017 Power Smart Plan was prepared in consultation with the Minister Responsible for Manitoba Hydro in accordance with the Act.

> "This year we – we consulted with them again to – to see if they wanted a three (3) year plan and a fifteen (15) year plan as well. And it was concluded that we would proceed with the three year plan, and so we developed that. And then subsequent to that we developed the fifteen (15) year plan." (Tr. p. 9855, lines 18 -23)

This evidence outlines Manitoba Hydro's understanding of the Province's preference to focus on the three year plan and programs to meet the targets identified. The longer term 15 year plan, also provided to government, is used by Manitoba Hydro for its resource planning.

The Chair (at Tr. p. 9984-85), posed the question whether or not the framework that's in place in Manitoba is adequate to ensure success for DSM programs by Manitoba Hydro. Manitoba Hydro submits that this is precisely the framework identified by *The Energy Savings Act*. The Act is quite new, only two years old, and has been used to ensure consultation with the Province to allow them input into energy efficiency programs and plans, and to review Manitoba Hydro's success in achieving those targets through annual reporting on the outcomes achieved, which report is tabled in the Legislature and thereby available for public review.

CAC/GAC, through the evidence of Mr. Dunsky has suggested that independent oversight and an accountability framework is required in Manitoba. Manitoba Hydro submits that the Energy Savings Act creates the framework for success that has been referred to by Mr. Dunsky in his testimony (Tr. p. 8088, lines 2-11), The Province of Manitoba has considered this issue, and has given its direction as to the framework appropriate for Manitoba in the legislation, and continues to provide its review and oversight by the ongoing consultation and reporting contemplated by *The Energy Savings Act*.

5.0 RESOURCE PLANNING

5.1 Resource Planning Methodology and Need

Manitoba Hydro has undertaken an Integrated Resource Planning process which evaluates various combinations of supply-side and demand-side options to obtain an overall optimum combination and plan. The NFAT submission filed in August 2013 focused on supply side resources and DSM options were evaluated as the information on higher levels of DSM became available. The Integrated Resource Planning process relies on the Generation Planning Criteria for the purpose of ensuring sufficient resources are available to meet Manitoba load reliably and to determine when those new resources are required.

5.2 Integrated Supply and DSM Plan Evaluation

Manitoba Hydro is committed to pursuing all economic DSM. As part of fulfilling that commitment, Manitoba Hydro has undertaken an Integrated Resource Planning process which evaluates various combinations of supply-side and demand-side options to obtain an overall optimum combination and plan.

During the course of the hearing, Manitoba Hydro provided information on three DSM options which, in combination with the original base DSM plan, enabled four DSM options to be evaluated; each with increasing levels of DSM.

Various participants have expressed concern that they do not believe Manitoba Hydro is undertaking Integrated Resource Planning. Mr. Dunsky expressed concerned that Manitoba Hydro "risks locking itself into a path of new supply that, as a result, will lock out the much less expensive option of more efficient demand". (CAC Exhibit #19, page 16)

Manitoba Hydro is undertaking integrated planning that combines supply and demand options. Manitoba Hydro has not locked itself into a new supply path. The purpose of this NFAT process is to assess and make recommendations as to which future path will be followed. This selection of resources and any commitment will depend on the outcome of the NFAT process and subsequent government decisions.

Manitoba Hydro's Power Smart Plan is in integral component of the Corporation's resource plans. Manitoba Hydro's DSM strategy is to pursue all economic DSM opportunities. The Power Smart Plan is developed following this principle and results in DSM being a preferred option relative to alternative supply side options within the integrated resource planning process. This has been the case for many years and as a result, the Power Smart Plan has and continues to be a component of the Corporation's strategy to meet the future electricity needs of Manitoba.

All the NFAT development plans and the pathways include DSM and whichever plan or pathway is ultimately pursued will involve expanding DSM.

As stated in the NFAT submission, the DSM sensitivities were intended to assess the impact on the supply option selection arising from different levels of DSM which potentially would be developed by Manitoba Hydro. Mr. Dunsky took the position and Mr. Thomson acknowledged (Tr. p. 195-196) that the 1.5x DSM and 4x DSM sensitivity evaluations in Chapter 12 did not provide an integration of DSM and supply which determines the optimum level of DSM.

An integrated evaluation of DSM and supply options to determine the optimum level of DSM could not be provided in the August 2013 NFAT submission due to the delay in the DSM Potential Study. The DSM options were assessed in combination with the supply options after the August 2013 submission and were provided to the NFAT process by Ms. Flynn on March 10, 2014 (MH Exhibit #95, Slide 129).

These Integrated Resource Plans (IRPs) are further documented in Manitoba Hydro Exhibit #104-16. Mr. Wojczynski explained that this exhibit contains evaluations of different combinations of DSM and supply options which can each be compared to any of the others to determine the overall optimum combination.

> "And so this -- this analysis is -- is an IRP, but it's an IRP that looks at gas, looks at hydro, looks at interconnections with its associated imports, exports, and everything and looks at DSM levels that are different.
>
> We have the three (3) levels of -- well, actually if you look here and I'll explain how we do that. We have under the DSM levels -- effectively we have four (4) levels of DSM. And then we have the different plans. And -- and you know the plans. I don't have to go through them all. And these are all comparable against each other. You'll notice that we have in the All Gas Base DSM we have a zero there. But all the others we have an -- an NPV number which is relative to that point.
>
> And this is using the TRC analysis, so this is the -- the TRC analysis. We've talked about benefits and costs previously. So all of these can be compared against each other."[4]

[4] Tr. p. 9872, lines 18-25 and Tr. p. 9873, lines 1-11

The DSM option evaluation results are discussed in Final Argument Sections 10.3 and 19.2.5.

The planning for DSM programs and integration with supply options will not stop with the NFAT analysis but will carry on in further stages (Manitoba Hydro Rebuttal, February 28, page 33). Manitoba Hydro will continue to evaluate both DSM and supply options and pursue the economic level of DSM.

5.3 Generation Planning Criteria

5.3.1 Manitoba Hydro's Generation Planning Criteria Ensures Reliability

Manitoba Hydro has a duty to provide for a reliable and dependable supply of power[5]. The Generation Planning Criteria is the means by which Manitoba Hydro plans its system to provide reasonable assurance that load can be met over winter peaks, during droughts or other contingencies including equipment outages and extreme loads, and recognizing that loads can be higher than forecast due, for example, to exceptionally cold weather. It should be understood that the Generation Planning Criteria is used to ensure that sufficient resources exist to respond to contingencies, but in no way does it limit Manitoba Hydro's ability to respond to these types of contingencies on an operational basis.

Manitoba Hydro's Generation Planning Criteria was discussed in the NFAT submission at Section 4.3.1 and further detailed in Appendix 4.1. Manitoba Hydro's Generation Planning Criteria consists of an energy criterion and capacity criterion, <u>both of which must be satisfied</u> in order to ensure a reliable supply of electricity adequate for the needs of the province.

Manitoba Hydro's capacity criterion requires that:

> "Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time."

[5] See *The Manitoba Hydro Act* at Section 2 "to provide for the continuance of a supply of power adequate for the needs of the province".

Manitoba Hydro's Energy Criterion requires that:

> "The Corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated. Imports may be considered as dependable energy resources provided they utilize Firm Transmission Service and are sourced from either an Organized Power Market or a bilateral contract. The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load."

Manitoba Hydro's Generation Planning Criteria is a fundamental reliability criteria that must be met by all components of proposed development plans. Economic substitutions which would compromise reliability are not permitted. The Generation Planning Criteria represent the minimum requirements, as determined by Manitoba Hydro in its role as a Planning Coordinator for Manitoba under the North American Electric Reliability Corporation (NERC) Reliability Functional Model, to ensure for a reliable and dependable supply of power for the needs of the province of Manitoba.

5.3.2 La Capra Associates Have No Expertise in the Determination of Need for a Large Predominately Hydro System

Manitoba Hydro notes that La Capra's Dan Peaco and John Athas were only conditionally qualified as expert witnesses with regard to large hydro projects:

> "The comments in respect of the expertise of these witnesses in the areas of large hydro projects and climate change have been noted, and the Board will attribute the weight to those areas that it judges appropriate under the circumstances.[6]"

More specifically, the Expert Testimony and Appearances listed in Mr. Peoco's curriculum vitae contains six limited references to hydro amongst some 58 appearance references, as provided in response to MH/LCA-001b. Significantly, none of the six references provided by Mr. Peaco related to resource planning in a predominately hydro system. Four of the six references are asset valuations of existing small hydro plants ranging in size from 4 MW to

[6] Transcript, April 7, 2014, p. 5551, lines 21-25.

260 MW (combined capacity of 4 hydro plants); valuations which would not involve any determination of need or involve the application of generation planning criteria in a predominately hydro system. Two of the references involve contracts with Hydro Quebec: one a contract dispute and the other an avoided cost comparison. Neither of these last two references describe any determinations of need in the hydro system or involve the application of generation planning criteria. La Capra Associates has no relevant expertise or related experience in the determination of the need for new resources in a large predominately hydro system. The Board should be very mindful of this lack of experience when it assesses the comments of La Capra, particularly with respect to the possibility of relaxing a critical reliability component of Manitoba Hydro's Generation Planning Criteria.

5.3.3 Manitoba Hydro's Planning Criteria are Appropriate and Consistent with Other Predominately Hydro Utilities

As discussed in detail in Manitoba Hydro's Rebuttal Evidence[7], Manitoba Hydro's Generation Planning Criteria are appropriate. Further, Manitoba Hydro's Generation Planning Criteria are reasonable, prudent, and consistent with both industry practice and the duties and responsibilities with which the Corporation is charged.

No party to the proceeding, including La Capra, raised any issues with regard to the capacity criterion of the Generation Planning Criteria.[8]

Manitoba Hydro shares the concerns articulated by MIPUG in its Final Argument with respect to La Capra's comments regarding Manitoba Hydro's energy criterion. While La Capra acknowledged in its report that Manitoba Hydro's energy criterion requiring dependable resources be available in the event of the driest flow conditions "is generally consistent with other hydro-dependent systems" it claimed that limitations on import energy in the energy criterion are "very conservative"[9] , and summarized the energy criterion as having "some unique and limiting features which restrict resource planning options"[10].

[7] See Section 4.1 "Manitoba Hydro's Generation Planning Criteria is Appropriate" of the Manitoba Hydro Rebuttal Evidence, dated February 28, 2014.
[8] See La Capra Associates Technical Appendix 1 - Resource Planning, pages 1-10 "There is no available evidence upon which to conclude that MH's capacity reserve requirement should be any different than the current 12% standard. La Capra believes this to be a reasonable assumption for the NFAT analysis."
[9] La Capra Associates Technical Appendix 1 - Resource Planning, pages 1-17
[10] La Capra Associates Technical Appendix 1 - Resource Planning, pages 1-57

Manitoba Hydro notes that according to the North American Electric Reliability Corporation (NERC), such an energy criterion is typical for a predominately hydro region[11]. In both Manitoba Hydro's Rebuttal Evidence[12] and during cross examination, Manitoba Hydro pointed out a number of other jurisdictions including British Columbia, Ontario, Hydro-Quebec, the Maritimes area, and the US Pacific Northwest region where there exist limitations on external supply or imports.

In its written evidence La Capra contrasted Manitoba Hydro's "desire for self sufficiency" in the event of the driest flow conditions on record with the approach adopted by BC Hydro and its target of self sufficiency during average flow conditions.[13] La Capra erroneously described the difference in the approaches as "drastic" and suggested that Manitoba Hydro's approach was overly conservative.[14] The flaw in this superficial analysis became apparent during cross examination where it was demonstrated that relative to the size of domestic load, and exposure to drought conditions, Manitoba Hydro's energy criterion actually allows greater reliance on imports than British Columbia with its self sufficiency target.[15]

At the conclusion of this lengthy cross examination and despite comparisons made in their written evidence to other hydro based systems such as BC Hydro and Bonneville Power, La Capra indicated that its comments regarding the "unique and limiting features which restrict the resource planning operations" in Manitoba Hydro's energy criterion were not made with respect to other hydro systems, but rather in comparison to a thermal system[16]:

> "MS. PATTI RAMAGE: Help me by explaining what is unique about Manitoba Hydro's energy criterion.
>
> MR. DANIEL PEACO: What's unique about it? It's -- a hydro system has -- has different criterion than other systems would.
>
> MS. PATTI RAMAGE: So it's not unique among hydro systems; it is unique as compared to a –

[11] NERC Resource and Transmission Adequacy Recommendations, June 15, 2004, page 10; NFAT Submission, Chapter 4, page 37
[12] See Section 4.1.4 "Manitoba Hydro Import Limitations are Consistent with other Predominantly Hydroelectric Utilities" of the Manitoba Hydro Rebuttal Evidence, dated February 28, 2014.
[13] La Capra Associates Technical Appendix 1, pages 1-15
[14] La Capra Associates Technical Appendix 1, pages 1-16
[15] Transcript, April 9, 2014, page 6179, lines 21-25
[16] Transcript, April 9, 2014, page 6196, lines 1-22

MR. DANIEL PEACO: Yeah, as I said before –

MS. PATTI RAMAGE: -- a thermal system, is that what you mean?

MR. DANIEL PEACO: -- that statement is in our report, and you read it.

MS. PATTI RAMAGE: If you could clarify for me. Is it -- you're saying it's not unique amongst hydro systems but hydro systems are unique as compared to, for example, a thermal system.

MR. DANIEL PEACO: Right.

MS. PATTI RAMAGE: Is that what you mean?

MR. DANIEL PEACO: Exactly."

Manitoba Hydro does not disagree with Mr. Peaco's conclusion in his oral testimony that hydro systems are unique in their use of an energy criterion as opposed to a thermal system. However Manitoba Hydro does not agree that this conclusion is consistent with La Capra's written evidence, which while acknowledging the requirement for dependable resources to be available in the driest flow conditions, nevertheless portrayed Manitoba Hydro's limitations on import energy in the energy criterion to make up potential energy shortfalls as being unique amongst hydro systems. It is important that the Board recognize that this is not the case, that such limitations are common in predominately hydro systems and that Manitoba Hydro's criteria is not overly conservative, and in fact allows greater reliance on imports than other hydro based systems such as BC Hydro. Manitoba Hydro believes that La Capra's lack of expertise and experience with large predominately hydro systems has resulted in La Capra's failure to recognize the critical need for and significance of the energy criterion as part of the Generation Planning Criteria in a predominately hydro system.

La Capra's lack of expertise in the determination of need for a large predominately hydro system was shown clearly when they made a serious error in responding to Information Request PUB/LCA-020. In this response La Capra determined the potential need dates based on various changes to planning or planning criteria assumptions. As part of the response to PUB/LCA-020, La Capra assessed the need date for new resources based on a planning criteria assumption entitled "Use Average Hydro Supply" in place of Manitoba Hydro's planning criteria assumption of dependable hydro supply. In cross examination, La Capra ultimately agreed that such a proposal would not meet the needs of the province during a drought and in fact would be reckless:

> "MS. PATTI RAMAGE: So if Hydro's physical import capability on its existing firm interconnection is only 6,443 gigawatt hours per year but it needs to rely on 11,000 gigawatt hours of firm imports during a critical drought, would you agree it's simply not feasible in these circumstances? And in fact it would be reckless for a resource planner to plan to a 2046/'47 energy need date?
>
> MR. DANIEL PEACO: Yes." (Tr. p. 6228)

5.3.4 Energy Criterion is not an Economic Consideration which can be waived

La Capra's lack of expertise in the determination of need for new resources in a large predominately hydro system was also shown in their desire to increase Manitoba Hydro's reliance on energy imports within the energy criterion of the generation planning criteria without any consideration of the reliability impacts. In fact, La Capra sees the energy criterion of the generation planning criteria as an economic consideration to be optimized, rather than a fundamental part of the generation planning criteria needed to ensure a reliable supply of power adequate for the needs of the province. This was evident when Mr. Daniel Peaco of La Capra Associates stated[17]:

> "The -- the next thing we did is we asked Hydro to relax the reliance on imports to 20 percent from their current 10 percent planning criteria, meaning they currently have a planning criteria where they will not rely on imported energy for more than 10 percent of the dependable energy in their -- in that calculation in their planning standards. And so we -- we wanted to -- to relax that to see if -- if, by relaxing that, that that led to any better performance in the -- in the plan or not."

La Capra's apparent perspective that the energy criterion of the generation planning criteria can be adjusted based on the optimization of economic considerations without consideration of the reliability impacts was further evidenced in the response Mr. Daniel Peaco provided to a question from Board Member Bel:[18]

[17] Transcript, April 7, 2014, page 5610, lines 1-10.
[18] Transcript, April 10, 2014, page 5328, lines 2-17.

> "MR. RICHARD BEL: ...The first question is about the discussion about the relaxing the import constraint. Okay. And a simple question. Is there any risk or negative to relaxing that import constraint?...
>
> MR. DANIEL PEACO: The -- the policy is just that; it's a policy. And what we tried to do in our investigation was to test the policy to see, you know, how much of the -- the policy is -- is an economic-based policy and how much of it is -- is a reliability-based policy."

As previously stated, Manitoba Hydro's Generation Planning Criteria, including all parts of the energy criterion, is a fundamental reliability criteria that must be met by all proposed development plans.

Even though La Capra acknowledged that hydro systems are subject to an energy criterion, they treated the energy criterion as an economic consideration to be optimized rather than a criterion that must balance an adequate level of reliability with economics[19]:

> "MR. DANIEL PEACO: ... the No Gen case we did was a construct to say, I just want to see -- test how the system performs if you do relax the policy. It doesn't go beyond that to say, When do you hit, you know, physical risk or other kinds of risk.
>
> But it would say -- but it -- but it would at least tell us, if you could relax it, you know, does it -- does it tend to -- to bring more benefits. And I think in this case it really pointed to the fact that it -- it -- to the extent you can relax it, it can improve the economics and the performance of the plan."

La Capra has missed the point of the energy criterion of the Generation Planning Criteria. The question is not whether relaxing a reliability requirement might be economically beneficial. The question that should be asked is "If you relax the reliability requirements of the planning criteria, will the system continue to provide an adequate level of reliability for the province?" La Capra did not even attempt to address how relaxing the reliance on imports to 20 percent or some other level would impact reliability for the province of Manitoba. Not respecting the reliability aspect of the energy criterion once again highlights La Capra's lack of experience with predominately hydro systems, and as previously explained, any comments La Capra has on the Energy Criterion of Manitoba Hydro's Generation Planning Criteria should treated with extreme caution.

[19] Transcript, April 7, 2014, page 6330, lines 3-16.

In planning for the reliability of the generation resources in a power system, there is a balance which must be struck between having sufficient resources under virtually all conditions and the net cost associated with having resources in excess of requirements. Reducing resources, including energy resources in an energy constrained predominately hydro system, is likely to have a negative effect on power system reliability. In its long term planning, Manitoba Hydro limits its reliance on imports to maintain reliability and thereby reduces the risk of unserved load and blackouts in Manitoba should an unusual operating event occur. La Capra did not acknowledge this negative effect on power system reliability when it proposed increasing Manitoba Hydro's reliance on imports from other power systems.

In the operating time horizon, imports are limited only by the physical capability of the transmission interconnection, and the available supply. This will allow Manitoba Hydro to manage energy contingencies or other unusual operating events as required.

As explained in Manitoba Hydro's Rebuttal Evidence[20], the Capacity Criterion has a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand. The Energy Criterion has no similar reserve margin. However, like the capacity calculations which have uncertainty due to forced generation outages ("breakdown of plant") and load forecast uncertainty ("increase in demand above forecast"), there is also uncertainty in the energy supply situation.

There are a number of sources of uncertainty in the dependable energy supply situation which were discussed at page 55 of Manitoba Hydro's Rebuttal Evidence. Further, two specific energy contingencies, increased energy demand due to an extremely cold winter or reduced energy availability due to an extended outage of a Manitoba thermal unit were discussed in the hearings in detail[21] The conclusion of this discussion highlights the fact that such energy contingencies are not explicitly considered in the energy criterion of the generation planning criteria:

> "MS. PATTI RAMAGE: So would you agree, then, that energy contingency events such as extreme winter or an extended outage of a thermal unit or, you know, a

[20] See Section 4.1.7 "Energy Contingencies are Likely" of the Manitoba Hydro Rebuttal Evidence, dated February 28, 2014.
[21] See Transcript for April 9, 2014, pages 6199-6204.

drought worse than the drought of record can occur, and none of those events are explicitly considered in Manitoba Hydro's energy criterion?

MR. DANIEL PEACO: I didn't -- it doesn't -- the criterion doesn't articulate that, no."[22]

MIPUG's expert witness, Mr. Patrick Bowman demonstrated an appreciation of the potentially disastrous impacts of tinkering with reliability based planning criteria in an attempt to optimize economics without consideration of whether the increase in risk is acceptable:

> "And I would strongly recommend that that criteria not be departed from lightly, if at all, because yielding on that criteria is the decision about the lights going out. It's a decision -- and not -- not for short periods of time. It's a decision about not having enough power for an entire winter."[23]

In summary, Manitoba Hydro's Generation Planning Criteria is the means by which Manitoba Hydro plans its system to provide reasonable assurance that load can be met over winter peaks, during droughts or other contingencies including generation outages, and recognizing that loads can be higher than forecast Both the energy criterion and capacity criterion in the Generation Planning Criteria must be satisfied in order to ensure a reliable supply of power adequate for the needs of the province of Manitoba.

The Generation Planning Criteria represents reliability criteria that must be met and cannot be treated as an economic consideration to be optimized. Manitoba Hydro's Generation Planning Criteria are reasonable, prudent, and consistent with both industry practice and the duties and responsibilities with which the Corporation is charged. All development plans prepared and analyzed by Manitoba Hydro meet the Generation Planning Criteria and thus provide an appropriate level of reliability for the Manitoba load.

5.3.5 Relationship between Energy Criteria, Need Determination, Production Costing and Operations

Manitoba Hydro long-term planning assumptions for import are applicable to the

[22] Transcript, April 9, 2014, page 6203, lines 23-25 and page 6204, lines 1-6.
[23] Transcript, May 2, 2014, page 10121, lines 6-21 and page 10122, lines 1-5.

determination of need for new resources and long-term modeling done in the context of resource planning. The long-term planning assumptions do not apply directly to the operational timeframe. The operation timeframe will have specific limitations and assumptions. These applications are generally as follows:

1. Determination of Need for New Resources

   The Supply and Demand Tables compare total system resources to total system demand to determine the need for new resources. The amount of imports which may be considered as dependable energy in total system supply is included in the Supply and Demand Tables. This amount of dependable imports is prescribed in Manitoba Hydro's Generation Planning Criteria.

2. Long Term Modeling (SPLASH) – Production Costing

   A primary objective of the SPLASH model is to generate production costs including net flow related revenue and costs. In the process of optimizing flow related revenues SPLASH optimizes the interaction with the market subject to transmission and market constraints.

   Imports in production costing are not defined by the Generation Planning Criteria. In production costing, the SPLASH model is simulating future operations. As a result the amount of imports assumed in the SPLASH model, in production costing, generally represents the amount of economic imports available to Manitoba Hydro. This amount is subject to the physical constraints of the system but is not limited, for example, by the 10% of Manitoba load limit or the off-peak limit found in the Generation Planning Criteria.

3. Operating Timeframe – Production Costing and Resource Optimization

Manitoba Hydro operates and dispatches its generation fleet and manages its export obligations on an ongoing and continuous basis in a manner that maximizes net revenue while maintaining a reliable and dependable supply of power. The amount of imports, in the operating time horizon, that can be accessed in the operation of the system is limited only by the physical capability of the transmission interconnections.

5.4 The Need for New Resources

Manitoba Hydro's Generation Planning Criteria provide the basis for determining when new resources are required to ensure an adequate supply of capacity and energy for Manitoba. Chapter 4 of the NFAT Business Case describes how Manitoba Hydro establishes the need for new supply resources in order to meet expected Manitoba load and firm export commitments. The Executive Summary of the NFAT submission on Page 10 states:

> "To determine Manitoba's electricity supply need, Manitoba Hydro regularly assesses domestic demand (load growth net of reductions resulting from DSM) and firm export commitments to arrive at total demand. Total demand is then compared to current supply. Total demand is currently projected to exceed existing supply beginning around 2023 even with no new export commitments. The need for new supply to meet Manitoba domestic load is the principal driver for the preferred development plan."

In determining the need for new resources, the limiting dependable energy criterion of the Generation Planning Criterion related to imports is the amount of energy that can be imported in the off-peak hours on firm transmission service.[24]

Increased levels of DSM will defer the need for new resources to serve Manitoba load. The results of the Supply and Demand tables in MH Exhibit #104-3 are summarized below and demonstrate the impact of the levels of DSM and new industrial load used in the DSM evaluation on the dates for the need for new resources.

[24] MIPUG/MH I-041c

Need for New Resources

	Dependable Energy
2012 Planning Assumptions	2022/23
2013 Planning Assumptions	2023/24
NFAT DSM 1	2028/29
NFAT DSM 2	2031/32
NFAT DSM 2 with increased pipeline load	2024/25
NFAT DSM 3	2033/34
NFAT DSM 3 with increased pipeline load	2029/30

5.4.1 Uncertainty in Load Growth and DSM Suggest Need to Protect Early ISD for Keeyask

It has been suggested that there is no justification for new generation related to the need to supply Manitoba load until late in the 2020's or beyond. In general the assumption is that with a combination of low load growth and continually expanding DSM there is an ability to forego new hydro generation for the early or mid 2020's and instead count on natural gas generation or some other short-lead time resource in the event that new generation is required earlier. While there is no absolute certainty that new generation is needed before the mid 2020's, there is inherent uncertainty in the need date and there is a high likelihood that new generation will be required in the mid 2020's (i.e. by or before 2025.) It would be imprudent for Manitoba Hydro to assume that no new generation is required until the late 2020s and not provide for new generation in an earlier time frame.

In effect, the 750 MW interconnection together with the advancement of Keeyask G. S. to serve long-term exports contracts reduces risk related to uncertainty in load growth and provides a form of insurance for higher load growth. In addition plans with Keeyask and the 750 MW interconnection provide economic benefits even if the higher load growth does not materialize. This is evidenced by plans with Keeyask, the interconnection and long-term export sales resulting in approximately $400 Million NPV benefits to Manitoba Hydro regardless of the level of DSM or even in a scenario of flat load growth not requiring any new generation[25]

From a supply planning perspective, committing to Keeyask for 2019 and a 750 MW interconnection together with long-term export sales has two distinct and major fundamental advantages which protect both load and supply and provide economic value:

1. When considering the risk of higher load growth, the system surplus under development plans with Keeyask, the 750 MW interconnection and long-term exports sales inherently provide a higher degree of assurance, reliability and energy security as opposed to counting on short lead time resource options such as natural gas or wind generation.

   As stated by MIPUG, and contrary to the suggestion of GAC in its final submission, large industrial loads may be committed by customers with relatively short lead time. Development plans with Keeyask, the 750 MW interconnection and long-term exports sales are better able to accommodate sudden higher domestic load growth as compared to shorter lead time resource options.

2. From a supply perspective, when compared to other development plans, plans with Keeyask, the interconnection and exports sales inherently provide a large amount of emergency reserve Load Carrying Capacity and Energy which provides additional insurance against major equipment failures, or more severe conditions than would be protected through resource planning.

5.4.2 High Likelihood of Needing New Generation in Early 2020's

Assuming the scenario with 2013 Load forecast plus 1700 GWh pipeline load minus level 2 DSM and assuming no new exports (as tabulated in Exhibit #104-3, pg 79), application of the dependable energy planning criteria would require new supply in 2024. If the one year deficit in 2024 were to be ignored, and the need date could be deferred to 2027, the beginning of persistent deficits.

However, there is uncertainty in the need date being 2027 because load growth is uncertain. For example, over the last ten years, the load forecasts for the load year 2023 has increased

[25] Tr. p. 9948, line 3

from one year to the next by up to 1292 GWh and decreased from one year to the next by 959 GWh.

The dependable energy supply and demand calculations utilize the expected load forecast. By using the expected load forecast, it is equally likely that actual load growth will be either higher or lower than forecast. As referenced in MH Rebuttal Evidence Exhibit #85-2, and as shown in the table below there is a material probability of the domestic load growth exceeding the dependable supply in the early 2020's. Given uncertainty in load growth, new supply could be required in 2023 with 41% probability or 2022 with 31% probability. These probabilities consider uncertainty in the underlying load growth and do not consider load variations due to extreme weather.

These probabilities of load exceeding dependable supply also do not take into account the uncertainty in DSM achievement. Similar to load growth, the amount of DSM actually achieved will be lower or higher than forecast and thus there is additional uncertainty in the amount of surplus energy and the date when new supply will be required.

MH Exhibit #188 provides the percentage of DSM achievement compared to the target for two years 2011 and 2012 for 26 US states. While the average of the 26 states approximately equals the target in 2011 and exceeds the target in 2012, there are many states in which the actual DSM falls short of the target. Maryland only achieved 50% of the 2011 target and New York only achieved 73% in 2012. While Manitoba Hydro is not aware of any studies determining the probabilities of long-term targets being achieved, an illustrative indication of such probabilities can be obtained from the 2011 and 2012 achievements for the 26 states. Applying the standard deviations calculated from the state statistics, there is a 10% probability that the incremental target one year into the future can be underachieved by 30%. While not a rigorous assessment, the state statistics and the illustrative probability calculation suggest that there is a risk the Manitoba Hydro aggressive plan to quadruple its DSM program may underachieve its target by a significant amount. This risk of DSM underachievement increases the likelihood of new supply being required in the early and mid 2020's.

Advancing Keeyask to 2019 takes advantage of the interconnection opportunity, is economic and provides risk management through protecting against potential increases in load growth and/or lower levels of DSM.

Table 1: Probability that Load Growth Greater than Supply When Considering Uncertainty in Economic Load Growth

– Not considering weather more extreme than normal or uncertainty in DSM Achievement
– 2013 Load forecast plus 1700 GWh pipeline load minus level 2 DSM (MH Exhibit #104-3, p. 79)

	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
2013 Base Load Forecast	27789	28197	28605	29013	29418	29822	30225	30625	31041	31453	31863
Pipeline Load Including Losses	1478	1478	1478	1478	1478	1478	1478	1478	1478	1478	1478
2013 Load Forecast Plus Pipeline [1]	29267	29675	30083	30491	30896	31300	31703	32103	32519	32931	33341
Economic and Model Standard Deviation	1038	1121	1202	1280	1357	1433	1507	1579	1651	1721	1791
Surplus Dependable Energy - No New Exports or Generation	1138	872	590	275	-39	661	298	-10	-369	-726	-1109
Probability Point - Load Growth Uncertainty Exceeds Surplus [2]	**24%**	**22%**	**31%**	**41%**	**51%**	**32%**	**42%**	**50%**	**59%**	**66%**	**73%**

5.5 Generation System Modelling

The Simulation Program for Long-term Analysis of System Hydraulics (SPLASH) is a computer-based generation system simulation model developed by Manitoba Hydro to support the long-term resource planning process. SPLASH simulates system operational, revenue and cost impacts of changes to generating resources, interconnections, energy contracts or key input assumptions such as reservoir operating limits or export prices.

As explained in Chapter 9 of the NFAT Business Case the forecast information associated with Manitoba domestic load, DSM, electricity export prices, natural gas prices, current and future carbon adders, and proposed export power sales is incorporated into the SPLASH model. The SPLASH model outputs include flow-related electricity export revenue and production costs such as fuel and variable operating and maintenance costs. The requirements of the Generation Planning Criteria are incorporated into the SPLASH model.

5.5.1 System Production Cost Based on the Average of 99 Flow Years

The SPLASH model is used to simulate the operation of the Manitoba Hydro system for the 35-year planning horizon (load years 2014/15 to 2047/48, inclusive). The 35 year planning horizon is simulated using 99 historic flow sequences, and the results are averaged to derive production costing data that is representative of all of the 99 flow years. The average values incorporate the effects of drought and flood flows. Specific analysis of the impact of drought is undertaken separately and focuses on specified historic periods of below average flow (e.g. 1988-1992).[26]

In Section 3.3.2 of the MPA report (page 34), the following statement is made, "Critically, Manitoba Hydro assumed average hydroelectric performance in every year throughout their models." MPA has misinterpreted how Manitoba Hydro utilizes the 99-year streamflow record to incorporate variability into the long term simulations.

Manitoba Hydro does not assume average hydro-electric performance in any year but rather Manitoba Hydro models the 35 year study period using 99 different flow sequences. The 35 year chronological flow sequences are taken from the 99 year historic record, allowing the last year of record to be followed by the first year (i.e. flows from 2010/11 are followed by flows from 1912/13). This allows 99 unique 35 year historic flow sequences to be modeled. Operating revenues and costs are determined for each of the 99 flow sequences for each year

[26] Manitoba Hydro Exhibit #85, Section 4.2.

of the forecast. The average of the 99 resulting annual revenues and costs is used to represent the economics of the forecast year, thus the economics from each year will reflect operations ranging from droughts to floods. The resulting averages for any given year will include some drought support costs, as well as significant opportunity export revenue associated with high system flows.

Therefore, the methodology employed by Manitoba Hydro does incorporate the variability inherent to the long-term flow data. The production-costing results are not based on system simulation using a (single) average flow condition.

5.5.2 Natural Gas Generation Representation in Splash is Accurate

While La Capra appears to have expertise in the modeling of thermal generation, the treatment of thermal generation within a predominantly hydro system presents different challenges. In Technical Appendix 3B La Capra questioned the SPLASH model results when comparing between the All Gas and All CCGT plans. In plotting the net opportunity exports against flow duration for the year prior to the need date, it was noted that there was a slight difference between the plan with a SCGT in 2022 and the plan with a CCGT in 2022. La Capra states "MH has provided no information that explains why there are differences in the resource mix for 2021, the year before the new resources are commissioned. The difference in net exports seen in the separation between the curves in this figure is small, but indicates inconsistency in modeling results"[27]. They further state "Since the resource mix and all other assumptions are the same between the plans in 2021, there is no explanation for the variation. The difference in gigawatt-hours is not large (approximately 250 GWh in hydro generation), but the fact that there is any difference at all could be a modeling error or change in prior year storage that we have not been able to reconcile with the material we have been provided"[28].

In an exchange with Board Counsel La Capra confirmed that intuitively there should be no difference in the resource mix the year before new resource are commissioned and they did not know why this was occurring. (CSI Tr. p. 849) Shortly thereafter, after being prompted by Manitoba Hydro Counsel that the reason for the different treatment was SPLASH's knowing a lower cost CCGT was coming into service in the next year allowed the assumption of additional economic exports in the current year, La Capra indicated that was a possibility they considered but weren't as familiar with SPLASH as they would have liked. (CSI Tr. p. 931) What is important to take from this exchange is that there was no

[27] LCA Technical Appendix 3B, page 3B-11, footnote 2.
[28] LCA Technical Appendix 3B, page 3B-13.

inconsistency in modeling results nor modeling error. The erroneous suggestion to this effect was in our view due to inexperience modeling a predominantly hydro system. The model results from the SPLASH model are consistent and accurate between the different development plans and scenario assumptions modeled for planning purposes.

Manitoba Hydro maintains that the model results from the SPLASH model are consistent and accurate between the different development plans and scenario assumptions modeled for planning purposes.

5.6 Resource Planning Methodology and Need – Conclusions

Manitoba Hydro is committed to pursuing all economic DSM. As part of fulfilling that commitment, Manitoba Hydro has undertaken an Integrated Resource Planning process which evaluates various combinations of supply-side and demand-side options to obtain an overall optimum combination and plan. The planning for DSM programs and integration with supply options will not stop with the NFAT analysis but will carry on in further stages (Manitoba Hydro Rebuttal, February 28, page 33). Manitoba Hydro will continue to evaluate both DSM and supply options and pursue the economic level of DSM.

The Generation Planning Criteria represents reliability criteria that must be met and cannot be treated as an economic consideration to be optimized. Manitoba Hydro's Generation Planning Criteria are reasonable, prudent, and consistent with both industry practice and the duties and responsibilities with which the Corporation is charged. All development plans prepared and analyzed by Manitoba Hydro meet the Generation Planning Criteria and thus provide an appropriate level of reliability for the Manitoba load.

Chapter 12 of the NFAT submission, total demand was projected to exceed existing supply beginning around 2023 even with no new export commitments. The need for new supply to meet Manitoba domestic load is the principal driver in the resource planning process. Increased levels of DSM defer the need for new resources to serve Manitoba load. For example under DSM Level 2 with Pipeline Load the need for need for new resource could be deferred until 2027.

However, there is uncertainty in the need date being 2027 because load growth is uncertain. For example, over the last ten years, the load forecasts for the load year 2023 has increased from one year to the next by up to 1292 GWh and decreased from one year to the next by 959 GWh. There is also a risk that Manitoba Hydro's aggressive plan to quadruple its DSM program may underachieve its target by a significant amount. This risk of DSM underachievement increases the likelihood of new supply being required in the early and mid 2020's.

In effect, the 750 MW interconnection together with the advancement of Keeyask Generating Station to serve long-term exports contracts provides a form of insurance for higher load growth and economic benefits even if the higher load growth does not materialize. Such plans are a means to reduce risks related to uncertainty in load growth. This is evidenced by Plans with Keeyask, the interconnection and long-term export sales resulting in approximately $400 Million NPV benefits to Manitoba Hydro regardless of the level of DSM or even in a scenario of flat load growth not requiring any new generation (Tr. p. 9948, line 3).

The results of the Economic Analysis are contained in Section 10.

6.0 Supply Options

As described in NFAT Business Case Chapter 7, Manitoba Hydro reviewed a range of resource technologies potentially suitable for utility-scale generation in Manitoba and, based on a high level screening, reduced this list to those technologies that were economically and realistically achievable within Manitoba over the detailed study period. This list includes DSM, large hydro, natural gas-fired generation, wind and imports. In order to evaluate the resource options, Manitoba Hydro made assumptions related to key characteristics including such factors as capital cost, operating and maintenance costs and efficiency/performance over time. These assumptions were informed by information from third party consultants and available industry information and are applicable for resource options developed in the Province of Manitoba.

6.1 Screening of Resource Technology Options

As described in NFAT Business Case Chapter 7, Manitoba Hydro undertook a thorough and structured screening of potential supply options. This screening process identified key attributes for resource options and, in particular, those specific attributes that would cause a resource option to be screened out of further analysis. The screening process resulted in the selection of DSM, Keeyask, Conawapa, natural gas-fired generation, a generic wind farm and imports for further consideration and evaluation. These resource options were considered technologically achievable, environmentally and socially acceptable, and cost competitive. Further, they had to be practical options that could be incorporated into development plans necessary to meet Manitoba's future needs.

La Capra, in Technical Appendix 3A, was critical of Manitoba Hydro's screening process. However, in La Capra's "Short-term View of Potential" as provided in response to PUB/LCA-048, their assessment paralleled Manitoba Hydro's screening results for all technologies considered except for biomass which La Capra considered as having a medium likelihood under their "Short-term View of Potential". In the same Information Request response, La Capra also provided a "Long-term View of Potential" which differed somewhat from their short-term view as La Capra considered both In-Lake Wind and Solar PV to have long-term potential.

Manitoba Hydro has acknowledged in the NFAT submission and during the NFAT process that changing circumstances over time may improve the attractiveness of certain resource options. However, it is Manitoba Hydro's position that, at this time, the uncertainty is significant enough to screen out these resource options from further analysis as it relates to development in Manitoba. From a utility scale perspective, biomass, solar and in-lake wind each have their own specific challenges at this time for development in Manitoba. These challenges are described in NFAT Business Case Chapter 7, and include environmental, technical and cost considerations. These factors render these resources options impractical as utility scale options for consideration for this NFAT development plan analysis.

6.2 Levelized Cost of Energy is only Appropriate as a High Level Screening Metric

As stated in Appendix 7.2 of the NFAT submission, "Levelized cost is a standard measure of the cost of constructing and operating a generating resource over its life. While it is a useful measure for comparing or screening of technologies, it should be noted that levelized cost does not indicate the value of the generation, but is a relative measure of the cost associated with a unit of energy." As a result, levelized cost of energy is most applicable when comparing like resource options or as a high level screening metric as was used in the screening analysis in the NFAT submission.

Caution must be exercised in comparing the levelized cost of wind to the levelized cost of the large hydroelectric projects, Keeyask and Conawapa Generating Stations, as provided by GAC's Mr. Wesley Stevens[29]. In Mr. Stevens' comparison, he observes that the levelized costs are similar but does not provide the context that hydro resource options are dispatchable, and wind resource options are non-dispatchable, intermittent resource options which do not provide the same product. To manage the intermittency and make the wind and hydro more comparable, the cost of a back-up generating resource, such as natural gas-fired generation, would have to be added to the wind costs, increasing the levelized cost of wind significantly.

6.3 Hydro Options

The evidence presented to the PUB clearly demonstrates that the methodology used by Manitoba Hydro to develop the Keeyask and Conawapa capital cost estimates is industry standard and best practice. Knight Piésold (KP), the independent expert consultant retained by the PUB, confirmed the approach and methodologies used by Manitoba Hydro for its capital cost, operation and maintenance estimates for Conawapa and Keeyask and stated they were "consistent with industry best practices" (page 1 of 4 January 13, 2014 KP report).

[29] GAC Exhibit #23, Slide 9

Further KP commented that the anticipated operation costs were within "industry norms and are well-documented."

The estimate for Keeyask now reflects the value of the signed General Civil Contract together with contingencies and management reserves that incorporate the lessons learned from earlier major infrastructure projects in Manitoba and North America. Although Conawapa is not as advanced as Keeyask, a similar process for developing the estimate for Conawapa has been utilized.

It is significant that at this stage of the Keeyask project, 80% of the contracts have been awarded or completed and these costs have been incorporated into the estimate. Manitoba Hydro has presented to the PUB both a project budget, which has been described as the control budget ($6.5B), together with a range of probable costs reflecting various contingencies set out in what has been described as the NFAT Low, Reference and High cases ($5.61B, $6.35B and$7.18B respectively). This range reflects the appropriate range of cost contingencies for the project and is in line with the risk of overrun estimated for other major infrastructure projects in North America.

6.3.1 The Most Current Information was used to Update the Estimate so as to Create the Highest Level of Precision Prior to Construction

Manitoba Hydro's methodology for developing capital cost estimates is outlined in the NFAT Business Case (Appendix 2.4 – Developing the Keeyask and Conawapa Capital Cost Estimates). A rigorous process was followed in establishing the point estimate; the risk-free, escalation-free (or bare) costs based on an initial set of assumptions and current market indicators. This is also referred to by KP in their report as the "overnight cost". There are no allowances for risk or uncertainty in the point estimate. These risks are included in the contingency analysis and incorporated into the control budget and further refined in the NFAT analysis.

The Keeyask and Conawapa GS capital cost estimates were developed following the Association for Advancement of Cost Engineering International ("AACEI") recommended practices for cost estimate development (page 1 of 27 of Appendix 2.4 - NFAT Business Case). KP described a high quality estimate as satisfying four characteristics: it is credible, well –documented, accurate, and comprehensive (January 17 Report Rev 0, pages 70-71) and found that Manitoba Hydro's estimates met all of these criteria.

Developing the point estimate started with the development of the project scope, compilation of all engineering design and a definition of all quantity information from the current design. The assumptions that form the basis of the point estimate for both Keeyask and Conawapa are derived from multiple sources, including: lessons learned from previous Manitoba Hydro generating station projects, information from current North American hydroelectric projects and other heavy civil projects and broadly-gathered market intelligence (page 2 of 27 of Appendix 2.4 – NFAT Business Case, August 2013 Appendix 2.4 Page 3 of 27). Direct cost items are those directly attributable to the construction of the primary asset under construction including but not limited to concrete costs, excavation costs and major equipment. These costs are developed in accordance with the design, quantities and contract packaging established by the project definition (January 17 Report Rev 0, page 7) and are subject to market factors at the time of the estimate. The assumed construction sequence and any specific work restrictions related to the site including seasonality of key work items are important factors to the cost estimate. Labour, material and equipment costs were all considered on the basis of industry experience, industry data and economic projections. These are contained and addressed within the GCC.

The lessons learned from Wuskwatim were applied to the Keeyask and Conawapa estimates and execution plans. Manitoba Hydro anticipates that the lessons learned will continue to improve the outcomes on its upcoming projects (page 36 and 37 of 51 of Chapter 15 of NFAT Business Case, and Pages 13 to 20 of 27 of Appendix 2.4 NFAT Business Case. Technical Conference presentations made on September 6, Slide 27). These lessons learned include:

- The benefits of an early start for the infrastructure project;
- An earlier completion for the detailed design engineering;
- Means to attract and retain project staff and labour;
- Engage the General Civil Contractor early by utilizing an Early Contractor Involvement project delivery strategy for the GCC;
- Project management practices; and
- Contingency planning.

These learnings are described in some detail below.

a) <u>The benefits of an early start for the supporting infrastructure</u> – The Keeyask Infrastructure Project ("KIP") was commenced early to reduce the risk to the construction schedule and provide additional benefits to the Aboriginal communities. KIP is on schedule and is nearing completion. In contrast, when the NFAT process for Wuskwatim was conducted and the subsequent regulatory decision to proceed was made, the project infrastructure had not yet begun.

b) Engineering – Manitoba Hydro is endeavouring to have an earlier completion date for the detailed design engineering. An earlier completion of design will allow for input from the contractors on how the constructability of the design can be improved upon, utilizing the experience and expertise of the contractor, thereby improving outcomes during construction (Technical Conference Tr. p. 380, lines 14-20).

c) Attract and retain project staff and labour – Issues with the attraction and retention of site labour became a major challenge on the Wuskwatim project and contributed to the increase in costs. Manitoba Hydro has taken steps to address this issue and has built mitigation measures into the Keeyask and Conawapa estimates (KP Evidence, Exhibit KP 3 -4, page 32/33 and Tr. p. 1464, lines 19-21). Labour challenges are being mitigated by having a premier camp, strategies developed jointly with the GCC during the Early Contractor Involvement phase, modifications to the Burntwood Nelson Agreement ("BNA") and the inclusion of a labour reserve to help address additional labour-related issues. In addition, Manitoba Hydro has also included additional costs in the recent update to the Keeyask capital cost estimate for hiring a third party construction management firm to oversee the on-site construction activities and mitigate this risk.

d) Early Contractor Involvement and project delivery strategy for GCC – Manitoba Hydro is using an Early Contractor Involvement delivery strategy for the General Civil Contract. Multiple contracts such as the Electrical and Mechanical works will also be bundled under the GCC to help reduce potential interface and scheduling issues (page 30 of 51 of Chapter 15 of the NFAT Business Case). KP has supported this decision as "a very sound move" (Tr. p. 6735, line 16).

Contract tendering on Keeyask has been a mixture of methods tailored to the individual contracts. The decision to award the GCC using a target price contract reflects Manitoba Hydro's experience with Wuskwatim and that of the industry in recent years. KP has endorsed this overall approach as appropriate in principle (Tr. p. 6733, lines 4-11). KP commented that the overall delivery strategy is to transfer risk away from the contractor in order to better understand and share the risks and obtain a better contract price as a result (page 2 of 4 of KP report, January 17, 2014, Revision 0). Mr. Robertson who gave evidence on behalf of KP, stated that their recent experience has led them to conclude that it is more appropriate and affordable to share the risks between the owner and contractor and therefore KP affirmed Manitoba Hydro's decision to proceed with a target price contract (page 25 of 73, KP report, January 17, 2014, Revision 0. See also Tr. p. 6878, lines 2-23). This is one of the key reasons why Manitoba Hydro used this form of contract. For the Keeyask Project, Early Contractor Involvement was implemented with the selection of a general civil contractor two years before construction of the principle structures including powerhouse, spillway, dams and dykes is scheduled to proceed. The main objective served by engaging the contractor early is that it allows for the contractor's construction knowledge to be incorporated into the final design and provides the contractor an opportunity to plan their work, secure their staff and the necessary labour, and form alliances with Manitoba suppliers and sub-contractors well before the actual site work begins (NFAT Exhibit KP 3 (presentation) page 14 and Tr. p. 6733, lines 15-25).

e) ***Project management practices*** – KP supports Manitoba Hydro's approach to the management of the GCC and stated that the Early Contractor Involvement process reflected a genuine and appropriate opportunity for Manitoba Hydro to optimize and to bring as much certainty to the contract as possible (KP supplemental report, April 8, 2014, Revision 0, page II of III). The approach to tendering the contract was deemed to be comprehensive, well-documented and applied and the timing of the tendering appeared to be on track (KP Supplemental Report, April 8, 2014, Revision 0, page 1 of 3).

Manitoba Hydro has developed methods to identify and monitor risks to the project as well as strategies to manage and mitigate these risks during construction. The risks will be managed through the development of a risk registry which has been reviewed and revised with the assistance and input of external experts and with the insight gained from Wuskwatim, KIP and other projects. KP has indicated, "The approach to construction risk management is industry standard and consistent with best practices with specific roles and responsibilities associated with risk management in the overall management process. As far as can be seen the risk management strategy is well set up and is being monitored and acted upon appropriately." (KP Supplemental Report, April 8, 2014, Revision 0, I of III).

f) ***Contingencies*** – Manitoba Hydro developed contingencies using the AACEI recognized parametric and expected valuing method (see page 7 of 27 of Appendix 2.4 – NFAT Business Case). The inclusion of the contingency at a P50 level addressed the majority of the uncertainty associated with the point estimate. Other key items are addressed through the use of a management reserve. Manitoba Hydro worked with Validation Estimating, an independent expert, to establish its contingency reserves and ensure that internal optimism from the project team did not bias the process. KP stated that Manitoba Hydro has examined the causes that lead to increased capital costs and made "a realistic appreciation of current trends in their cost estimating process" (III of IV of KP report, January 17, 2014, Revision 0). While there will always be challenges associated with determining the appropriate range of contingency for projects of the scale of Keeyask, the uncertainty is usually associated with the degree of systemic risk in the project and is naturally greater earlier on in the project development. The PUB has been provided with evidence that for Keeyask 80% of the contracts are now awarded. As a result, much of the uncertainty and systemic risk has been addressed.

KP has been clear in its reports and testimony that Manitoba Hydro has employed best practices/industry standard practices in the preparation of the estimates with respect to *both* Keeyask and Conawapa. Manitoba Hydro submits that the PUB can have confidence in the estimates provided.

6.3.2. Keeyask Estimate

The Keeyask estimate captures all current information and is based on the fact that 80% of the contracts have been awarded to date.

On March 10th, Manitoba Hydro awarded the General Civil contract (GCC) to BBE Hydro Constructors Limited Partnership consisting of Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. for the amount of $1.4B. The GCC represents the single biggest contract on the Keeyask Project. The decision to award the GCC to BBE was made after a thorough and complete analysis of the four bidders (proponents) proposals, all of whom had been prequalified for their knowledge, expertise and capacity to deliver a project of this magnitude. Bechtel was also the primary lead of the general civil contractor consortium on the Limestone project, which came in on schedule and under budget. The contract award price was slightly higher than the estimate. This increase contributed to the $300M (or 5%) increase to the control budget that was presented to the Panel on March 10th.

Keeyask

To choose a contractor, Manitoba Hydro first utilized an RFP process in which it prequalified four proponents and retained the services of an independent estimator to produce a baseline bid using the materials and information provided to the prequalified proponents. The proponents were provided with detailed project specifications and provided the opportunity to meet with and discuss the issues with Manitoba Hydro following which they provided comprehensive bids. Manitoba Hydro then carefully and thoroughly reviewed those bids and measured them against the Manitoba Hydro Engineer's Estimate, which had been developed with an engineering consulting firm and against the independent estimate (Tr. p. 6877, lines 1-6).

KP stated in both its reports and in its oral evidence that Manitoba Hydro staff were professionals and had expertise in estimating, consulted industry experts in their deliberations, and were open and forthcoming with KP in assisting KP in their inquiries.

KP satisfied itself as to the reasonableness of Manitoba Hydro's estimates by undertaking a review of the direct estimate tables and found the indicated quantities and unit rates to be reasonable (page 14 of 73 of KP report, January 17, 2014, Revision 0). KP also reviewed Manitoba Hydro's material quantities and applied typical unit prices to produce a high level estimate. The estimate KP was able to produce had similar values to the Keeyask and Conawapa estimates using a different methodology. As noted by KP, this "affords some comfort that the cost estimate is in the correct ballpark" (page 18 and 19 of 73 of KP report, January 17, 2014, Revision 0). KP stated that Manitoba Hydro had been diligent in their internal comparisons between the four GCC tenders, their Engineer's Estimate and the independent estimate (KP Supplemental Report, April 8, 2014, Revision 0, page 21 of 26 and Tr. p. 6757, lines 4-7).

The P50 base estimate includes some measures and contingency to deal with the degree of labour availability and productivity issues (page 15 of 27 of Appendix 2.4 – NFAT Business Case). The escalation reserve is intended to cover additional costs over CPI.

KP looked at these issues and noted that the labour reserve appeared to be in the correct order of magnitude (page 30 of 73 of KP report, January 17, 2014, Revision 0). KP also noted that Manitoba Hydro was justified in increasing the direct and indirect costs associated with labour to address productivity and shortages, competition with other large civil projects, and the remote location of the project site (Page III of IV of KP report, January 17, 2014, Revision 0).

KP concluded that it was apparent that new procedures set up for Keeyask and Conawapa were the direct result of the lessons learned from Wuskwatim and reflected "genuine Manitoba Hydro concern to manage the whole process better". They stated that the risk management strategy was well set up and was being followed and concluded that at this stage the most significant technical risks have been addressed, a significant financial risk has been removed with the awarding of the GCC (Exhibit KP 3, pages 46-47 and Tr. p. 6746, lines 2-12).

In its presentation to the Panel on April 14th, and in their report dated April 8, 2014 page II of III, KP identified key risks to be addressed in the contingencies, and which they had identified from their review of the Validation Estimating report produced for Manitoba Hydro. The perceived concerns associated with those risks were addressed in Mr. Bowen's evidence and in the cross examination of KP as follows:

- Resource challenges;
- Systemic risks associated with Manitoba Hydro's maturing system;
- Schedule risks associated with MH's maturing system;
- Adverse labour productivity (addressed through labour reserve);
- Risks that could cause a year of delay: Stage 1 Coffer Dam delay, extreme weather, etc.

[redacted]

[redacted]

Like many organizations planning to construct major capital assets, Manitoba Hydro made the decision to plan for contingency at a P50 level. Using a P50 level in the Control Budget ensures that the budget is adequate, realistic and achievable. Manitoba Hydro views this as the appropriate balance between establishing a control budget that is aggressive enough to help promote a lower ultimate cost outcome and realistic enough to complete the project within budget. The control budget will set a benchmark to measure project performance. The concern being that if contingency was set too high, there may be a tendency to spend up to that value while if the budget is set too low, the project may exceed the budget. Others support this as a reasonable concern (Tr. p. 6890, lines 2-25).

Manitoba Hydro is at a stage in the project development where the technical risks have been addressed and mitigated. They have hired a suitable, reputable and experienced company for the GCC. The remaining construction risks are now associated with the contractor performance in terms of its quality, cost and schedule. Portions of the overall contingency had been allocated to the individual contracts to provide allowances to cover these risks (KP Supplemental Report, April 8, 2014, Revision 0, I of III).

The overall expected in service cost for Keeyask has been prepared by Manitoba Hydro with as much completeness as can be reasonably expected at this stage. The current estimate is no longer bottom-up as was the estimate created in 2009. It is now a blended estimate that includes the awarded contracts (KP Supplemental Report, April 8, 2014, Revision 0, III of III). It is also of significance to note that Manitoba Hydro retained Validation Estimating, an external resource with expertise in estimating and establishing contingency reserves. KP relied on the Validation Estimating statement that "the recent incorporation of the GCC contract costs reduced the uncertainty in respect of competiveness of the estimate". KP then commented that the reassessment included a reappraisal of their contingency and management reserves and further stated that KP has no better data to offer or better estimate of the expected in service cost for Keeyask. (KP Supplemental Report, April 8, 2014, Revision 0, page 23 of 26).

6.3.3 How Much Could Keeyask Cost?

In order to be fully informed of the potential risks associated with the capital cost estimates of the Preferred Development Plan as compared to alternatives, it is appropriate to consider the potential risk of a project exceeding the capital cost budget. Manitoba Hydro has, through the NFAT Low, Reference and High scenarios, identified a range of probable costs that may occur for the Keeyask GSP, and has incorporated those ranges into its economic and financial analysis of the various plans. These scenarios use contingency values of P10, P50 and P90 respectively.

The NFAT High scenario (P90) was used to help establish the appropriate and real upper limit of costs. As noted in the evidence before the PUB, the use of a P90 is debatable. As noted in Manitoba Hydro's Rebuttal Evidence, Exhibit #85-2, in an effort to bring more clarity to the issue, KP and Manitoba Hydro met with Mr. John Hollmann from Validation Estimating via teleconference on April 24th, after KP had presented their evidence to the Panel. Hollmann advised that while a P90 tends to be used for a high business case scenario, it is not appropriate to plan for anything higher than a P90 as the tails of the contingency curve tend to drag out and are not generally used for quantitative analysis.

With 80% of the contracts having been awarded, the Keeyask project is more solidly defined than at any point in the past and is more defined and advanced than with any other project in any previous NFAT. The award of the GCC, a major component of the control budget is known, which can only enhance the confidence, and we submit should increase the comfort level of the Board in considering the costs of this project. (KP Supplemental Report, April 8, 2014, Revision 0, page 1 of 26).

Much has been made about the increase to the capital costs of Wuskwatim as the project progressed and of the tendency for major infrastructure project costs to increase. Manitoba Hydro has identified the reasons for the Wuskwatim cost increases and has appropriately accounted for them in the estimates of Keeyask. In addition to identifying *why* the cost increases occurred, it is important to also identify *when* they occurred. The capital costs for the Wuskwatim project increased from $988M in CEF-03 to $1.771B in CEF-12 (PUB/MH I-038). Included in this increase is a deferral in the Wuskwatim in-service date by three years as well as other increases incurred as the project increased in definition. It is therefore not appropriate to use Wuskwatim as a reference or criticism of Manitoba Hydro's ability to estimate, or to infer that the costs of Keeyask are at risk of similar increases. On Keeyask, the supporting infrastructure is being developed through KIP and is essentially complete, providing Manitoba Hydro an additional level of cost certainty. The GCC has been awarded. Calculating the cost increases on Wuskwatim from a similar point in the project until project completion would yield an increase of approximately 10% (Tr. p. 1459, lines 7-15). If this same increase were to occur with Keeyask, Manitoba Hydro would utilize the P50 contingency as well as the labour and escalation reserves and remain within the control budget of $6.5B. Manitoba Hydro has learned from the experience with Wuskwatim and has confidence that the Keeyask project has an appropriate control budget and includes sufficient reserves to offset specific increases in capital costs such as those that occurred during Wuskwatim.

Industry has recently recognized that the tendency for major infrastructure project costs to increase is predominant in the early definition phases and is largely a systemic risk. One of the reasons the Keeyask cost estimate has increased over the past few years is because Manitoba Hydro has captured this systemic risk in its estimate.

KP was complimentary of Manitoba Hydro's openness to learning from its experience, the expertise of its staff and their willingness to consult. Manitoba Hydro therefore submits the rigorous review engaged in first by Manitoba Hydro and then by the PUB through the independent expert consultant should provide the PUB with confidence that Manitoba Hydro has established an appropriate control budget and the range of costs used in the NFAT are appropriate.

Manitoba Hydro, the PUB and its independent expert KP, have all had the benefit reviewing both Manitoba Hydro's estimating process and the outcome of that preparation. With the recent updates to the Keeyask and Conawapa capital cost estimates presented at the NFAT hearings, the Panel has access to the most current and accurate information possible at this time. While Manitoba Hydro's initial analysis originally led to estimates that were lower than the ultimate contract price for the Keeyask GCC, it is important to recall that KP's initial report (January 18, 2014) supported the process MH had utilized to arrive at those estimates. Despite the increase to the expected in-service cost of Keeyask, there is greater certainty in the estimate with the award of the GCC (Tr. p. 6761, lines 3-4).

There has been concern expressed by some parties, and by the Board itself as to the possibility of the costs of Keeyask continuing to increase. Manitoba Hydro would remind the Board of the comments of Dr. Borison who cautioned against assuming that because costs have recently increased that they will continue to do so. At transcript page 1651 and following, Dr. Borison discussed the concept of anchoring, and said:

> "And there certainly have been changes, no doubt about that, and particularly in capital costs.
>
> But there is -- one of the number-one biasses that people have in their judgment is what's called anchoring, which you tend to really, really remember what happened today, but you -- you don't realize, well, maybe that's -- maybe the future will be different from that. And so there is a tendency to almost jerk around, like if you're sailing, to basically go one way, and then the other way when things change. You have to be careful about that. It doesn't mean you don't want to use the latest information. But you have to be careful you don't over weight what you just found out, like gas prices just went down or they just went -- went up. So not -- not contradicting the idea of updating and being careful about that, but you have to be careful, let's say, not

to over adjust your forecast for the year 2030 based on what happened last week..."

The PUB should take comfort from the fact that Manitoba Hydro has incorporated all current information into the estimate, made the required adjustments to the estimate and that KP has thoroughly reviewed Manitoba Hydro's estimating process and confirmed the methods are industry standard. The output of Manitoba Hydro's industry-standard estimating practices is the $6.5 billion capital cost estimate for the Keeyask Generating Station, which KP confirms is a sensible, best estimate for the cost of the project (Tr. p. 6761, lines 5-10).

6.4 Wind

6.4.1 Manitoba Hydro's Costs Estimates for Wind Projects in Manitoba are Reasonable

Manitoba Hydro has based the assumption for the cost of building wind in Manitoba on a Manitoba specific estimate provided by the independent consult GL Garrad Hassan and has verified this estimate using applicable industry information.

In the report [30] provided by GL Garrad Hassan a Manitoba specific capital cost estimate [redacted] was developed for a utility scale, 150 MW generic wind farm built in southern Manitoba. In order to assess the validity of this cost estimate, the findings of the report were compared to costs for on-shore wind projects from another confidential source, the EPRI 2012 Renewable Energy Technology Guide, published in 2013 by the Electric Power Research Institute. The EPRI report provided an average installed cost for wind generation [redacted]

La Capra, Knight Piésold, and the Green Action Centre and its consultant Power Advisory have argued that Manitoba Hydro's cost estimate for a wind project built in Manitoba is too high[31].

The main source for the capital cost of wind used by La Capra, Knight Piésold and GAC[32] to

[30] Confidential "CAPEX & OPEX Estimate for a Generic Wind Farm in the Province of Manitoba" prepared for Manitoba Hydro by GL Garrad Hassan dated September 7, 2011.
[31] La Capra Technical Appendix 2, Page 2-20; La Capra Initial Expert Analysis Report, page LCA-14; LCA-6, La Capra Technical Appendix 3A, Page 3A-32; Knight Piésold Independent Expert Consultant Report, page 49; Green Action Centre Evidence on Fuel Switching, DSM and Wind, page 4-14.
[32] La Capra Technical Appendix 2, Page 2-9; Knight Piésold Independent Expert Consultant Report, page 49; Green Action Centre Evidence on Fuel Switching, DSM and Wind, page 4-3.

support their arguments regarding Manitoba Hydro's alleged high capital costs for wind is the US Department of Energy (DoE) report, "2012 Wind Technology Market Report" (2012 DoE report) which presents an average cost of $1,760/kW for wind projects constructed in the "Interior" Region of the USA in 2012[33].

Manitoba Hydro contends that the average project costs of approximately $1,760/kW (2012$) for wind projects constructed in the "Interior" Region of the USA in 2012 is not representative of the cost to develop wind generation in Manitoba. Mr. Peaco acknowledged that the Interior Region included forty-two (42) wind projects installed in 2012 from North Dakota to Texas with a range of capital costs from $1,400 to $2,400 per kilowatt and recognized that these costs were based largely on projects from southern states such as Texas. He also acknowledged that while the cost reported for the Interior US may be most representative, "it's not the Manitoba data". [34] Manitoba Hydro provided evidence based on construction industry data that costs to build are generally higher in Manitoba than in North Dakota". (MH Exhibit #85 page 72)

Power Advisory's Mr. Stevens initially recommended[35] using the $1760/kW (2012$) for the cost of wind generation and then in his direct evidence[36]changed this recommendation to the use of $1940/kW (2012$). As a basis for using the higher estimate he stated "I can't say with confidence that I understand why costs are lower in the Midwest. So we thought it was certainly more conservative to use the average for all of the US rather than the -- the average specifically for -- for the Midwest."[37] This further illustrates that caution must be applied when comparing construction costs in Manitoba to US industry data and that Manitoba Hydro's reference case estimate of capital costs for a wind project without transmission costs of $2,100/kW (in 2012$) or $2,200/kW (in 2014$) is reasonable and appropriate.

During cross examination by Manitoba Hydro Mr. Stevens indicated that he would have preferred to rely upon a study of wind costs specifically adjusted for Manitoba:

> MR. WESLEY STEVENS: And I'd like to add that. What I would love to see or have seen is a reasonable cost—a reasonable estimate for a North American wide cost, and then an adjustment factor for—Manitoba; why-how is Manitoba different from the North America as a whole. That would have been a very reasonable approach.

[33] MH/LCA 014a, page 47.
[34] Transcript pages 6237-6240.
[35] Resource Insights/Power Advisory Report, page 4-3.
[36] GAC Exhibit 23, Wesley Stevens of Power Advisory direct evidence, Slide 4.
[37] Transcript page 9668.

> PATTI RAMAGE: So if I understand you correctly, your preferred approach would be one that's taken North American-wide costs and adjusted for Manitoba, something that was specifically done?
>
> MR. WESLEY STEVENS: Yes. Starting out with a reasonable number for the North American-wide cost. (Tr. p. 9831, line 20)

Manitoba did better than the approach described by Mr. Stevens. In developing its capital cost estimates Manitoba Hydro retained third party consultants to develop specific estimates for Manitoba based on actual costs provided by actual turbine manufacturers – not just a survey of costs adjusted for Manitoba. The PUB and IECs have access to the Garrad Hassan Report that was relied upon for this purpose.

6.4.2 Manitoba Hydro's Assumptions for Future Wind Cost and Capacity Factors are Appropriate

Manitoba Hydro maintains that using a constant capital cost, with no real escalation, and a constant capacity factor for future wind projects, are appropriate assumptions for the economic comparison of development plans with wind resource options in the NFAT submission.

La Capra, Knight Piésold, and GAC's witness Mr. Stephens, predict a declining trend in the cost of on-shore wind projects[38]. The primary source that all three of these consultants used for this assumption is a report produced by National Research and Engineering Laboratory (NREL). While the report provides perspectives on the future costs and performance of wind technologies, the report also provides the following conclusion[39] characterizing the state of the current knowledge and providing context to the information contained within the report:

> "The technology is now at a point where an optimal cost of onshore wind energy may result from little or no further capital cost reductions (and perhaps even modest capital cost increases), but continued performance improvements. In this environment, it is possible to see capital costs remain relatively flat—with possible modest reductions or increases, depending on local market conditions—into the future and to see performance increases as

[38] LCA Technical Appendix 2 Generation Alternatives, Pages 2-10 to 2-11; Knight Piésold Independent Expert Consultant Report, Page 48; Green Action Centre Evidence on Fuel Switching, DSM and Wind, page 4-4 to 4-5;GAC Exhibit 23, Wesley Stevens of Power Advisory direct evidence, Slide 7.
[39] NREL, The Past and Future Cost of Wind, IEA Task 26, May 2012, Conclusions and Future Work, Page viii

the primary target of original equipment manufacturers (OEMs)."

As evidenced by the NREL conclusion, whether the capital cost of wind will decline in the future is unknown and uncertain, particularly when factoring in potential cost increases required to achieve improved performance (higher capacity factor). Caution associated with assuming declining capital costs and increased performance was noted by GACs expert Mr. Stevens of Power Advisory where he stated "To assume both declining capital costs and increasing capacity factors runs the risk of double counting"[40]. La Capra has taken liberties in application of the information contained within the NREL report to wind projects in Manitoba, assuming both a significant continuing decline in capital cost in the order of 1% per year until 2030 and a higher capacity factor (43%)[41]. Manitoba Hydro finds this position to be optimistic and hopeful given the inherent uncertainty in the future costs of wind development.

Based on current experience with the wind projects in operation in Manitoba, Manitoba Hydro has assumed a capacity factor of 40%[42]. As demonstrated in MH Exhibit #85[43], meteorological monitoring and analysis of seven (7) sites in southern and central Manitoba, shows that potential capacity factors ranged from a high of 38.2% down to a low of 22.8%. A second study, specifically targeting 7 additional sites in the St. Leon/Darlingford area, shows potential capacity factors ranging from a high of 37.4% down to a low of 29.2%. Based on this information, Manitoba Hydro expects that new wind projects built in Manitoba will be developed on sites which will have progressively less ideal wind resources, which in turn will reduce performance and related capacity factors. This position was supported by Mr. Stevens who confirmed that, holding all else constant, one would expect to see a drop in the capacity factors as better sites are developed[44].

Despite the reality of declining site conditions, Manitoba Hydro assumed in the NFAT submission that technological improvements will achieve incrementally higher capacity factors at future sites. These competing considerations effectively result in a constant system capacity factor for wind projects into the future. Manitoba Hydro also assumes that these technological improvements will come at a cost and that will approximately offset potential future capital cost reductions. The net effect is a constant capital cost and a constant capacity factor for wind projects into the future, which are the assumptions that have been used in the NFAT submission.

[40] Green Action Centre Evidence on Fuel Switching, DSM and Wind, Pages 4-8.
[41] LCA Technical Appendix 3, Page 3A-26.
[42] NFAT Business Case, Chapter 7, page 34, Table 7.5.
[43] MH Exhibit 85, pages 61-65.
[44] Transcript page 9768.

6.4.3 Wind Integration Costs Are Appropriate For the Manitoba Hydro System

GACs Power Advisory raised issues with regard to the conservative nature of Manitoba Hydro's integration cost assumptions for screening wind generation[45]. Manitoba Hydro notes that wind generation was not rejected as a result of the screening exercise for resource options – and accepting Power Advisory's recommendation would not change the NFAT analysis or conclusions.

With respect to Manitoba Hydro's economic analysis, the wind integration costs were scaled based on the costs provided in Appendix 9.3: $4.22/MWh for 500 MW of wind generation and $4.99/MWh for 1000 MW of wind generation (2005 US dollars). Actual wind integration costs used in any one particular year are impacted by actual levels of wind development and changing export prices over the detailed study period. Manitoba Hydro's wind integration costs were explained at page 23 of Appendix 9.3 of the NFAT Application, and further clarified in Manitoba Hydro Exhibit #136. Manitoba Hydro notes that according to CAC Exhibit #45, BC Hydro used wind integration costs of $10/MWh in the base case for their November 2013 Integrated Resource Plan filing, and performed additional sensitivities with wind integration cost of $5/MWh and $15/MWh. Manitoba Hydro's wind integration costs are based on Manitoba Hydro specific system studies and are reasonable.

6.5 Solar Photovoltaic (PV) Appropriately Screened Out In the NFAT Analysis

In Chapter 7 of the NFAT submission, solar PV resource options were considered for evaluation as utility scale options. Manitoba Hydro also recognizes that there is potential over the longer term it may become attractive for customers to install solar generation as a form of self generation. The potential and timing of the adoption of solar PV for self generation Manitoba is discussed in Section 4.3, DSM (grid parity).

In NFAT Business Case Chapter 7, Manitoba Hydro provided two key reasons for screening out utility scale solar photovoltaic generation in the development plan analysis in the NFAT submission: cost and the significant intermittency of the solar resource[46]. In their evidence[47], La Capra criticized Manitoba Hydro for screening out solar PV.

Manitoba Hydro acknowledges that solar photovoltaic is an established technology with

[45] GAC Exhibit #23, Green Action Centre Evidence on Wind, page 8.
[46] NFAT Business Case, Chapter 7, page 18.
[47] La Capra Technical Appendix 3A, Page 3A-17.

significant opportunity for potential technological improvement and that a good-quality potential solar resource exists within southern Manitoba. Manitoba Hydro agrees that these attributes may combine to make solar photovoltaic alternatives more competitive in the future[48].

In its Rebuttal Evidence Manitoba Hydro stated that "Due to the intermittent nature of solar PV, significant instantaneous variability in generation must be either managed with backup generation or with a type of storage technology, increasing the capital cost significantly and/or incurring system integration costs."[49] The additional costs associated with managing intermittency were not recognized by La Capra.

Given uncertainty in the future cost of solar PV as well as the additional costs associated with managing intermittency, costs which were not specifically included in the calculation of Levelized Cost of Energy, Manitoba Hydro maintains that solar PV was appropriately screened out of further analysis.

Knight Piésold concurred with Manitoba Hydro's conclusions on solar PV capital costs stating that "In our view, MH's capital costs are in-line with the range of reported costs for recent Solar PV projects."[50] They further stated that "KP agrees with MH that solar PV generation is not cost-competitive in Manitoba in 2014."[51]

In cross examination, Mr. Dunsky recognized the need to include additional cost to manage intermittency of the solar PV resource options when he said "Absolutely. There's an additional cost for capacity. But absolutely on storage, yeah, you need to add storage costs to do an apples-to-apples comparison" [52]

As described in its response to MH/LCA I-288, Manitoba Hydro acknowledges that solar PV is one of the resource technologies which is experiencing a downward trend in cost and which has potential for additional decline. Manitoba Hydro notes that additional decline in the price of solar PV installations will also require a reduction in the balance of system cost not associated with the solar PV modules themselves (planning/permitting processes, civil and electrical works and related labour). Current experience in Manitoba is that civil and electrical works and related labour costs have been increasing not decreasing.

[48] NFAT submission, Appendix 7.2.
[49] Manitoba Hydro Exhibit #85 page 73.
[50] Knight Piésold response to PUB/KP I-017b.
[51] Knight Piésold response to PUB/KP I-017a.
[52] Transcript pages 8133-8134.

Further, Manitoba Hydro is of the view that the current competitive position of solar generation remains heavily dependent upon North American governments promoting solar generation through feed-in-tariffs, tax credits, renewable portfolio standards, and climate change legislation.[53] Ms. Flynn provided additional context with respect to recent solar development in the US which is concentrated in California where high electricity rates and the State's renewable portfolio standard are driving development.[54]

Manitoba Hydro's caution regarding the guarantee of a perpetual decline in solar PV pricing is echoed by MIPUGs Mr. Patrick Bowman where in a discussion of solar pricing trends he stated "At this point, I'm not sure it's as rosy as some people present, but it's certainly got some uncertainty involved in it."[55]

6.6 Natural Gas-Fired Generation Assumptions are Reasonable

The natural gas-fired generating resource options and costs used in the NFAT submission were based on recommendations for technology options suitable for development in Manitoba provided by a third party consultant, Gryphon International Engineering Services Inc.

Knight Piésold supported Manitoba Hydro's capital cost assumptions for natural gas-fired generation when they stated "Use of the natural gas capital cost … for the CCGT and … for the industrial style SCGT is appropriate"[56]

With respect to Manitoba Hydro's assessment of natural gas-fired generation, La Capra, in their Initial Expert Analysis Report page 14, stated "MH's analysis does not factor in any anticipated improvements in efficiency over time in the future in its planning."

Manitoba Hydro acknowledged in Chapter 7 of the NFAT Business Case that innovation in the field of combustion turbines will lead to more efficient machines that operate at lower heat rates. While continued improvements in turbine technology can be expected, Manitoba Hydro made the decision to leave turbine efficiencies constant over time to recognize the effect of off-setting factors. The expectation of technological improvement is offset by degradation in performance over time and by operational inefficiencies related to units operating at lower than optimum efficiencies at times. In its analysis Manitoba Hydro does

[53] NFAT submission, Appendix 7.2, page 21.
[54] Transcript pages 10309-10310.
[55] Transcript page 10204
[56] Knight Piésold Independent Expert Report , January 13, 2014 – pages 54

not assume either technological improvements or reductions in performance and considers this assumption to be reasonable for use in the NFAT analysis.[57]

6.7 Brandon Unit 5 Retirement Assumptions Are Appropriate

For the purposes of resource planning, Manitoba Hydro assumes that the sole remaining coal-fired generating unit, Brandon Unit 5 is only available until December 31, 2019. This unit cannot be counted on beyond this date primarily due to the uncertainty related to its remaining physical life; and the potential to maintain the current conditions of its operating license.

In 2006, Manitoba Hydro filed a plan with Manitoba Conservation for their Environment Act Licence Review process to operate Brandon Unit 5 until approximately 2020. The Province has not concluded its license review. If the plan were to be amended to include operation beyond 2019 it is uncertain that the Provincial government would support extended operation given its perspectives related to a fossil free future as illustrated by the Clean Energy Strategy. If the Province of Manitoba did not explicitly preclude operation beyond December 31, 2019, additional environmental controls could be imposed. Given the age (50 years in 2019), it's already very restricted operation and its small size, the costs of additional environmental controls would not likely be justifiable. In addition, while the federal coal regulations allow for standby operation until 2030, it remains unclear if this includes a workable provision for protracted operation during drought (a primary role of this unit).

La Capra's Brandon 5 Retirement Approach is Flawed

La Capra Associates has asserted that Manitoba Hydro makes several conservative assumptions, including the retirement date of Brandon Unit 5, which could mitigate the need for new capacity.[58] They further indicate that keeping the Brandon coal unit as a dependable energy source extends the energy year of need by five years under 2013 assumptions[59]. The evidence presented to support the La Capra argument fails to recognize the circumstances of this unit presented in the original NFAT submission and subsequent interrogatories. La Capra chooses to simply conclude "MH has provided no evidence that it must remove Brandon from service in 2019, and could keep the unit in service for capacity purposes"[60] and more

[57] Manitoba Hydro Exhibit 85, pages 75-76
[58] La Capra Associates, Initial Report, page 5.
[59] La Capra Associates, *Technical Appendix 01 – Resource Planning*, pages 1-39.
[60] La Capra Associates, *Technical Appendix 01 – Resource Planning*, pages 1-29.

generally that "MH's needs analysis uses the most conservative assumptions on resource availability. These assumptions include retiring the Brandon Unit #5 before necessary,…"[61].

The 2012/13 Power Resource Plan filed with the Board outlines the Brandon Unit 5 retirement assumptions. Brandon Unit 5 is governed by Manitoba's *Climate Change and Emissions Reductions Act* and its subsequent MR 186/2009, the Coal-Fired Emergency Operations Regulation which restricted coal-fired operation to "…support emergency operations"[62].

Brandon Unit 5 will also be regulated under Environment Canada's Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulation. As provided in evidence[63], these coal regulations will come into effect July 1, 2015 and will place additional constraints on Brandon Unit 5 after December 31, 2019[63]. The regulations require that coal-fired units that cannot meet a performance standard will have to shut down at the end of their useful life (defined as 50 years from the date of commissioning). Brandon Unit 5 was commissioned in 1969 and will reach its 50 year of service in 2019. This is considered the full useful life of a coal generating unit under the federal coal regulation. While the federal regulation makes provision for emergency standby operation beyond 2019 until 2030, prolonged operation during drought would require the Minister responsible for the Emergency Measures Act of Manitoba to declare a state of emergency[64]. It remains unclear if this provides a workable provision for protracted operation during drought which is a primary role of this unit.

As discussed previously, given their perspectives related to a fossil fuel free future, it is uncertain that the provincial government would support extended operation beyond 2019. This is supported by MNP's overview[65] of national and Manitoba coal policy. Mr. Sabine concluded that the number of regulations will "wean Canadian regions from the use of coal in electricity generation. Certainly that's the case in Manitoba."[66]

The opportunity to convert this unit to natural gas will also be considered. However, the age of the unit, the low efficiency that would result with conversion to natural gas (as

[61] La Capra Associates, *Technical Appendix 01 – Resource Planning*, pages 1-44,
[62] *Manitoba Hydro 2012/13 Power Resource Plan*, page 11.
[63] LCA/MH I-421.
[64] LCA/MH I-422.
[65] MNP, NFAT Review: A Review of Manitoba hydro's macro Environmental Considerations, pages 15-16.
[66] Mr. Sabine, MNP, Transcript page 5258, lines 1-3.

experienced with Selkirk Generating Station) and the uncertainty regarding future licensing and regulatory requirements would make the outcome unlikely[67].

[67] CAC/MH I-066.

7.0 TRANSMISSION

7.1 MH Position: Transmission Plan Meets Reliability Criteria

The technical analyses undertaken by Manitoba Hydro for the transmission portion of the Preferred Development Plan demonstrate that the proposed transmission facilities are technically justified as consistent with Manitoba Hydro reliability criteria and NERC reliability standards that have been adopted pursuant to provincial law. This position is supported by Independent Expert Consultants Power Engineers ("PE") and La Capra and Associates ("LCA").

7.2 Reliability Criteria

In its May 2014 Rebuttal Evidence filed in this proceeding, Manitoba Hydro identified the applicable NERC reliability standards related to transmission planning that were used in the analysis of the proposed transmission facilities. In addition, several internal criteria were identified that have been voluntarily adopted by Manitoba Hydro to ensure the continuance of an adequate supply of electricity for Manitobans, in accordance with its corporate mandate under *The Manitoba Hydro Act*. The key criteria include:

- Manitoba Hydro Generation Planning Criteria (NFAT Appendix 4.1) – These criteria include a capacity criterion that ensures a minimum generation reserve of 12% above the demand forecast as well as an energy criterion to ensure sufficient resources are available to supply the energy needs in the event that the lowest recorded river flow conditions are repeated.
- NERC Transmission Planning Standards TPL-001 through TPL-003 – These criteria determine the minimum transmission requirements needed to meet the performance criteria for withstanding credible single and multiple contingencies as defined in Table 1 of the NERC TPL standards.
- HVdc Adequacy criteria – Manitoba Hydro has adopted criteria in addition to the NERC standards that help to plan the HVdc system, including the following:

  (i) Since 1986, Manitoba Hydro has had an HVdc pole criterion for determining the supply adequacy in the event of a dc pole outage.

  (ii) Conducting an annual probabilistic reliability assessment regarding loss of load expectation ("LOLE") has also been used as a guideline since 1996, but was added as an explicit criterion in 2012 to comply with the new Manitoba regulations governing NERC data reporting requirements. The annual NERC long term reliability assessments require an assessment of whether the Planning Authority can meet a 0.1 day/year LOLE metric.

(iii) In addition, once Bipole III is constructed Manitoba Hydro will require the minimum of one HVdc valve group in on-line spare capability equivalent to the largest valve group above northern generation in a single northern collector system configuration (i.e. 500 megawatts (MW) in on-line valve group spare pre-Conawapa). Manitoba Hydro's initial plans were to have one HVdc valve group in on-line spare capability in each of the two isolated northern collector systems after the construction of Conawapa (i.e. 300 MW spare with Bipole I and 575 MW spare with Bipoles II and III). However the criterion to be applied after the construction of Conawapa is under review.

- NERC Standard TPL 004 – In addition to the above criteria, Manitoba Hydro also assesses the risks to reliability of low-probability high-impact events according to NERC Standard TPL-004. This NERC standard requires an evaluation of the risks and consequences of extreme contingencies but, unlike standards TPL-001 through TPL-003, does not require the transmission planner to mitigate such risks.

7.3 Technical Analyses and Conclusions

Manitoba Hydro performed extensive studies and analyses using the above-referenced criteria that support the technical sufficiency of the proposed transmission additions and upgrades to the Manitoba transmission system, the results of which are contained in the following reports. Given that the scope of work for IEC NFAT Review included the requirement to review the completeness and reasonableness of the existing transmission system as well as the new facilities proposed in the Preferred Development Plan, Manitoba Hydro provided these reports to PE and LCA, on a confidential basis, for their review:

- 2012 System Performance Assessment – NERC Planning Standards TPL-001 through TPL-004 – This assessment is performed on an annual basis, as required by the NERC TPL standards, and demonstrates that the current system as well as the planned system meets the required NERC performance requirements over the ten year planning horizon.
- Interconnection Evaluation Study Report for Keeyask, June 8, 2012 – This study and the associated report were conducted pursuant to the Manitoba Hydro Open Access Interconnection Tariff. This Tariff has been adopted pursuant to section 15.0.3 (1) of *The Manitoba Hydro Act* and outlines a process for studying and interconnecting new generating units to the Manitoba transmission system. The Tariff is non-discriminatory and applies equally to independent power producers and Manitoba Hydro-owned

generating facilities. The report examined several options, involving both firm and non-firm interconnection service, for the connection of the proposed Keeyask generating station to the Manitoba Hydro grid and confirmed the adequacy of the proposed transmission upgrades to meet the NERC TPL standards.

- Integrated Transmission Plan for Keeyask and Conawapa Generation, SPD 2011/11, June 6, 2012 – The scope of the report includes an integrated generation-transmission planning study that looked at alternatives for connecting Keeyask and Conawapa to the transmission grid. Based on the results of this study, the report recommended that the NCS be split, that the Bipole III converters be upgraded to a 2300 MW rating and that the north-south transmission be upgraded to accommodate one 102 MW Kettle unit to increase the amount of on-line dc valve group spare.
- Preliminary Group Facility Study: MHEM 1100/750/250 MW Export/Import, October 2, 2013 – This study and its associated report were conducted under Manitoba Hydro's Open Access Transmission Tariff in response to several transmission service requests submitted by Manitoba Hydro's electricity marketing business unit. The report outlined various transmission options that would increase the existing Manitoba to US transfer capability by 250 MW, 750 MW and 1100 MW, including the proposed Manitoba-Minnesota Transmission Project.

Manitoba Hydro conducted sufficient analyses to determine the necessary transmission facilities to meet reliability criteria and be included in the Preferred Development Plan. Notably, PE endorsed the thoroughness of Manitoba Hydro's 2012 System Performance assessment in their January 20, 2014 report (PE Exhibit-3, p. 14, lines 31-33).

7.4 Power Engineers and La Capra Support

Although the initial reports provided by Power Engineers (MH NFAT IEC Transmission Line Construction and Management Report, January 20, 2014), and La Capra (NFAT Review of MH's Proposal for the Keeyask and Conawapa GS – Appendix 8 Transmission, January 24, 2014) raised some initial concerns regarding the ability of the plan to meet NERC standards, these concerns were later resolved through information requests and rebuttal evidence.

In response to a concern raised by LCA that Manitoba Hydro had not provided sufficient information regarding its ability to call on contingency reserves from MISO in order to withstand a single contingency and meet compliance with NERC TPL standards, Manitoba Hydro filed Rebuttal Evidence on February 28, 2014. Section 6.4 of the Rebuttal confirms that, pursuant to the Coordination Agreement between Manitoba Hydro and MISO, MISO is obligated to provide up to 1850 MW of contingency reserves to Manitoba Hydro on a firm basis when called upon during a contingency (MH Exhibit #85, p. 81, lines 12-17). LCA testimony on cross-examination by Manitoba Hydro on April 9, 2014 indicated that LCA had no outstanding concerns with Manitoba Hydro's ability to call on contingency reserves from MISO (Tr. p. 6262, lines 5-25 and Tr. p. 6263, lines 1-5).

Similarly, uncertainties raised by PE and LCA regarding the appropriateness of curtailing Firm Transfers under NERC standard TPL-002-0a were resolved through Manitoba Hydro's Rebuttal Evidence. Manitoba Hydro demonstrated that note b of NERC TPL-002-0a allows for curtailment of Firm Transfers to prepare for the next contingency. As explained in detail (MH Exhibit #85, p.81, lines 5-34), although the automatic operation of special protection systems temporarily curtails Firm Transfers, this curtailment prepares for the next contingency and does not result in any loss of electricity supply to firm customers (i.e. "demand"). Manitoba Hydro's contingency reserve sharing arrangement with MISO, ensures there is no loss of demand following a valve group or pole loss in Manitoba. Because of this contractual arrangement, Manitoba Hydro does not have to maintain its own generation reserves equivalent to a dc pole loss or maintain the equivalent of a spare pole in DC transmission.

In light of the evidence provided, both Power Engineers and La Capra support the transmission facilities included in the Preferred Development Plan. Independent expert witness, Mr. Glenn Davidson from Power Engineers, provided the following testimony on April 11, 2014, "Our finding is that the existing Manitoba Hydro system is reliable and it meets the NERC standards. We believe that the proposed system meets the NERC reliability standards using the current Bipole III model, and that is demonstrated in Manitoba Hydro's Integrated Transmission Plan for Keeyask and Conawapa." (Tr. p. 6519, lines 8-15). Mr. Davidson also provided a presentation with two key conclusions in his direct testimony:

- "The Existing MH System is reliable and meets NERC Standards, as demonstrated in the 2012 System Performance Assessment report."
- "The Proposed System Reliability (sic) meets NERC Standards using existing BPIII model, as demonstrated in the Integrated Transmission Plan for Keeyask and Conawapa report…" (Exhibit PE-5, p. 23)

LCA's support for the sufficiency of the proposed transmission plans in meeting reliability criteria was evidenced by the direct testimony of Mr. Peaco on April 7, 2014 (Tr. p. 5536, lines 19-23).

7.5 Conclusion

Manitoba Hydro has completed sufficient technical analyses to determine a transmission plan that meets reliability criteria. The transmission plan permits the interconnection of Keeyask and Conawapa as well as an increase of 750 MW in Manitoba to US export/import capability.

7.6 MH Position: Transmission Export Limit is Reasonable

The proposed 750 MW tie line capacity increase as part of the PDP above the existing 1950 MW long term firm export level is reasonable. During summer peak and summer off peak load levels in Manitoba, it is expected that the additional tie line capacity will be fully utilized after the addition of Keeyask depending on water conditions. In Power Engineers Jan. 13, 2014 report they state on page 23, "POWER agrees that new facilities will be needed to increase the MH-US transfer capability by 750 MW, and to mitigate constraints in the MISO system."

7.7 Manitoba Hydro Analysis and Main Conclusions

Chapter 5 of the NFAT Submission presents an overview of the capability of the existing interconnections and existing import contracts. Table 5.7 on page 61 of the NFAT business case notes that the firm export schedule limit to the US is 1950 MW and in Table 5.8, the firm import limit is 700 MW. Part of the PDP assumes construction of a 750 MW capacity new interconnection with the US. This new tie line will increase the firm export schedule limit to the US to 2700 MW and the firm import limit to 1450 MW.

Section 5.1.4 of the NFAT Business case summarizes the current import capacity contract level of 500 MW (Table 5.2) plus an additional 500 MW energy services agreement that may be scheduled within the firm 700 MW import limit. There are sufficient long term transmission service requests to match with the import contracts.

Existing winter peak export commitments of 605 MW reducing to 358 MW in 2015/16 are discussed in Section 4.2.4 of the NFAT Business Case. New export contracts associated with the PDP are described in Table 6.4 of the NFAT Business Case. They include a 250 MW sale to Minnesota Power and up to a 300 MW sale to Wisconsin Public Service that are contingent on a new US interconnection.

From the information provided in the NFAT Business Case, it's not immediately clear why a 750 MW capacity interconnection is required. In the response of LCA to MH/LCA-046, they state "To date, MH has not provided documentation supporting the value used for the existing TSRs in the analysis or the basis for assuming continuation of all TSRs is a reasonable assumption." LCA stated in their direct evidence (Page 7 April 7, 2014) that "MH had not demonstrated the need for the US transmission."

Additional information was provided to help support the need in two key areas. First of all the existing transmission commitments were clarified to show insufficient available transfer capability and second it was shown that the existing system could not be upgraded without new transmission.

Transmission service reservation information for Manitoba to US export contracts was provided in response to PUB/MH II-332a. Manitoba Hydro CSI Undertaking #12 provided further details on reconciling the difference between network service and the total available transfer capability. The information provided verifies that there are approximately 1850 MW of long term yearly firm transmission service requests in place in 2020 that have rollover rights. The Manitoba Hydro Transmission Service Provider is functionally separate from the Energy Marketing function and according to the Manitoba Hydro Open Access Transmission Tariff (OATT) must assume that existing long term firm confirmed transmission service requests that are eligible for rollover will rollover unless advised otherwise by the Transmission Customer[68]. Manitoba Hydro Export Power Marketing would perform a business case analysis to determine whether they would be seeking to rollover existing TSRs.

In response to PUB/MH I-189, an assessment was provided of the transmission constraints that limit the firm export capability to 1950 MW and firm import capability to 700 MW. It was clarified in response to MMF/MH I-037 that only a minimal increase of 50-100 MW in the import limit was feasible without a major new interconnection. The response to PUB/MH II-332b clarified why there was insufficient transmission available to increase the firm export capability above 1950 MW and verified that new transmission was required to meet the 250 MW Minnesota Power export sale contract.

The NFAT Business Case focused on the ability of the PDP to meet Manitoba winter peak loads and winter export commitments (e.g. Figure 4.20 shows the need for new winter capacity); however, the Manitoba to US tie line export capacity is not sized based on winter peak needs. Manitoba Hydro takes advantage of seasonal diversity where loads in Manitoba

[68] Further evidence is provided in Section 6.7 of MH's February 28, 2014 rebuttal.

are low in the summer but high in the US. In order to secure long term transmission service, the service must be reserved on a yearly basis. In the winter, Manitoba Hydro does not fully utilize the available transfer capacity to the US, however, in the summer, depending on water conditions, the capability is fully utilized. Summer peak loads in Manitoba are approximately 70% of winter peak loads. Given a 5000 MW winter peak load, for example, means roughly 1500 MW of spare generation capacity is available for summer peak exports with more generation capacity available during off peak load periods.

7.8 La Capra and Power Engineers Support

La Capra (LCA) makes the following statement on pages 8-30, of their Technical Appendix 8, in reference to results from the MISO Wind Synergy Study, "In addition, the study found that after the new hydro (Conawapa and Keeyask) is operational and the new transmission interconnection is completed, the interface flow from MH to MISO is only increased on average by 358 MW. This indicates a less than optimal transfer on the MH-US intertie."

When asked for the basis of this statement in MH/LCA-043a, LCA referenced its response to PUB/LCA 073c, which refers to a MISO November 5, 2012 presentation. Manitoba Hydro referred LCA to slide 16 from the referenced MISO presentation[69] during cross examination on April 9, 2014. The slide demonstrates the expected Manitoba to MISO interface flow of the existing facilities as well as the expected Manitoba to MISO interface flow after the addition of a new 500 kV interconnection. The Option 1-Duluth noted on the slide is essentially the 750 MW tie line referred to in the PDP. With the addition of this tie line option, the maximum MH to MISO flow is roughly 2800 MW in the summer and roughly 1100 MW from MISO to MH in the winter. Mr. Daniel Peaco, expert witness from La Capra, agreed that using the average interface flow over a full year was not the best method to determine the increased capacity that would be gained from the new interconnection (Transcript Page 6257 Lines 1-7). He also acknowledged that the effective increase of the new interconnection was roughly 750 MW. (Tr p. 6258, line 19 through Tr. p. 6259, line 3).

Part of Power Engineers scope of work was to review and assess the technical need for the construction of the Manitoba to US tie line. On page 29 of Power Engineers report they state "POWER's assessment confirms the technical need for US transmission infrastructure to support the planned 750 MW increase in the MH-US interconnection. In our view, it is not

[69] Manitoba Hydro Book of Documents LCA – Volume 1 page 87 (Manitoba Exhibit #167-1).

feasible to increase the rating of the existing interconnection by 750 MW without the new proposed Dorsey-Blackberry 500 kV line and associated facilities."

7.9 Conclusion

The existing Manitoba to US interface is nearly fully subscribed in 2020 with 1850 MW of long term firm transmission service requests. These requests facilitate sales of surplus Manitoba Hydro generation that is available during the summer peak and summer off peak load period. It is not feasible to increase the capability of the Manitoba to US interface by 750 MW without constructing new transmission. It is expected that the 750 MW increase will be fully utilized by Keeyask during summer peak and summer off peak conditions depending on water conditions in Manitoba.

7.10 MMF Outstanding Criticisms are Unwarranted

WRA raised a few questions and concerns regarding the ability of the proposed transmission facilities to comply with applicable reliability criteria. As discussed below, Manitoba Hydro has provided ample evidence to demonstrate that these concerns are unwarranted.

7.11 Compliance with NERC TPL-002

WRA stated in their February 12, 2014 report that "As noted previously, Manitoba Hydro's existing transmission HVDC system does not meet this N-1 criterion. If Manitoba Hydro loses one of its DC poles, it can no longer transmit all of its existing hydro power from the Nelson River. Indeed, this is why it appears that some (if not all) of its export contracts allow the exports to be dropped under system emergencies." (MMF Exhibit-14, p.30) Manitoba Hydro provided Rebuttal Evidence on February 28, 2014 to explain that the Manitoba Hydro network does meet the NERC standards when note b of NERC Standard TPL-002 is taken into consideration (See MH Exhibit #85, p. 80, lines 13-31). Through the automatic operation of Special Protection Systems, Firm Transfers are temporarily curtailed, but there is no loss of Manitoba firm load. The Coordination Agreement between Manitoba Hydro and MISO outlines MISO's obligations to provide up to 1850 MW of contingency reserves on a firm basis in the event of a severe outage like a DC pole loss to prevent the shedding of firm retail load. The supply obligations for Manitoba Hydro and its export customers following an outage are defined in the export contracts (MH Exhibit #85, p. 89, lines 23-36, p. 90, lines 1-12). For HVDC outages, Manitoba Hydro is not responsible for delivering the firm export. The purchaser is responsible for making arrangements to ensure its load is supplied so that they are compliant with the NERC TPL-002-0a standard. (MH Exhibit #85, p. 89, lines 23-26, p. 90, lines 1-12)

In its response to MH/MMF-WRA-004b, MMF interprets note b of TPL-002-0b differently than Manitoba Hydro. MMF states in their response, "Note b is designed to excuse modest special case exceptions to the N-1 criteria which precludes dropping firm customers for the more common contingencies. Specifically, the Note b reference to "radial customers" allows use of a single radial line extending from the main grid to a small remote load that does not justify redundancy by, for instance, building a second long parallel line…Manitoba Hydro interprets this note b exception clause to allow dropping of massive amounts of firm load across its main AC grid upon loss of key main grid elements such as one or two Nelson River Bipoles…The note b exceptions are not permitted to 'impact the overall reliability of the interconnected transmission system.' Manitoba Hydro's interpretation of note b would do so." Based on the foregoing, MMF equates curtailment of Firm Transfers with loss of firm load. This is not accurate. Manitoba Hydro provided further Rebuttal Evidence on this issue on May 8, 2014 (MH Exhibit #85-1). In Section 1.5 of the May 8, 2014 Rebuttal Evidence, Manitoba Hydro provided reference to FERC Orders 693 and 786 that clarified NERC TPL-002, including note b. There is no limit to the amount of Curtailment of Firm Transfers as long as it can be demonstrated sufficient re-dispatch is available to prevent Non-Consequential Load loss. As noted by Manitoba Hydro, the reference to "redispatch of resources" would include the deployment of contingency reserves (MH Exhibit #85-1, p.7, lines 6-16). In Manitoba Hydro's case, curtailment of Firm Transfers of up to 1850 MW is possible without violating the standards and without any Load loss.

In WRA's direct evidence provided on May 13, 2014, Whitfield Russell still contends that Manitoba Hydro is not in compliance with the NERC Standard TPL-002 in spite of all of the rebuttal evidence provided to support Manitoba Hydro's position and in spite of supporting testimony from independent expert witness, Mr. Glenn Davidson from Power Engineers. MMF advocates a position that would require Manitoba Hydro to build significant transmission facilities at the cost of billions of dollars to meet the interpretation that "Note b is applicable to minor firm load interruptions that are costly to avoid" and ". . . automatically dropping firm customers or transfers with an SPS does not qualify as an adjustment." (MMF Exhibit-31, p. 51, 52)

WRA's position also flies in the face of Canadian law governing statutory interpretation, as well as the underlying facts. As discussed above, curtailing Firm Transfers is not equivalent to "dropping firm customers" or "firm load interruptions". Furthermore, Manitoba Hydro's obligation to adhere to NERC standards is a legislated requirement. Section 5 of Manitoba's

Reliability standards Regulation (M.R. 25/2012), enacted pursuant to *The Manitoba Hydro Act*, requires Manitoba Hydro to adhere to the NERC reliability standards adopted under Schedule 1 of the regulation, including TPL-002-0b. Accordingly, the text of this standard is incorporated by reference into the regulation. The primary rule of statutory interpretation is that words and phrases of technical legislation are used in their technical meaning if they have acquired one and otherwise in their ordinary meaning (Maxwell On the Interpretation of Statutes (1976), p.28). In this context it is worthy to note that while NERC often capitalizes and defines terminology in a standard, the phrase "System adjustment" in footnote b is not defined in NERC's Glossary of Defined Terms. Since the term "System" is defined in the NERC Glossary of Defined Terms as "a combination of generation, transmission and distribution components", an SPS would clearly be considered part of a System. However, since the word "adjustment" is not defined, it takes on the ordinary meaning, which would include both automatic and manual adjustments of the System.

For the existing TPL standards, performance of an SPS is defined in Requirement R1 of PRC-012-0. For example, "the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0." All of Manitoba Hydro's SPSs are fully redundant and have been reviewed by NERC and the Midwest Reliability Organization in their capacity as bodies that are authorized to monitor compliance with reliability standards under Section 3(1) of the Reliability Standards Regulation. Use of the SPS has been confirmed to be a valid corrective action to ensure system performance in annual NERC transmission planning assessments.

WRA's stated position is also inconsistent with the facts. Manitoba Hydro uses a Special Protection System (SPS) to automatically lower the power order on its HVDC bipoles following an outage of one of the Manitoba to US tie lines. The SPS is not designed to automatically drop firm customers.

7.12 Adequacy of Facilities

Mr. Whitfield Russell demonstrates his lack of understanding of fundamental concepts such as probability and expected value in his criticism of Manitoba Hydro's Preferred Development Plan and Bipole III during his direct testimony on May 13, 2014 as well as in his report "NFAT Review of Manitoba Hydro's PDP – report prepared for MMF by WRA" of February 12, 2014. On page 33 of his Feb. 12, 2014 report (MMF Exhibit-14), Mr. Russell states, "The probabilities of catastrophic contingencies are all less than the industry's loss of load expectation of one day in 10 years." On page 43 of his direct evidence presentation (MMF Exhibit-31), he characterizes the probability of an event as a 1 day in 17 year event. By stating "1 day" in his testimony, Mr. Russell is equating probability with expected value, which is incorrect. Probability is a measure of how certain we are that a particular event will occur while the expected value represents the average outcome of a series of random events repeated over a long period.

On page 31 of MMF Exhibit-31, Mr. Russell quotes the probability of a single pole outage as less than 1% or 0.01 based on the response to CAC/MH II-013b. In his calculation on page 29 of his February 12, 2014 Report (MMF Exhibit-14), he speculates that a double Bipole outage would have a probability 0.01. This is an oversimplified calculation. System reliability data was provided in Appendix A (page 11) of Appendix 13.1 in the NFAT Business Case (MH Exhibit-14). The actual probability of a forced pole outage can be calculated from the data as 2*((BP1 failure rate*outage duration) + (BP2 failure rate*outage duration))/8760 hours. Using this detail results in a historic outage probability of 0.46% per year for a pole forced outage and 0.02% for a Bipole forced outage. The data examined the last 15 to 25 years of historic operation experience. Data provided in Appendix A from the weather study, which uses a much larger data set[70], listed the summer weather outage frequency as 1 event in 17 years with an outage duration of 6 weeks. In his presentation (MMF Exhibit-31, p.43), Mr. Russell characterizes the risk of an extended loss of both Bipoles I and II as "… an event expected to occur no more than 1 day in 17 years, a 1-day-in-17-year event.", which is an incorrect representation.

Mr. Russell is sending mixed messages as to the combined reliability of the three Bipole systems. On page 34 of his presentation (MMF Exhibit-31), it states "MH's failure to evaluate these impacts seem to be an oversight in that the same type of catastrophic events that could take out Bipoles I and II could also take out Bipole III as well, trapping immense portions of Manitoba Hydro's resources". In contrast, on Page 43 of the presentation it states, "We accepted the proposition that the spare transmission capacity created by Bipole III without Keeyask and Conawapa would lessen risks and costs associated with loss of both Bipoles I and II." The former response is in reference to Manitoba Hydro's Rebuttal Evidence provided on May 9, 2014 where Manitoba Hydro provided information demonstrating the planned route and design of Bipole III is such that a common mode failure of all three bipoles is too low a probability to reasonably consider being credible requiring mitigation (MH Exhibit #85-1, p. 1, lines 8-23).

[70] Data sources include records of tornado events from 1950 to 2009 (page 20, Teshmont report January 2012)

The HVDC reliability data provided in Appendix A of Appendix 13.1 of the NFAT Business Case (MH Exhibit #14) is only part of the input data used to determine whether the Manitoba Hydro system meets the industry minimum standard loss of load expectation (LOLE) of 0.1 days/year or 1 day in 10 years. Other data includes the load forecast, load forecast uncertainty, available energy from generation, generator unit forced outage rate and duration, and export and import contract commitments. The results given in Figure 2 of Appendix 13.1, quantify the LOLE of the Preferred Development Plan as well as several alternatives and demonstrate that the PDP exceeds industry minimum standards.

7.13 Need for US Tie Line

Mr. Russell makes the following claim on Page 33 of his May 13, 2014 presentation (MMF Exhibit-31), "The 2000 MW spare transmission capacity initially created by adding Bipole III will drop when Keeyask is added and virtually disappear once Conawapa is added. Under the PDP, Manitoba Hydro plans to upgrade its ability to import capacity from the USA to replace the diminishing spare capacity in Bipole III." Further on Page 48, he states "In the NFAT, the hydro-based plans call for filling the spare capacity of Bipole III with the output of Keeyask and/or Conawapa. This would diminish the ability of Bipole III to provide spare capacity to cover the loss of both Bipoles I & II." Mr. Russell misunderstands the various criteria that were used to plan the transmission system in spite of Manitoba Hydro's attempts in Rebuttal Evidence provided in Section 6 on February 28, 2014 (MH Exhibit #85, p. 78-90) and further Rebuttal Evidence provided in Section 1.2 on May 9, 2014 (MH Exhibit #85-1 p. 1-4). Mr. Russell is confused about how the transmission plan is designed to respond to frequent events (e.g. valve group or pole outages covered by NERC Standard TPL-002) and infrequent events (e.g. Bipole I/II outage covered by NERC TPL-004).

First of all, the transmission capacity of 2000 MW being added by Bipole III in 2017 will not change until Conawapa is added and additional facilities are added to upgrade the transmission capacity to 2300 MW. In the event of a loss of Bipoles I and II, Bipole III can deliver 2000 to 2300 MW of Northern collector system generation. This role does not change with the addition of Keeyask and Conawapa as was also stated in MMF/MH II-020a.

Second of all, Mr. Russell is partly correct in stating that the on-line spare HVDC capability needed to deal with more probable events will reduce as Keeyask and Conawapa generation are added. However, Manitoba Hydro plans to maintain a reliability margin equal to the largest valve group (i.e. 575 MW post Conawapa) spare above generation connected in the NCS to ensure that frequent HVDC valve group outages do not require reliance on MISO contingency reserves. The on-line HVDC spare does not "virtually disappear", (MMF

Exhibit-31 p. 33) as Mr. Russell infers. In his own calculations on Page 24 of his February 24, 2014 report (MMF Exhibit-14), he notes 567 MW[71] of spare capability post Conawapa, assuming a single Northern Collector system, compared with today's system spare of 292 MW. Once Conawapa is added, Manitoba Hydro plans to split the Northern Collector System into two isolated networks as explained in Dr. Jacobson's testimony and direct evidence (MH Exhibit #95, p.83) on March 10, 2014. As noted in Manitoba Hydro's Rebuttal Evidence of May 9, "Manitoba Hydro's initial plans were to have 300 MW of on-line HVDC spare with Bipole I in Northern Collector System 1 and 575 MW of on-line HVDC spare with Bipole II and III in Northern Collector System 2, however this criterion is under review (MH Exhibit #85-1, p. 3, lines 5-9), the Preferred Development Plan has 677 MW of on-line DC spare, which implies Conawapa should be derated by 200 MW. However, the Preferred Development Plan derated the firm capability of Conawapa to 1300 MW and increased the north-south transfer capability by 185 MW with additional transmission of which 102 MW is used by a Kettle unit. Rather than derating Conawapa below 1395 MW, future Open Access Interconnection Tariff studies will consider using Manitoba spinning reserves (150 MW available) to cover loss of the largest valve group, if insufficient on-line DC spare is available.

Manitoba Hydro does not plan to upgrade its import capacity to the US to replace diminishing on-line spare HVDC capacity as suggested by Mr. Russell (MMF Exhibit-31, p. 33). The PDP has been planned to ensure it meets Manitoba Hydro's criteria of maintaining a reliability margin equal to the largest valve group (i.e. 575 MW post Conawapa) spare above generation connected in the NCS, as pointed out in the Rebuttal Evidence (MH Exhibit #85-1, p.3, lines 1-9). A key component of the PDP is the 750 MW tie line. The new tie line improves import capability, which does provide an additional benefit that Manitoba Hydro peak load can be served in the event of loss of both Bipoles I and II. However, the line is being justified mainly to increase exports to the US in order to sell increased energy available from Keeyask and Conawapa. If the sales were cancelled and the new 750 MW tie line was not built, Manitoba Hydro would continue to assess the risks and consequences of extreme disturbances, as per NERC Standard TPL-004, and would make a decision in the future whether future system changes are justified.

Mr. Russell completely misunderstands the value of Bipole III in his comparisons of Bipole III with an import line. He states, "Moreover, by insisting that a new US tie be accompanied by an additional 1500 MW of gas generation, MH creates an apples-to-oranges comparison because all that Bipole III provides (if Keeyask and Conawapa are not built) is an alternative

[71] 567 MW becomes 575 MW if the firm generation level of 3554 MW is used instead of 3562 MW.

path for MH to reach its existing Northern Hydro. It does not create an additional 1500 MW of generation. Under MH's logic, Bipole III should also be backed up by 1500 MW of generation. In reality, a 1500 MW tie to the US has access to an array of generation sources while Bipole III can access only existing Northern generation" (MMF Exhibit-31, p. 46). However, this position is unfounded. There is 3554 MW of firm Manitoba Hydro owned hydro generation in the Northern Collector System. In the event of loss of Bipole I and II, all of this generation is isolated and not able to supply load. Bipole III allows 2000 MW of this firm generation in the NCS to be delivered to load year round at no cost. The worst case outage duration considered during the Bipole III hearings was two to three years. However in the resource adequacy analysis one year was assumed for failure of the Dorsey converter station (see MH Exhibit #14, Appendix A of Appendix 13.1 from the NFAT Business Case). In order to be equivalent to the reliability provided by Bipole III, alternatives had to be able to provide firm power for one year. 2000 MW of gas turbines in Manitoba or 500 MW of gas turbines in Manitoba with a 1500 MW tie line backed up by 1500 MW of firm generation were in fact an apples-to-apples comparison with Bipole III.

8.0 DEVELOPMENT PLANS

8.1 Manitoba Hydro Has Formulated a Sufficient Number of Feasible Development Plans for the NFAT

Manitoba Hydro's development plans are the result of rigorous vetting and multi-year processes that considered all feasible options. The formulation of each of the 15 development plans included in Chapter 8 of the NFAT Business Case and the 19 development plans with various levels of DSM, provided subsequently, is based on the need for new resources and the requirement to achieve a reliable and dependable supply of bulk power for the system in Manitoba through the application of Manitoba Hydro's Generation Planning Criteria. The purpose of each development plan and the strategies and components of the various development plans is described in Chapter 8 of the NFAT Business Case. Plans are determined in consideration of various strategic business opportunities and are comparatively evaluated to identify the most favourable plan for Manitobans from an overall perspective.

In the NFAT pre-hearing conference of May 2013 (Tr. p. 46, line 25) Manitoba Hydro informed the PUB that analysis on higher levels of DSM as a resource option would not be available for inclusion in Manitoba Hydro's August 2013 NFAT submission. Manitoba Hydro's NFAT Business Case did include analysis to test the effect of higher levels of DSM on select development plans. Subsequent to the August 2013 NFAT submission, Manitoba Hydro provided a substantial amount of information and analysis (MH Exhibit #104 and MH Exhibit #171) on three additional levels of DSM which, in combination with the original base DSM, enabled four DSM options to be evaluated. All development plans include a base level of DSM.

The table below summarizes the 19 additional development plans which were included in the DSM evaluation performed subsequent to the filing of the NFAT Business Case.

Plans Included in the DSM Evaluation

Development Plan	Level 1 DSM	Level 2 DSM	Level 3 DSM	Level 2 DSM with Pipeline Load	Level 3 DSM with Pipeline Load
1. All Gas	x	x	x	x	x
2. Keeyask/Gas		x			
4. Keeyask/Gas/250 MW*		x			
5. Keeyask/Gas/750 MW with WPS	x	x	x	x	x
6. Keeyask/Gas/750 MW		x			
12. Keeyask/Conawapa/750 MW No WPS		x			
14. Keeyask/Conawapa/750 MW with WPS	x	x	x	x	x

*Note: Plan 4 is considered hypothetical from a business perspective.

Even with the volume of analysis provided by Manitoba Hydro in the NFAT process, one of the key findings contained in the direct evidence of La Capra (LCA Exhibit #45, Slide 7) is that Manitoba Hydro's alternative development plans were too limited.

The additional plans proposed by La Capra are: an All CCGT Development Plan, a No New Generation Plan, Sensitivity to the Wind/Gas Plan (Plan 3) and an Alternative Hydro Based Plan.

All CCGT Development Plan – La Capra requested that Manitoba Hydro provide an alternative all CCGT Gas Plan (Tr. p. 5598, line 5), alleging that the All Gas Plan used by Hydro was not optimized. Manitoba Hydro provided to La Capra the results of the 27 scenarios for the All CCGT plan. Mr. Peaco conceded "The combined cycle case actually was slightly less economic overall on the – on the –the analysis, but there – it – it was not very different."[72] The expected value of the All CCGT plan was $180 M NPV less economic than the All Gas Plan, and the All CCGT plan was less economic under 80% of the potential conditions[73].

No New Generation Plan – La Capra proposed a development plan with the intent of deferring new generation as long as possible. The development plan includes increased DSM and fuel switching, a new 750 MW interconnection, relaxation of the import criteria to allow up to 20% of Manitoba Load to rely on import energy, and extension of the existing Diversity agreements to the end of the 35 year detailed planning horizon[74]. La Capra

[72] Transcript page 5599, line 18
[73] La Capra Appendix 9A&B update p 22– Figure 9-95U
[74] LCA Exhibit 45, Slide 29

accepted and described this plan as "hypothetical" [75], but then proceeded to present and analyze it as a viable development plan.[76] The LCA No New Generation plan can only be considered as a hypothetical development plan as explained in Section 8.5 and provided little or no new information.

Wind/Gas Plan (Plan 3) – The LCA Wind/Gas plan is not a new development plan but is described by La Capra as a wind cost assumption sensitivity[77]. In the analysis presented by La Capra, the Manitoba Hydro Wind/Gas development plan was not modified but the cost assumptions in the economic analysis evaluation were changed by La Capra to lower the capital costs, increase the capacity factor, and extend the life of the assets[78]. Mr. Peaco conceded that even with the "relatively optimistic scenario" in the economic analysis the Wind/Gas scenario is still less economic than the Preferred Development Plan[79].

Alternative Hydro Based Plan – Mr. Peaco testified that La Capra combined the results from Plan 1 and Plan 2 to create Plan 2A which adds gas generation first, and then Keeyask Generating Station. La Capra concluded that the NPV of Plan 2A and Plan 2 were "exactly the same", and the benefits of Keeyask would be preserved if the plant was deferred.[80] Manitoba Hydro discusses the economics of Keeyask Generating Station or natural gas generation as the next resource to meet Manitoba load in Section 10.3.1 of this Final Argument.

To summarize the information provided by La Capra's proposed additional development plans, the All Gas CCGT plan proved to be less economic than Plan 1 All Gas; the LCA No New Generation plan is hypothetical and all of the main elements of the plan have already been considered in Manitoba Hydro's development plans; the LCA Wind/Gas analysis provides an optimistic view of wind in the future and can only be considered as a stress test. The economic impact of La Capra's alternative No New Generation plan, Wind/Gas Analysis and Gas/Keeyask plans are discussed further in Section 10.3.2.

[75] LCA Exhibit 45, Slide 33.
[76] LCA Exhibit 45, Slides 58, 59 and 71.
[77] LCA Exhibit 45, Slide 35 and La Capra Technical Appendix 3A, page 3A-27, 28.
[78] Transcript page 5632, line 11 to page 5633 line 15; see also Section 10.3.2 of Manitoba Hydro's Final Argument.
[79] Transcript page 6234, lines 10-24.
[80] Transcript pages 5640 and 5641.

8.2 Need and Opportunity

As previously outlined in Section 5.4 – The Need for New Resources, using the 2013 planning assumptions at base DSM, total demand is projected to exceed existing supply beginning around 2023 even with no new export commitments. The need for new supply to meet Manitoba domestic load is a primary driver for the development plans formulated in the NFAT Business Case. Increased levels of DSM will defer the need for new resources to serve Manitoba load.

There currently is a tremendous opportunity for the development of a new transmission interconnection facilitated by long-term export sales from large new hydro resources advanced prior to the need to serve Manitoba load. As recognized by Mr. Bowman, "There are two possible competing visions – one based on Need and one based on Opportunity – both of which are valid."[81] Mr. Bowman concludes that "Given the information available, an Opportunity-based vision (advance Keeyask, take up MP export deal, build new transmission to US) is likely better than a Need-Based vision utilizing Plan 1 (All Gas)."[82]

8.3 Opportunity

8.3.1 New Major Transmission is Beneficial

Manitoba Hydro's Preferred Development Plan takes advantage of the tremendous opportunity that exists today to build transmission which will provide Manitoba Hydro with increased firm transmission access extending into Minnesota and Wisconsin in perpetuity. At the outset it is important that the Board recognize that the benefits associated with this opportunity are broad and as Mr. Cormie testified are not confined to just the benefits associated with firm export sales.

> "So the basket of benefits that Manitoba Hydro receives as a result of the big line is quite broad, and to only look at the firm power sale as the only benefit ignores other -- the other benefits that -- that are there." (Tr. p. 2651, line 8)

It is also vital that the Board understand that this opportunity is time sensitive. It would be a critical error to assume that Manitoba Hydro can defer acting on this opportunity and expect that the same or even a similar project will be available at a later date. The Great Northern

[81] Pre-filed Testimony of P. Bowman, pages 1-5.
[82] Pre-filed Testimony of P. Bowman, pages 1-7.

Transmission Line project is at best a once in a lifetime opportunity. Again in the words of Mr. Cormie:

> "And—and I-- I think when I look at this project -- and think about all the broad things --the broad basket of benefits it brings, you know, I -- I -- and knowing how valuable interconnections are -- are and how difficult they are to build, you know, it's my judgment and -- and Manitoba Hydro's judgment that -- that this is something that we have an opportunity to go for now, and that we should -- we should do that, and that -- that's why it's kind of in our - in our plans as this is a must. This will provide long-lasting value to the Company." (Tr. p. 2651, line 14)

Benefits of new transmission include improved system operation reliability, improved system import capability for buy/sell opportunities and drought supply, and expanded access to US markets to maximize Manitoba Hydro's system operations with the benefit of selling dependable energy for securing firm revenue from long term export sales and surplus energy for additional export revenue. All of these benefit the Manitoba ratepayer and Manitoba.

Additional transmission capacity is necessary to maximize the value of Keeyask, Conawapa and DSM investments. The interconnections make the economics of hydro generation work. As Mr. Bowman testified, "you can only do it with transmission" (Tr. p. 10068, line 9) in reference to maximizing the value of hydro.

A new 750 MW transmission line with Keeyask would support development pathways that involve Conawapa and associated major export contracts. This includes the signed 308 MW Wisconsin Public Service sale contract which is dependent upon the new MISO firm transmission reservations that reach into Wisconsin associated with the new line (Tr. p. 1586, line 11). Not proceeding with the 750 MW line would result in a loss of these reservations leaving Manitoba Hydro's access into Wisconsin limited to 100 MW (PUB/MH II-332i).

As noted by Mr. Bowman, building more hydro, even for just Manitoba load, increases the need for new transmission because new hydro increases the amount of surplus energy. New transmission allows the surplus energy to get to the US market and export sales revenue to be earned in the valuable on-peak period rather than the lower priced off-peak period. The generation is required for system reliability and without the transmission, the water to produce hydro energy is spilled in Manitoba and no revenue is captured. "So even if you're only building for your own needs…you still need more and more transmission over time" (Tr. p. 10068, line 15).

As indicated by Mr. Cormie, the transmission used to reach the MISO market has to be firm transmission, as non-firm transmission is subject to curtailment because Manitoba Hydro is not in MISO. If imports from Manitoba cause congestion in MISO and Manitoba Hydro is using non-firm transmission service, MISO will cut the import schedule, Manitoba Hydro spillways will open and the energy will be lost. (CSI Tr. p. 521, line 1). All of Manitoba Hydro's existing MISO firm transmission is required to manage Manitoba Hydro's existing energy surpluses (CSI Tr. p. 522, line 13).

Indirect benefits of the 750 MW interconnection include increased import capability and improved reliability at no additional cost. La Capra concurred stating "it looks like every plan we have with transmission in it, to some level, so long as it includes some import capability, it has some value." (Tr. p. 5701, line 19). Mr. Bowman stated:

> "The information we reviewed suggests that the 750 MW line brings benefits even if you never built Conawapa. The latest information also suggests, ... that your economic benefits and the value from things like DSM are improved by having the line. The line isn't doubling down on product – on future production. It's also doubling down on future energy savings. It improves – improves all of your future scenarios." (Tr. p. 10084, line 8).

Building new US transmission needs a US champion. New transmission needs to be permitted in the US by an entity who can demonstrate "need", in order to serve US load and who has the ability to successfully finesse a Presidential Permit for an international transmission line from the US government (Tr. p. 1334, line 4). Manitoba Hydro's President Mr. Scott Thomson testified "so we get our US customer to build a transmission line that we would never get built without them". (Tr. p. 221, line 3)

The timing of this window of opportunity is critical. Mr. Cormie explained that the new transmission is part of a "window of opportunity" for Manitoba Hydro to work with our neighbours in a manner that maximizes the benefit for all parties but it's a limited opportunity:

> "...they are also making strategic decisions now. It's a limited opportunity because we've convinced them over the past several years to expand their set of planning options to include significant reliance on Manitoba Hydro.
>
> ...

> These companies have seen values in these offers, and have seen the value of having increased certainty. On the basis of our long-standing reputation with them, they have agreed that this is an opportunity for them too, in facing the future with Manitoba Hydro as a partner. This opportunity won't come again soon.
>
> ...
>
> With these contracts, these utilities are choosing not to build alternate supply resources, but to rely on Manitoba Hydro as the supplier. Without these contracts, these utilities will invest in other long-term supply options to meet their needs. The opportunity for Manitoba Hydro to displace these other options will not return. They will be lost." (Tr. p. 1310, line 9 to Tr. p. 1312, line 15)

In a discussion between Dr. Bel and Mr. Chernick on May 1 regarding the wisdom of proceeding with Keeyask and the interconnection when load growth in Manitoba potentially could run flat, Mr. Chernick suggested that all the other benefits Manitoba Hydro would secure could be a very good investment even without the Manitoba load.

> "... Manitoba is not an island, and you have an unusually good opportunity here to do the right thing and reduce environmental damage and make money at the same time, and -- and help out your neighbours to the south, as well. And it's entirely possible that Keeyask and -- and the transmission line will be part of a long-term strategy to do that." (Tr. p. 9790, line 5)

Morrison Park Advisors (MPA) witness Mr. Pelino Colaiacovo noted that it should not be presumed that amendments to the commercial arrangements between Manitoba Hydro and its US partners can be easily achieved or achieved at all. (Tr. p. 7254, line 9-21). Mr. Colaiacovo placed high value on these commercial arrangements:

> "These are actually negotiated commercial agreements. This is a bird in the hand. And if they are going to be rejected in favour of an alternative, there is a very high burden on alternatives to be demonstrated to be significantly superior to the real package and the real opportunity that—that is before us in completing the Keeyask construction and in the 750 megawatt intertie and all the associated export contracts." (Tr. p. 7256, lines 6-14)

When asked whether failing to start construction of Keeyask in the summer of 2014 would result in loss of all opportunities to build the transmission line, Mr. Bowman provided a conclusion similar to that of Mr. Colaiacovo, emphasizing the required confluence of events to achieve the benefits of the Preferred Development Plan:

> "No, but...There's room for some delays , we've heard, but not much. And having been involved in developing these type of –of projects, there is a mind bogglingly long list of—of balls in the air, of juggling of rings in the circus that somebody is trying to orchestrate to make all these pieces of the plan come together.
>
> And—and as—as Morrison Park was saying, when they do, you have to recognize it as something different. And—and Keeyask, shovel in the ground this summer, is one piece of that. You—you—it's not a buffet. It's a coherent option that—that's set out.
>
> It may be that there's reasons to move it, but when you have a –a contractor and a counterparty and financing markets and Aboriginal partners and licenses and the federal government and –and, you know, everything from, you know unions to governments moving in a a certain direction and you've managed to get this choir to sing together, it's –it's very hard to say, Oh wait, wait, wait I want – I want to change this one." (Tr. p. 10227, line 21)

8.3.2 Both the Minnesota Power Sale and Upsizing the US Transmission Line From 250 MW To 750 MW, are Dependant on Minnesota Power Having a Transmission Investment Opportunity

Transmission investment is a condition of Minnesota Power's and Manitoba Hydro's power sale arrangements (MH Exhibit #201) in order to offset the financial effects of the 250 MW Sale Agreement on Minnesota Power's balance sheet. Minnesota Power will pay all the costs for 250 MW of new US transmission line capacity.

Mr. Wojczynski testified that although it was studied, a 250 MW transmission interconnection is not an option for Minnesota Power and as a result not an option available to Manitoba Hydro. "Manitoba Hydro has not said that we prefer to do the seven fifty (750) over the two fifty (250). What we said is that the two fifty (250) option, as it stands now, is not a viable option, and is not an option available to Manitoba Hydro. It's off the table." (Tr. p. 2874).

Mr. Cormie testified that the 250 MW transmission line is not an option. Minnesota Power, in their Certificate of Need filing for the Great Northern Transmission Line (GNTL), have stated "that a 250 megawatt project would not meet the long-term needs of the region, would not prove to be cost effective for their customers, nor is it the environmentally preferable line over the long term." (Tr. p. 1335, line 10).

Further, as indicated in the response to LCA/MH I-037 (pages 3-4), the 250 MW interconnection is significantly more expensive for MP, is not as advanced and does not provide significant economic or reliability benefits to Minnesota or the MISO region. As such, a 250 MW interconnection has significant risk of not being approved and proceeding. In contrast, the new 750 MW line is attractive as it facilitates additional innovative wind storage provisions that optimize the value of Minnesota Power's wind energy investment, and when combined with increased storage capacity improves savings in production costs, load costs, and reserve costs as well as reduced wind curtailment. Recognizing Manitoba Hydro's longer term need for more interconnections, building the new tie line large enough the first time will limit proliferation of new transmission line corridors in the future. A lower capacity line greatly reduces these utility, state and regional benefits.

Plans with a 750 MW line provide significant benefits making the line worth pursuing. Given Minnesota Power's statutory right to own, invest and earn on 100% of the 750 MW transmission line, an arrangement where Minnesota Power's ownership share is 51% has been negotiated (Tr. p. 1326, line 20). Manitoba Hydro is satisfied with the negotiated 51% level of transmission line ownership by Minnesota Power, because as Mr. Thomson testified on March 3, 2014 "we don't want to hold a majority interest in a US asset." (Tr. p. 112, line 3).

Negotiations with Minnesota Power on the business arrangements associated with the proposed 750 MW line have evolved from the time of the NFAT filing in August 2013. During the hearing Mr. Cormie updated the Board on these arrangements, indicating that Minnesota Power will invest in 51% of the GNTL compared to the NFAT funding assumptions which included a 55% Minnesota Power ownership assumption as described in detail in MH Exhibit #139 and MH CSI Exhibit #17.

The issues of GNTL ownership, investment, use, and funding are complex, and remain under negotiation by Manitoba Hydro and Minnesota Power. However the key terms of the proposed arrangements are expected to be as follows (Tr. p. 1326, line 3 to Tr. p. 1328, line 8);

1. Minnesota Power will develop, permit and construct the GNTL.

2. Manitoba Hydro will have the right to offload its ownership position to a third party.

3. All the firm US transmission rights to move electricity across the border (exports and imports) will be held by Manitoba Hydro, Wisconsin Public Service and Minnesota Power, with Minnesota Power's rights limited to 383 MW in the southbound direction associated with its power purchase from Manitoba Hydro.

4. With regard to GNTL funding;

    a) Minnesota Power will have funding responsibility (33%) for the transmission needed for the 250 MW Power Sale Agreement, and
    b) Manitoba Hydro will have funding responsibility (66%) for the additional investment necessary to bring the capacity of the line up to 750 MW.

Manitoba Hydro's funding for the 66% share will be achieved in two different parts, 49% directly as a result of Manitoba Hydro's ownership position and 18% via a scheduling fee payable to Minnesota Power to cover its increased revenue requirements associated with the additional 133 MW (18%) of capacity it will own above that necessary for the 250 MW Power Sale Agreement. Manitoba Hydro's expected funding responsibilities remain consistent with those assumed in the NFAT no-WPS-investment analyses. (CSI Tr. p. 246, line 5)

The 18% scheduling fee arrangement will be paid on an ongoing basis over the life of a 133 MW Energy Sale Agreement under negotiation (CSI Tr. p. 108, line 10 and Tr. p. 1669, line 7). In exchange for this fee, Manitoba Hydro will have the rights to use the 133 MW to export and import energy. The fee will be set to offset the increase in Minnesota Power's revenue requirements as a result of owning and operating a larger portion of the GNTL. This includes earning a rate of return on the additional equity Minnesota Power invests into the transmission line. Mr. Cormie testified with respect to Minnesota Power "They're investing the additional 18 percent on behalf of Manitoba Hydro, and they expect to earn on that 18 percent." (Tr. p. 1584, line 10).

8.3.3 Minnesota Power 250 MW Sale Tied to Early Keeyask

Manitoba Hydro and Minnesota Power have signed a 250 MW System Power Sale Agreement with deliveries to commence on June 1, 2020. As set out in MH Exhibit #201, the commencement of construction of Keeyask is a condition precedent in the Agreement in favour of Manitoba Hydro. While there is no condition precedent in the Agreement in favour of Minnesota Power, both parties to the Agreement have conducted themselves based on the shared understanding that if construction of Keeyask does not commence by June 1, 2016, the Agreement will terminate and no interconnection will be built. This shared understanding is confirmed in the Energy Exchange Agreement signed contemporaneously with the 250 MW Sale Agreement, the Preamble of which sets out this understanding:

> "AND WHEREAS, MP is developing significant wind resources and desires to pump and store wind energy, in conjunction with the construction of a new transmission interconnection between MP and MH and MH's proposed new hydraulic generation development;"

Further, with regard to the new US interconnection, Manitoba Hydro has represented to Minnesota Power that the need for it is based on increased amounts of exports of surplus capacity and energy destined for the MISO market resulting from the construction of Keeyask and Conawapa. Minnesota Power echoed this justification in its Certificate of Need filing and its ongoing proceedings for the Great Northern Transmission Line with the Minnesota Public Utilities Commission. The Certificate of Need identified Manitoba Hydro's plans for major new hydraulic generation as justification for a 750 MW interconnection and specifically identified Keeyask as being needed for the supply of power under the Agreement.

On this side of the border, the Province of Manitoba's Order in Council 304/11 authorizing Manitoba Hydro to enter into the 250 MW MP Sale Agreement references the need for Manitoba Hydro to construct new power generation in order for Manitoba Hydro to fulfill its obligations under the contract.

Mr. Cormie indicates that "Minnesota Power requires the new generation early in -- either in 2020. They can -- they can cope with a delay up to '22. The contract reflects that. Anything beyond that date does not work to meet their -- their load requirements, and -- and a delay to 2031 or -- or some later date, it's not -- it's not part of the -- of the contract." (Tr. p. 9894, line 17). This accurately represents the business arrangement carried out in good faith between the Parties. It would be unrealistic to think one could foist an alternative arrangement not involving major new hydraulic generation upon Minnesota Power. As noted by Mr. Colaiacovo,

> "Commercial negotiations are just that; they're negotiations between independent parties. And while all in -- all of us external experts and all Intervenors and -- and commentators and analysts external to the situation, to the transactions between Manitoba Hydro and its -- and its partners, can question whether those particular transactions may or may not be the best transactions which could have been negotiated, the reality is those are the contracts and arrangements that have been negotiated. And they can either be accepted or rejected. And it shouldn't be presumed that amendment can be easily or achieved at all." (Tr. p. 7254)

It is important to recognize that like Manitoba Hydro, Minnesota Power must demonstrate the benefits of this arrangement to its regulator. It must be a win-win transaction in order for it to move forward. If Keeyask does not commence by June 1, 2016 the MP 250 MW Sale Agreement will terminate and no interconnection will be built.

With the apparent attractiveness of expanded Demand Side Management, there have been suggestions that Manitoba Hydro could have the option of serving Minnesota Power's capacity and energy needs as outlined in the 250 MW Agreement from surplus dependable hydro energy, freed up as a result of lower Manitoba load. This would not be an acceptable source of supply for Minnesota Power, as increased DSM does not provide the additional wind synergy benefits associated with the construction of new hydraulic generation.

The benefits to Minnesota Power of expanded DSM in Manitoba are significantly smaller than the step function changes that would occur if both Keeyask and Conawapa are built. In addition, new storage at Conawapa makes the Manitoba Hydro storage battery significantly bigger and the loss of the associated benefits from wind hydro synergy would be a very significant issue (Tr. p. 1671, line 21).The loss of new wind synergies would also be important to the state and to MISO as new storage leverages many more MW's of potential wind development in the US.

In theory a new relationship with Minnesota Power could be established over time around a development plan based upon freed up resources as a result of expanded DSM. However Minnesota Power needs new resources to serve its load in 2020, and it is Manitoba Hydro's view that if Keeyask does not proceed prior to June 1, 2016, Minnesota Power will chart a different course to meet its 2020 load requirements without Manitoba Hydro.

Manitoba Hydro is firmly of the view that Minnesota regulatory approval for the Great Northern Transmission Line would be at significant risk if Keeyask does not proceed given that the Minnesota benefits of the 750 MW interconnection could not be realized. The Minnesota statutory "need" justification to build new transmission would no longer be satisfied as the existing Manitoba–US interconnection has adequate capacity to manage Manitoba Hydro's current surplus energy supplies. Further, a recommendation in Manitoba that at this early juncture rules out the possibility of developing Conawapa in the future could also have serious repercussions for obtaining approval in Minnesota of the 750 MW interconnection.

Manitoba Hydro submits that the construction of the 750 MW interconnection without a commitment to build Keeyask is not a viable option.

8.3.4 Manitoba Hydro's Sales Activities Reduce Export Price Risk

Manitoba Hydro's Preferred Development Plan includes the early construction of both Keeyask and Conawapa which can be expected to produce over 11,400 GWh of new hydraulic generation per year on average. (Chapter 2, NFAT Overview). Manitoba Hydro has been actively marketing both the surplus dependable and other surplus energy from these stations since 2007 in order to capture premium fixed prices, minimize financial risk and to facilitate a major new interconnection to the US. As Mr. Thomson confirmed, financial risk associated with uncertain dependable and surplus export prices is a major risk to the Corporation (Tr. p. 168, line 2).

To date Manitoba Hydro has been successful in selling most of the dependable output of Keeyask and 30% of the output of Conawapa at fixed prices which has significantly reduced the risk of these projects, especially Keeyask. "The contracts that have been signed to date for hydraulic energy effectively use up most of the surplus power -- hydro power available from Keeyask." (Tr. p. 1312, line 16). With regard to the significance of the fixed price 308 MW WPS sale, Mr. Cormie explained "To put the size of the sale in context, the energy quantities associated with this sale are significant, relative to Conawapa. It's 33 percent of its generation under dependable flow conditions, and under average flow conditions it's 29 percent of Conawapa generation." (Tr. p. 1322, line 7).

The remaining gap in unsold dependable energy until Conawapa is built is associated with the additional dependable supply made available as a result of the new interconnection (Tr. p. 1328, line 3). Mr. Cormie indicates there is much more customer interest than unsold product remaining.

> "... all of the discussions that we are having with the various customers exceed the dependable energy supply line that we're showing there. And so we're in discussions for more dependable energy post-Conawapa than -- than we have -- have supply. So there is room there. And there's market interest there to -- to increase, should the Manitoba load be lower. And -- and we are continuing to seek out all opportunities, so that at the end of the day, we can bring back the best value and best portfolio to -- to fill the -- to fill that -- to fill that gap, or whatever it is." (Tr. p. 1512, line 11)

Expressed interest exists, particularly with SaskPower and Great River Energy. Both have recently signed MOUs with Manitoba Hydro. Mr. Cormie indicates that with Saskatchewan we "are working quickly on several stage[d] long-term sales that would require Keeyask and Conawapa." (Tr. p. 1313, line 8). And "Again, it is a -- there's a 500 megawatt MOU, and under that MOU, discussions are occurring for a -- an earlier power sale that would be dependent on Keeyask, and then a larger power sale that would be dependent on Conawapa. And again, Saskatchewan knows when our investment decision needs to be made and it aligns with the years in which they need the power." (Tr. p. 2419, line 3).

With regard to Great River Energy, it signed a Memorandum of Understanding for 600 MW for long term power from Keeyask and Conawapa in February 2014. (Tr. p. 2416, line 13) As confirmed in MH Exhibit #95, it is expected that the Northern States Power sales will be extended in 2025. Mr. Cormie testified that "Manitoba Hydro and NSP expect to extend that sale for ten (10) years, but that extension is not shown here."(Tr. p. 1317, line 24).

These expressions of interest are not yet formalized into signed contracts, and as such the need for Conawapa will be reviewed on an ongoing basis. Manitoba Hydro intends to continue to undertake studies for an early Conawapa in service date, and will reevaluate its plans in the next power resource planning exercise. Manitoba Hydro expects that if conditions are favourable, including progress on export power negotiations, it will continue to plan for an early Conawapa (Tr. p. 2588).

8.3.5 New Hydro Is a Unique and Valuable Export Product

As indicated in response to GAC/MH I-028 Manitoba Hydro's long term firm export product is needed and valued in the export market because it is a unique product that our counterparties do not have themselves, unlike gas and wind resources. The contracts are tied to the development of major new hydro generating resources with associated renewable attributes. Manitoba Hydro is unique in being able to offer a large dispatchable hydro supply option to its export customers. Other Manitoba Hydro options are not of interest to Manitoba Hydro counterparties because they have their own supply options such as wind, natural gas or DSM, which can be developed locally at a lower cost than from Manitoba.

Mr. Cormie confirmed that US utilities do not need or want to buy wind and gas generated power from Manitoba, as they have ample supplies of their own. "They're adding wind and they're adding gas. So our resource is no better than -- than the resource that they can put in place themselves, because there's lots of wind and they have access to gas." (Tr. p. 2108, line 8).

Not only do they have their own wind resources, US utilities are able to install wind at less cost than Manitoba Hydro because the United States government offers a production tax credit on wind. Mr. Cormie explained, "but they also have the advantage of the production tax credit, and so for us to assume that we could find the customer who wants to buy our wind gas product, and -- and use that in -- as opposed to doing it themselves, the -- something would have to happen to the economics of wind in Manitoba." (Tr. p. 2108, line 13).

With regard to whether existing hydro freed up by expanded Demand Side Management is an acceptable alternative to new hydro, evidence was provided on page 2 of MH Exhibit #201 that for Minnesota Power, it specifically wants new hydro because of the new benefits associated with expanded storage in Manitoba.

> "Part of the benefits MP has identified in the CON filing for the 750 MW interconnection are the result of increased imports to Minnesota associated with a large increase in hydraulic energy production from new generation at Keeyask and Conawapa in the form of: a) additional environmental attributes; b) significant wind synergy benefits to MP, other Minnesota utilities, and regional MISO load as indicated in the MISO-MH Wind Synergy Study; and c) lower Locational Marginal Prices at the MP-MISO pricing nodes."

Finally it should be noted that the Wisconsin Public Service 308 MW Agreement is tied solely to the new capacity and energy associated with the addition of Conawapa to the Manitoba system. Mr. Cormie explained that:

> "Both parties have the right to terminate the sale if Manitoba Hydro does not commit to Conawapa by 2029. So it -- not only do we have the right to terminate the sale; they also have the right. If we're not prepared to build, Conawapa they have the right… it doesn't obligate us to build it. But if we do

> build it, they're -- we're obligated to deliver and they're obligated to take. But if we don't build it -- and this is -- this is new. If -- if we don't build it they have the option of cancelling the sale." (Tr. p. 2581, line 4).

8.3.6 Firm Export Contract Prices Benefit From Gas Price and Carbon Regulation Uncertainty

Not only is there presently a window of opportunity to build transmission in order to expand market access to Minnesota and Wisconsin, there is also an opportunity now to achieve premium prices for long term new hydraulic generation. Mr. Cormie has indicated that export customers are prepared to pay a premium for price certainty to hedge against factors such as natural gas price volatility and Manitoba Hydro's fixed price product monetizes that value. (Tr. p. 2563, line 8).

Mr. Wojczynski also testified that one of the biggest risks that the industry generally is facing is de-carbonization, moving away from coal and to a lesser degree, natural gas. This risk to most of the industry is conversely a benefit to Manitoba Hydro. He indicated three-quarters of the energy is thermal in the United States whereas Canada is 80% hydro. "--the utility industry in the US actually has become and is, in effect, an opportunity for Manitoba Hydro." In proceeding now with the export contracts Manitoba Hydro is taking advantage of the need for US customers to transform a portion of their generation fleets to a non-emitting technology at attractive long term firm prices for the firm hydro product. (Tr. p. 2568, line 7).

A more detailed discussion on export contract pricing can be found in Section 9.1.2 of this Final Argument.

8.3.7 Benefits of Plans with New Interconnection May Go Up

In the economic analyses of plans involving the 750 MW transmission line interconnection (assuming no Wisconsin Public Service investment) Manitoba Hydro assumed that it would be responsible for its share of the costs of the Great Northern Transmission Line for its full economic life. However, as Mr. Cormie has indicated permanent ownership is not Manitoba Hydro's goal and Manitoba Hydro is pursuing discussions to divest the line to others:

> "As a result, Manitoba Hydro's ownership is only as a last resort, but it is necessary to ensure that the large line is built and can be put into service by 2020. Manitoba Hydro is in ongoing discussions with other US transmission owners at this time who are interested in assuming Manitoba Hydro's 49

> percent investment and ownership position. We need to give Minnesota Power the assurance that the path that they're following will result in having the line costs paid for. Manitoba Hydro has made that assurance, but we expect that we will be able to transfer that responsibility to another US transmission owner. In the meantime, the line can proceed. So we are there as an owner of last resort." (Tr. p. 1327, line 1).

Manitoba Hydro is in active discussions with a US transmission owner who is keenly interested in investing in Manitoba Hydro's share of the GNTL (Tr. 2295). If such negotiations are successful, the long term costs assumed in the economic analyses associated with plans involving the 750 could be significantly reduced.

In addition to reducing costs by divesting ownership, the Great Northern Transmission Line will provide benefits from increasing Manitoba Hydro's ability to sell to more customers in Wisconsin. Mr. Cormie states "we've doubled the size of our market by having market access into Wisconsin. That – that optionality – the value of that optionality is – is huge because it will benefit Manitoba Hydro forever". (Tr. p. 2428, line 11). The value of having increased competition as a result of expanded market access into Wisconsin has not been reflected in the export prices used in the NFAT economic analysis.

8.4 The Future Role of Seasonal Diversity Agreements

Seasonal diversity contracts play an important role in Manitoba Hydro's resource plan providing capacity during Manitoba's winter peak season, and justifying the preservation of firm transmission service for exports and imports. Seasonal diversity contracts have the effect of reducing the need for Manitoba Hydro to build for capacity in the winter, but in exchange they increase the need for capacity resources in the summer to meet the export customer's summer peak load. Manitoba Hydro has looked at both increasing the quantity of seasonal diversity arrangements as well as extending the term of seasonal diversity contracts out into the future.

As indicated in MH Exhibit #195, there is significant uncertainty in the future in the difference between Manitoba's seasonal load peaks especially given the potential impact of proposed DSM programs to reduce electrical heating load over the winter peak. As a result there may be only a limited opportunity for significantly more Seasonal Diversity contracts than the 550 MW already under contract with Northern States Power and Great River Energy.

Extending the term of the existing seasonal diversity contracts beyond their current termination dates would not defer the need for new resources in Manitoba. As indicated in MH Exhibit #195, Manitoba Hydro needs additional energy resources before it needs additional capacity, so assuming the seasonal diversity sales contracts could be extended is of limited value in deferring the timing of new generation. Mr. Cormie explained "because we are generally building for energy and capac -- our capacity lags behind, freeing up additional capacity would just -- would just defer the need to build for our capacity to an even later date. So because we're building for energy, you know, there -- there are reliability benefits, but we are building because of energy, not necessarily for capacity under the -- under the Hydro scenarios." (Tr. p. 1339, line 3).

For the purpose of long-term planning, Manitoba Hydro does not include an extension of diversity agreements in the supply and demand tables unless they are signed or are in negotiation related to a signed Term Sheet. This is because Manitoba Hydro has no indication whether counterparties will or will not extend these agreements.

In the future, Manitoba Hydro expects the seasonal diversity contracts to attract additional value and has considered extending them, but only as a part of a package of long-term firm power products that will be available from Conawapa and not just strictly as seasonal capacity exchanges. (Tr. p. 4731, line 14). By way of example, Mr. Cormie described discussions with Great River Energy regarding up to 600 megawatts of power and additional seasonal diversity power to meet their needs post-2025 and confirmed that these sales would be subject to Keeyask/Conawapa and the new interconnection" (Tr. p. 1313, line 3).

It was also suggested that because there was no capacity charge associated with the summer capacity sale that Manitoba Hydro was not receiving value from its capacity exchanges. When cross-examined, Drs. Patton and Sinclair of Potomac Economics confirmed that money did not have to be exchanged for there to be value in seasonal capacity exchange agreements (Tr. p. 4729, line 14).

8.5 Hypothetical Development Plans

A number of development plans have been identified by Manitoba Hydro as being hypothetical plans due either to a change in circumstances (Plans with a 250MW US Interconnection) or due to infeasible assumptions associated with the LCA No New Generation plan. In addition, the PUB explored the potential that Manitoba Hydro could proceed with additional DSM, the new interconnection, and defer Keeyask until a later date.[83]

8.5.1 Plans with a 250 MW US Interconnection

Manitoba Hydro presented three alternative development plans in Chapter 8 of the NFAT Business Case which include a US interconnection with 250MW of export and 50MW of import: Plan 4 (K19/Gas24/250MW), Plan 11 (K19/C31/250MW) and Plan 13 (K19/C25/250MW).

These plans with a 250 MW interconnection are now considered hypothetical from a business perspective and as such can no longer be considered as viable alternative development plans. From a business perspective, a 250 MW interconnection would require renegotiation with Minnesota Power which would not be expected to result in the same level of benefits to Manitoba Hydro given that the entire economic analysis is now in the public forum. Further, MP has taken the position in its October Certificate of Need filing (Section 7.4.2.1, page 77) that "such a project would not meet the long-term needs of the region and would not prove to be cost-effective for customers or environmentally preferable over the long-term." The 250 MW interconnection is not likely to be approved by US authorities and proceed.[84]

Further discussion on the reasons that the 250 MW interconnection is no longer a viable option can be found in Section 8.3.2.

8.5.2 LCA No New Generation Plan

La Capra has proposed a development plan that attempts to defer new generation for as long as possible. The development plan includes increased DSM and fuel switching, extending the existing diversity sales to 2047, a new 750 MW import line and relaxation of the import criteria to allow up to 20% of Manitoba Load to rely on import energy. (LCA Exhibit #45, Slide 29).

The LCA No New Generation plan is not feasible. This plan included "expanded transmission for import" (Tr. p. 5609, line 13). La Capra testified that "...we wanted to test to see what would happen if -- if you increased the import limits on this. For purposes of this

[83] TR page 9890-9891, 9894
[84] Manitoba Hydro Exhibit 104-15 (Revision 2)

analysis, basically the parameters of the 750 line – to Minnesota was – was that was represented in this case (Tr. p. 5609, lines 18-22).

Manitoba Hydro noted in its Rebuttal Evidence (page 93, lines 8-12) that an import-only line was not feasible from Minnesota referring to the Winthrop and Weinstine Report attached as Schedule 1 to MH Exhibit #85. Mr. Swanson states, "… multiple statutory, regulatory and other factors would almost certainly prevent the certification, construction or operation of such an Import Line. Further, the Minnesota Public Utilities Commission (MPUC) has already found that new transmission must be constructed to facilitate the export of power from Manitoba to Minnesota. In short, an Import Line has no viability and does not offer a reasonable alternative for meeting Manitoba's firm supply needs going forward."[85] The report confirms that including a transmission interconnection intended primarily for import is not a feasible as an element in a development plan for Manitoba Hydro.

In response, Mr. Peaco suggested that an import line from other neighbouring jurisdictions should have been considered in Manitoba Hydro's analysis. "…if you are really of the mindset, I'm going to build transmission for import, you would probably look to a different point than you would if you were building a transmission line for export." (Tr. p. 5630, line 1). On cross examination, Manitoba Hydro reviewed the supply situation in North Dakota, Saskatchewan and Ontario wherein Mr. Peaco conceded that these markets are short of energy and not in a surplus position capable of supplying Manitoba (Tr. p. 6210-6214).

Although building a transmission interconnection primarily for import is not a feasible supply option, the 750 MW interconnection assumed in Manitoba Hydro's development plans provides increased import capabilities. It appears that La Capra did not recognize that Manitoba Hydro's development plans with a new 750 MW interconnection were in fact benefitting from the 750 MW of import capability from the new interconnection. Although Mr. Peaco stated (Tr. p. 5596, line 9) "There was – there was nothing really in any of the fifteen (15) plans that looked at increased imports," he went on to acknowledge that Manitoba Hydro did in fact increase imports in plans with a new interconnection. Mr. Peaco noted "In the dry years, the Preferred Development Plan is importing and that was not something that we'd really sort of thought of before." (Tr. p. 5628, line 3). The benefits of increased imports from a new interconnection have been a fundamental driver of Manitoba Hydro's development plans as described in Chapter 5 of the NFAT Submission.

[85] MH Exhibit #85 - Schedule 1, pages 2-3.

8.5.3 Plan with 750MW US Interconnection and Export Sales with Keeyask Deferred

Board Counsel explored the notion that Manitoba Hydro could proceed with additional DSM and the new interconnection to fulfill the MP 250 Sale, and defer Keeyask until a later date.[86] This notion is not feasible and should not be considered. The 750 MW interconnection will not proceed without Keeyask. As explained by Mr. Cormie, "It has been clear since we began negotiations with Minnesota Power back in 2007 that there needed to be a package, a package of new generation associated with new transmission. And that's what is necessary in order to have the interconnection built."[87] As explained in MH Exhibit #201, Manitoba Hydro and Minnesota Power share the understanding that if construction of Keeyask does not commence by June 1, 2016, the Agreement will terminate and no interconnection will be built. The response also indicates that additional DSM would not be an acceptable alternative to Minnesota Power as increased DSM does not provide new wind synergy benefits associated with the construction of new hydraulic generation. The response also states that it is Manitoba Hydro's view that regulatory approval of Minnesota Power's Certificate of Need filing is at significant risk if Keeyask does not proceed.

8.6 Development Plan Optimization

La Capra criticized Manitoba Hydro's development plan optimization from two aspects: optimization of the all gas plan for comparison purposes and optimization of resource options within development plans.[88]

In Manitoba Hydro's response to PUB/MH I-171, an explanation of the process used to optimize natural gas-fired resources in development plans was provided. The All Gas plan, which consists of a mix of combined cycle and simple cycle gas turbines, was optimized using firm capacity and dependable energy to meet Manitoba Load and existing contracts, and selling opportunity energy on the export market. Manitoba Hydro maintains that the All Gas plan was optimal or near optimal, and suitable for use in analyzing development plans. As explained in Section 8.1 above, an all CCGT Plan was evaluated and was demonstrated to be more costly than the Manitoba Hydro optimized All Gas Plan.

With respect to the optimization of resource options within development plans, judgment and experience in operating and planning a predominantly hydro system, together with

[86] TR page 9890-9891, 9894
[87] Tr. p. 9892 Line 5
[88] La Capra Initial Expert Analysis Report, Page 6 and La Capra Technical Appendix 3A, pages 3A-23.

information from past planning studies and economic evaluations allows Manitoba Hydro to develop representative sets of development plans for inclusion in studies. It is not necessary to analyze every possible combination of generation resource options using every possible in service date to provide meaningful information to decision-makers.

La Capra states (Technical Appendix 3A, Page 3A-20), that Manitoba Hydro's "process lacks quantitative optimization that is typically used by utilities in resource planning. Internal or third party model software (such as Ventyx Strategist) offer resource planning tools that optimize resource build out given a set of inputs." Manitoba Hydro responded to this comment in its rebuttal evidence, where Dr. Borison states "there is few, if any, third party resource planning tools (including Strategist) that are capable of true automated optimization under uncertainty."[89]

Further to this, when asked by the Chairman "How do you optimize – how do you do that before proceeding with the quilt and so on?"[90] Mr. Peaco responds as follows:

> "Well you know, it-it-having said that – it is a challenge. I mean, the limitations with Hydro and doing this analysis of – are – are real, because their – their modeling system, their – their physical generating system is very complicated. Their modeling system is very complicated, and it is very difficult the – for them to turn around – to postulate cases and turn around analyses on those until you can have those.
>
> So they have – they're – they're situated in a case where they – they are only able to do a few postulated tests. You know, in more simple models where you can – you can hit "go" on a computer, and it can generate thousands of alternatives, and you can get data from that, and – and look at that in a more efficient time frame, and that really isn't practical for the – for the modeling system that they're currently working with.
>
> And so the – part of the commentary here is simply an observation, is they – they aren't really in a position to test a limited set of options."[91]

[89] Manitoba Hydro Exhibit 85 Schedule 3, Section 2.2.2.
[90] Transcript page 5648, line 6.
[91] Transcript pages 5648-5649.

Manitoba Hydro submits that it undertakes a focused level of optimization in its resource planning process and in the development plans that is appropriate for a meaningful and robust evaluation.

8.7 Manitoba Hydro Resource Planning is driven by Metrics

Manitoba Hydro has, in Chapter 8, Section 8.2 of the NFAT Business Case, detailed its process for establishing the development plans to be studied. CAC suggested in its closing submission that Manitoba Hydro perhaps "believes too deeply" in its plans. Mr. Wojczynski (Tr. p. 3696) addressed the notion that Hydro staff were "too invested" in the Preferred Development Plan. He testified that:

> "…people from Hydro, a lot of them, including myself, we're talking about engineers and accountants, … and MBAs, we're driven by metrics, customer reliability, security, our economics, the financial, the social benefit cost, metrics on environment and socioeconomic. We don't just do something because we happened to have been doing it in the past and want to carry on."

Mr. Wojczynski discussed examples where Hydro has indeed demonstrated that its decisions are made on the basis of objective criteria. Manitoba Hydro's direct evidence (MH Exhibit #129-7, Slide 11) includes a series of examples where, on account of changing circumstances, Manitoba Hydro has adjusted its decisions. These examples include the construction of Limestone which was commenced and then halted for over 10 years before it was built. Conawapa had previously been a committed project with PUB approval and signed contracts with Ontario and was subsequently cancelled. The Pointe du Bois powerhouse replacement project was cancelled and only the dam replaced when it became apparent that the economics did not support replacement of the powerhouse. Manitoba Hydro has also included combustion turbines and wind in its resources when it was economically feasible to do so. The GRE Diversity Exchange agreement has been extended, and DSM has been increased. Significantly, when new capital cost information became available in February, the PDP was taken back to the Manitoba Hydro Electric Board for their review and consideration as to whether Manitoba Hydro should continue to proceed with the Preferred Development Plan. These examples demonstrate Manitoba Hydro's ongoing commitment to making sound decisions based on the appropriate metrics, and suggestions to the contrary are unsupported by the evidence.

9.0 ENERGY PRICE FORECASTS

9.1 Electricity Export Price Forecast

9.1.1 Forecasting Methodology

Manitoba Hydro employs a consensus forecasting methodology whereby a number of independent experts are engaged to ensure that the corporation captures a broad range of perspectives on the future of electricity prices in the US upper Midwest.

The consultants are required to produce and justify their own assumptions independently to best represent the market as noted in the response to PUB/MH I-56a (lines 13-22). Manitoba Hydro does not provide direction to the consultants in their representation/modeling of the key input assumptions associated with their outlook of electricity prices.

The assumptions used by the consultants are based on the most up-to-date information available at the time the forecast is being prepared. The consultants apply their expert judgment to make reasonable assertions for inputs into their forecasting models. As the forecast is done on an annual basis, the consultants have the opportunity to continually update these assumptions as the market evolves and more clarity is gained on key issues such as domestic natural gas resources, coal retirements, carbon pricing and emission policies.

9.1.1.1 Consensus Forecasting is Appropriate

As described in Manitoba Hydro's Rebuttal Evidence (MH Exhibit #85 Section 8.1.2), consensus forecasting has been validated by a number of different economists, statisticians and other academics as a robust approach to reducing forecasting error over use of a single forecast.

From Manitoba Hydro's perspective, the consensus approach to forecasting, which aggregates a suite of independent market price forecasts, provides a number of benefits over using a single expert forecast. These benefits are outlined as follows:

- Ensures a wide range of future outlooks are considered, capturing both bearish and bullish views of future export price trajectories providing a more diverse set of perspectives of the future.
- Avoids utilizing a single view that may be overly optimistic or pessimistic relative to other market participants; using either extreme would result in a biased analysis.

- Dampens the effect of a significant change in a single consultant input assumption.

It should be noted that the use of consensus forecasting was acknowledged to be consistent with the approach used by other generators in North America by Potomac. (Tr. p. 4623, lines 6-14). Further, when questioned by the Chairman on what other approaches are employed (if not the use of outside experts), Dr. Sinclair was unable to cite any examples of alternative methodologies (Tr. p. 4624, lines 1-11).

9.1.1.2 Manitoba Hydro Uses Well-Established, Reputable Consulting Firms That Have Expertise in This Field

Manitoba Hydro's 2013 consensus forecast aggregated six independent price forecasts. The external price forecasting consulting firms Manitoba Hydro engages are recognized experts in their field who utilize sophisticated methodologies and software tools. This includes formal production costing models which simulate actual market dispatch characteristics and capacity expansion methodology that calculates the value of capacity price using a Net Cost of New Entry (Net Cone) analysis. All six external consultants used in the 2013 price forecast, are well-regarded, reputable, and highly active throughout North America in providing expert advice to the electricity industry on regulatory, financial and technical issues. Documents summarizing the demonstrated expertise of each of the 2013 price forecast consultants were provided in MH CSI Exhibit #16.

During their NFAT testimony, Potomac Economics agreed with the characterization that all six consultants used by Manitoba Hydro are well-established and reputable firms within the energy industry during their NFAT testimony (CSI Tr. p. 599, lines 12-15).

9.1.1.3 Adjustments Made By Manitoba Hydro in the Export Price Forecasting Process Are Appropriate

In the electricity export price forecasting process Manitoba Hydro makes adjustments to account for congestion and losses, to apply appropriate pricing premiums and to extend the forecast to the end of the detailed planning horizon.

<u>Accounting for Congestion and Losses</u>

Manitoba Hydro acknowledges the presence of transmission congestion between Northwest MISO and the rest of the MISO region. Manitoba Hydro's response to CAC/MH I-31 provides some context on the level of historical pricing divergence between the Minnesota hub and other major commercial hubs in the region. As noted in the response to CAC/MH I-32a, Manitoba Hydro accounts for congestion and losses by requiring external consultants provide a forecast for prices based at the Minnesota hub locational pricing node. This Minnesota hub price already captures congestion and losses between other Minnesota hubs and the MISO system. Potomac agreed with this description (Tr. p. 4588, line 25), and confirmed that Manitoba Hydro would only need to account for congestion and losses between the Minnesota Hub and the Manitoba border in adjusting its forecast (Tr. p. 4589, lines 8-11).

Manitoba Hydro documents the congestion and losses factor it applies to adjusted prices between the Minnesota hub and the border in Appendix E of the 2013 Electricity Export Price Forecast report as noted in the response to CAC/MH I - 75a. Neither Potomac nor La Capra noted it as an area of concern during the NFAT. Potomac's testimony (Tr. p. 4589, lines 17-20) acknowledges that Manitoba Hydro applies a factor for congestion and losses. La Capra comments in their report (Technical Appendix 6, page 6-69), with reference to Potomac's evidence on congestion, that "Potomac Economics has performed an analysis of future MISO congestion and losses. ... Potomac Economics' forecast of MISO prices is also done on an annual basis, and so does not provide a lot of insight into seasonal pattern changes, but its assumptions and methods do not seem inconsistent with MH's."

Initial concerns raised by Dr. Gotham in his report related to congestion and losses were satisfied based on his response to PUB/CAC-Gotham-1 "La Capra does indicate that MH did adjust for forecast congestion."

On-Peak Long-Term Dependable Price

Manitoba Hydro applies a [redacted] premium to the bundled On-Peak Energy & Capacity forecasts to produce an On-Peak Long-Term Dependable product price forecast. This Long-Term Dependable price is applied to bilateral on-peak (5 x 16) energy and capacity sales. The premium recognizes additional value such factors as price certainty, reliability and the virtually carbon-free attributes of the product provide to Manitoba Hydro's counterparties.

Support for the [redacted] premium is provided in Manitoba Hydro's CSI response to LCA/MH I- 433. In the response, contract revenues for long-term dependable export contracts are compared to forecasted values for the same product, inclusive of the [redacted] premium. The analysis indicates that for contracts signed since 2005, the average price negotiated for the On-Peak component of the sales are [redacted] of the Long Term Dependable forecast price, or [redacted].

This analysis supports the assumption that Manitoba Hydro can achieve a [redacted] premium, [redacted] on long-term dependable sales over the base market forecast. This has held true since 2005, a period encompassing both high and depressed energy price environments (i.e. pre and post 2008 economic downturn).

On-Peak Opportunity Revenue

Appendix 9.3 of the NFAT Submission outlines Manitoba Hydro's price forecast products. For those plans that have exportable hydro-electric dependable energy, this product is assumed to be sold under firm contract(s) at the On-Peak Long-Term Dependable Price. Other surplus dependable energy is assumed to be sold into the export market when it is economic to do so and is valued at the on-peak opportunity price or off-peak opportunity price.

As discussed in Manitoba Hydro's response to PUB/MH I-013c, surplus dependable energy other than hydro-electric energy is not assumed to be sold under firm contract(s) as Manitoba Hydro is at a competitive disadvantage when the same resources can be built in the MISO market due to transmission losses between Manitoba and major MISO load centers such as Minneapolis.

On-peak opportunity energy is assumed to be sold at the on-peak energy price [redacted]. This [redacted] pricing takes into account on-peak day ahead energy sales as well as accounting for the additional revenue realized through sales activities which take place within the one year time frame. Sales activities include firm energy and capacity sales, forward energy sales and other sources of revenue from the export market. Manitoba Hydro's response to LCA/MH II- 471b provides an analysis which supports the pricing of on-peak exports at the on-peak energy price [redacted].

Off-peak opportunity energy is assumed to be sold at the off-peak energy price.

Extrapolation Methodology

Section 1.5.1 of NFAT Appendix 9.3 (page 9) notes that external price forecast consultants normally produce a market forecast for a 20-year period. Starting with the 2013/14 forecast, Manitoba Hydro has established a process to extrapolate the consensus forecast beyond 20 years to the end of the 35 year detailed study timeframe. The extrapolation results in reducing the annual growth rate to 0% by 2047 in a linear fashion.

This extrapolation methodology produced lower than historical growth rates for the final 15 years of the forecast when compared to previous forecast vintages (when consultants provided a full 35 years of data). The applied extrapolation methodology therefore produces more conservative results as can be seen in Appendix A of the 2013 Electricity Export Price Forecast report (provided CSI).

In Section IV in their report[92], Potomac Economics did not take exception to this methodology, although they do surmise that running a 0%/year real escalation rate "sensitivity" might provide some additional insight.

During the NFAT hearing, Potomac did acknowledge that the growth rate Manitoba Hydro applies is "not a very large rate" and "it declines very quickly and is zero after that" (Tr. p. 4463, lines 12-14). As a result, this would lead to the conclusion that it likely would not have a major impact in the economic analysis. Further to the question of the appropriateness of Manitoba Hydro's calculation, Mr. Sinclair stated "... But we don't have a -- we don't -- we don't see that growth rate as being a particular problem as far as the impact on the overall analysis."[93]

Potomac admits that (Tr. p. 4592, lines 22-25) it is unlikely that a significant drop in the growth rate would occur in years immediately following the end of the 20 year forecast. Manitoba Hydro's methodology captures the drivers influencing growth at the end of the 20 year period, and thereafter reduces the annual growth rate quickly in the following years. As a result, Manitoba Hydro submits that its extrapolation methodology is reasonable and appropriate.

9.1.1.4 Potomac Improperly Dismissed Consultant Forecasts

Potomac notes that their access to consultant models', assumptions and inputs was limited. "At the outset, we note that detailed info regarding each of the consultants' models, assumption and output was limited. We generally only received high-level representations of the models and inputs. This limited our ability to critically review the consultants' results and ultimately compelled us to produce our own forecast"[94]. Manitoba Hydro notes that

[92] Potomac Economics Report – Section IV, page 45.
[93] Transcript page 4707.
[94] Potomac IEC report, page 10 – 2nd paragraph.

Potomac's scope of work explicitly required them to produce a comparable electricity and gas price forecast to compare against Manitoba Hydro's benchmarks[95]. Potomac's evidence in this regard was that they expected to be able to use more of the independent forecasters underlying assumptions and get an understanding of the underlying models and then from that develop a forecast. (Tr. p. 4557)

This expectation ignores the fact that price forecast consultant models and the underlying methodology is extremely proprietary and closely guarded as commercially sensitive information and corporate trade secrets. In fact even the output and content of the forecast reports are confidential and were only released in the PUB CSI process after written assurances that they would be subject to confidentiality agreements. It is an unrealistic expectation that Potomac Economics, who can be characterized as a market competitor to other energy analyst firms, would be granted open and unfettered access to rigorously review, assess and test the inner most details of the production costing models used by Manitoba Hydro's price forecast consultants. Potomac Economics agreed that due to the high value of these price forecast reports, the consultants have strong business motivation for wanting to protect their information (CSI Tr. p. 600, lines 16-21).

Potomac's Scope of Work required that Potomac assess Manitoba Hydro's export price forecast methodology as it related to the NFAT analysis. To support the Potomac analysis, Manitoba Hydro provided unfettered and complete access to the content of the price forecast consultants' forecast reports as well as Manitoba Hydro's own analysis files and full methodology utilized in producing its annual Electricity Export Price Forecast report. During the NFAT hearing Potomac did acknowledge that they believed Manitoba Hydro had turned over all internal documentation the corporation had in its possession related to the production of the export price forecast. (Tr. p. 4563 lines 1-11)

Potomac reviewed all of Manitoba Hydro's documentation and did not raise any objections to the methodologies employed by the corporation in the 2012 Adjusted and 2013 price forecasts. However, Potomac chose to summarily dismiss each of the six independent price forecast consultant reports used to produce the 2013 electricity price forecast, on the basis they did not find them to be credible because Potomac was unable to access the price forecast consultant models and the output of the those models. (Potomac Economics report, Section III-C)

Manitoba Hydro submits that it is not reasonable to dismiss the prices of the six independent

[95] Potomac Scope of Work - clause 12 states *"Provide a comparable natural gas price and MISO electricity market price history and forecast over 20/40/80 years."*.

industry experts, acknowledged by Potomac as well-established and reputable,[96] simply because they differ from Potomac's results. Potomac Economics itself acknowledged that the EIA input assumptions they relied upon to create the Potomac export price forecast were subject to this same uncertainty (Tr. p. 4566, lines 23-25 and Tr. p. 4567, lines 1-6). Long-term forecasting has an inherent level of uncertainty associated with it and no private or public entity has any special ability to predict the future.

9.1.1.5 Manitoba Hydro's Electricity Export Price Forecast Is Reasonable for Long-Term Planning

Manitoba Hydro's Electricity Export Price Forecast report provides a 35-year forecast of electricity prices in the upper Midwest region of the United States, a long forecast period relative to industry standards; however one that is necessary due to the long life of hydraulic generating facilities.

In Section 8.1.3 of Manitoba Hydro's Rebuttal Evidence (MH Exhibit #85), the Corporation provided evidence demonstrating that Potomac's price forecast is within the range of individual outlooks received from external price forecast consultants in 2013, although it was acknowledged that Potomac's forecast is somewhat [redacted] than the average view considered. Manitoba Hydro considers Potomac's price forecast to be another reasonable view of the future, however it is just one single view, and as such it should be provided no more or less weight than other independent outlooks considered by Manitoba Hydro.

Manitoba Hydro recognizes that there is uncertainty in the long-term forecasting of any economic variable or commodity and further that forecasting these variables is complex, largely due to the sheer number of assumptions involved. Manitoba Hydro also recognizes that, among experts, there is generally no ability for one expert to predict the future better than another. Potomac Economics acknowledged this (Tr. p. 4579, lines 16-18) when Mr. Sinclair stated "I mean, there's better experts than others, but there can be legitimate disagreements about how to proceed".

9.1.2 Contract Prices Support Manitoba Hydro's Electricity Export Price Forecast

There have been a number of long-term bilateral contracts signed recently between Manitoba Hydro and US counterparties that can be used to gain insight into the reasonableness of the Electricity Export Price forecast. These signed contracts represent agreements between

[96] CSI Transcript Page 599, lines 12-15.

sophisticated market participants agreeing on a set price for energy and capacity resources to be delivered during the horizon of the price forecast. If Manitoba Hydro's price forecast was [redacted], it would be very unlikely that agreements would be reached with US counterparties. However, if these contract prices are favourable, it should be a strong indication that the Corporation's price forecast is reasonable [redacted].

The chart below was provided in Manitoba Hydro's direct evidence – CSI Exhibit #1. It compares a number of relevant pricing points to determine how current market expectations relate to Manitoba Hydro's and Potomac's 2013 price forecasts:

- The Potomac's Reference Case <u>(with carbon)</u> price forecast for an On-Peak bundled energy & capacity product
- Manitoba Hydro's price forecast for its Long-Term Dependable product (On-Peak energy & capacity product + [redacted] premium)
- Recent long term firm sales signed by Manitoba Hydro

[redacted]

The chart above demonstrates that the recently signed contracts [redacted] Manitoba Hydro's long-term dependable price forecast, providing confidence that Manitoba Hydro's electricity export price forecast is reasonable [redacted] for the purpose of long-term resource planning.

These contracts compare [redacted] to Potomac's Reference Case price forecast. It should be noted this is Potomac's Reference Case forecast with the full value of MNP's carbon price, not a weighted probability of the two reference cases (carbon and no carbon). Using a weighted average of Potomac's two Reference Cases would show an [redacted] between realized contract prices and Potomac's forecast.

This demonstrates the reasonableness of Manitoba Hydro's electricity export price forecasts for long-term planning and casts doubt on Potomac's assessment that the consultant prices and Manitoba Hydro's forecast [redacted]. Although this analysis does not speak to the eventual accuracy of either the Manitoba Hydro or Potomac forecasts, it does provide confidence that Manitoba Hydro is [redacted] in its outlook of future electricity export prices.

9.1.3 MISO Prices Will Increase under Low Load Growth

The question of the impact of a reduction in load growth on electricity prices in the MISO market was raised during the NFAT hearings by Elanchus' Mr. Todd. The essence of Mr. Todd's evidence is that conventional economic theory would suggest that, all other factors being equal, a reduction in load growth would put downward pressure on electricity prices. (Tr. p. 4926, lines 19-23). Mr. Todd also notes that without modeling the effect, it is impossible to quantify the impact of assuming load growth in MISO is flat.

All six of the expert industry market consultants used by Manitoba Hydro in the preparation of the electricity export price forecast incorporated small positive load growth in the 2013 price forecast. Potomac Economics relied on annual load growth figures from the EIA's 2013 Annual Energy Outlook (Potomac Report, Section II – 5a). EIA outlooks for annual load growth for the Midwest US are also around 0.5%/year. The effect of projected annual load growth estimates are captured in the export price forecasts provided by the price forecast consultants used by Manitoba Hydro, Potomac Economics and in the EIA's retail electricity price forecast. While the annual load growth figures are relatively small, all of these entities expect consistent real price growth over the next twenty years.

Dr. Dean Murphy from the Brattle Group explained the relative impacts of load growth assumptions during the NFAT hearing (Tr. p. 1407-1409).

> "So I'll turn the page, and talk briefly about a couple of other factors that are, I think, a little less important than fuel costs and a potential CO2 price, and even coal plant retirements, but – but not unimportant. The first of these is load growth, and here I mean load growth in MISO. Growth has been quite low in the last five (5) to ten (10) years, particularly in the last five (5) years after the -- the recession. Load actually fell considerably, you know, around 2008, 2009, but the expectations are that we're not going to rebound to a 3 percent load growth rate, which we saw as of a few decades ago, but rather that load growth will continue on this very low -- at this low level of maybe 0.7 percent, less than 1 percent, or -- or maybe as much as 1 percent. And, so one of the reasons that I -- that I say that load growth is a less important factor for determining power prices in MISO is simply because it's not very uncertain. There's a general agreement that load growth will be low. Perhaps disagreement about whether it'll be 0.7 percent or 1.0 percent, but in the end, that makes very little difference to the supply/demand balance, and to energy prices.
>
> And so simply because there's relatively little uncertainty in load growth, I would -- I would argue that it will not make a big difference in power prices in MISO. It is swamped by other effects. In particular, coal plant retirements, because the – the coal plant retirements are -- if -- if MISO is right and they expect 12,000 megawatts of coal retirements, the difference between a 0.7 and a 1 percent load growth is three-tenths (3/10s) of a percent, so that's -- that's less than 1,000 megawatts of load growth. In fact, it might be a few hundred megawatts of load growth relative to thousands of megawatts of adjustment on the supply side. So -- so I don't think it's a – a terribly large effect."

As noted by Dr. Murphy, the supply side pressures in the medium term (which include US Environmental Protection Agency's emerging GHG regulations for coal and expiration of nuclear licences in the 2030's) (Tr. p. 1405, lines 12-20) effectively require new generation supply in MISO to meet load obligations, even under the assumption of very low or flat load growth. In addition, the evidence from the Brattle Group suggests that because of the characteristics of MISO's supply curve, changes in load growth assumptions are not a primary driver of power prices.[97]

[97] NFAT Appendix 5.3, page 66.

The muted impact of MISO load growth assumptions on long-term electricity prices is also explicitly addressed by the Brattle Group in other documents provided as evidence during the NFAT process.[98]

9.1.3.1 Interrelationship of Supply Side Resources and Load Growth

As described in Appendix 5.2 of the NFAT submission, under a competitive market structure, the absolute level of electric load determines which units are dispatched in any specific hour. The electric load in effect determines what resources "clear" an energy auction and the prices that are paid to the generators being run to serve that load. To model future prices, assumptions of the change in regional load must be made, along with a number of other assumptions that will affect the generation supply stack for the region. Examples are provided in Appendix 5.2 of the NFAT submission and in the Potomac Economics' report, Section II. B. 3 Formation of Supply Curves, which illustrate how energy prices are affected by both supply and demand.

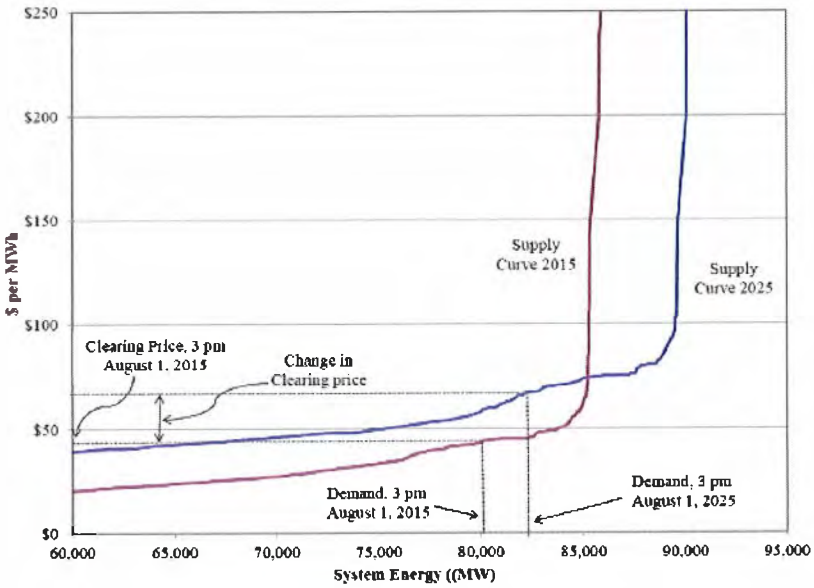
Due to the interrelationship of these factors, the impact of load growth must be thought of from a more holistic perspective in the context of other factors that affect price. In Section II: B - 3 of their report, Potomac Economics provides a useful summary of these key factors in their discussion of the creation of future supply curves.

> "If all key supply variable remain fixed, then the forecast of each future hour would be identical to the base historical hours from 2011-2012. However, of course, key variables change. In particular, we create new supply curves for each hour based on projections of (1) fuel prices, (2) additional and retirements of generating capacity; (3) load growth; and (4) carbon taxes."

These factors are considered in Figure 10 in Section II: B – 3 of Potomac Economics' report (provided below) which illustrates two anticipated supply curves, one for the year 2015 (red line) and the second for year 2025 (blue line). The change in supply curves in Figure 10 provides an illustrative tool as the effect electric load has on price is disaggregated from the other factors noted above.

98 Slide 52 in NFAT Appendix 3.1 (Long-Term Price Forecast for Manitoba Hydro's Export Region), Slide 72 of Manitoba Hydro's Panel 2 Direct Evidence Presentation, and Slide 66 of NFAT Appendix 5.3 (Electricity Market Overview for Manitoba Hydro's Export Market in MISO).

Figure 10: Example of Change in Supply Curve



Note: The figure shows the change in forecast clearing price in our model resulting from changes in supply and demand between 2015 and 2025.

In Potomac's Figure 10, demand is increased slightly from 80,000 MW in 2015 to around 82,000 MW in 2025 to account for load growth in a particular hour. As a result, price increases from approximately $45/MWh (relative to the red line) to approximately $70/MWh (relative to the blue line). Using an assumption that load growth was flat over that period (i.e. load remains at 80,000 MW in 2025), the chart illustrates that the market clearing price would still be higher than it was in 2015 due to factors other than load growth. At a demand of 80,000 MW the market clearing price in 2025 would be about $60/MWh under a flat load growth assumption. This is a markedly higher price than the (approximately) $45/MWh the market would clear at in 2015 under the same demand assumption.

This example illustrates that load (and subsequently load growth) can influence price; however, with MISO's relatively flat supply curve other factors can become the dominant influence on price. Even in a situation with no load growth and using Potomac Economics' Figure 10, prices would be expected to increase by over 30% by 2025 strictly due to non-load effects. The conclusion that load growth has a minor effect on price was also reached by the Brattle Group through their extensive modeling of the region.

9.1.3.2 Coal Retirements in MISO Relative to Expected Load Growth

As noted in the NFAT filing, MISO expects 12 GW of coal to be retired in the near term (i.e. by 2020) due to a confluence of emerging EPA regulations on mercury and due to moderate natural gas prices. These retirements represent almost 20% of MISO's total coal generating fleet. The effect of three separate load growth assumptions on coal retirements is presented in the table below.

	Cumulative GW by 2020	Net New Supply Needed due to Coal Retirements & Load Growth (GW)
MISO Coal Retirements	12	
Cumulative Load Growth (2014-2020)*		
1%/year	7	19
0.35%/year	3	15
0%/year	0	12

**% annual load growth is based on the base resource of 120 GW year used for illustrative purposes*

The table demonstrates that even under a 1%/year load growth estimate, coal retirements would still represent about two-thirds (12 GW of 19 GW) of the supply shortfall between now and 2020. This analysis does not capture other supply side retirements of other technologies such as oil and natural gas (end of life units). Although these technology retirements (to 2020) are not expected to be significant, they will add to the supply deficit for the region.

When considering nuclear generation, most potential retirements are not expected until the 2030 timeframe when extended licences are set to expire. When nuclear retirements do occur, they have a significant impact due to the large size of the generating units. Although load growth assumptions are an important input required to estimate the long-term electricity price for the MISO region, the impact of load growth in determining prices in relative terms is less important than key drivers such as fossil fuel prices, carbon pricing and expected changes to the generation fleet.

9.2 Carbon Pricing (MDB inserted May 19)

9.2.1 Carbon Price Assumptions are Reasonable

The carbon price assumptions embedded in the electricity price forecast are reasonable and prudent because they are:

- Consistent with climate change science and emerging policies
- Based on a sound consensus methodology
- Reflective of a comprehensive range of outcomes,
- Conservative

Future carbon pricing represents an important factor in the market price of electricity. While the timing and magnitude of policy responses are uncertain, there are broad expectations that the US electricity sector will experience carbon pricing within the next 10 years as climate or environmental policies evolve to address the physical realities of climate change (MH Exhibit #95, p.68). This view is supported by Dr. Murphy from The Brattle Group, "I expect that there will be a carbon price at some point in the future. I can't tell you exactly when that will happen. The --the inconvenient truth is that CO2 emissions do contribute to -- to climate change, and the planet will continue to remind us of that over time." (Tr. p. 1809, lines 11-16).

As detailed in Section 16 of this document, greenhouse gas (GHG) emissions are facing increasing constraints through federal regulations and state legislation in the United States. These policies will increase the demand for low and non-emitting resources and in many instances will deliver increasing market prices that will provide an incentive for these types of resources.

Environmental factors including carbon pricing policies are among many factors considered in developing the consensus electricity export price forecast. While the price forecast consultants provide the carbon values that have been assumed for each scenario, the consultants rely on their own perspective of the future to determine what, if any value for carbon will be included in their price forecast. In fact [redacted] six consultants in the 2013 electricity price forecast have a [redacted] for carbon in their reference case through the forecast horizon (MH CSI Exhibit #1, p. 14). The consensus approach results in forecasts that leverage the expertise and diversity of leading forecasters and moderates results by blending the perspectives equally.

There is a broad range of potential carbon pricing and climate policy outcomes. For example Brattle considered six CO2 price / climate policy scenarios in its electricity market price analysis (***Appendix 3.1 – Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group***, Page 40). For Manitoba Hydro's Electricity Export Price Forecast, Brattle narrowed the range to three carbon pricing scenarios: low (no carbon pricing), base and high.

Reducing carbon pricing to a 50/50 split as discussed by MNP (Tr. p. 5469, lines 3-9) is an inappropriate oversimplification. A similar argument was presented by Dr. Gotham, saying of carbon pricing "It's on or off. It will happen or it doesn't happen" (Tr. p. 8562, lines 8-9). Future carbon policy is not a binary all or nothing situation but rather a continuum of potential outcomes all of which could have a variety of direct or indirect carbon pricing implications. The outcomes range from no climate policies or action, to a variety of non-pricing policy options to an array of pricing policy options and pathways (see MH Exhibit #95, p. 67). However given the policies that have been implemented in a number jurisdictions and which are under consideration elsewhere and the regulatory approach being aggressively pursued by the Obama administration, the potential for there to be absolutely no further climate change policies affecting electricity market prices is unlikely. [redacted] (including Brattle) in the 2013 electricity price forecast assume [redacted] in their reference case (MH CSI Exhibit #1, p. 14).

Dr. Gotham's carbon price views appear to be influenced by the political position of the former governor of Indiana (Page 8436, lines 9-15). Dr. Gotham offered an interpretation of carbon pricing "I think that the likelihood of the Midwest region imposing their own carbon restrictions is very small." (Page 8436, lines 3-5). However, it should be noted that in its Indiana applications Duke Energy includes a carbon price in its planning assumptions (MNP CSI Undertaking 30). While Dr. Gotham's view may or may not accurately reflect Indiana's current outlook, his view is not indicative of the whole Midwest region. In Minnesota, regulatory costs of carbon are expected. Minnesota requires utilities to include future cost of carbon regulations in the range of $9 to $34 per ton of carbon emitted in utility resource plans (MNP CSI Undertaking 30).

Even though it is unlikely that there will be absolutely no further climate change policies affecting electricity market prices, this possibility is fully considered by the electricity price forecasters in the 2013 low electricity export price forecast where all of the consultants assumed no carbon pricing.

As demonstrated in CSI MH Exhibit #1 the carbon pricing assumed in the reference case of the Manitoba Hydro export price forecast is [redacted] to the MNP's Reference Forecast. It is also [redacted] to the range of carbon price risks Minnesota generators are required to consider as described above. In the long run MH's consensus of carbon pricing assumed in the consensus export price forecast is [redacted] of MNP's reference case, (MNP CSI Undertaking #30, line 33). [redacted]

There would likely be [redacted] in the economic outcome between Manitoba Hydro's [redacted] and a 50/50 split between MNP's [redacted] base carbon pricing scenario and a no carbon price scenario. During the course of the NFAT, MNP and Manitoba Hydro came to a better understanding of each other's risk management approaches in dealing with carbon pricing assumptions. In its recent undertaking MNP concludes that MH's approach is analytically reasonable and acceptable and provides conservative results. (MNP CSI Undertaking #29.)

Even the highest carbon price forecasts considered during these proceedings are modest relative to the estimates of global carbon damages. MH Exhibit #185, p. 3 compares the assumed social cost of carbon with the carbon price forecasts prepared by MNP. As discussed in Section 18, for the range of policies under consideration today, a very significant portion of the total social cost of carbon is expected to remain an economic externality. Pressure over time will tend to push for stronger policies and this represents a significant additional upside opportunity for the development plans with more hydro development and high exports and a further downside risk for development plans reliant on natural gas generation. MNP indicates that carbon prices are expected to continue to grow past 2048 and it is not likely that prices will experience zero real growth at any point in the future. (MNP CSI Undertaking #29, lines 9-14)

In light of the existing and emerging energy policies, Manitoba Hydro's export customers are choosing or exploring the purchase of hydroelectricity in part as a hedge against future GHG emission constraints and to achieve future pricing certainty. Utilities in the US Midwest are aware that a strong reliance on emission intensive generation will likely be a future competitive disadvantage. Therefore corporate mandates have been adjusted to reduce their emission profile and in turn their carbon risk. Minnesota Power's Energy Forward strategy is an example of this shift in strategy (NFAT Chapter 6, page 15) from a coal dominated supply mix, to a diversified portfolio incorporating significant quantity of carbon free electricity. The potential of future carbon pricing in the electricity sector has already substantially affected the industry's approach to long-range planning, risk mitigation and strategic direction.

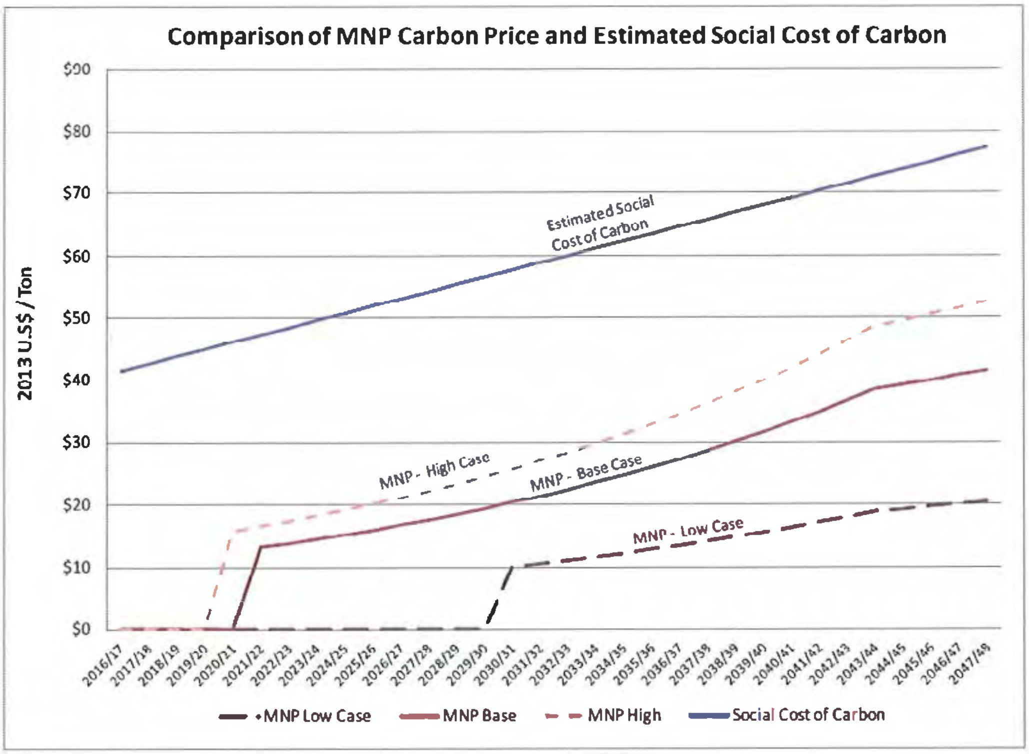
With Minnesota counterparties considering in their planning and decisions the potential cost of carbon, the value they are able to pay relative to other thermal resource options increases. [redacted]

[redacted] This indicates that these counterparties are willing to pay [redacted] Manitoba Hydro's reference electricity price that includes carbon pricing. This is also true for WPS even though Wisconsin doesn't have a formal state mandate to consider a carbon price.

9.2.2 Conclusion

The carbon price assumptions embedded in the electricity price forecast are reasonable and prudent. These assumptions are consistent with climate change science and emerging policies. They are based on a sound consensus based methodology that utilizes diverse independent expertise. The forecasts recognize a continuum of possible climate change policy outcomes and a range of implied or direct carbon prices (including the possibility of a zero carbon price). [redacted]. In the long term, consideration of externality costs associated with climate change damages may push policies and carbon market prices higher than current scenarios indicate offering additional potential export price benefits.

[redacted].



Source: MH Exhibit #185, page 3.

9.3 North American Natural Gas Price Uncertainty

Throughout these proceedings, there has been considerable focus on the risks associated with wholesale electricity prices, but little discussion of the risks related to natural gas prices. Dr. Murphy made reference to the speed in the turnaround from a gas-constrained future to one where gas is seen as abundant enough that LNG facilities that were originally built for importing LNG are now being converted for export (Tr. p. 1399-1400). Despite the abundance of technically recoverable natural gas resources in North America, prospects for future production from shale resources continue to be uncertain due to the lack of production history from many of the formations (Tr. p. 3695, lines 6-13). While future technology could increase well productivity and reduce the cost of production (this has been evident since the onset of the shale gas revolution), innovations could become stifled if local and/or national environmental concerns regarding fracking-related chemical use, seismic activity, and emissions become more widespread (Tr. p. 5169, lines 6-13).

The final end-use of this future production is also uncertain, particularly in some sectors. Residential and commercial consumption of natural gas are generally expected to remain flat due to end-use efficiency gains. Natural gas consumption in the electricity generation sector is expected to continue to increase as coal-fired power plants are either retrofitted or retired in order to comply with the requirements of the Mercury and Air Toxics Standards (MATS) (Tr. p. 1398-1399). Future regulation of carbon emissions has the potential to further increase the consumption of natural gas in this sector as well. The US industrial sector is experiencing significant increases in natural gas consumption as expansion in the chemicals industry continues.

There is a vast but uncertain potential for demand for natural gas in the transportation (Tr. p. 10205, lines 3-4) and LNG export sectors. Demand in the transportation sector is particularly difficult to predict because they are dependent not only on the future price of natural gas, but on the inter-relationship between the price of natural gas and the price of crude oil. If the large disparity between prices of the two commodities continues, the economics of conversion from oil-based fuels remains very attractive, particularly in the heavy-duty vehicle and railway sub-sectors.

Similarly, the potential for significant LNG exports is dependent upon the price differential between the North American market and export markets being large enough and sufficiently stable to justify the investment in export facilities (Tr. p. 1399-1400). There are also further complications regarding the approval of facilities to allow the export of a resource that some see as providing a key input for an industrial renaissance in the United States.

Like other commodities, there is fundamental uncertainty and volatility as to what the evolving equilibrium price will be in the natural gas market. Credible consideration of natural gas generation needs to account for the fact that there is risk uncertainty associated with natural gas prices.

10.0 ECONOMIC ANALYSIS

In the NFAT Business Case, Manitoba Hydro provided three major sets of analyses: economic, financial and multiple account. The economic analysis determines the investment value over the life of the longest lived assets and is integral to resource decisions. When evaluating and choosing among alternative development plans, the appropriate measure is the net present value or NPV of the incremental costs and benefits associated with one plan relative to another.

Manitoba Hydro has conducted a high quality economic uncertainty analysis that is fundamentally sound. Manitoba Hydro prepared the analysis for the NFAT business case with the guidance and support of Navigant Consulting, Inc. Dr. Adam Borison[99] of Navigant assisted Manitoba Hydro in developing its probabilistic analysis approach to evaluating the uncertainty associated with the development plans included in the NFAT submission.

As described in Dr. Borison's evidence[100], there are three major steps in uncertainty analysis:

- Formulation – deciding on the elements of the uncertainty analysis and their relationships
- Inputs – collecting and processing the data that goes into the uncertainty analysis
- Outputs – generating and interpreting the results that come out of the uncertainty analysis.

Manitoba Hydro's approach to all three of these steps is fundamentally sound and follows well-established analytical principles and relevant empirical evidence. It is in many ways "state-of-the-art" in utility resource planning. The high quality of this work should provide the panel with confidence that conclusions based on this analysis are on solid ground.

Sufficient economic analysis has been provided from the overall project perspective through the economic evaluations provided by Manitoba Hydro in Chapters 9, 10 and 12 of the NFAT submission and subsequently in Manitoba Hydro exhibits, particularly MH Exhibits #95, #104, #129-7 and #171. Economic analysis information is one of the primary building blocks for the financial, multiple account and optionality/pathways analyses.

[99] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, p. 4.; Dr. Borison is an expert in decision analysis, economic and financial analysis, real options, optimization, risk analysis and related methods and has more than 25 years of consulting experience applying uncertainty analysis methods to investments and operations in electric power, oil/gas and biofuels.

[100] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, page 6.

10.1 NFAT Analysis is Robust

The robustness of Manitoba Hydro's analysis is demonstrated through the provision of the major sets of analyses: economic, financial, multiple account, and optionality/pathways. This robustness is supported by MIPUG in Mr. Bowman's pre-filed testimony where he stated with respect to Manitoba Hydro's approach to analysis that the approach "is comprehensive, reasonable and more thorough than typically found in utility resource plan assessments."[101]

The economic analysis determines the investment value over the life of the longest lived assets. The financial evaluation focuses on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk. Affordability and the temporal distribution of costs and benefits are also addressed in the financial analysis. The multiple account benefit cost analysis takes into consideration consequences for Manitobans that are not reflected in the revenues and expenditures of Manitoba Hydro and provides a comprehensive assessment of all the benefits and costs to Manitobans to address the question of overall socio-economic benefit. The pathways analysis uses the economic evaluations as its basis and assesses the flexibility of options to allow for a change in course based on future conditions. The use of pathways recognizes the reality of allowing decisions to be made incrementally as uncertainties resolve.

La Capra criticized Manitoba Hydro for not providing numerous metrics in its economic analysis.[102] The metrics suggested by La Capra are only appropriate when undertaking financial analysis.[103] Despite the fact that Manitoba Hydro provided additional metrics in its financial analysis that reflect the timing of costs and benefits and the associated risks, La Capra paid no regard to this analysis and instead attempted to do this work through economic analysis using inappropriate metrics in its Appendices 9A and 9B.

Manitoba Hydro presented the sets of analyses – economic, financial, multiple account, and optionality/pathways – in separate chapters of the NFAT submission in order to compartmentalize the analysis to assist in the comprehension and utility of the discrete metrics that each of the sets of analyses provides. When all the analyses are taken together, the NFAT analysis is robust.

[101] Mr. Bowman's Pre-filed Testimony; pages 3-14.
[102] La Capra, Technical Appendix 9A, pages 9A-21.
[103] La Capra, Technical Appendix 9A, pages 9A-22.

10.2 Economic Analysis Assumptions and Methodology are Appropriate

As described in Chapter 9 of the NFAT Business Case, economic comparisons of alternatives are used to assist in making decisions regarding which resources to pursue and when. When evaluating and choosing among alternative development plans, the appropriate measure is the NPV of the incremental costs and benefits associated with one plan relative to another. The economic analysis determines the investment value over the life of the longest lived assets, while the financial evaluation provides the affordability and the temporal distribution of costs and benefits as well as the corporate financial indicators.

Manitoba Hydro uses standard economic analysis for project evaluation, known as NPV as explained in Chapter 9 NFAT Business Case[104]. This approach is supported by CACs witness Mr. Bill Harper[105] as well as by La Capra who commented "Present value analysis is a common approach for economic analysis of an investment in which annual costs and revenues are discounted to a common point in time or an equivalent comparative analysis."[106]

Incremental analysis is a relative perspective where the focus is on the differences between development plans rather than the absolute value of the costs and benefits of each development plan. As a result, it is more important for the incremental differences between the plans to reflect the components of the plans. For example, applying appropriate annual real escalation rates in the analysis to the capital costs of the different resource options of wind (0%), hydro (0.6%) and natural gas (0.5%), results in a meaningful comparison between plans that include these resource options, as described in Appendix 9.3 of the NFAT submission.

In La Capra's Economic Analysis Technical Appendix 9A, pages 9A-22 and 9A-49, are examples where the purpose of the economic analysis has been confused with that of the financial analysis. The following table provides a comparison of the major attributes related to economic and financial evaluations.

[104] NFAT Business Case Chapter 9, pages 4-5.
[105] CAC Harper Econalysis, page 15.
[106] La Capra, Technical Appendix 9A, pages 9A-15.

	Economic Evaluations (standard benefit/cost methodology)	Financial Evaluations
Type of Costing	Incremental, only those costs/revenues that would be incurred if the project proceeded	All relevant costs/revenues including reallocated and overhead costs and sunk costs
Operations	Project only or project with considerations of how other operations may be affected	Total financial operations of the corporation
Measurement	Net Present Value benefit to Manitoba Hydro (domestic customers and project partners)	Rate increases & consumers revenue for domestic customers, effect on financial targets
Price Levels	Constant currencies with real escalation, ignoring general inflation (real $)	Nominal currency with real escalation & inflation (current $)
Financing	Specific funding requirements not relevant; reflected in the discounting of cash flows	Project funding, interest payments, debt repayments explicitly included in costs and revenue requirements
Depreciation	Depreciation not directly applicable. Residual Value calculated for project life longer than 35 year study period	Depreciation used. Residual value not needed as project cost calculated annually

10.2.1 Use of 78-Year Total Study Life is Appropriate

As stated in Appendix 9.3 of the NFAT submission, the total study life used in the economic analysis is 78 years. To reflect this total study life, Manitoba Hydro combined two approaches - a 35 year detailed evaluation and a long-life asset evaluation which extends from the end of the 35 year study period to the end of the 67 year service life of hydro-electric generation assets as representing the longest lived assets. The 78 years reflects the in-service dates of new hydro-electric generation will occur in approximately 2025.

The appropriate primary metric in economic analysis that reflects the total study life is NPV. La Capra's Mr. Peaco acknowledged the importance of this metric stating that "-- the net present value over -- over the life of the investment asset clearly is an important metric, and we've -- we -- we would routinely do that as a matter of course anyway."[107] In addition, MPA agreed that the calculation of a 78 year NPV represents both a detailed study period and a residual or terminal value.[108]

Whitfield Russell Associates however argued that a shorter time frame should have been used.[109] In addition, La Capra, while acknowledging the superior total study life analysis, suggested shorter timeframe analysis could have complemented the 78 year NPV analysis.[110] In particular, Mr. Athas says, "We've actually said many times that they [20-year to 50-year NPV's] complement the information of the seventy-eight (78) year NPV"[111] and, "NPV is always an important measure. Most of these other measures. . . you probably wouldn't want to use without having – being aware of what the NPV is."[112] Mr. Bowman on behalf of MIPUG indicated that although a coarse tool, he would have liked to have seen NPVs calculated over a horizon that is shorter than the full forecast scenarios.[113]

While it is certainly true that shorter-term metrics may be helpful and insightful, there is little justification for shorter-term NPV as a metric in economic analysis. Rather, because financial analysis inherently provides short term metrics, it is more appropriate for this purpose.

In order to compare alternatives on an "apples to apples" basis, it is important that the time frame of the economic analysis extend to the end of the useful life of the longest-lived assets under consideration. In this context, these assets are hydroelectric and transmission facilities and the 78-year time frame reflects their useful life. Any analysis with a substantially shorter time frame, without significant terminal value, attributes insufficient value to these assets. As Dr. Borison points out in his report[114], the effect of adopting this approach is to assume that the long-term future is known with certainty and all assets are known to have zero value in that future. This position is inconsistent with the expectation that these assets will have value in the long-term.

As a result, metrics which ignore residual or terminal value are of little value in an economic analysis. La Capra provided a number of such metrics which ignore residual or terminal value, the cumulative present value or CPV metric is one such metric. La Capra describes the

[107] Transcript, Peaco, page 5583, lines 13-17.
[108] Transcript, MPA, page 7271, lines 13-16 and p. 7536, lines 14-24.
[109] Direct Evidence, WRA, Slide 5.
[110] Transcript pages 6094-6097.
[111] Transcript page 6096, lines 1-3.
[112] Transcript page 6398, lines 5-8.
[113] Mr. Bowman's Pre-filed Testimony, page B-3.
[114] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, pages 9-10.

CPV metric as one that provides "valuable information to decision makers"[115] and that can be "especially useful in reviewing risk, since the risk profile of different development plans can vary greatly over time"[116]. In testimony, Mr. Peaco confirmed that the residual value of the capital stock is not included in the CPV metric used in La Capra's economic analysis.[117] Mr. Peaco also confirmed Dr. Grant's understanding that,

> "... both the breakeven column and the CPV columns are really just saying that the Keeyask/Conawapa based projects are more capital intensive, and so there's large capital outlays initially. So you're not going - - they're going to show up as negative CPV..."[118]

Effectively, the CPV analysis favours investments in resources with shorter lives such as natural gas and wind generation as it attributes insufficient value to the long-lived resources such as hydro. Manitoba Hydro submits that the CPV analysis provided by La Capra in their initial and supplemental Appendices 9A and 9B is not an approach that should be used for decision making.

La Capra states its preference for anything more involved such as development plan comparisons to be done with a revenue requirements analysis.[119] However, it is the financial analysis, not the economic analysis, that encompasses the revenue requirements analysis. In financial analysis, shorter timeframes and the temporal distribution of costs and benefits are appropriately addressed and that is why Manitoba Hydro dealt with these factors in Chapter 11 of the NFAT submission and its Financial Analysis panel of witnesses. The financial analysis provides the decision-maker information on a year by year basis and on a cumulative basis for a range of critical metrics, including rates and financial targets such as debt/equity and interest coverage, all of which are based on the utility's revenue requirement.

10.2.2 Use of NPV as the Primary Metric is Appropriate

Manitoba Hydro chose NPV as the primary metric for its economic analysis. The economic analysis was designed to show the economic impact of each alternative, and NPV is the "gold standard" in such an analysis as Dr. Borison indicated in his report[120] and testimony[121]. A

[115] La Capra Technical Appendix 9A, pages 9A-68.
[116] La Capra Technical Appendix 9A, pages 9A-68.
[117] Transcript, Peaco, p. 5592, lines 8-11.
[118] Transcript, Peaco, p. 5592, lines 15-19.
[119] La Capra, Technical Appendix 9A, pages 9A-17.
[120] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, page 11.
[121] Transcript, Borison, pages 1377-8.

quote from finance experts Ross, Westerfield and Jaffe[122] included in Dr. Borison's report is instructive:

"While we found that the alternatives [payback period, discounted payback period, accounting rate of return, IRR, and profitability index] have some redeeming qualities, when all is said and done, they are not the NPV rule; for those of us in finance, that makes them decidedly second-rate…"

This position is supported by Dr. Harper in his testimony[123].

> MR. BOB PETERS: As between the internal rate of return and an expected value calculated on an NPV basis, which is the preferred metric?
>
> MR. WILLIAM HARPER: …since I prefer the net present value analysis, …it would be the expected value…that would be the preferred of the two (2)…

Metrics other than NPV may be helpful and insightful in particular contexts, but they must be used with care in a resource planning context. As Dr. Borison described in his testimony[124], if one had to choose between two investments, a $1,000,000 investment that makes $500,000 (a 50% IRR) or a $1 investment that makes $2 (a 200% IRR), IRR would lead to choosing the $2 gain over the $500,000 gain. On the other hand, NPV would make you richer by $499,998.

Mr. Bowman has described the debate over metrics as a "tempest in a teapot."[125] While the debate can certainly be overdone, this example should make it clear that the choice of metric can be very important. For most of us, passing up an opportunity for $499,998 because of the choice of the wrong metric is more than a tempest in a teapot. While IRR and other metrics are useful as supplements, NPV is the most appropriate and best one to use in this context.

Morrison Park Associates points out the problem with IRR and similar metrics in its testimony[126].

[122] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, page 8 and MH Exhibit #95 (MH Panel 2 Direct Evidence) Slide 57.
[123] Transcript, Harper, pages 8699-8700.
[124] Transcript, Borison, pages 1878-1879.
[125] Transcript, Bowman, page 10040.
[126] Transcript, MPA, pages 7273-7276.

> "Traditional methods and metrics, such as the, you know, internal rate of return, or the rate of return on equity, or the rate of return on capital employed, don't appear to fit very well to the analysis that's required of the Preferred Development Plan and its alternatives".[127]

Dr. Borison emphasized the major role that NPV plays in the evaluation of major capital projects when he said,".... virtually all the work I've done with clients who are interested in decision making about major capital investments, pipelines…mines, power plants, have been based on NPV or a similar metric."[128]

10.2.3 Derivation of Interest Rates, Equity and WACC is Appropriate

A discount rate is a powerful instrument that has the ability to make an investment look strong or vulnerable depending on the selection of a few decimal points, and in the case of this NFAT application, all figures are tremendously significant. Given that sensitivity, Manitoba Hydro carefully reviewed its methodologies for developing and applying these rates. Fundamentally, the choice of a discount rate depends on the perspective of an investor and it was in recognition of this that Manitoba Hydro chose to use several rates: from an economic perspective using the Weighted Average Cost of Capital; from a financial perspective of Manitoba rate payers using a time-preference value; and finally, from the broader perspective of society in the multiple-account analysis.

Embedded within the development of a discount rate are assumptions based upon careful research conducted by Manitoba Hydro and expert consultants. These assumptions were scrutinized in detail throughout the past several months by all Interveners and Independent Expert Consultants. Specifically related to discount rates used in the economic and financial analysis are the key assumptions of interest rates, equity rates, and the application of uncertainty against these.

By combining interest, equity, weighting them by corporate policies, adjusting for inflation and for uncertainty, one comes to final values of the ranges of discount rates used in the economic analysis. Manitoba Hydro used 3.37% as a low real discount rate, 5.05% (updated to 5.4% in 2013) as a reference real discount rate, and 6.5% as a high real discount rate.[129] Probability weightings of 15%, 50% and 35%, respectively, were derived based on historic patterns and also to recognize that there is greater scope for interest rates to rise from their

[127] Transcript, MPA, p. 7274, lines 3-8.
[128] Transcript, Borison, page 1686.
[129] CAC/MH I-127.

current levels than for rates to decline.[130] These weightings produce a weighted average value of 5.3%. As demonstrated in PUB/MH I-165a, this is in fact slightly higher than the average historic rate levelized over a twenty year period.

10.2.3.1 Interest Rates

The core of the discount rate used by Manitoba Hydro in the economic analysis is the assumed interest rate. Simply put, the higher the interest rate, the higher the cost of debt, the higher the discount rate, and the less attractive an investment becomes. Manitoba Hydro's interest rate is determined through the industry best practice of obtaining a consensus view of interest rates from a number of credible, well-respected forecasting agencies and banks. Details of all sources and the method for averaging were provided in PUB/MH I-065, along with the forecasts of other key economic indicators like inflation, economic growth and exchange rates. Next, the consensus average, or view of projected long term Canadian bond rates, are adjusted for the Province of Manitoba's borrowing spread over Canada's costs, and finally, the current 1% provincial guarantee fee is added. The response to Information Request CAC/MH I-104 details how the 6.3% interest rate, or cost of debt was calculated, and a very detailed calculation of the 2012 and 2013 real weighted average cost of capital (including interest rates) is provided in the response to PUB/MH I-156a.

Given the sensitivity of investment decisions to the assumption of an interest rate, it was the focus of much attention in this proceeding. Morrison Park Advisors (MPA) argued that Manitoba Hydro biased their analysis: "...there's been a bit of bias in Manitoba Hydro's evidence with respect to recent history, particularly with respect to inflation and interest rates."[131] MPA points to the fact that history has experienced a much broader range of both interest and inflation and supports this by citing the amount of data available from both Statistics Canada and the Bank of Canada. This suggestion overlooks the fact that Manitoba Hydro takes a very long-run perspective of the data from both Statistics Canada and the Bank of Canada, as well as from the Federal Reserve in the United States.[132] As demonstrated in the response to PUB/MH I-165a, Manitoba Hydro used 20-year levelized values of real interest rates. These calculations start with data from 1940, thus starting at a low interest rate point similar to current conditions, capturing several social, political and economic eras, including the peaks and troughs experienced during the 1980's, 1990's and the recession in 2008.

[130] NFAT Appendix 9.3, pages 54-56.
[131] Transcript pages 7271-7272.
[132] PUB/MH I-163a, PUB/MH I-165a, LCA/MH I-207.

The reference nominal long-term debt assumed by Manitoba Hydro for the 2012 planning assumptions used in the NFAT submission was 6.30%, the low nominal long-term debt was 3.65% and the high nominal long-term debt was 8.95% (Appendix 11.2). When adjusting these for inflation they are 4.40%, 2.65%, and 5.95%, respectively, and compared to historical values cited by MPA and filed in PUB/MH I-165a, these real rates are well within the range experienced by a history beginning in 1940, and in fact, is biasing toward higher rates.

In response to information request PUB/MPA I-029b, MPA suggested that nominal Bank of Canada interest rates of 3.00%, 5.00% and 7.00% may be more appropriate to use, and that these would convert to Manitoba Hydro interest rates of 4.3%, 6.6% and 8.9% nominal when the 1% provincial guarantee fee and the Manitoba/Canada spread of 0.3%, 0.6% and 0.9% are added.

Using MPA's suggested nominal rates to determine real discount rates based on a 3% imputed return on equity for a 75/25 debt/equity ratio, and based on inflation set at 1%, 2% and 3% respectively, results in a low real discount rate of 4.02% (compared to Manitoba Hydro's of 3.35%), a reference real discount rate of 5.26% (as compared to Manitoba Hydro's of 5.05% - updated to 5.4%) and a high real discount rate of 6.48% (as compared to Manitoba Hydro's of 6.5%).

MPA does state that their reference and high rates are "...basically consistent with the choices made by Manitoba Hydro", but that but the low rate is higher.[133] Using the same probability weightings of 15%, 50% and 35%, results in a weighted discount rate of 5.50%, which is only slightly higher than the 5.30 used by Hydro. MPA suggested that there was little support for Hydro's low discount rate but when pressed under cross examination admitted that the interest rates at or below this level have occurred on a number of occasions.[134] Similarly, La Capra assigned a zero probability to the low interest rate scenario, despite not conducting any analysis of the assignment of probabilities[135] and on cross-examination agreed that "...there's definitely not a zero probability".[136]

Oddly, Mr. Harper suggested that in order to provide a better comparison between high and low capital cost and export price cases, the discount rate should be held constant and no

[133] PUB/MPA I-029b.
[134] Transcript pages 7546-7547.
[135] Transcript page 6279, line 20.
[136] Transcript pages 6276-6277.

discount rate sensitivities should be undertaken.[137] Manitoba Hydro quite simply does not agree that holding a known uncertainty constant will help uncover uncertainty.

10.2.3.2 Equity

Manitoba Hydro is not an investor-owned company and so equity in the traditional sense does not apply. Manitoba Hydro is not regulated on a rate-of-return basis – rates are set to recover costs and to make contributions to retained earnings. Retained earnings provide an equity buffer that can accommodate normal business risks. As a proxy for an allowed rate of return, Manitoba Hydro estimates the return on equity as 3% over its cost of debt. Allowed rates of return on equity (ROE) for other utilities were used to determine the 3% equity adder that Manitoba Hydro utilizes as this proxy for an allowed rate of return. Regulated returns on equity in the utility industry across North America are regularly examined, and Manitoba Hydro remains satisfied that its policy to add 300 basis points (3%) to the forecasted "all-in debt" remains appropriate. A discussion of this point was provided in the response to PUB/MH II-381b; the calculations can be confirmed in PUB/MH I-156a; and examples of recent returns on equity can be found in MH Exhibit #182, Tab 18.

Mr. Harper took the view that the WACC was 0.15% too low because the spread (4.65%) between Hydro's cost of equity and its 2018 forecast of the Canadian long bond rate was less than the current (5.25%) spread approved for some Canadian utilities.[138] Specific spreads between the Bank of Canada long-term (10+ years) interest rate and the allowed returns in other jurisdictions can help to verify the reasonableness of Hydro's imputed return on equity, but they must be used with a degree of caution. It is common in rate of return hearings to express the allowed equity returns as a fixed spread from the 10 and/or 30 year Bank of Canada rate. Automatic adjustment mechanisms are often implemented to allow for equity returns to vary with interest rates. Since equity returns required by the market do not move in lockstep with interest rates, bounds on interest rate movements or time limits are often attached to these mechanisms. During periods of dramatic interest rate swings, many of these adjustment mechanisms are abandoned. Recently, many of the adjustment mechanisms have included additional factors in attempt to recognize the plasticity of the spread between equity returns and the Bank of Canada rate. Mr. Harper cited BC, Alberta and Ontario decisions as support for a higher Manitoba Hydro discount rate based on their fixed spreads above the Bank of Canada rate.[139] In fact, the approved mechanisms demonstrate that equity returns are not fixed relative to the Bank of Canada rate. The BC mechanism, which expires

[137] CAC Exhibit #30, page 41.
[138] CAC Exhibit #30, page 21.
[139] CAC Exhibit #30, page 21.

in December 2015, has a set floor and movement in the Bank of Canada rate drives only 50% of the change in the return on equity.[140] Equity returns in Alberta are set at a fixed 8.75% with no provision to adjust to changes in the Bank of Canada rate.[141] The equity return approved in Ontario at 9.36% also has an adjustment mechanism that uses only 50% of the change in the Bank of Canada rate and 50% of the change in a utility bond index.[142] No intervener or IEC witness provided evidence as to what spreads over the Bank of Canada rate would be allowed in 2018, the year that Manitoba Hydro uses in the determination of its WACC. The equity returns recently allowed in BC (8.75%), Alberta (8.75%) and Ontario (9.36%) suggest that the imputed nominal equity return of 9.3% (now 9.75%), used to calculate Manitoba Hydro's real WACC is reasonable and is somewhat above the average allowed return.

Morrison Park Advisors criticized Manitoba Hydro's value and application of a fixed equity premium within the calculation of the WACC. In PUB/MPA 1-030(a) MPA suggested a premium should be "…at least 5% above Canada Long Bonds…" as compared to Manitoba Hydro's 4.5% above Canada Long Bonds. MPA however readily acknowledges the inherent challenge faced by Manitoba Hydro with respect to embedding equity within the WACC: "…the complicating factor is you're—we're not looking at the project. We're looking at Manitoba Hydro as a whole. And, you know, it – it operates under a cost-of-service legislation. So the – the question of weighted average cost of capital and what's appropriate is always a challenging one, in – in this case, as it is and most others."[143] This point is similarly reinforced in their report: "…Manitoba Hydro is governed by "cost of service" legislation, which nominally requires Manitoba ratepayers to bear all of Manitoba Hydro's costs, and Manitoba Hydro benefits from a Province of Manitoba guarantee of substantially all of its debt."[144] MPA underscores the critical aspect that Manitoba Hydro does not have investors by the most common definition, but rather invests on behalf of the public: "…there's no investor that's putting equity into a new project. Manitoba Hydro gets its revenue – gets its capital either from retained earnings from ratepayers or from government-guaranteed debt."[145]

Although there has been criticism levied against Manitoba Hydro with respect to the value and application of equity within the weighted average cost of capital calculation, the question regarding what is appropriate has been acknowledged to be challenging and any attempts to

[140] MH Exhibit #182, Tab 15, page 69.
[141] MH Exhibit #182, Tab 16, page 72.
[142] MH Exhibit #182, Tab 17, pages 74-76.
[143] Transcript page 7429, lines 19-25.
[144] MPA Report, pages 90-91.
[145] Transcript pages 7456-7457.

provide alternatives have resulted in values immaterially different. Manitoba Hydro submits that the equity component of its weighted average cost of capital calculation is reasonable.

10.2.3.3 Weighted Average Cost of Capital

Projected debt and equity rates are weighted by Manitoba Hydro's 75/25 debt/equity ratio target, resulting in the weighted average cost of capital (WACC) that is used as the discount rate. The 75/25 weighting is used irrespective of when the target ratio is actually achieved for each alternative. Manitoba Hydro's methodology for deriving the WACC disregards years prior to 2018 so as to determine a stable long-term rate, and in this case, the WACC is based upon the significantly higher interest rates forecasted for 2018 and years following.[146]

It should also be noted that economic and financial analysis by Manitoba Hydro were conducted in inflation-adjusted or 'real' values. This simply means that the effects of inflation are removed to examine what economists phrase a 'real' effect, not subject to inflationary changes in prices. Over the course of the hearings there has been some confusion on this topic. It is important that the reader of the material be mindful of whether the information they are reviewing is in real or nominal values, as these values are not interchangeable. For example, MPA incorporated nominal values in their analysis[147], while Manitoba Hydro used real values. Both nominal and real calculations were provided in numerous information requests and are referenced in detail in PUB/MH I-156a.

10.2.3.4 Uncertainty in the Forecast of Interest Rates

It is important to identify the foundation of uncertainty that influences a decision or an assumption. In the formation of Manitoba Hydro's WACC, the principal uncertainty is derived directly from the core assumption: the forecast of interest rates. Uncertainty within this context is best dealt with through recognition and study of the inherent uncertainty incorporated within the interest rate forecast. Acknowledging this sensitivity, a reasonable and appropriate range of rates that could persist for long periods of time was established.[148] This range was not intended to capture short-term fluctuations in interest rates. Detailed in the response to PUB/MH I-165a are historic Bank of Canada long-term nominal interest rates from 1940 through 2012, and these have varied from a low of 2.33% to a high of 15.22%. Inflation rates have ranged from a low of minus 1.41% to a high of 14.56%. By combining these, one can calculate the resultant real interest rate, which has ranged from a low of minus

[146] NFAT Appendix 11.2, PUB/MH II-455.
[147] Transcript page 7272, lines 1-2.
[148] NFAT Appendix 9.3, page 32.

10.16% to a high of 8.10%. The mathematical treatment used for inflation adjustment is provided in PUB/MH II-503b. As demonstrated in PUB/MH I-156a, when these values are averaged over a twenty year period (equivalent to a compounded 20 year interest rate), values range from a low of minus 0.19% to a high of 5.36%, and an average of 2.94%.

With respect to inflation, in addition to the historical data provided above, it is very important to examine and consider the monetary policies set forth by the Bank of Canada. Ever since it was established in February 1991, the Bank of Canada has targeted inflation of 2% plus or minus 1%, and it was this logic along with historical data that formed the basis of the range of inflation. The current policy was filed in LCA/MH I-207 as well as the historical data from the Consumer Price Index (CPI), a measure of inflation.

10.2.4 Use of 27 Scenarios is Appropriate

As described in Dr. Borison's evidence,[149] Manitoba Hydro initially identified eleven separate uncertainties in six categories. Based on an examination of the timing and magnitude of these uncertainties, Manitoba Hydro chose to incorporate the three factors with the greatest impact explicitly in the probabilistic analysis. Other important uncertainties were captured using sensitivity analysis.

In his evidence, Mr. Harper argued that Manitoba Hydro could and should have incorporated more uncertainties into its probabilistic analysis[150]. There is a disadvantage to including additional uncertainties. It requires time and effort, reducing the amount that can be spent on other important aspects of the analysis and it adds to the complexity of generating, interpreting and communicating results. This would impede the ability of parties to understand the case. Furthermore, as noted in the NFAT submission[151], Manitoba Hydro's examination of the uncertainties indicated that those uncertainties not included in the uncertainty analysis had relatively little impact, meaning that the benefits of including them in the uncertainty analysis would be minimal even if it is technically feasible.

10.2.5 Treatment of Discount Rate Uncertainty is Appropriate

Manitoba Hydro chose to incorporate the discount rate (and associated economic indicators) as one of the uncertainties in the probabilistic analysis. Both Mr. Bowman and Mr. Harper have argued that it is not appropriate to include discount rate as an uncertainty either because

[149] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, pages 6-7.
[150] Transcript, Harper, pages 8510-8513.
[151] NFAT Business Case, Chapter 10, page 4, Figure 10.1.

1) it makes comparison of alternatives difficult or 2) it makes discount rates and interest rates hard to separate.[152,153] In contrast, as initially explained by Dr. Borison[154] and discussed further in testimony[155], the explicit treatment of discount/interest rate uncertainty in a long-term context, while analytically challenging, is well accepted and even required. A quote from an article by Harvard Professor Weitzman[156] cited in Dr. Borison's report is instructive, both as far as the treatment of discount rate uncertainty is concerned and the link with interest rates:

> While there is uncertainty about almost everything in the distant future, perhaps the most fundamental uncertainty of all concerns the discount rate itself. The question before us is how to discount this distant future in such a way as will induce us to make the best possible investment decisions now, in our present state of uncertainty about the relevant interest rate that will then apply.

10.2.6 Use of the Probability Tree Approach Is Appropriate

There are three major uncertainties in Manitoba Hydro's analysis:

- Energy prices
- Capital costs
- Discount rate (and other Economic Indicators)

In uncertainty analysis, the fundamental goal is to estimate the range of possible outcomes for key metrics if a particular alternative is chosen. Generally, the range is expressed as a probability distribution. This analysis enables stakeholders to compare alternatives rigorously and make more informed decisions. In most business and policy decisions, one relies on an engineering/economic model for estimating outcomes for a particular setting of inputs. The inputs include both the choice of alternative (such as building a dam) and the setting of various parameters that we cannot directly choose (such as natural gas prices). As emphasized in cross examination, there are two fundamental ways of using a model to

[152] Mr. Bowman's Pre-filed Testimony, page B-7.
[153] ECS, Pre-filed Testimony, page 41.
[154] Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, pages 10-11.
[155] Transcript, Borison, pages 2535-6.
[156] Martin L. Weitzman, *Why the Far-Distant Future Should be Discounted at its Lowest Possible Rate,* Journal of Environmental Economics and Management, Volume 36, 1998.

generate the desired uncertainty analysis output.[157] These are Monte Carlo simulation and probability (or decision) tree analysis.

Manitoba Hydro chose to take a probabilistic scenario or probability tree approach for quantifying these uncertainties, while Dr. Simpson favours a Monte Carlo simulation approach[158].

These two approaches can really just be thought of as alternative sampling methods for uncertainty analysis. Monte Carlo tends to work well with simple spreadsheet-level operational models with lots of similar well-behaved inputs. One can associate known distributions with the inputs, press go, run the simple model thousands of times or more, and generate an accurate and credible outcome distribution quickly. Probability trees tend to work well with more complex investment models with fewer, more diverse inputs. One can evaluate each input in depth, develop customized scenarios, run the complex model hundreds of times or fewer, and generate an accurate and explainable output distribution efficiently.

It is important to point out that probability trees can be extended naturally to the analysis of optionality. One can easily expand the tree with current and future decisions, learning and flexibility. It is extremely difficult (and perhaps impossible) to incorporate optionality well into a Monte Carlo simulation. That is one reason it is more of an operational than a strategic tool.[159] [160]

It is instructive to consider that Dr. Simpson was unable to provide a single example of the use of Monte Carlo simulation in the development or evaluation of a long-term resource plan or a single example of the use of Monte Carlo simulation to evaluate alternatives in Integrated Resource Plans.[161]

Dr. Bowman concurs regarding the benefits of the probability tree or probabilistic scenario approach in this context[162].

> MS. MARLA BOYD: Would you agree that probabilistic scenario analysis often provides more transparency than Monte Carlo simulations?

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[157] Transcript, Simpson, page 8664.
[158] Transcript, Simpson, page 8571.
[159] John Wiley and Sons, 2013, *Handbook of Decision Analysis*, page 259.
[160] Deloitte, 2014, *The Full Monte Carlo – Common Pitfalls and Leading Practices in the Application of Monte Carlo Simulation*, page 10.
[161] Transcript, Simpson, page 8665, line 1.
[162] Transcript, Bowman, page 10256-8.

MR. PATRICK BOWMAN: Yes, absolutely, and...especially in a regulatory forum. If -- it would be different if you were running a university department or something where a bunch of people could gather around a computer monitor and rerun scenarios and -- and discuss them or something of that nature. But if you've got a file -- some evidence and people need to be able to cross-examine you on it, Monte Carlo simulation is a very difficult way to find out if you've -- if you've done everything correctly, to be tested, to -- to have a proper cross-examination and evidence.

10.2.7 Approach Used to Assign Probabilities is Appropriate

Manitoba Hydro agrees that quality data is important in uncertainty analysis, just as it is in other forms of analysis. As Dr. Borison noted in his report, the inputs in the analysis were developed and calibrated carefully using a mix of historical data, model results and expert judgment.

Manitoba Hydro went to considerable lengths to draw upon available data, models and judgments in developing the underlying probability distributions, and in assigning discrete probabilities. This stands in contrast with La Capra who have relied on what appear to be largely arbitrary and casual probability assignments in what Mr. Athas referred to as a "mathematical exercise".[163]

Manitoba Hydro also updated its inputs to the probability analysis as soon as new information became available. Capital costs were refined based on new estimates[164], and the treatment of common factors (those not incremental to a particular alternative) was improved to better reflect the relative risk of individual alternatives[165].

10.2.8 Use of the Utilitarian Approach Is Appropriate

Manitoba Hydro's probabilistic analysis is based on the "utilitarian" approach to measure the impact of uncertainty for each development plan, rather than the "regret" approach. The utilitarian approach is based on "What Is" - the actual incremental impact of each alternative in each scenario. There is a fixed base value, but the choice of this base makes absolutely no difference in the comparison of alternatives. The regret approach is based on "What Could Have Been" - the difference between the actual incremental impact in that scenario and the

[163] Transcript, Athas, page 6031.
[164] Transcript, Bowen, pages 2601-2609.
[165] Transcript, Miles, pages 2517-2522.

impact if another base alternative had been chosen. The choice of this base alternative (not just a base value) is arbitrary, and can make a significant difference in the comparison of alternatives.

The distinction between utilitarian and regret approaches is not simply an academic debate, as the choice between approaches can have real significance. For example, the utilitarian approach provides a stable, useful measure of the risk of each alternative. No matter what base value is chosen, the relative risk of the alternatives remains the same. The regret approach provides no such stable, useful measure. The alternative that is chosen as the base, whatever that might be, appears as "riskless" not because there is no risk but because there is no disappointment when an alternative is compared to itself.

As La Capra acknowledges, in reality, each alternative, including the base, has risk[166]. Yet the approach that La Capra used in its analysis will show as riskless whatever alternative is chosen as the base, whether this is the All Gas plan, the Preferred Development Plan or another plan[167]. This makes use of this approach, except as a very limited supplement, suspect. Despite this, La Capra persists in discussing the outputs of this approach as if it provides an indication of risk. This is evident when Mr. Peaco says[168]:

> You can see how much the range is, so if it's net present value of...a billion dollars, but it's plus or minus $3 billion, that's important to know as opposed to if it's plus...or minus 10%.

However, this approach provides no such indication since the "risk" depends entirely on the arbitrary choice of the baseline alternative. The lack of foundation and the resulting problems with the regret approach are described in more detail in the response to MIPUG/MH II-004a.[169]

Manitoba Hydro addressed the use of the regret approach in its Rebuttal Evidence[170], where it referred to the regret approach as fundamentally descriptive (i.e., what individuals do naturally) rather than prescriptive (i.e., what organizations should do rationally). In this context the regret approach may be helpful to particular stakeholders but only as a supplement to the better-founded and better-accepted utilitarian approach.

166 Transcript, La Capra, page 6084.
167 Transcript, La Capra, pages 6284-6288.
168 Transcript, La Capra, page 5660.
169 MIPUG/MH II-004a.
170 MH Exhibit #85, pages 131-132.

As Dr. Borison indicated in his testimony, any approach that is based on a regret table is fundamentally a regret approach.[171] It is basing comparisons and recommendations not on "What Is" but on "What Could Have Been". Further, as Dr. Borison makes clear, there is no justification for arguing that a rational organization should make important decisions this way. Any S-curves generated with this approach are fundamentally regret-based and have little if any decision-making value[172]. Mr. Bowman supports Dr. Borison's position when he says, "I -- I think Dr. Borison was correct in -- in not advocating that... but La Capra's graphs are the same graphs you would draw if you were advocating that type of approach [a regret approach]."[173]

Manitoba Hydro chose to use the more appropriate utilitarian approach in its probabilistic analysis. This was supported by Dr. Borison in his direct testimony[174]:

> ...virtually all the theory about how to do decision making on uncertainty says you should compare things to a fixed base....you should look at your current wealth and say...If I did this, I'd be that much wealthier; if I did that, I'd be that much wealthier....That is the fundamental theoretical basis of utility theory.... The approach that is...not well regarded as a guideline...is to compare where you are to what would have happened in that particular scenario....I refer to that as the regret approach....the fundamental difference is having a bunch of zeros for any alternative in all scenarios...saying I'm going to compare things to what might have happened in that scenario...whatever you want to call it, I think it is, frankly, unconventional and misleading, comparatively speaking...

There are numerous examples of the use of the utilitarian approach in resource planning. There are no such examples of the use of the regret approach.[175]

10.2.9 Use of 10th Percentile Risk Metric is Appropriate

One key output of economic uncertainty analysis is typically the expected value, obtained by weighting each outcome with its probability. However, it is useful to go beyond expected value to look at the variability around this "central tendency." As explained in two

[171] Transcript, Borison, pages 2458-2460.
[172] Transcript, Boris on, page 2461-2463.
[173] Transcript, Bowman, page10254, lines 10-14.
[174] Transcript, Borison, pages 2467-2469.
[175] MIPUG/MH II-004a.

interrogatories[176], Manitoba Hydro agrees that risk should be considered, and that risk/return tradeoffs and "efficient frontier" graphics are insightful. However, it is critically important that the right risk measures be used.

Dr. Simpson argues that risk should be measured using interdecile ranges or similar metrics such as standard deviation that incorporate both downside and upside variability.[177] These metrics are commonly used in academic and financial contexts where distributions are assumed to be symmetric (as with the normal distribution). But they can misinform where the distributions are not symmetric, which is often the case in non-academic and non-financial applications such as utility resource planning.

Manitoba Hydro chose to measure risk based on the 10th percentile value – a bad or worst case – because this better captures the essence of risk in the utility planning context. As explained in detail in CAC/MH I-0184a[178] and Dr. Borison's testimony[179], the 10th percentile risk measure is better than traditional financial measures such as interdecile range and standard deviation. It provides a much better sense of the true risk/return tradeoff.

10.3 Economic Analysis Results

In the NFAT Business Case Chapters 9, 10 and 12, Manitoba Hydro provided economic analysis and economic uncertainty analysis for up to 15 development plans. Through the course of the NFAT process, Manitoba Hydro has provided supplementary analyses[180] with respect to additional levels of DSM and updated assumptions such as updated capital cost estimates for Keeyask and Conawapa Generating Stations.

In the NFAT Business Case, Manitoba Hydro provides the impact of potential transfers to the Province which includes water rentals, capital tax and the provincial guarantee fee[181]. Appendix 9.3 Section 1.4 of the NFAT submission discusses the return on equity (ROE) included in the real weighted average cost of capital (real WACC). The real WACC is used in the economic analysis as a discount rate. In its supplementary analysis filed as MH Exhibit #171, Manitoba Hydro presents the NPV at the real WACC which has in it an embedded ROE. Manitoba Hydro also presents the increase in NPV by excluding the embedded

[176] CAC/MH I-176a and CAC/MH I-184.
[177] Transcript, Simpson, page 8571.
[178] CAC/MH-0184A.
[179] Transcript, Borison, pages 2496 – 2499.
[180] MH Exhibits #104 and #171, as examples.
[181] NFAT Business Case Chapter 9, pages 23-25.

ROE[182]. The total NPV including ROE represents the return, in excess of debt costs, which is available to Manitoba Hydro. It should be noted that a portion of the embedded ROE is required to maintain Manitoba Hydro's debt equity ratio of 75:25. The cash transfers to the Province are shown in addition to the NPV excluding ROE in order to provide an indication of the total direct economic benefit to Manitoba.

Embedded Return on Equity in Discount Rate

Manitoba Hydro's WACC includes an imputed return on equity of 3% over the projected cost of long-term debt. Equity is assumed to constitute 25% of Manitoba Hydro's capital structure, consistent with its current financial targets. Unlike many other jurisdictions, the requirement for an equity return in Manitoba Hydro's WACC is not to produce a required return to a shareholder, but to be the vehicle by which Manitoba Hydro can achieve its financial objectives and to provide tangible ratepayer benefits. While generally seen as a benefit to Manitoba Hydro, retained earnings are really another form of ratepayer benefit; they provide rate stability in adverse situations and preserve Manitoba Hydro's self-sustaining financial status to ensure its continued access to low cost financing through the Province. MPA also supported this view in their evidence, "By definition, because Manitoba Hydro is structured as a cost-of- service company, all of its retained earnings are invested in capital, which are -- are used for the benefit of providing service to ratepayers."[183]

As there was some confusion regarding embedded return on equity, the concept is explained as follows: a project that has a zero net present value using a debt-only discount rate (no equity premium) will, over the long term, cover all of its financing costs but nothing more. Any return above the debt-only discount rate constitutes a net positive cash flow that can be used to provide benefits. As has been stated by Manitoba Hydro in Ms. Flynn's testimony[184], a portion of this return is necessary to make contributions to retained earnings otherwise known as net income. The relative share of the 3% equity premium necessary to contribute to retained earnings will be similar in all of the alternative plans.

The portion of the 3% equity premium not required to maintain financial reserves is available for two purposes: to act as a buffer against business risk, and to reduce the rates that would otherwise be required to be recovered from customers.[185] This embedded equity return is not

[182] MH Exhibit #171.
[183] Transcript page. 7550, lines 10 – 14.
[184] Transcript page1483, lines 17-21.
[185] Transcript page 7550, line 23 to Transcript page 7551, line 3.

readily identifiable in the corporate financial statements, but is a real benefit that is a direct result of projects that earn returns in excess of their debt-only cost of capital.

Transfers to the Province

The construction and operation of the development plans include a range of financial transfers to the Province of Manitoba, in the form of capital taxes, water rental fees, and loan guarantee fees. With respect to the capital tax and the water rental fee, explained by Mr. Rainkie (Tr. p. 2977), and quantified in Exhibit #171, there has been no disagreement that these represent cash transfers which benefit the Province of Manitoba. There has been some discussion regarding the classification of the provincial guarantee fee, and whether or not it is a benefit to the Province. This subject merits attention because the potential magnitude of incremental benefit could be up to and beyond $1.0 Billion dollars as seen in Exhibit #171. Manitoba Hydro takes the position that a portion of the provincial guarantee fee should be included in the determination of total benefits to the province associated with the development plans. Excluding the debt guarantee fee would be justified if the province incurred direct costs or assumed risk proportionate to the fee. While the entire 1% fee represents value for service provided to Manitoba Hydro, the actual cost to the province is unclear (Tr. p. 3971-3972).

Dr. Marvin Shaffer, retained by Manitoba Hydro to undertake the Multiple Account Benefit Cost Analysis took a conservative approach when considering the net benefit of the provincial guarantee fee to the Province, "…in some respect […] the debt guarantee that the government is providing, and there are – there are costs or risks associated with that."(Tr. 3656) Consequently, he decided to not include provincial guarantee fee as a net beneficial transfer to the Province; however as demonstrated below, the issue is clearly not black-or-white.

Mr. Colaiacovo in testimony was asked by the Chairman whether the fee was too high or low, and in response explained that they did not make that determination. However, in this explanation MPA suggested that the evaluation would include an analysis of the "likelihood and magnitude of a call on that guarantee," and while they did not provide that analysis, he did explain that in other jurisdictions the fee is "..twenty (20) basis points, or thirty (30) basis points, or fifty (50) basis points." (Tr. 7298) This testimony underscores the uncertainty as to whether and by how much the fee is offset by cost and risk.

One intervener took the position that the provincial guarantee fee should be classified as a benefit - Mr. Bowman testified: "And—and I definitely include debt guarantee fees in that mix. I think of somebody is going to sit down and – and sort out a solution here, debt guarantee fees would – would need to be on the table for this" (Tr. 10277-10278). Mr. Bowman takes the position that while the provincial guarantee fee does reflect an offset of a cost, there should be some recognition that there is a net benefit.

10.3.1 Economic Conclusions Based on Updated Assumptions

Manitoba Hydro's supplementary economic analysis provided in MH Exhibit #171 reflects higher levels of DSM, potential for increased pipeline load, updated capital costs for the Keeyask and Conawapa Generating Stations, and 2013 planning assumptions. Since the filing of the NFAT submission in August 2013, it has become known that WPS will not invest in the 750 MW interconnection and that development plans with a 250 MW interconnection are not viable possibilities, and are now considered hypothetical.

In MH Exhibit #104-2, and in MH Exhibit #104-8 a portion of which is reproduced below, Manitoba Hydro provided updates to the economic uncertainty analysis results. These updates reflected the updated capital costs for Keeyask and Conawapa Generating Stations and the associated probability weightings for capital costs, removed the WPS investment in the 750 MW interconnection, and updated the treatment of common factors. The uncertainty analysis was not updated for higher levels of DSM.

Revised Capital Costs and Revised Treatment of Common Factors

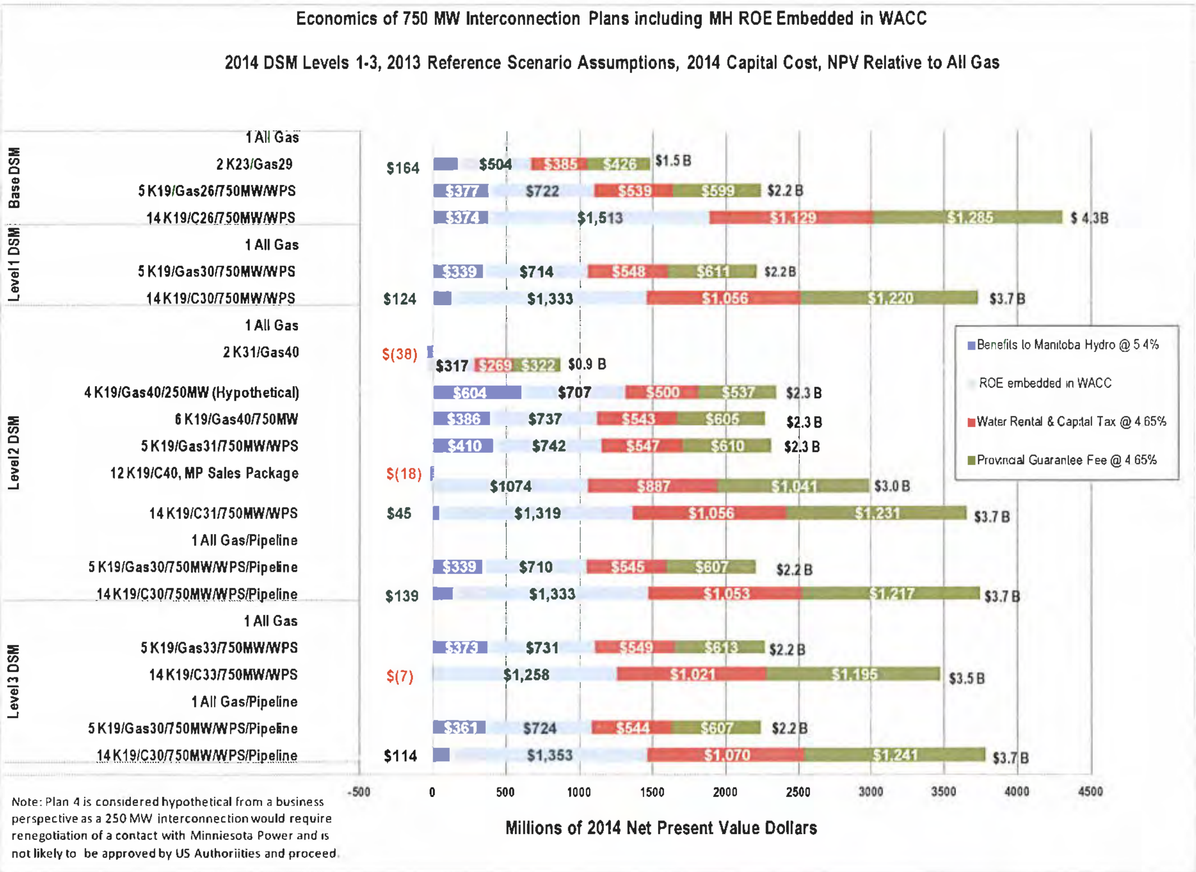
		Development Plan	1	2	4	8	6	12	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
									WPS Sale & no WPS Inv	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars							
Low	Low	H	-1062	-1401	-851	-1501	-1079	-2143	-758	-1825
		Ref	-68	16	646	106	392	-53	698	424
		L	734	1205	1898	1449	1613	1750	1906	2359
	Ref	H	-463	-1751	-1512	-2398	-1793	-3717	-1546	-3989
		Ref	208	-677	-334	-1085	-614	-1977	-355	-2010
		L	750	232	658	15	369	-476	637	-325
	High	H	-88	-1782	-1781	-2625	-2080	-4202	-1872	-4838
		Ref	416	-891	-748	-1480	-1033	-2858	-820	-3044
		L	823	-133	110	-519	-172	-1345	61	-1500
Ref	Low	H	-2033	-120	543	325	298	1410	-7	1869
		Ref	-1039	1296	2040	1932	1770	3501	1449	4118
		L	-237	2486	3292	3275	2991	5304	2658	6053
	Ref	H	-671	-585	-260	-910	-517	-1204	-707	-1345
		Ref	0	489	917	403	662	536	484	614
		L	542	1397	1910	1503	1645	2037	1477	2300
	High	H	17	-716	-620	-1343	-880	-2214	-1034	-2759
		Ref	520	175	393	-198	148	-680	18	-966
		L	927	933	1251	762	1008	643	899	578
High	Low	H	-3454	892	1647	2005	1333	4820	402	5388
		Ref	-2460	2309	3143	3612	2804	6911	1858	7638
		L	-1658	3498	4396	4955	4025	8714	3066	9573
	Ref	H	-1158	402	797	469	526	1178	-103	1125
		Ref	-487	1476	1974	1782	1704	2918	1088	3084
		L	55	2384	2967	2882	2687	4418	2081	4770
	High	H	-82	210	368	-156	115	-352	-384	-824
		Ref	422	1101	1381	989	1143	1182	669	969
		L	828	1859	2239	1949	2003	2505	1549	2513

Development Plan	1	2	4	8	6	12	5	14
	All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & no WPS Inv	
	Millions of 2014 NPV Dollars							
10th Percentile -"Risk"	-953	-862	-727	-1457	-1007	-2512	-909	-2946
25th Percentile	-244	-622	-290	-980	-556	-1482	-367	-1760
75th Percentile	483	1026	1339	916	1099	1232	824	1105
90th Percentile - "Reward"	738	1448	2019	1898	1749	3239	1475	3653
Expected Value	-9	268	651	143	386	115	268	120
Ref-Ref-Ref NPV	0	489	917	403	662	536	484	614

In the updated uncertainty analysis, the updated treatment of common factors had no effect on the expected value calculation. The updates for capital costs and interconnection investment reduced the expected value for all plans with Keeyask and/or Conawapa Generating Stations.

From an uncertainty perspective, Plan 14 continues to have the highest upside potential but also has the highest downside risk. When considering expected value and the NPV at Ref-Ref-Ref, the focus shifts from Plan 14 to Plans 5 and 6 (Plan 5 – K19/Gas25/750MW (WPS Sale & no WPS Inv); Plan 6 – K19/Gas31/750MW).

MH Exhibit #95, Slide 129 confirms that Level 2 DSM is the most economic of the additional three levels of DSM shown. As a result, Manitoba Hydro focused additional analysis on plans with Level 2 DSM. The majority of the results from the economic analysis are summarized in MH Exhibits #171 and #104. MH Exhibit #171 is reproduced below.



With reference to MH Exhibit #171, at the real discount rate of 5.4%, which includes an embedded ROE, and at Level 2 DSM, the NPVs for Plans 5 and 6 ($410 million and $386 million, respectively) which include the Keeyask Generating Station and a 750 MW interconnection followed by natural gas-fired generation, are higher than the incremental NPV for the Preferred Plan ($45 million) and are higher than all other Plans evaluated under DSM Level 2. Plan 4 (K19/250MW) economics are not discussed because it is hypothetical, as noted in the Exhibit.

From the perspective where the NPV excludes the embedded ROE, the incremental NPV of $1.364 billion for the Preferred Plan is at least $200 million greater than the NPV of the other plans evaluated. The NPVs of Plans 5 and 6 are approximately $1.1 billion higher than the All Gas Plan, and are approximately $0.8 billion higher than the Keeyask/Gas Plan.

When considering cash transfers to the Province, the Preferred Plan with both Keeyask and Conawapa Generating Stations results in a total NPV of $1.4 billion higher compared to Plans 5 and 6. The NPVs of Plans 5 and 6 are approximately $2.3 billion higher than All Gas and $1.4 billion higher than the Keeyask/Gas Plan.

The incremental NPVs support the development of Keeyask Generating Station and a 750 MW interconnection as represented in Plans 5 and 6. The incremental NPV with respect to Plan 14, from the perspective where the NPV excludes the embedded ROE, supports protection of Conawapa Generating Station as an option. However, consideration must be given to the tradeoffs between Plans 5 and 6 and Plan 14. Further analysis of other perspectives (financial, multiple accounts, and optionality) which are discussed in Sections 13, 19 and 21 of Manitoba Hydro's Final Argument are important to the overall conclusions and recommendations provided in Section 22.

10.3.1.1 Keeyask and Conawapa High Capital Cost Stress Test

In MH Exhibit #170, stress test results are provided for Keeyask and Conawapa Generating Station 2014 updated high capital costs. The stress test evaluated the risk associated with capital cost increases that would be uniquely associated with the Keeyask and Conawapa generation stations and considered no concurrent offsetting increases in the capital costs of natural gas generation or in energy prices.

The high capital cost stress test assuming no additional pipeline load for Plans 5 and 6 results in a NPV cost relative to the All Gas Plan of $-168 million and $-192 million, respectively, at the 5.4% real WACC. Including Manitoba Hydro's embedded return on equity would provide an NPV amount of over $500 million that would be available to Manitoba Hydro, relative to the All Gas Plan. In addition, incremental transfers to the Province are approximately $1.3 billion in NPV for Plans 5 and 6. From the perspective where the NPV excludes the embedded ROE, Plans 5 and 6 can withstand increases in capital costs consistent with the updated high capital cost estimate for Keeyask Generating Station resulting in Manitoba Hydro having available to it in the order of $500 million incremental NPV over the All Gas plan.

The high capital cost stress test assuming no additional pipeline load for Plan 14 also incorporates updated high capital cost estimates for both the Keeyask and Conawapa Generating Stations. At the real WACC of 5.4%, the NPV is over $1.2 billion less than the NPV for the All Gas plan. The perspective where the NPV excludes the embedded ROE would result in approximately breaking even with the All Gas plan. Incremental transfers to the Province under this stress test are approximately $2.6 billion.

Experience from the Keeyask Project will inform Manitoba Hydro's cost estimates for Conawapa and as such Manitoba Hydro would not proceed to commit to Conawapa in the face of high capital costs unless there were offsetting factors such as sufficiently higher export revenues. The scenario presented does not take into account such offsetting factors and as such the case presented with both Keeyask and Conawapa experiencing high capital costs would not be considered a feasible or realistic scenario.

10.3.1.2 Manitoba Load - Hypothetical Flat Load Growth Analysis

In MH Exhibit #156 and MH CSI Exhibit #35 an analysis is undertaken of the hypothetical circumstance where Manitoba load growth would remain flat beyond 2022/23.

The analysis of this circumstance used the economic output from existing reference cases including the following assumptions:

- The no new generation case was based on the All Gas plan up to and including 2022/23, with existing export commitments beyond 2022/23 based on future contract terms and conditions.
- The Keeyask & 750MW interconnection case was based on Plan 5 K19/Gas25/750MW (MP & WPS Sales and no WPS investment) up to and including 2022/23, with existing export commitments beyond 2022/23 based on future contract terms and conditions.
- No domestic load growth (flat load) beyond 2022/23.
- From 2023/24 to 2048/49 all energy volumes were held constant.
- Beyond 2048/49, the long-life asset evaluation methodology was applied.

As shown in the following table, if there is no load growth assumed beyond 2022/23 and surplus energy is valued using the 2013 long-term dependable export price forecast, building Keeyask and a new interconnection results in an incremental net present value of $402M (at real WACC of 5.4%) relative to building no new generation. If surplus dependable energy is valued at prices similar to the recently negotiated export contracts, the benefit would be higher than shown in the table below. [redacted]

	Present Valued at a 5.4% Real WACC				
	Capital Cost PV Millions 2014$	Revenue (LTD) PV millions 2014$	Rev-Cost (LTD) NPV millions 2014$	[redacted]	[redacted]
No new Generation	0	3160	3160	[redacted]	[redacted]
Keeyask & 750MW	4605	8167	3563	[redacted]	[redacted]
Incremental NPV			402		[redacted]

The following table shows the same evaluation with the impact of the embedded return on equity removed resulting in a real discount rate of 4.65%. As shown in the table below there is an incremental net present value of $1190M (at 4.65%) relative to building no new generation. [redacted]

The table also shows the NPV benefit of transfers to the province (water rentals, capital tax, and provincial guarantee fee) which when included in the analysis increase the NPV of benefits from $1190M (at 4.65%) to $2422M if surplus energy is valued at the long-term dependable export price forecast. [redacted]

	Present Valued at Real Discount Rate of 4.65% Return on Equity of 3% removed				
	Capital Cost PV Millions 2014$	Revenue (LTD) PV millions 2014$	Rev-Cost (LTD) NPV millions 2014$	[redacted]	[redacted]
No new Generation	0	3675	3675	[redacted]	[redacted]
Keeyask& 750MW	4816	9681	4865	[redacted]	[redacted]
Incremental NPV			1190		[redacted]
Water Rental and Capital Tax NPV			569		[redacted]
Provincial Guarantee Fee NPV			663		[redacted]
Incremental NPV with provincial transfers			2422		[redacted]

From the perspective of hypothetical flat load growth in Manitoba, the analysis shows that there is considerable value in building Keeyask and a new interconnection even under that extreme circumstance.

The question was raised by Ms. Kapitany as to how the MISO market might be affected in the future with respect to lower load growth and how successful Manitoba Hydro might be at selling power to those markets in the future. While Mr. Dunsky recognized there would continue to be a requirement for supply due to retirement of coal plants, he referenced grid parity and DSM programs suggesting that load growth would be flat in MISO in the future.[186] As discussed in Section 9.1.3 (on MISO load growth effect on prices), although load growth assumptions are an important input required to estimate the long-term electricity price for the MISO region, the impact of load growth in determining prices in relative terms is less important than key drivers such as fossil fuel prices, carbon pricing and expected changes to the generation fleet.

As noted by Dr. Murphy in his testimony, supply side pressures in the medium term (which include emerging GHG regulations for coal and expiration of nuclear licenses in 2030s)

[186] Transcript pages 8100-8104.

effectively require new generation supply in MISO to meet load obligations, even under the assumption of very low or flat load growth.[187]

In addition, the evidence from the Brattle Group suggests that because of the characteristics of MISO's supply curve, changes in load growth assumptions are not a primary driver of power prices.[188] In Section 9.1.3 of this Final Argument, it is shown that even under a 1%/year load growth estimate, coal retirements would still represent about two-thirds of the supply shortfall between now and 2020.

As the impact of load growth in determining prices in MISO is, in relative terms, less important than key drivers such as fossil fuel prices, carbon pricing and expected changes to the generation fleet, Manitoba Hydro is confident that it will continue to be successful at selling power to the MISO market in the future and there will continue to be a demand for Manitoba Hydro's predominantly hydro-based product.

10.3.1.3 Keeyask as Next Resource to Meet Manitoba Load

In Section 4 of MH Exhibit #85-2, Manitoba Hydro provided additional economic analysis related to Pathway 1, (Gas 2023 only for domestic load, later gas generation or hydro) and Pathway 2 (Keeyask 2023 only for domestic load, later gas generation or Conawapa). The analysis built on the 2012 and 2013 planning assumptions used in the NFAT submission with the most recent capital cost estimates for Keeyask but does not include higher levels of DSM. The analysis included incremental NPV comparisons related to the timing of Keeyask Generating Station relative to the All Gas plan and resulted in a positive NPV associated with development plans that include Keeyask as a resource option. Overall, these economic evaluation results demonstrate that there remains a net benefit to pursuing Keeyask Generating Station as the next resource for Manitoba load. Based on the analysis in MH Exhibit #85-2 there is value in advancing Keeyask from 2028.

MH Exhibit #171 provides a comparison of Plan 2 (K31/Gas, DSM Level 2) to All Gas (DSM Level 2) and shows the economics to be marginal between the two plans. Based on the information contained in MH Exhibit #85-2, it can be inferred that advancing Keeyask would improve the economics of Plan 2 relative to the All Gas Plan.

[187] Transcript page 1405, lines 12-20.
[188] NFAT Appendix 5.3, page 66.

When considering the NPV excluding the embedded ROE, the incremental NPV for Plan 2 is greater than that of the All Gas plan by $317 million. These results are supportive of Keeyask as the next resource.

10.3.2 La Capra Economic Analysis to be Considered with Caution

10.3.2.1 La Capra's CPV Analysis

In Section 8.2.1, Manitoba Hydro explains that in order to compare development plans on an "apples to apples" basis, it is important that the time frame of the economic analysis extend to the end of the useful life of the longest-lived assets under consideration. In the context of the NFAT, these assets are hydroelectric and transmission facilities and the 78-year time frame reflects their useful life. Any analysis with a substantially shorter time frame, without significant terminal value, attributes insufficient value to these assets.

La Capra calculates the cumulative present value (CPV) of a development plan, which reflects the present value of all costs and benefits that have occurred to a particular point in time. Therefore, a CPV calculation does not include residual value. La Capra agrees that CPV considers only the present value of costs and revenues up to a particular point in time and, by definition, ignores all cashflows whether positive or negative that occur beyond that point in time.[189]

Effectively, the CPV analysis favours investments in resources with shorter lives such as natural gas and wind generation as it gives insufficient value to the long-lived resources such as hydro. However, CPV analysis can be useful in certain limited contexts. For example, La Capra confirmed that CPV could instruct a decision if a potential disruptive technology was of concern at some point in the future.[190] Manitoba Hydro submits that the CPV analysis provided by La Capra in their initial and supplemental Appendices 9A and 9B is an approach that can provide insights but is not an approach that should be used for decision making.

10.3.2.2 LCA No New Generation Plan (Hypothetical) of Little Value

At the request of La Capra, Manitoba Hydro provided SPLASH output and other supporting economic cashflow information which allowed La Capra to prepare an analysis of the LCA No New Generation plan. The plan consisted of increased DSM, as well as fuel switching,

[189] Transcript page 6267.
[190] Transcript pages 6331-6332.

extended diversity agreements, a 750 MW interconnection to the US, and planning criteria for imports increased from 10% to 20% with respect to dependable energy.[191]

Manitoba Hydro considers this plan to be hypothetical as developing an interconnection primarily for import to Manitoba without a counterparty, without identifying whether the region has energy to export, and without identifying any benefit to the region from such an interconnection is unrealistic. While proposed by La Capra, they too acknowledge in their direct evidence[192] that the LCA No New Generation plan is hypothetical. In addition Mr. Peaco was unable to confirm the feasibility of an interconnection primarily for import from Minnesota when he stated "I don't have any basis to know whether it is or isn't feasible."[193]

Mr. Peaco also said that "while it is a hypothetical plan, the results do point to the potential for added elements. DSM, import -- import limit cap -- capabilities are all elements of -- of a plan that -- that may be some -- may be of some promise, either by themselves or in some combination."[194]

Manitoba Hydro sees little value in the hypothetical LCA No New Generation plan as Manitoba Hydro has incorporated the elements of DSM and an interconnection into its development plans and analysis. For example, the 750 MW interconnection (both export and import) evaluated in Manitoba Hydro's development plans recognized the need for a counterparty when developing an interconnection.[195] In MH Exhibits 171 and 104, Manitoba Hydro provides analysis of DSM at various levels. At best, the hypothetical plan confirms that key elements that Manitoba Hydro has already included in its plans are in fact beneficial.

In LCA Exhibit #45, Slides 32 and 71, La Capra calculates an incremental NPV of $1.421 billion for the LCA No New Generation Plan and compares it to the incremental NPV of Manitoba Hydro's Preferred Development Plan of $1.696 billion, a decrease of $275 million. La Capra mainly attributes the $1.421 billion incremental NPV of the LCA No New Generation plan over the All Gas Plan to relaxing the planning criteria related to imports.[196] Mr. Peaco states, ". . . this case was an -- was an opportunity for us to test, you know, does it make any difference if we relax that. And -- and so -- so you see the combined effect of both

[191] La Capra Supplemental Expert Analysis Report, page LCA-5.
[192] La Capra Exhibit #45, Slide 33.
[193] Transcript page 6209.
[194] Transcript page 5626.
[195] NFAT Business Case, Chapter 8.
[196] Transcript pages 5728-5734.

of those things [relaxing the import planning criteria and the 750 MW interconnection] in that case."[197]

In MH Exhibit #104-14, Manitoba Hydro demonstrates that, on a comparable basis, when including the same La Capra load reduction into Manitoba Hydro's analysis the incremental NPV of the Preferred Development Plan increases to $2.607 billion from $1.696 billion, an additional $0.911 billion in incremental NPV as a result of assuming the same load reduction as assumed in the LCA No New Generation plan. This clearly shows that the incremental value associated with the LCA No New Generation plan was primarily due to the assumed La Capra load reduction not the increased level of imports associated with relaxing the import planning criteria. La Capra's analysis was not sufficiently complete to arrive at conclusions with respect to Generation Planning Criteria with respect to the limitation of imports. In this regard, their conclusions are seriously flawed and have led to undue concern with the Generation Planning Criteria with respect to the limitation of imports.

In addition, the comparison of the incremental NPV of the hypothetical LCA No New Generation plan and the Preferred Plan made by La Capra in LCA Exhibit #45, Slides 32 and 71 is not an "apples to apples" comparison as they do not incorporate the same load reduction. The more comparable analysis is provided by Manitoba Hydro in MH Exhibit #104-14, where the NPV of the Preferred Development Plan is shown to increase to $2.607 billion when incorporating the same load reduction as assumed in the La Capra plan. The incremental NPVs of the two plans can then be fairly compared. The resulting comparison shows that the incremental NPV of the Preferred Development Plan with the incorporated load reduction is approximately $1.2 billion higher than that of the hypothetical LCA No New Generation plan.

As discussed in Section 5.3 of this Final Argument, Manitoba Hydro has justified its Generation Planning Criteria with respect to the limitation of imports. All of Manitoba Hydro's analyses respect the Planning Criteria and the importance of maintaining a reliable and dependable supply of power. LCA's No New Generation plan ignores the Planning Criteria without any analysis or regard to the potential impact on system reliability.

In conclusion, as Manitoba Hydro has captured the value of the 750 MW interconnection (import and export) and higher levels of DSM there is little to be learned from the analysis provided by La Capra with respect to the individual or combined elements in the hypothetical LCA No New Generation plan.

[197] Transcript page 5732

10.3.2.3 La Capra Wind/Gas Analysis Provides Skewed Economic Results

In Technical Appendix 3A, La Capra provides an analysis of Manitoba Hydro's Wind/Gas plan (Plan 3) by reducing cost assumptions associated with Plan 3.

In their analysis, La Capra adjusted wind assumptions related to capital cost, capacity factor, asset life and technological improvement.[198] Each one of these assumptions was adjusted specifically to improve the relative economics of the Wind/Gas plan. When taken together, the degree to which these adjustments were made are representative of a stress test which pushes the limits of potential realization for these assumptions (capital cost, capacity factor, asset life and technological improvement).

As discussed in Section 6.4.2, Manitoba Hydro maintains that using a constant capital cost, with no real escalation, and a constant capacity factor for future wind projects are appropriate assumptions for the economic comparison of development plans with wind resource options in the NFAT submission. As explained in Section 6.4.2 using a constant capacity factor and capital cost recognizes improvement as it is typical for capital costs to escalate and for capacity factors to deteriorate when considering wind generation development in the future. Manitoba Hydro maintains that La Capra's capital cost for wind is at the low end of the range and, further, application of technological improvements to this low starting point is not representative of the future capital cost of wind in Manitoba. Manitoba Hydro's position is supported by GACs expert, Power Advisory[199], where they stated "To assume both declining capital costs and increasing capacity factors runs the risk of double counting".

As provided by La Capra[200], the effect on NPV of changes in assumptions made by La Capra to the Wind/Gas plan is $1,234M ($576M + $157M + $234M +$267M). In addition, as shown in LCA Exhibit #45 - Slide 70, even under this stress test, the La Capra Wind/Gas stress test yields the lowest 78 year NPV of the seven plans referenced. Mr. Peaco confirmed that even with the relatively optimistic scenario in the economic analysis the Wind/Gas scenario is still less economic than the Preferred Development Plan.[201]

The magnitude of the changes in the wind assumptions made by La Capra can only be described as extremely optimistic given the inherent uncertainty in the future costs of wind

[198] LCA Technical Appendix 3A, page 3A-28.
[199] Green Action Centre Evidence on Fuel Switching, DSM and Wind, pages 4-8.
[200] LCA Technical Appendix 3A, pages 3A-29.
[201] Transcript page 6234, line 24.

development and, therefore, La Capra's Wind/Gas analysis only has value as a stress test. For the purposes of long-term planning, it would be imprudent for resource planners to present such a stress test in a reference scenario comparison.[202] As a result, caution should be exercised when using the economic results related to the La Capra Wind/Gas analysis.

10.4 Risks of Proceeding with Hydro Generation as Next Resources

The risk analysis and the development of risk mitigation strategies are integral to the planning, design and implementation of new resources. This section will discuss the main risks and risk mitigation associated with hydro generation as the next resources.

10.4.1 Risks Associated with Keeyask and the 750 MW Interconnection

It is recognized that there are scenarios with downside risks in which Keeyask and the 750 MW interconnection would not have economic benefits to Manitoba Hydro, although most of the other benefits would still occur. Manitoba Hydro believes that these risks can be mitigated, as described below:

1. *Capital costs increase higher than expected*: Economic and Financial Evaluations, presented in Final Argument Sections 8 and 11, respectively, demonstrate this risk is manageable. Also, if Keeyask capital costs are higher than currently estimated, they likely would also be higher in the competing plans with Keeyask and no interconnection.

2. *Interest rates higher than reference scenario*: This risk was assessed in the economic and financial evaluations and would be manageable.

3. *Electricity export prices lower than reference scenario*: This risk was assessed in the economic and financial evaluations and would be manageable. This risk is mitigated by having long-term export contracts which reduce the exposure to market variations.

4. *750 MW Interconnection not approved by US and Canadian regulatory authorities*: The plans would revert to Plan 2, Keeyask followed by Gas. The benefits would be reduced but the impacts are manageable.

[202] LCA Exhibit# 45, Slide 70.

5. *Lake Sturgeon being listed under Species at Risk Act (SARA)*: If sturgeon are listed as endangered or threatened on the Lower Nelson River, there would be challenges in obtaining SARA operating permits in a timely manner. There could be cost impacts and a risk of delay in commissioning, but these are considered unlikely.

10.4.2 Risks Associated with Conawapa (Following Keeyask and the 750 MW Interconnection)

It is also recognized that there are scenarios with downside risks in which Conawapa would not have economic benefits to Manitoba Hydro, although most of the other benefits would still occur. Manitoba Hydro believes that these risks can be mitigated as follows:

1. *Capital costs increase higher than reference*: This risk can be mitigated by the optionality associated with Conawapa. Information directly pertinent to Conawapa will be obtained during Keeyask construction and if this information indicates that Conawapa costs are likely to increase, Manitoba Hydro would account for that in the business case and halt Conawapa protection and construction if warranted.

2. *Interest rates higher than reference scenario*: This risk would be taken into account in the ongoing monitoring and business case decisions.

3. *Electricity export prices lower than reference scenario*: This risk would be taken into account in the ongoing monitoring and business case decisions.

4. *Inability to successfully negotiate additional long-term contracts which would utilize Conawapa output*: Manitoba Hydro is actively progressing in negotiations with GRE, SaskPower and others. As discussed elsewhere, progress of the negotiations will be closely monitored and will influence decisions on Conawapa activities. The outcome of these negotiations will likely be known well before any Conawapa construction decision is contemplated.

5. *750 MW Interconnection not approved by Canadian and US regulatory authorities*: While Manitoba Hydro believes the interconnection most likely will be approved, the current schedule has the line approved in 2017, prior to a Conawapa construction decision. Should the approval not be forthcoming, the Conawapa activities would be delayed or cancelled.

6. *Lake Sturgeon being listed under SARA*: If sturgeon on the Nelson River are listed as endangered or threatened, there could be challenges in obtaining SARA permits related to Critical Habitat destruction and operations. While Manitoba Hydro expects these challenges will be manageable, the listing decision is expected prior to the Conawapa construction decision and would be taken into account.

10.5 Other Factors That Improve the Economic and Financial Analysis

The economic and financial evaluations utilize the most current information available when the evaluations are performed. Uncertainties are dealt with in the probabilistic scenario analysis, sensitivities and stress tests. However, when undertaking the reference scenario evaluations the input factors and assumptions do not account for certain factors which would affect the evaluations significantly but are not included because there is insufficient specific information to include them at the time or because they became known after the evaluations had been started. Relative to the original August 2013 submission, certain important factors have been included in the 2014 updates such as project capital costs, WPS contract terms and conditions and DSM program updates. As provided in Section 14.5 of the Submission and updated by Mr. Wojczynski during oral testimony[203], there are other factors common to the economic and financial evaluations which have not been able to be included in the updates which are judged to be significant.

10.5.1 Additional Long-term Export Contracts

The economic and financial evaluations do not include a number of known potential export contract opportunities for which the specifics are not sufficiently known to include in the evaluations at this time. As Ms. Flynn testified, inclusion of these export opportunities would increase the economic and financial net benefits and decrease risk, especially of the new interconnection and Conawapa. These export contract opportunities include Great River Energy 600 MW, SaskPower 500 MW, NSP 500MW extension beyond 2025, NSP Diversity beyond 2025 and others which are under discussion but cannot be publicly discussed at this time at the request of the counterparty.

[203] Transcript pages 3682-3683.

10.5.2 Interconnection to Wisconsin Increases Market Access and Overall Export Market Price for Manitoba Hydro

While the evaluations assume that the amount that could be exported or imported would increase with the addition of the new interconnection, they also assumed that the export market price structures with the interconnection addition would remain similar to the price structures without the new interconnection. Mr. Cormie testified that in actuality, the likelihood is that the export prices would increase with the addition of the interconnection.[204] The prices would be increased because there would be a significant number of new counterparties for Manitoba Hydro to contract with and compete with existing counterparties for long-term firm and opportunity term sales. The amount of increases cannot be readily be estimated but would be noticeable and thus increase the benefits associated with adding the interconnection and new hydro.

10.5.3 Interconnection Investment Likely Transferred to Other Counterparties

The evaluations of the 750 MW Interconnection plans assume Manitoba Hydro will be investing in and owning a portion of the US segment of the 750 MW interconnection and that the percentage amount owned stays constant for the life of the interconnection asset. As discussed in Chapter 14 of the NFAT submission, at page 31, it is Manitoba Hydro's intent to arrange for some or all of the Manitoba Hydro ownership to be transferred to another owner for the economic benefit of Manitoba Hydro as soon as an appropriate opportunity can be developed. Mr. Cormie indicated he expects there will be US entities interested in taking over such transmission ownership due to the investor benefits that would accrue and that Manitoba Hydro is in fact in active discussions with a transmission owner who is keenly interested. This would reduce the cost to Manitoba Hydro and increase the net benefits of the plans with the 750MW interconnection.[205]

10.5.4 Interconnection Likely has More Operational Benefits than Captured by Current Modeling

Any modeling of physical or economic systems inherently involve approximations and cannot capture precisely the variety of ways that value can be extracted from those systems. History has demonstrated that Manitoba Hydro's modeling of the generation/transmission system and exports/imports is conservative and does not capture all the benefits associated with expanding the interconnections. Mr. Colaiacovo noted in his evidence that

[204] Transcript, p 2427
[205] Transcript, p.1628

"Optimization is something that you can only do once the assets are actually there. And transmission assets are very flexible and allow you to make optimization decisions after the fact. There is a reason that transmission assets commercially command very high premiums: because you can make money on transmission assets in a variety of different ways."[206]

[206] Transcript page 7295, line 13.

11.0 DROUGHT

11.1 MH Position

Manitoba Hydro's drought management plan is consistent with the requirements of: the Manitoba Hydro Act, and includes elements of the Generation Planning Criteria[207], the Power Resource Plan[208], System Operating Priorities[209], Energy Operations Planning Processes[210], and its Detailed Operating Plans.

11.2 Drought: Keeping Drought from Being an Emergency

La Capra's evidence (LCA Technical Appendix 5, page 5-7) and testimony (Tr. p. 6451-54) suggests that La Capra was not able to find answers to the questions they were asked to pursue in the Manitoba Hydro drought management information they reviewed. Drought management is an integral part of all of Manitoba Hydro's financial and facilities planning and operations; it begins with its legislative mandate to "provide for the continuance of a supply of power adequate for the needs of the province" (*The Manitoba Hydro Act*, Section 2) and culminates with detailed energy operations plans that are prepared weekly. As explained by Ms. Flynn, Manitoba Hydro takes drought very seriously:

> "With respect to Manitoba Hydro's generation planning criteria, Manitoba Hydro has technical criteria for ensuring that the lights stay on, that our homes are warm, and industry continues to hum in the province. This is a responsibility that Manitoba Hydro takes very seriously and that generation planners and systems operators lose sleep over. We cannot underestimate the responsibility that [Manitoba Hydro] has for reliability and dependability of supply to Manitobans." (Tr. p. 1292-93)

Manitoba Hydro's drought management plan, in its most broad form, is the combination of the Manitoba Hydro Act, Generation Planning Criteria, Power Resource Plan, System Operating Priorities, Energy Operations Planning Processes and MH's detailed operating plans.

<u>Planning for Drought: *The Manitoba Hydro Act*</u>

[207]NFAT Application Appendix 4.1 - Manitoba Hydro Generation Planning Criteria.
[208]NFAT Application Appendix B - Manitoba Hydro 2011/12 Power Resource Plan.
[209] Attachment 1 to PUB/MH I-147(a)(ii) of the 2010/11 & and 2011/12 GRA and Risk Review, also included in MH CSI Undertaking #15 Energy Operations Planning – Drought Management.
[210]MH CSI Undertaking #15 Energy Operations Planning – Drought Management.

Manitoba Hydro's planning and operations are governed by *The Manitoba Hydro Act*,

> "The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power ..." (*The Manitoba Hydro Act*, Section 2)

Accordingly, Manitoba Hydro plans the development and the operation of its system to be prepared for drought.

Planning for Drought: Generation Planning Criteria

Drought preparedness for Manitoba Hydro begins with the Generation Planning Criteria which includes an energy criterion that recognizes the predominately hydro nature of Manitoba Hydro's system. Manitoba Hydro must plan to have sufficient energy in its system in the event of a repeat of the worst drought on the record of 99 years of hydraulic flow data. In its review, La Capra did not raise any concerns with Manitoba Hydro's energy criterion as it is applied to hydro resources, stating "MH's energy criterion requires dependable resources to be available in the event of a repeat of the driest flow conditions, which is generally consistent with other hydro-dependent systems[211]."

Planning for Drought: The Power Resource Plan

The Power Resource Plan is a product of the Generation Planning Criteria.

> "Through the power resource planning process, Manitoba Hydro assesses the need for new resources, reviews potential resource options, and evaluates new resource development plans. The process and results are documented in the Power Resource Plan. The recommendations define the long-term development plan which best ensures that adequate supply resources are available to meet all firm domestic load requirements together with existing electricity export sale commitments." (NFAT Business Case, Chapter 1, page 19).

[211] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-17.

Planning for Drought: System Operating Priorities

As explained in the response to LCA/MH II-461, Manitoba Hydro plans its operations with the guidance of System Operating Priorities. Documented in 1988, those priorities were first filed with the PUB as part of the 2010/11 & 2011/12 GRA and Risk Review[212]. The System Operating Priorities (updated to explicitly include Safety) were also included in the document "Energy Operations Planning – Drought Management" filed as MH CSI Exhibit #15. They are as follows:

1. Safety;
2. Energy Supply;
3. Energy Reserves;
4. Reliability;
5. Citizenship Concerns;
6. Economic Operation

Planning for Drought: Energy Operations Planning

Manitoba Hydro has documented the procedures and processes involved in energy operations planning, including under drought conditions, in the CSI document, "Energy Operations Planning – Drought Management"[213]. The purpose of this document is to outline the factors Manitoba Hydro must consider in maintaining an adequate supply of electricity for its customers in anticipation of and during drought conditions. The document outlines the roles and responsibilities, processes and reporting requirements related to drought. This document also provides guidance on the issues that should be considered in operations planning and operational drought risk management.

Planning for Drought: The "Drought Operating Plan"

The Energy Operations Planning – Drought Management document[214] describes in detail the assumptions behind the Drought Operating Plan. The Drought Operating Plan is a forward looking supply and demand balance – a sequence of planned reservoir releases, generation and import and export activities for a defined set of conservative assumptions. Key assumptions include future water supply conditions, thermal generation availability, wind generation supply, import capability and domestic load.

[212]Attachment 1 to PUB/MH I-147(a)(ii) from 2010/11 & 2011/12 GRA and Risk Review.
[213]MH CSI Exhibit #30, "Energy Operations Planning – Drought Management".
[214] MH CSI Exhibit #30, "Energy Operations Planning – Drought Management".

In essence, the Drought Operating Plan, which is updated weekly, is a detailed supply and demand plan based on conservative assumptions for the remainder of the operating horizon. The Energy Operations Planning - Drought Management document[215] sets out in detail the fundamental requirements of the Drought Operating Plan.

La Capra was provided with The Energy Operations Planning - Drought Management document which was also filed with the PUB as MH CSI Exhibit #30. The operating parameters and many of the assumptions that make up the Drought Operating Plan were also described in the twenty-seven IR responses from past GRAs, which were included in Manitoba Hydro's response to LCA/MH II-461.

Manitoba Hydro Reasonably Addresses and Manages Drought Risk in Resource Planning

Manitoba Hydro mitigates and incorporates drought risks through various steps in the resource planning process. Managing the reliability risk to the energy supply is achieved by adhering to Manitoba Hydro's Generation Planning Criteria, while the financial risk is incorporated into the main economic and financial analyses and studied separately through sensitivity analysis. Manitoba Hydro maintains that while the financial impacts of a prolonged drought are significant, corporate strategies for managing financial impacts of drought are not significantly influenced by the different development plans being studied as the Manitoba Hydro system is a predominantly hydroelectric system and will remain so well into the future.

Manitoba Hydro has the benefit of a long history of streamflows that provides a well-defined hydrologic risk profile which includes significant flood and drought events. Dr. Roy noted that Manitoba Hydro was fortunate to have such a long streamflow record[216]. Manitoba Hydro's economic and financial analysis used for planning, rate setting and financial forecasting purposes benefit from this long record. Manitoba Hydro uses the SPLASH model to simulate system operations for each of the 99 historical streamflow conditions in order to cover the range of possible flow conditions that may occur in any given year in the future. The individual components of the annual production costs and extraprovincial revenues are then averaged over the 99 flow cases to create average annual values based on all of the historical hydrologic conditions, including all historic droughts. The average annual values are then used as Manitoba Hydro's projection of long-term production costs and extraprovincial revenues.

[215] Ibid.
[216] Transcript page 1932, lines 9-13.

In addition to including all historical drought conditions in the expected projections of production costs and extra provincial revenues, Manitoba Hydro has performed an economic sensitivity analysis on the specific occurrence of a prolonged drought[217].

Manitoba Hydro maintains that the five-year historical drought from 1987/88 to 1991/92 modeled in the NFAT submission is both reasonable and appropriate for illustrating the differences in hydrological risks between development plans required to support long-term resource planning decisions.

La Capra initially raised concern with respect to Manitoba Hydro's drought analysis, however, La Capra ultimately supports Manitoba Hydro's position that the 1987/88 to 1991/92 period is adequate for reflecting drought risk when they stated "We examined the -- the effects of a number of different stream flow sequences from the period of record included in this -- in this technical appendix, and showed some of the sensitivity that -- I think that we found -- we didn't find that there was substantial added exposure for extended periods of drought consideration."[218]

Manitoba Hydro's economic analysis of drought assessed the impact of a repeat of the prolonged five-year historical from 1987/88 to 1991/92 on plans with increasing amounts of new hydro generation and interconnections compared to plans with new thermal generation[219].

Manitoba Hydro's analysis shows that in development plans with additional hydro resources, the negative impact of a prolonged drought is incrementally larger than that of development plans with additional thermal generation. This is expected as there is incrementally more projected surplus opportunity revenue when additional hydro resource options are added that will not be realized under drought conditions. Notably, the economics for plans with additional thermal resources, under prolonged drought, are more sensitive to changes in energy prices than plans with additional hydro resources. This is mainly attributable to plans with additional thermal generation having a greater overall proportion of variable fuel costs which are sensitive to energy prices.

Manitoba Hydro has also performed a financial drought sensitivity analysis to explore the impact of a prolonged drought on the Corporation's retained earnings (Chapter 11, Section 11.4 of the NFAT Business Case). Three development plans were used to illustrate the

[217] Chapter 10 NFAT Business Case
[218] Transcript page 6454.
[219] MH Exhibit #125.

impact on retained earnings on varying levels of investment in hydro development and interconnections. Similar to the economic sensitivity of drought, the droughts were applied in the financial analysis over the same range of future start dates and across the energy prices studied. Plans with additional hydro resources are robust in that hydro has the capability to absorb the adverse financial effects of a prolonged drought. At the end of the prolonged drought the retained earnings remain higher and consistently positive with additional investment in hydro development.

A key conclusion from the analysis of drought is that the impact of prolonged drought is a significant reduction in retained earnings regardless of timing of the drought or resource planning decisions. This result is to be expected in predominantly a hydro system as acknowledged by MPA when they state:

> "But as we referred to in our report, if you have, you know, the drought of the century, it doesn't matter which choice you make between the Development Plans of the fifteen (15) plans presented to Manitoba Hydro. If you have the drought of the century, it's a severe blow to Manitoba Hydro regardless of the Development Plan chosen, right, because you have 5,000 megawatts of hydro capacity already mostly on, you know, the same group of river systems."[220]

Overall Manitoba Hydro's development plans which include new hydro resource options are robust in their ability to absorb the incremental adverse financial effects related to drought. Manitoba Hydro submits that it reasonably addresses and manages its exposure to drought.

[220] Transcript pages 7290-7291.

12.0 RELIABILITY AND ENERGY SECURITY

By having increased access to imports and by having increased domestic generation, Pathways 4 & 5 provide Manitobans with a higher level of system reliability to address generation or major transmission outages or unexpectedly high load peaks. They also provide Manitobans with a higher level of energy security to mitigate unexpectedly severe droughts or unexpectedly high energy consumption (Submission Chapter 14 and LCA/MH I-0037). None of the NFAT participants disagreed with or challenged Manitoba Hydro's evidence in this regard. A number of witnesses concurred that adding interconnection capability is valuable for a number of reasons, one of them being improvement in system reliability.[221] [222] [223]

The measure for grid reliability is the loss of load expectation which is a standard industry engineering technique used to evaluate capacity reliability (Tr. p 1493 lines 4-9). Manitoba Hydro analyzed the different plans and compared system reliability using loss of load expectation. Mr. Wojczynski indicated:

> "when we analyze the plans and -- and determine how much reliability we have, we have a result where the plans with the interconnections and generation advanced for export provide a much higher level of reliability than a plan where you have an all gas plan where you get just exactly the minimum amount of generation and nothing extra" (Tr. p. 1494, line 5).

The Preferred Development Plan with a 750 MW interconnection provides 500 to 1,000 megawatts more load carrying capability (Tr. p. 1494, line 19). Mr. Wojczynski contrasted this with the All Gas plan, wherein he testified: "If you have a gas plan, those gas generators don't bring you anything extra". (Tr. p. 1495, line 6).

Over the 20 years starting with the 2019 Keeyask ISD, should Manitoba experience a drought significantly more severe than the worst drought on record, the 750 MW Interconnection Plans provide significant 3,000 to 6,500 GWh emergency energy imports from Minnesota and Wisconsin to meet Manitoba domestic load compared to the All Gas Plan and Keeyask/Gas Plan.

[221] Power Engineers, Mr. Arnold, Transcript page 6588.
[222] La Capra, Mr. Peaco,Transcript page 5701.
[223] Mr. Bowman, Transcript page 10068.

Manitoba Hydro estimated the benefit of increased reliability to Manitoba electricity consumers from the Preferred Plan relative to the All Gas plan to be $101 Million NPV. The interconnection plans without Conawapa would provide a large portion of these reliability benefits. The additional energy security benefits would be even larger than the reliability benefits (Tr. p. 3701, line 15). The importance of reliability to Manitoba electricity users was confirmed by MIPUG in its Final Argument (Page 40, lines 37-38): "Specifically for MIPUG, the current interconnection and hydro system has generally proven to support the reliability, stability and long-term benefits important to industrials." When the reliability and energy security benefits are added together, they would total more than $200 Million NPV.

In conclusion, the 750 MW Interconnection plans provide a major enhancement to the reliability and energy security of the electrical supply to Manitobans; the benefits to electricity consumers are expected to be greater than $200 Million NPV.

13.0 FINANCE

There has been a significant amount of evidence, and a number of alternative analyses filed during the course of this proceeding. In considering the financial analysis of the PDP and alternatives, Manitoba Hydro focused on comparative impacts on future customer rates, and Manitoba Hydro's comparative exposure to financial risk. Notwithstanding the significant review and exchange on information, Manitoba Hydro finds that its conclusions with respect to the comparative impacts on future customer rates and financial risk have remained largely unchanged from the original NFAT Submission.

First considering the impact on future customer rates, Manitoba Hydro's conclusions with respect to the future customer rates can be summarized as follows:

1) Near-term rate increases in the order of 3.95% are required regardless of the development plan chosen;
2) In the medium term, the Preferred Development Plan is projected to have cumulative rate increases that are generally higher than other alternatives. All other plans evaluated have similar rate increases in the medium term;
3) In the long term, plans with both Keeyask and Conawapa are projected to have the lowest cumulative rate increases. The All Gas Plan and Keeyask/Gas/no interconnection have the highest cumulative rate increases. The plans with Keeyask and the 750 MW Interconnection have significant lower cumulative rate increases than the All Gas Plan and Keeyask/Gas/no interconnection;
4) The Preferred Development Plan is projected to have the lowest cumulative rate increases to Manitoba customers over the long term, supporting the position that an early in-service date for Conawapa should be protected.

Manitoba Hydro's conclusions regarding financial risks will be addressed below.

13.1 The Myth of the 2% Electric Rate Increase in Canada

Electric utilities across Canada are facing cost pressures driving the need for higher than inflationary rate increases. Manitoba Hydro is not unique or alone in this regard. As outlined by Mr. Barnlund in his testimony at transcript pages 2746 to 2749, Canadian electric utilities expanded and built their electrical systems after the Second World War and this infrastructure is now at or near the end of its useful life requiring refurbishment or replacement. The Conference Board of Canada produced analysis that electric utilities across

Canada will be required to invest approximately $350 billion between 2011 and 2030 (MH Exhibit #111, slide 27).

The rate increases sought and approved in other Canadian jurisdictions have and continue to be significantly driven by the need for this specific reinvestment. As Mr. Rainkie stated,

> "That's why the myth of the 2 percent rate increase in Canada is -- is that, a myth." (Tr. p. 3047).

Higher than inflation rate increases are being proposed by other utilities across Canada for 2014 and on. For example:

- BC Hydro rates increased by 9.0% effective April 1, 2014 and will increase by 6.0% in 2015 as directed by the British Columbia government. The rate increases for 2016, 2017 and 2018 have been capped by the BC government at 4.0%, 3.5% and 3.0% respectively;
- SaskPower implemented a rate increase of 5.5% effective January 1, 2014, and has received approval to increase rates by 5.0% in 2015;
- Nova Scotia Power implemented a general rate increase of 3% in 2014, which when combined with increases to the DSM Cost Recovery Rider, resulted in overall rate increases ranging from 3.1% to 4.5% depending on the rate class;
- The Régie de l'énergie approved a rate increase of 4.3% (3.5% for the large industrial customer class) for Hydro Quebec effective April 1, 2014;
- Lastly, in accordance with the Ontario government's 2013 Long Term Energy Plan, residential bills for Ontario consumers could increase by approximately 9.6% in 2014, 5.8% in 2015 and 15.0.% in 2016.

By direct comparison, Manitoba Hydro's projected 3.95% rate increases are moderate relative to other Canadian utilities. Even when considering rate increases approved and proposed by other Canadian electric utilities since 2006, Manitobans continue to enjoy electricity rates that are at or near the low end for rates of Canadian utilities as evidenced by Manitoba Hydro's lower relative current rate index found in the Cumulative Rate Table in Manitoba Hydro's rebuttal evidence (MH Exhibit #85, p.137). MPA stated,

> "fundamentally, you are a Hydro province and you're going to remain that way with all of the benefits that that brings, because it does bring a lot of benefits: the fact that your rates over the last twenty (20) years have been much lower than most other jurisdictions" (Tr. p.7291).

In reviewing the projected annual bill comparisons between Manitoba, British Columbia, Saskatchewan and Quebec over the next 10 years (MH Exhibit #111, p. 30), Mr. Barnlund surmises that:

> "there's no information available to us that suggest that utility costs are going to become dramatically cheaper in other jurisdictions compared to where we are today in Manitoba. So the relative relationship between our rates and those other rates, you know, will not diminish significantly." (Tr. p. 2756, lines 13-19).

As in the past, Manitoba Hydro will continue to balance rate increases with customer sensitivity in a fiscally prudent manner. Furthermore, Manitoba Hydro's current ratepayers will continue to benefit into the future from the low cost past long-term investments in addition to the future long-term investments proposed by the Corporation.

13.2 Near-Term Rate Increases of 3.95% are Required Regardless of the Development Plan Chosen

Manitoba Hydro currently has more than $13 billion worth of assets on its balance sheet which the Corporation must maintain and for which the Corporation must recover costs. Additional investment in Manitoba Hydro's existing assets is required to ensure ongoing safe and reliable service. It is important that rates are increased gradually over this time period in order to provide adequate revenues for the required investment in existing infrastructure, meanwhile avoiding the necessity of seeking higher rate increases in the future.

Even with the addition of development plans, the Manitoba Hydro electric system will be comprised predominantly of existing infrastructure for a significant period of time. As a result, the need for rate increases in the first 5 to 10 years is driven by the need to invest in system reliability enhancements and in aging utility assets that are becoming significantly more costly to maintain and renew. Costs related to development plans are deferred and have no direct impact on rates prior to their in-service dates.

Manitoba Hydro has historically funded base capital expenditures (that is, capital expenditures not related to the development plans) through internally generated funds. However, Manitoba Hydro is now projecting capital coverage ratios below 1.0 until approximately 2016/17, indicating that projected revenues at current rates are not sufficient to fund base capital expenditures. Gradual rate increases are required to ensure Manitoba Hydro is collecting the necessary revenues to maintain its financial sustainability over the long run. As such, projected rate increases of 3.95% over the near term are the minimum rate increases required under all development plans to provide for the necessary investment in infrastructure, and to allow the Corporation to continue to provide safe and reliable service.

Regardless of which plan Manitoba Hydro develops, there are financial challenges in the near term and rate increases are required under all development plans. Mr. Rainkie testified that:

> "…the reality is, in the next five (5) to seven (7) years, there is no new generation source in. We would be asking for the 3.95 percents under the All Gas Plan, as well. In fact, there's more pressure under the All Gas Plan, because we're amortizing some of the sunk costs of Keeyask and Conawapa" (Tr. p. 2774).

This position was supported by MPA at transcript pages 7315 and 7316, wherein MPA describes the relative competitiveness of Manitoba Hydro's projected rates:

> "…regardless of the plan, it includes years of rate increases for a variety of reasons … ratepayers are not going to be happy about many years of increases. But the mitigating factor is that in other jurisdictions there are rate increases as well. Ontario has had nothing but rate increases for the past fourteen (14) years. Quebec is facing rate increases. Newfoundland is facing rate increases. British Columbia is facing rate increases."

13.3 50 Year Time Period Is Appropriate For Financial Evaluation

A 50 year time period was selected for the NFAT financial evaluation to be consistent with the long-term nature of hydro-electricity assets, and to provide a sufficient time frame to analyze the benefits and costs of each development plan recognizing that in all cases the first plant is not in place until 2019, and in the case of Conawapa, the earliest in-service date is 2026. The Electric Operations Financial Forecast was the starting point for each set of pro forma financial statements and was extended to encompass the 50-year study period for evaluation purposes.

13.4 Rate-Setting Methodologies

The August 2013 NFAT submission rate setting methodology assumed even-annual rate increases in order to achieve the targeted debt:equity ratio by the end of 2031/32. Once the debt:equity target was reached, the projected comparative annual rates for the remainder of the 50-year financial forecast period utilized the corporation's interest coverage ratio target of 1.20.

In order to mitigate cumulative losses in the early years of the financial evaluation period and to smooth rate increases in the 2032 timeframe, the April 2014 supplementary financial analysis (MH Exhibit #104-12) provided two additional alternative rate setting methodologies:

1) Maintaining annual 3.95% rate increases in each development plan until 1.20 interest coverage ratio is achieved and rates required to maintain 1.20 thereafter (similar in methodology to MPA financial modeling); and
2) Modifying alternative 1 with rate increases as necessary in the period 2016 to approximately 2022 in order to minimize losses, followed by annual 3.95% rate increases until a 1.20 interest coverage ratio is achieved (and with subsequent rates required to maintain a 1.20 interest coverage ratio).

These additional methodologies eliminated the large decrease in rates that occurred in 2033 as a result of the application of the first rate setting methodology (the so-called "correction factor"). In addition to achieving moderate levels of net income (or minimizing losses), the alternatives provided were in direct response to the discussion between the Chairman and Mr. Rainkie beginning at transcript page 2773 and were intended to aid in the Panel's understanding of the rate impacts without the dramatic changes in rates following the initial 20-year period. The alternative rate methodologies were designed to be more closely aligned to rate changes based on income levels that Manitoba Hydro may propose in practice.

As shown in the following table (excerpted from MH Exhibit #104-12-7), even with rate increases of 3.95% per year using Alternative Rate Method #1, the Plans 1, 5, 6 and 12 result in cumulative losses to 2021/22 of approximately $0.3 to $0.7 billion. It is not until rate increases are raised using Alternative Rate Method #2 to between 4.32% and 5.60% for 5 to 7 years that the cumulative losses are minimized. As noted previously, Plan 4 is considered hypothetical from a business perspective as a 250MW interconnection would require renegotiation of a contract with Minnesota Power and is not likely to be approved by US authorities.

	Main Submission Rate Method Even-Annual Rate Increases	Main Submission Rate Method Cumulative Net Income/(Loss) 2014/15 – 2021/22	Alt. Rate Method #1 Cumulative Net Income/(Loss) @ 3.95% 2014/15 – 2021/22	Alt. Rate Method #2 Even-Annual Rate Increases	Alt. Rate Method #2 Cumulative Net Income/(Loss) 2014/15 – 2021/22
Plan 1	3.36%	$(1,019)	$(688)	5.46% (2016-2020)	$7
Plan 2	3.55%	(504)	(279)	5.60% (2016-2020)	403
Plan 5	3.74%	(550)	(434)	4.60% (2016-2022)	(59)
Plan 6	3.75%	(536)	(426)	4.59% (2016-2022)	(59)
Plan 12	3.76%	(443)	(333)	4.44% (2016-2022)	(53)
Plan 14	4.27%	82	(99)	4.32% (2018-2022)	10

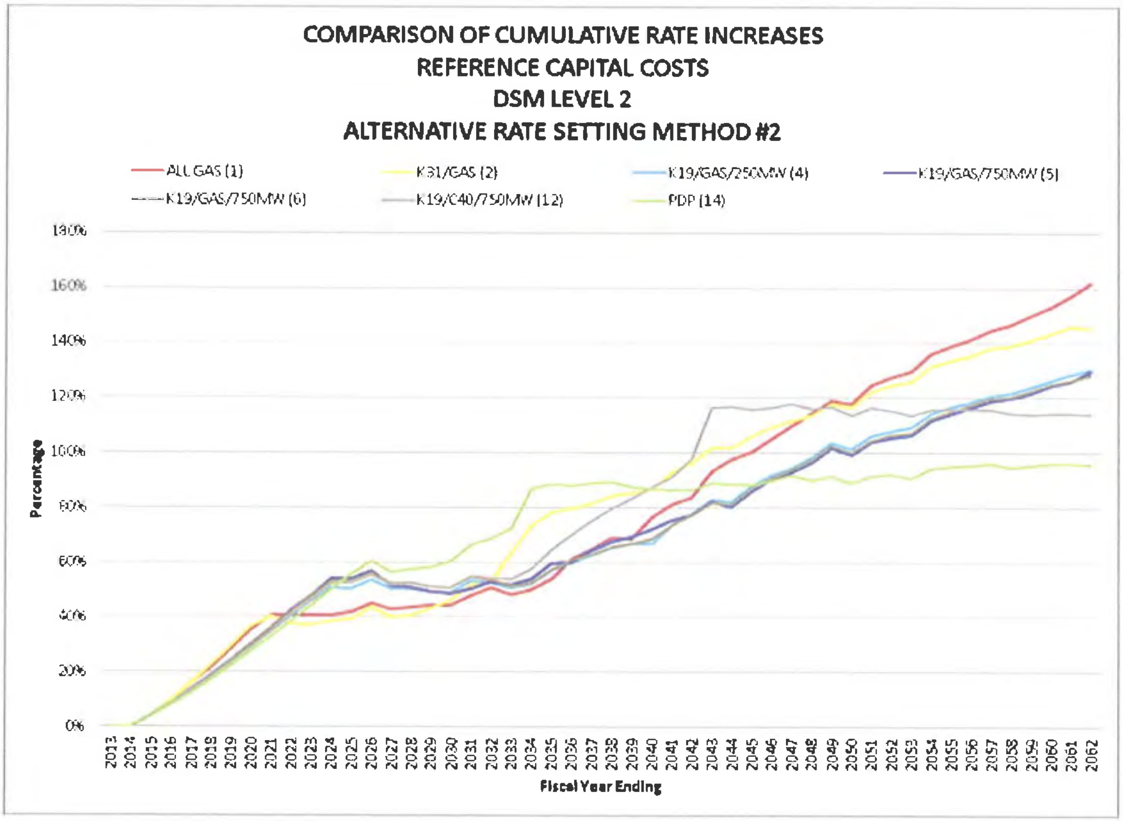
13.5 Projected Cumulative Rates 2015-2062

In the August 2013 NFAT submission, Manitoba Hydro prepared its financial evaluation based on eight (8) of the development plans included in the economic analysis under 27 different combinations of scenario assumptions including economic variables, capital cost and export prices to form 216 distinct sets of pro forma financial statements.

The April 2014 supplemental filing (Manitoba Hydro Exhibits #104-12-1 to 104-12-4) provided an update to two of the plans analyzed in the August 2013 NFAT submission financial evaluation (the All Gas Plan 1 and the PDP Plan 14), along with a new financial analysis of Plan 5 (Keeyask/Gas/750). Manitoba Hydro filed the May 2014 supplemental information (Manitoba Hydro Exhibits #104-12-5 to 104-12-7) to the August 2013 NFAT submission and the April 2014 supplemental filing which included Plans 2, 4, 6 and 12 with DSM Level 2 as well as Plans 1, 5 and 14 under DSM Level 2 with incremental pipeline load.

These plans were updated to reflect 2013 planning assumptions as well as the March 2014 updated capital costs for Keeyask and Conawapa, and consumption savings and utility costs associated with increased DSM (capitalized in a deferral account and amortized over 10 years). The 750 MW US interconnection in the updated Plans 14 and 5 assumes no WPS investment. It should also be noted that the aforementioned updates were made to the IFF12 forecast model used for NFAT evaluation purposes as the IFF13 forecast model was not extended for the 50-year study period. As such, the base capital expenditures (common capital) reflect IFF12 assumptions and there was no update for actual 2013 financial results.

The Figure and Table below show the cumulative rate increases based on alternative rate setting method #2 at DSM Level 2. This rate setting method is reflective of the approach that may be applied by Manitoba Hydro in future General Rate Applications, and as explained in Section 10.3.1, is the level of DSM upon which Manitoba Hydro focused its analysis.



Excerpted from MH Exhibit #104-12-5, p. 2

CUMULATIVE RATE INCREASES AT DSM LEVEL 2 USING ALTERNATIVE METHODOLOGY #2 AND REFERENCE CAPITAL COSTS		
	2031/32	**2061/62**
ALL GAS (1)	51%	162%
K31/GAS (2)	53%	145%
K19/GAS/750 MW (5)	53%	130%
K19/GAS/750 MW (6)	53%	128%
K19/C40/750 MW (12)	54%	114%
PDP (14)	69%	96%

Excerpted from MH Exhibit #104-12-5, p.3

The Figure and Table above demonstrates that:

1) In the medium term, the Preferred Development Plan is projected to have cumulative rate increase of 69%. All other viable plans evaluated have similar rate increases that range from 51 – 54%;

2) In the long term, plans with both Keeyask and Conawapa are projected to have the lowest cumulative rate increases. The PDP at 96% and Plan 12 at 114%. The All Gas Plan and Keeyask/Gas/no interconnection have the highest cumulative rate increases at 162% and 145% respectively. The plans with Keeyask and the 750 MW Interconnection have significantly lower cumulative rate increases in the order of 130% when compared to the All Gas Plan (162%) and Keeyask/Gas/no interconnection Plan (145%).

The Preferred Development Plan is projected to have the lowest cumulative rate increases to Manitoba customers over the long term, supporting the position that an early in-service date for Conawapa should be protected.

13.6 Manitoba Hydro Financial Targets

The alternative rate methods are provided as information to this NFAT proceeding and are in no way an indication that Manitoba has recommended or accepted revisions to its financial targets.

In its final argument at page xii, MIPUG concluded that Manitoba Hydro should adopt lower debt:equity and interest coverage targets for at least the next 20 years in order to mitigate the costs of higher rates and risks associated with higher debt in pursuing a development plan with a Keeyask 2019 in-service date and a 750 MW transmission line to the US. In making this conclusion, MIPUG referenced the alternate rate setting methodologies #1 and #2 that were presented by Manitoba Hydro in MH Exhibit #104-12 as a suggestion that Manitoba Hydro is prepared to significantly yield on the debt:equity target. MIPUG goes on to state at page 46 of its written argument at lines 25 to 28 "There was no opportunity to cross-examine Hydro on these Rate Design Alternatives, so it is not clear the extent to which they truly represent a potential policy decision to yield on financial targets imposed on customers, or are solely a theoretical analytical exercise".

While Manitoba Hydro did not have an opportunity to speak to the alternate rate setting methodologies that were filed towards the end of the hearing, the filing of this additional material arose from a discussion between the Chairman and Mr. Rainkie at pages 3025 to 3032 of the transcript. To be clear, this additional material does not suggest a policy change or yielding of financial targets on the part of Manitoba Hydro as suggested by MIPUG, but rather is a means of providing additional flexibility in terms of the quantum of the rate increases and the "pace" of moving towards the attainment of the financial targets. The alternate rate setting methodology is consistent with the approach successfully used in the past by Manitoba Hydro to promote rate stability for customers while at the same time ensuring the financial integrity of the Corporation.

While Manitoba Hydro may be prepared to accept some slippage in returning to its financial targets beyond 2032, it is only prepared to do so if it is fiscally prudent. Manitoba Hydro had indicated in its rebuttal evidence that:

> "If circumstances such as favourable water flows and sufficient cash flows are present [emphasis added] in the latter part of the 20-year time period, Manitoba Hydro may have some flexibility to taper off the projected even-annual rate increases but this would have the effect of extending the timeframe of achieving the 75:25 debt/equity ratio target" (MH Exhibit #85, p. 136).

It is not clear whether or not MIPUG is requesting the PUB to make a recommendation in its NFAT report that Manitoba Hydro should adopt lower financial targets, or if this is simply a suggested option for future consideration. Manitoba Hydro notes that in Order 43/13, Directive #10, the PUB has directed Manitoba Hydro to review the adequacy of its financial targets and report on this subject to the PUB at the next General Rate Application which is anticipated to be filed late in 2014 or early in 2015. As such, it would be premature for the NFAT panel to make any firm recommendations on Manitoba Hydro's financial targets in advance of the review of this matter by the Manitoba Hydro-Electric Board and the receipt and consideration of this report by the PUB at the next GRA.

MIPUG has also argued that the projected level of retained earnings under each of the development plans is in excess of the amounts required to mitigate the financial effects of a drought (Tr. p. 11236, MIPUG Exhibit #28, p. xii and 76-77). Manitoba Hydro's financial targets were established to aid the Corporation in managing all of the risks faced by the Corporation. While drought is a high impact, high likelihood type of risk, there are others such as a major infrastructure loss that are a high impact, lower likelihood risk but that the magnitude and duration of such a loss could overwhelm the impacts of a drought. If the Corporation faces more than one risk concurrently, the importance of having adequate retained earnings increases. MIPUG's use of drought as a measure of retained earnings adequacy would be insufficient and would potentially expose customers to significant rate increases.

13.7 Sunk Costs

In discussing the issue of sunk costs, MIPUG concluded that the sunk cost calculations favour plans with Keeyask and Conawapa and produce artificially high rate increases to plans without these plants.

Manitoba Hydro stated in the Information Request process that the full amount of sunk costs related to prior spending will likely not be written-off but rather portions of those sunk costs may be written-off periodically as they are deemed to no longer provide future benefit. Manitoba Hydro indicated that a simplifying assumption was made to amortize the total sunk costs over an 18-year period. The choice of a long period, as compared to a shorter period or a one-year period, was intended to achieve approximately the same net income impacts as a series of one-year write-offs for portions of the sunk costs deemed not useful. As a result, the simplifying approach does not skew projected rate impacts in plans with no Conawapa.

Morrison Park Advisors supported Manitoba Hydro's view that sunk costs must be considered in the evaluation of development plans:

> "If however, Manitoba Hydro does not go forward with it, that real money that was spent still has to be addressed somewhere in the Company's financial

statements. And typically it's expensed. It -- it becomes an expense item and in the year or years in which it's expensed, then Manitoba Hydro will have either no profit, or negative profits, or less profit than it otherwise would have, which will have an impact and a consequence on its equity ratio, because it will reduce retained earnings. The -- there is no way around It -- it's real money, real cash that was spent. And so it has to be taken into account somehow....

However, the reality is if you don't go forward with the Keeyask project, you still have to pay the $1.4 billion. So that $1.4 billion loss, if you will, in certain circumstances has to be addressed and taken into account. So is that in some sense unfair to other options? Well, I suppose. If an alternative option only costs $4 1/2 billion and Keeyask all-in costs 5 1/2, once you add the sunk costs of Keeyask onto the other option, suddenly it doesn't look so attractive. Fair or not, that's reality. Right? And that's how you have to address the attractiveness of the different options, because it's what ratepayers have to pay." (Tr. p. 7282-7283)

The Chairman raised a question regarding the potential rate impact associated with proceeding with Conawapa protection in the event that the project is later cancelled. Manitoba Hydro provided a response in MH Exhibit #149.

Based on the projected expenditures in the response to PUB/MH I-238c, the total actual and projected expenditures, including escalation and interest, are approximately $650 million (in nominal dollars) to the end of 2016/17. If at the end of 2016/17 the Conawapa Generating Station was deferred, the Corporation would continue to regard the facility as a potential resource option and would periodically assess whether the costs incurred to date would continue to provide future benefit. Costs which continue to provide future benefit would continue to be deferred and costs which do not provide future benefit would be required to be expensed. If a simplifying assumption is made, similar to the All Gas development plan, where the costs incurred to the end of 2016/17 are amortized over an 18 year period and the debt/equity ratio of 75:25 is achieved by 2032, the impact on rates is approximately an additional 0.07% per year to 2032.

13.8 Cumulative PV of Consumers' Revenue

The primary focus of the financial analysis is on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk. Affordability and the distribution of costs and benefits on a year by year basis are also addressed. As part of the

Information Request process, Manitoba Hydro was requested to provide the additional metric of cumulative PV of consumers' revenue. This is only one metric to be considered in the financial analysis. It should be given no more weight than any of the other metrics provided by Manitoba Hydro.

The table below provides the Cumulative PV of Consumers' Revenue based on the updated information.

CUMULATIVE PV OF CONSUMERS REVENUE AT DSM LEVEL 2 USING ALTERNATIVE METHODOLOGY #2 AND REFERENCE CAPITAL COSTS DISCOUNTED AT 1.86% REAL (In Billions)

	2031/32	2061/62
ALL GAS (1)	$26.9	$57.6
K31/GAS (2)	$26.8	$58.5
K19/GAS/750 MW (5)	$27.4	$56.2
K19/GAS/750 MW (6)	$27.5	$56.3
K19/C40/750 MW (12)	$27.4	$58.0
PDP (14)	$27.7	$57.0

Excerpted from MH Exhibit #104-12-5, p. 4

At a real discount rate of 1.86%, plans with Keeyask and a 750 MW Interconnection have the lowest consumers' revenue 50-year NPV. Plans with Keeyask and the 750 MW Interconnection (Plans 5 and 6) are virtually indistinguishable from one another based on a 50-year NPV. Based on the 50-year NPV, the PDP is lower than the All Gas Plan.

While Plans 5 and 6 have a lower NPV of consumers' revenue, the PDP has significantly lower cumulative rate increases by the end of the of study period; 96% versus 130% (shown in MH Exhibit #104-12-5, p.3 above). This supports the position that an early in-service date for Conawapa should be protected.

While Manitoba Hydro accepts that NPV may be utilized to examine consumers' revenues for NFAT purposes (see PUB/MH I-149(a), Figure 11.13, p.6), Manitoba Hydro fundamentally disagrees with applying extremely high discount rates in the determination of the time value of money for customers' bills. Manitoba Hydro demonstrated through cross-examination of MPA (Tr. p. 7564) that a nominal discount rate of 10% translates to an imputed return on equity of 21.1% (assuming a cost of debt of 6.30% and the assumed 75:25 target capital structure in Manitoba Hydro's WACC calculation). At transcript pages 2947 to 2948, Mr. Rainkie refuted the concept of disproportionately high rates of return to customers on revenues paid to Manitoba Hydro for their energy consumption:

> "I guess I've never, from a policy perspective, ever thought that Manitoba Hydro was going to offer a 21 percent rate of return, especially since we don't, in our -- in our actual revenue requirements, we don't follow a rate-based rate of return methodology. We don't charge the customers a 9 or 10 percent rate of return. In fact, if you look at our net income and -- and -- and kind of back calculate that over our equity, we probably charge a 3 to 5 percent rate of return. So, am I going to pay the customer 21 percent when I'm only charging them, you know, 3 to 5 percent in the first -- first instance? That would seem rather perverse. I -- I've never thought of Manitoba Hydro as a financial institution where you put your money and we offer a rate of return. We provide a critical service to Manitobans at a fair cost."

Manitoba Hydro's analysis shows that plans with Keeyask and an interconnection have lower NPV's of customers' bills at a fairly wide range of higher discount rates but plans with Conawapa have lower NPV's at lower discount rates (PUB/MH I-149(a), Figure 11.13, p.6). However, Mr. Rainkie cautioned:

> "... when I impute a 21 percent rate of return and use a 10 percent discount rate, essentially what I'm saying is: I don't really care what happens to, you know, rates ten (10) or twenty (20) years down the line. I'm only worried about the -- you know, the next five (5) or ten (10) years. Because, mathematically, at that type of a discount rate, the -- the fact that -- that you're multiplying any value of it is so small. So, I think what you're doing is actually imputing intergenerational inequity in the situation. You just have to be careful that by jacking up discount rates or truncating evaluation periods, that you're really not just screening hydro-electric power out; the very same fuel that's got us to the -- you know, the favourable rate position that we have right now." (Tr. p. 2949-2950)

Mr. Rainkie further stated:

> "Manitoba Hydro is here, through its mandate, to provide power for the long-term. We have to care about what's happening in the current generation and

the future generation -- future generations of Manitobans." (Tr. p. 2952)

Manitoba Hydro submits that Conawapa should not be dismissed out of hand based on extremely high discount rates applied to analyze the NPV of customers' bills and that plans which include an early in-service for Conawapa should be protected.

13.9 IEC Financial Models

While there may be some benefit in utilizing the third party financial models developed by IECs for indicative initial long term planning purposes, these IEC models are not sufficiently robust to be considered reliable for detailed short-term decision-making or rate setting purposes. MPA confirmed that their financial model was "designed to be indicative and informative in showing directional trends and providing comparative results between development plans and scenario assumptions" (Tr. p. 7542) and not designed to be used for rate setting purposes. La Capra also indicated that the intended purpose of the LCA Dynamic Rates model was focused on the NFAT proceeding (Tr. p. 6334).

In the context of cost of service regulation, Manitoba Hydro has the flexibility to smooth rate increases, which means that at times, not all expenditures that are incurred in a period are passed directly through to customers but rather are deferred to future periods for recovery. When expenditures are not immediately recovered from rates, Manitoba Hydro must fund these cash outflows, typically through debt financing which in turn increases interest expense and consequently future cash requirements. Alternatively, if Manitoba Hydro has surplus cash flow from operations, then the resulting incremental cash flow reduces borrowing that otherwise would have been required, thereby potentially reducing finance expense, future cash requirements and rate increases. Financial modeling must consider these cash flows in order to have validity for revenue requirement or rate setting purposes.

In this regard, Manitoba Hydro concludes that the LCA Dynamic Rates model fails to provide credible financial forecasts and ought not to be used for financial analysis for the purposes of an NFAT process or for rate-setting. La Capra's financial model does not forecast impacts to cash, net debt, or the compounding effects of finance expense impacts resulting from changes to rates, domestic revenues, load forecasts, capital costs, net debt, export sales, fuel and power purchases, or the target value and timing of achieving financial ratios.

La Capra's fundamental omission of these cash flows has a <u>material</u> impact on their modeled results as demonstrated in the comparison of results between Manitoba Hydro's and La

Capra's interest coverage target ratio sensitivity. For example, La Capra's modeling of the interest coverage ratio sensitivity depicts cumulative rate increases of 120% by 2062 (shown in MH Exhibit #167-3, Tab 3, page 9). By comparison, Manitoba Hydro's modeling of the same sensitivity results in cumulative rates of 87% by 2062 (MH Exhibit #167-3, Tab 4, p. 15). This is a cumulative rate overstatement by LCA of 33% (or 0.5% per year for 30 years). On a NPV cash flow basis, the difference between Manitoba Hydro's analysis and the flawed LCA modeled results is approximately One Billion dollars.

La Capra suggests that the differences between the La Capra model and Manitoba Hydro financial modeling are "due to the assumption that cash coming in was not used to change the schedule of paying down debt ..." (Tr. p. 6351). La Capra's model does not incorporate the standard methodology for cash flow analysis. In Manitoba Hydro's view, La Capra's cash flow assumption is a fatal flaw that renders the La Capra model as invalid and unreliable for financial and rate analysis.

The MPA model, while constructed with more sophisticated modeling logic and included the effects of cash flow, also had shortcomings which would limit its use. Manitoba Hydro brought to MPA's attention that MPA's simplifying assumption regarding their interest capitalized calculation would tend to overstate gross interest expense, understate net income, and understate the gross interest coverage ratio in some years. Rate increases in those years would also tend to be overstated. Correspondingly, the amount of stranded debt calculated for the purposes of MPA's illustrative stranded debt analysis would also tend to be overstated in some years.

In summary, while there may be some benefit in utilizing the third party financial models developed by IECs for indicative initial long term planning purposes, these IEC models are not sufficiently robust to be considered reliable for detailed short-term decision-making or rate setting purposes. In Manitoba Hydro's view, La Capra's model is invalid and unreliable for financial and rate analysis. The MPA model, while constructed with more sophisticated modeling logic and included the effects of cash flow, also had shortcomings which would limit its use.

13.10 FINANCIAL RISKS

With respect to Manitoba Hydro's conclusions regarding financial risks, Manitoba Hydro's conclusions can be summarized as follows:

1) In the medium term, development plans with both Keeyask and Conawapa have the highest fixed assets and retained earnings;
2) In the long term, plans with both Keeyask and Conawapa have the strongest balance sheet, with high levels of fixed assets and retained earnings;
3) Development plans with both Keeyask and Conawapa are more robust in their ability to absorb adverse financial impacts in the medium term and extending through to the end of the study period;
4) Net debt levels are converging toward the end of the study period for all development plans.

Manitoba Hydro is embarking upon its developments plans from a position of financial strength. The history of Manitoba Hydro development shows weakening of financial metrics, as measured by the equity ratio, through periods of expansion but recovery following in-service (MH Exhibit #111, Slide 72). The period following Limestone, in particular, shows strong recovery in the equity ratio at a time when rates charged to Manitoba customers did not change largely due to Manitoba Hydro's expanding access to the US export market. Coming from a period with the highest equity ratio in its history, the Corporation is well situated to move forward with its upcoming capital investments with a greater ability to protect ratepayers from sudden or excessively large rate increases.

The following table summarizes the updated projected net fixed assets, net debt, retained earnings and debt/equity ratios as at 2031/32 and 2061/62.

Development Plan	Plan #	(F) Net Fixed Assets	(G) Net Debt	(H) Retained Earnings	(I) Debt:Equity Ratio as at 2031/32	(J) Net Fixed Assets	(K) Net Debt	(L) Retained Earnings	(M) Debt:Equity Ratio as at 2061/62
		As at 2031/32 in Billions of Nominal Dollars				As at 2061/62 in Billions of Nominal Dollars			
All Gas	1	$19.0	$14.5	$4.1	78%	$29.9	$14.5	$10.2	59%
K31/Gas	2	$26.9	$21.5	$4.8	82%	$34.2	$15.8	$12.8	55%
K19 Gas 750 MW	5	$24.7	$19.4	$4.7	81%	$32.7	$15.5	$11.8	57%
K19/Gas/750MW	6	$24.5	$19.2	$4.7	80%	$32.3	$15.1	$11.8	56%
K19/C40/750MW	12	$25.8	$20.5	$4.7	81%	$43.0	$21.5	$15.6	58%
K19 Sales C31 750 MW	14	$36.9	$30.6	$5.3	85%	$39.1	$17.8	$15.3	54%

Extracted from MH Exhibit #104-12-6

As can be seen in the table above, net assets and retained earnings are highest throughout most of the study period under plans with Conawapa. While net debt levels are the highest with the development plans that include Keeyask and/or Conawapa in the medium term, they also have the highest fixed assets and retained earnings.

In the long term, development plans with Keeyask and Conawapa have the strongest projected balance sheet with high levels of fixed assets and retained earnings. Regardless of the development plan undertaken, Manitoba Hydro's system is and will remain predominantly hydro-based and the impact of an extended drought affects all development plans similarly in the near term. The impacts of drought increase over time with Keeyask and Conawapa; however, development plans with both Keeyask and Conawapa generating stations are more robust in their ability to absorb adverse financial impacts in the medium term and extending through to the end of the study period, given their comparatively higher level of retained earnings.

Turning to debt, net debt levels are converging towards the end of the study period for all development plans. The plans with Conawapa have the highest level of net debt in the near term which declines following the in-service of Conawapa. In considering the delayed implementation of Conawapa to 2040 (Plan 12) in the above table, such a deferral leads to this plan requiring a longer period of time to retire its debt. Therefore, Plan 12 shows the highest net debt levels by 2062 relative to the other plans. The All Gas plan has the lowest level of net debt initially but increases throughout the study period and converges with the PDP net debt by 2062 due to the continuous addition of gas facilities.

Manitoba Hydro's debt management strategies are strong. This was evidenced by Moody's in their credit report on Manitoba Hydro wherein they stated that the "view Manitoba Hydro as being capable of prudently managing debt" (MH Exhibit #111, slide 82). This view was also affirmed by MPA when they stated that "Manitoba Hydro has a very sophisticated treasury plan" (Tr. p. 7466, lines 8-9).

As part of this treasury plan, Mr. Schulz described the Corporation's debt management strategy to take advantage of the existing low interest rate environment by securing low interest rate financing that is fixed over an extended period of time. As an example, Mr. Schulz described a recent debt issue secured by Manitoba Hydro with an interest rate of 3.87% fixed over a 50 year term to its maturity in 2063 – thereby eliminating refinancing risk on the debt and reducing interest rate risk within the overall debt portfolio (Tr. p. 2828-2831).

With respect to Manitoba Hydro's borrowings, the Corporation receives a flow through credit rating from the Province of Manitoba. In exchange for this flow through borrowing capability, Manitoba Hydro pays a provincial guarantee fee to the Province of Manitoba which was described as a "fair exchange" from Manitoba Hydro's perspective by Mr. Schulz in discussion with Chairman (Tr. p. 2840-2843).

As Manitoba Hydro makes interest and principal payments to bondholders on an uninterrupted basis, Manitoba Hydro's debt is considered by the credit rating agencies to be self-supporting. To the extent that Manitoba Hydro prudently manages its debt and maintains its self-supporting status, Manitoba Hydro's capital investment plans should have no significant impact on the Province of Manitoba's credit rating (Tr. p. 2828, lines 12-17).

In the response to PUB/MPA I-027(a), MPA introduced a calculation of implied stranded debt in which they address the upper limit of potential unsupported debt. At transcript page 7566, MPA clarified that:

> "So it's a purely mathematical calculation, and it's a theoretical upper limit, and by no means is that a judgment of an actual financial distress situation. It's simply one measurement that was used to indicate for us -- when we were trying to understand how financial distress could conceivably occur, this would be a directional flag for us to look at certain kinds of situations."

On cross-examination, MPA confirmed that Manitoba Hydro's interest coverage ratio includes non-cash items, and if those non-cash items are added back, that Manitoba Hydro has sufficient cash flow to meet bondholder payments to an interest coverage ratio as low as approximately 0.8 times (Tr. p.7567-7568). As a result, MPA's calculation of potential unsupported debt using the 1.20 times interest coverage is flawed.

MPA's final conclusion on the various levels of debt between the plans is that the financial risk is acceptable: "...do any of the levels of projected debt present an unacceptable risk to the province? It doesn't appear so when you go through this analysis." (Tr. p.7513)

MIPUG concurs with MPA's assessment of the risk of debt in its closing submission:

> "the evidence is that this debt is readily manageable, is highly unlikely to lead to any adverse impacts on the provincial credit rating under even extreme adverse conditions (and further even if there were severe financial pressures at Hydro at most a fraction of Hydro's debt would be considered not self-

sustaining - this fraction of debt would remain well within the province's ability to defend to credit agencies)." (MIPUG Exhibit #28, p. 17-18)

The flexible pathways provide Manitoba Hydro with options to manage through future uncertainties. Management has additional options such as cash conservation, deferring spending, bridge financing and rate increases to manage liquidity risk and ensure Manitoba Hydro debt remains self-supporting. As Manitoba Hydro has historically managed adverse conditions, including drought, in a balanced way, the Corporation will continue to do so.

13.11 The Risk of Deferral

Delaying the decision to build to a future decade may not necessarily be cost effective. There is risk that not taking the opportunity to have export customers today help fund the "basement suite" or "apartment building" may result in higher costs for Manitoba customers in the future. As described by Mr. Rainkie,

> "people are trying to set this up as this risky great big hydro plan versus this tiny little gas investment that you make at the – at the front end, which is, of course – slide 61 [MH Exhibit #111] shows you quite a different perspective" (Tr. p. 2811, lines 16-19).

Mr. Rainkie further summarized the evidence which demonstrates Plan 14 has "stable, low-cost larger investments at the front end versus a series of investments under All Gas, but in the end, we end up with the same level of net – net debt and higher levels of equity" (Tr. p. 2812, lines 18-22).

The financial evaluation demonstrated that uncertainty in customer rates is greater in the medium term but lesser in the long term under the Preferred Development Plan relative to All Gas and Keeyask/Gas/750. Variation in escalation and interest rates is the dominant factor in customer rate sensitivity rather than capital costs and export and natural gas prices. Once a hydro facility has been constructed, the cost is relatively fixed. Comparatively in a gas-based plan, the continuous addition of gas facilities throughout the study horizon is subject to inflationary impacts on capital costs.

Although it is tempting to focus on the short-term risks associated with the large hydro-electric investments, one ought to be mindful of the longer term risks of plans with gas or deferred Conawapa. Hydro-electric construction costs are growing at more than the rate of inflation. As described by Mr. Schulz,

> "one could make the argument that there's higher interest rate risk, for instance, in the – in the All Gas Plan as compared to the Preferred Development Plan, particularly at a time when we have a low interest rate environment and we can secure many of the near-term or, you know, about to be near term financings at historically low levels, as opposed to rolling the dice and seeing what happens in the future with all those cascading gas plans that are coming on" (Tr. p 3358-9).

This observation was also reinforced by MIPUG in their final submission when they stated that:

> "the other thing we have to be careful about when we de - defer a plant. If construction is happening now, we know what the interest rates are now. They're low. ... we have to be careful ... to take the conclusion that deferring is always better, because we know with a fair amount of certainty what our debt's going to cost us now, but do we have the same certainty in six (6) or seven (7) years?" (Tr. p 11288-11289).

Similarly, deferring the construction start of Conawapa exposes this project to the same inflationary and interest rate risks. It is wise to take advantage of the existing low interest environment to finance Manitoba Hydro's development plans, as opposed to waiting until a future date when interest rates could be higher. As stated by MPA,

> "we have been for the last five (5) years at a very peculiar point in the long-term capital markets life cycle where debt is very cheap, and long-term bonds are available. And that's great for investors that are seeking cash right now, or have been seeking cash for the last five (5) years. I'm not sure it's fair to assume that those conditions are going to continue to pertain for the next ten (10) or fifteen (15) years" (Tr. p. 7465 lines 9-17).

While the savings to ratepayer costs in plans with Conawapa have diminished with higher capital cost and deferral of Conawapa, it is prudent to maintain the optionality between development plans which may include, and continue, to protect Conawapa given the upside potential. As part of the regular planning cycle, Manitoba Hydro will continue to assess the capital costs and economic, financial and export conditions including opportunities to negotiate additional export sales.

13.12 Affordability Is an Issue of More than Just Electricity Rates

During the NFAT process, a number of Intervenors submitted that Manitoba Hydro's future rate increases as projected in the Preferred Development Plan will disproportionately impact low-income customers. As indicated by Manitoba Hydro during oral testimony, rate increases will be required under all development plans, driven in the next several years by requirements to invest in the reliability of the electricity system (Tr. p. 2773-2775). As a result, all of Manitoba Hydro's customers will be impacted by rate increases, regardless of the plan selected.

CAC expert witnesses, Mr. Stevens and Dr. Simpson, provided evidence in respect of the impact of increases in electricity rates on low and non-low income households in Manitoba. Manitoba Hydro recognizes the issue of low-income rate affordability, but submits that this issue does not have a bearing on the determination of which development plan should be chosen given that rate increases will be required under all plans and will impact all of Manitoba Hydro's customers. Furthermore, as has been the subject of prior General Rate Applications, Manitoba Hydro's legislative mandate does not extend to addressing issues of income distribution or social policy.

Manitoba Hydro's mandate flows from *The Manitoba Hydro Act* and is "to provide for the continuance of a supply of power adequate for the needs of the Province and to engage in and to promote economy and efficiency in the development and the generation, transmission, distribution, supply and end-use of power..." (NFAT Business Case, Ch. 1, p. 1). Manitoba Hydro charges rates adequate to recover its costs of supplying power and has a legislative requirement to charge equal rates to each class of customers, which rates shall be the same throughout the Province. Manitoba Hydro does not and cannot distinguish whether or not a customer is low income in establishing rates for each customer class.

In Manitoba Hydro's respectful submission, issues of poverty and distributional effects are complex and extend beyond considerations associated with indicative electricity price increases. Furthermore, these issues ought to be addressed through the setting of social policy which is within the purview of the government.

13.13 Testimony from CAC Ratepayer Panel

CAC presented a ratepayer panel to offer opinions and some personal information as to the potential impacts of rate increases on the individuals who appeared. CAC has suggested that based on the evidence of these ratepayers that the Board should understand that ratepayers prefer lower rate increases in the immediate term with higher increases coming later, and generally fewer rate increases overall.

Manitoba Hydro acknowledges that payment of utility bills and other expenses are not easy for all customers, however we respectfully submit that the role of the PUB either in General Rate Applications or in this proceeding is to ensure a financially stable utility capable of providing safe and reliable electricity to Manitobans, being mindful of the impacts of rate increases on customers. However, it is not within the mandate of Manitoba Hydro or this Board to take on the role appropriately reserved to the Province of Manitoba to provide social assistance programs directed to low income customers by providing low-income rates or rate subsidies.

Ultimately, Manitoba Hydro concurs with the position expressed by Dr. Simpson at Tr. p 7865 and 7867 that transfers to address affordability of electricity rates should be delivered through income based credits, rather than adjusting rates charged by the utility.

13.14 Testimony from CAC's Expert Witnesses

Mr. Stevens and Dr. Simpson testified that direct subsidies to low income customers are the appropriate way to address distributional issues, not through electricity pricing. When asked about recommendations for mitigation of impacts of rate increases on low-income customers, Mr. Stevens and Dr. Simpson emphasized the use of government income transfer payments to low-income households (April 23, p. 7864). When asked if they have considered conservation rates (or block pricing) to help low-income customers, Mr. Stevens and Dr. Simpson indicated that, while on balance they might help low-income, most of their work suggest that such transfer should be made conditional on income, not on prices, because of the unintended spillover effects on customers that are not low-income. As stated by Mr. Stevens and Dr. Simpson, "if you are concerned about the hardship associated with poverty [...] in households with low-income, that direct transfers are a much wider way of dealing with that then[*sic*] trying to fiddle around with prices which may have all sorts of unintended consequences" (Tr. p. 7867).

Manitoba Hydro generally concurs with MKO that the financial impact of the development plans will affect customer groups differently depending on how these costs are ultimately reflected in rate schedules (MKO Exhibit #7, p. 2). However, matters associated with how costs will be allocated and rates designed to recover the costs associated with the development plan, are matters more appropriately addressed in a future process, such as a

Cost of Service Review or General Rate Application. The MKO recommendations outlined at pages 10 to 18 of MKO's final argument (Tr. p. 11400-11423) have not been appropriately examined and tested in this proceeding. Some of these recommendations are contrary to Provincial legislation, some may be more appropriately addressed in a separate regulatory proceeding, and some are not matters which ought to involve Manitoba Hydro or the Public Utilities Board, but rather are matters to be addressed between the MKO communities and government agencies who have jurisdiction over those matters.

As indicated above, rate increases will be required regardless of the development plan chosen. Manitoba Hydro concurs with Mr. Stevens and Dr. Simpson in that the best way for Manitoba Hydro to assist lower-income customers with respect to the impact of rate increases is through energy efficiency:

> [...] in general terms, any measures that can reduce a low-income household's expenditure on electricity would serve the same purpose. And in that regard, the demand-side management programs that were targeted to low-income households would have the desired effect of making them less vulnerable to price increases of electricity. It would cushion that impact by allowing them to reduce their consumption of electricity [...] (Tr. p. 7880-7881).

Manitoba Hydro continues to provide, through its Affordable Energy Program, sustainable, long-term solutions to customers by improving energy efficiency of their homes which results in ongoing reduced consumption and lower energy bills.

14.0 MACRO-ENVIRONMENTAL AND SOCIO-ECONOMIC ISSUES

The NFAT Terms of Reference stipulate on page 3 the factors that the assessment is to take into consideration including, "The socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities…." and "The macro environmental impact of the Plan compared to alternatives." The Terms of Reference on page 4 goes on to identify a number of items that are not in scope of the NFAT, including:

> "The environmental reviews of the proposed projects that are part of the Plan, including Environmental Impact Statements (these will be conducted through individual processes by the Manitoba Clean Environment Commission ("CEC"), and where possible the impacts of the matters to be considered by the CEC are included in the costs of the projects that are part of the Plan)…and…Historic environmental costs." (PUB Exhibit #2)

With respect to the PDP, an EIS for the Keeyask Generation Project has already been completed and those for the Conawapa Project and the 750MW Manitoba-Minnesota Transmission Project are underway – all have had or will have extensive consultation and regulatory review processes before they are approved. For Keeyask, both environmental and socio-economic issues have been extensively reviewed through both the provincial and federal regulatory processes.

After its review of the Keeyask materials filed by the Partnership, the Canadian Environmental Assessment Agency completed a Comprehensive Study Report (currently on its website for public commentary). It concluded that:

> "…the Project is not likely to cause significant adverse environmental effects when implementation of the proposed mitigation measures, the follow-up program and adherence to conditions and requirements related to the necessary federal permits, authorizations and approvals are taken into account." (Executive Summary, CSR, Page ii) (PUB Exhibit #70)

The Clean Environment Commission, which held hearings on the Keeyask Generation Project starting on September 16, 2013 and concluding on January 9, 2014, issued its Report on Public Hearing in April 2014, and came to the conclusion that:

> "...the Panel is more than satisfied that the record is sufficiently complete for it to offer sound advice to the minister. The Commission will recommend that an environmental licence be issued to the Keeyask Hydropower Limited Partnership for construction of the Keeyask Generation Project. " (Foreward, CEC Report, Page xiii) (PUB Exhibit #69)

The CEC also recommended a number of conditions be attached to the licence "...in order to provide some assurance that the goals of the Keeyask Generation Project can be met without compromising the environment of Manitoba." (Executive Summary, CEC Report, Page xvi) The Keeyask Generation Project was also reviewed by independent assessors from the International Hydropower Association based on its Sustainability Assessment Protocol. The IHA assessment found that 95% of the assessed aspects ranked above the good practice level. The project received the highest possible score on 16 of the 22 topics assessed which is more than any other project officially assessed in at that date world-wide. In fact, during his testimony, Mr. Tyson of Typlan noted:

> "In regard to more global perspectives on best management practices, we -- we reference the Hydropower Sustainability Assessment Protocol. The Keeyask Limited Partnership had a third-party review based on that document, and the results indicated that the project meets or exceeds basic good practice in all of the twenty-two (22) categories studied, and it meets best proven practice in sixteen (16) categories. We note that there are some gaps identified, but all of those gaps can be somewhat rationalized by the fact that there are different regulatory requirements in Canada compared to the rest of the world." (Tr. p. 7013, line 21 to Tr. p. 7014, line 7)

In reviewing the evidence submitted by the Independent Expert Consultants (IECs) and the Interveners, as well as their testimony, a number of interesting issues have been identified; however, in many cases, the evidence either does not look at the macro environmental impact of the Preferred Development Plan (PDP) compared to its alternatives or it addresses detailed topics that are typically the subject of project-specific Environmental Impact Statements (EIS).

14.1 Where is the Macro-Environmental Discussion?

Many of the environmental-related reports have focused on details typical of project-specific environmental assessment, rather than provide what is generally understood to be included in a macro-environmental assessment to assist the panel in its deliberations.

For example, in Mr. Hendriks' report entitled "Evaluating Macro Environmental Impact", he indicates the following as one purpose of his report:

> "...I was requested by the Manitoba Métis Federation (MMF) to review the available evidence concerning the macro environmental impact of the PDP and the alternative Plans, paying particular attention to the requirements of the definition of macro environmental impact provided by the PUB." (Hendriks Report, page 5, MMF Exhibit #15).

His report then goes on to document copious amounts of information from previous NFAT reviews (most of which were completed as part of EISs under CEAA, and provide little to no macro-environmental analysis on alternatives) and on the effects of the generating stations reviewed as part of these EISs. No discussion is actually provided on the macro-environmental effects of the PDP or most of its alternatives. As well, as Mr. Hendriks acknowledged in his testimony on May 12, that he has never carried out an environmental assessment or cumulative effects assessment on behalf of a proponent, nor been to the Nelson River watershed region where major component(s) of the PDP would be developed (Tr. p. 10491-10492).

Mr. Hendriks does provide some commentary on the possible effects and benefits of wind development in his second report, entitled "Evaluating the Macro Environmental and Socio-economic Implications of Additional Wind Resource in Manitoba." While the description of wind development and its possible effects (both positive and negative) is reasonably thorough, the report never actually makes any comparison of these effects to the PDP or other alternatives, nor does it discuss any socio-economic implications beyond the costs of development and related employment and business opportunities.

Most notably, the basis of the socio-economic analysis undertaken by Mr. Hendriks appears to be premised on two assumptions: 1) That wind would be developed in Partnership with Aboriginal groups on the basis of new grant/subsidy programs not yet in place; and 2) That the employment and long-term benefits provided by these developments has been underestimated by Manitoba Hydro.

While it is true that for the purposes of the NFAT, Manitoba Hydro has assumed that it will develop and own these resources, historically, this has not been the case. Wind development in Manitoba has been undertaken by private developers with access to government-based grant and subsidy programs, and the energy produced is then purchased by Manitoba Hydro. Although Mr. Hendriks references several initiatives in other jurisdictions, there are currently no provincially based grant programs in Manitoba to encourage the involvement of partnerships with Aboriginal stakeholders in wind development and, presumably, the costs of such a program if it is to be funded by Manitoba Hydro, would need to be built into the cost per MW of developing wind. Mr. Hendriks also notes that an advantage of wind is its ability to be decommissioned quickly if base load decreases (Hendriks Report, pg. 17). A point that Mr. Hendriks neglects to mention is that development of wind on this premise is unlikely to provide the long-term revenue certainty sought by investors, particularly Aboriginal stakeholders, or the related long-term benefits that come from this revenue source.

Mr. Hendriks has also criticized the employment estimates for wind provided by Manitoba Hydro, suggesting that they are likely to be greater and longer-term in nature than anticipated. The basis for this is a comparison to analysis provided by BC Hydro in its 2013 Integrated Resource Plan and an inclusion of direct, indirect and induced employment. Manitoba Hydro's estimates are based on advice provided by GL Garrad Hassan (GL GH), experts in wind development, and reflect the anticipated employment likely to be generated if wind projects are developed provincially. GL GH is an engineering consultant in the design and construction of wind energy projects in North America and worldwide.

It is important to note that many of the construction jobs associated with wind facilities are highly-specialized, with assembly of the turbines themselves undertaken by individuals trained specifically in the field. As such, it is unlikely that detailed training for neither these jobs nor the mandatory experience to fill them would be fully realized within Manitoba. Other available employment, even if there are Aboriginal employment preferences, is much more limited and primarily involves the development of access roads and pad installation for the towers.

This contrasts greatly with the training, employment and business opportunities available through the PDP. Construction and long-term operations employment associated with the PDP far exceed what is available through wind development. The differences would be even greater if the analysis and comparison were based on a consideration of direct, indirect and induced employment for these different alternatives. As well, many of the skills required and gained through the construction of generation projects are applicable to other job opportunities in northern Manitoba and throughout the province.

It is also notable that Mr. Hendriks acknowledged in his testimony that wind developments are most likely to take place in southern Manitoba, which has far superior wind resources than compared to northern Manitoba. Wind projects developed in southern Manitoba would result in limited, if any, benefits for northern Manitobans, especially northern Aboriginal residents and communities (Tr. p. 10526-10527).

> MR. SVEN HOMBACH: And in your view, if there were to be more wind development in this province, do you see it as feasible for any of that development to take place in northern Manitoba as opposed to in southern Manitoba where it's taken place to date?
>
> MR. RICK HENDRIKS: I do not. The wind resources in southern Manitoba are far superior to those in -- in northern Manitoba, and I wouldn't think that a project in northern Manitoba could compete.
>
> MR. SVEN HOMBACH: And it follows, then, that there wouldn't be any northern Aboriginal benefits flowing from wind projects in southern Manitoba?
>
> MR. RICK HENDRIKS: I would say that would be correct, yes.

Ultimately, it is not clear how Mr. Hendriks reached the conclusion that wind development "supports the maximization of socio-economic benefits for Manitobans, including Aboriginal groups". Using BC Hydro's assumptions, wind is much more costly to develop, typically requires the support of subsidy programs, and provides considerably less employment (both construction-based and longer term) than those realized through hydro generation projects.

Unlike others, Gunn and Olagunju have discussed macro-environmental analysis in their expert report; however, the entire report is based on a literature review. It identifies some potential macro-environmental impacts of hydro-electric generation, natural gas-fuelled generation, wind energy, solar photovoltaic and demand side management (DSM) without ever examining how these types of macro-environmental impacts apply to the PDP or the alternative plans. In fact, they explicitly state in a small footnote of their report the following caution, confirmed again during oral testimony:

> "Note that information provided regarding the macro environmental impacts of various power supply options may inadvertently misinform as it is a high-level review based primarily on academic literature. The intent is to present an objective overview of each and the kinds of environmental impacts each is known to be associated with. The discussion is not context-specific to Manitoba, and may not be up to date with rapid movements in the

> marketplace, especially with respect to wind and solar photovoltaic technologies." (Gunn & Olagunju Report, 2014, p. 15, CAC Exhibit #29)

A good example of this lack of context is the identification in their report that hydro-electric developments have the potential to cause earthquakes, inundation of agricultural areas and resettlement problems. Keeyask and Conawapa are included in the PDP and are the subject of the NFAT, yet they would have none of these types of impacts. This was clearly noted in their responses to IRs, and confirmed in the testimony of Dr. Gunn. (Tr. p. 9272, line to Tr. p. 9275, line 11).

The report also identifies the types of benefits associated with the various types of generation and DSM, although similarly it does not link what benefits would specifically apply to the Plan and its alternatives.

In response to why the actual macro-environmental effects of the PDP and its alternatives were not reviewed, Gunn and Olagunju indicate:

> "The intent of the Gunn and Olagunju (2013) report was not to critique the reported macro-environmental and social effects of the actual Preferred Development Plan and its alternatives: this work was deliberately left to other subject-area experts with specific training in the areas of wildlife, fisheries, human health, etc. Moreover, the macro-environmental deliberations of the PUB were not to duplicate the detailed review of the EIS." (CAC Exhibit #29)

This leaves one to question the utility of their report in evaluating and understanding the PDP and its alternatives. This response is also puzzling given that a "detailed review" comparable to an EIS is not at all what is envisioned – rather a high-level overview of the pros and cons of the different options under consideration and within the context of the Manitoba situation. In fact, in discussing strategic environmental assessment, versus an EIS, on page 10 of their report, Gunn and Olagunju articulate that the benefits of such a process (which presumably they endorse and which is macro in nature) is that it is "Broad focus, low level of detail, non-technical", which Dr. Gunn reiterated in her testimony on April 29, 2014. They then go on to state that:

> "One form of SEA, known as 'policy appraisal', is often used to select among competing policy options when there is a need to determine which is most desirable, rather than to predict with accuracy the physical impacts of subsequent development projects (Therivel 1993)."

Although macro-level environmental analysis is conspicuously absent from most of the environmental reports, virtually all of the authors have spent a considerable amount of time commenting on select aspects of the impacts of hydro-electric development. Notably, very few of the reports mention the benefits of such developments, including the huge benefits they provide in the context of low greenhouse gas emissions, training, employment, business opportunities, capacity and community development benefits for local Cree Nations, and economic benefits for Manitoba and Canada.

The macro-environmental reports, which tend to focus on the negative effects of hydro-electric development, in most cases fail to mention that other options within the PDP also come with their own adverse environmental effects. Again, the exceptions here are Mr. Hendriks, who has provided information on wind development (although no comparison to other options is really provided in the report) and the Gunn and Olagunju report, which specifically notes:

> "All of the power supply options will have profound potential impacts on the environment, and that trade-offs among them are complex." (CAC Exhibit #29).

14.2 All Options Have Environmental Effects

It cannot be lost in this process that all of the options outlined in the PDP and its alternatives have some level of environmental effect. For example, a 100 MW wind farm would produce an estimated 13 tonnes of CO_2 equivalent per GWh (see Appendix 7.3 of Manitoba Hydro's NFAT submission, Life Cycle Greenhouse Gas Assessment Overview and response to NFAT information request CAC/MH I-123a). It would also impact an area between 1 000 and 3 000 hectares and would have adverse effects on birds and bats.

Similarly, the development of natural gas plants requires an increased reliance of fossil fuels, contributing to greenhouse gas emissions. On a life cycle basis a simple cycle gas turbine is estimated to emit 764 tonnes of CO_2 equivalent per GWh, and a combined cycle gas turbine estimated to emit 509 tonnes of CO_2 equivalent per GWh (see Appendix 7.3 of Manitoba Hydro's NFAT submission). These values include the upstream greenhouse gas implications associated with the extraction and production of natural gas. Further detail on this is provided later in this final argument in the section on climate change.

The production and combustion of natural gas also has adverse environmental effects. For example, natural gas development in Alberta causes a variety of environmental effects, which have been summarized by the Government of Alberta as follows:

> "Exploration activities, processing facilities and pipelines can have significant effects on the environment in areas where natural gas is produced. The largest impact results from processing gas to render the raw gas acceptable for pipeline transportation to markets. Processing removes carbon dioxide, hydrogen sulphide, natural gas liquids and water vapour. On average, processing plants in Canada recover almost 99 per cent of the sulphur compounds in raw gas, but the remaining amount is released into the atmosphere as sulphur dioxide. Processing facilities use energy and may also release volatile organic compounds (VOCs). Other concerns arising from natural gas production include sour gas odours, groundwater contamination, waste management, land use, and impacts on wildlife habitat in producing areas."
> (From the Alberta Energy website http://www.energy.alberta.ca/NaturalGas/742.asp)

And as noted by Mr. Wojczynski in his testimony related to caribou:

> "With Gas, there isn't any effect in Manitoba, but there would be in Alberta. As a matter of fact, the federal Species at Risk Act has listed the boreal woodland caribou in the area that there's gas production in there and have cited the oil and gas production as being a major issue for them." (Tr. p. 3610).

It was noted by those who testified that in considering options, like gas, it is important to look beyond our borders to the effects that may result if that option were to be pursued. For example:

From the testimony of Mr. Sabine on April 4, 2104:

> MR. DOUGLAS BEDFORD: And drilling gas wells bring their own set of macro-environmental impacts, do they not?
>
> MR. CRAIG SABINE: They would bring a number of environmental impacts into play, one of which we -- one of which [effects of fracking] we discussed to some extent.

> MR. DOUGLAS BEDFORD: Going to suggest to you with an historical precedent in mind, that in the 1930s, it was popular in many places in the world with respect to the treatment of international issues to take what was known as an isolationist stance, in effect, to say, What happens outside my country or my province is no concern of mine.
>
> But if I turn to the year 2014 and macro-environmental issues, would you agree with me that a similar isolationist stance doesn't sensibly hold in today's world to repeat with respect to macro- environmental issues?
>
> MR. CRAIG SABINE: I would commend this hearing for its -- for its willingness to think about things globally and act locally in that context. I'm not so sure that a generalization of that paradigm of thinking can be made.
>
> Certainly, other provinces in our country think about their energy assets in specific ways that are in the best interests of the borders of their own province, and not necessarily to Manitobans, or the rest of the country, for that matter. (Tr. p. 5452-5453).

From the testimony of Ms. Orenstein on April 28, 2014:

> MS. JANET MAYOR: And while no adverse impacts would accrue to those in the north under an All Gas Plan, you're not saying that there are no adverse impacts to human health from an All Gas Plan, are you?
>
> MS. MARLA ORENSTEIN: No. I think at the distribution of where those effects are and what they are likely to be would be -- would be quite different than the effects that we've discussed in the report up to that point.
>
> MS. JANET MAYOR: So to truly understand the -- the overall health effects of an All Gas Plan, you would have to look at the potential health impacts in southern Manitoba and -- and perhaps across Canada --
>
> MS. MARLA ORENSTEIN: Absolutely, and a full health impact assessment would have to do that. (Tr. p. 9059)

From the testimony of Ms. Gunn on April 29, 2014:

MS. JANET MAYOR: There's been discussion during this hearing, and even between you and I, about the potential impacts of gas fuel generation, such as land fracturing and seismic activity. If you were to look at the impacts of an All Gas Plan, for example, in comparison to the Preferred Development Plan, would it, in your view, be appropriate to consider the impacts not only in Manitoba, but also in those areas where fracking, drilling, gas extraction is taking place?

DR. JILL GUNN: Yes, that would be appropriate. (Tr. p. 9280-9281)

In fact, one of the benefits of the PDP is the ability of Manitobans to ensure that its energy needs are being met through the development of well-planned projects, subject to comprehensive environmental reviews, that incorporate appropriate avoidance, mitigation, compensation and offsetting measures and that include province-specific enhancement measures (e.g., employment preferences for our residents). This was stated well by Mr. Tyson in his testimony:

> We've also identified as part of our socioeconomic review that if the best management practice that is -- that have been implemented for Keeyask are also implemented for Conawapa, the benefits to Northern Aboriginals and Northern communities would be optimized." (Tr. p. 7120)

14.3 IECs and Intervenors Focus on the Micro versus Macro Level Effects

Despite noting that the focus of their reports are on macro-environmental effects, many of the authors suggest the need for detailed environmental reviews, akin to an EIS, or have chosen to focus on providing their own detailed reviews of the Keeyask and Conawapa projects (in some cases, pulling directly from the Project's EIS, or from evidence submitted during the CEC Hearing process).

For example, Mr. Hendriks argued in oral testimony that each component of the PDP and presumably its alternatives should undergo a complete environmental assessment process before being evaluated by the PUB through its NFAT process – something that would be exceptionally time consuming, costly and not all macro in nature:

> MR. BRAD REGEHR: So what you're saying, essentially, is that each component must go through a complete environmental regulatory hearing, and then presumably, those regulatory bodies would have to issue their final reports before the Public Utilities Board can make a decision on the NFAT?

MR. RICK HENDRIKS: Yes. (Tr. p. 10474-10475).

As well, many of the other reports looked at micro-level, detailed environmental effects specific to Keeyask and Conawapa. Setting aside that this level of detail is outside the scope described in the Terms of Reference, it requires either summarizing the huge volume of information that was presented in the Keeyask environmental licensing process, which inevitably results in some level of inaccuracy, or the reliance on only portions of the evidence, which leads to incorrect conclusions. Further, the only project for which this level of information is available is Keeyask since detailed environmental assessments have not been done for the other forms of generation in the alternative plans such as gas turbines or wind farms.

For example, the report from MNP and related testimony contains a number of factual errors, which is understandable given the volume of material reviewed in such a short time frame. Some illustrative examples are provided below for caribou and Lake Sturgeon, respectively. Another example where information from the Keeyask process was presented inaccurately comes from the final argument of Ms. Saunders, legal counsel for the MMF, on May 21. Ms. Saunders mischaracterized the Keeyask public engagement process and the principles that Manitoba Hydro relied upon in making its partnership decisions with the KCNs and this is also discussed below.

Finally, the Consumer's Association of Canada and some of its expert witnesses, as well witnesses for the MMF, have provided evidence in their reports and in oral testimony with respect the past hydro-electric developments and the significance of related environmental and social effects. There are important subtleties associated with the term "significant" within the context of environmental legislation that are also presented below for information purposes.

These inaccuracies highlight the importance of the Keeyask environmental licensing process; its specific focus on the Keeyask Generation Project has allowed a level of rigour to be applied in drawing conclusions on environmental matters that simply cannot be matched based on the level of detail in the NFAT process. And, while out of scope of the NFAT, these issues are clarified below in the interest of having a clear and consistent record.

14.4 Caribou

On page 49 of the MNP report it states that for boreal woodland caribou, "The herd's population is estimated to be less than 3,000 and are listed as a threatened species..." (MNP Exhibit #2) This population estimate is for all of Manitoba, as is clear in the referenced Manitoba Conservation's Recovery Strategy for Boreal Woodland Caribou (2005). As such, it does not apply to the lower Nelson River area because the specialists employed in the Department of Conservation and Water Stewardship currently are of the opinion that there are no boreal woodland caribou in the lower Nelson area. While the KHLP opted to treat the ""summer resident caribou" living in the vicinity of the proposed Keeyask Generation Project Station as boreal woodland caribou in its EIS, and this was done as part of the Partnership's precautionary approach; neither Manitoba Conservation, as noted, through the Manitoba Boreal Woodland Caribou Management Committee, nor Environment Canada, in its 2012 Recovery Strategy for the Woodland Caribou, has listed this group of caribou as a distinct boreal woodland caribou herd.

MNP Exhibit #2, page 54 of this same report goes on to state,

> "Typically, there are fewer caribou present in the region as a result of declining migrations in more recent years and lower population numbers of resident caribou due to low utilization of the regional study area. These findings are supported by First Nations oral record as well as by population monitoring conducted as part of the Keeyask EIS work."

The declining migration noted began in the 1950s and, according to Aboriginal Traditional Knowledge (ATK), these caribou are now returning. There is no mention of lower population numbers of resident caribou in any of the EIS materials, including those produced by the Partner First Nations, and this "decline" has not been supported by environmental assessment studies. Apparently, the change in the 'range' of the migrating herds was confused with the size of the herds. The populations of both the Cape Churchill and Pen Islands caribou have increased since the 1970s (Keeyask EIS, Terrestrial Environment Supporting Volume, pp. 7-63). In fact, as noted by Ms. Pachal in her testimony on March 26:

> And -- and I might mention, last year, when we had our Keeyask infrastructure project going, I think there was thousands -- I can't remember. There's some people in the room who might remember how many thousands of caribou came across at the -- at the Keeyask infrastructure project site. It

> was an amazing thing. Thousands of caribou right in the middle of the construction site. It was quite something to see. (Tr. p. 3886)

Mr. Sabine of MNP also incorrectly stated during testimony that:

> There is risk, however, that the caribou will not respond to that new habitat. There's no scientific evidence that supports that they would use new islands that are generated. (Tr. p. 5275-5276)

Yet, there is ample evidence presented in the EIS and documented in the KCNs' Environmental Evaluation Reports that many caribou do in fact use the islands on Stephens Lake to calve – virtually all of which were created by the development of the Kettle Generating Station forebay which is immediately downstream of Keeyask (Keeyask EIS, Terrestrial Environment Supporting Volume, pp. 7-65, 7-69. See also p. 54 of the Fox Lake Cree Nation Environmental Evaluation Report).

14.5 Lake Sturgeon

The MNP report contains similar inaccuracies about Lake Sturgeon. In section 7.2 of the MNP report on page 59 it states,

> "Manitoba Hydro plans to use stocking as a mitigation strategy to maintain the existing population. It has been suggested by Manitoba Hydro that their conservation stocking program would include either developing another hatchery on the lower Nelson River or using the facilities at the Grand Rapids hatchery. The strategy calls for the genetic integrity and diversity of existing stocks to be preserved. If the option to use the Grand Rapids hatchery is employed, they must ensure local fish are used to supply the brood stock in order to maintain separate genetic stocks." (MNP Exhibit #2).

Stocking being proposed under the Keeyask Project will use brood stock would be used from the same genetic population as the target stocking areas. Although genetic differentiation of populations in the Nelson River has already been established through past studies, research is currently underway to develop a high resolution genetics tool that will provide even greater confidence in delineating genetically distinct populations within the Nelson River (2013 LSSEP Annual Report). All fish brought to Grand Rapids hatchery will be raised using biosecurity protocols that prevent any contact between genetically distinct populations.

Also on page 59 of MNP Exhibit #2, the MNP report concludes,

> "If the project proceeds without lake sturgeon being listed as 'protected' under SARA, there is a risk that populations will not adequately recover after construction, making extinction more likely."

Rather, if the project does not proceed, it is likely that the existing Lake Sturgeon population is not self-sustaining due to the low number of fish and only intermittent recruitment. Listing under SARA would not address the crucial issue of population numbers being at or below a self-sustaining level, which the Keeyask conservation stocking program, including mitigation and adaptive management, is designed to reverse (see Keeyask EIS Aquatic Environment Supporting Volume, Appendix 1A – Part 2).

In Section 7.3.2 on page 60 of the MNP report it states,

> "Lake Sturgeon were once a key source of traditional food for First Nations communities in the area, but this is no longer the case due to drastic declines in the population of this fish since hydroelectric development began in the 1950s...The Keeyask Project is being developed in an area where lake sturgeon have already been impacted negatively by hydroelectric development and remaining populations estimated to be in low numbers." (MNP Exhibit #2, p. 60)

The Keeyask EIS acknowledges that habitat changes resulting from hydro-electric development have likely had a detrimental impact on already depressed populations. However, what is not included in the above quote, is that Lake Sturgeon populations were dramatically reduced due to commercial overharvest before hydroelectric development even began on the Nelson River in the late 1950s (Keeyask EIS, Aquatic Environment Supporting Volume, Section 6.3.1).

On April 4, 2014, in his testimony Mr. Sabine, acknowledges that,

> "Hydro does have a number of substantial mitigation strategies in place in its planning." (Tr. p. 5279, lines 5-6)

He goes on to say,

> "It's difficult to ascertain whether these strategies, which are aimed at preserving and enhancing actually the population, will be sufficient over the long term." (Tr. p. 5279, lines 5-9)

This comment ignores that long term monitoring and adaptive management are essential components of the KHLP approach, as noted in the presentation by Ms. Pachal of Manitoba Hydro on March 25, 2014, (Tr. p. 3594, lines 19-23), and reinforced in the CEC Report through its comments and related licencing recommendations (see Chapter Thirteen, Monitoring and Follow-up of the Keeyask Generation Project Report on Public Hearing).

During Mr. Sabine's testimony, he also posited that,

> "…it's reasonable that passage will be necessary to ensure that the sturgeon are – are able to fill all their – their life stages and requirements for population sustainability." (Tr. p. 5281, lines 1-5).

However, the need for fish passage is site specific. For Keeyask, DFO has determined that:

> "…there is insufficient data at this time to conclude that there is or is not significant upstream movement of fish past the site of the proposed Keeyask generating station…The requirement for fish passage facilities will be determined by the DFO, in consultation with MCWS, based on the results of monitoring, established fisheries management objectives and support for ongoing fisheries productivity." (CAC Exhibit #45-11, Tab 2, DFO letter to KHLP, July 12, 2013)

Mr. Sabine also stated that,

> "…habitat fragmentation and loss, and the loss of spawning habitat particularly at Birthday Rapids, Gull Rapids, and Gull Lake will have an impact on the populations of sturgeon in the Kelsey to Kettle reach." (Tr. p. 5278, lines 15-19).

This is another example where summarizing from an extensive body of information has resulted in inaccurate reporting. The Keeyask EIS concluded that flows at the spawning habitat at Birthday Rapids will be affected, but it is uncertain if it will affect spawning. If monitoring identifies an effect, mitigation measures will be taken and these have already been identified by the Partnership. And while the habitat at Gull Rapids is suitable for spawning, studies have not found evidence of spawning taking place in recent years, which may be a reflection of the present, low population numbers. No Lake Sturgeon spawning habitat was found in Gull Lake itself. (Keeyask EIS, Aquatic Environment Supporting Volume, Section 6).

In fact, the Manitoba Lake Sturgeon Management Strategy (Manitoba Conservation and Water Stewardship, Fisheries Branch, 2012) makes the following observation:

> "The experience of managing lake sturgeon in Manitoba has shown that limiting mortality is the single most effective means of sustaining lake sturgeon stocks. The failure to do this effectively during the latter part of the 1800s and the early part of the 1900s in the historical commercial fishery led to dramatic declines that left lake sturgeon stocks throughout most of the province in the state they are today. Protecting habitat is also important but lake sturgeon in several parts of the province have demonstrated that they can adapt to fairly severe habitat alterations while proving unable to adapt to excessive levels of harvest." (MH Exhibit #162, p. i)

14.6 The Engagement of Partners and Others

In her final argument for the MMF, Ms. Saunders contends that,

> "...Manitoba Hydro seems to arbitrarily determine on what projects and with what Aboriginal communities it will apply its proactive approach to, even when there are a number of other Aboriginal communities, including the Manitoba Métis community, in the local and regional study areas of the Keeyask project, and certainly in the Conawapa and Manitoba-Minnesota Transmission Project areas." (Tr. p. 1182, lines 5-12).

> "So we think that the headway that Hydro has made with respect to its KCNs in going from the Northern Flood Agreement to the JKDA will only be undermined if it continues in this generation in pursuing these projects, to continue to deny another Aboriginal people that same opportunity to be a part of something that will directly impact them." (TR pg. 11217, lines 6-12)

It is well known that the Keeyask Generation Project is being developed by a Partnership involving Manitoba Hydro and four Cree Nation communities. The decision to partner with these First Nations on Keeyask, and any future decisions with respect to partnering on new developments, are business decisions made by the Corporation. In making these decisions, a number of factors are considered, including, but not limited to:

- Manitoba Hydro's obligations under existing settlement agreements;
- The vicinity of a community to the project;
- The potential for these communities and their members to be adversely affected by its development; and
- Historical and contemporary use of the project area by community members for traditional purposes.

Perhaps most importantly, the company also considers whether it is reasonable and makes good business sense to enter into a partnership for a particular project. For example, in her testimony on March 25, Ms Pachal noted with respect to transmission that:

> Manitoba Hydro has the authority under the Act to structure transmission arrangements. We've used that authority to structure those arrangements in the best interests of Manitoba ratepayers, and as such Manitoba Hydro retains 100 percent ownership of all transmission assets in Manitoba. (Tr. p. 3584-3583).

Based on the considerations above, a business decision was made to partner with the four Cree Nations on the Keeyask Generation Project. These communities all have historical relationships and existing settlements with Manitoba Hydro, they are those most affected by the Project's development, and are those resident in and using those areas most affected by the Project. To date, no other party, including the Métis, have demonstrated that they have a direct interest in the area where the Keeyask Project is to be built (see MH Exhibit #183). In the case of the Métis community, Aboriginal rights of the Métis are not recognized by the courts, the Provincial or the federal government in Northern Manitoba, unlike southern Manitoba. Those Manitobans who self-identify as Métis and who wish to hunt in northern Manitoba are required to purchase hunting licenses just like non-Aboriginal hunters.

Despite this, the Partnership made explicit and concerted efforts to involve others, including the Métis, in planning for the Project, through its Public Involvement Program (PIP). The PIP was intentionally designed to be extensive and thorough and provided opportunities for participation and input throughout Manitoba. In developing the PIP, the Partnership sought to apply the following principles consistently in all of its activities:

- Accessible process;

- Opportunities at key stages
- Transparent and open
- Use of a variety of communication mechanisms
- Engagement with Aboriginal peoples, and
- Responsive and adaptive

In fact, after several rounds of IRs and several weeks of hearings, including extensive evidence and debate on the involvement and participation of the Métis and others, the CEC in its Report on Public Hearing concluded the following:

> "Efforts were made to consult with other communities beyond the KCNs and they appear to have been relatively thorough. A large number of communities, NGOs, First Nations, Aboriginal organizations and individuals were provided with the opportunity to question the Proponent, raise concerns about the Keeyask Generation Project and have these concerns documented within the supporting material for the EIS. After review of the Proponent's public consultation process, as requested by the minister, the Commission is of the view that the process was comprehensive, inclusive and more than met the requirements for consultation." (CEC Report on Public Hearing Keeyask Generation Project, April 2014, p. 37)

A similar approach will be used to guide public engagement processes for future development projects in the PDP, building on the lessons learned from Keeyask and other recent developments. This should provide comfort to the PUB and others, that the engagement efforts made by the Corporation on its developments are sound and represent best practice in this field.

14.7 Engagement with the MMF

Detailed information on the engagement of the Métis in the Keeyask Generation Project, and the potential effects of this Project on the Métis, were thoroughly reviewed in the Keeyask CEC Hearing and through the s.35 consultation activities undertaken by the federal and provincial governments.

The topic of engagement with the MMF was discussed at length during the Keeyask CEC hearings, the details of which can be found on pages 39 through 48 of MH Exhibit #183 filed in this proceeding by Mr. London.

It is notable that in this hearing the MMF did not put forward a single witness, or ask any of the Manitoba Hydro witnesses questions, related to the engagement of the Métis in the planning for new development projects outlined in the PDP. This would have provided a similar opportunity for all of those involved in the NFAT process to review and test the assertions put forward by the MMF in its final argument - assertions that were vigorously tested during the Keeyask CEC process, and that lead the CEC to the conclusion cited above.

Since 2004, over 150 meetings that have addressed Keeyask in some way have taken place with the MMF. For the purposes of clarifying the record, and for addressing the assertions advanced by the MMF in its final argument, the following summarizes the special engagement processes implemented to seek the input of the Métis, through the MMF, in the planning process for the Keeyask (more detail is provided in MH Exhibit #183 and in the Partnership PIP filings):

- The MMF was involved in processes related to Keeyask from a very early stage as a participant in the Hydro Northern Training and Employment Initiative, beginning in the early 2000s. Testimony on their engagement was provided at this hearing and confirmed that they received a portion of the funding from this initiative and participated on the Board of Directors of the consortium responsible for implementing the training program.
- The MMF and its members were invited, and encouraged, to participate in the PIP and special arrangements were offered to support their participation – however, these offers to the MMF were refused in all but Round 1 of the three round program.
- After five years of negotiation and over 30 meetings, in June 2013 Manitoba Hydro (on behalf of the Partnership) and the MMF reached an agreement on a work plan and budget for the MMF to undertake a Métis-specific Keeyask Traditional Land Use and Knowledge Study (TLUKS), an historical narrative for the Keeyask Region and a Socio-economic Impact Assessment documenting the potential impacts on the Project on the Métis. The Partnership has always committed to reviewing and discussing these studies with the MMF once they are complete and to modifying or enhancing mitigation measures, if required, based on study findings. The results of these studies were due in October 2013. Manitoba Hydro has agreed three times to extend the Contribution Agreement and, to date, has only received a brief historical narrative. The MMF did present preliminary results of the TLUKS at the CEC Hearing, and these results confirmed the following:
    - The traditional area of Métis use recognized by the provincial government and agreed to with the MMF does not extend to the Keeyask Region. This means that any hunting, trapping or fishing activities undertaken by Métis in the Keeyask area are

done through licences issued by the provincial government. Licensed harvest activities and associated mitigation are well documented in the Partnership's EIS.

- The majority of resource use undertaken by Métis residents in the region takes place in areas near Thompson and Thicket Portage – areas not affected by the Keeyask Project and also outside of the traditional region identified through an agreement between the MMF and Manitoba.
- There is very little, if any, use of the Keeyask region and mitigation measures planned by the Partnership to address resource use activities are robust and apply equally to Métis residents of the region.
- There is no persuasive evidence of a historical Métis community in the Keeyask region whose descendants continue to live and/or use the region today, contrary to what was stated by Ms. Saunders. According to the Supreme Court of Canada, it is the existence of this type of Métis community which gives rise to the Métis rights identified in s.35 of the Constitution

For other projects, Manitoba Hydro has and will continue to attempt to engage with the MMF to review, discuss and understand the potential effects of new developments on Métis living in or using resources near to these projects. With respect to the MMTP, initial engagement of stakeholders is now taking place and the MMF have been invited to participate in this process.

The potential effects of a Project on the exercise of Treaty and Aboriginal rights is specifically assessed by the Province of Manitoba and by Canada under their duty to consult with Aboriginal groups as per Section 35 of The Constitution Act. These Section 35 duties have not been delegated to Manitoba Hydro and are different and distinct from Manitoba Hydro's obligations as a project proponent. For the Keeyask Project, the federal s.35 process is complete and the provincial process is near completion. The MMF was engaged in both of these consultation processes. Manitoba Hydro is generally not privy to the outcomes of these consultation activities, but it is notable that the Comprehensive Study Report completed by the federal government did not find any concerns with respect to Métis rights and interests in the Keeyask area.

14.8 The "Significance" of Past Developments

Finally, much has been said at the NFAT hearing about the effects of and lessons to be learned from past developments.

Ms. Pachal testified on March 25, 2014:

> "So Manitoba Hydro, as you've heard, prior to Wuskwatim planned and developed projects in a much different way than we do today. Our past projects, while in line with contemporary practices of the time and consistent with government requirements, involved much less consultation than would be considered acceptable today and considerable -- considerably less upfront planning with respect to environmental concerns.
>
> And as a result, environmental effects were not always fully understood in advance. And related avoidance, mitigation, and enhancement measures were not always identified and implemented in advance of project construction, and nor were they typically included in the capital project estimates.
>
> The planning and development processes for today's projects are very different, as you've heard many times this morning. The project planning process involves early and extensive engagement with communities in the vicinities of these projects, particularly the Aboriginal communities. And there is a concerted effort to prevent and reduce as much as possible potential impacts through improved project design and implementation of project mitigation and community-based programming.
>
> Efforts are also made to enhance project benefits as much as possible, especially for local communities, through measures like income oppor -- opportunities, training, employment, and business opportunities." (Tr. p. 3572-2573)

Witnesses for the CAC and the MMF talked extensively about Manitoba Hydro's past developments and their legacy. For example, the foundation of Mr. Hendriks' report is a suggestion that the best way to understand possible macro-environmental effects is to review effects experienced in other watersheds for comparable projects. Manitoba Hydro agrees with this approach, but would note that such a comparison needs to be context-specific – both in terms of the environments and the nature of the projects being proposed. For this reason, considerable efforts are undertaken to understand the possible effects of new developments based on a review and understanding of the outcomes of past hydroelectric developments within northern Manitoba. In fact, this is well documented in the Keeyask EIS, with ample discussion documenting relevant lessons learned from the Kelsey, Kettle, and Long Spruce generating stations and Notigi control structure, and the effects of the Churchill River Diversion and Lake Winnipeg Regulation Projects. Many areas affected by these earlier developments are used as proxies for understanding the possible effects of Keeyask (for example, Stephens Lake was used in the Keeyask EIS for several aquatic parameters including water quality and ice cover (Keeyask EIS, Executive Summary, pp. 22-24) and would also be used to understand the possible effects of Conawapa.

Oddly, the report by Mr. Hendriks criticizes the nature of the information provided in the Keeyask EIS –

> "My review indicates that the EIS and environmental evaluations describe the adverse nature of the effects of the prior development in very general terms and provide overall perspectives on the implications of these effects for use of the affected lands and waters." (Hendriks Report, pg 20 – MMF Exhibit #15).

This is a very broad generalization for a reviewer who discloses at the outset of his report and again in oral testimony (Tr. p. 10479-10488) that he has read only the aquatic portions of the EIS and it appears he did not read even those very thoroughly. In fact, the aquatic, terrestrial and socio-economic environment sections of the Keeyask EIS discuss historical change as a result of previous hydroelectric and other developments in the Keeyask Region. In the case of the terrestrial environment, these changes are quantified (because it is feasible to do so), and were discussed in detail through the CEC Process (for example, see the response to CEC Rd 2 CEC-102c, which quantifies change in terrestrial habitat and several related indicators over time for all developments in the Keeyask region).

Mr. Hendriks also states on page 22 of his report that,

> "My review of materials on the company website confirmed the existence of some programs designed to monitor environmental quality in the existing reservoirs. However, these programs do not seem to be designed with the overall intention of understanding the residual environmental effects of the existing facilities." (MMF Exhibit #15)

In fact, Manitoba Hydro and Manitoba have established a Coordinated Aquatic Monitoring Program (CAMP), in cooperation with Manitoba Conservation and Water Stewardship, to study and monitor the health of water bodies affected by Manitoba Hydro's generating system. CAMP's objective is to determine the health of aquatic environments and track them over time by:

- Monitoring the important physical, chemical and biological components of selected water bodies within Manitoba Hydro's generating system.
- Monitoring water bodies outside of Manitoba Hydro's hydroelectric generating system. These off-system water bodies will help determine how other factors, like climate, affect the aquatic environment.

Manitoba Hydro is also very fortunate that it has been provided the opportunity to work directly with many communities located in the vicinity of its proposed new projects. These communities have been affected by past developments and are those most affected by possible future hydro-electric developments. They have a wealth of knowledge about what has been experienced as a result of earlier developments and, based on this, what can be anticipated with future developments. For the KCNs, this knowledge is documented in the Keeyask EIS through their own Environmental Evaluation Reports and has informed many of the mitigation measures for this Project, most notably the adverse effects agreements.

In its report on the Keeyask Generation Project, the CEC made specific note of the positive contribution of ATK and the Keeyask Cree Nations' environmental evaluations, in particular:

> "The Commission found that the three KCN evaluations added greatly to an understanding of the Keeyask Project and to the environmental, historical, cultural, social and spiritual context of the Project. In addition to documenting the experiences and knowledge of members of the communities that will be most affected by the Project, these three reports provided a better idea of how the KCNs came to their decisions to participate in Keeyask and how they put forward issues of great importance to them. They added immeasurably to the ability of Panel members to consider the holistic nature of impacts to the environment of the Lower Nelson River. The reports presented a range of views regarding the Project – pro and con and mixed – and this helped the Panel to better understand the relationship between hydroelectric development and neighbouring communities." (PUB Exhibit #69, page 59).

The knowledge gained through CAMP as well as numerous post project environmental reviews, combined with the experience and knowledge of local Cree Nations, provides a solid, relevant foundation that has been used to understand the potential macro-environmental effects of the PDP.

On the topic of past projects, Gunn and Olagunju also make comments in their report about the effects of past hydro developments, stating on page 40 that,

> "The Nelson sub-watershed has already been substantially altered by hydroelectric development, and it is agreed past alterations have been cumulatively significant." (CAC Exhibit #29, p 5, 13 and 39).

This was repeated by Dr. Gunn in her testimony on April 29, 2014, when she stated:

> So we know that <u>significant</u> stress has already been experienced in -- in that region over the fifty-five (55) plus years of hydroelectric development that's gone on. All those kinds of effects are -- are well documented through the Keeyask hearing, through the Bipole III hearing, and elsewhere. But it is important to note that both Manitoba Hydro and the Keeyask Cree Nations partners, you know, have agreed along with -- with others, including independent experts like myself, that the Nelson River sub-watershed has already been substantially altered and has sustained significant environmental impacts. (Tr. p. 9224)

It is important to note that this is a conclusion that she has personally arrived at, despite also indicating that she has not studied the area extensively or even visited the Nelson River region, has never undertaken a cumulative effects assessment and that the report prepared did not critique the PDP and its alternatives because "this work was deliberately left to other subject-area experts with specific training in the areas of wildlife, fisheries, human health, etc." (Tr. p. 9119, line 7 to Tr. p. 9121, line 8 and Tr. p. 9272, line 2 to Tr. p. 9275, line 11).

Mr. Williams, legal counsel for the Consumers' Association of Canada, similarly used the term significant with respect to the PDP when he stated in final argument that,

> "There are going to be significant adverse consequences for the communities." (Tr. p. 11118, lines 15-17)

Setting aside the fact that the Terms of Reference identify historic environmental and social costs as outside the scope of the NFAT, it is notable that Gunn and Olagunju and legal counsel for their client have chosen to use the term "significant" – a term they understand and know has a very specific meaning in environmental regulatory processes and one discussed at great length during the course of the Keeyask CEC Hearing Process.

Under the Canadian Environmental Assessment Act, a number of specific factors must be taken into account when determining the "significance" of a project on selected Valued

Environmental Components ("VECs") within the context of environmental law. These include factors such as the magnitude, geographic extent, and duration and frequency.. It is important that the term significance – as it is used in environmental law – not be confused with the everyday use of the word. For example, the everyday definition of significant from the Merriam-Webster online is, "large enough to be noticed or have an effect: very important: having a special or hidden meaning". Based on the macro-level review being undertaken by the PUB and the explicit exclusion of project-specific EISs in the Terms of Reference, it is this everyday use of the term that is most appropriate to the PUB's review. Applying this common language definition of significant, past hydro-electric developments have had a profound impact on the environment and people of Northern Manitoba. This was noted in the Keeyask Clean Environment Commission (CEC) hearings on October 24, 2013 by Ms. Vicky Cole,

> "I think what's become very clear during the course of opening presentations, what is acknowledged in the EIS, it's talked about through the Keeyask Cree Nation environmental evaluation reports, is that -- and I'm now going to use the everyday common use of the term, that there is no doubt that these projects have had a significant impact on the communities that we're working with." (Tr. p. 833, lines 17-26).

However, federal and provincial regulators who assessed the Keeyask Generation Project EIS and were obligated to apply the professional, and obviously technical, interpretation of the word significant, found no significant adverse effects following their review of the detailed cumulative effects assessment undertaken by the Partnership.

14.9 Macro Environmental and Socio-Economic Conclusions

In preparing its submission, Manitoba Hydro took care to observe the definition of macro-environmental and socio-economic effects in the NFAT Terms of Reference and in PUB Order No. 92/13 along with items that are identified as being out of scope of the review. It provided appropriate and relevant information on the macro-environmental and socio-economic effects of the PDP and its alternatives in Chapters 13 and 15 of the NFAT submission. Additional information was provided in IRs such as CAC/MH I 231a and MMF/MH II 040a and associated testimony during the hearing. The results from the analyses undertaken by Manitoba Hydro demonstrate that the PDP and the plans with Keeyask and the 750 MW Interconnection provide superior benefits in terms of income, training, employment, capacity and community development, and business opportunities, especially for northern and aboriginal communities in Manitoba over the alternative plans. No compelling evidence has been presented during the course of this hearing that demonstrates otherwise.

The fact that this NFAT process includes consideration of the macro-environmental and socio-economic effects of the PDP and the alternative plans should be applauded as this level of analysis is not typical of many NFAT reviews. Including the consideration of those effects in the NFAT provides the opportunity for the Panel's recommendations to be informed by more than just economic and financial implications of the PDP and its alternatives. As noted above, it is important to remember that this is not the only environmental review these projects will receive. Detailed and thorough environmental assessment and licensing processes will be undertaken for all of the projects, including Conawapa and the MMTP, as they are advanced, and these projects will not proceed unless they also receive the necessary approvals through those processes. These reviews will properly examine the important issues that have been touched on by the NFAT IECs and Interveners in their submissions including cumulative effects assessment, the significance of effects and the details of direct and indirect effects to land, water, air, flora and fauna and the socio-economic environment.

It is notable that the Clean Environment Commission recommended that the Keeyask Project be issued a licence to proceed and that the Canadian Environmental Assessment Agency found that this Project would have no significant adverse effects with the implementation of the Partnership's follow-up program. This Project was planned by Manitoba Hydro and the same Cree Nation communities that will be involved in the planning and development of the Conawapa project. The same level of detail and rigour will be applied to planning and developing that project.

We would like to close this section by reminding the Board of some of the important statements made by Manitoba Hydro's Cree partners in the Keeyask Generation Project.

From Karen Anderson of Fox Lake Cree Nation:

> "Projects like Wuskwatim, Keeyask, and potentially Conawapa move us into a new era where we can strengthen our communities and do business in ways that we could have not done without those avenues." (Tr. p. 3538)

From Ted Bland of York Factory First Nation:

> "York Factory First Nation chose to support Keeyask, not just so our people could benefit from employment, business, and investments opportunities. York Factory chose to become a partner so we could have a voice in how the project is developed and managed. We want to be on the inside and influence the project." (Tr. p. 3559)
>
> "We have entered into the partnership insisting on a long-term ongoing commitment to healing, reconciliation, mutual respect, and self-determination. We intend to sustain our Cree values, customs, and traditions in the process." (Tr. p. 3560).

From Victor Spence of the Cree Nation Partners (Tataskweyak Cree Nation and War Lake First Nation):

> "I have a whole text here that I could read, but the words of my people are in my heart. It hurts many times when we chose as people a path where somehow there are others that seems to question how an Indian should think, how an Aboriginal should talk and make choices for their own people. We chose as a nation, a sovereign nation, a members of a nation. We are not merely objects within the hydro operational system. We are people. We cry. We feel pain. We have needs to better housing, better education, better healthcare services for our people, our Elders, our youth.
>
> That is why TCN choose the path it did in regards to do this development. If it was based on economics, solos -- just solely on economic, we would have said, No, to Keeyask or any development, but it gave more. It provides hope. An opportunity to say, We are involved. We continue to be involved. There's a new vision." (Tr. p. 3565 3566).

15.0 SUSTAINABLE DEVELOPMENT

The NFAT Terms of Reference direct the Board to consider, "The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*."

The policy alignment of the PDP was confirmed by both Manitoba Hydro witnesses and independent expert consultants during the hearing.

With respect to alignment to the principles of sustainable development, Mr. Brandson, the only witness who had expertise in the history, development and implementation of the legislation, indicated that Manitoba Hydro has embraced sustainable development and acted to integrate the concept into its daily operations, as well as future planning and development. (Tr. p. 3636, lines 9-12). Appendix 14.1 of the NFAT filing presents each principle and guideline in the order they appear in the act and Manitoba Hydro provides data and examples for each principle. Further, one whole chapter in the environmental impact statement of the Keeyask partners was devoted to documenting the alignment of the project with sustainable development legislation and with Manitoba Hydro's sustainable development code of practice (Tr. p. 3637, lines 6-10).

Norm Brandson testified that "the province has articulated its strategy to achieve sustainability in a particular sector in fairly concrete measureable terms. The provincial clean energy strategy is an example."[224] In evidence, Mr. Brandson also specifically asked the question "How does the proposal before the panel align with the principles of sustainable development contained in the Manitoba Sustainable Development Act"? Manitoba Hydro submits that the summary for each principle provided by Mr. Brandson on Tr. p. 3637-3641 provides the information this panel requires in order to answer this question:

> "Principle 1 is the integration of environmental and economic decisions. As documented in the NFAT submission, and identifying its Preferred Development Pran -- Plan, Hydro screened sixteen (16) resource options against fifteen (15) characteristics divided into four (4) categories: technical, environmental, social and policy, and economic. A melding of environmental, social, and economic concerns was thus incorporated at the earliest stage of planning. The needs assessment cast a wide net that included clearly articulated assumptions for load growth, domestic and export, demand-side

[224] Transcript page 3634, lines 16-19.

management, and existing resources. As options were reduced, the multiple account cost benefit analysis was applied to take into consideration consequences not reflected in a simple accounting of revenues and expenditures.

Principle 2, stewardship. Consideration of the potential impact on future generations loomed large in the thinking of the Keeyask/Cree partners. Throughout the decade long process of developing the partnership measures were agreed upon designed to minimize the impacts and maximize the benefits to future generations. For example, a considerably smaller project than the maximum technically feasible design was agreed upon to greatly reduce flooding. Environmental effects agreements were concluded that ensure ongoing future benefits to the communities. The development of renewable hydro power minimizes greenhouse emissions to the benefit of present and future generations.

Principle 3, shared responsibility and understanding. The Keeyask partnership is founded on respecting the culture, customs, and world view of the Tataskweyak Cree Nation, the War Lake First Nation, the York Factory First Nation, and the Fox Lake First Nation. Aboriginal traditional knowledge had a significant role in the environmental assessment of the Keeyask Project and will continue to loom large in the various plans that will govern the operation of future facilities. Ways to help alleviate the current economic disparity between northern and southern Manitoba have been factored into the plan. To the wider Manitoba public, Hydro has provided numerous opportunities to be informed about the development of its plans and to make their views known. As a Manitoba Crown Corporation, all Manitobans are its partners.

Principle 4, prevention. An initial guiding principle in the planning process was to focus on river systems currently managed for hydro-electric developments. The size of the Keeyask proposal and the preliminary design for the Conawapa development have both been reduced from technically feasible maximum in order to avoid and reduce potential adverse environmental and social effects due to reservoir flooding. Recognizing that predictive science is not infallible, the principle of adaptive management will be applied to Keeyask and Conawapa projects.

Principle 5, conservation and enhancement. The construction of the projects is governed by strict rules to minimize the disruption to terrestrial and aquatic habitat due to construction activities. Lake sturgeon has received considerable attention related to the Keeyask Project. The goal is to enhance the local population through a stocking program. Efforts will be closely monitored and adaptive measures taken if necessary. And opportunities to enhance fish habitat will also be implemented.

Principle 6, rehabilitation and reclamation. All construction-related disturbance not associated with the operation of the hydro-electric plants at Keeyask and Conawapa will be re-vegetated and returned as closely as possible to pre-development conditions. Adaptive management measures again will be implemented to deal with any unforeseen effects.

And finally, and in conclusion, Principle 7, global responsibility. By developing renewable hydro-electric power, Manitoba Hydro will be, through export sales, replacing future greenhouse gas emitting fossil fuer -- fuel power plants. This will contribute to the long-term mitigation of effects of climate change, the most serious global intergenerational issue of our time. Once the power is required to meet Manitoba needs, it will contribute to the province's stated goal of a fossil fuel free Manitoba economy."[225]

So is Manitoba Hydro's PDP aligned with Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in the Sustainable Development Act? Yes, it is well aligned.

The Consumers Association of Canada (Manitoba Branch) has submitted a document to the Manitoba Public Utilities Board's Need For And Alternatives To Assessment of Manitoba Hydro's preferred development plan and alternatives, entitled Framework for Sustainability Assessment authored by Dr. Kyrke Gaudreau and Dr. Robert B. Gibson. The response to this paper, the concepts contained therein and subsequent oral testimony at the PUB NFAT Hearings is organized around three key questions:

1. Is the sustainability assessment framework (SAF) proposed by the CAC mandated by the *Manitoba Sustainable Development Act*?[226]
2. Does the proposed framework fall within the terms of reference issued to the Public Utilities Board Need For and Alternatives To (NFAT) Panel?

[225] Transcript pages 3637-3641).
[226] It is only necessary to deal with this issue with respect to the *Sustainable Development Act*; if the framework is supported by the Act no further support is required from the *Environment Act* and if it is not so supported it is not reasonable to infer that the *Environment Act* which uses language almost identical to the *Sustainable Development Act* could provide such a mandate; the *Canadian Environmental Assessment Act* does not apply to the present PUB NFAT process and therefore is not relevant.

3. Is the proposed framework widely accepted as an assessment methodology for major development initiatives in Canada?

15.1 Is the proposed sustainability framework mandated by the Manitoba Sustainable Development Act?[227]

The Gaudreau/Gibson Sustainability Assessment Framework Paper (hereinafter referred to as "the Gibson Framework") asserts that:

> "it is clear that there is substantial and significant overlap in the substantive requirements for sustainable development between the generic sustainability criteria and the three Acts" (CAC Exhibit #20, Tr. p. 54).

There is in fact overlap in language between the framework and the Act. This is not at all surprising given that a common vocabulary of sustainable development has emerged over the 27 years that have elapsed since the government of Manitoba first embraced the concept of sustainable development. But there is no overlap in requirements. Language is very carefully chosen in the drafting of legislation. Concerning the substantive subject areas of sustainable development the Manitoba Sustainable Development Act – passed by one government and endorsed by its successor –is uniformly permissive, not prescriptive, and uses adjectives that are intended to allow for flexibility in interpreting if and how the principles and guidelines are applied to individual projects. Examples from the Principles and Guidelines contained in the Act include:

- Economic decisions should adequately reflect environmental, human health and social effects. [Principles 1(1)]
- Environmental and health initiatives should adequately take into account economic, human health and social consequences. [Principles 1(2)]
- Manitobans should (a) maintain ecological processes … (b) harvest renewable resources on a sustainable yield basis (c) make wise and efficient use of renewable and non-renewable resources [principles 5]
- Efficient use of Resources – which means (a) encouraging and facilitating development and application of systems for proper resource pricing … [Guidelines 1(a)]
- Public Participation – which means (a) establishing forums which encourage and provide opportunity … [Guidelines 2(a)]

[227] Background testimony, Norman Brandson, March 25/14 beginning Transcript, p. 3628.

- Access to Information – which means (a) encouraging and facilitating the improvement and refinement of economic, environmental, human health and social information [Guidelines 3(a)]
- Integrated Decision Making and Planning – which means encouraging and facilitating decision making and planning processes that are efficient, timely, accountable and cross-sectoral … [Guidelines 4]

The substance of what the government of Manitoba considers to be at the heart of sustainable development is clearly intended to be flexibly applied and directional, not prescriptive. Nowhere do the words must or shall appear in the Principles or Guidelines. Whenever these words are used in the Act they apply to administrative rather than substantive measures. The words Principles and Guidelines themselves connote an approach that is far more discretionary than command and control. This distinction between prescriptive and permissive is a critical issue in the drafting of legislation. To suggest that the Legislature of Manitoba intended to imply that sustainable development be implemented through the application of prescriptive criteria, but inadvertently neglected to mention it in the legislation, while never sanctioning a process to develop such criteria, completely ignores how legislation in general is, and the Sustainable Development Act in particular, was developed.

The New Democratic government of Premier Pawley embraced the concept of sustainable development when it accepted the 1987 report of the Canadian Council of Resource and Environment Ministers (CCREM) Task Force on Environment and Economy[228] and proceeded to implement its recommendations. This included the passage of the Manitoba Environment Act. In May of 1988 this government was succeeded by the Conservative administration of Premier Filmon. The Filmon government not only confirmed the province's commitment to sustainable development but also identified it as a flagship initiative. A Sustainable Development Coordination Unit was established as a central agency of government. The Manitoba Round Table on Environment and Economy[229] was directed to manage a highly public process to develop sectoral sustainable development strategies for Manitoba.[230] The Sustainable Development Unit also developed a White Paper on the

[228] *Report of the National Task Force on Environment and Economy* submitted to the Canadian Council of Resource and Environment Ministers – September 24, 1987.
[229] The National Task Force had recommended that "Round Tables on environment and economy" (the phrase "environment & economy" was eventually replaced by "sustainable development") of opinion leaders be established in every province and territory and by the federal government. All jurisdictions established these but today almost all have either been eliminated or fallen into disuse.
[230] The Task Force Report recommended all jurisdictions prepare a "Conservation Strategy"; Manitoba's component strategies included Land & Water (Water, Soil, Forests), Capital Region, Waste Minimization, Energy and Minerals.

possible content of sustainable development legislation. The Legislature ultimately adopted a *Sustainable Development Act* in 1997, the substance of which remains in today's Act.

The fact that government, while enthusiastically embracing the concepts of sustainable development, has had considerable difficulty in articulating how to implement its concepts, is evidenced by the flexible approach taken in the legislation, and by the launch of the Consultation on Sustainable Development Implementation (COSDI) to further examine the question in 1997[231]. The Filmon Government was replaced by the New Democratic Government of Premier Doer in October 1999. The Doer administration acknowledged the COSDI report and accepted in concept the nested planning scheme recommended by COSDI, which resulted in the East Side Planning Initiative as Manitoba's first Wide Area Plan. But the government did not pursue any of the recommendations relating to the development of more specific sustainable development evaluation criteria.

A further review of the *Manitoba Environment Act* in 2002-2003 offered yet another opportunity for discussion of more concrete criteria for sustainability to be built into that legislation. Again government declined to pursue such a course and retained the discretionary language contained in the *Sustainable Development Act*. So to suggest that the *Sustainable Development Act* implies a mandate for the SAFP framework and criteria, when government was well aware of this approach to SD implementation and has not chosen to pursue it, is to make an assertion not supported by the evidence. To argue that the flexibility designed into the Principles and Guidelines accommodates and even mandates the development of ninety criteria based on these Principles and Guidelines as the test of acceptability for Manitoba Hydro's proposed development plan, is to ignore the history of the development and application of the Act.

The Gibson Framework states that:

> "...Gibson's framework explicitly states that contribution to sustainability should be prioritized as an overarching goal, and applied at all stages of decision making and planning. The Acts are less explicit in this regard, although they implicitly require a higher test, ...
>
> Likewise the intent of the Environment and SD Acts to ensure the long-term sustainability of Manitoba and its citizens is evidence that sustainability is a long-term overarching goal..." (CAC Exhibit #20, page 55).

[231] Report on the Consultation on Sustainable Development Implementation (June, 1999).

Even if one agrees that indeed "sustainability is a long-term overarching goal" of the Manitoba government it does not follow that the means of achieving that goal is the application of the Gibson framework in this case at this time. This is an example of confusing means with ends.

As noted above, government has explicitly ruled out the adoption of sustainability criteria at this time, and the language of both the Sustainable Development and Environment Acts makes it clear that sustainability is a balance of several not always compatible attributes that preclude a hard and fast "rule" that sustainability shall be the pre-eminent test of acceptability. It is one factor and an important one but at this stage in the development of our sustainable development thinking we lack the societal consensus needed for it to be the litmus test of acceptability.

In his testimony, Dr. Gibson stated:

> "And the basic sustainability wisdom is you can't get towards sustainability by balancing. Balancing is about sacrificing economic or social or ecological objectives. And since they're all completely independent [sic – interdependent] sacrificing any one of them is sacrificing the whole to some extent."[232]

In fact, the concept of sustainability is itself all about balancing.[233] Where possible, positive social, economic and environmental benefits are sought for all development; but this is not always possible. In fact if this is to be the test of acceptability, then a substantial portion of the development upon which the functioning of our modern society rests, would fail.

In defense of the conclusion that the framework is mandated by the *Sustainable Development Act*, the Gibson Framework states:

> "Since both the substantive and procedural requirements of sustainability assessment are already consistent with what is established in the Acts, adoption of a more explicit and more fully elaborated framework for sustainability assessment would be a useful next step in clarifying expectations and facilitating implementation." (CAC Exhibit #20, page 55).

[232] Testimony, Dr. Robert Gibson, April 29/14, Transcript page 9186, lines 10-15.

As noted above, the agreement on substance refers to the use of common sustainable development vocabulary in the legislation and the framework. There is general agreement on the broad components of sustainability. There is certainly no agreement whatsoever on "procedural requirements".

The Gibson framework requires the application of sustainability criteria to be used as the final arbiter on project acceptability; the Act requires that the elements of sustainable development should be (not must be, or shall be) considered, their application encouraged and facilitated. It may well be that government may decide that development of a more rigorous framework for the implementation of sustainable development would be useful, in which case, as it did with the development of both the Sustainable Development and Environment Acts, an extensive and inclusive public consultation process would be undertaken to inform the development of a framework that would have enormous implications for future development in Manitoba. Consultations leading to the *Sustainable Development Act* transpired over almost three years. The COSDI process ran for about a year and a half.

Finally, it should be noted that where government has determined that there is sufficient consensus to better define some of the broad concepts of sustainability, such as social equity, and open, accessible and transparent decision-making, it has developed regulatory and policy instruments governing their application. Examples include the Province's Aboriginal training, employment and business development policies, and various regulatory requirements for access to information, and intervener funding. The Manitoba Energy Strategy is an explicit statement by the government of the people of Manitoba concerning a sustainable energy future for the Province – a fossil fuel free future – and how to get there.

15.2 Does the proposed framework fall within the Terms of Reference issued to the Public Utilities Board NFAT Panel?[234]

The Gibson Framework states that … "the NFAT Terms of Reference (TOR) also require consideration of sustainability concerns". This is correct. The Terms of Reference also are quite specific as to the focus of this consideration. In assessing Hydro's plan:

> The assessment will take the following factors into consideration:
> b. The alignment of the plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in the *Sustainable Development Act*.

[234] Testimony, Norman Brandson, March 25/14, beginning Transcript page 3635.

In assessing Hydro's plan as compared to potential alternatives, the identical language is employed to describe how sustainability is to be considered.

We must assume that the wording of the TOR was chosen with care. The PUB will take into consideration the alignment of the plan to the Principles of Sustainable Development as outlined in the *Sustainable Development Act.* This language in no way implies that the Principles should be the preeminent test of acceptability. In fact the TOR directs the Panel's attention to the highest, most general level of consideration of sustainability, the Principles; the Guidelines, also contained in the *Sustainable Development Act* are pointedly not included. This level of generality certainly does not support the notion of the development and application of prescriptive sustainability criteria to the assessment of Manitoba Hydro's plan.

Therefore it is reasonable to conclude that the proposed Gibson sustainability assessment framework falls outside of the panel's Terms of Reference.

15.3 Is the proposed framework widely accepted as an assessment methodology for major development initiatives in Canada?

The Gibson Framework relies on "the literature", experience outside of North America, and the work of the World Commission on Dams[235] to demonstrate the acceptance of the proposed framework as best practice. The paper cites some Canadian examples where sustainability has been considered in the project assessment – as indeed it has been considered in the development and assessment of Manitoba Hydro's preferred plan – but it appears that in only one case, the MacKenzie Valley Gas Project, has the Gaudreau-Gibson framework been applied[236]. The analysis utilizing the framework is contained in 32 pages of the 600-page report. It is worth noting that the Joint Panel adopted the SAF approach without direction from the governments, and that its report was filed twenty-five months after the conclusion of public hearings. The Panel stated in its report that … "The Panel cannot stress too strongly the importance of the phrase subject to the full implementation of the Panel's recommendations. Absent such implementation the Panel does not expect the project to make a net positive contribution to sustainability, or to justify approval and permitting." Nonetheless, the governments rejected several recommendations and only conditionally accepted many others. The Panel then withdrew its endorsement of the project and the

[235] Dams and Development – A New Framework for Decision-Making: World Commission on Dams (2000).

[236] Foundation for a Sustainable Northern Future: Report of the Joint Review Panel for the MacKenzie Gas Project (2009).

governments concluded, "The governments stand behind their assertion that the implementation of the final [government] response will eliminate or mitigate any significant adverse effects of the project."[237]

It is neither at all clear exactly what the experience has been outside North America, nor what application it might have in the Canadian context, and a simple assertion that the sustainability assessment framework approach has been accepted in parts of Europe, Asia and Australia cannot be taken as evidence that it constitutes best practice for project reviews in Canada, let alone that it should be applied to the PDP for the NFAT analysis.

The "literature" cited is largely academic, and although of possible interest if and when Manitoba examines a more prescriptive approach to sustainable development, it cannot be said to demonstrate best practice. It is necessary to look to what is actually practiced by the authorities in Canada responsible for major development review to determine best practice; and to date no government in Canada has adopted the sustainability assessment framework approach in assessing development initiatives.

The approach used in the Gibson Framework has defined ninety sustainability criteria that are to be applied to each alternative to determine the preferred alternative (or to propose or define some other alternative). The criteria – many of which are not quantifiable – are to be taken altogether, because of the interrelationships amongst them, and applied at all stages of development planning. "These criteria are specified for this particular case alone and have never been applied by anyone."[238]In order to apply the criteria the "desired future" must be defined. It is further asserted that not only is there no "best practice" in the development and application of a sustainability assessment framework, there may never be a "best practice"! "No there isn't a best practice that's clearly established … there will never be a … a fully defined approach."[239] A framework would have to be constructed anew in each and every case. All of this hardly adds up to a methodology, lacking as it does objectivity, reproducibility, and broad societal input into defining the values inherent in many of the criteria. And it must be emphasized that the SAF is not being proposed as a simple checklist, an additional tool in the assessment toolbox; it is being proposed as the basis upon which a final decision on a preferred development plan must rest. "The centre of it is that we're talking about a positive contribution to sustainability as the essential test on whether proposed undertakings are worthy of approval."[240]

[237] Governments of Canada and of the Northwest Territories Final Response to the Joint Review Panel Report for the Proposed Mackenzie Gas Project – November 2010.
[238] Testimony, Dr. Robert Gibson, April 25/14, Transcript page 9134, lines 4-6.
[239] Testimony, Dr. Robert Gibson, April 29/14, Transcript page 9304, lines 12-13.
[240] Testimony, Dr. Robert Gibson, April 29/14, Transcript page 9127, lines 8-11.

As noted above, it is intended that the framework criteria are to be applied at every stage of project and system design and development. This poses a problem as this particular set of 90 criteria have never been previously applied anywhere. "…one of the challenges that the criteria you are proposing create … we [PUB] would be called upon to … retrospectively apply criteria to a project that … where those criteria were not used to design the project to begin with."[241] "…what Manitoba Hydro has done in this case is quite a bit closer to the standard that we are proposing than most other cases we have seen."[242]

The most widely quoted source in the Gibson Framework is the World Commission on Dams. It should be noted that:

- The Commission's work is somewhat out of date. Its report was completed in 2000 and the actual contents developed over several years prior to that date.
- The Commission relied heavily on case studies. None of these looked at Canadian experience and the only North American example was Hoover Dam, a depression era US project several times larger than any existing or potential Manitoba projects.
- The Commission examined projects in countries where corruption was endemic, democratic, participatory review processes were non-existent and planning at best rudimentary; this had a strong influence on the focus of its assessment.
- The report does not reflect contemporary Canadian practice whereby many of the issues related to the planning for and construction and operation of hydroelectric dams are addressed in standard practices supported by legislation and institutional infrastructure.

Finally, the Manitoba Law Reform Commission has recently initiated a public review of Manitoba's Environmental Assessment and Licensing Regime. In the Commission's consultation prior to preparation of a discussion paper the topic of sustainability assessments was considered. The Commission stated its considered conclusion on this topic in its discussion paper:

> "In the Commission's view it is not yet possible to identify a best practice of sustainability assessment. Moreover, the adoption of a sustainability assessment framework would represent a significant policy choice, involving new forms of knowledge, different participants and a change in focus." [243]

[241] Chairperson, April 29/14, Transcript page 9262, lines 14-20.
[242] Testimony, Dr. Robert Gibson, April 29/14, Transcript page 9263, lines 11-14.
[243] Discussion Paper: Manitoba's Environmental Assessment and Licensing Regime – Manitoba Law Reform Commission (January 2014)

Sustainable Development Conclusion

In conclusion, although it is fair to say that the dialogue surrounding sustainability assessment is stimulating thinking about how to better define sustainability, democratically elected governments in Canada have not yet obtained consensus on many of the broad components of sustainability. This is reflected in the fact that sustainability assessment is not supported by the Manitoba Sustainable Development Act, and that the Terms of Reference issued to the Manitoba PUB NFAT Panel mandate consideration of sustainability in the broadest, high level, non-prescriptive terms leading to the conclusion that a sustainability assessment does not fall within the TOR. And it also fair to conclude that sustainability assessment, even as a concept, is not only not best practice in Canada, but is not "practice" at all; and that the specific framework proposed in the SAFP relies on authority that does not support the assertion that it is a widely accepted methodology.

Manitoba Hydro has, as Mr. Brandson testified, embraced sustainable development and acted to integrate the concept into its daily operations, as well as future planning and development, and has aligned its PDP with Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in the *Sustainable Development Act*.

16.0 ENERGY AND CLIMATE POLICY ALIGNMENT

Manitoba Hydro's Preferred Development Plan (PDP) offers the strongest alignment with current and expected international, Canadian, US and regional/local climate change policies and strategies. To a lesser degree development plans featuring Keeyask (without Conawapa) and the 750 MW interconnection are also well aligned while development plans reliant on natural gas generation are generally misaligned.

Greenhouse gas (GHG) emissions are facing increasing constraints in the US and Canada through federal regulations and state/provincial legislation.[244] These policies have the potential to increase future fossil fuel generation costs, increase demand for lower-emitting resources, and deliver more favorable market prices for low- and non- emitting resources. Hydroelectric generation provides a hedge for both Manitoba Hydro and its US customers against the cost and risk associated with these current and emerging policies.[245]

16.1 Manitoba Policy Context

The NFAT Terms of Reference direct the Board to consider, "The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in The Sustainable Development Act." CAC and MIPUG echoed this direction, further recommending the Board consider factors that go beyond economics, including the "extent of consistency with provincial Government policy and objectives (e.g., Clean Energy Strategy) and national Government policy and objectives (e.g., long-term commitments to reduce Greenhouse Gas Emissions)."[246]

Norm Brandson testified that "the province has articulated its strategy to achieve sustainability in a particular sector in fairly concrete measureable terms. The provincial clean energy strategy is an example."[247]

MNP confirmed the strong alignment of the PDP to existing and future climate policies in both their evidence and direct testimony:

> "By and large, the preferred plan's consideration for resource conservation, sustainable energy development and avoidance of contribution to ongoing

[244] Panel II Direct Evidence (Energy Policy & Pricing Trends in MISO), NFAT Chapter 3.
[245] NFAT Chapter 6, Page 11.
[246] Response to Interrogatory Request CAC/MIPUG I-2.
[247] Transcript page 3634, lines 16-19.

> human-driven climate change increases the attractiveness of the projects in comparison to most of the alternative plans studied as part of the NFAT. The preferred plan also provides the most upside value in a policy scenario that explicitly merits the avoidance of carbon emissions and provides mid-continent regional benefits that support reduction of the continued reliance on more intensely emitting forms of generation."[248]

Mr. Bowman of InterGroup agreed that protecting the option to build Conawapa through the planning and licencing phase is consistent with the Clean Energy Strategy.[249]

MNP concluded that, "The preferred plan more strongly aligns to the current and expected international, Canadian, US and regional/local climate change policies and strategies."[250]

Sustainable development has already been reviewed in Section 15.0 Consideration of both the domestic and global GHG implications and their effect on Climate Change are fully aligned with these principles. Mr. Brandson provides the following comments in regards to Principle 7 – Global Responsibility:

> "By developing renewable hydro-electric power, Manitoba Hydro will be, through export sales, replacing future greenhouse gas emitting fossil fuer -- fuel power plants. This will contribute to the long-term mitigation of effects of climate change, the most serious global intergenerational issue of our time. Once the power is required to meet Manitoba needs, it will contribute to the province's stated goal of a fossil fuel free Manitoba economy." (Tr. p. 3640-3641).

Manitoba Hydro's hydroelectricity exports offer customers a hedge against future GHG emission constraints. Development plans which include natural gas generation are viewed as misaligned with current policies and exposed to future policy implications. Manitoba's Clean Energy Strategy recognizes the clear advantages of hydroelectric generation over natural gas generation; reduced reliance on imported fossil fuels, significantly fewer GHG emissions (See Section 17.6 in the Final Argument entitled The Preferred Development Plan Delivers the Greatest Greenhouse Gas Reductions), fuel price stability, and energy security[251].

[248] MNP, NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations, page 1.
[249] Page 13 of Written Testimony of Mr. Bowman of InterGroup.
[250] MNP, NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations, page 36.
[251] PUB Exhibit #58-5, page. 339.

16.2 North American Policy Context

Concern over environmental implications and climate change impacts are increasingly driving policy decisions. Under the Copenhagen Accord, both Canada and the US committed to reduce GHG emissions to 17% below 2005 levels by 2020.

The Obama Administration continues to pursue its energy and environmental objectives through regulations promulgated by its Environmental Protection Agency.[252] In the near term, the most consequential current regulation is the Mercury and Air Toxics Standards (MATS) which requires reductions in mercury and other air toxins from coal- and oil-fired power plants. Along with MATS, the Cross-State Air Pollution Rule, Coal Combustion Residuals Handling Regulations and Cooling Water Regulations will increase environmental compliance costs for generators. In May 2014, the White House released its third National Climate Assessment[253] which outlines the effects of climate change on the United States and sets the stage for the expected June 2014 release of EPA regulations to limit carbon emissions from existing power plants.[254] Ultimately, these regulations could have a transformative impact on the US electricity sector.

The Canadian Federal Government is similarly taking regulatory action to address emissions on a sector-by-sector basis through Environment Canada.[255] In addition to the existing Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulation, Environment Canada is currently discussing regulations to limit emissions from natural gas-fired power plants. Plans that include gas-fired generation, MNP suggests, are at risk of facing difficult future Canadian performance standards and could face carbon pricing penalties which would decrease the margins they could earn in export and domestic markets.[256]

Several provinces and states have taken legislative action to limit emissions. A group of eastern states established the Regional Greenhouse Gas Initiative (RGGI), a regional cap-and-trade program. Quebec and California have also established and linked cap-and-trade programs. Other actions include: Alberta has an emission intensity reduction program, British Columbia has a carbon tax, and Nova Scotia set a hard cap on GHG emissions from its electricity sector.

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[252] MH Exhibit #95, page 67.
[253] MH Exhibit #191-1.
[254] MH Exhibit #95, page 67.
[255] Chapter 3, page 17.
[256] MNP Report, page 15.

Within Manitoba, there is a tax on coal as well as regulations which preclude coal-fired electricity generation except to support emergency operations. Manitoba also has a Clean Energy Strategy which provides clear preference for the expanded use of low and non-emitting energy resources.

In Minnesota, utility resource plans must consider both the estimated regulatory costs of emissions – the cost of compliance with future regulations affecting electricity generators (see Section 9.2 in this Final Argument on carbon pricing), and externality costs of emissions - an estimate of all the economic damages associated with an increase in carbon emissions (see Section 19.2 in this Final Argument on externality costs of emissions). In addition to including these costs in utility resource plans, Mr. Eric Swanson noted in his testimony that Minnesota current state law essentially prohibits the construction of new nuclear facilities and a prohibition against the construction of any new base load coal- fired facilities unless and until there is either a state or federal hard cap, essentially, on greenhouse gas emissions (Tr. p. 1965, lines 1-9). Combined with federal EPA regulations, Mr. Swanson advises that in Minnesota "there's severe doubt as to the future of some of the current fleet as - -as well, which is why hydro has been so attractive to some of the US utilities" (Tr. p. 1965, lines 10-16).

Concerns over carbon regulation are driving utilities to advocate for carbon policies that are economically efficient and reduce policy uncertainty. As noted during the NFAT hearing[257] Great River Energy is publicly advocating for a MISO wide carbon fee to demonstrate regional compliance with the EPA's emerging GHG regulations for existing generating facilities. If the GRE proposal or one with a similar framework can gain traction across MISO stakeholders, states could enable MISO to incorporate a carbon fee into its operations.

[257] TR pg. 1390, lines 16-17

17.0 MH POSITION: CLIMATE CHANGE IMPACTS FOR MANITOBANS

The Intergovernmental Panel on Climate Change has determined that the warming of the climate system is unequivocal and it is extremely likely due to the observed increase in anthropogenic greenhouse gas concentrations. Changes in temperature and subsequent changes in precipitation and other environmental components have been observed throughout Manitba and are projected to ontinue to change into the future. Impact studies have been conducted globally, nationally and regionally to examine both the observed and projected impacts of climate change. These studies show that climate change impacts are occurring and are projected to continue into the future. MH Exhibit #191 contains a summary of observed and future projected impacts of climate change in Manitoba. This report reviews a sample of scientific literature on climate change impacts within Manitoba and many of these studies show that climate change is occurring and that the impacts are already being felt in many areas such as freshwater and terrestrial ecosystems. Furthermore, they show that impacts are projected to continue into the future. MH Exhibit #191-1 includes reference to the recently released US National Climate Assessment, which was prepared by the US Global Change Research Program, a scientific panel overseen by the US Government. This US climate assessment speaks to national and regional climate change impacts in the Midwest export region which may extend into Manitoba

Stakeholders in Manitoba are becoming more aware of the observed and projected impacts of climate change to their regions of interest. For example, as a result of these potential impacts of climate change to Lake Winnipeg, the Lake Winnipeg Foundation has developed and adopted the following position statement which guide their decision-making in regards to climate change:

> Global climate warming, from human-driven increases in atmospheric CO_2 with associated changes in rainfall, runoff, evaporation, ice duration, and temperatures in the Lake Winnipeg watershed, is impacting the Lake Winnipeg ecosystem. Extreme hydrological events, such as flooding and drought, are becoming more common and are detrimental to the lake's ecology and biodiversity. Increasing water temperatures are contributing to proliferation of toxic blue green algae and to invertebrate species changes which ultimately influence the Lake Winnipeg fish community. Lake Winnipeg Foundation supports policies and practices that reduce greenhouse gas emissions (February 1, 2012). (Lake Winnipeg Foundation, 2012) – MH Exhibit #191

17.1 MH Position: Climate Change Impacts Reasonably Addressed

Climate Change is a topic of interest for Manitoba Hydro and as such, strategies have been established to shape the organization's response to climate change which is described in NFAT, Appendix K. For the NFAT, the climate change sensitivity analysis undertaken by Manitoba Hydro is appropriate and reasonable given the state of the science, and its work is consistent with that of other major hydroelectric utilities. Expert witness, Dr. Rene Roy from the Ouranos Consortium which employs some of Canada's leading climate change researchers testified on March 12, 2014 that "[Manitoba Hydro] did the best they could with the information that was available[258]". Furthermore La Capra Associates (LCA) testified on April 9, 2014 and stated in MH/LCA-024 that they are not aware of any other generation developer, similar to Manitoba Hydro who have undertaken a more extensive analysis or advanced modeling of climate change impacts in a resource planning application[259].

17.2 Manitoba Hydro Sensitivity Analysis and Main Conclusions

Chapter 10, Section 10.2.2 of the NFAT Submission presents an analysis of the potential impacts of climate-changed streamflow on projections of average revenue under the All Gas development plan, the K22/Gas development plan and the Preferred Development Plan (K19/C25/750MW (WPS Sale & INV)). Manitoba Hydro employed state of the art Global Climate Model (GCM) runoff data to assess potential future changes to annual water availability in the Nelson-Churchill watershed under a changing climate. To account for the major source of uncertainty, a large ensemble of 109 simulations taken from 21 different GCMs driven by three future greenhouse gas emission scenarios was employed. The GCMs were used to create a broad range of future streamflow projections; which were input into the Simulation Program for Long-Term Analysis of Hydraulics model (SPLASH) to determine the long-term operations of Manitoba Hydro's system under the various Development Plans. In general, the projections of GCMs indicated that it is more likely there will be an increase in average annual streamflow as approximately 70% of projections show an increase in runoff. As the Manitoba Hydro system currently consists of predominately hydro-based generation, all plans will be affected by changes in streamflows driven by climate change. As a result there is a greater likelihood of an increase in average annual revenues than there is of decreased annual average revenues..

[258] March 12, 2014 Transcript page 1948, lines 17-18.
[259] April 9, 2014 Transcript page 6248, line 18.

17.3 LCA and MNP Outstanding Criticisms and Lack of Expertise

LCA and MNP both commented on Manitoba Hydro's climate change sensitivity analysis[260] [261]. The main criticism from these Independent Expert Consultants (IECs) relates to Manitoba Hydro's consideration of changes to seasonally altered precipitation in the climate change sensitivity analysis and the absence of analysis on the probability and severity of future droughts as result of climate change and its related impact. Over the course of the hearings, these criticisms were addressed through Manitoba Hydro's rebuttal evidence[262], LCA/MH II-492 and expert witness testimony which demonstrated that the original criticisms were a function of the IECs incomplete understanding of the physical nature in which Manitoba Hydro operates its system.

MNP testified on April 4, 2014, that "In Hydro's rebuttal evidence[263] they provided greater clarity on the reason that they elected to conduct modeling on an annual average basis rather than on a seasonal basis. And we found that to be reasonable, acceptable[264]". It can therefore be concluded that MNP's criticism on Manitoba Hydro's consideration of seasonality is no longer a significant concern.

Through cross-examination, it was demonstrated that MNP's criticism on drought was based upon a literature review. It was revealed that MNP's "work on drought certainly isn't primary research. We reviewed documentation relating to climate change impacts which relied on other studies of the science of drought[265]". Careful examination of MNP's cited documents demonstrated that the strength of the literature reviewed by MNP was hindered by a lack of acceptable literature and failing to communicate key assumptions and limitations contained in the materials reviewed.

MNP's commentary on drought primarily relied upon work by Stern (2006)[266] which relied upon Burke et al. (2006)[267] for future drought analysis[268] [269]. Burke et al. (2006) assessed shorter-term meteorological drought and the authors acknowledges that their method

[260] LCA, 2013. Technical Appendix 4.
[261] MNP, 2013. NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations.
[262] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, pages 114- 117.
[263] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, pages 114- 117.
[264] April 4, 2014 Transcript page 5246, lines 8-13.
[265] April 4, 2014 Transcript page 5444, lines 21-24.
[266] Stern, Nicholas. 2006. The Economics of Climate Change: The Stern Review. Cambridge, UK: Cambridge University Press, Retrieved online (May 5, 2014) at: http://mudancasclimaticas.cptec.inpe.br/~rmclima/pdfs/destaques/sternreview_report_complete.pdf.
[267] Burke, E.J., S.J. Brown and N. Christidis, 2006. Modeling the Recent Evolution of Global Drought and Projections for the Twenty-First Century with the Hadley Center Climate Model. J. Hydrometeorology, 7, 1113-1125.
[268] MH/MNP-008a IR.
[269] April 4, 2014 Transcript page 5443, lines 12-13.

"...should not be used as a measure of hydrological drought[270]". On April 4, MNP concurred that the Burke paper was based on meteorological drought[271]. As such, Burke's research does not directly apply to Manitoba Hydro's system, where multi-year hydrological drought is of primary interest. Furthermore, Burke et al. (2006) recognizes the limitations of their studies which utilizes a single climate model, and states that: "there is a need for these results to be corroborated by other climate models[272]. Therefore, since uncertainty was not adequately considered, the results in these studies cannot be taken with absolute confidence.

It should also be noted that "No Nelson-Churchill River Basin studies were used[273]" when MNP conducted their assessment and instead, "MNP has made inference based on reported results of global modeling and impacts on northern watersheds[274]". MNP's inferences originate from Nordic/Baltic region report[275] which includes areas considerably different in size, climatology and geography, when compared to the Nelson-Churchill watershed and therefore the Nordic/Baltic region report does not constitute a reasonable base on which to make inferences.

On April, 9, 2014, LCA testified that they do not have any expertise in climate change modeling or hydroclimatology[276] and their review was simply reporting on the limitations that Manitoba Hydro had already identified[277 278].

17.4 Ouranos Support

In light of these criticisms, Manitoba Hydro sought the opinion of the Ouranos Consortium on Regional Climatology and Adaption to Climate Change ("Ouranos)", regarding Manitoba Hydro's use of the scientific data, including future climate change projections of extreme events such as prolonged hydrologic drought[279]. Ouranos was created in 2001 as a joint initiative of the Quebec Government, Hydro-Quebec and Environment Canada. The consortium brings together 450 scientists and professionals that have considerable experience in climate change impacts and adaptation including a focus on energy supply and water

[270] Burke, E.J., S.J. Brown and N. Christidis, 2006. Modeling the Recent Evolution of Global Drought and Projections for the Twenty-First Century with the Hadley Center Climate Model. J. Hydrometeorology, 7, 1114.
[271] April 4, 2014 Transcript page 5445, lines 9-10.
[272] Burke, E.J., S.J. Brown and N. Christidis, 2006. Modeling the Recent Evolution of Global Drought and Projections for the Twenty-First Century with the Hadley Center Climate Model. J. Hydrometeorology, 7, 1124.
[273] MH/MNP-008b IR.
[274] MH/MNP-008b IR.
[275] Norden, Climate Change and Energy Systems. 2012. Accessed in 2013. (http://www.nordicenergy.org/wpcontent/uploads/2011/12/Climate-Change-and-Energy-Systems-CES-project.pdf).
[276] April 9, 2014 Transcript page 6247, line 15.
[277] April 9, 2014 Transcript page 6248, lines 9-11.
[278] MH/LCA-024 IR
[279] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, pages 114- 117.

resources. Ouranos has developed an internationally recognized expertise, participates in international research projects and regularly publishes in scientific journals. Ouranos conducts integrated research projects that combine the development of regional climate change projections, the assessment of physical and human impacts related to climate change and adequate measures to prepare them and different stakeholders in adaptation[280].

In Ouranos' written testimony[281] and in their oral testimony given by expert witness Dr. Rene Roy on March 12, 2014, Ouranos stated that they do not agree with the concerns raised by the IECs[282]. Research is still ongoing and there is currently no power utility accepted standard methodology to quantify climate change impacts on extreme events (i.e. floods and droughts)[283] [284] [285]. As a result of the state of the science, there is low confidence in future projections of drought as it relates to climate change in the Nelson-Churchill watershed and as such the information is not available to undertake a quantitative assessment based on a scientific consensus as suggested by MNP. In the absence of clear information on future droughts, it is best to use historical records. Consequently Manitoba Hydro has quantitatively addressed drought on the historical record of water flows in NFAT Chapter 10, Section 10.2.1 and has qualitatively assessed the impacts of a drought worse than the drought of record in NFAT Chapter 10, Section 10.3.3. This was supported by Ouranos "if you need clues on the future droughts is to look in the back and analyze your historical information[286]". Ouranos went on to state in their oral testimony "... considering the worst drought in their historical records was by far the best approach they could have used at this time[287]" and with "99 years records of flow, [MH has] lot of years behind that [MH] can rely on[288]". In Ouranos written testimony they went on to state that ".... maintaining historical droughts from the meaningful LTFD records presents a good way to compensate the limitations of the delta approach with respect to representing drought in future climate scenarios[289]". Furthermore, they described a hydropower generating station being planned in 2008 by Hydro Quebec where they "haven't been using climate change information[290]" and that if they did it again they "would use an approach such as Manitoba Hydro[291]".

[280] See http://www.ouranos.ca.
[281] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, pages 114- 117.
[282] March 12, 2014 Transcript pages 1905, lines 24-25.
[283] Canadian Dam Association, 2007. Technical Bulletin. Hydrotechnical Considerations for Dam Safety. 49 pp. (http://www.imis100ca1.ca/cda/CDA/Publications_Pages/Dam_Safety_Guidelines.aspx).
[284] Federal Emergency Management Agency, 2013. Selecting and Accommodating Inflow Design Floods for Dams. FEMA P-94/August 2013. (http://www.fema.gov/media-library-data/1386108128706-02191a433d6a703f8dbdd68cde574a0a/Selecting+and+Accommodating+Inflow+Design+Floods+for+Dams.PDF).
[285] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, page 117.
[286] March 12, 2014 Transcript page 1937 lines 18-20.
[287] March 12, 2014 Transcript page 1908 lines 3-5.
[288] March 12, 2014 Transcript page 1932, lines 9-13.
[289] Exhibit 85- Manitoba Hydro's Rebuttal Evidence, page 117.
[290] March 12, 2014 Transcript page 1915, lines 9-10.
[291] March 12, 2014 Transcript page 1915, lines 12-13.

17.5 Conclusion on Climate Change

Studies show that climate change is occurring and that the impacts in Manitoba are already being felt in many areas such as freshwater and terrestrial ecosystems. Furthermore, they show that impacts are projected to continue into the future. As described in NFAT Appendix K, Manitoba Hydro has demonstrated that the Corporation has a very comprehensive climate change impact study program and is "ahead of the curve" in terms of being well informed about changes in the climate sciences field. At this time, given the current state of the science, Manitoba Hydro has done a reasonable climate change sensitivity analysis and the results show that the PDP continues to be viable under climate change projections, as do the Plans with Keeyask and the 750 MW Interconnection.

17.6 The Preferred Development Plan Delivers the Greatest Greenhouse Gas Reductions

Manitoba Hydro's PDP results in the least GHG emissions within Manitoba and the greatest displacement of GHG emissions outside of the province. To a lesser degree, development plans featuring Keeyask (without Conawapa) and the 750 MW interconnection also deliver significant emission reductions, while plans that rely on natural gas generation result in the greatest emissions within Manitoba and the least displacement of GHG emissions outside of Manitoba.

The physical realities of climate change require a development plan which reduces GHG emissions globally and is well aligned with a carbon constrained future. The Intergovernmental Panel on Climate Change (IPCC) has determined that climate warming is unequivocal, human influence on the climate system is clear, and continued emissions of GHGs will cause further warming and changes in all components of the climate system. The IPCC stresses that limiting climate change will require substantial and sustained GHG emission reductions.[292]

The Pembina Institute's life cycle assessment figure below (MH Exhibit #85, page 111) demonstrates that the Keeyask and Conawapa projects have the lowest GHG emissions per unit of generation compared to any other resource option, including wind. "A comparably size high efficiency combined cycle natural gas turbine would have more direct GHG emissions in its first half year of operation than the full life cycle GHG emissions of the

[292] CAC/MH I-231a.

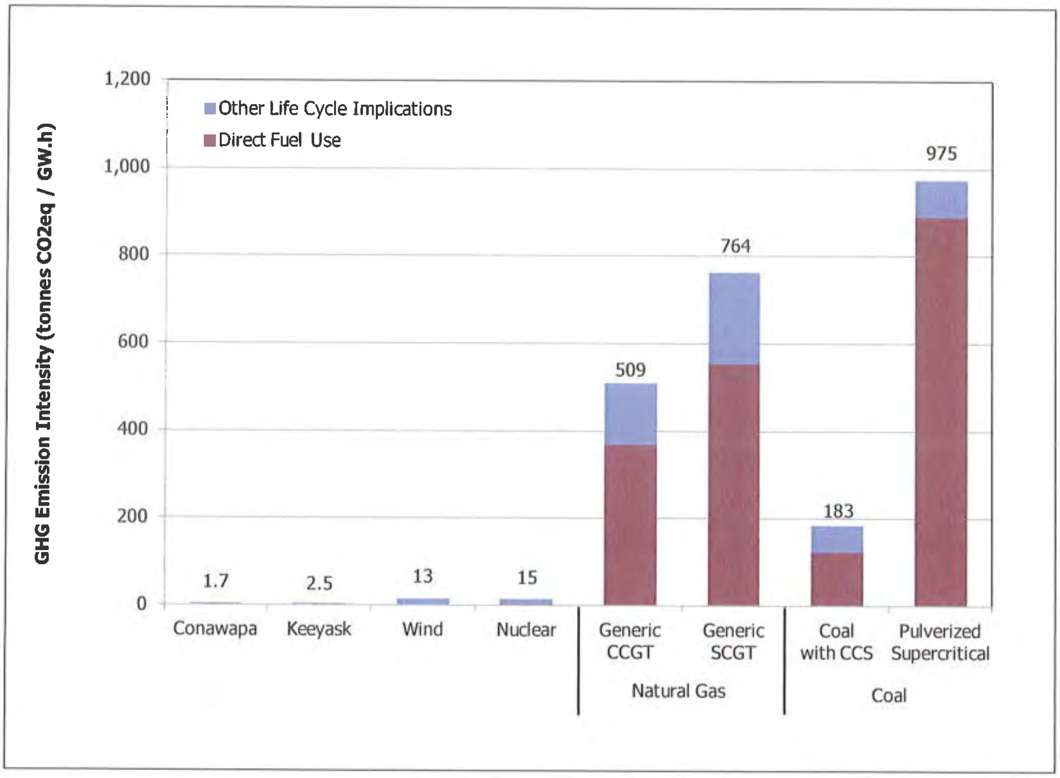
Keeyask G.S. over its 100 year life".[293]

The various development plans outlined by Manitoba Hydro affect GHG emissions both within and outside Manitoba, resulting in different climate change impacts. Plans which rely on natural gas generation increase local GHG emission and correspondingly reduce the potential for GHG displacement outside of the province. As MNP indicates, "The most significant long-term impacts are those direct -- are those associated with the direct impacts of climate change, which may be further exacerbated by GHGs and air pollutants in the short term that would be associated with alternative plan that are reliant on gas generation"[294]. The PDP offers the greatest opportunity to displace fossil fuel-fired electricity and associated GHG emissions in jurisdictions outside of Manitoba through exports of lower emitting hydroelectricity (Table 1 – Response to MNP Undertaking 98).[295]

As discussed in the previous climate change Section 17.5, studies show that climate change is occurring and that the impacts in Manitoba are already being felt in many areas such as freshwater and terrestrial ecosystems and that these impacts are projected to continue into the future. Emission reductions both inside and beyond the border of Manitoba will contribute to mitigating Manitoba climate change impacts. Science continues to demonstrate the increasing urgency to reduce GHG emissions associated with human induced climate change. Development plans that maximize hydropower production in association with a 750 MW interconnection deliver the greatest emission reductions. Furthermore, emerging policies are expected to increasingly constrain high emitting resources and reward lower emitting resources. The PDP which includes Keeyask and Conawapa hydroelectric generating stations will deliver the greatest GHG emission reduction benefits in a carbon constrained future, while those with Keeyask and the 750 MW Interconnection the second largest reductions.

[293] MH Rebuttal, page 114, lines 9-13.
[294] C. Sabine, MNP, page 5287, lines 3-9.
[295] MNP Undertaking #98.

Comparison of Lifecycle GHG Emissions For Electricity Generation[296]



Selected Plan Air Impacts (Source: MNP Undertaking #98)

Air Impacts*	Preferred Plan #14: K19/C25/ 750MW (WPS Sale & Investment)	Plan #1: All Gas	Plan #4: K19/Gas24/250MW	Plan #5: K19/Gas25/750MW (WPS Sale & Investment)	Plan #7: SGCT/C26	Plan #8: CCGT/C26
Cumulative GHG Operating Emissions	7.5 Mt CO2e	33.2 Mt CO2e	25.4 Mt CO2e	16.3 Mt CO2e	13.0 Mt CO2e	17.5 Mt CO2e
Cumulative Regional GHG Displacement Potential	191.6 Mt CO2e	22.5 Mt CO2e	107.7 Mt CO2e	94.4 Mt CO2e	102.1 Mt CO2e	113.1 Mt CO2e

[296] MH Rebuttal, page 111,

18.0 GREENHOUSE GAS EXTERNALITIES FAVOUR THE PREFERRED DEVELOPMENT PLAN

The PDP results in the lowest greenhouse gas externalities within Manitoba and the greatest displacement of greenhouse gas externalities outside of the province. The remaining Keeyask and 750 MW interconnection plans have the second lowest greenhouse gas externalities in Manitoba and the second highest displacement outside the Province.

The Manitoba Sustainable Development Act requires the integration of environmental and economic decisions. This involves ensuring that no costs associated with a decision or action, including externalized costs, are left unaccounted for. Further the principles require global responsibility. Manitobans should think globally when acting locally, recognizing that there is economic, ecological and social interdependence among provinces and nations. [297]

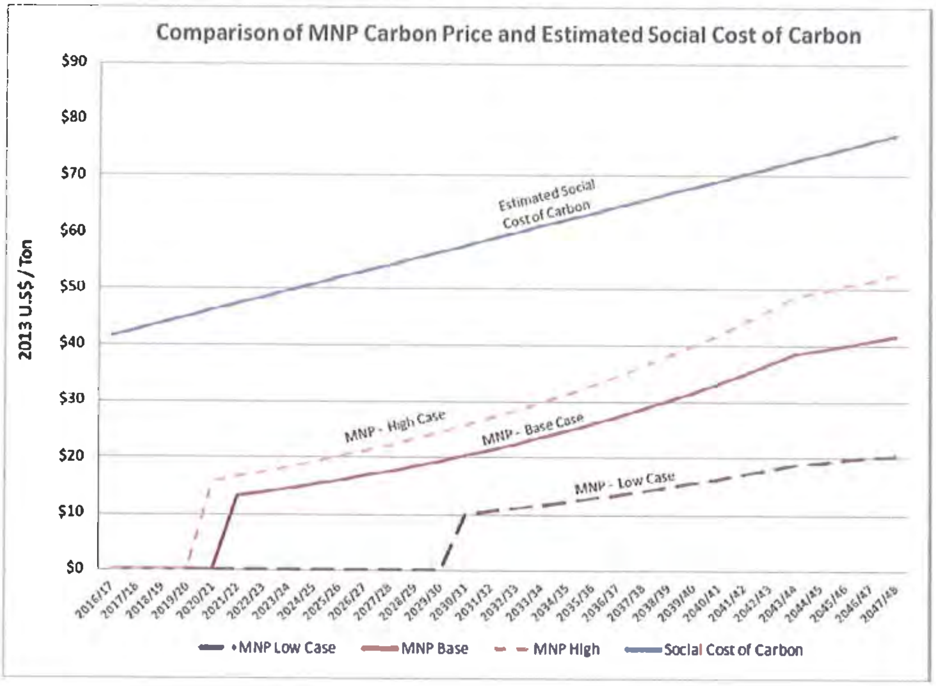
The Green Action Centre highlighted the externality issue identified in *The Economics of Climate Change: The Stern Review* authored in 2007:

> "Climate change is a result of the greatest market failure the world has seen. The evidence on the seriousness of the risks from inaction or delayed action is now overwhelming. The problem of climate change involves a fundamental failure of markets. Those who damage others by emitting greenhouse gases generally do not pay."[298]

Manitoba Hydro's economic analysis dealt with expected carbon price cost however these only captured a modest portion of the total externality cost of GHG emissions. MH Exhibit #185 demonstrates that the range of climate change policies under discussion would deliver only a modest portion of the total social and environmental damages and risks associated with climate change. To further account for environmental externalities, the multiple accounts analysis acknowledged that "*Recent estimates of the social cost of GHG emissions are much higher than the assumed carbon charge*"[299]. Within the multiple account analysis, the social cost of carbon was thus used to represent the environmental and social damage costs and risks of climate change due to Manitoba thermal generation-related GHG emissions. As part of the direct evidence, the reduced Manitoba GHG externality cost associated with the PDP relative to the all gas plan was estimated to be $320 Million (6%

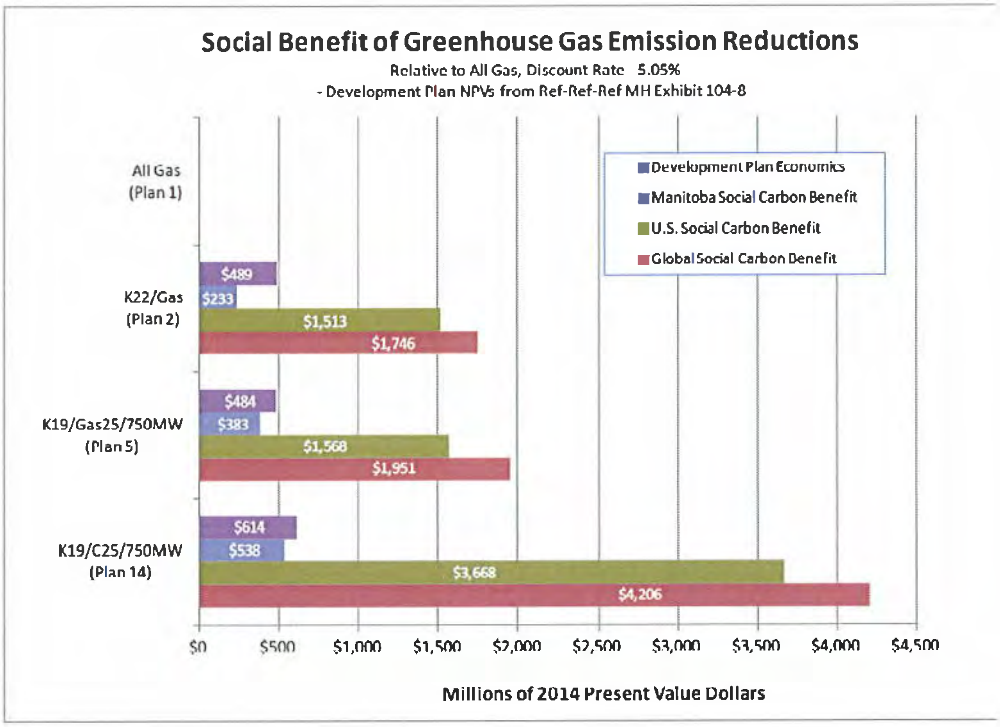
[297] The Sustainable Development Act (Manitoba)
[298] Page 2508, Lines 9-18 of Testimony
[299] Chapter 13 – Integrated Comparisons of Development Plans – Multiple Account Analysis, Page 44, Line 15.

discount rate, present value $2014)[300]. This value from the multiple accounts analysis nets out internalized costs such as the Manitoba coal tax and an estimate of future carbon charge payments.



MH Exhibit 185 – Figure 2

300 MH-129-6, Page 8.



MH Exhibit # 185 – Figure 1

The global GHG externality was not quantified as part of the multiple accounts analysis. However, in response to a request from the Green Action Centre, Manitoba Hydro prepared additional analysis which determined the approximate externality benefit of GHG emission reductions from three perspectives: Manitoba, U.S. and the combined global perspective. The PDP offers the greatest global externality benefit from the reduction of GHG emissions – in excess of $4 Billion (present value $2014).[301] This results directly from the PDP having both the lowest GHG emissions within the province and the greatest displacement potential of emissions outside of the province relative to the all gas plan. The Keeyask, Gas 25, 750 MW plan yields approximately a $2 Billion (present value $2014) global externality benefit.

[301] MH Exhibit 185

19.0 MULTIPLE ACCOUNTS SOCIETAL BENEFIT COST ANALYSIS

19.1 Introduction

Chapter 13 of the NFAT Application presented the results of a multiple account benefit-cost analysis (MABCA) of the preferred development plan compared to alternatives with and without the Keeyask project; and with and without a new US interconnection and new export sales agreements. The MABCA extended the assessment of alternatives from a Manitoba Hydro perspective to a broad Provincial social perspective and was specifically intended to assist the Panel in addressing the question of overall socio-economic benefit as called for in the NFAT Terms of Reference.

Benefit-cost analysis is widely recognized as a logical, consistent method of evaluating alternative projects and policies from a broad social or societal perspective. MABCA is an extension of traditional benefit-cost analysis that explicitly recognizes not all consequences can reliably be monetized. It highlights the advantages, disadvantages and trade-offs among the alternatives – not simply the overall bottom line. In terms of conducting the analysis, Manitoba Hydro ensured that it was thorough and went as far as hiring a recognized expert in the field of benefit-cost analysis; Dr. Marv Shaffer. Dr. Shaffer developed the MABCA framework for the evaluation of major crown corporation policies and projects in British Columbia and is a recognized expert in benefit-cost analysis. He teaches a course in benefit-cost analysis in the Public Policy Program at Simon Fraser University and has written a highly regarded textbook on the multiple account approach. No other expert who appeared before this Board has the same type or level of expertise in benefit cost analysis as Dr. Shaffer.

19.2 Findings

The findings of the MABCA are clear and are important in the integrated comparisons of development plans. These findings can be summarized as follows:

1. There are greater net benefits for Manitobans in developing the Keeyask project than relying on gas-fired generation when needed to meet growing load;
2. There are greater net benefits in developing Keeyask with the 750 MW interconnection and export sales opportunity than without;

3. The advantage of the development of Keeyask with the 750 MW interconnection and sales agreements increases when moving from a Manitoba Hydro perspective to a broad Provincial social perspective;
4. The monetized net benefits for Manitobans are greatest for the Preferred Development Plan, though generally similar to other plans that include Keeyask and the 750 MW interconnection and sales agreements.

These findings were based on the initial analysis performed and were confirmed in the updated capital cost sensitivity analyses which included Manitoba Hydro's latest detailed project estimates of higher capital costs and the elimination of the WPS investment (MH Exhibit #166). The MABCA also examined the GHG externalities implications which are dealt with later on in Section 18.0 – Greenhouse Gas Externalities Favour the Preferred Development Plan.

It is important to note that the monetized values in the MABCA were based on a number of purposely conservative assumptions – assumptions intended not to overstate the benefits of the Preferred Development Plan. The monetized results do not include the estimated value of the additional reliability that the preferred development plan offers and it does not recognize all of the potential government revenue benefits (for example the debt guarantee fee, sales taxes embedded within the project expenditures or the income taxes paid by in-migrants). The monetized values are also based on conservative assumptions with respect to the employment benefits for Manitobans and do not include the potential long term bequest value the hydro projects can offer. In terms of the social cost of carbon, a conservative approach was taken in two respects: the relatively low values for the benefits of lower GHG emissions in Manitoba, and not including any of the benefits of GHG reductions outside Manitoba even though Manitobans will share in that benefit as well. (Tr. p. 4163-4165 and Tr. p. 4233-4234).

19.2.1 Validity of the Evaluation Methodology

Dr. Gibson raised an issue regarding the potential for non-monetized consequences in an MABCA being 'marginalized' (Tr. pg. 9153-9154). That, however, misses the very point of the MABCA. The intent of the analysis is to identify the full range of consequences, assess their significance and highlight both the monetized and non-monetized trade-offs. As indicated by Dr. Shaffer, the important question to ask in this case is whether there is a reason to believe that the non-monetized consequences of the PDP are in the magnitude of a billion dollars (which is the difference between the monetized net benefit of the PDP versus All Gas shown in the updated analysis under MH Exhibit #166). (Tr. pg. 3999-4000).

MABCA enables reasoned, well-considered judgments to be made within the well-established, logical and consistent framework of benefit-cost analysis. Dr. Shaffer explained very clearly how that trade-off analysis assists in making reasoned, well-considered judgments about the relative merits of different plans. (Tr. pg. 3998-4000). That cannot be said about the application of an ad hoc set of criteria that one individual or group might think is appropriate.

19.2.2 Need for Fully Completed Environmental Assessments

Mr. Hendriks suggested that fully completed environmental assessments are required before any NFAT conclusions can be reached based on MABCA or presumably any other evaluation methodology (MMF Ex. 26, p.15). That, however, is neither practical nor true. Just as with the staged assessment and subsequent refinement of engineering, market and other information critically important to the evaluation of alternatives, reasoned judgments can be made with quite extensive and well-considered, even if not finalized, environmental and social impact assessments.

While Mr. Hendriks may wish to dismiss the important choices people make (Tr. pg. 9154 and MH/MMF Camerado Response to IR -016), the fact is that the willing participation of a majority of the Keeyask First Nation partners indicate the assessment that these First Nation partners made and the conclusion they reached – that it is better to proceed with the Keeyask project than not. The residual adverse effects will be sufficiently minimized or offset by the benefits the project offers. In economic terms, that means that the impacts in the view of those most directly affected by that project have been addressed in the design, implementation and partnership plans.

With respect to environmental and social impacts of Keeyask and other projects that may affect others, the MABCA explicitly recognizes there may be non-monetized adverse (as well as positive) effects. However, as stated in Chapter 13, p.67, Manitoba Hydro's assessments suggest there would not be major residual effects or trade-offs "given the extensive monitoring, mitigation and other measures that are planned, **but this will be addressed in detail in the environmental hearings the projects require"** (emphasis added).

> Conclusions can be reached and judgments made providing the rationale for next steps, including further investment in detailed project-specific planning, design, and hearing processes.

19.2.3 Consistency in the Use of the 6% Real Discount Rate

An issue was raised about whether the 6% rate was consistently used in the MABCA. Specifically, it was suggested that the 6% rate was only used up to 2047, but a rate of 5.05% was used after 2047 (Tr. p. 8537).

The monetized present values in the MABCA were calculated with a 6% real discount rate. As explained in Chapter 13, p.5 (see especially footnote 7), this was based on recent research into the estimated weighted average opportunity cost of capital. Also, it was a rate considered appropriate for an analysis from a provincial perspective where more of the capital would come from outside the jurisdiction (as opposed to displacing other capital investment within it).

While there is considerable debate in the economics profession and within government agencies as to the appropriate discount rate to use in benefit-cost analysis, the 6% rate is well within the norm and many would argue that it is higher than what is appropriate, especially for projects with long term consequences.

As Dr. Shaffer explained, that suggestion that the 6% rate was not consistently used in the analysis fails to recognize that the present value calculations in the MABCA were only done for estimated values over the 2014-2047 planning period. (Tr. pg. 4236-7). As is standard and necessary in discounted cash flow analyses with assets having useful project lives beyond the end of the planning period, residual asset values in the final year of the analysis (in this case 2047) was estimated and the differences among the plans taken into account. The residual asset values that the MABCA used were the 2047 present values that Manitoba Hydro calculated with its post 2047 projections and somewhat lower discount rate.

One could argue that the MABCA could have used lower residual asset values, ones for example that Manitoba Hydro would have calculated had it applied a higher discount rate to the long term (post 2047) projections. The effect of that would be to give less weight to the long term benefits of very long life assets.

If anything, however, the stronger argument is that the MABCA should have used higher residual asset values, ones that were based on lower intergenerational discount rates. That is what many economists now argue should be done to give proper weight to the very long term effects different projects may have – in this case to fully recognize the very significant bequest value the assets offer future generations. (See Chapter 13, page.62-4). Had that been done it would have increased the monetized advantage of the Preferred Development Plan.

19.2.4 Inconsistent Discount Rate, and Use of Declining Discount Rate

In CAC final argument, Exhibit 91-1, Mr. Harper argues that the MABCA uses different discount rates pre and post 2047. As explained in the previous point, this fails to recognize that the MABCA does not in itself discount beyond 2047. The market valuation account uses MH estimates of cash flows and residual values. With respect to the latter, the MABCA did not adjust the residual value MH calculated with MH's own discount rate.

The only reason to adjust the MH-estimated residual values in the MABCA would be if they didn't reflect the residual value of the assets from a broader social as opposed to MH perspective. But as Dr Shaffer explained in his evidence and under cross examination, if any adjustment should be made it should be to increase the residual values (based on a lower the long term intergenerational discount rate). There is a large and growing body of literature suggesting inter-generational discount rates should be lower than the standard weighted average opportunity cost of capital used over an intra-generational planning period.

Mr. Harper asserts that there is no agreement on the use of declining discount rates. First it should be noted that the **MABCA did not apply a declining discount rate to calculate a social bequest value of the residual assets**, as many would recommend. It simply noted there may be such a value. And second, whatever uncertainty there may be with respect to declining discount rates, Mr. Harper would find little support for arguing that a higher rate than MH used to calculate residual values should be used to determine their worth from a social perspective. That is what he seems to want – to give even less weight to the very valuable hydro assets the preferred and other hydro plans offer. Had Manitobans in the past done what Mr. Harper seems to recommend Manitoba Hydro would never have developed the existing hydro assets which have and continue to serve Manitoba ratepayers so well.

19.2.5 Impact of Higher Levels of DSM

As Mr. Harper notes higher levels of DSM were not part of the reference case analyzed in the MABCA (CAC Final Argument Exhibit #91-1, page 47). However, the resource analyses that Manitoba Hydro provided during the hearing indicate how the market valuation of the plans would be affected, and that directionally indicates how the MABCA results would be affected. The key point is that it wouldn't alter the main conclusions of the MABCA – that the pathways with Keeyask and the new 750 MW interconnection are better than the alternatives.

A further consideration is that the market account evaluations of the plans which include Keeyask and 750 MW, with updated capital costs, yield approximately the same level of NPV benefits regardless of the level of DSM.

19.2.6 Rate Impacts

Mr. Harper asserts that it would have been better to calculate an NPV of the rate impacts in the customer account in the MABCA (CAC final argument, Exhibit #91-1, Pg. 49-51). This, he asserts, would better capture the overall effect on ratepayers.

First, Mr. Harper does not recognize the express purpose of this part of the customer account in the MABCA. It was to address the distributional issue – how rates would be affected in the short to medium versus long run. That is something an overall present value calculation would not do.

Second, Mr. Harper fails to recognize that the market valuation account effectively does what he is calling for – determine the present value costs of the different plans that customers will ultimately have to pay for. It would be a mistake (and is certainly not done elsewhere) to calculate a present value of estimated rate impacts in addition to a present value of net utility expenditures. The present value of rate impacts would double-count what is already incorporated in the market valuation account. And it would fail to include any provision for the residual value of assets at the end of the rate forecast period. In the context of long lived hydro assets that would be a serious error and provide very misleading results.

Mr. Harper goes on to discuss what discount rate he would recommend for calculating the present value impact on ratepayers. He says a rate between 3% and 8% should be used. The MABCA used a rate of 6%, well within the range Mr. Harper recommends (indeed arguably conservatively so). What he is calling for has been done, and where it appropriately should be done – in the calculation of present value MH expenditures less export revenues – the net costs customers will have to pay for.

19.2.7 Trade-Offs In MABCA Results

Mr. Harper notes that the MABCA results point to trade-offs between the market valuation and government accounts (CAC final argument, Exhibit #91-1, Pg. 51-52). That is correct. However, from a Manitoba point of view it is the sum of these accounts that matters most. That will indicate how Manitobans as ratepayers and taxpayers are best served. As for whether government should take steps to change the distribution of benefits – whether there should be, for example, lower taxes than otherwise or lower rates – is a policy issue that only government can address.

19.2.8 Consideration of Aboriginal Consultation Costs from Government

In its Final Argument, MMF (Tr. p. 11188-9) raises an issue that the government costs for aboriginal consultation (Constitution, Section 35 consultation) have not been included or broken down in the multiple account evaluation, in the government account. In cross-examination (Tr. p. 4004) Dr. Shaffer clarified that these costs are either sunk (particularly with respect to the Keeyask project); common (at least for those projects that are included in the different plans); or included in the costs that Manitoba Hydro estimates it would incur for the other projects, including the transmission lines MMF is specifically concerned about. The key point is that it is Manitoba Hydro's best assessment that there will be no significant differences in government costs between the different plans that have not already been taken into account in the analysis.

19.3 Conclusions about MABCA

Typlan, the independent expert consultant to the Public Utilities Board who reviewed the evaluation in Chapter 13, recognized the MABCA methodology as standard and appropriate. (Tr. p. 6999; Tr. p. 7021-22; and Tr. p. 7024). CAC Consultant, Dr. Gibson, also recognized it as having some very clear advantages, including that it is an extension from relatively conventional economic analysis practice, the methodology uses available data and the ability for the methodology to capture quantified comparisons on some important considerations. (Tr. p. 9153).

In short, the findings of the MABCA are solid and robust. Manitoba Hydro conducted the analysis and placed the results before this Board in an open and transparent manner in order for them to be tested and challenged. It is important to note that there was very limited cross examination on the MABCA, there were no specific challenges to the findings of the MABCA and no evidence presented to the Panel which contradicts those results.

20.0 ECONOMIC IMPACT ANALYSIS

Economic Impact Analysis is one piece of the overall study of the impact that development plans would have on the Province of Manitoba. This analysis provides an estimate of the gross total employment impacts, labour income of a project, tax revenue impacts and of the total Gross Domestic Product. The magnitude of the impacts depends upon the amount of material, equipment and labour required for the project, and their likely origin of supply. The result of the economic impact analysis indicates that the Preferred Development Plan will result in nearly seven times more direct and indirect employment benefits as compared to the All Gas Plan (Appendix 2.3 – Economic Impact Assessment). The plans with Keeyask and the 750 MW Interconnection, but without Conawapa would have approximately half the impact of the Preferred Development Plan. While there was some criticism of Manitoba Hydro's analysis, the independent expert retained by the Public Utilities Board stated that, "...the results confirm that the PDP creates the greatest economic impacts..." (Typlan, 2014, iii). Moreover, if Manitoba Hydro was to reassess the Economic Impacts using the model suggested by Typlan, Typlan concluded that "...the benefits to Manitobans is greater than what was reported."(Ibid.)

20.1 Preferred Development Plan

The Preferred Development Plan (PDP) is expected to have significant, positive economic impacts on the Province of Manitoba with the major economic impact being from construction: *"Overall the PDP exhibits the greatest socio-economic benefits to the people of Manitoba, northern communities and First Nations compared to other plans based on the reference plans evaluated."(Typlan, 2014, vii)* As detailed in Appendix 2.3, these impacts are as follows:

a) Total provincial direct and indirect employment impacts are estimated at 19,246 person-years;
b) The total provincial labour income impact is estimated at $1,480,224 million;
c) Total provincial Gross Domestic Impact is estimated at $1,944,640 million;
d) Provincial and local tax revenues generated in Manitoba are estimated at $581,845 million.

During the operational phase, it is estimated that the PDP will generate 295 person years of direct, indirect and induced employment, $12,641 million of labour income, and $2,133 million in provincial and local tax revenues annually.

The total Manitoba direct employment impact for the PDP project is 10,524 person years, compared to 1,491 for All Gas. This represents a difference of about 9,033 person years. The total direct, indirect and induced employment impact for PDP is 19,246 person years, compared to 2,829 person years for All Gas. This represents a difference of 16,417 person years.

Economic Impact Summary for Preferred Development Plan

	Construction	O&M (Average Annual)
Employment (Direct, indirect and induced) in Person Years	19,246	295
Provincial and Local Taxes ($million)	$581,845	$2,133
Provincial GDP ($Million)	$1,944,640	$14,697
Labour Income (SMillion)	$1,480,224	$12,641

Preferred Development Plan Employment Versus All Gas Plan Employment

Impact	Construction	O&M (Average Annual)
PDP Employment (Direct, indirect and induced) in Person Years	19,246	295
All Gas Plan Employment (Direct, Indirect and induced) in Person Years	2,829	579
Difference: PDP – All Gas	16,417	(284)

20.2 Approach and Criticism of Manitoba Hydro

Economic impacts were estimated using the Manitoba Bureau of Statistics Input-Output (I-O) Model that can trace the demand for one good to demands for all goods in the economy (Appendix 2.3). The model is based on statistical information about the flow of goods and services among various sectors of Manitoba's economy. In effect, it allows one to trace the demands placed on one industry resulting from increased activity in another. Thus the model provides estimates of direct, indirect, and induced impacts of the proposed project. These estimates indicate gross impacts and not incremental or net benefits impacts. Typlan utilized a different model to analyze the impacts and concluded that potential benefits to Manitoba may be understated. Despite this, Mr. Tyson agreed that the use of a provincial I-O model, as opposed to a national-level model, is consistent with standard practice in other utilities across Canada (Tr. Pg. 7160, lines 13-17).

Mr. Tyson indicated that the treatment of many purchases as leakages, as presented by Manitoba Hydro, may have underestimated the impact of the project on Manitoba, while overstating the impact on Canada (PUB/TyPlan -006a; Tr. p. 6970). Manitoba Hydro's economic impact analysis approach is based on project-specific expenditures or data, and requires breaking down overall expenditures by appropriate goods and services (and by jurisdiction in which the expenditure will take place, i.e., Manitoba, Rest of Canada and Foreign). The non-Manitoba sourced expenditures represent leakage or loss to local economy. This project specific analysis is based on expert opinion and experience from past projects, as well as knowledge of changes to the structure and composition of Manitoba's economy. On cross-examination, Mr. Tyson confirmed that, "without a full understanding of either the Manitoba economy or how it functions and an understanding of ongoing contractual arrangements between Hydro and its service providers, it is difficult to ascertain the extent of leakages and how margins are treated" (Tr. Pg. 6968).

21.0 PATHWAYS AND OPTIONALITY

21.1 Uncertainty and the Value of Optionality

In its planning and the NFAT submissions, Manitoba Hydro proactively recognizes that the future is uncertain and that optionality – flexibility, learning and adapting – is critically important and assists in a plan being more robust (Wojczynski, Tr. p.81-87.) Some argue that Manitoba Hydro should have addressed optionality more extensively (Bowman filing, p. 3-6). Manitoba Hydro understands that more analysis is always possible, but has addressed optionality both qualitatively (Manitoba Hydro NFAT Filing, Chapter 14) and quantitatively (PUB/MH 1-279). As Dr. Borison, an expert in this area, pointed out in his report:

> "Manitoba Hydro put considerable emphasis…on flexible pathways in addition to fixed plans, and on recognition that events going forward should be monitored over time, updated analysis conducted and adjustments made." (Schedule 3 of Rebuttal Evidence of Manitoba Hydro, MH Exhibit #85, p. 10)

Optionality is captured more fully in the NFAT analysis than is typically the case, even for large investments.

Mr. Bowman agrees that optionality and decisions unfolding over time are key to making decisions about the development plans and that "it's advisable to decide the things you have to decide and then set out the processes to make the other decisions" (Tr. p 10040, lines 15-24).

As suggested in the Introduction to Final Argument, the decisions required up front on proceeding with Keeyask and the 750 MW Interconnection need to consider the uncertainties in the future and the range of future possible decisions associated with each pathway. This includes being aware of opportunities that are lost if these developments are deferred or not pursued. Once the initial path is selected, the decisions that can be made later should be left to a time when the decision is required, at which time more updated information will be available. The most critical of such future decisions relates to the timing and commitment of Conawapa.

21.2 Conawapa Protection, Commitment and Optionality

The Preferred Development Plan was defined in the August 2013 NFAT Submission to include Conawapa with an earliest in-service date (ISD) of 2026.

The Submission specifically recognized that conditions would be continuously monitored to determine if the in-service date for Conawapa should be deferred and if continued protection of Conawapa was warranted (Executive Summary, Pages 1-2). The Submission (Chapter 14, pages 48-49) further goes on to discuss benefits of the optionality associated with Conawapa which allows Manitoba Hydro to mitigate the downside risk while preserving the upside potential of this project.

While there has been a reduction in the net economic benefits resulting from plans that include Conawapa, Manitoba Hydro has decided to continue to include Conawapa as a possibility in the Preferred Development Plan and its associated pathways (Tr. p. 3717, lines 10-19).

Conawapa Schedule and Protection Costs

Manitoba Hydro is currently protecting Conawapa for an ISD of 2026 which would require a construction commitment by early 2018. As depicted in the Pathways Optionality diagram in MH Exhibit #192, Manitoba Hydro will monitor annually the benefits and cost of protecting Conawapa and decide whether to continue protecting for the target ISD, defer the date or stop protecting Conawapa at all. As discussed in Section 17.2, protecting an early date for Conawapa is still relevant, even with the updated analysis, because (a) it fits with the timing of specific actual and potential new export arrangements that would have long term benefits for Manitoba Hydro and its ratepayers and (b) it preserves the value of the investment already made in Conawapa.

The decisions regarding the continued protection of Conawapa will be affected by factors such as progress on negotiations on additional long term export contracts, export prices, capital cost estimates, interest rates, load forecast and DSM plans.

The Conawapa activities for the current fiscal year 2014/15 are already underway and include engineering, environmental studies, licensing and aboriginal discussions and are estimated to be in the order of $50 Million (Tr. p. 3718). If a decision were made in the summer of 2014 not to pursue construction of Conawapa, much of the work planned for the current fiscal year would have been undertaken or committed, and Manitoba Hydro would incur additional costs to wind-down contracts and studies already underway (Tr. p. 3722-3723). If Conawapa were halted and then restarted at some later date, additional work, cost and time would be required to restart the processes. As Mr. Wojczynski testified, if such a halt period were five years or more, most of the environmental studies which have been undertaken would need to be repeated, the community processes repeated and some engineering reworked (Tr. p. 3724-3725).

Activities and costs currently planned for Conawapa for subsequent years are outlined in Manitoba Hydro's response to PUB/MH I-238c and were also discussed by Mr. Wojczynski during the hearing (Tr. p. 3723-3725). These activities include completing community consultations, concluding development agreements with certain communities, obtaining environmental licenses and other approvals, undertaking detailed engineering and arranging construction procurement so that construction can start January 2018 for a 2026 ISD. These same costs would be similar but spread out should the protection ISD be deferred one or a few years but less than five.

As Mr. Wojczynski indicated, if a decision is made to continue protecting Conawapa for an early date and subsequently factors begin to indicate that Conawapa may not be proceeded with, it is likely that only a portion of the expenditures would be incurred as Manitoba Hydro would slow down its spending on protection activities as these factors become more certain. The Conawapa business case will be closely monitored on an ongoing basis and the work activities adjusted or terminated as appropriate.

As noted earlier, Manitoba Hydro is currently planning to protect Conawapa until 2018 or until such earlier time as new information indicates that the project should be abandoned. The 2018 date for a commitment decision arose initially from the ISD of 2026 that was part of the original Preferred Development plan. As a result of the increased levels of DSM that now appear possible, the optimum ISD for Conawapa will be reviewed by Manitoba Hydro. By summer of 2015, power resource evaluations will have further assessed the appropriate ISD to be protected for Conawapa. MH has testified that 2026 may not be the most likely date that will continue to be protected (Tr. p. 3720, lines 4-12). Assuming DSM level 2 and assuming Plan 6 (Keeyask 2019, MP 250 Sale, new interconnection), Conawapa could be deferred well beyond 2026 if it is required only for Manitoba load. With the 2013 load forecast that date could be 2040 assuming the incremental pipeline load does not occur (MH Exhibit #171) and a number of years earlier than that with the pipeline load.

There are a number of long term export contracts under negotiation which would require an earlier Conawapa ISD. The Wisconsin Public Service (WPS) 308 MW contract would require Conawapa no later than 2030. Conawapa would need to be earlier than this if the Northern States Power (NSP), Great River Energy (GRE), SaskPower or other long term contracts were to proceed. As Mr. Wojczynski indicated (Tr. p. 3707, lines 6-21) it is likely that having only a portion of the potential new export contracts would be sufficient to trigger such earlier dates for Conawapa.

22.0 RECOMMENDATIONS AND JUSTIFICATION

22.1 Keeyask and 750 MW Interconnection Recommendation and Justification

This section addresses the recommendation as to whether the plan to develop Keeyask Generation Station for a 2019 ISD and a 750 MW Interconnection for a 2020 ISD is needed and in the best long-term interest of Manitoba and Manitobans when compared to other options and alternatives. Section 17.2 addresses the future development of Conawapa.

"Need" is interpreted by Manitoba Hydro to mean a requirement for new electrical power resources to ensure that Manitoba domestic firm load along with committed firm exports can be supplied with adequate reliability and certainty (MIPUG/MH I-001a).

There is inherent uncertainty as to the specific future date when new resources are required due to uncertainty in load growth and uncertainty in resources, whether they are supply-side or demand side. As discussed in Final Argument Section 5.4, application of the Generation Planning Criteria results in a need date which can vary depending on which load forecast is assumed, the amount of DSM targeted and achieved, and the assumptions as to supply.

Plans with Keeyask advanced to 2019 and a new interconnection simultaneously provide for a range of potential domestic load need dates and provide a wide range of benefits to electricity consumers and Manitobans generally.

The most current information indicates that plans with Keeyask in 2019 and the Interconnection in 2020 are more economic from the Manitoba Hydro perspective than viable plans without Keeyask and the Interconnection. This information also indicates that advancing Keeyask to 2019 and developing the Interconnection is more economic than developing Keeyask at a later date without the Interconnection.

Plans with Keeyask 2019 and the Interconnection are also favourable to ratepayers as they provide lower rates over the long term relative to plans without Keeyask and the Interconnection or Keeyask at a later date without the Interconnection; provide benefits to the provincial government through financial transfers; provide reliability and energy security benefits to Manitoba domestic electricity consumers; provide a large reduction in GHG emission; and overall provide the most socio-economic benefits to Manitobans, especially Northern and aboriginal communities.

22.1.1 Need for the Keeyask / Interconnection Plan

The NFAT process has identified a range of need dates, depending upon assumptions included. Need dates range from 2023 to 2031, as described in Section 5.4 of this Final Argument. The evidence has demonstrated that Level 2 DSM represents the economic level of DSM appropriate for Manitoba Hydro to adopt. Assuming the 2013 load forecast along with the pipeline load and combined with DSM level 2, the projected Keeyask ISD for domestic need would be 2024. (MH Ex 104-3 and Tr. p. 9853 –9854). This date could be later or earlier due to adjustments in the load forecast, the DSM program and the supply situation (Final Argument, Section 5.4).

Advancing Keeyask by five years to 2019 would allow associated export sales and the new interconnection to proceed. Aside from the economic and other benefits, such a plan would help ensure that the uncertain needs of domestic customers can be met. As explained in Manitoba Hydro's oral evidence, higher than anticipated load growth is a greater challenge to deal with than lower load growth. Plans with Keeyask and development of the 750 MW Interconnection can inherently accommodate for the possibility of higher load growth. In effect the advancement of Keeyask to 2019 for exports and the interconnection provide a form of insurance for higher load growth and provide economic benefits even if the higher load growth does not materialize. Such plans are a means to reduce risks related to uncertainty in load growth, DSM and supply. (Final Argument, Section 5.4.2)

22.1.2 Economic Evaluation of Plans with Keeyask 2019 and 750 Interconnection 2020

Economic evaluations of the development plans are discussed in Final Argument, Section 10.3. The discussion below focuses on comparing plans with Keeyask and the Interconnection to those without Keeyask and the Interconnection.

MH Exhibit #104-8 provides the plan evaluations for 27 scenarios based on the most recent Keeyask and Conawapa capital costs, WPS transmission investment removed and the 2012 forecast assumptions. The Expected Values from the 27 scenarios for Plans 5 and 6 (comprising Keeyask 2019, the Interconnection and Gas) are higher than or equal to the Expected Values for the viable plans without them (i.e. Plans 5 and 6 relative to Plans 1, 2 and 8). The same conclusion holds true for the reference scenario NPVs.

MH Exhibit #171 provides plan evaluations with the 2013 reference scenario and updated capital costs along with various levels of DSM with and without additional pipeline load.

Assuming DSM level 2 both with and without the pipeline load, the Plans 5 & 6 are more economic than the All Gas Plan or the Keeyask/Gas Plan without Interconnection.

MH Exhibit #104-16 provides an Integrated Resource Planning presentation of the same 2013 updated evaluations instead using the TRC approach which enables comparisons simultaneously across the combination of supply plan options and different levels of DSM. Plans 5 and 6 at DSM Level 2 have a higher NPV benefit than any of the other combinations of viable plans and DSM levels.

Referring again to MH Exhibit #171 and assuming DSM level 2, the economic advantage of Plans 5 & 6 improve when the embedded return on equity is considered.

In MH Exhibit #171 when including cash transfers to the Province, Plans 5 and 6 have approximately $1.4 Billion greater benefit than Plan 2 (Keeyask, no Interconnection) and $2.3 Billion greater than the All Gas Plan.

The main risks can be mitigated and managed as discussed in Section 10.4.

22.1.3 Financial Evaluation of Keeyask 2019 and 750 MW Interconnection 2020

Financial evaluations of the development plans are discussed in detail in Final Argument Section 13.0. The discussion below focuses on the plans which contain Keeyask and the new 750 MW Interconnection.

Exhibits #104-12-1 to 104-12-4 provide new financial analyses for Plan 5 (Keeyask/Gas/750 with the WPS sale) under the reference scenario reflecting 2013 assumptions for the load forecast (with no new pipeline load), escalation, interest and exchange rates, electricity export prices, capital costs and DSM Level 2.

Exhibits #104-12-5 to 104-12-7 provide financial updates to plans with Keeyask and a 750 MW Interconnection (Plans 5 and 6) under reference scenario with the same assumptions noted above, as well as Plan 5 with new pipeline load.

Plans with Keeyask and a 750 MW Interconnection provide the lowest customer bills on a present value basis over the long term. Rates charged to customers are lower relative to plans without Keeyask and the 750 MW Interconnection by 2032 or Keeyask at a later date without the 750 MW Interconnection by about 2027.

22.1.4 Societal Perspective on Plans with Keeyask and New Interconnection

The other societal perspectives on the development plans are discussed in various Final Argument sections; the following discussion focuses on Plans 5 & 6.

Reliability of electrical supply to Manitobans – The plans with Keeyask and the 750 MW Interconnection provide significantly greater reliability than the plans with no new interconnection. They provide over 500 MW of additional Load Carrying Capacity to deal with supply interruptions and unexpectedly high short term load increases such as those due to an unusually severe cold snap over winter peak (LCA/MH I 037).

Energy security for Manitobans – The plans with Keeyask and the 750 MW Interconnection provide significantly greater emergency energy during droughts than the plans with no new interconnection. They provide in the order of 3,000 to 5,000 GWh of emergency energy in the event of droughts worse than the worst on record, outages of thermal generation or import lines and unusually cold winters or hot summers (LCA/MH I-037)

Socio-economic benefits in Manitoba especially to Northern and aboriginal communities – Development of Keeyask and the 750 MW Interconnection provide enhanced employment, income, training and business opportunities. The projects would have no significant residual impacts to community infrastructure, services, personal & family & community life, resource use and heritage resources (Final Argument Section 14.0).

Macro-environmental impacts and benefits - Developing Keeyask and the 750 MW Interconnection results in a major reduction in greenhouse gas emissions in Manitoba and regionally with no significant residual impacts to air, land, water, flora, fauna and key environmental functions (Final Argument Section 14.1).

22.1.5 Benefit Cost Evaluation from Overall Manitoba Societal Perspectives

The NPV evaluations discussed above are analyzed from the perspectives of Manitoba Hydro and Manitoba domestic ratepayers. The Multiple Accounts Benefit Cost evaluation by Dr. Shaffer integrates those perspectives and others into a single quantitative and qualitative evaluation. (Finance Section 13.0 and MH Exhibit #166).

The evaluation with the updated capital costs concludes that Plan 6 with Keeyask and the 750 MW Interconnection and Plans 14 and 12 which also include Conawapa, all are approximately equal in NPV at the 6% Real Social Discount Rate, approximately $400

Million more beneficial than Plan 2 (Keeyask/Gas) and $1Billion more beneficial than Plan 1 (All Gas).

When considering these quantitative results along with qualitative considerations, the Multiple Accounts Societal Benefit Cost evaluation concludes that proceeding with Keeyask and the 750 MW Interconnection is in the best interests of Manitobans considering the overall societal benefits and costs.

22.1.6 Ten Reasons to Decide Now to Commit Keeyask and Interconnection

Manitoba Hydro believes there is more than sufficient information available in the NFAT proceeding for the PUB to confidently draw conclusions and make recommendations about Manitoba Hydro's development plans.

CAC has suggested that there is insufficient information about the economic and financial evaluations and about the possibility of a better alternate export arrangement to recommend proceeding with Keeyask and the 750 MW Interconnection; instead the projects should be delayed. (CAC – Tr. p. 11149, line 18 – p. 11150, line 5)

Manitoba Hydro believes these concerns are not warranted and is confident that there is sufficient information and a strong enough rationale to proceed with Keeyask and the 750 MW Interconnection for the following ten reasons:

1) **Substantial amount of high quality information** – There is more than adequate information to make sound judgments and decisions. By Manitoba Hydro's count, there have been two pre-Hearing Conferences, four days of workshops and two rounds of Information requests with roughly 2400 responses placed on the public record. Inclusive of all the sub-parts, Manitoba Hydro filed over 300 exhibits which when combined with the Exhibits of other parties mean this Board has reviewed in excess of 500 exhibits. In addition to MH's 5000 page filing, the PUB has received 16 reports from the experts called by Intervenors and 8 reports from the IECs, plus their supplemental reports. In total there were will have been 48 public hearing days and over 13,000 pages of transcript. The PUB will have heard from 33 Manitoba Hydro witnesses and 52 Intervenor and IEC witnesses. In addition, for the first time the panel and IECs were able to review Manitoba Hydro's most commercially sensitive documents – its export contracts, its Power Resource Plan, its export price forecast and its construction contract information. No panel in the history of

Manitoba Public Utilities Board has ever reviewed a matter at this level of detail – it is unprecedented.

MIPUG quotes Mr. Bowman on this topic:

> MR. PATRICK BOWMAN: I've been through a number of different processes like this, and a lot of hearings on different subjects, and I can't remember hearing where the Board has had as high a quality of advice and information put to it as this one.
>
> I think that there has been some exceptional work done. I think you've had Manitoba Hydro's A-team in respect of economics. It's the best Manitoba Hydro has to offer, and although I'm always a skeptic about new people coming in and managing to find their feet on a system as complicated as Manitoba Hydro is, I think people like Morrison Park did a very, very good job, and I think you should -- I'll try to, as I work through my comments, not spend time dwelling on things that I think they have covered very well. (Final Argument, page 9).

2) **Ability to make reasonable inferences –** An area of information that was noted by CAC and LCA to be absent is an uncertainty matrix (or quilt) based on the 2013 Load Forecast and related assumptions rather than the 2012 assumptions. The NFAT deliberations can be informed by utilizing the reference scenario evaluations with 2013 information and updated capital costs in combination with the 2012 uncertainty matrix which also utilized the updated capital costs for Keeyask and Conawapa. (Mr. Wojczynski Tr. p 3923, line 19 to p. 3929, line 18). The latter matrix indicates how the economics of each plan are affected by variation in the three parameters of energy prices, capital cost and discount rate. The 2013 updated reference scenario evaluations provide a current set of economic results which can be used as a base starting point from which to use judgment to consider the variations indicated by the matrix. The information is not perfect but it is more than sufficient. (Tr. p. 1540, lines 3018)

   Similar comments can be made in regard to information provided for the financial and rate evaluation of the plans. While only the reference case was analyzed for these updates, they can be combined with the earlier sensitivity analysis to permit judgments on how the plans will perform financially and with respect to rates under different conditions.

3) **Deferring the decision does not eliminate uncertainty** – Deferring the decisions on Keeyask and the 750 MW Interconnection does not eliminate or even reduce uncertainty. (Tr. p. 4515-4516).

Most uncertainties will stay uncertain. For example load growth, capital costs, interest & escalation will always remain uncertain. (Tr. p. 3694, lines 18-20).

Some uncertainties will diminish but persist to a large degree. Impacts of shale gas likely will be better known but natural gas prices will still be subject the uncertainties of market forces and thus remain uncertain and volatile.

Some new factors will arise increasing uncertainty. These are the "unknown unknowns".

Perfect information is never available. The perfect is the enemy of the good is an aphorism or proverb meaning that insisting on perfection often results in no improvement at all. While there are remaining uncertainties and it is always helpful to be able to have additional information to inform a decision, it is impractical and imprudent to insist on trying to have a perfect set of information and comparisons. Good management and optimization of benefits to Manitobans require making a judgment as to whether there is adequate information to make a decision and then use judgment to make a reasoned decision. Time does not stand still while decisions are being considered, and the Board, like Manitoba Hydro, must make its judgments based on the information available to it. (Mr. Todd, Tr. p 4962, lines 1-10, Mr. Peaco, Tr. p. 6099 lines, 20-24, Mr. Gibson, Tr. p. 9296-9297).

Dr. Borison provides a thorough discussion of this issue at Transcript pages 2560:2561:

DR. ADAM BORISON: ...this is an industry that has been, for decades, quite dynamic, quite changing, and quite uncertain. And that I was looking back in the literature for the use of the term 'unprecedented uncertainty', which I have used, and Dr. Murphy has used. And I found that in every single year, at least going back ten (10) years on the Internet, and then I actually found an article from 1983 about -- that said the -- the utility industry is facing unprecedented uncertainty. But I actually don't think that's untrue. I think what 'unprecedented' means in that context is there are a set of things that appear very uncertain right now that -- that haven't been there before. And so in '83 it were -- was things like Three Mile Island, or something of that nature, electromagnetic fields. There were issues that were there that people had never heard about before which all of a sudden made things very uncertain. I think the -- the fantasy though is that -- that somehow those are going to go away."

Although the 250MW sale agreement with Minnesota Power includes delay provisions tied to the start of Keeyask, exercising them for the purpose of studying other alternatives will greatly increase uncertainty for Minnesota Power and the Minnesota Public Utilities Commission, raising concerns and putting into question whether to proceed with the 750 MW interconnection. Any indication that Manitoba is delaying and is uncertain whether to commit to Keeyask is likely to result in a suspension of its 750 MW interconnection development and permitting activities including the public hearing scheduled to commence in August of 2014.

4) **The Interconnection provides flexibility to manage uncertainty** – While there are uncertainties, the development of the interconnection facilitated by Keeyask is a means to provide options and flexibility to respond to, adapt to, to manage and to take advantage of the uncertainties. The pathways have demonstrated how the interconnection assists in managing risks and opportunities. If energy prices or carbon regulation increase, Conawapa can be developed; if not, Conawapa does not need to proceed. If export contract negotiations are successful, or net load growth increases greatly, Conawapa can proceed. If net load growth diminishes, system surplus from Keeyask and DSM can be exported over the expanded interconnection. If climate change causes increased water supply, the interconnection assists in exporting the additional surplus hydro energy. If climate change causes more severe droughts, the interconnection and expanded hydro can provide additional emergency energy during droughts to Manitoba domestic customers. (Mr. Peaco, Tr. p. 5995, lines 4-12, Mr. Tyson, Tr. p. 7021, lines 17-23, Mr. Bowman, Tr. p. 10040, lines 15-25, Mr. Wojczynski, Tr. p. 2302, line 13 – p. 2303, line 12).

5) **Keeyask and the 750 MW Interconnection economic over wide range of net loads** – An area of concern in the NFAT process has been the uncertainty in future net load growth given the inevitable variation in gross load growth and the added uncertainty as to how much DSM potential there is in the future. While the economics of adding Conawapa is affected by assumptions as to future net load growth, studies indicate that the economics of developing Keeyask with the Interconnection are remarkably stable. The reference scenario evaluations result in approximately a $400 Million NPV benefit from the MH perspective regardless of whether DSM is assumed to be

base, Level 1, 2 or 3 and whether pipeline load is included or not. The NPV is also approximately $400 Million in the sensitivity evaluation where net load growth was assumed to flatten to zero and Keeyask became a pure merchant plant (Tr. p. 9947-9948).

6) **The window of opportunity for developing the 750 MW interconnection infrastructure is time limited** – The confluence of factors which enable the opportunity will likely not remain for an extended time:

- US utilities need change in supply mix away from coal generation
- US utilities want to avoid overexposure to natural gas generation and are making strategic decision now
- In the US, regulators, government & MISO are favorably disposed to the 750 MW interconnection project and Keeyask imports due to the wind synergies resulting from hydro and transmission expansion
- Minnesota Power is willing to develop the 750 MW interconnection now and is in the midst of the regulatory proceeding for the interconnection
- Manitoba Hydro has preferential positioning for firm transmission service into Wisconsin with MISO that will be lost if the transmission requests have to be resubmitted at later date;
- Keeyask project is construction ready and supported by First Nation partners
- Currently there is a low interest rate environment for Manitoba Hydro to commit 30 year bonds while in future years interest rates may be higher

(Mr. Wojczynski, Tr. p. 306 line 12 – p. 307 line 20, Tr. p. 2308 lines 15-25, Tr. p. 3693 line 11 – p. 3694 line 17)

7) **An infinite circle of information** – CAC suggests that given the MP 250MW contract has a provision to allow for up to a two year delay, there is time to hold another NFAT process in which Manitoba Hydro ought to be required to provide economic and financial uncertainty evaluations with updated capital costs and 2013 forecast information to supplement the evaluations done for the reference scenario. If such a process were followed it is inevitable that once the NFAT#2 process were underway there would be requests to update the reference scenario evaluations for 2014 forecasts of loads and other parameters and once those were available there would be requests for the other 26 scenarios and by the time all this was available and under review there would be demands for 2015 updates. This would become an infinite circle.

8) **A Bird in Hand** – The reality is that MH has undertaken much effort and investment to create a viable commercial opportunity which is indicated by studies to benefit Manitobans over a wide range of perspectives. The opportunity before us today with Keeyask and the interconnection is a known quantity with certainty as to its existence. To seek an alternative in the hope that there might be a better new arrangement places the onus on there being strong evidence supporting the existence, viability and benefits of this other alternative. This was strongly supported by Mr. Colaiacovo of MPA (Tr. p. 7614) and confirmed later in the MPA May 23 Supplement Report:

"MR. PELINO COLAIACOVO: … our point was that given all of the money that's been spent on Keeyask, given the commercial arrangements that have been a made for Keeyask, a decision to not proceed has to -- could only occur if there was very, very strong evidence that not proceeding would be advantageous to the ratepayer and to other stakeholders. That it's not sufficient to say that financial modeling, or economic modeling suggests that All Gas is preferable to -- to going ahead with Keeyask on some narrow basis. That the burden of proof, frankly, lies on people who question the decision to go forward with Keeyask, to demonstrate that other options are conclusively better. If they can't demonstrate that their -- their other options are conclusively better, then Keeyask is the real option that -- that is before the Government of Manitoba, is before the NFAT process. There has been some new information. The cost of Keeyask has gone up. It's legitimate to recalculate numbers to ensure that those -- that new information doesn't change all of the analysis that's happened so far to date."

9) **Cancelling Contracts Now Would Harm Manitoba Hydro Commercial Credibility** – Deferring Keeyask and cancelling the export contracts which have been negotiated for over six years would harm the credibility and trust Manitoba Hydro has with counterparties in the export market regarding the ability of Manitoba Hydro to carry through and deliver on such arrangements. While this would not harm the willingness of counterparties to arrange short term exports it likely would impede long term contractual negotiations. This would harm the ability to secure favorable long term export contracts to the detriment of future export revenues. Mr. Coloaiacovo from MPA explains (Tr. p. 7255, line 4):

> "there is also an issue of the commercial reputation of Manitoba Hydro and its ability to do business in the future. It has been working for a number of years on the Keeyask project, the intertie project, and the export contracts. It's been working with a wide variety of parties who

have come to the table in good faith and negotiated these arrangements on the assumption that there was an ability to actually execute on them. That is not determinative. Deals fail all the time in the world. But when deals fail there are consequences to deal failure. And those are -- consequences are not always easily calculated in dollar terms. There is a loss of reputation, and there is a loss of the ability to do business. None of the alternative plans of the many different alternative plans that have been put before the panel address that issue. There is a cost consequence in terms of the writing off of some costs, but there is no additional cost burden that is understood to be related to the commercial consequences of the collapse and cancellation of the plans."

10) **Deferring Keeyask Increases Capital Cost** – Deferral of Keeyask would involve increased capital costs due to real escalation in costs, additional activity required to maintain the project readiness and interest on expenditures. A one year deferral has been estimated to increase the In-service cost $250 to $300 Million. Each additional year of delay would entail further and similar cost increases.

22.1.7 NFAT Participant Support for Keeyask and 750 MW Interconnection proceeding

A common position of most participants is that adding additional interconnection capacity to utility grids whether in Manitoba or elsewhere is generally overall beneficial in terms of enhanced efficiency in electrical system development and operation and enhanced reliability. (MPA - Tr. p. 7293, line 15 – p. 7295, line 19, Bowman - Tr. p. 10064, lines 12-15, GAC - Tr. p. 9788, line 17 – p. 9790, line 11, Mr. Russell Tr p. 10631, line 24).

> "But the fact of the matter is having interconnections – and this is one (1) of the major advantages of interconnections – is that you can rely upon your neighbours. There's a long history in the industry of doing so. And indeed, in the NFAT, I quote in my report portions where Manitoba Hydro cites just this kind of opportunity is being available from enhanced interconnections."

A number of participants support the specific proposal by MH to advance Keeyask to 2019 and develop the 750 MW interconnection.

Independent Expert Consultant Mr. Colaiacovo on April 17 supported proceeding with Keeyask and the 750 Interconnection (Tr. p. 7614).

> "MR. PELINO COLAIACOVO: … Should Keeyask proceed or not? I -- our point was that given all of the money that's been spent on Keeyask, given the commercial arrangements that have been a made for Keeyask, a decision to not proceed has to -- could only occur if there was very, very strong evidence that not proceeding would be advantageous to the ratepayer and to other stakeholders. That it's not sufficient to say that financial modelling, or economic modelling suggests that All Gas is preferable to -- to going ahead with Keeyask on some narrow basis. That the burden of proof, frankly, lies on people who question the decision to go forward with Keeyask, to demonstrate that other options are conclusively better. If they can't demonstrate that their -- their other options are conclusively better, then Keeyask is the real option that -- that is before the Government of Manitoba, is before the NFAT process. …
>
> And therefore a judgment to not proceed with it has to be made with strong evidence and strong grounds. And all of the financial modelling and analysis that we did as part of this process suggests there isn't that strong evidence and strong grounds based on the data we had. And we came to the conclusion, therefore, that, in our view, commercially Keeyask makes sense as a project to go forward with based on that analysis and information."

MPA in their May 23 supplemental report (Page 43) confirmed that they continue to hold the view that proceeding with Keeyask for 2019 and the 750MW Interconnection for 2020 is warranted.

MIPUG expert witness Mr. Bowman concluded the plans with Keeyask 2019 and the 750MW Interconnection should proceed (MIPUG Exhibit #24, Slide 65)

> "Pursue Keeyask, MP 250, 750 MW T-Line"

MIPUG in its Final Argument also supported proceeding with Keeyask 2019 and the 750 MW Interconnection as long as some modifications were made to improve benefits sharing between the Province and Manitoba Hydro and as long as there was some temporary relaxation of the Manitoba Hydro financial targets, (Mr. Antoine Hacault, TR page11234, line 9):

> "So moving to the second subject on our one (1) page summary, Keeyask19 with a 750 megawatt line could be preferred, but needs revised benefit sharing to achieve fairness."

CAC takes the position in final argument that it is premature to conclude whether Keeyask should proceed in the near term with the 750 MW Interconnection and that MH should be directed to provide additional information to a second NFAT process. CAC takes this position despite the fact that two of their own expert witnesses (Harper and Higgin) concluded that plans with Keeyask and the 750 MW Interconnection were the most economic of the plans.

CAC witness Mr. Harper on April 26(TR page 8552, line 19, CAC Exhibit #68, slide 61) supported the position that plans with Keeyask 2019 and the 750MW Interconnection are more economic than plans without the interconnection.

- "From information available to-date advancing Keeyask/750/gas-based plan appears economic relative to plans with no intertie
  - supported by the updated 2012 uncertainty analysis
  - the 2013 reference case results indicate that at dsm2 levels these economics will improve"

CAC witness Dr. Higgin (TR page 9477, line 11, CAC Exhibit #76, slide 18) supported proceeding with Keeyask 2019 and the 750MW Interconnection:

> "So I would tell my client, I think because of the terms of reference, the path should be DSM for domestic need, and Keeyask for export opportunity with the intertie, with certain conditions to be met in the 2015 period.

GAC in its Final Argument also supported proceeding with Keeyask 2019 and the 750MW Interconnection (GAC Exhibit #27, page 29-30)

> "The PUB should approve Keeyask and the 750 MW transmission intertie to Duluth for immediate construction.
>
> The new 750 MW intertie to Minnesota (expandable to 1100 MW), with complementary reserved transmission to Wisconsin, is the most important asset in Hydro's plans. It has net benefits to Manitoba and contributes to

regional sustainability, including facilitation of economic firm exports, economic imports (particularly in drought conditions and to meet winter peak load, but also for profitable resale on-peak), enhancing other renewable resources by firming wind and solar power, and enhancing the reliability of domestic power supply. While the evidence in support of Keeyask for domestic need is more equivocal and the analysis under flat loads is sketchy, Green Action Centre believes that Keeyask is likely to be justified for exports, especially because a commitment to that plant appears to be necessary to promote the prompt construction of the intertie and it already has its capacity contracted out in profitable sales for the early years."

22.1.8 Development of Keeyask 2019 and 750 MW Interconnection 2020 is Justified.

Keeyask construction for a 2019 ISD and development of the 750 MW Interconnection for a 2020 ISD is justified. This pathway includes the associated long-term export contracts (MP 250 MW, WPS 100 MW and WPS 308 MW, NSP 125 MW extension) and the expanded DSM plan. The pathway meets the electricity needs of Manitobans and is in the best long-term interest of Manitobans and the province of Manitoba when compared to other options and alternatives.

Risks associated with advancing Keeyask and development of the 750 MW Interconnection have been evaluated and can be mitigated and managed, refer to Final Argument Section 10.4 and Section 13 (Financial Risks)

Plans with Keeyask and the 750 MW Interconnection are shown to result in the lowest long term cost of supply for Manitoba Hydro; are favourable in the long term to ratepayers; provide significant benefits to the provincial government through financial transfers; provide reliability and energy security benefits to Manitoba domestic electricity consumers; provide a large reduction in GHG emissions; and overall provide the most socio-economic benefits to Manitobans, especially Northern and Aboriginal communities, including employment, income, training, business opportunities and capacity building.

22.2 Conawapa Recommendations & Justification

This section addresses the recommendation as to whether Conawapa should proceed in the event that Keeyask is committed for a 2019 ISD and the 750MW Interconnection is committed for a 2020 ISD.

The most current information indicates that proceeding with Conawapa for an ISD earlier than required for domestic load would be economic from the Manitoba Hydro perspective in the likely situation that current negotiations on additional long term export contracts are favourable. Proceeding with Conawapa would also provide incremental benefits to the provincial government though cash transfers, provide a larger reduction in GHG emissions and from an overall perspective provide the most socio-economic benefits to Manitobans especially Northern and aboriginal communities.

Under the reference scenario, the direct economic benefit to Manitoba Hydro for the plans with Conawapa is only greater than the plans without Conawapa if the embedded return on equity is considered. Plans with Conawapa as a resource also have higher downside risks and incur higher mid-term rate increases. However, the direct benefits to Manitoba Hydro and ratepayers are expected to be higher than identified in the current evaluations because it is expected that negotiations and discussions currently underway with US and Saskatchewan utilities will be successful and increase the benefits while reducing risks (Final Argument Sections 6 and 8.5, Higgin TR page 9500 line 22). The direct benefits would also significantly rise in scenarios with higher export prices, lower interest rates and /or lower capital costs.

Fortunately, a decision to commit construction of Conawapa does not need to be made for several years. By 2017 or early 2018 there will be better information on these potential sales and on US approvals for the proposed 750MW tieline. As discussed in Section 16.2, Manitoba Hydro will intensively monitor the Conawapa business case to determine the appropriate early ISD to protect for Conawapa and to delay or halt Conawapa if the favourable business case does not materialize as expected.

22.3 Economic Evaluation of Conawapa Benefits to Manitoba Hydro

Economic evaluations of the development plans are discussed in Final Argument Section 10.3. This discussion below focuses on the Conawapa plans.

MH Exhibit #104-8 provides the plan evaluations for 27 scenarios based on the most recent Keeyask and Conawapa capital costs, WPS transmission investment removed and 2012 forecast assumptions. The expected value of the 27 scenarios for plans with Conawapa are lower than the plans without Conawapa (i.e. Plan 14 relative to Plan 5, Plan 12 relative to Plan 6.) As noted, there is considerable upside NPV opportunity for the Conawapa plans in scenarios such as with high export prices, low capital costs and/or low discount rates.

Furthermore the Conawapa plan economics would improve and the risk diminish if, as expected, additional export contracts are successfully negotiated.

MH Exhibit #171 provides plan evaluations with the 2013 reference scenario and updated capital costs along with various levels of DSM both with and without additional pipeline load. Assuming DSM level 2 with or without the pipeline load, the Conawapa plans approximately meet the NPV test relative to the All Gas Plan but are less economic than the Keeyask/Interconnection plans without Conawapa. Assuming DSM level 2, the Conawapa plans have approximately the same or greater benefits than the Keeyask/Interconnection plans without Conawapa if the embedded return on equity is considered.

The most powerful economic argument for maintaining Conawapa as an option lies in the analysis which includes economic benefits to the Province as a whole. In MH Exhibit #171, plans with Conawapa have significantly greater benefits when including cash transfers to the province: $0.7 Billion under DSM 2 with no pipeline load, $1.4 Billion under DSM 2 with pipeline load and up to $2.1 Billion for Base DSM with no pipeline load. Plans which include Conawapa are also distinguished by an increased number of jobs, economic spinoff and opportunities for Northern and aboriginal communities.

The aforementioned scenarios with upside assumptions are ones where there would clearly be the full suite of benefits arising from plans with Conawapa. It is recognized that there are also scenarios with downside risks in which Conawapa would not have the economic benefits to Manitoba Hydro although most of the other societal benefits would still occur. Manitoba Hydro believes that these risks can be mitigated and are manageable as discussed in Section 10.4.

There has been confusion as to the situation regarding the WPS 308 MW sale and Conawapa. As explained in the Final Argument Introduction, the WPS sale contract is a finalized and signed contract but the delivery of exports under the contract are determined by various contract conditions. One condition is that delivery is contingent on four Conawapa units being in-service by 2031. Should the units be in by that time and the 750 MW interconnection be in place, then the WPS sale deliveries are to occur. Should MH choose not to develop Conawapa for that time period, the parties may mutually agree to amend the WPS contract to allow it to proceed, or, in the event the parties do not agree, the sale agreement will terminate.

22.4 Financial Evaluation of Conawapa Plans

Financial evaluations of the development plans are discussed in detail in Final Argument Section 13; the following discussion focuses on the Conawapa plans.

Exhibits #104-12-1 to 104-12-4 provide an update to Plan 14 (reference scenario) reflecting 2013 assumptions, updated capital costs and DSM Level 2. Exhibits #104-12-5 to 104-12-7 provide an update to Plan 12 (reference scenario) with the same assumptions noted above, as well as Plan 14 with new pipeline load.

In the long term, rates charged to customers for plans with Conawapa are lower than other plans. However, cumulative rates for plans with Keeyask and an Interconnection are lower than plans with Conawapa in the medium term. While plans with Keeyask and an interconnection have a lower NPV of consumers' revenue than the plans that also have Conawapa, the Preferred Development Plan has significantly lower cumulative rate increases by the end of the of study period, 96% versus 130% (shown in MH Exhibit #104-12-5, p.3 above).

As with the economic analysis, there is sufficient evidence to indicate potential upside to ratepayer benefits for plans with Conawapa in addition to the benefit to Manitoba as a whole to continue to protect the optionality of Conawapa.

22.5 Societal Perspective on Conawapa Plans

The other societal perspectives on the development plans are discussed in various Final Argument sections. The following focuses on the Conawapa plans.

Socio-economic benefits in Manitoba especially to Northern and Aboriginal communities- Development of Conawapa provides enhanced employment, income, training and business opportunities with no significant residual impacts to community infrastructure, services, personal & family & community life, resource use and heritage resources. (Final Argument Section 14)

Macro-environmental impacts & benefits- Developing Conawapa in addition to Keeyask results in approximately a doubling in the reduction in greenhouse gas emission in Manitoba and regionally with no significant residual impacts to air, land, water, flora, fauna & key environmental functions (Final Argument Section XXX)

22.6 View of NFAT Participants on Conawapa Advancement

A position of several participants is that the full justification for proceeding with Conawapa has not been established but that it is possible that the justification will be there once more information is available on the success of negotiations on the export contracts and on future export prices.

MIPUG takes the position in its Final Argument (page 59) that the potential for the Conawapa project proceeding for 2026 should not be abandoned. MIPUG suggests that there should be limitations on Conawapa spending and timing.

As described in Section 16.2 there will be extensive monitoring of Conawapa activities and expenditures. Manitoba Hydro expects that there will be sufficient progress on the export contract negotiations early enough that the four years of protection and investment will not be required to be in a position to make decision on Conawapa. However, Manitoba Hydro suggests that setting some form of cap on such time frame and investment is not appropriate given that the business case at the time should be the determinant of decision on Conawapa protection. It would not be practical or prudent to recommend a funding cap or time limitation to government.

In its May supplementary report (page 4), MPA supports continued protection of Conawapa:

> "Conawapa as a competing alternative for future generation:
> MPA continues to support its comments to the PUB that Conawapa should be considered a development opportunity, competing with other potentially superior alternatives, and continued expenditures to develop Conawapa should be justified in that light."

22.7 Conclusion: Conawapa Advancement for Exports Likely Warranted

The NFAT TOR includes Conawapa as well as Keeyask and the rest of the Preferred Development Plan. As discussed in the Final Argument Introduction and Section 16.2, no decision on committing Conawapa construction is required for at least several years. If the upside opportunities to the Conawapa business case do not arise due to failure of the current export contract negotiations and /or other conditions occur which are unfavorable to the business case, the Conawapa protection activities would be halted and Conawapa would not proceed.

This creates a somewhat different situation for the PUB NFAT report and recommendations than is the situation regarding Keeyask. Manitoba Hydro had been asked under what conditions Conawapa should be approved and Manitoba Hydro suggested that it would be reasonable for Conawapa to proceed if, at the time of commitment, the trajectories of economics are not significantly adverse compared to what we're looking at in the NFAT evaluations and if some of the positive upsides happen as we expect will happen as a result of successful negotiation of additional export sales contracts (Wojczynski, TR pp 4240:4241)

> "First of all, Manitoba Hydro is quite aware that for a decision out in 2018 or the end of 2017, that whole timeframe, that given the uncertainties that -- to have an unqualified endorsement and that -- and let me exaggerate to make the point, to say, no matter what happens, Conawapa should proceed, and we agree that that is not something Manitoba Hydro's asking for or looking for. And -- but something that is more along the line of -- if the trajectories of economics are not significantly adverse compared to what we're looking at and if some of the positive upsides happen as we expect will happen with some of this additional sales and that -- then that it would be reasonable for Conawapa to proceed. I think something in that realm would be what Manitoba Hydro would reasonably be looking for this panel to be commenting on. We recognize, Mr. Chair and panel, that given there are a few years to go, a totally unqualified endorsement is -- is not something that would be reasonable to -- to ask for. But to give an indication of the reasonability or proceeding in the more positive portion of the -- the circumstances that happen and can happen in the future, I think would be something that would be reasonable and -- and Manitoba Hydro is looking for."

Assuming that previously Keeyask has been committed for a 2019 ISD and the 750MW Interconnection committed for a 2020 ISD, it is in the interests of Manitobans for to maintain Conawapa as an option and to plan for the possibility that it may be developed for export earlier than needed for domestic load. As noted, Conawapa has significant provincial and macroeconomic benefits. It is worth maintaining this option for a few more years to confirm the expectation that additional export opportunities will emerge, allowing the project to capitalize on its significant upside.

TABLE OF CONCORDANCE

The following table details each component of the mandate given to the PUB by the NFAT Terms of Reference, and provides the location within Manitoba Hydro's Written Final Submission where the item is addressed. Some components are also dealt with in the separate Final Argument Submission from the Keeyask Cree Nations.

Terms of Reference	Addressed in Final Argument Sections and Subsections
Recommendations to the Government of Manitoba on the needs for Hydro's preferred development Plan	5.1,5.4,5.6,12,22.1.1
An overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.	19,22
1. An assessment as to whether the needs for Hydro's Plan are thoroughly justified and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate. The assessment will take the following factors into consideration:	2,3,4,5,7,8,9,11,12,22.1.1
a) The alignment of the Plan to Hydro's mandate, as set out in Section 2 of the Manitoba Hydro Act;	5.3, 5.4
b) The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in The Sustainable Development Act.	15, 16, 17,18
c) The extent to which the Plan is needed to address reliability and security requirements of Manitoba's electricity supply.	5, 7, 11, 12 ,22.1.1
d) The reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied upon for its justification of its needs. This should include Hydro's planning load forecast and future load scenarios,...	2,3,4,5
...its demand and supply analysis,...	5.3,5.4, 6
...export expectations and commitments,....	9.1, 9.2, 8.3, 8.4
...demand side management and conservation forecasts.	2,3,4, 5.4

Terms of Reference	Addressed in Final Argument Sections and Subsections
2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need. The assessment will take the following factors into consideration: a) If preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound;	 5,6,8,10,11,13,21,22
b) The alignment of the Plan and alternatives to Manitoba's Clean Energy Strategy, The Climate Change and Emissions Reduction Act and the Principles of Sustainable Development as outlined in The Sustainable Development Act;	15, 16, 17, 18
c) The accuracy and reasonableness of the modeling of export contract sale prices, terms, conditions, scheduling provisions, export transmission costs, and the reasonableness of projected revenues;	5.5,7,8,.3,8.4,8.5,8.6,9.1.2
d) The reasonableness of forecasted critical inputs including construction costs,	6
…opportunity export revenues,…	9
… future fuel prices,…	9
…electricity market price forecasts,…	9
…the determinants of those values,…	9
…and export volumes;	5
e) The reasonableness of the scope and evaluation of risks and the benefits proposed to arise from the development and the reasonableness and the reliability of Hydro's interpretation of the most likely future outcomes as a result of climate changes, interest rate fluctuations, export market prices, domestic load fluctuations, droughts, competing technologies, fuel prices, carbon pricing, technology developments, economic conditions, Hydro's transmission positions and other relevant factors;	5,10,11,12,13,17,22
f) The impact on domestic electricity rates over time with and without the Plan and with alternatives;	13
g) The financial and economic risks of the Plan and export contracts and export opportunity revenues in relation to alternative development strategies;	8.3, 9.1.1.3, 10, 13
h) The socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities;	14,19,20
i) The macro environmental impact of the Plan compared to alternatives;	14

Terms of Reference	Addressed in Final Argument Sections and Subsections
j) If the Plan has been justified to provide the highest level of overall socio-economic benefit to Manitobans, and is justified to be the preferable long-term electricity development option for Manitoba when compared to alternatives.	19,22

Tab 19

Manitoba Hydro

November 2009

Capital Expenditure Forecast (CEF09-1)

2009/10 - 2019/20

Corporate Controller Division

Finance & Administration

Foreword

The *Capital Expenditure Forecast* (CEF09-1) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in the Capital Expenditure Forecast will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner.

The *Capital Expenditure Forecast* is comprised of a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "domestic items." Major items are normally over $2 million in total cost and the construction period on each major item usually extends beyond one year. Domestic items typically represent the ongoing and recurring capital requirements to meet electricity and natural gas service replacements and expansions throughout the province. All major and domestic capital projects are subjected to a rigorous review and approval process before being included in the *Capital Expenditure Forecast*.

In constructing and maintaining its capital facilities, Manitoba Hydro adheres to the principles of sustainable development. For example, the Corporation is committed to reduce the net emissions from its own facilities and to contribute towards global emission reductions through the export of renewable electricity. Manitoba Hydro exceeded its past voluntary commitment to reduce its average net greenhouse gas (GHG) emissions from 1991 to 2007 to 6% below 1990 levels. Manitoba Hydro also has a separate contractual commitment under its participation in the Chicago Climate Exchange (CCX) to progressively reduce its generation related emissions until 2010. The Corporation is in full compliance with the CCX target.

Manitoba Hydro has one of the most aggressive Demand Side Management (DSM) programs in North America. The target to be achieved by 2025 is for electrical savings of 915 MW and 3,271 GWh, and natural gas savings of 172 million cubic meters. In total, Manitoba Hydro's DSM programs are expected to result in greenhouse gas emission reductions of nearly 2.5 million tonnes annually by 2025.

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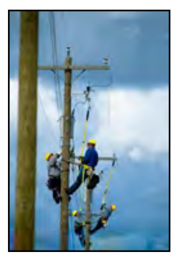


Section 1

Overview

Capital Expenditure Forecast Summary
Comparison to CEF-08
Capital Expenditure Forecast Summary Table

1.0 Overview

Capital Expenditure Forecast Summary

This Consolidated Capital Expenditure Forecast (CEF09-1) totals $16 480 million for the 11 year period to 2019/20. Expenditures for Major New Generation & Transmission and the New Head Office total $11 763 million, with the balance of $4 717 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and efficiency improvements.

Comparison to CEF08

The Capital Expenditure Forecast (CEF09) for the ten year period ending 2018/19 totals $15 189 million compared to $15 358 million for the same ten year period included in last year's Capital Expenditure Forecast (CEF08).

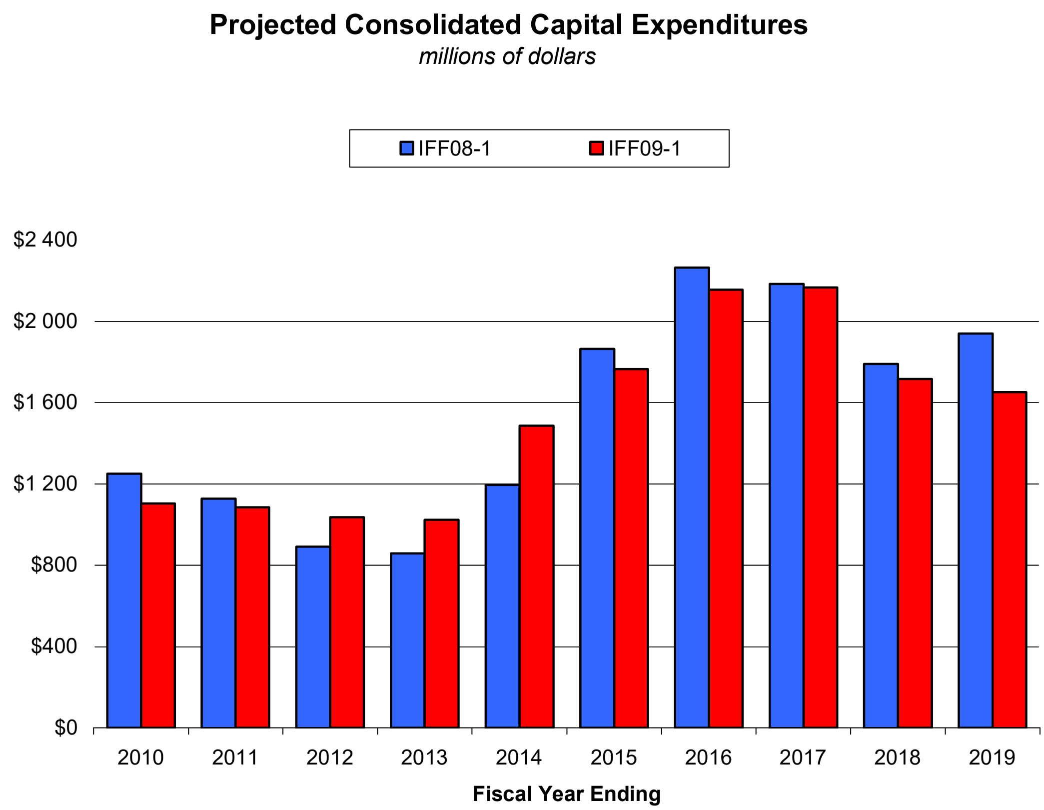
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	10 Year Total
CEF08	1 248	1 127	891	858	1 196	1 864	2 263	2 183	1 790	1 938	15 358
Increase (Decrease)	(144)	(42)	145	167	290	(99)	(107)	(18)	(74)	(287)	(169)
CEF09	1 104	1 085	1 036	1 025	1 486	1 765	2 156	2 165	1 716	1 651	15 189

The decrease of $169 million in capital expenditures over the ten year forecast period is comprised of the following:

	10 Year Increase
Keeyask Generating Station	$ 792
Demand Side Management - Electric	57
13.2 kV Shunt Reactor Replacements	33
System Refurbishment and Other Projects	184
Conawapa Generating Station	(224)
Pointe du Bois Improvements & Upgrades	(500)
Target Adjustment	(511)
	$ (169)

New energy resources are required to meet forecasted domestic requirements by 2022/23. Some of the key assumptions underlying future spending on new generation and transmission include:

- The in-service date (ISD) of the Wuskwatim Generating Station will be September 2011.
- Kelsey generating station to be upgraded by 77 MW by 2012/13.
- Bipole 3 is assumed to follow a route west of the Interlake and this route will require 2 000 MW of converters to operate, with an in-service date of October 2017.
- Manitoba Hydro has signed term sheets with Northern States Power (NSP) for 375/500 MW starting in 2015, Wisconsin Public Service (WPS) for 500 MW starting in 2018, and Minnesota Power (MP) for 250 MW starting in 2022 (for firm power).
- Keeyask and Conawapa are necessary to meet domestic load requirements and export sales commitments and have first power in-service dates of December 2018 and May 2022, respectively.



The following table provides a listing of each capital project with a forecast of expenditures for each year to 2019/20. The subsequent section provides high-level descriptions of each capital project with brief justifications and comparisons to the previously approved capital expenditure forecast.

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1 274.6	364.4	275.3	105.1	12.1	-	-	-	-	-	-	-	756.8
Wuskwatim - Transmission	316.3	90.1	30.5	18.9	-	-	-	-	-	-	-	-	139.5
Herblet Lake - The Pas 230 kV Transmission	93.2	41.9	30.4	7.2	1.9	-	-	-	-	-	-	-	81.5
Keeyask - Generation	4 591.6	67.7	85.0	195.3	198.6	182.3	485.5	799.1	808.3	584.7	537.5	263.9	4 207.9
Conawapa - Generation	6 324.8	60.4	60.4	75.0	111.8	190.1	231.5	308.2	290.3	513.6	846.1	881.7	3 569.2
Kelsey Improvements & Upgrades	189.6	45.1	6.8	0.5	-	-	-	-	-	-	-	-	52.5
Kettle Improvements & Upgrades	75.6	11.1	18.4	6.6	20.1	18.6	-	-	-	-	-	-	74.8
Pointe du Bois Improvements & Upgrades	318.0	13.8	14.8	15.5	53.0	83.1	110.7	-	-	-	-	-	290.9
Pointe du Bois - Transmission	85.9	9.0	26.3	10.4	20.6	13.9	3.1	-	-	-	-	-	83.2
Bipole 3	2 247.8	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	159.9	-	-	2 220.4
Riel 230/500 kV Station	267.6	36.1	58.4	79.6	45.1	38.2	4.6	-	-	-	-	-	262.0
Firm Import Upgrades	4.8	0.6	2.1	2.1	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	-	0.5	1.9	8.2	17.6	32.4	79.3	64.8	-	-	-	204.8
Brandon Combustion Turbine Pipeline Upgrade	5.4	5.4	-	-	-	-	-	-	-	-	-	-	5.4
Demand Side Management	NA	40.3	43.0	42.5	38.4	33.9	29.9	29.0	27.1	25.6	25.1	21.8	356.5
Planning Study Costs	NA	5.7	8.0	1.9	-	-	-	-	-	-	-	-	15.6
		808.1	681.5	599.4	623.1	844.1	1 318.0	1 843.4	1 748.4	1 283.8	1 408.7	1 167.4	12 325.8
New Head Office													
New Head Office	278.1	14.8	-	-	-	-	-	-	-	-	-	-	14.8
Corporate Relations													
Waterways Management Program	NA	5.3	5.4	-	-	-	-	-	-	-	-	-	10.7

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Power Supply													
Converter Transformer Bushing Replacement	5.9	0.1	0.4	1.9	-	-	-	-	-	-	-	-	2.3
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.0	0.0	1.6	-	-	-	-	-	-	-	-	1.6
Dorsey Synchronous Condenser Refurbishment	32.3	3.0	2.5	3.6	2.5	2.6	2.8	-	-	-	-	-	17.0
HVDC Bipole 1 Roof Replacement	5.9	0.7	-	-	-	-	-	-	-	-	-	-	0.7
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.3	1.3	0.3	-	-	-	-	-	-	-	-	1.9
HVDC AC Filter PCB Capacitor Replacement	34.5	2.4	6.0	-	-	-	-	-	-	-	-	-	8.3
HVDC Transformer Replacement Program	105.7	1.0	1.1	7.3	5.3	1.1	-	-	-	-	-	-	15.8
Dorsey 230 kV Relay Building Upgrade	73.8	1.1	1.9	4.0	16.4	32.1	12.0	4.9	-	-	-	-	72.5
HVDC Stations Ground Grid Refurbishment	4.3	0.6	0.5	0.6	0.6	0.0	-	-	-	-	-	-	2.3
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.7	0.4	-	-	-	-	-	-	-	-	-	3.1
HVDC Bipole 1 Pole Differential Protection	3.3	-	1.0	2.3	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	4.6	8.2	5.6	1.2	-	-	-	-	-	-	20.1
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.8	7.2	1.0	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.0	0.1	0.1	0.1	4.0	18.0	7.2	2.5	-	-	-	31.8
HVDC Bipole 1 Converter Station, P1 & P2 Battery Bank Separation	3.2	-	0.0	1.0	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	0.6	2.8	0.8	3.9	1.1	2.3	0.1	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacements	8.7	-	-	0.5	1.0	1.7	5.2	0.2	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	-	0.1	3.3	4.5	4.6	4.7	2.0	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.1	1.5	0.9	1.0	0.6	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.8	1.7	0.8	-	-	-	-	-	-	-	-	4.3
HVDC Bipole 2 Smoothing Reactor Replacement	17.1	0.8	3.5	3.2	5.7	3.8	-	-	-	-	-	-	17.1
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	1.0	1.0	1.6	1.6	1.1	0.5	-	-	-	-	-	6.8
Pine Falls Rehabilitation	56.2	2.8	4.2	17.4	12.2	2.1	2.9	3.2	4.8	-	-	-	49.6
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	-	2.3	2.6	18.6	24.5	25.1	73.1
Power Supply Dam Safety Upgrades	34.0	9.7	1.7	-	-	-	-	-	-	-	-	-	11.4
Winnipeg River Riverbank Protection Program	19.7	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.5	-	-	-	10.4
Power Supply Hydraulic Controls	16.0	3.1	1.9	1.2	-	-	-	-	-	2.2	2.7	0.7	11.7
Slave Falls Rehabilitation	198.3	13.0	4.0	1.1	16.3	11.8	15.6	54.3	59.4	11.8	-	-	187.3
Great Falls Unit 4 Overhaul	19.7	3.0	7.0	7.8	-	-	-	-	-	-	-	-	17.8
Great Falls 115 kV Indoor Station Safety Improvements	11.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Generation South Transformer Refurbish & Spares	21.0	0.0	1.5	3.1	5.3	4.4	2.8	2.7	1.1	-	-	-	20.9
Water Licenses & Renewals	40.8	4.4	6.0	6.0	5.7	5.9	4.9	3.2	-	-	-	-	36.1
Generation South PCB Regulation Compliance	4.7	0.2	0.3	0.1	0.1	0.2	3.8	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.6	6.6	6.5	6.6	6.8	7.4	-	-	-	-	-	35.4
Generation South Breaker Replacements	9.4	1.6	3.1	2.2	2.0	0.4	-	-	-	-	-	-	9.3
Seven Sisters Upgrades	9.5	1.8	5.3	1.2	1.0	-	-	-	-	-	-	-	9.4
Generation South Excitation Upgrades	18.3	-	2.0	1.0	1.1	1.7	1.4	1.3	1.5	0.6	7.7	-	18.3
Brandon Unit 5 License Review	18.7	0.3	2.5	11.1	-	-	-	-	-	-	-	-	13.9
Selkirk Enhancements	14.2	5.8	5.2	-	-	-	-	-	-	-	-	-	11.0
Laurie River/CRD Communications and Annunciation Upgrades	4.8	0.2	3.5	0.0	1.1	-	-	-	-	-	-	-	4.8
Notigi Marine Vessel Replacement & Infrastructure Improvements	2.6	0.0	1.3	1.3	-	-	-	-	-	-	-	-	2.6
Fire Protection Projects - HVDC	5.2	0.5	0.4	1.6	1.7	-	-	-	-	-	-	-	4.2
Halon Replacement Project	42.5	14.6	13.1	9.1	-	-	-	-	-	-	-	-	36.8
Power Supply Fall Protection Program	13.5	0.2	-	-	-	-	-	-	-	-	-	-	0.2

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Power Supply - continued													
Oil Containment - Power Supply	19.1	0.6	0.4	1.0	0.5	0.3	0.3	0.1	0.9	-	-	-	4.1
Grand Rapids Townsite House Renovations	5.2	0.1	0.4	0.9	1.2	1.3	1.3	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	2.2	0.1	1.1	0.9	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	7.8	8.4	5.4	-	-	-	-	-	-	-	-	21.6
Site Remediation of Contaminated Corporate Facilities	34.7	2.3	1.2	1.1	1.1	0.2	-	-	-	-	-	-	5.9
High Voltage Test Facility	26.9	10.6	13.5	-	-	-	-	-	-	-	-	-	24.1
Power Supply Security Installations / Upgrades	43.2	9.7	16.0	8.7	2.1	1.5	1.0	1.0	0.5	-	-	-	40.6
Power Supply Sewer & Domestic Water System Install and Upgrade	15.1	7.3	3.4	0.7	-	-	-	-	-	-	-	-	11.4
Power Supply Domestic	NA	19.1	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	230.9
		139.5	161.4	157.2	134.6	116.4	108.9	108.1	96.5	55.5	57.5	48.9	1 184.6
Transmission													
Winnipeg - Brandon Transmission System Improvements	40.0	3.1	1.6	3.4	3.6	5.0	21.7	-	-	-	-	-	38.4
Transcona East 230-66 kV Station	31.0	1.1	11.0	13.2	5.1	-	-	-	-	-	-	-	30.5
Neepawa 230 - 66 kV Station	30.0	1.1	14.1	9.5	5.1	-	-	-	-	-	-	-	29.9
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	0.3	0.9	4.4	20.6	7.8	-	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	3.2	-	-	-	-	-	-	-	-	-	-	3.2
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	0.8	0.9	2.6	6.0	9.6	20.0
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Rosser - Inkster 115 kV Transmission	5.1	3.3	1.4	-	-	-	-	-	-	-	-	-	4.7
Transcona Station 66 kV Breaker Replacement	6.0	0.0	3.6	1.8	0.6	-	-	-	-	-	-	-	6.0
Transcona & Ridgeway Stations 66 kV Bus Upgrades	2.8	1.7	0.7	-	-	-	-	-	-	-	-	-	2.4
Dorsey 500 kV R502 Breaker Replacement	2.6	2.3	0.2	-	-	-	-	-	-	-	-	-	2.6
13.2kV Shunt Reactor Replacements	33.0	0.0	0.0	4.1	4.2	4.3	4.4	4.4	4.5	4.6	2.5	-	33.0
Birtle South-Rossburn 66 kV Line	4.9	-	-	-	-	0.1	0.3	4.5	-	-	-	-	4.9
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	1.8	8.1	7.6	3.5	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	4.9	1.2	-	-	-	-	-	-	-	-	-	6.1
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.0	0.0	-	2.7	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	0.5	0.5	0.0	-	-	-	-	-	-	-	-	1.0
Interlake Digital Microwave Replacement	19.7	3.5	0.4	-	-	-	-	-	-	-	-	-	3.8
Communication System - Southern MB (Great Plains)	21.9	2.4	-	-	-	-	-	-	-	-	-	-	2.4
Communications Upgrade Winnipeg Area	7.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	9.6	1.3	1.4	-	-	-	-	-	-	-	-	-	2.7
Transmission Line Protection & Teleprotection Replacement	21.1	1.4	6.1	6.1	2.3	1.1	0.9	-	-	-	-	-	17.9
Winnipeg Central Protection Wireline Replacement	9.3	2.5	0.6	-	-	-	-	-	-	-	-	-	3.1
Mobile Radio System Modernization	30.7	0.3	2.5	9.2	10.6	8.0	-	-	-	-	-	-	30.6
Cyber Security Systems	10.1	3.6	0.4	-	-	-	-	-	-	-	-	-	4.0
Site Remediation	13.3	1.3	3.8	1.1	-	-	-	-	-	-	-	-	6.2
Oil Containment	7.4	0.9	0.5	-	-	-	-	-	-	-	-	-	1.4
Station Battery Bank Capacity & System Reliability Increase	46.5	5.3	4.7	6.4	6.4	6.6	6.3	-	-	-	-	-	35.7
Red River Floodway Expansion Project	1.8	0.3	-	-	-	-	-	-	-	-	-	-	0.3
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	1.0	0.6	0.4	0.5	-	-	-	-	-	-	3.0
Transmission Domestic	NA	29.6	30.0	30.6	31.2	31.8	32.4	33.1	33.8	34.4	35.1	35.8	357.7
		77.5	86.0	86.9	78.3	86.2	81.4	46.4	39.2	41.6	43.6	45.4	712.6

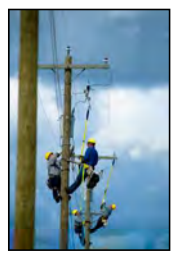
CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	14.9	1.7	-	-	-	-	-	-	-	-	-	-	1.7
Defective RINJ Cable Replacement	8.7	0.5	2.6	-	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	0.3	-	-	-	-	-	-	-	-	-	-	0.3
Stony Mountain New 115 - 12 kV Station	5.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Rover Substation Replace 4 kV Switchgear	12.7	0.4	3.3	3.9	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.0	14.5	9.1	2.4	-	-	-	-	-	-	-	27.0
Frobisher Station Upgrade	14.4	4.4	0.0	-	-	-	-	-	-	-	-	-	4.5
Burrows New 66 kV-12 kV Station	28.6	9.1	12.2	5.0	-	-	-	-	-	-	-	-	26.3
Winnipeg Central District Oil Switch Project	7.1	1.8	-	-	-	-	-	-	-	-	-	-	1.8
William New 66 kV-12 kV Station	10.3	0.5	3.6	3.1	2.9	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	4.4	-	-	-	-	-	-	-	-	-	-	4.4
St. James 24 kV System Refurbishment	65.9	1.3	14.1	31.6	18.9	-	-	-	-	-	-	-	65.8
Shoal Lake New 33 - 12.47 kV DSC	3.6	3.2	-	-	-	-	-	-	-	-	-	-	3.2
York Station	4.0	2.0	1.8	0.1	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	3.0	0.1	1.2	-	-	-	-	-	-	-	-	4.3
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.6	3.1	1.9	0.6	-	-	-	-	-	-	-	6.2
Winkler Market Feeder M25-13 Conversion	2.9	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	-	1.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.4	2.0	-	-	-	-	-	-	-	-	-	2.4
Niverville Station 66-12 kV Bank Replacements	2.6	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Gas SCADA Replacement	4.6	1.0	3.0	0.6	-	-	-	-	-	-	-	-	4.6
Customer Service & Distribution Domestic	NA	115.9	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	1 402.9
		158.1	177.8	176.3	147.0	124.7	127.2	129.8	132.4	135.0	137.7	140.5	1 586.4
Customer Care & Marketing													
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	28.8
Customer Care & Marketing Domestic	NA	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	30.6
		2.5	6.5	8.0	8.1	8.3	7.1	7.1	2.9	2.9	3.0	3.1	59.5

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Workforce Management (Phase 1 to 4)	11.3	3.9	1.0	-	-	-	-	-	-	-	-	-	4.9
Fleet	NA	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	161.2
Finance & Administration Domestic	NA	24.1	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	291.6
		49.2	46.9	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	545.7
Capital Increase Provision		-	-	-	-	-	-	63.1	90.4	82.8	97.3	99.2	432.8
ELECTRIC CAPITAL SUBTOTAL		1 255.0	1 165.5	1 074.5	1 038.6	1 228.0	1 691.7	2 247.6	2 160.5	1 653.3	1 800.3	1 557.9	16 872.9
GAS													
Customer Service & Distribution													
Customer Service & Distribution Domestic	NA	20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
		20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.3	-	-	-	-	-	-	-	14.6
Demand Side Management	NA	13.5	13.1	11.6	11.7	11.1	10.2	10.6	10.3	7.7	5.5	5.1	110.3
Customer Care & Marketing Domestic	NA	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	33.5
		16.2	16.9	19.8	22.9	14.1	13.2	13.7	13.5	11.0	8.8	8.4	158.5
Capital Increase Provision		-	-	-	-	-	-	-	-	2.3	4.9	5.0	12.1
GAS CAPITAL SUBTOTAL		37.0	38.2	41.5	45.0	36.6	36.2	37.2	37.4	37.6	38.5	38.8	423.9
CONSOLIDATED CAPITAL		1 292.0	1 203.6	1 116.0	1 083.6	1 264.6	1 727.9	2 284.8	2 197.9	1 690.9	1 838.8	1 596.6	17 296.7
TARGET ADJUSTMENT		(188.0)	(118.6)	(80.0)	(59.1)	221.4	37.1	(128.8)	(32.7)	25.4	(187.8)	(305.6)	(816.7)
		1 104.0	1 085.0	1 036.0	1 024.5	1 486.0	1 765.0	2 156.0	2 165.2	1 716.3	1 651.0	1 291.0	16 480.0



Section 2

Project Summaries

Electric

Gas

ELECTRIC OPERATIONS:

MAJOR NEW GENERATION & TRANSMISSION:

Wuskwatim - Generation

Description:
Design and build the new Wuskwatim Generating Station with three generators and installed capacity of approximately 200 MW on the Burntwood River upstream of Thompson.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power September 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 1 274.6	$ 326.9	$ 256.4	$ 126.8	$ 20.8	$ -	$ -
Increase (Decrease)	-	37.5	18.9	(21.7)	(8.7)	-	-
Revised Forecast	$ 1 274.6	$ 364.4	$ 275.3	$ 105.1	$ 12.1	$ -	$ -

Wuskwatim - Transmission

Description:
Design and build the associated transmission facilities necessary to integrate the Wuskwatim Generation Station into the Manitoba Hydro 230 kV transmission network.

Justification:
The existing 230 kV transission system in Northern Manitoba does not have sufficient capacity to accommodate the additional output of the Wuskwatim Generating Station. This project will increase the ability of the transmission system to carry the full output of Wuskwatim to load anywhere in Manitoba.

In-Service Date:
September 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 316.3	$ 52.5	$ 32.2	$ 15.5	$ 0.9	$ -	$ -
Increase (Decrease)	-	37.6	(1.7)	3.4	(0.9)	-	-
Revised Forecast	$ 316.3	$ 90.1	$ 30.5	$ 18.9	$ -	$ -	$ -

Herblet Lake - The Pas 230 kV Transmission

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Flin Flon Cliff Lake and The Pas Ralls Island as follows: *Transmission*: 230 kV line 160 km from Herblet Lake to The Pas Ralls Island. *Terminations*: Extend 230 kV facilities at Herblet Lake and The Pas Ralls Island stations. *Communications*: Upgrade and co-ordinate with existing Herblet Lake and The Pas facilities.

Justification:
The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads. In addition, this line facilitates the transmission of power from the Wuskwatim Generating Station.

In-Service Date:
September 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 93.2	$ 39.3	$ 29.0	$ 4.2	$ -	$ -	$ -
Increase (Decrease)	-	2.6	1.4	3.0	1.9	-	-
Revised Forecast	$ 93.2	$ 41.9	$ 30.4	$ 7.2	$ 1.9	$ -	$ -

Keeyask - Generation

Description:
Design and build the Keeyask Generating Station with seven generators and installed capacity of approximately 630 MW on the Nelson River downstream of Thompson. Project costs include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. The estimate is comprised of costs associated with extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power December 2018.

Revision:
Estimate updated to reflect the acquisition of all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 3 700.4	$ 25.9	$ 33.1	$ 36.1	$ 64.3	$ 220.3	$ 2 974.9
Increase (Decrease)	891.2	41.8	51.9	159.2	134.3	(38.0)	504.1
Revised Forecast	$ 4 591.6	$ 67.7	$ 85.0	$ 195.3	$ 198.6	$ 182.3	$ 3 479.0

Conawapa - Generation

Description:
Design and build the Conawapa Generating Station with ten generators and installed capacity of approximately 1,300 MW on the Nelson River downstream from Thompson. Project costs include activities associated with extensive First Nations and other community consultations, pre-project training, environmental studies, impact statement preparations, submissions, regulatory review processes, acquiring all necessary licensing, improvements to access roadways, and detailed pre-engineering required to obtain a license and all necessary approvals to construct the Conawapa Generating Station.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power May 2022.

Revision:
Estimate updated to reflect current market conditions along with the addition of access roadway improvements.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4 978.4	$ 60.5	$ 60.7	$ 57.7	$ 62.3	$ 67.7	$ 3 705.7
Increase (Decrease)	1 346.4	(0.1)	(0.3)	17.3	49.5	122.4	(634.3)
Revised Forecast	$ 6 324.8	$ 60.4	$ 60.4	$ 75.0	$ 111.8	$ 190.1	$ 3 071.4

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all Kelsey generating station units (1-7) including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform unit 1 to 7 draft tube modifications, perform unit 1 to 5 intake gate rehabilitation, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey Generating Station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11 MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230 kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77 MW of additional Kelsey output.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 189.6	$ 45.8	$ 7.4	$ 0.3	$ -	$ -	$ -
Increase (Decrease)	-	(0.7)	(0.6)	0.2	-	-	-
Revised Forecast	$ 189.6	$ 45.1	$ 6.8	$ 0.5	$ -	$ -	$ -

Kettle Improvements & Upgrades

Description:
Rewind stator for units 5-12, and install a new stator frame, core and winding for unit 4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Re-wedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Unit 4 requires repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core.

In-Service Date:
October 2022.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 75.6	$ 7.0	$ 7.3	$ 6.4	$ 6.0	$ 3.8	$ 28.0
Increase (Decrease)	-	4.1	11.1	0.2	14.1	14.8	(28.0)
Revised Forecast	$ 75.6	$ 11.1	$ 18.4	$ 6.6	$ 20.1	$ 18.6	$ -

Pointe du Bois Improvements & Upgrades

Description:
Design and build a spillway and earth fill dam to replace the existing spillway structures. Includes engineering and environmental studies, community consultation, obtaining regulatory approval, construction and de-commissioning the existing spillway.

Justification:
Pointe du Bois does not currently meet Dam Safety guidelines with respect to spillway capacity. A new spillway is required to meet these guidelines.

In-Service Date:
October 2014.

Revision:
Project estimate decreased $500.0 million to reflect scope change to exclude the construction of a new four unit powerhouse, and in-service date advanced three years from October 2017.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 818.0	$ 13.8	$ 14.8	$ 15.5	$ 91.5	$ 141.1	$ 514.5
Increase (Decrease)	(500.0)	-	-	-	(38.5)	(58.0)	(403.8)
Revised Forecast	$ 318.0	$ 13.8	$ 14.8	$ 15.5	$ 53.0	$ 83.1	$ 110.7

Pointe du Bois - Transmission

Description:
Install 17 kms of single circuit 115 kV transmission line with 795 ACSR conductor between Rover and the intersection of GT1/ST2 and the transmission right-of-way near the floodway. Install 43 kms of single circuit 115 kV transmission line with 795 ACSR conductor between Pointe du Bois and GT1/ST2 transmission line south of Lac du Bonnet. The estimate is based on the utilization of the previously vacated transmission line corridor from Pointe du Bois to GT1-ST2 transmission line south of Lac du Bonnet and from Ridgeway station to Rover station. Install a second communications link from Pointe and Slave to the System Control Center.

Justification:
To address aging infrastructure concerns with the existing 66 kV P Lines, provide adequate outlet transmission for future Pointe du Bois generating station expansion, and to integrate the Winnipeg Central System into the Manitoba Hydro System.

In-Service Date:
May 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 85.9	$ 19.1	$ 12.5	$ 13.2	$ 16.4	$ 13.0	$ 2.8
Increase (Decrease)	-	(10.1)	13.8	(2.8)	4.2	0.9	0.3
Revised Forecast	$ 85.9	$ 9.0	$ 26.3	$ 10.4	$ 20.6	$ 13.9	$ 3.1

Bipole 3

Description:
Design and build a transmission line (west of Lakes Winnipegosis & Manitoba), conduct environmental impact assessments, select route, acquire property for right of way, and obtain licensing for Riel Station, a +/- 500 kV DC transmission line from proposed line paralleling site near Radisson and proposed Riel Station, and a 230 kV AC line from Riel Station to Dorsey Station (normally operated at +/- 500 kV DC).

Design and build an HVDC transmission line from Riel Converter Station (CS) to Conawapa CS; a converter station with 2000 MW of converters at Conawapa; six AC transmission lines approximately 30 kms long to connect the Conawapa converter station to the Henday converter station; and a converter station with 2000 MW of converters at Riel, including three synchronous compensators.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power at full load, due to decreased line losses (approximately 78 MW).

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 2 247.8	$ 16.6	$ 21.4	$ 36.7	$ 113.4	$ 266.5	$ 1 774.4
Increase (Decrease)	-	-	-	-	-	-	(8.7)
Revised Forecast	$ 2 247.8	$ 16.6	$ 21.4	$ 36.7	$ 113.4	$ 266.5	$ 1 765.7

Riel 230/500 kV Station

Description:
Sectionalize Dorsey to the United States 500 kV transmission line D602F at Riel (on the southeast side of Winnipeg), and establish a station including a 230 and 500 kV ring bus, the installation of a 230/ 500 kV transformer bank, and line reactors salvaged from Dorsey 500 kV Station.

Justification:
The sectionalization of the 500 kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.

In-Service Date:
May 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 267.6	$ 30.7	$ 68.8	$ 75.7	$ 43.5	$ 36.4	$ 4.7
Increase (Decrease)	-	5.4	(10.4)	3.9	1.6	1.8	(0.1)
Revised Forecast	$ 267.6	$ 36.1	$ 58.4	$ 79.6	$ 45.1	$ 38.2	$ 4.6

Firm Import Upgrades

Description:
Reconductor and resag transmission lines R23R, WT34, HS5 and SM26, and replace risers and current transformers for stations at Rosser, Ridgeway, Great Falls, Transcona, Mercy St., and Parkdale.

Justification:
This project will improve Manitoba Hydro's firm import capability during periods when we are expected to be energy deficient.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.8	$ 0.4	$ 2.1	$ 2.1	$ -	$ -	$ -
Increase (Decrease)	-	0.2	-	-	-	-	-
Revised Forecast	$ 4.8	$ 0.6	$ 2.1	$ 2.1	$ -	$ -	$ -

Dorsey - US Border New 500kV Transmission Line

Description:
Design and build a 63 KM 500 kV transmission line between Riel station and Dorsey station, and a 125 KM 500 kV transmission line between Dorsey station and the U.S. border. Acquire property for right-of-way, conduct environmental impact assessment, conduct community consultations, obtain licensing and perform environmental monitoring for all facilities.

Justification:
Manitoba Hydro has received transmission service requests for more than 750 MW of new import and export service between the U.S. and Manitoba. Term sheets have been signed for a potential 500 MW power sale to Wisconsin and a 250 MW power sale to Minnesota. These additional power sales require the construction of a new high voltage tieline between Manitoba and the U.S.

In-Service Date:
May 2018.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 204.8	$ -	$ -	$ 0.8	$ 1.8	$ 10.7	$ 191.4
Increase (Decrease)	-	-	0.5	1.1	6.4	6.9	(14.9)
Revised Forecast	$ 204.8	$ -	$ 0.5	$ 1.9	$ 8.2	$ 17.6	$ 176.5

Brandon Combustion Turbine Pipeline Upgrade

Description:
Install 11,403 meters of 12” steel transmission pressure pipeline and one control point valve assembly to assist in supplying the Brandon thermal generating station natural gas turbines.

Justification:
In order to meet Manitoba Hydro’s contractual obligation to KOCH Fertilizer Canada Ltd., as well as the firm service agreement with the Brandon thermal generating station, it is necessary to construct an additional 11,403 meters of 12” pipeline for supply to the Brandon thermal generating station natural gas turbines.

In-Service Date:
October 2009.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.5	$ 5.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(0.1)	0.2	-	-	-	-	-
Revised Forecast	$ 5.4	$ 5.4	$ -	$ -	$ -	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce electricity consumption in Manitoba. When combined with savings realized to-date, total electricity savings of 915 MW and 3,271 GWh are expected to be achieved by 2025.

Justification:
The electricity Demand Side Management plan is cost effective as a resource option and is included in Manitoba Hydro's *Power Resource Plan*. Provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, and by protecting the environment and promoting sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
The increase in total expenditures is primarily due to the addition of the Industrial Emergency Preparedness Program, revisions to the Performance Optimization and BioEnergy Optimization Programs resulting in higher program costs, an increase in contingency dollars and the inclusion of another year of expenditures in 2019/20.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 34.6	$ 33.3	$ 31.8	$ 29.4	$ 26.0	$ 122.3
Increase (Decrease)		5.7	9.7	10.7	9.0	7.9	36.2
Revised Forecast		$ 40.3	$ 43.0	$ 42.5	$ 38.4	$ 33.9	$ 158.5

Planning Study Costs

Description:
Perform assessments, create conceptual designs and planning studies of potential supply options and associated transmission facilities. Areas of study include establishment of design parameters, structure layouts, support facilities, hydraulic model testing, exploration, data collection, environmental assessments and public input, schedules, and cost estimates.

Justification:
To plan for the orderly development of new sources of generation and related transmission facilities, and to explore supply-side efficiency improvements.

In-Service Date:
Ongoing.

Revision:
Ongoing.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 5.9	$ 4.7	$ -	$ -	$ -	$ -
Increase (Decrease)		(0.2)	3.3	1.9	-	-	-
Revised Forecast		$ 5.7	$ 8.0	$ 1.9	$ -	$ -	$ -

NEW HEAD OFFICE:

Description:
Construction of a 695,742 square foot 22 storey Head Office in downtown Winnipeg.

Justification:
A new Head Office location is required to consolidate approximately 2,000 staff including management and administrative functions of Manitoba Hydro in a modern, centralized location.

In-Service Date:
May 2008.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 278.1	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	14.8	-	-	-	-	-
Revised Forecast	$ 278.1	$ 14.8	$ -	$ -	$ -	$ -	$ -

CORPORATE RELATIONS:

Waterways Management Program

Description:
Waterways management at Grand Rapids and Lake Winnipeg Regulation / Churchill River Diversion.

Justification:
The Waterways Management Program (WMP) includes activities related to boat patrols, debris clearing, and supplementary works and is required to ensure ongoing safety and environmental management of waterways.

In-Service Date:
Ongoing.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 5.3	$ 5.5	$ -	$ -	$ -	$ -
Increase (Decrease)		-	(0.1)	-	-	-	-
Revised Forecast		$ 5.3	$ 5.4	$ -	$ -	$ -	$ -

POWER SUPPLY:

Converter Transformer Bushing Replacement

Description:
Replace converter transformer bushings with NGK bushings, and purchase spares as follows: at Dorsey replace six 230 kV AC, and six 25 kV tertiary bushings; and at Radisson/ Henday replace five 138 kV, two 150 kV, four 230 kV, and three 15 kV tertiary bushings, and purchase two 300 kV and two 450 kV spares.

Justification:
The bushing replacement program was undertaken due to failure of a 230 kV bushing in Dorsey T21 A-phase converter transformer that resulted in costly repairs to the transformer, and loss of revenue due to the outage. Also during the repair of the Dorsey T31S converter transformer in Pauwel's Canada plant, two out of two 230 kV bushings that were tested failed at far below the full test voltage. The manufacturer's expected service life is 25 years. These bushings have all been in-service more than 19 years. Replacement cost is justified when compared to transformer damage due to an in-service failure.

In-Service Date:
October 2011.

Revision:
Cost flow revision, and in-service date deferred 12 months from October 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.9	$ 1.3	$ 1.0	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(1.2)	(0.6)	1.9	-	-	-
Revised Forecast	$ 5.9	$ 0.1	$ 0.4	$ 1.9	$ -	$ -	$ -

Bipole 1 & 2 Electrode Line Monitoring

Description:
Install a Siemens pulse-echo electrode line fault detection system on Dorsey Bipole 1 and 2, Radisson Bipole 1, and Henday Bipole 2 Electrode lines.

Justification:
There is a need for detection of open circuit, faulted, or partially down electrode line conductors based on public safety concerns, possible damage to equipment, and the security of Bipole 1 and 2.

In-Service Date:
September 2012.

Revision:
Cost flow revision, and in-service date deferred 24 months from September 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 1.7	$ 1.5	$ 0.1	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(1.5)	(0.1)	1.6	-	-	-
Revised Forecast	$ 1.7	$ -	$ -	$ 1.6	$ -	$ -	$ -

Dorsey Synchronous Condenser Refurbishment

Description:
Major inspection, re-wedging and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, and SC23Y. Replace coolers to restore original thermal performance on SC21Y, and SC23Y. Repair corrosion problems and replace GEM80 PLC on SC7Y, SC8Y and SC9Y. Modify the 600 V transfer scheme for SC8Y, SC7Y & SC9Y.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
March 2015.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 32.3	$ 4.5	$ 2.8	$ 3.8	$ 2.6	$ 2.7	$ 3.4
Increase (Decrease)	-	(1.5)	(0.3)	(0.2)	(0.1)	(0.1)	(0.6)
Revised Forecast	$ 32.3	$ 3.0	$ 2.5	$ 3.6	$ 2.5	$ 2.6	$ 2.8

HVDC Bipole 1 Roof Replacement

Description:
Remove existing roofs over Bipole 1, valve groups 11, 12, 13, 21, 22, and 23 at Dorsey and Radisson stations. Design, supply, install and test replacement roofs, simultaneously, and during pre-planned outages. The new roofs are to be two-ply modified bitumen membrane with R20 insulating values, and meeting FM Global fire spread and wind uplift requirements.

Justification:
The existing asphalt roofs were installed in 1970, and with maintenance have exceeded their life expectancy of 15 years. Damage to equipment due to water leaks, fire spread within a roof system, or high wind uplift and/or possible lost export sales could be very costly. Each of the six valve halls contains equipment valued at $7.0 M.

In-Service Date:
June 2009.

Revision:
In-service date advanced four months from October 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.9	$ 0.7	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 5.9	$ 0.7	$ -	$ -	$ -	$ -	$ -

HVDC System Transformer & Reactor Fire Protection & Prevention

Description:
The supply and installation of fire protection upgrades on 33 converter transformers and eight smoothing reactors. The re-design and replacement of the deluge system on the Dorsey converter building south wall and the Henday converter building north east wall, and the construction of a fire response building in a safe location at Dorsey converter station.

Justification:
To minimize the high risk of fire spread and catastrophic damage throughout the AC and DC switchyards, and a potential transformer and revenue loss of an estimated $30 to $50 million. To provide adequate fire protection for personnel in accordance with National Fire Protection Association (NFPA) Life Safety Code 101.

In-Service Date:
December 2011.

Revision:
Cost flow revision, and in-service date deferred 14 months from October 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 10.4	$ 1.1	$ 0.6	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.8)	0.7	0.3	-	-	-
Revised Forecast	$ 10.4	$ 0.3	$ 1.3	$ 0.3	$ -	$ -	$ -

HVDC AC Filter PCB Capacitor Replacement

Description:
Replace all Bipole 1 & 2 AC PCB filled high power capacitors at the Dorsey, Radisson, and Henday Converter Stations, with non-PCB replacement capacitors.

Justification:
Numerous PCB filled capacitor failures at HVDC converter stations have resulted in requests for outages via the System Control Centre to allow for repairs. The catastrophic failure of a capacitor in an AC filter bank of B2 would result in a pole outage. Manitoba Hydro is committed to being PCB free as outlined in corporate policy statement CP486B. The capacitors will be 27 years old and are approaching the end of their usable life.

In-Service Date:
November 2010.

Revision:
Cost flow revision, and in-service date deferred 18 months from May 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 34.5	$ 3.0	$ 4.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.6)	1.3	-	-	-	-
Revised Forecast	$ 34.5	$ 2.4	$ 6.0	$ -	$ -	$ -	$ -

HVDC Transformer Replacement Program

Description:
Maintain an inventory of eight spare converter transformers for use at Radisson, Henday and Dorsey converter stations.

Justification:
Maintenance of an inventory of spare converter transformers will limit outage durations and outage costs in the event of converter transformer failures.

In-Service Date:
October 2013.

Revision:
Cost flow revision, and in-service date deferred 19 months from March 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 105.7	$ 4.5	$ 10.0	$ (0.2)	$ 0.3	$ -	$ -
Increase (Decrease)	-	(3.5)	(8.9)	7.5	5.0	1.1	-
Revised Forecast	$ 105.7	$ 1.0	$ 1.1	$ 7.3	$ 5.3	$ 1.1	$ -

Dorsey 230 kV Relay Building Upgrade

Description:
Upgrade the 230 kV relay building at Dorsey and provide mobile protection and control trailers.

Justification:
Upgrades to the building will reduce the risk of damage from weather related perils and limit the consequence of a Bipole failure due to fire related perils. Mobile protection and control trailers will facilitate the quick restoration of service in the case of a catastrophic event to this or other relay buildings.

In-Service Date:
March 2016.

Revision:
Cost flow revision, and in-service date deferred seven months from August 2015.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 73.8	$ 2.8	$ 3.5	$ 1.7	$ 15.8	$ 32.9	$ 15.8
Increase (Decrease)	-	(1.7)	(1.6)	2.3	0.6	(0.8)	1.1
Revised Forecast	$ 73.8	$ 1.1	$ 1.9	$ 4.0	$ 16.4	$ 32.1	$ 16.9

HVDC Stations Ground Grid Refurbishment

Description:
Upgrade the existing ground grid systems at Dorsey, Radisson and Henday Stations.

Justification:
These upgrades improve the safety of employees and contractors working in and around the HVDC converter stations, by ensuring that touch and step potential are within safe levels.

In-Service Date:
October 2013.

Revision:
Cost flow revision, and in-service date deferred seven months from March 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.3	$ 0.4	$ 0.3	$ 0.4	$ 0.5	$ -	$ -
Increase (Decrease)	-	0.2	0.2	0.2	0.1	-	-
Revised Forecast	$ 4.3	$ 0.6	$ 0.5	$ 0.6	$ 0.6	$ -	$ -

HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement

Description:
Replace the existing 34 HLR operating mechanisms with new operating mechanisms, evaluate five HLR breaker and drive mechanisms, purchase one spare HLR operating mechanism, rebuild 126 AHMA drives, purchase six AHMA drives, remove 203 600V arc chutes and rebuild the associated 600V breakers, and the replacement of all 600V breaker hydraulic overloads with electronic overloads.

Justification:
System reliability will be improved. BLG1002A breaker operating mechanisms are designed to handle the frequent switching experienced by these 16 breakers, reduce repair and maintenance frequency, and reduce the risk of failure. A breaker failure results in a bus outage and single contingency of the 230 kV bus. There is a Bipole outage risk, if bus B1 or B2 at Dorsey is out of service for any reason.

In-Service Date:
December 2013.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.4	$ 1.3	$ 0.8	$ 0.3	$ -	$ -	$ -
Increase (Decrease)	-	1.4	(0.4)	(0.3)	-	-	-
Revised Forecast	$ 9.4	$ 2.7	$ 0.4	$ -	$ -	$ -	$ -

HVDC Bipole 1 Pole Differential Protection

Description:
Prepare an engineering report to determine all possible options, scope of work, cost analysis, and detailed cost estimate. Implement the preferred option at both Dorsey and Radisson stations.

Justification:
Upgrading Bipole 1 pole differential protection is necessary to eliminate healthy pole blocks, thus reducing outages and increasing availability.

In-Service Date:
December 2011.

Revision:
Cost flow revision, and in-service date deferred 24 months from December 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 3.3	$ 3.3	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(3.3)	1.0	2.3	-	-	-
Revised Forecast	$ 3.3	$ -	$ 1.0	$ 2.3	$ -	$ -	$ -

HVDC Bipole 1 By-Pass Vacuum Switch Removal

Description:
Remove the existing By-Pass Vacuum Switch (BPVS) and By-Pass Switch (BPS) and replace both with a single BPS at Dorsey and Radisson stations (Bipole 1 valve halls). In addition, Radisson will have its AC line switch (ACCQ) removed.

Justification:
The equipment is nearing the end of its service life and requires substantial maintenance. By-pass vacuum switches were part of the replaced mercury arc valves switching scheme. The new thyristor valves may be more reliably served by other types of switches, thus reducing the forced outage rate.

In-Service Date:
March 2014.

Revision:
Cost flow revision, and in-service date deferred one year from March 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 20.4	$ 4.7	$ 5.4	$ 4.4	$ 5.8	$ -	$ -
Increase (Decrease)	-	(4.2)	(0.8)	3.8	(0.2)	1.2	-
Revised Forecast	$ 20.4	$ 0.5	$ 4.6	$ 8.2	$ 5.6	$ 1.2	$ -

HVDC Bipole 2 Refrigerant Condenser Replacement

Description:
Remove and replace existing air conditioning systems in the Bipole 2 valve halls, maintenance blocks and administration areas at both Dorsey and Henday converter stations.

Justification:
The present systems are nearing the end of their service life. Maintenance is increasing, along with the likelihood of costly valve outages. In addition, the present systems contain R-22 (an ozone depleting substance).

In-Service Date:
April 2013.

Revision:
Cost flow revision, and in-service date deferred one year from April 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 11.0	$ -	$ 2.9	$ 7.2	$ 0.9	$ -	$ -
Increase (Decrease)	-	-	(2.9)	(4.4)	6.3	1.0	-
Revised Forecast	$ 11.0	$ -	$ -	$ 2.8	$ 7.2	$ 1.0	$ -

HVDC Bipole 1 Smoothing Reactor Replacement

Description:
Remove existing oil-filled Bipole 1 smoothing reactors at Dorsey and Radisson, and replace with new air core reactors.

Justification:
Existing Bipole 1 smoothing reactors are approaching the end of their service life. Replacement will ensure continued availability and reliable operation of the HVDC system. Removal of oil–filled reactors will reduce the risk of oil spills and fires within the work place.

In-Service Date:
October 2018.

Revision:
Cost flow revision, and in-service date deferred six years from October 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 31.8	$ 3.1	$ 10.5	$ 12.8	$ 5.1	$ -	$ -
Increase (Decrease)	-	(3.1)	(10.4)	(12.7)	(5.0)	4.0	27.7
Revised Forecast	$ 31.8	$ -	$ 0.1	$ 0.1	$ 0.1	$ 4.0	$ 27.7

HVDC Bipole 1 Converter Station, P1 & P2 Battery Bank Separation

Description:
Separate Pole 1 & Pole 2 battery banks at Dorsey and Radisson converter stations. Upgrade the battery banks and charger ratings to comply with current Manitoba Hydro design criteria.

Justification:
Pole 1 & Pole 2 battery banks have to be physically separated in order to provide a reliable first grade supply to the HVDC controls and protection and communication system.

In-Service Date:
February 2013.

Revision:
Cost flow revision, and in-service date deferred one year from February 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 3.2	$ -	$ 1.0	$ 2.2	$ -	$ -	$ -
Increase (Decrease)	-	-	(1.0)	(1.2)	2.2	-	-
Revised Forecast	$ 3.2	$ -	$ -	$ 1.0	$ 2.2	$ -	$ -

HVDC Bipole 1 DCCT Transductor Replacement

Description:
Replace existing oil-filled DC transductors with optical transductors at Dorsey and Radisson stations.

Justification:
Existing BP1 DCCT transductors are reaching the end of service life and spares are no longer available. Failure of a transductor to transmit a required signal to protective and controls equipment at Dorsey and Radisson stations can cause a lengthy pole outage. A fire in the existing oil-filled transductors could result in irreparable damage to adjacent equipment and a lengthy pole outage. Replacement will contribute to reliable operation of the HVDC system. Removal of the oil-filled transductors will reduce the risk of oil spills and fires within the workplace.

In-Service Date:
October 2016.

Revision:
Cost flow revision, and in-service date deferred two years from October 2014.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 11.7	$ 2.5	$ 1.2	$ 3.5	$ 1.3	$ 1.8	$ 0.7
Increase (Decrease)	-	(2.5)	(0.6)	(0.7)	(0.5)	2.1	2.8
Revised Forecast	$ 11.7	$ -	$ 0.6	$ 2.8	$ 0.8	$ 3.9	$ 3.5

HVDC BP1 & BP2 DC Converter Transformer Bushing Replacements

Description:
Remove and replace transformer bushings on all converter transformers over 25 years old.

Justification:
Bushings on converter transformers over 25 years old are reaching the end of their service life. A bushing failure while in-service would cause a costly valve group outage to repair or replace the bushing and could cause irreparable damage to a converter transformer.

In-Service Date:
March 2015.

Revision:
Cost flow revision, and in-service date deferred 18 months from September 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 8.7	$ 0.5	$ 1.0	$ 1.6	$ 5.1	$ 0.5	$ -
Increase (Decrease)	-	(0.5)	(1.0)	(1.1)	(4.1)	1.2	5.4
Revised Forecast	$ 8.7	$ -	$ -	$ 0.5	$ 1.0	$ 1.7	$ 5.4

HVDC Bipole 2 Valve Hall Wall Bushing Replacements

Description:
Replace all oil-filled wall bushings in the Bipole 2 valve halls with new solid core bushings or SF6 filled bushings.

Justification:
Existing wall bushings in the Bipole 2 valve halls are over 20 years old and are reaching the end of their service life. The risk of bushing failure and fire in a valve hall increases as the bushings age. Replacing the bushings will ensure reliable operation of the valve group well into the future, and provide a safer working environment for employees at the converter stations.

In-Service Date:
June 2015.

Revision:
Cost flow revision, and in-service date deferred two years from June 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 19.2	$ 3.4	$ 4.6	$ 4.7	$ 4.8	$ 1.8	$ -
Increase (Decrease)	-	(3.4)	(4.5)	(1.4)	(0.3)	2.8	6.7
Revised Forecast	$ 19.2	$ -	$ 0.1	$ 3.3	$ 4.5	$ 4.6	$ 6.7

HVDC Bipole 1 CQ Disconnect Replacement

Description:
Replace the existing Radisson and Dorsey DC disconnects, and Dorsey AC disconnects with new disconnects.

Justification:
Major failures of CQ disconnects cause costly pole outages, and these disconnects are reaching the end of their service life. They have been in-service for 36 years, their failure rate is increasing, and spare parts are no longer available.

In-Service Date:
April 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.2	$ -	$ 1.2	$ 1.6	$ 0.9	$ 1.1	$ 0.3
Increase (Decrease)	-	-	(1.2)	(0.5)	0.6	(0.2)	1.3
Revised Forecast	$ 5.2	$ -	$ -	$ 1.1	$ 1.5	$ 0.9	$ 1.6

HVDC Bipole 2 Thyristor Module Cooling Refurbishment

Description:
Refurbish 1 566 thyristor module cooling components in Bipole 2 by replacing the manifolds, connectors and cooling tubes.

Justification:
The cooling components are reaching the end of their life, and are starting to leak, resulting in forced outages. Refurbishing the module cooling components will improve the reliability of the cooling system and extend its life until the replacement of the Bipole 2 system equipment, which is in approximately 10 - 15 years.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.7	$ 1.8	$ 1.8	$ 0.8	$ -	$ -	$ -
Increase (Decrease)	-	-	(0.1)	-	-	-	-
Revised Forecast	$ 4.7	$ 1.8	$ 1.7	$ 0.8	$ -	$ -	$ -

HVDC Bipole 2 Smoothing Reactor Replacement

Description:
Replace four existing oil-filled Bipole 2 smoothing reactors with air core smoothing reactors at Dorsey and Henday.

Justification:
The smoothing reactors have already exceeded their estimated useful life of 25 years. Each DC line fault and AC system fault in the southern AC system results in sudden current surges in the smoothing reactors resulting in physical shaking and contraction of the windings. As a result, the blockings in the winding become loose and have to be retightened. The reactors have been subject to these faults for many years. When the reactors do eventually fail, the units will be replaced with air core reactors. Replacing them with an air core reactor now would alleviate the environmental and fire concerns, and provide a reliable system for the future and reduce maintenance and protection systems requirements.

In-Service Date:
September 2013.

Revision:
Cost flow revision, and in-service date advanced one year from September 2014.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 17.1	$ -	$ -	$ 7.0	$ 6.5	$ 3.0	$ 0.6
Increase (Decrease)	-	0.8	3.5	(3.8)	(0.8)	0.8	(0.6)
Revised Forecast	$ 17.1	$ 0.8	$ 3.5	$ 3.2	$ 5.7	$ 3.8	$ -

HVDC Bipole 1 Transformer Marshalling Kiosk Replacement

Description:
Replace nine Bipole 1 transformer marshalling kiosks with insulated Programmable Logic Controllers (PLC) monitoring marshalling kiosks, and upgrade 19 control boxes at the transformer with a quick disconnect system.

Justification:
The new control boxes will remove the 600V from the controls and monitoring section of the panel which will eliminate the present safety concerns that site workers face while performing maintenance or trouble shooting.

In-Service Date:
November 2014

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	6.8	1.0	1.0	1.6	1.6	1.1	0.5
Revised Forecast	$ 6.8	$ 1.0	$ 1.0	$ 1.6	$ 1.6	$ 1.1	$ 0.5

Pine Falls Rehabilitation

Description:
Rehabilitation, replacement of and addition to various electrical and mechanical equipment and systems such as spillway mechanical components, station service upgrade, station lighting, 11 kV cable replacement, spillway electrical distribution, water system, air system, transformer lightning arrestors, and station drawings. Replace unit 1 and 2 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials. Conduct a model test and up-rate study. Replace potential transformers, synchronizers, annunciators, generator breakers, excitation and governor systems, step-up transformers and electrical back-up systems.

Justification:
Assessment of the electrical and mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
March 2015.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 56.2	$ 4.6	$ 24.5	$ 5.2	$ 3.8	$ 3.2	$ 6.6
Increase (Decrease)	-	(1.8)	(20.3)	12.2	8.4	(1.1)	4.3
Revised Forecast	$ 56.2	$ 2.8	$ 4.2	$ 17.4	$ 12.2	$ 2.1	$ 10.9

Jenpeg Unit Overhauls

Description:
Major overhaul of all generating units (1-6) to inspect, repair, modify, and replace components of the turbine/ generator. Areas of concern include journal bearings, thrust bearings, turbine seals, servo motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, and auxiliary systems.

Justification:
A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

In-Service Date:
December 2021.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 128.1	$ -	$ -	$ -	$ -	$ -	$ 49.2
Increase (Decrease)	-	-	-	-	-	-	23.9
Revised Forecast	$ 128.1	$ -	$ -	$ -	$ -	$ -	$ 73.1

Power Supply Dam Safety Upgrades

Description:
Perform necessary engineering design and remedial construction to upgrade generating stations to present day dam safety standards: 1) Kettle generating station – upgrade main and saddle dams for freeboard; 2) Kelsey generating station – armour plating at spillway rollways, erection of heated hoist housing, insulating of spillway gates, upgrading of dikes, upgrading of spillway feeders and electrical systems at the spillway, and upgrading of the station service transformers due to increased loading; and 3) southern generating stations - capital works identified in the dam safety certification process or identified through observation and discussion with staff.

Justification:
Work is required to correct deficiencies to all the plants, in order to operate in a safe and reliable manner.

In-Service Date:
March 2016.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 34.0	$ 3.5	$ 1.2	$ 1.2	$ 1.2	$ 1.3	$ 3.2
Increase (Decrease)	-	6.2	0.5	(1.2)	(1.2)	(1.3)	(3.2)
Revised Forecast	$ 34.0	$ 9.7	$ 1.7	$ -	$ -	$ -	$ -

Winnipeg River Riverbank Protection Program

Description:
Placement of rock protection and construction of slope stabilization to reduce the erosion of riverbanks along the Winnipeg River. The work includes inspection, design, mapping, land acquisition, and remedial construction at priority locations along reaches of the Winnipeg River affected by Manitoba Hydro hydraulic operations.

Justification:
Provision of riverbank protection and stabilization work along the Winnipeg River between Seven Sisters forebay and Manitou rapids to protect private property from erosion partially due to hydraulic operations.

In-Service Date:
March 2017.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 19.7	$ 1.1	$ 1.2	$ 1.2	$ 1.2	$ 1.3	$ 4.0
Increase (Decrease)	-	0.2	-	-	0.1	-	0.1
Revised Forecast	$ 19.7	$ 1.3	$ 1.2	$ 1.2	$ 1.3	$ 1.3	$ 4.1

Power Supply Hydraulic Controls

Description:
Install an optimization system to run all 39 units at Kelsey, Kettle, Long Spruce, and Limestone at their most efficient gate opening. Install a Decision Support System (DSS) to provide accurate short-term Hydro scheduling (water resource management) and feedback information. Install required automation, remote control, and protective devices for unmanned operation.

Justification:
By increasing unit efficiency, the Corporation can reduce or delay the need for capital expenditures for new plant, increase export net revenues, improve financial strength, and protect the environment.

In-Service Date:
March 2020.

Revision:
Cost flow revision, and in-sevice date deferred 63 months from December 2014.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 16.0	$ 1.8	$ 0.9	$ 2.5	$ 2.4	$ 0.9	$ 1.0
Increase (Decrease)	-	1.3	1.0	(1.3)	(2.4)	(0.9)	4.6
Revised Forecast	$ 16.0	$ 3.1	$ 1.9	$ 1.2	$ -	$ -	$ 5.6

Slave Falls Rehabilitation

Description:
Perform major overhaul for all eight units at Slave Falls Generating Station, including spillway improvements/ replacements, excitation upgrades, and the addition of a Unit Control and Monitoring System (UCMS) Framework.

Justification:
Many safety, reliability, environmental, efficiency, operational & dam safety issues have been identified relating to the Slave Falls infrastructure. Extensive repairs, modifications and/or replacements will be required to ensure the serviceability of the plant and spillway infrastructure. Economics of this work may suggest that a new spillway be constructed to replace existing spill infrastructure. Current operating procedures include ice load reduction activites at the spilling structures to ensure structural stability. A dam safety concern has been identified with respect to the minimal remote spilling capability at Slave Falls.

In-Service Date:
December 2017.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 198.3	$ 13.7	$ 10.4	$ 8.9	$ 23.6	$ 29.9	$ 96.5
Increase (Decrease)	-	(0.7)	(6.4)	(7.8)	(7.3)	(18.1)	44.6
Revised Forecast	$ 198.3	$ 13.0	$ 4.0	$ 1.1	$ 16.3	$ 11.8	$ 141.1

Great Falls Unit 4 Overhaul

Description:
Major overhaul to generating Unit 4 including generator rewind, turbine re-runnering, new water passage embedded components, one 3-phase unit transformer, and modernization of components.

Justification:
The re-runnering and major overhaul will provide an opportunity to upgrade/modernize the unit while taking advantage of an already planned outage for the intake gates. The re-runnering will add both capacity and efficiency. The existing transformer is in poor condition and water passage components are starting to fail. The overhaul will increase reliability and extend the asset life by 40 to 50 years.

In-Service Date:
December 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 19.7	$ 4.1	$ 8.1	$ 5.4	$ -	$ -	$ -
Increase (Decrease)	-	(1.1)	(1.1)	2.4	-	-	-
Revised Forecast	$ 19.7	$ 3.0	$ 7.0	$ 7.8	$ -	$ -	$ -

Great Falls 115 kV Indoor Station Safety Improvements

Description:
Improve electrical safety clearance in the 115 kV switching gallery by replacing the air blast breakers with separate current transformers (CTs) with smaller dead tank SF_6 breakers with integral CTs, raise potential transformer (PT) equipment, install Lexan insulating panels to improve the separation between buses, improve grounding provisions, and add safety screens around disconnects.

Justification:
The indoor switching gallery has many instances of electrical clearances that are less than the absolute minimum limit of approach, and do not meet the minimum standard outlined in the Manitoba Hydro safety book.

In-Service Date:
April 2009.

Revision:
Cost flow revision, and in-service date advanced seven months from November 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 11.6	$ 0.9	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.7	-	-	-	-	-
Revised Forecast	$ 11.6	$ 1.6	$ -	$ -	$ -	$ -	$ -

Generation South Transformer Refurbish & Spares

Description:
Purchase a spare generator step-up transformer and refurbish the existing generator step-up transformers at Jenpeg GS; purchase a spare three phase generator step-up transformer at Pine Falls GS; refurbish ten generator step-up transformers at Grand Rapids GS; and purchase two 3-phase generator step-up transformers and install one in Bank 6 at Great Falls GS.

Justification:
To minimize the occurrence and duration of transformer-related forced outages, it is imperative that spare transformers are available.

In-Service Date:
March 2017.

Revision:
Cost flow revision, and in-service date deferred two years from March 2015.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 21.0	$ 2.9	$ 5.3	$ 4.5	$ 3.1	$ 2.6	$ 1.6
Increase (Decrease)	-	(2.9)	(3.8)	(1.4)	2.2	1.8	5.0
Revised Forecast	$ 21.0	$ -	$ 1.5	$ 3.1	$ 5.3	$ 4.4	$ 6.6

Water Licenses & Renewals

Description:
Conduct hydraulic studies, geotechnical assessments, property status and severance line determinations, mapping, license documentation, environmental reviews, and community informational sessions necessary to secure license finalization and/or renewals for the Corporation's hydraulic plants.

Justification:
All hydraulic generating facilities must be authorized under Water Power licenses and these licenses need to be clearly in force to significantly reduce risk exposure, maintain operating flexibility, maximize export revenues, and contribute to financial strength.

In-Service Date:
May 2016.

Revision:
Cost flow revision, and in-service date deferred two months from March 2016.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 40.8	$ 5.1	$ 5.6	$ 4.9	$ 4.8	$ 4.6	$ 9.5
Increase (Decrease)	-	(0.7)	0.4	1.1	0.9	1.3	(1.4)
Revised Forecast	$ 40.8	$ 4.4	$ 6.0	$ 6.0	$ 5.7	$ 5.9	$ 8.1

Generation South PCB Regulation Compliance

Description:
Replace equipment identified as containing polychlorinated biphenyl (PCB) content > 50 ppm at generation south generating stations.

Justification:
Required to comply with Federal legislation regarding the replacement of equipment in non-sensitive areas with PCB content > 50 ppm.

In-Service Date:
March 2015.

Revision:
Cost flow revision, and in-service date deferred three months from December 2014.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.7	$ 2.0	$ 1.6	$ 0.4	$ 0.4	$ 0.2	$ -
Increase (Decrease)	-	(1.8)	(1.3)	(0.3)	(0.3)	-	3.8
Revised Forecast	$ 4.7	$ 0.2	$ 0.3	$ 0.1	$ 0.1	$ 0.2	$ 3.8

Kettle Transformer Overhaul Program

Description:
Purchase two spare transformers, one for the Kettle GS and one for the Long Spruce/Limestone generating stations. Subsequent to receiving the new transformers, the remaining 12 step-up transformers will be overhauled.

Justification:
Kettle step-up transformers have been in operation for 37 years, with a life expectancy of between 30 and 50 years. During this time frame there have been more transformer winding failures at the Kettle GS than anywhere else in Manitoba Hydro.

In-Service Date:
April 2014.

Revision:
Cost flow revision, and in-service date advanced two years from April 2016.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 35.6	$ 3.3	$ 3.8	$ 4.6	$ 4.9	$ 5.7	$ 12.4
Increase (Decrease)	-	(1.7)	2.8	1.9	1.7	1.1	(5.0)
Revised Forecast	$ 35.6	$ 1.6	$ 6.6	$ 6.5	$ 6.6	$ 6.8	$ 7.4

Generation South Breaker Replacements

Description:
Remove the four existing 115 kV current transformers and breakers at McArthur Falls GS, and replace with new 115 kV breakers with internal current transformers, and replace the fourteen 115 kV breakers at the Pine Falls GS.

Justification:
The breakers at both stations require replacing as spare parts are no longer available. In addition, the breakers at both stations are PCB contaminated. Proposed federal PCB regulation currently states that all equipment with a concentration >50ppm must be removed from service by December 31, 2014.

In-Service Date:
October 2013.

Revision:
Cost flow revision, and in-service date deferred seven months from March 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.4	$ 2.5	$ 0.9	$ 2.8	$ 1.6	$ -	$ -
Increase (Decrease)	-	(0.9)	2.2	(0.6)	0.4	0.4	-
Revised Forecast	$ 9.4	$ 1.6	$ 3.1	$ 2.2	$ 2.0	$ 0.4	$ -

Seven Sisters Upgrades

Description:
Rewind and rehabilitate Seven Sisters Unit 5 to maintain station MW output and prevent a high probability stator in-service failure through a planned generator rewind outage. Replace and upgrade generator and transformer protection on units 1, 2, 3, 4 and 6 to a redundant multifunction system with breaker fail protection, transient fault recording, and metering replacement.

Justification:
Seven Sisters Unit 5 stator winding has been identified as a candidate for potential failure through electrical condition assessment. The stator condition has deteriorated such that normal operation now contributes to accelerating the stator failure. In addition, transmission line events (115 kV faults) have been identified which would cause generator damage for the station. The existing protection system is incapable of detecting and interrupting these specific events, and is of a similar vintage to the replaced Kelsey electro-mechanical system, but with a longer operating history. Original electro-mechanical relay manufacturers no longer exist and replacement parts are currently salvaged from other recently upgraded generating stations.

In-Service Date:
August 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.5	$ 3.5	$ 2.5	$ 1.2	$ 1.0	$ -	$ -
Increase (Decrease)	-	(1.7)	2.8	-	-	-	-
Revised Forecast	$ 9.5	$ 1.8	$ 5.3	$ 1.2	$ 1.0	$ -	$ -

Generation South Excitation Upgrades

Description:
Implement a generator excitation system replacement program to phase out unsupported and obsolete equipment at the Great Falls, Grand Rapids and McArthur Falls generating stations.

Justification:
Original excitation systems on the Winnipeg River have a frequent failure rate which has negative effects on export revenue. Spare parts for the excitation systems at these GSs are no longer available, and the salvage inventory from Seven Sisters GS and Laurie River GS are exhausted. The current systems cannot be tuned due to physical wear and have failing rotating exciter insulation systems, which will renderl the generators inoperable in the event of an exciter failure.

In-Service Date:
February 2019.

Revision:
Cost flow revision, and in-service date deferred 34 months from April 2016.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 18.3	$ -	$ 2.0	$ 3.2	$ 3.9	$ 3.3	$ 6.0
Increase (Decrease)	-	-	-	(2.2)	(2.8)	(1.6)	6.5
Revised Forecast	$ 18.3	$ -	$ 2.0	$ 1.0	$ 1.1	$ 1.7	$ 12.5

Brandon Unit 5 License Review

Description:
Renewal of Brandon Generating Station Unit 5 (Manitoba Environment Act license) is required for continuing operation. License renewal requires minor plant refurbishment. The timing and extent of additional future environmental regulatory changes is uncertain. The base case conservatively assumes that environmental controls must be installed. Should the need for additional controls be identified during the licensing process or subsequently thereafter, the economic viability of such controls will be assessed accordingly. Per the Manitoba Climate Change and Emissions Reductions Act (Bill 15), Manitoba Hydro must not use coal to generate power after December 31, 2009, except to support emergency operations.

Justification:
Unit 5 plays an important role in Manitoba Hydro's system, contributing economic generation and enhancing system reliability.

In-Service Date:
March 2012.

Revision:
Cost flow revision, and in-service date deferred one year from March 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 18.7	$ 6.2	$ 7.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(5.9)	(5.2)	11.1	-	-	-
Revised Forecast	$ 18.7	$ 0.3	$ 2.5	$ 11.1	$ -	$ -	$ -

Selkirk Enhancements

Description:
Perform environmental enhancements in accordance with the revised license terms and conditions approved by the Province of Manitoba on April 30, 2008. The approval was based on continuing operation of the once-through cooling system with modifications to the cooling water intake fish screen, lube oil cooling system and condenser re-tubing.

Justification:
Provides assurance that the station will be able to operate as planned with the addition of the cooling tower, and provides long-term southern system reliability benefits.

In-Service Date:
August 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 14.2	$ 4.9	$ 2.8	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.9	2.4	-	-	-	-
Revised Forecast	$ 14.2	$ 5.8	$ 5.2	$ -	$ -	$ -	$ -

Laurie River/CRD Communications and Annunciation Upgrades

Description:
Upgrade the communications infrastructure and replace the annunciation systems with Programmable Logic Controller (PLC) based Unit Control Monitoring Systems (UCMS) at Laurie River, Missi Falls and Notigi.

Justification:
Updated communications infrastructure and annunciation systems will provide more accurate water level information from the Churchill River Diversion allowing Manitoba Hydro to optimize water flows through the lower Nelson River Generating Stations. In addition, the maintenance costs will be reduced significantly with the implementation of the new system.

In-Service Date:
August 2012.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	4.8	0.2	3.5	-	1.1	-	-
Revised Forecast	$ 4.8	$ 0.2	$ 3.5	$ -	$ 1.1	$ -	$ -

Notigi Marine Vessel Replacement & Infrastructure Improvements

Description:
Replace the existing Notigi marine vessels with one self-propelled unit and upgrade the vessel tramway to prevent damaging vessels when removing them from the water.

Justification:
The marine vessels are over 30 years old and in need of numerous repairs and upgrades, including hull repairs which are very difficult to weld repair. In addition, changes in Canadian Coast Guard regulations will require stability tests, and it is expected that at least one of the vessels will not pass this test, and will be deemed unsuitable for operation.

In-Service Date:
June 2011.

Revision:
New Item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	2.6	-	1.3	1.3	-	-	-
Revised Forecast	$ 2.6	$ -	$ 1.3	$ 1.3	$ -	$ -	$ -

Fire Protection Projects - HVDC

Description:
The replacement of the existing Incipient Fire Detection (IFD) panels at all HVDC Stations with new Fenwal Fire Detection Systems, the replacement of the Radisson station building fire piping and fire pumps, and the installation of a fire water backup system at Henday Station.

Justification:
More than half of the existing IFD panels have failed. They are costly to maintain and parts are difficult to obtain. The backup fire protection does not meet the fire code. The Radisson fire piping and pumps are inadequate and have no water left to fight fire spread should a transformer fail and deluge be activated. The current Henday fire water backup system is inadequate and runs dry up to 30 minutes prior to the fire department's arrival at site. New tanks will ensure fire containment and prevent spreading until the fire department's arrival.

In-Service Date:
October 2012.

Revision:
Cost flow revision, and in-service date deferred 23 months from November 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.2	$ 2.5	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(2.0)	0.4	1.6	1.7	-	-
Revised Forecast	$ 5.2	$ 0.5	$ 0.4	$ 1.6	$ 1.7	$ -	$ -

Halon Replacement Project

Description:
Remove and replace the existing Halon fire protection systems with approved state-of-the-art alternative technologies such as water and gaseous based systems.

Justification:
Replacing the existing Halon fire protection systems with approved alternative technologies improves the HVDC, hydraulic, and diesel systems availability, minimizes the risk of extremely expensive outage and repair costs, and minimizes lost revenue. Halon replacement is becoming a mandatory requirement through Federal and Provincial environmental regulations and legislation. National Fire Protection Association (NFPA) Life Safety Code 101 requires the adequate provision of fire protection where, in addition to equipment, the human element is also involved.

In-Service Date:
March 2011.

Revision:
Cost flow revision, and in-service date deferred nine months from June 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 42.5	$ 19.2	$ 11.0	$ 0.4	$ -	$ -	$ -
Increase (Decrease)	-	(4.6)	2.1	8.7	-	-	-
Revised Forecast	$ 42.5	$ 14.6	$ 13.1	$ 9.1	$ -	$ -	$ -

Power Supply Fall Protection Program

Description:
Implement fall protection for Power Supply stations (excludes switchyards), including four diesel sites, in compliance with Provincial Regulation 189/85, under Workplace Safety and Health Act W210.

Justification:
Provincial regulation requires employers to establish fall protection systems for work performed where there is danger of falling more than 2.5 meters into unprotected operating machinery or in/onto hazardous substances and objects.

In-Service Date:
March 2009.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 13.5	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.2	-	-	-	-	-
Revised Forecast	$ 13.5	$ 0.2	$ -	$ -	$ -	$ -	$ -

Oil Containment – Power Supply

Description:
Modifications and/or additions are required to prevent and contain oil spills: 1) *southern and northern hydraulic generating stations*: install oil/ water separators, modify drainage systems, and upgrade sump, fuel storage facilities and dyking systems; 2) *converter stations*: install an oil containment system to collect and recover any oil spilled within the station and encapsulate oil filled transformers/smoothing reactors at the three HVDC stations to stop gasket leaks.

Justification:
Previous experience with oil spills requires the Corporation to demonstrate due diligence with respect to containing and minimizing the potential for any further occurances.

In-Service Date:
May 2017.

Revision:
Cost flow revision, and in-service date deferred one year from May 2016.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 19.1	$ 2.1	$ 0.5	$ 0.1	$ 0.1	$ 0.3	$ 0.3
Increase (Decrease)	-	(1.5)	(0.1)	0.9	0.4	-	1.0
Revised Forecast	$ 19.1	$ 0.6	$ 0.4	$ 1.0	$ 0.5	$ 0.3	$ 1.3

Grand Rapids Townsite House Renovations

Description:
Renovate 26 homes within the Grand Rapids Hybord Townsite, over a five year construction period.

Justification:
Providing adequate and modern housing is critical to attracting employees to fill job vacancies at Grand Rapids.

In-Service Date:
March 2015.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	5.2	0.1	0.4	0.9	1.2	1.3	1.3
Revised Forecast	$ 5.2	$ 0.1	$ 0.4	$ 0.9	$ 1.2	$ 1.3	$ 1.3

Grand Rapids Fish Hatchery

Description:
Rehabilitate the main hatchery building, the aeration building, the east and west pump houses, shops building, the exterior tanks and grounds, and replace the water meter.

Justification:
Provide for the benefits of environmental protection, employee safety and the modernization of obsolete and high maintenance assets.

In-Service Date:
March 2012.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	2.2	0.1	1.1	0.9	-	-	-
Revised Forecast	$ 2.2	$ 0.1	$ 1.1	$ 0.9	$ -	$ -	$ -

Generation Townsite Infrastructure

Description:
Gillam townsite: 1) interior and exterior retrofit of 66 corporate houses; 2) replace 40 doublewide trailers on basements with ready-to-move (RTM) homes and construct 32 new housing units over eight years; and 3) construct a new shopping centre (possibly in partnership).

Justification:
Gillam infrastructure evaluation lists the following as substandard: water quality, sewage treatment, water and sewer lines, asphalt repairs, recreation facility, trailer park improvements, and town office building renovations.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 52.1	$ 9.6	$ 5.3	$ 4.5	$ -	$ -	$ -
Increase (Decrease)	-	(1.8)	3.1	0.9	-	-	-
Revised Forecast	$ 52.1	$ 7.8	$ 8.4	$ 5.4	$ -	$ -	$ -

Site Remediation of Contaminated Corporate Facilities

Description:
Conduct geotechnical investigation of the various contaminated corporate facilities and remediate contaminated areas to environmentally acceptable limits.

Justification:
Environmental concerns and/or regulations require that corporate facilities be investigated and remediated to restore them to a level which permits unrestricted use of the site.

In-Service Date:
March 2013.

Revision:
Additional funds allocated for the clean-up of construction era debris and remediation of the South Bay Channel.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 30.9	$ 0.7	$ 0.5	$ 0.4	$ 0.3	$ -	$ -
Increase (Decrease)	3.8	1.6	0.7	0.7	0.8	0.2	-
Revised Forecast	$ 34.7	$ 2.3	$ 1.2	$ 1.1	$ 1.1	$ 0.2	$ -

High Voltage Test Facility

Description:
Build a new high voltage test facility at 1840 Chevrier Blvd., including a high voltage hall with rail access, supporting labs, shop, storage, and office and receiving space.

Justification:
This facility will enable Manitoba Hydro to adequately meet present industry standards (CAN/CSA C88.1-96, CAN3-C13-M83, CAN/CSA C225-00, and the recently adopted IEC 619361-1) for the testing of all bushings, instrument transformers and aerial lift devices, while improving the efficiency and safety of our insulation testing practices. Testing extra high voltage equipment to industry standards is the optimal way to avoid costly forced outages and life threatening and environmentally damaging failures, safeguard the reliability of our power supply, and enhance safety during live line work.

In-Service Date:
June 2011.

Revision:
Cost flow revision, and in-service date deferred three months from March 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 26.9	$ 15.9	$ 5.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(5.3)	7.8	-	-	-	-
Revised Forecast	$ 26.9	$ 10.6	$ 13.5	$ -	$ -	$ -	$ -

Power Supply Security Installations / Upgrades

Description:
Install, upgrade and enhance security systems, such as fencing, close circuit TV, and card access systems at Power Supply HVDC and generating stations. Implement of a comprehensive "Public Water Safety Around Dams" program, which is generally compliant with the draft Canadian Dam Association (CDA) 2007 technical bulletin for Public Safety and Security Around Dams.

Justification:
The scope of work is intended to raise the security standards of the stations to the levels outlined in the Security Readiness Report and to be compliant with NERC standards.

In-Service Date:
March 2016.

Revision:
Increased project scope to include the implementation of a comprehensive "Public Water Safety Around Dams" program. In-service date deferred 62 months from January 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 36.3	$ 21.4	$ 7.4	$ -	$ -	$ -	$ -
Increase (Decrease)	6.9	(11.7)	8.6	8.7	2.1	1.5	2.5
Revised Forecast	$ 43.2	$ 9.7	$ 16.0	$ 8.7	$ 2.1	$ 1.5	$ 2.5

Power Supply Sewer & Domestic Water System Install and Upgrade

Description:
Upgrade or replace domestic water and waste water systems at southern plants, northern plants, converter stations, and an extension of the water distribution main from Rosser including a line that will run past the Dorsey station.

Justification:
Ensure safety and compliance with legislation. The lack of filtration systems result in organic and other matter reacting with chlorine treatment to create possible carcinogenic substances.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 15.1	$ 4.1	$ 1.6	$ 1.3	$ -	$ -	$ -
Increase (Decrease)	-	3.2	1.8	(0.6)	-	-	-
Revised Forecast	$ 15.1	$ 7.3	$ 3.4	$ 0.7	$ -	$ -	$ -

Power Supply Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to provide safe, reliable, efficient power supply, and to replace plant facilities which are at the end of their useful life.

Justification:
Enhancements or rehabilitation to the power supply facilities will ensure a safe reliable and efficient source of energy.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 19.4	$ 19.8	$ 20.2	$ 20.6	$ 21.0	$ 135.0
Increase (Decrease)		(0.3)	(0.5)	(0.5)	(0.5)	(0.5)	(2.9)
Revised Forecast		$ 19.1	$ 19.3	$ 19.7	$ 20.1	$ 20.5	$ 132.1

TRANSMISSION:

Winnipeg - Brandon Transmission System Improvements

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Portage South as follows: *Transmission:* 230 kV line 70 km Dorsey - Portage South, 230 kV double circuit line with only one side strung. *Terminations:* Extend 230 kV facilities at Dorsey and Portage South. Install three 10 MVAR, 66 kV capacitor banks at Portage South. Extend the 66 kV facilities with the addition of one breaker, one selector switch, three circuit switchers, three disconnect switches, and associated equipment. Replace one existing 66 kV breaker. Install a fourth 54 MVAR 115 kV capacitor at Brandon GS to match the existing installation of capacitors, including the associated circuit switcher and disconnects. *Communications*: Integrate with existing facilities at Dorsey and Portage South stations.

Justification:
These facilities provide improvements required to supply Western Manitoba area future load growth.

In-Service Date:
October 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 40.0	$ 1.4	$ 1.6	$ 3.6	$ 3.7	$ 5.2	$ 22.0
Increase (Decrease)	-	1.7	-	(0.2)	(0.1)	(0.2)	(0.3)
Revised Forecast	$ 40.0	$ 3.1	$ 1.6	$ 3.4	$ 3.6	$ 5.0	$ 21.7

Transcona East 230-66 kV Station

Description:
Design and build a new 230-66 kV station adjacent to the existing Transcona station. Make provision for a second bank and ring buses.

Justification:
This station is required to supply increased load to East Winnipeg.

In-Service Date:
March 2013.

Revision:
Cost flow revision, and in-service date deferred one year from March 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 31.0	$ 8.6	$ 11.9	$ 9.4	$ -	$ -	$ -
Increase (Decrease)	-	(7.5)	(0.9)	3.8	5.1	-	-
Revised Forecast	$ 31.0	$ 1.1	$ 11.0	$ 13.2	$ 5.1	$ -	$ -

Neepawa 230-66 kV Station

Description:
Perform environmental assessments and route selection, design and construct terminal facilities to provide firm supply to Neepawa as follows: *Transmission:* Sectionalize 230 kV T/L D54C into Neepawa 230 kV station, creating Dorsey - Neepawa and Neepawa - Cornwallis 230 kV circuits. Build a 66 kV tie line between the new 66 kV terminal and the existing 115/66 kV station. *Terminations*: Establish Neepawa 230-66 kV station, including three 230 kV circuit breakers, a 50/66/83.3/93.3 MVA, 230-66 kV LTC transformer, six 66 kV circuit breakers and associated equipment. Adjust line protection equipment at Dorsey and Cornwallis 230 kV stations. Terminate two 230 kV transmission lines to Dorsey and Cornwallis. *Communications*: Integrate with existing facilities at Neepawa, Dorsey, and Cornwallis 230 kV stations. *System Control:* automate control, protection, equipment communications and software programming.

Justification:
These facilities provide transmission improvements required to supply Neepawa and related Western Region future load growth.

In-Service Date:
November 2012.

Revision:
Cost flow revision, and in-service date deferred 13 months from October 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 30.0	$ 5.8	$ 11.3	$ 12.8	$ -	$ -	$ -
Increase (Decrease)	-	(4.7)	2.8	(3.3)	5.1	-	-
Revised Forecast	$ 30.0	$ 1.1	$ 14.1	$ 9.5	$ 5.1	$ -	$ -

Pine Falls – Bloodvein 115 kV Transmission Line

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide 115 kV supply to Bloodvein station as follows: *Transmission*: Construct 115 kV line 80 km Pine Falls - L48 to L5 Tap near Manigotagan. Disconnect L48 from L5 at tap location and connect L48 to new line, converting L48 from 66 kV to 115 kV operation up to Bloodvein. *Terminations*: Extend 115 kV facilities at Pine Falls. Replace 66 KV transformers at Loon Straits with two 115-7.2 kV 500 kVA transformers, and modify station for 115 kV supply. Construct 115-66 kV station at Bloodvein, including two 115-66 kV 28 MVA transformers.

Justification:
This project provides increased transmission capacity required to supply Lake Winnipeg East area load increases.

In-Service Date:
October 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 34.1	$ -	$ 0.3	$ 0.9	$ 4.5	$ 21.2	$ 7.1
Increase (Decrease)	-	-	-	-	(0.1)	(0.6)	0.7
Revised Forecast	$ 34.1	$ -	$ 0.3	$ 0.9	$ 4.4	$ 20.6	$ 7.8

Transmission Line Re-Rating

Description:
Refurbish 292.6 km of double circuit and 120.7 km of single circuit 230 and 110 kV transmission lines in the Winnipeg area. Refurbish 16.9 km of double circuit and 49.2 km of single circuit 63.5 kV subtransmission lines in the Winnipeg area. Upgrade the Winnipeg River transmission line system to 100 °C. The refurbishment will correct insufficient ground clearances of line conductors. Using resagging, reconductoring, and tower extensions where required, the lines are to be upgraded to maintain safe ground clearances under thermal conductor loading. Estimate increase reflects costs for project scope increase to address all high risk, all medium risk and certain low risk spans of four 115 kV and five 230 kV transmission lines, in order to minimize public safety concerns associated with line sag violations.

Justification:
Lines in the Winnipeg area built pre-1970 cannot accommodate thermal conductor loading without violating required ground clearances. The refurbishment program will increase line to ground clearances to allow higher conductor temperatures under all potential heavy current line loads.

In-Service Date:
October 2012.

Revision:
Cost flow revision, and in-service date deferred 19 months from March 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 24.1	$ 0.4	$ 0.4	$ -	$ -	$ -	$ -
Increase (Decrease)	-	2.8	(0.4)	-	-	-	-
Revised Forecast	$ 24.1	$ 3.2	$ -	$ -	$ -	$ -	$ -

St Vital - Steinbach 230 kV Transmission

Description:
Build a new 230 kV line between St. Vital and Steinbach stations.

Justification:
Provides a 230 kV supply into the Steinbach area which will support load growth in south eastern Manitoba.

In-Service Date:
October 2020.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 32.2	$ -	$ -	$ -	$ -	$ -	$ 19.5
Increase (Decrease)	-	-	-	-	-	-	0.4
Revised Forecast	$ 32.2	$ -	$ -	$ -	$ -	$ -	$ 19.9

Rosser Station 230-115 kV Bank 3 Replacement

Description:
Replace Rosser bank 3 with a 150/200/250 MVA transformer similar to bank 1. Replace the 13.8 kV tertiary reactor supply circuit breaker and if necessary the bus. Upgrade protection as required.

Justification:
With continued load growth on the North Winnipeg and Selkirk 115 kV systems due to summer peak loads, low water conditions on the Winnipeg River and exports to Ontario; additional capacity will be required. In addition, this replacement will prevent equipment overloads in the event of a failure to bank 1 at Rosser station, and maintain export power.

In-Service Date:
March 2010.

Revision:
Cost flow revision, and in-service date deferred nine months from June 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.8	$ 2.4	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.2	-	-	-	-	-
Revised Forecast	$ 5.8	$ 2.6	$ -	$ -	$ -	$ -	$ -

Rosser - Inkster 115 kV Transmission

Description:
Build a second 8.2 km 115 kV line between Rosser and Inkster stations.

Justification:
A second line between Rosser and Inkster stations will alleviate contingency overloading issues on the St. James to Tylehurst 115 kV underground cable, in the event of the failure of the existing Rosser – Inkster circuit.

In-Service Date:
October 2010.

Revision:
Cost flow revision, and in-service date deferred seven months from March 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.1	$ 2.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	1.1	1.4	-	-	-	-
Revised Forecast	$ 5.1	$ 3.3	$ 1.4	$ -	$ -	$ -	$ -

Transcona Station 66 kV Breaker Replacement

Description:
Replace nine 66 kV breakers and one disconnect at 115/66 kV Transcona station.

Justification:
The breakers are being replaced based on fault levels that exceed 95% of the breaker interrupting rating. These breakers are old (34-37 years), were made by a company that is no longer in business (Canadian General Electric) and cannot be certified for a higher interrupting rating. Failure of one of these lines or bank breakers will cause a transformer or line outage and lost supply power to customers between 7.3 MW and 42.8 MW, which would affect more than 10 000 customers.

In-Service Date:
February 2014.

Revision:
Cost flow revision, and in-service date deferred 15 months from November 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 6.0	$ 1.0	$ 2.9	$ 1.7	$ 0.3	$ -	$ -
Increase (Decrease)	-	(1.0)	0.7	0.1	0.3	-	-
Revised Forecast	$ 6.0	$ -	$ 3.6	$ 1.8	$ 0.6	$ -	$ -

Transcona & Ridgeway Stations 66 kV Bus Upgrades

Description:
Perform the following upgrades to the 230-66 kV Ridgeway station: upgrade section of the existing 66 kV ring bus between bank 1 and liner 93 to 2500 AMPS of summer rating, replace R24 breaker and associated selector switches, upgrade section of the existing 66 kV ring bus between bank 2 and liner 95 to 2500 AMPS of summer rating, replace R28 breaker and associated selector switches, and make necessary protection and communication system changes.

Justification:
A study was undertaken to identify overloads of sections of the 66 kV ring bus at 230-66 kV Ridgeway station. Loading on the 66 kV ring bus at Ridgeway is limited by ring bus sections that are rated only 948A. In 2009, single contingencies caused unacceptable overloads on breakers R24 and R28 (107.9%), and sections of the Ridgeway ring buses (136.6%).

In-Service Date:
October 2009.

Revision:
Cost flow revision, and in-service date advanced seven months from May 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 2.8	$ 1.5	$ 0.3	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.2	0.4	-	-	-	-
Revised Forecast	$ 2.8	$ 1.7	$ 0.7	$ -	$ -	$ -	$ -

Dorsey 500 kV R502 Breaker Replacement

Description:
Replace the Dorsey 500 kV R502 breaker with a new 500 kV SF6 filled breaker complete with pre-insertion resistors, remove the GE ATB-80 air blast circuit breaker, remove the 3000 PSI compressor system, and purchase one spare breaker pole.

Justification:
The R502 breaker is now operating beyond its expected useful life cycle, without an option to rebuild. Two 3000 PSI compressors work simultaneously to supply the breaker with compressed air, and are now at the end of their useful lives and need to be replaced. Without replacement, breaker failure could result in cleanup, outage and damage costs that would exceed $1.0 million. Additionally, should a second breaker fail at the same time that a breaker was being replaced; there would be a significant reduction in export power.

In-Service Date:
October 2009.

Revision:
Cost flow revision, and in-service date deferred six months from April 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 2.6	$ 0.4	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	1.9	0.2	-	-	-	-
Revised Forecast	$ 2.6	$ 2.3	$ 0.2	$ -	$ -	$ -	$ -

13.2kV Shunt Reactor Replacements

Description:
Purchase and install fifteen 13.2kV, 20MVA oil-type shunt reactors to replace all of the Ferranti Packard reactors currently in the system.

Justification:
Ferranti Packard reactors are installed at six stations throughout Manitoba (Cornwallis, Rosser, Raven Lake, Overflow River, Mystery Lake and LaVerendrye). These reactors are 45 years old and now 15 years past their estimated useful life. There are currently no replacements on hand to replace a failed reactor, which would affect system operation.

In-Service Date:
October 2018.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	33.0	-	-	4.1	4.2	4.3	20.4
Revised Forecast	$ 33.0	$ -	$ -	$ 4.1	$ 4.2	$ 4.3	$ 20.4

Birtle South - Rossburn 66 kV Line

Description:
Build a new 66 kV line from the 66 kV Birtle Queen station to Rossburn station. The new line will be terminated at Birtle South station with a new 66 kV breaker.

Justification:
This new transmission line will increase reliability for the Birtle South 230-66 kV station area by reducing the occurrence of line outages. In addition, voltage levels on the Birtle South 66 kV system will become adequate to maintain acceptable voltage levels at regulated distribution stations.

In-Service Date:
October 2015.

Revision:
No change.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.9	$ -	$ -	$ -	$ -	$ 0.1	$ 4.8
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 4.9	$ -	$ -	$ -	$ -	$ 0.1	$ 4.8

Stanley Station 230-66 kV Transformer Addition

Description:
Purchase and install a 230-66 kV transformer and associated equipment for the Stanley Station, install transformer protection equipment, relocate 230 kV towers for line S60L outside of the station to allow for the desired 230 kV bus ring configuration, and re-terminate three lines (S60L, Line3 and Line 51).

Justification:
The absence of firm transformation capacity at Stanley station requires the station's load to be transferred to St. Leon, Portage South, and Morden Corner stations. This load transfer creates unacceptably low sub-transmission and distribution voltages, which negatively impacts customer equipment and automated processes in Morden, Winkler and the surrounding areas. This project is high risk as more than 15,000 customers could be affected.

In-Service Date:
October 2015.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 21.1	$ -	$ -	$ -	$ 1.9	$ 8.4	$ 10.8
Increase (Decrease)	-	-	-	-	(0.1)	(0.3)	0.3
Revised Forecast	$ 21.1	$ -	$ -	$ -	$ 1.8	$ 8.1	$ 11.1

Stanley Station 230-66 kV Hot Standby Installation

Description:
Install an 84/112/140 MVA, 230-66 kV transformer and associated equipment at Stanley station as a hot standby, along with transformer protection equipment.

Justification:
The low sub-transmission and distribution voltages created by transferring Stanley station load will negatively impact customer equipment and their automated processes in the towns of Morden and Winkler and the surrounding areas, potentially affecting customer service to more than 15 000 customers. Deferral will place quality of supply to local customers at risk. Customer equipment and product will be damaged, and automated (voltage sensitive) processes will be halted. In addition, one of Manitoba Hydro's major customers will be adding significant new load in 2009, also necessitating this installation.

In-Service Date:
October 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 6.2	$ 3.8	$ 0.8	$ 0.1	$ -	$ -	$ -
Increase (Decrease)	-	1.1	0.4	(0.1)	-	-	-
Revised Forecast	$ 6.2	$ 4.9	$ 1.2	$ -	$ -	$ -	$ -

Ashern Station 230 kV Shunt Reactor Replacement

Description:
Purchase a 230 kV, 50MVAR shunt reactor to replace the existing Ashern station reactor.

Justification:
The Ashern reactor was installed in 1972 and has now reached the end of useful life, and is now considered a risk to the area's transmission and distribution system. When this reactor is down, one unit at Grand Rapids has to be switched from generator to synchronous condenser for the duration of the outage. Additionally, Manitoba Hydro currently does not have a system spare reactor that will support the 230 kV class.

In-Service Date:
December 2012.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	2.7	-	-	-	2.7	-	-
Revised Forecast	$ 2.7	$ -	$ -	$ -	$ 2.7	$ -	$ -

Tadoule Lake DGS Diesel Tank Farm Upgrade

Description:
Design and install four 500 000 litre single wall above ground vertical diesel fuel tanks and associated piping, spill containment dyke modifications to accommodate the new tanks, and a fuel tank level monitoring system. Project also includes salvaging the existing 30 above ground horizontal diesel fuel tanks.

Justification:
The current permit to operate a petroleum storage facility at Tadoule Lake will expire on December 31, 2010. Of the 30 tanks, 11 are not built to Underwriters Laboratories of Canada S601 standards, and must be withdrawn from service by December 31, 2010. Additionally, the remaining 19 tanks require replacement by December 31, 2012, to be compliant with Canadian Council of Ministers of the Environment PN 1326.

In-Service Date:
December 2010.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	1.1	0.1	0.1	-	-	-	-
Revised Forecast	$ 1.1	$ 0.1	$ 0.1	$ -	$ -	$ -	$ -

Interlake Digital Microwave Replacement

Description:
Build a modern communications system between the Dorsey transmission station and the Lower Nelson River. The existing Interlake Digital Microwave system is approximately 30 years old, is one of two communications systems used to operate the DC power system, and requires replacement by a modern, highly dependable communications system.

Justification:
A replacement communications system is required for dependable communications to operate the DC power system, and to provide for the continued supply of reliable power to Manitoba Hydro's domestic and export customers.

In-Service Date:
October 2010.

Revision:
Cost flow revision, and in-service date deferred ten months from December 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 19.7	$ 3.9	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.4)	0.4	-	-	-	-
Revised Forecast	$ 19.7	$ 3.5	$ 0.4	$ -	$ -	$ -	$ -

Communication System - Southern MB (Great Plains)

Description:
Replace part of the Great Plains microwave system with an optical fiber cable communication system. The route includes Letellier TS, Stanley TS and Crocus Plains TS; as well as the existing Great Plains microwave stations of St. Leon TS and Glenboro TS. The system will carry the Reston TS and Virden TS traffic as far as the Brandon South microwave site.

Justification:
Required to provide continuous supply of reliable power to all of Manitoba Hydro's customers.

In-Service Date:
November 2009.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 21.9	$ 1.6	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.8	-	-	-	-	-
Revised Forecast	$ 21.9	$ 2.4	$ -	$ -	$ -	$ -	$ -

Communications Upgrade Winnipeg Area

Description:
Replace part of the Winnipeg area system with optical fiber cable and electronics, in order to provide increased communication capacity to carry rural power system and administrative data traffic from the Winnipeg perimeter terminal stations to the Dovercourt system control centre and to 820 Taylor; as well as to carry increased local Winnipeg area traffic between stations.

Justification:
This communication capacity is required to carry modern high speed data traffic on Manitoba Hydro's Wide Area Network (WAN), as required by modern corporate operations. This project will provide more secure communications and replace cable that is nearing the end of useful life.

In-Service Date:
March 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 7.4	$ 0.8	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.1)	-	-	-	-	-
Revised Forecast	$ 7.4	$ 0.7	$ -	$ -	$ -	$ -	$ -

Pilot Wire Replacement

Description:
Replace existing Pilot Wire protection schemes to provide redundancy to major industrial and residential customers that are either running without protection or must be subject to an outage because of repairs on Pilot Wire schemes that generally have no alternative routes.

Justification:
The current equipment is no longer manufactured or supported by vendors.

In-Service Date:
October 2009.

Revision:
Cost flow revision, and in-service date advanced 22 months from August 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.6	$ 0.4	$ 1.1	$ 0.9	$ -	$ -	$ -
Increase (Decrease)	-	0.9	0.3	(0.9)	-	-	-
Revised Forecast	$ 9.6	$ 1.3	$ 1.4	$ -	$ -	$ -	$ -

Transmission Line Protection & Teleprotection Replacement

Description:
Replace obsolete protection and associated communications equipment for 30 transmission lines with phase comparison protection schemes. The new protection will provide "A" and "B" redundant relay schemes, and all communication signals will provide "A" and "B" teleprotection units and shall have redundant channels.

Justification:
The difficulty experienced in repairing and restoring existing failed teleprotection equipment. There is concern that the remaining spare parts, which are the same vintage as the failing in-service equipment, may not be functional, and cannot be repaired. Loss of the teleprotection equipment means the loss of the high-speed primary protection for these important lines. The backup protection for these lines has been identified as too slow by system performance. The availability of these lines has a direct impact on how much power Manitoba Hydro is able to import or export.

In-Service Date:
August 2014.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 21.1	$ 2.0	$ 5.7	$ 6.4	$ 2.4	$ 1.2	$ 0.3
Increase (Decrease)	-	(0.6)	0.4	(0.3)	(0.1)	(0.1)	0.6
Revised Forecast	$ 21.1	$ 1.4	$ 6.1	$ 6.1	$ 2.3	$ 1.1	$ 0.9

Winnipeg Central Protection Wireline Replacement

Description:
Migrate the former Winnipeg Hydro area communications from metallic wireline to optical fibre cables.

Justification:
Wireline communications cables are unsuitable for most modern power system control and protection equipment applications; and therefore, retention of such cables has little future value. This project also minimizes or eliminates the need for hazardous work adjacent to high voltage cables.

In-Service Date:
September 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.3	$ 2.4	$ 1.2	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.1	(0.6)	-	-	-	-
Revised Forecast	$ 9.3	$ 2.5	$ 0.6	$ -	$ -	$ -	$ -

Mobile Radio System Modernization

Description:
Replace the VHF mobile radio system with a modern digital system of increased capability.

Justification:
Manitoba Hydro requires a very dependable mobile radio communication system under its own control and independent of any public system, as public systems cannot guarantee service under adverse conditions and are affected by peak public traffic which can overload the system.

In-Service Date:
December 2013.

Revision:
Cost flow revision, and in-service date deferred 21 months from March 2012.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 30.7	$ 0.5	$ 13.9	$ 16.2	$ -	$ -	$ -
Increase (Decrease)	-	(0.2)	(11.4)	(7.0)	10.6	8.0	-
Revised Forecast	$ 30.7	$ 0.3	$ 2.5	$ 9.2	$ 10.6	$ 8.0	$ -

Cyber Security Systems

Description:
Install or upgrade security and network systems for secure remote access, industrial data network installations, and compliance to NERC standards CIP-002-1 to CIP-009-1.

Justification:
The Cyber Security Standards CIP-002-1 are part of NERC reliability standards, which Manitoba Hydro is obligated to comply with, or be subject to penalties or sanctions as per contractual arrangements with MISO.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 10.1	$ 2.8	$ 0.6	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.8	(0.2)	-	-	-	-
Revised Forecast	$ 10.1	$ 3.6	$ 0.4	$ -	$ -	$ -	$ -

Site Remediation

Description:
Conduct geotechnical investigations and remediate any hydrocarbon contaminated sites at the remaining former isolated diesel generating stations in Little Grand Rapids, Manigotogan, The Pas, Moose Lake, Norway House, Wanless, Cormorant, Cranberry Portage, Shamattawa, Berens River, and Churchill. Conduct geotechnical investigation for the various contaminated corporate facilities, prepare a report with cleanup recommendations, remediate any contaminated areas identified, and issue a final report confirming the facility and surrounding area were remediated and all areas of the work were left in accordance with applicable environmental regulations.

Justification:
Due to concerns, and in compliance with current environmental regulations and standards applicable to unrestricted use of abandoned former diesel sites, the sites must be investigated, remediated, and restored to equivalency of the surrounding area.

In-Service Date:
March 2012.

Revision:
Cost flow revision, and in-service date deferred one year from March 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 13.3	$ 3.1	$ 2.0	$ 0.3	$ -	$ -	$ -
Increase (Decrease)	-	(1.8)	1.8	0.8	-	-	-
Revised Forecast	$ 13.3	$ 1.3	$ 3.8	$ 1.1	$ -	$ -	$ -

Oil Containment

Description:
Design and construct oil containment systems to collect and recover any oil spilled within the system.

Justification:
Minimize environmental impact of oil spills.

In-Service Date:
March 2011.

Revision:
Cost flow revision, and in-service date deferred one year from March 2010.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 7.4	$ 1.3	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.4)	0.5	-	-	-	-
Revised Forecast	$ 7.4	$ 0.9	$ 0.5	$ -	$ -	$ -	$ -

Station Battery Bank Capacity & System Reliability Increase

Description:
Conduct individual studies, replace and/or upgrade battery bank capacity and chargers in 156 transmission and distribution stations (over the next ten years) and seven stand-alone communications sites to meet the North American Electric Reliability Council's (NERC) battery bank sizing criteria. Includes AC service upgrades and building extension costs required to complete this project.

Justification:
Present battery banks were designed to an eight hour standard (normal DC loads), and there are concerns many may no longer meet the standard, due to additional DC loads and age related deterioration. Current corporate simulations indicate that system restoration will be inhibited if a black start situation should occur. NERC's requirements are to have a workable system restoration plan, with 12 hours capacity, dual battery systems and multiple chargers where practical, or without a restoration plan capacity for 16 hours duration. This project provides the battery bank systems for a workable system restoration plan into the future, and offers a coordinated means of changing the banks as they reach their end-of-life.

In-Service Date:
March 2015.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 46.5	$ 6.9	$ 7.0	$ 6.7	$ 6.7	$ 3.9	$ 3.6
Increase (Decrease)	-	(1.6)	(2.3)	(0.3)	(0.3)	2.7	2.7
Revised Forecast	$ 46.5	$ 5.3	$ 4.7	$ 6.4	$ 6.4	$ 6.6	$ 6.3

Red River Floodway Expansion Project

Description:
Complete communications, distribution, and transmission utility crossing work required along the Red River Floodway to accommodate the Manitoba Floodway Authority's floodway expansion. The project budget of $1.8 million represents 50% of the total estimated costs, with the other 50% to be received in contributions from the Manitoba Floodway Authority.

Justification:
Cost sharing in accordance with the agreement with the Province of Manitoba, which applies to all construction costs including: planning, design, project management, and any other associated costs required to complete the changes required to electricity and supporting communication equipment.

In-Service Date:
December 2009.

Revision:
Cost flow revision, and in-service date deferred 16 months from August 2008.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 1.8	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.3	-	-	-	-	-
Revised Forecast	$ 1.8	$ 0.3	$ -	$ -	$ -	$ -	$ -

Waverley Service Centre Oil Tank Farm Replacement

Description:
Replacement of all remaining single wall oil tanks at the Waverley Service Centre Oil Tank Farm.

Justification:
The tanks at this tank farm have reached their end of life and must be removed from service to ensure compliance with all environmental regulations. The tanks cannot be repaired due to the standard imposed by the Province of Manitoba. Failure to replace the tanks will significantly restrict the ability to provide clean processed oil for maintenance requirements.

In-Service Date:
November 2013.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	3.0	0.5	1.0	0.6	0.4	0.5	-
Revised Forecast	$ 3.0	$ 0.5	$ 1.0	$ 0.6	$ 0.4	$ 0.5	$ -

Transmission Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. The majority of projects consist of additions, improvements and maintenance of transmission lines; replacement, development and upgrades to communication systems; additions and replacement of field maintenance equipment; as well as station upgrades.

Justification:
This program ensures the reliability of transmission with respect to load, outages, and import/export requirements; as well as addresses safety issues and provides the necessary support for the operation and maintenance of the transmission system.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 30.1	$ 30.7	$ 31.4	$ 32.0	$ 32.6	$ 210.0
Increase (Decrease)		(0.5)	(0.7)	(0.8)	(0.8)	(0.8)	(5.4)
Revised Forecast		$ 29.6	$ 30.0	$ 30.6	$ 31.2	$ 31.8	$ 204.6

CUSTOMER SERVICE & DISTRIBUTION:

Winnipeg Distribution Infrastructure Requirements

Description:
Complete assessment and emergency replacement as required of distribution underground equipment in the City of Winnipeg, including plant previously associated with Winnipeg Hydro.

Justification:
As the Underground Assessment (UGA) project progresses throughout Winnipeg, the number of failures caused by transformers has decreased. Other benefits of the UGA project include: decreased potential for employee accidents, decreased potential for public contact, extending transformer life, decreased outage duration, and increased customer satisfaction.

In-Service Date:
March 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 14.9	$ 1.8	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.1)	-	-	-	-	-
Revised Forecast	$ 14.9	$ 1.7	$ -	$ -	$ -	$ -	$ -

Defective RINJ Cable Replacement

Description:
Replace approximately 62,500 metres of underground distribution 5kV and 15kV copper rubber insulated neoprene jacketed (RINJ) concentric neutral cable (also known as or ”Red Jacket” cable) installed in the Winnpeg area between 1955 and 1965.

Justification:
RINJ underground cable installed between 1955 and 1965 failed at a rate of 9.6 failures per 100 kilometers, which was three times higher than the failure rate at which cable replacement is recommended by the CEA. Replacement of the cable reduces the number of underground cable failures and the negative impacts on customer reliability.

In-Service Date:
March 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 8.7	$ 1.1	$ 1.0	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.6)	1.6	-	-	-	-
Revised Forecast	$ 8.7	$ 0.5	$ 2.6	$ -	$ -	$ -	$ -

Brereton Lake Station Area

Description:
Build a new 124-12/25 kV steel station complete with two 7.5/10 MVA 124-12/25 kV LTC transformers and two 560A WVE 12 kV OCRs; 0.5 km 266.8 MCM ACSR single circuit two 124 kV line taps (consisting of steel tap-off and dead end structures) between line SK1 and the new Brereton Lake Station; and two feeder exits from the new Station to PR307. Convert 33 kV line 29 and underbuilt circuit to be operated at 12 kV. Salvage 33 kV line 29 from Rennie to Elma Tap and convert 8 km to 7.2 kV single phase.

Justification:
The existing 33 kV line from SW 293 to White Lake Station, Rennie Station and SW 1810 is at the end of its useful life. In addition, there are deficiencies associated with White Lake and Rennie stations. A new station complete with a rebuilt distribution system will provide more acceptable customer service reliability, and fewer disruptions to Ontario Hydro.

In-Service Date:
March 2010.

Revision:
Cost flow revision, and in-service date deferred 11 months from April 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 9.0	$ 0.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.1	-	-	-	-	-
Revised Forecast	$ 9.0	$ 0.3	$ -	$ -	$ -	$ -	$ -

Stony Mountain New 115 - 12 kV Station

Description:
Build a new Stony Mountain Station, and 1.5 miles of line to supply Bristol. Salvage existing Stony Mountain and Rockwood Stations, 33 kV lines 15 and 35, and 33 kV breakers 150 & 350 at Parkdale Station.

Justification:
The station equipment and supply lines are in a deteriorated condition and must be replaced. The 115-66-33 kV transformers that supply these stations from Parkdale are over 50 years old and reaching the end of their life expectancy. Load forecasts indicate Stony Mountain will also require a capacity increase and the only other 33 kV feed from Parkdale Station, Garson Station will require 115 kV supply by 2013. It is not economically viable to maintain a 33 kV source to only supply Stony Mountain and Rockwood Stations.

In-Service Date:
October 2009.

Revision:
Cost flow revision, and in-service date deferred seven months from March 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 5.0	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.7	-	-	-	-	-
Revised Forecast	$ 5.0	$ 0.7	$ -	$ -	$ -	$ -	$ -

Rover Substation Replace 4 kV Switchgear

Description:
Remove existing 4 kV switchgear and supervisory protection equipment and replace with new equipment capable of withstanding fault levels at this site. Install a current limiting reactor. Modify one feeder and relocate two others. Build a new substation building, replace three 66-4 kV transformer banks, extend the distribution ductline system and feeders to the new building, salvage the carpenter shop building, and the 4 kV building and its transformer banks.

Justification:
This equipment has been in-service since 1950 and its safe operation requires inefficient procedures and fault levels exceed its rating. Protective relaying, local control and metering functions are provided via electro-mechanical relays, manual switches, and analog meters located in a separate building, and provide decreasing reliability due to mechanical deterioration. During removal of the existing concrete surfacing (after removal of the first section of switchgear), it was determined that the floor could not withstand the stresses and no further floor repair can be undertaken.

In-Service Date:
November 2011.

Revision:
Cost flow revision, and in-service date deferred two months from September 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 12.7	$ 5.9	$ 1.1	$ 0.4	$ -	$ -	$ -
Increase (Decrease)	-	(5.5)	2.2	3.5	-	-	-
Revised Forecast	$ 12.7	$ 0.4	$ 3.3	$ 3.9	$ -	$ -	$ -

Martin New Outdoor Station

Description:
Install a new 3 bank outdoor station complete with 18 feeder positions and protection to replace the existing Martin station.

Justification:
Martin station is a 50 year old, two bank 12.47/4.16 kV station that has exceeded firm capacity. It is supplied from Rover station which is also being upgraded. Neither bank can be relied on as backup for the other, and there is no mobile backup available or external tie to neighbouring stations. Without improvements, 7,500 customers including residential, apartment blocks, heavy industry, and commercial businesses could be without power for an unacceptable period (48 hours minimum) in the event of an emergency, such as a transformer failure at Rover.

In-Service Date:
March 2012.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 28.2	$ 12.6	$ 9.0	$ 5.4	$ -	$ -	$ -
Increase (Decrease)	-	(11.6)	5.5	3.7	2.4	-	-
Revised Forecast	$ 28.2	$ 1.0	$ 14.5	$ 9.1	$ 2.4	$ -	$ -

Frobisher Station Upgrade

Description:
Replace both 7.5/10 MVA transformer banks with 18/24/30 MVA banks complete with 66 kV and 12.47 kV breakers, including eight new 12 kV feeder positions and two 4.5 MVAR capacitor banks. Upgrade six existing feeder automatic circuit re-closers (ACRs). Salvage banks 1 and 2 - 7.5/10 MVA transformers. Construct a new building, install a Remote Terminal Unit (RTU), communications, security system and fire protection.

Justification:
Two fully utilized 12 kV stations serving the south St Vital area were loaded to a combined 8.1 MVA over firm capacity in the summer of 2003. Load has grown an average of 2.25 MVA per year for the last ten years, and is projected to grow another 46.3 MVA over the next 16 years. Land acquisition problems prevented building a new station north of the perimeter highway.

In-Service Date:
March 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 14.4	$ 2.9	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	1.5	-	-	-	-	-
Revised Forecast	$ 14.4	$ 4.4	$ -	$ -	$ -	$ -	$ -

Burrows New 66 kV-12 kV Station

Description:
Build a new two bank 66 kV-12 kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations.

Justification:
Most of the equipment in this part of Winnipeg has been in service for 75 years. Alfred Station (which supplies Charles Station) lacks access to a satisfactory alternate supply in the event of a 12 kV interruption out of Rover Station. Remedial action was recommended for both stations in the Due Diligence Report. It indicated the 4 kV switchgear lineups at Alfred and Charles Stations lack arc-resistance and at Alfred Station are sometimes underrated for the available fault current during normal operating conditions. It also had concerns that neither station has an appropriate battery room, all station transformers have patched leaks, they contain asbestos materials, and that spare parts are in short supply.

In-Service Date:
March 2012.

Revision:
Cost flow revision, and in-service date deferred three months from December 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 28.6	$ 10.7	$ 10.2	$ 2.4	$ -	$ -	$ -
Increase (Decrease)	-	(1.6)	2.0	2.6	-	-	-
Revised Forecast	$ 28.6	$ 9.1	$ 12.2	$ 5.0	$ -	$ -	$ -

Winnipeg Central District Oil Switch Project

Description:
Remove the remaining 26 oil switches located in various manhole sites throughout Winnipeg Central District. Install pad-mount switchgear and/or pad-mount transformers, and reroute existing primary feeder and customer service cables as required.

Justification:
The oil switches are corroding and are not rated for the maximum available fault current on the system. If a failure occurs or the oil must be replaced, a lengthy shutdown will be required. Replacement will alleviate the risks associated with switching primary feeders in confined spaces. Pad-mount equipment allows adequate clearances and efficiency for switching, maintaining, and upgrading for future customer load additions.

In-Service Date:
November 2009.

Revision:
Cost flow revision, and in-service date deferred five months from June 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 7.1	$ 0.5	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	1.3	-	-	-	-	-
Revised Forecast	$ 7.1	$ 1.8	$ -	$ -	$ -	$ -	$ -

William New 66 kV-12 kV Station

Description:
Build a new two bank 66-12 kV indoor station, on Manitoba Hydro owned property, with protection and communication capability to the Central District Control Centre (CDCC) and the System Control Centre (SCC) for ten feeder positions. Costs associated with the potential installation of new 12 kV feeders to the new William Station are not included.

Justification:
This project will allow for load transfers from King station, which will alleviate overloading as a result of operating limits imposed by cooling problems. Load transfers from Sherbrook station will allow for redundant feeds from different stations to supply critical services reducing the implication of a contingency equipment failure. Improvements in service reliability and accommodation for future distribution automation can be realized from new equipment. Manitoba Hydro already owns land at the south east corner of William Avenue and Tecumseh Street for a new station.

In-Service Date:
October 2012.

Revision:
Cost flow revision, and in-service date deferred ten months from December 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 10.3	$ 2.8	$ 3.9	$ 3.3	$ -	$ -	$ -
Increase (Decrease)	-	(2.3)	(0.3)	(0.2)	2.9	-	-
Revised Forecast	$ 10.3	$ 0.5	$ 3.6	$ 3.1	$ 2.9	$ -	$ -

Waverley West Sub Division Supply - Stage 1

Description:
Install 20MVA capacity complete with pad mounted voltage regulators, 24 kV-2400 kVAR capacitor banks, S&C automated switching cubicles and fibre optic communication link.

Justification:
Waverley West subdivision is a new development in an area predominantly supplied by 12 and 24 kV feeders. The 12 kV feeders cannot support more load. The nearest viable 24 kV feeder does not allow standard distribution equipment to be used due to high available fault currents. In addition, by using the 24 kV feeders, reliability to existing customers is reduced. This project is required to ensure the Waverley West subdivision customers have reliable service.

In-Service Date:
December 2009.

Revision:
Cost flow revision, and in-service date deferred two months from October 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 6.5	$ 1.4	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	3.0	-	-	-	-	-
Revised Forecast	$ 6.5	$ 4.4	$ -	$ -	$ -	$ -	$ -

St. James 24 kV System Refurbishment

Description:
Terminate a new 24 kV Feeder (J54) at the St. James station to supply the Winnipeg Airport Authority load expansion. Install a gang operated switch between feeders J25 and J54 at the Ferry Road and Ness Avenue stations, and transfer 3.7 MVA of load from J25 to J54. Convert Berry station BY612, 4 kV customers to 24 kV along Ferry Road. Build a new 115-24 kV St. James Station, new and upgraded feeders, and conversion of St. James, Ness, Berry and King Edward station feeders from 4 kV to 24 kV.

Justification:
This project is required to ensure firm supply and a reliable system in the St. James area, and to ensure the Winnipeg Airport Authority continues to experience reliable service following a planned load expansion at the facility.

In-Service Date:
March 2013.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 65.9	$ 19.1	$ 11.1	$ 22.5	$ 12.5	$ -	$ -
Increase (Decrease)	-	(17.8)	3.0	9.1	6.4	-	-
Revised Forecast	$ 65.9	$ 1.3	$ 14.1	$ 31.6	$ 18.9	$ -	$ -

Shoal Lake New 33-12.47 kV DSC

Description:
Build a two bank Distribution Supply Centre (DSC) and rebuild and convert the town distribution system.

Justification:
The existing station is 48 years old and requires re-building. The distribution system has encountered problems with voltage drops. This project represents the least cost alternative for the restoration of reliable, quality service in the foreseeable future.

In-Service Date:
September 2009.

Revision:
No change.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 3.6	$ 3.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 3.6	$ 3.2	$ -	$ -	$ -	$ -	$ -

York Station

Description:
Add a transformer bank and switchgear for nine feeder positions.

Justification:
Increasing capacity at York station alleviates loading problems at King station and interim relief at Sherbrook, and provides for future new loads that cannot be adequately supplied by existing King, Edmonton, and York capacity.

In-Service Date:
September 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.0	$ 1.1	$ 2.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.9	(0.9)	0.1	-	-	-
Revised Forecast	$ 4.0	$ 2.0	$ 1.8	$ 0.1	$ -	$ -	$ -

Cromer Station Capacity and Reston RE12-4 25 kV Conversion

Description:
Convert the westerly portion of Reston Feeder RE12-4 from 12 kV to 25 kV by November 30, 2009, and install one 66-25 kV transformer in Cromer North Station by September 2011.

Justification:
A new five mile feeder and 25 kV feeder conversion is required at Reston to address the increased demand due to oilfield exploration.

In-Service Date:
September 2011.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	4.3	3.0	0.1	1.2	-	-	-
Revised Forecast	$ 4.3	$ 3.0	$ 0.1	$ 1.2	$ -	$ -	$ -

Brandon Crocus Plains 115-25 kV Bank Addition

Description:
Install two 15/20/25 MVA OLTC 115-25 kV transformers. Install one 115 kV breaker to connect the transformers to line BF52. Install 3x25 kV breakers, four reclosers and associated equipment to connect the transformers, and provide four additional 25 kV feeders into the industrial park.

Justification:
To supply the load growth and the industrial loads in the south Brandon area.

In-Service Date:
October 2011.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 6.3	$ 0.8	$ 3.1	$ 1.8	$ 0.4	$ -	$ -
Increase (Decrease)	-	(0.2)	-	0.1	0.2	-	-
Revised Forecast	$ 6.3	$ 0.6	$ 3.1	$ 1.9	$ 0.6	$ -	$ -

Winkler Market Feeder M25-13 Conversion

Description:
Rebuild and convert the 8 kV portion of Winkler Market Feeder WM25-13 (WM08-13) to 25 kV standards, and salvage the 3 x 500 kVA Hochfeld interchange banks.

Justification:
The load growth in the Winkler area is above Manitoba's average, and is experiencing a five year average load growth rate of 6%. This feeder is supplied by a 25 kV feeder and stepped down to 8 kV at Hochfeld. The 8 kV portion of this feeder is over 56 years old and has reached the end of its useful life. The increased load current has made it increasingly difficult to protect the 8 kV feeder ends due to lack of reach. It will soon not be possible to adequately protect the existing plant. The load has also caused feeder end voltage levels to fall below acceptable (CSA) limits.

In-Service Date:
August 2009.

Revision:
Cost flow revision, and in-service date deferred ten months from October 2008.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 2.9	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.8	-	-	-	-	-
Revised Forecast	$ 2.9	$ 0.8	$ -	$ -	$ -	$ -	$ -

Neepawa North Feeder NN12-2 & Line 57 Rebuild

Description:
Rebuild the main portion of feeder NN12-2 and a 16 km section of line 57.

Justification:
The poles have reached the end of their useful life and pole replacements must now be made or the entire line must be rebuilt. A section of line 57 that contains feeders NN12-4 and NN12-2 was built in 1953 and is over 55 years old. A field report indicates that 75% of the line is in poor condition. Larger under-build wire on feeder NN12-2 is required to improve voltage and losses, and a larger 66 kV wire is recommended to improve voltage fluctuations and losses.

In-Service Date:
February 2010.

Revision:
In-service date deferred four months from October 2009.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 1.9	$ 1.9	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 1.9	$ 1.9	$ -	$ -	$ -	$ -	$ -

Perimeter South Station Distribution Supply Centre Installation

Description:
Install one 10 MVA, 66 12 kV distribution supply centre, three 7.2 kV, single-phase 585 A padmount regulators, one 15 kV three-phase padmount recloser, one 15 kV S&C automated Vistagear switching cubicle, motorized bank 12 kV switches B10 & B20, MOV lightning arresters on 66 kV and 12 kV sides of banks 1 & 2, the distribution supply centre, and all 12 kV feeders. Salvage existing manual 12 kV bank switches and gap-type lightning arresters.

Justification:
This station supplies both the south Fort Garry and La Salle communities (both fast growing) and provides a back-up supply to St. Norbert single bank station. This option addresses the non-firm capacity issues at a significantly lower cost than the initial plan, provides superior system reliability and its automatic load transfer feature offers recovery in minutes versus hours when a transformer fails.

In-Service Date:
October 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 2.4	$ 0.3	$ 2.0	$ -	$ -	$ -	$ -
Increase (Decrease)	-	0.1	-	-	-	-	-
Revised Forecast	$ 2.4	$ 0.4	$ 2.0	$ -	$ -	$ -	$ -

Niverville Station 66-12 kV Bank Replacements

Description:
Replace two existing 66-12kV, 3.75/5.0 MVA transformers at Niverville station with two new 66-12kV, 7.5/10/12.5 MVA transformers.

Justification:
This project was initiated as last year's peak load readings indicated that the capacity of this station has been exceeded. In addition, the Town of Niverville is planning to develop a total of 600 residential subdivision lots over the next three years. To date, approximately 200 lots have been serviced and a request to service 160 more lots has been received.

In-Service Date:
October 2009.

Revision:
New item.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	2.6	2.6	-	-	-	-	-
Revised Forecast	$ 2.6	$ 2.6	$ -	$ -	$ -	$ -	$ -

Winnipeg Central District Underground Network Asbestos Removal

Description:
Remove or encapsulate asbestos wrap from high voltage cables currently present in approximately 1,800 manholes within the central Winnipeg area.

Justification:
Asbestos must be in a condition that does not pose a health risk to anyone in the workplace. As a result, the current exposure control plan requires the asbestos be properly sealed with a sealant, encapsulated or removed to eliminate the risk of exposure.

In-Service Date:
March 2010.

Revision:
Cost flow revision only.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 3.0	$ 0.8	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.1)	-	-	-	-	-
Revised Forecast	$ 3.0	$ 0.7	$ -	$ -	$ -	$ -	$ -

Gas SCADA Replacement

Description:
Replace the current Gas Supervisory Control and Data Acquisition (SCADA) system with a vendor-supported SCADA system.

Justification:
Replacement of the current gas SCADA system is required as product support is being discontinued by the vendor, and vendor alternative product does not meet the complete system requirements for Manitoba Hydro.

In-Service Date:
June 2011.

Revision:
Cost flow revision, and in-service date deferred three months from March 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 4.6	$ 1.1	$ 3.1	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.1)	(0.1)	0.6	-	-	-
Revised Forecast	$ 4.6	$ 1.0	$ 3.0	$ 0.6	$ -	$ -	$ -

Customer Service & Distribution Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to extend sub-transmission, distribution, and transformation facilities to supply service to residential, farm, commercial and industrial customers, and to replace plant facilities whose useful life has been exceeded. Specific types of expenditures that make up electric domestic items include station and line additions, modifications and rebuilds, bank additions, breaker replacements, defective cable replacement, highway changes, field maintenance equipment, and ice melting requirements. These costs are spread over many facility locations throughout the Province.

Justification:
The residential, farm, commercial and industrial loads are expected to grow at an average rate in excess of 1.5% per annum and will require a program of additions to the system to accommodate these anticipated loads.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 118.2	$ 120.6	$ 123.0	$ 125.5	$ 128.0	$ 823.4
Increase (Decrease)		(2.3)	(3.1)	(3.1)	(3.2)	(3.3)	(20.8)
Revised Forecast		$ 115.9	$ 117.5	$ 119.9	$ 122.3	$ 124.7	$ 802.6

CUSTOMER CARE & MARKETING:

Advanced Metering Infrastructure

Description:
Purchase and install an automated metering infrastructure (AMI) communication network to remotely read and electronically disseminate electric meter readings and other relevant customer information to appropriate departments and divisions.

Justification:
Satisfies the ongoing need for routine, periodic meter readings in customer billing as well as provides 'on demand' readings to respond to customer inquiries. Other benefits include: increased customer satisfaction due to greater billing accuracy; better detection of theft of service, meter tampering and defective meters; greater flexibility in the timing and consolidation of billings; and improved detection of customer and system power outages with shortened restoration times.

In-Service Date:
March 2015.

Revision:
Cost flow revision, and in-service date advanced one year from March 2016.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 30.9	$ 3.9	$ 4.0	$ 4.0	$ 4.1	$ 4.3	$ 8.8
Increase (Decrease)	-	(3.9)	-	1.3	1.3	1.3	(0.3)
Revised Forecast	$ 30.9	$ -	$ 4.0	$ 5.3	$ 5.4	$ 5.6	$ 8.5

Customer Care & Marketing Domestic

Description:
This program covers the additions and replacements of electric meters.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 2.6	$ 2.6	$ 2.7	$ 2.7	$ 2.8	$ 18.0
Increase (Decrease)		(0.1)	(0.0)	(0.1)	(0.0)	(0.1)	(0.5)
Revised Forecast		$ 2.5	$ 2.6	$ 2.6	$ 2.7	$ 2.7	$ 17.5

FINANCE & ADMINISTRATION:

Corporate Buildings

Description:
Cyclical acquisitions, refurbishments, and/or replacement of corporate facilities throughout the Province.

Justification:
Enables a safe, efficient, and productive environment for staff and customers.

In-Service Date:
Ongoing.

Revision:
No change.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 8.0	$ 8.0	$ 8.0	$ 8.0	$ 8.0	$ 40.0
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast		$ 8.0	$ 8.0	$ 8.0	$ 8.0	$ 8.0	$ 40.0

Workforce Management (Phase 1 to 4)

Description:
Implement a Workforce Management solution to integrate and automate the Customer Care & Marketing planning and dispatch functions, as well as provide for in-truck computing.

Justification:
Facilitates the integration of field processes to improve customer service and field productivity; as well as, reducing clerical functions and employee travel time.

In-Service Date:
June 2011.

Revision:
Cost flow revision, and in-service date deferred 27 months to June 2011.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 11.3	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	3.9	1.0	-	-	-	-
Revised Forecast	$ 11.3	$ 3.9	$ 1.0	$ -	$ -	$ -	$ -

Fleet

Description:
Cyclical procurement, refurbishment and/or replacement of corporate fleet vehicles and equipment.

Justification:
To provide a fleet of safe, reliable and efficient corporate vehicles and equipment.

In-Service Date:
Ongoing.

Revision:
No change.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 13.3	$ 13.5	$ 13.8	$ 14.1	$ 14.3	$ 92.2
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast		$ 13.3	$ 13.5	$ 13.8	$ 14.1	$ 14.3	$ 92.2

Finance & Administration Domestic

Description:
The programs consist primarily of information technology hardware, software, application development, and associated services to the corporation. In addition, there are programs to provide for property easements and to a lesser degree equipment for fleet, property and materials management.

Justification:
Computer system enhancements are required throughout the corporation to achieve ongoing improvements in resource productivity and reliability. Property easements and equipment purchases are required for supporting the appropriate areas of the corporation.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 24.6	$ 25.1	$ 25.6	$ 26.1	$ 26.6	$ 171.1
Increase (Decrease)		(0.5)	(0.7)	(0.7)	(0.7)	(0.7)	(4.3)
Revised Forecast		$ 24.1	$ 24.4	$ 24.9	$ 25.4	$ 25.9	$ 166.8

GAS OPERATIONS:

CUSTOMER SERVICE & DISTRIBUTION:

Customer Service & Distribution Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 21.4	$ 21.8	$ 22.2	$ 22.7	$ 23.1	$ 148.8
Increase (Decrease)		(0.7)	(0.6)	(0.5)	(0.6)	(0.6)	(3.8)
Revised Forecast		$ 20.7	$ 21.2	$ 21.7	$ 22.1	$ 22.5	$ 145.0

CUSTOMER CARE & MARKETING:

Advanced Metering Infrastructure

Description:
Purchase and install an automated metering infrastructure (AMI) communication network to remotely read and electronically disseminate gas meter readings and other relevant customer information to appropriate departments and divisions.

Justification:
Satisfies the ongoing need for routine, periodic meter readings in customer billing as well as provides 'on demand' readings to respond to customer inquiries. Other benefits include: increased customer satisfaction due to greater billing accuracy; better detection of theft of service, meter tampering, defective meters and leaks; and greater flexibility in the timing and consolidation of billings.

In-Service Date:
March 2015.

Revision:
Cost flow revision, and in-service date deferred two years from March 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 15.0	$ 3.7	$ 3.7	$ 3.5	$ 3.8	$ -	$ -
Increase (Decrease)	-	(3.7)	(2.7)	1.9	4.5	-	-
Revised Forecast	$ 15.0	$ -	$ 1.0	$ 5.4	$ 8.3	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba. When combined with savings realized to-date, total natural gas savings of 172 million cubic meters are expected to be achieved by 2025.

Justification:
Provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader implementing cost-effective energy conservation and alternative energy programs, protects the environment, and promotes sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Refinements to existing programs to reflect current information.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 14.2	$ 13.3	$ 12.4	$ 11.5	$ 10.7	$ 40.2
Increase (Decrease)		(0.7)	(0.2)	(0.8)	0.2	0.4	9.2
Revised Forecast		$ 13.5	$ 13.1	$ 11.6	$ 11.7	$ 11.1	$ 49.4

Customer Care & Marketing Domestic

Description:
This program covers the additions and replacements of gas meters.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.1	$ 19.7
Increase (Decrease)		(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.5)
Revised Forecast		$ 2.8	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 19.2

Tab 20

THE MANITOBA CLEAN ENVIRONMENT COMMISSION

IN THE MATTER OF: Bipole III Transmission Line Project

Environmental Impact Statement

FINAL ARGUMENT

MANITOBA HYDRO

MANITOBA HYDRO LAW DEPARTMENT

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THE MANITOBA CLEAN ENVIRONMENT COMMISSION

IN THE MATTER OF: Bipole III Transmission Line Project
Environmental Impact Statement

INDEX OF ARGUMENT

THE TASK BEFORE THE CEC

Terms of Reference were issued by the Minister of Conservation and Water Stewardship on December 5, 2011 requesting the Clean Environment Commission (the "CEC") to review and evaluate Manitoba Hydro's Environmental Impact Statement on its Bipole III Transmission Line Project ("the Project") and its public consultation summary. As part of its assessment of the Project, the CEC was also asked to hold public hearings to obtain input from stakeholders and the public.

On August 23, 2011, the Terms of Reference were clarified by the Minister of Conservation and Water Stewardship in a letter to the CEC wherein he stated: "In response to your specific question about a Needs For and Alternatives To (NFAAT) review, the Terms of Reference, which were issued in December 2011, do not include instruction for the CEC to conduct an NFAAT."

Numerous Information Requests, from stakeholders, Participants, and the Technical Advisory Committee, were answered over the course of the spring and summer of 2012. In addition, supplemental information was filed in both 2012 and in 2013 to further add to the materials filed in the EIS.

The CEC is now to provide a report outlining the Commission's review and recommendations on whether a licence should be issued to Manitoba Hydro for the Bipole III Project, taking into account the entirety of the evidence which is now before it.

If the Project is recommended, the CEC is also to propose the measures it suggests to mitigate and manage any residual effects and to outline what future monitoring is recommended.

This task is one of great importance to all Manitobans and has not been taken lightly by any of the parties.

NEED AND RELIABILITY

Reliability is Manitoba Hydro's primary concern and that concern underlies the whole proceeding. It is the reason this Project has been advanced. Manitoba Hydro is the only utility in the world that is dependent upon one corridor and one station for 70% of its northern hydro generation. The loss of this supply would necessitate rotating blackouts for extended periods. Our customers and regulator would consider Manitoba Hydro negligent if steps are not taken to address this significant supply risk should a catastrophic event occur. The North American Electric Reliability Corporation (NERC) is encouraging industry to design more robust systems to minimize impact of catastrophic events.

It is not possible to guarantee to Manitobans that any transmission system built can withstand every force of nature and that all outages of various causes can be avoided. However, with the construction and operation of this Project as proposed for 2017, reliability will be significantly enhanced through redundancy and increased physical separation of its facilities. The risk of serious outages in the future will be significantly reduced and the anticipated increased needs of Manitoba for domestic load will be better met.

None of the Participants or public presenters has argued that the need for reliability is not a grave concern. No party seriously challenged the assertion that there would be a catastrophic impact to both Manitobans and their economy should the Dorsey Converter Station ("Dorsey") fail – limiting the supply of energy up to three years, or should the two existing Bipole lines simultaneously go down – limiting the supply of energy for six to eight weeks. The 6 to 8 week estimate is based upon Manitoba Hydro's experience in line restoration over many decades.

The Bipole III Transmission Line Project is the best solution to improve reliability of the Manitoba Hydro system and the security of electricity supply. It is the culmination of work done over many years, using its expertise and experience in constructing, operating and maintaining over 18,000 kilometres of Alternating Current (AC) transmission lines and over 1,800 kilometres of Direct Current (DC) transmission lines over the past 60 years, as well as the construction and operation of three converter stations. Manitoba Hydro had an obligation to be prudent and rigorous in the planning and advancement of this Project, and it did so.

It is an important Project that needs to go forward at this time to ensure a safe and reliable source of electricity for years to come. The clear evidence before the Commission is that there will be a deficiency of 1,500 megawatts for domestic load by 2017, should Dorsey or the two existing Bipole lines be severely affected by an event.

Despite all of the evidence and the documentation that has been filed, the urgency for the Project may still not be well understood. It likely won't be truly understood until there is a significant outage at Dorsey, or until the two existing Bipole lines are damaged in the same event. This is not dissimilar to the Floodway, which was not well understood by some, nor appreciated, until the flood of 1997.

By direction of the Minister, alternatives to the Project were outside the scope of this hearing. However, the Bipole III Coalition ("the Coalition") provided a two-pronged proposal for consideration which suggests new technology be used (underground cables), new routes be selected through lands not yet assessed environmentally nor discussed with the public through consultation, and significant changes be made to the configuration of the backbone of Manitoba Hydro's electrical system.

The Coalition proposal recommended that Manitoba Hydro initially relocate the converter station for a new Bipole II from Dorsey to the Riel site by:

- installing new converters;
- constructing a new direct current (dc) line tapped off the Bipole II line north of Dorsey or by constructing underground cables from Dorsey to Riel; and
- deferring the Bipole III Project until 2025, with the southern converter station in the vicinity of LaVerendrye station.

This relocation proposal had previously been assessed by Manitoba Hydro, but was deemed unacceptable. As set out in the rebuttal evidence filed by Manitoba Hydro on March 5, 2013, Manitoba Hydro determined that the Coalition proposal does not address the critical need for improved reliability in the event of a corridor loss.

In particular, the Coalition proposal itself:

- fails to address the risk of a weather, or other, event causing the simultaneous loss, at any time of the year, of both Bipole I and II lines located in the Interlake corridor;
- only deems it appropriate to consider the shoulder and off-peak months for corridor outage, ignoring studies that indicate wide front winds and wind and ice storms can occur at any time of the year;
- fails to understand that load shedding of hundreds of megawatts, for weeks on end, is not acceptable to the customers of Manitoba Hydro and, instead, recommends that Manitoba Hydro shed load of 800 megawatts should an outage occur;
- fails to take into account that Manitoba Hydro's DC system is already fully loaded when it suggests that it could manage ice accretion by increasing the loading;
- does not address concerns with ice build up on sky wires and insulators which could also cause outages, though this risk was acknowledged;
- ignores the risk studies that Manitoba Hydro has done that demonstrate the high risk of a corridor outage at any time of the year;
- does not ever address the supply deficit for the corridor outage and requires further investment after 2025 that costs at least $1.2 billion more than the Manitoba Hydro Bipole III plan;
- relies on unachievable levels of imports in the event of a severe outage and underestimates the risks in relying upon such imports when the Corporation only has 700 megawatts of firm import capability;
- underestimates the time and effort required for Bipole I and II line restoration in the event of a severe outage;
- fails to provide for adequate spare capacity to avoid extended outages (both anticipated and unforeseen) during the relocation of the new Bipole II from Dorsey to Riel without Bipole III being in service to provide that extra capacity;
- minimizes the risk and complexity of separating the controls and other technical concerns while separating a heavily utilized Bipole I and II;
- proposes an incomplete Bipole I and II paralleling scheme;

- does not properly address the reliability and technical issues that would have to be resolved in the AC and DC systems if LaVerendrye were to be used as the Bipole III southern converter station instead of Riel;
- ignores the increased risk of failure caused by the necessity of leaving underground cables in the ground for two to three years prior to being energized; and
- overlooks the fact that the existing converter equipment at Dorsey cannot be maintained as a backup as it will no longer be technically compatible with the updated converter equipment at the Henday Converter Station designed to work with the new Riel converter.

It was also determined that the LaVerendrye proposal, in the long run, is more costly and would result in considerable delays in the delivery of enhanced reliability. For example:

- a new 500kV AC line must be built from LaVerendrye to Riel and several 230 kV lines must also be constructed to protect against the increased risks of the loss of that line; remedies would have to be studied and developed for a multitude of technical issues, as acknowledged by Messrs. Derry, Woodford and Lawson, such as:
  - the multi-infeed effects and dc performance of the proposed three bipole system;
  - short circuit levels at Dorsey;
  - resonance on the dc side of the system;
  - design of a complete 500 kV ring around Winnipeg; and
  - heavy transmission loading across Winnipeg from west to east and the impact of further power injections at LaVerendrye;
- a minimum of 65 kilometres of underground cables must be purchased and transported from abroad at a cost of at least $400 million (in 2012 dollars) more than for overhead lines, and significant investigations into licensing, transportation, storage, handling and installation would be required; [1]
- the useful life of an underground cable (approximately 40 years) is less than half the useful life of an overhead line (approximately 100 years), resulting in additional costs in the order of $422 million in 2012 dollars for underground cable replacement.

[1] If the shortest route is not selected due to its inappropriateness, or if Mr. Woodford's proposal for further underground cable is accepted, significantly more cable must be purchased, transported and installed;

Not even discussed in the Coalition proposal are the needs for further public engagement, extensive environmental assessment and additional licensing processes due to the new routes proposed outside of the study area. In addition, the new underground technology being introduced would have a significantly different potential impact on the environment than overhead lines. These would be both costly and time-consuming, and would certainly delay implementation of the reliability solutions sought by several years.

Exhibits MH 115 and MH 116 – Manitoba Hydro Rebuttal

Evidence of Ed Tymofichuk, October 1, Page 92, Pages 101 – 104, and Page 142, and October 29, Page 2029

Evidence of Gerald Neufeld, October 1, Page 103

Evidence of the Coalition, March 5, Page 6268, Pages 6273 – 6275, Page 6282, Page 6310, Page 6314

For the above reasons, Manitoba Hydro is of the strongest view that the CEC should not pursue the proposal of the Bipole III Coalition any further.

THE ENVIRONMENTAL ASSESSMENT CARRIED OUT BY MANITOBA HYDRO

The Chairman, in his opening remarks, stated that "the challenge for the proponent … is to assure that the record is complete, and that the panel, as well as the public, understand the conclusions set out in the Environmental Impact Statement."

Transcript, October 1, Page 10

In Manitoba Hydro's Opening Statement, it acknowledged that responsibility and stated:

> "Our purpose as a proponent … will be to demonstrate that, in fact, we have done our work in planning and assessing this project, that we have done our work responsibly and professionally…."

Transcript, October 1, Page 18

Because the Project crossed five eco-zones and seven eco-regions, and as the depth and diversity socially and biophysically from north to south was tremendous – from terrain to wildlife to people, Manitoba Hydro felt a generalized route selection process was not sufficient.

Evidence of Pat McGarry, October 5, Page 996

There are a myriad of issues to account for in routing a transmission system of this magnitude and with such distinctly different components. Manitoba Hydro embarked upon a comprehensive, multi-stage environmental assessment process starting in the fall of 2008 and engaged the services of numerous 20 biophysical and socioeconomic experts to assist it in evaluating the Project and balancing the multitude of interests (often competing), while still meeting the need for reliability and technical feasibility. The work was done thoroughly, responsibly and professionally, and the route chosen has the least impact on the west side of the Province.

Evidence of Ed Tymofichuk, October 1, Pages 142 – 143

Evidence of Gerald Neufeld, October 1, Page 153

Manitoba Hydro then brought together the people who were involved in the planning, assessment, and analysis, and those involved in making the predictions as to impact, to testify before this Commission and to answer any and all questions relating to their areas of expertise, to ensure there was a good understanding of the conclusions set out in the Environmental Impact Statement ("EIS") and the supplemental Environmental Assessment filed January 28, 2013 ("EA").

The CEC was then asked by Manitoba Hydro, in its Opening Statement, to keep five questions in mind as it listened to the testimony provided by the proponents and the participants. If the answer to each question was "yes", the CEC could then recommend to the Minister that the Project be licensed.

Transcript, October 1, Pages 20 - 21

Have those questions been answered to the satisfaction of the CEC, such that a licence can now be recommended? Manitoba Hydro believes that they have. It believes that the record is complete, and that its conclusions are understood, appropriate and supportable.

1. DID MANITOBA HYDRO ENGAGE THE PUBLIC AND DID WE RESPOND IN A CONSTRUCTIVE AND PRACTICAL WAY TO WHAT WE HEARD?

Manitoba Hydro engaged in an extensive environmental assessment consultation process ("EACP") which had three main goals:

i) Providing timely and relevant information on the Project to the public and stakeholders;

ii) Providing an opportunity for receiving feedback from the public and stakeholders; and

iii) Incorporating that feedback into Project decision-making.

Evidence of Trevor Joyal, October 2, Page 309

At its simplest, it was Manitoba Hydro's intention to make a better project.

Evidence of Pat McGarry, October 3, Pages 651 - 652

Due to the scope and breadth of the Project, and recognizing both the unique rights and interests of Aboriginal peoples and the challenges associated with engaging with many northern and Aboriginal communities, such as travel constraints, the EACP was divided into a public consultation process and northern and Aboriginal engagement process. The Aboriginal engagement process was not intended to deal with rights-based issues, as that is the responsibility of the Province. Rather, it was intended to deal with the concerns and potential impacts of the Project.

Evidence of Deirdre Zebrowski, October 3, Page 453

Evidence of Deirdre Zebrowski, October 29, Pages 2042 - 2043

Having received the direction from the Government of Manitoba to build the Project on the west side of Province in September of 2007, both engagement processes then commenced in 2008. They utilized a four round approach which occurred simultaneously. Briefly, those four rounds could be described as follows:

i) **Round 1** (fall of 2008):

- Providing broad Project information and identifying preliminary issues;

ii) **Round 2** (spring of 2009):

- Describing the site selection and environmental assessment process and determining constraints and opportunities for routing in the larger study area;

iii) **Round 3** (fall of 2009):

- Examining alternate routing options within 4.8 kilometre (or three mile) wide corridors;

iv) **Round 4** (summer of 2010):

- Presenting the preliminary preferred route within a 66 metre wide corridor.

Evidence of Trevor Joyal, October 2, Pages 310 - 311

Evidence of Deirdre Zebrowski, October 3, Page 453

A variety of notification and engagement mechanisms were utilized throughout the EACP. Advertisements were placed on television, on the radio, in local and provincial newspapers, and on posters placed in strategic community locations. 19,000 postcards were sent out at the start of Round 4, and property owners within a half mile of the Preliminary Preferred Route were invited to any of the 42 Landowner Information Centers which had been established. 244 meetings were held in total during those four rounds with communities, municipalities, First Nations, Northern Affairs Community Councils ("NACCs") and Aboriginal organizations. 137 community and regional Open Houses were held, some of which were added due to requests from the public. Manitoba Hydro also created a Project-specific website, a toll-free Project information line, and email address, all of which were kept open and up to date to ensure the public had continual access to Project information. They continue to be available to any interested party.

Evidence of Trevor Joyal, October 2, Pages 310 – 319; Pages 632 – 633; Pages 658 - 660

Direct mail outs were not provided to landowners in Rounds 1 through 3 as the Project study area at that stage was extremely large and would have required contacting thousands of individuals, most of whom are not now affected by the Final Preferred Route ("FPR"). Even in

Round 3, there were still three routes, over 1,300 kilometres long and 4.8 kilometres wide. Broad notification methods were deemed more appropriate.

Evidence of Trevor Joyal, October 3, Page 629

Evidence of Pat McGarry, October 3, Page 629

In addition to the engagement described above, the Aboriginal engagement process included a sharing of Aboriginal Traditional Knowledge ("ATK"). This was accomplished through workshops, through meetings arranged as part of existing processes and contractual obligations, and through self-directed studies. 49 invitations were sent out to First Nations, NACCs and the Manitoba Métis Federation ("MMF"). 19 chose to participate in workshops, while eight, including the MMF, chose to do self-directed studies.

Exhibit MH – 52

Evidence of Virginia Petch, October 30, Page 2410

Over the course of the four rounds, there was participation from 26 First Nations, the Manitoba Métis Foundation, 23 Northern Affairs Communities, and five Aboriginal or regional organizations.

Evidence of Deirdre Zebrowski, October 3, Pages 453 - 461

Manitoba Hydro funded eight self-directed ATK studies carried out by Fox Lake Cree Nation ("FLCN"), Tataskweyak Cree Nation ("TCN"), Opaskwayak Cree Nation ("OCN"), Sapotaweyak Cree Nation, Wuskwi Sipihk First Nation, Swan Lake First Nation ("SLFN"), Long Plain First Nation and the MMF.

Evidence of Deirdre Zebrowski, October 3, Pages 462 - 472

Funding was granted to the Southern Chiefs Organization in Round 3 for a two day gathering to share information on the Project with both Treaty 2 and Treaty 4 First Nations, which would have included Pine Creek First Nation and Wuskwi Sipihk First Nation.

Evidence of Deirdre Zebrowski, October 3, Page 624

Engagement with Pine Creek First Nation on matters of particular interest to it was ongoing and continued up to and including resumption of the hearing in March of 2013. Meetings and open houses were held with PCFN as early as Round 1, an ATK workshop was arranged and held in the community, and 17 key person interviews took place with individuals identified by the community itself.

Evidence of Deirdre Zebrowski, October 3, Pages 895 – 896; Page 898; Page 902

Answer to Undertaking, October 29, Page 2023

Although PCFN did express concerns about the ATK workshop, it acknowledged that the community was in a state of flux at the time and was not in a position to adequately respond to requests from Manitoba Hydro for more information.

Evidence of Warren Mills, March 6, Page 6486

Manitoba Hydro worked closely with FLCN further on the impacts of the Project pursuant to the Impact Settlement Agreement signed by the parties and, as a result, two background papers with the parties' perspectives were filed.

Evidence of Deirdre Zebrowski, October 3, Pages 473 - 474

Manitoba Hydro also demonstrated its willingness to continue discussions on Project impacts throughout the process and provided numerous examples including its work with TCN.

Evidence of Deirdre Zebrowski, October 3, Pages 463 - 477

Communications were exchanged with Peguis First Nation ("PFN") about funding for a self-directed ATK study. Manitoba Hydro was of the view that PFN was not within the Project Study Area and, as such, funding was not provided. Further, land required for the Riel Station had already been purchased and is not on Crown leased land. Thus, it does not affect PFN's future selection of Treaty Land Entitlement. Manitoba Hydro did, though, indicate that it was more than willing to meet to discuss any routing concerns it may have. No response to that invitation was ever received. Six months to one year later, PFN requested financial support for a land use and occupancy study, the results of which could possibly be applicable to the Project. Manitoba Hydro did provide some modest financial support for this undertaking and asked that the results be shared with it if it was shown that the results were indeed applicable to the Project or any other Manitoba Hydro initiative. No response was received.

Evidence of Deirdre Zebrowski, October 4, Pages 874 - 876

Manitoba Hydro also provided funding to WSFN to complete a self-directed ATK Study. At the time of filing the EIS, WSFN had provided Manitoba Hydro with some maps but not it's final ATK Study Report. Manitoba Hydro remains committed to working with communities, including WSFN, to discuss issues of concern and how they might be addressed through the Environmental Protection Plan.

Evidence of Deirdre Zebrowski, October 3, Pages 470 - 471, 479 - 482

ATK Technical Report # 2, Page 19

With respect to the engagement of MMF, MMF chose to do a traditional land use and knowledge study to identify any Métis rights and interests that had a potential to be affected by the Project. It was provided with $500,000 to do that study. The MMF developed a community engagement process through this work and used three different methodologies/mechanisms to gather information. That report was received by Manitoba Hydro on September 1, 2011.

Evidence of Deirdre Zebrowski, October 3, Pages 465 - 466

Evidence of David Chartrand, Nov. 14, Pages 4756 - 4759

Two specific meetings were held with the Winnipeg office of the MMF as part of the EACP process. Regional and Community Open Houses were held across the study area where representatives from MMF Locals could attend if desired. However, Manitoba Hydro was specifically directed by the Winnipeg home office of the MMF to deal with them and not with the locals, so meetings with the MMF Locals were not arranged.

Evidence of Deirdre Zebrowski, October 4, Pages 672 - 676

There has also been a Manitoba Hydro/Manitoba Métis Federation relationship task force in existence since 2004, negotiated by the President of the MMF, David Chartrand, whose purpose was to be a forum by which the two organizations could communicate with each other on a variety of topics including Manitoba Hydro projects such as this one.

Evidence of David Chartrand, Nov. 14, Pages 4756 - 4759

Manitoba Hydro also engaged with resource users in the vicinity of the Final Preferred Route. It did so through the application of its Trappers Notification/Compensation Policy to affected commercial trappers, and through communication with those trappers, trapping associations and other stakeholders whose commercial trapping activities may be affected by the Project. Manitoba Hydro notified lodge and outfitting operators at the onset of Round 4 to ensure these operators were aware of and had opportunity for input to the assessment of the Project. During the recent route adjustment EACP in December 2012 outfitters were asked again for their input, and were also encouraged to participate in the CEC process itself.

Evidence of Vince Kuzdak, October 30, Page 2343

Evidence of Paul Turenne, March 11, Page 6485

After the filing of the EIS, Manitoba Hydro continued to have ongoing engagement with Aboriginal communities, organizations and NACCs. Some of the items that have been discussed include the Access Management Plan, Environmental Protection Plan, employment and business opportunities, and so on.

Evidence of Deirdre Zebrowski, October 30, Page

Evidence of James Matthewson, November 8, Page 4049, Pages 4069 – 4071, Pages 4077 – 4080, Pages 4091 – 4094, Pages 4116 – 4117, Pages 4130 – 4131, Pages 4143 – 4145, Pages 4157 – 4164, Pages 4170 – 4172, and Page 4174

During the preparation of the Supplemental EA relating to the routing concerns expressed by Manitoba Conservation and Water Stewardship's Environmental Assessment Branch, Manitoba Hydro undertook a second engagement process with the public in general and with stakeholders, First Nations, NACCs, landowners and the MMF. Once again, a variety of notification methods and consultation activities were used to ensure local communities, interest groups, stakeholders, First Nations, NACCs, landowners and the MMF were informed of, and could participate in, these EACP activities. In total, 216 direct letters were mailed, 197 individuals signed into 12 venues where 27 comment sheets and eight Landowner Information Centre forms were submitted. Within a few days of letters being sent out to those First Nations communities directly affected by the routing revisions, telephone follow-up was also carried out. Manitoba Hydro held community engagement activities with 16 First Nation and NACC communities. Manitoba Hydro attempted to engage with the MMF but was unable to come to a mutually acceptable format of engagement.

Evidence of Trevor Joyal, March 4, Pages 5946 - 5961

Evidence of Trevor Joyal, March 6, Page 6382

Manitoba Hydro also continued in its efforts to engage with the MMF with respect to the most recent route alternatives being investigated. The unfortunate results of those efforts are contained in the two proposals and letters between legal counsel attached to the Supplemental EA filed on January 28, 2013.

Exhibit MH 109

Manitoba Hydro has demonstrated that its public and Aboriginal engagement process was thorough, thoughtful, effective, and professional. The adaptive process and inclusive nature of the engagement program allowed all stakeholders the opportunity to participate at various stages throughout the route selection process.

DID IT THEN RESPOND TO WHAT WAS HEARD IN A CONSTRUCTIVE AND PRACTICAL WAY?

There are numerous examples demonstrating that it did, proving the value of its public consultation process.

57 individual requests for route changes came out of the Round 4 consultations. Of the 57 requests, 23 adjustments were made to the preliminary preferred route. In addition, a route change in the Tourond area was undertaken to address concerns expressed in that area post-EIS submission. This involved an alternative route review and an additional engagement process with landowners and the general public.

Evidence of Trevor Joyal, October 2, Pages 329 - 331

Evidence of Pat McGarry, October 2, Pages 383 – 384

During the engagement process, Manitoba Hydro was requested by SLFN to provide further support for them to complete work in the areas of botanical surveys and archaeology. This support was in addition to the financial support provided to complete a traditional knowledge study. The work completed has identified the location of rare botanical species that are of importance to that First Nation and a number of previously unknown archaeological sites. Efforts will now be made through the Environmental Protection Plan to protect them and a commitment has been made to ensure community members are present when precise tower location is being determined to avoid particular areas of concern.

Evidence of Deirdre Zebrowski, October 3, Pages 467 – 469

Evidence of Pat McGarry, March 6, Pages 6416 - 6419

Manitoba Hydro is also continuing discussions with SLFN regarding routing through an area of cultural and heritage interest to SLFN.

Evidence of Pat McGarry, March 6, Pages 6419-6420

As a result of discussions with TCN, and the funding by Manitoba Hydro for two reports, two of three route changes proposed by TCN were incorporated into Final Preferred Route.

Evidence of Deirdre Zebrowski, October 3, Pages 469 – 470

Information about the use of traditional berry picking areas and medicinal plant gathering was obtained during the EACP process from First Nations such as Pine Creek First Nation ("PCFN"). This information led directly to the identification of an additional Valued Environmental Component ("VEC") by the expert on terrestrial ecosystems and vegetation, which was then incorporated into the review of domestic resource use. That input further led Manitoba Hydro to carry out additional review of certain segments such as B3 in Section 8, to give the vegetation VEC a higher rating, and to choose an alternative route. Further, Manitoba Hydro heard concerns about the spraying of blueberries with herbicides and has committed not to do so.

Evidence of Trevor Joyal, October 3, Page 616

Evidence of Pat McGarry, October 4, Pages 687 – 690

Evidence of Kevin Szwaluk, October 29, Page 2264

Evidence of Glenn Penner, March 12, Pages 6784 - 6786

More recently, during the course of this hearing, concerns were heard from Pine Creek First Nation ("PCFN") about flooding and other water issues. Such concerns had not been identified previously by Manitoba Hydro's expert, but Manitoba Hydro reacted by having its engineers conduct studies on the flooding problem and what, if any, the Project would have on it. Further, they provided presentations to both the community and the CEC. It was ultimately determined that the change in runoff from the Project would be undetectable.

Evidence of Kristina Koenig, Nov. 7, Pages 3752 - 3770

PCFN's concerns with respect to other cultural and heritage resources will not be ignored and will be taken into account, and addressed, through the construction process and environmental monitoring.

Evidence of James Matthewson, November 8, Page 4154

Moose, in the EIS, was not identified as a VEC of concern. Moose concerns were not cited by the MMF in its report dated August of 2011. Further Game Hunting Areas closures did not occur until July of 2011. At the time it first came to the attention of Manitoba Hydro, it had already completed Round 4 of the EACP process and was already finalizing the EIS for filing in the fall of 2011.

Evidence of Deirdre Zebrowski, October 3, Page 479

Evidence of Pat McGarry, October 4, Pages 668 – 669

Manitoba Hydro has demonstrated its responsiveness to those more recent concerns. Manitoba Hydro asked its experts to carry out further study and field work on moose in Game Hunting Area ("GHA") 14 and GHAs 19A/14A and filed two reports prior to resumption of the hearing in March. At the direction of MCWS, alternate routes have been examined in those areas arising out of concerns for moose and analysis done to determine if changes would benefit moose populations in the future.

Exhibit MH 107 and 109

Numerous concerns expressed about diagonal lines on agricultural land were also taken into account and altered the Final Preferred Route.

Evidence of Trevor Joyal, October 3, Page 616

Additional concerns were brought forward to Manitoba Hydro in its recent consultation process about increased wildlife access and the particular impact that may have on moose. As seen in the original letter of commitment dated October 29, 2012, and the associated table, and the letter to Manitoba Conservation and Water Stewardship in February of 2013, mitigation measures to address this concern have been contemplated and enhanced over time, such as allowing vegetation management to allow wildlife corridors (or higher tree growth) to exist in specific small segments under the Transmission Line, thereby reducing lines of site for hunters and reducing the use of the Right-of-Ways by wolves.

Exhibits MH 63 and MH 108

Manitoba Hydro also responded to community feedback that major transmission line projects do not provide concrete benefits to communities by creating a Community Development Initiative. Approximately 60 towns, villages, municipalities, First Nations and NACCs are potentially eligible to share in funding of approximately $4 to $5 million per year for a ten year period. That Initiative will be finalized if a licence is received and reviewed at the end of the ten years.

Evidence of Deirdre Zebrowski, October 3, Page 482

With respect to biophysical components, by way of example, feedback received with respect to the importance of certain bird types was incorporated into the selection of the VECs. There are over 400 bird species in Manitoba alone and this had to be narrowed down considerably. Concerns with respect to items such as bird collisions were incorporated into the mitigation measures through the use of bird diverters, the establishment of buffers in sensitive areas, and restrictions on construction (where possible).

Evidence of Robert Berger, October 29, Page 2226, Page 2241, Pages 2246 – 2247, and Pages 2254 - 2256

In the area of invertebrates, amphibians and reptiles, information with respect to garter snake hibernacula was received directly from the ATK workshop in Barrows and with respect to frogs from the Pelican Rapids ATK workshop. This was incorporated into the technical report and used in the determination and assessment of VECs.

Evidence of Kurt Mazur, October 29, Page 2276

ATK was incorporated into the wildlife biologist's work on mammals. By way of example, information obtained from interviews and workshops provided areas where the American Marten is found, which helped validate some of the assumptions made with respect to high quality habitat.

Evidence of Doug Schindler, October 30, Page 2325

It was also learned from the ATK workshops and self-directed studies that there were 156 occurrences of environmentally sensitive sites important to communities in the 4.8 kilometre wide corridor studied. That information became particularly important in the development of appropriate mitigation measures. That information also informed the decision of route selection in a number of instances, including on one of the routes analyzed in the latter route revision process.

Evidence of Virginia Petch, October 30, Page 245

Evidence of Pat McGarry, October 4, Page 687 and March 4, Page 5917

Manitoba Hydro has also heard about the interest from Aboriginal persons to benefit from the Project in terms of employment and business opportunities. As described, there are numerous opportunities being explored for employment with Manitoba Hydro, particularly in its apprenticeship programs. Hiring preferences have been incorporated into both the Burntwood Nelson Agreement and the Transmission Line Agreement. Ongoing discussions are taking place with various Aboriginal groups to contract out certain work, including but not limited to work related to clearing and camp operations.

Evidence of Glenn Penner, October 5, Page 1018, and March 12, Pages 6790 - 6791

Evidence of Rob Elder, October 5, Pages 1019 - 1020

In summary, Manitoba did respond in a constructive and practical way. Despite the wealth and volume of the information provided through the various sources, Manitoba Hydro was able to make good use of the information gathered to determine the appropriate VECs to be studied, to make the best possible routing choices, and to select the most effective mitigation measures so as to minimize the impact on the environment.

2. DID MANITOBA HYDRO IDENTIFY THE CORRECT VALUED ENVIRONMENTAL COMPONENTS ("VECS") AND THE RIGHT ISSUES?

Manitoba Hydro had the monumental task of trying to balance the needs of numerous stakeholders with a wide variety of environmental considerations when coming up with a Final Preferred Route. It was not able to look at route planning from a singular perspective, as others with particular special interests have done.

Manitoba Hydro followed a set of general guidelines for routing, including identification of routing opportunities and the establishment of avoidance criteria, so as to minimize the impact of the Project on the environment.

Evidence of Pat McGarry, October 2, Pages 337 - 343

Manitoba Hydro took advantage of routing opportunities, compatible with environmental protection. By way of example, it:

- used existing linear corridors or sites, where possible, for the sake of VECs such as the boreal woodland caribou in the Wabowden area;
- used existing road allowances, where possible;
- routed on the half mile line, where possible (approximately 32% of the route in agricultural Manitoba); and
- used land already purchased by Manitoba Hydro, where available, such as at the proposed site for the new Riel Converter Station.

Evidence of Jim Nielsen, October 30, Page 2477 – 2480

Evidence of Pat McGarry, October 2, Page 343

Manitoba Hydro also utilized the principle of avoidance – avoid where possible – to further protect the environment and minimize the impact of the Project. It avoided such things as:

- communities and heavily populated areas;
- reserves and Treaty Land Entitlement selections;
- water crossings; and

- Provincial parks, designated protected areas, areas of special interest and wildlife management areas.

Evidence of Pat McGarry, October 2, Pages 340 - 343

This approach is a reasonable and practical one, as the impacts of routing through those areas could be devastating.

In farming and rural areas, the route selected avoided such key things as:

- communities;
- airports;
- dwellings;
- farm buildings;
- farm yards;
- intensive livestock operations;
- row crop and intensive annual cropped areas;
- lands under irrigation or pivots; and
- encumbered land such as Treaty Land Entitlement selections.

Evidence of Pat McGarry, October 4, Pages 745 – 746

Evidence of Jim Nielsen, October 30, Pages 2469 – 2472, Page 2489

Based upon direct feedback from farmers, in-field placement and diagonals were also avoided to stay away from houses, barns and farm yards.

Evidence of Jim Nielsen, October 30, Page 2477 – 2480

Through this type of route selection process, opportunities for routing with minimal negative impact were maximized and constraints were avoided to the degree possible. The Project was able to avoid key VECs, such as the majority of boreal woodland caribou ranges, and only took out of production approximately 17.8 hectares of arable land. Further, only 60 square kilometers of undisturbed Crown land was used, so as to minimize the impact on harvesters.

Evidence of Cam Osler, October 29, Page 2190

Answer to Undertaking given at Page 2489 on October 30

Manitoba Hydro assembled a large team of highly qualified experts from all areas of environmental study and asked them to come together as a team to review the five eco-zones and seven eco-regions in depth and to determine the appropriate VECs.

The experts conducted field studies, carried out literature reviews, did habitat modeling, reviewed the input and information gathered from the EACP and ATK workshops, all in order to determine the appropriate VECs.

Evidence of Cam Osler, October 29, Page 2194

Not all environmental elements can be studied. In assessing the environmental impact on a project, you must find pathways for its effects on a VEC.

Evidence of Cam Osler, October 29, Page 2171 – 2172, Page 2196

There are hundreds of possible VECs but this team, using its combined expertise and experience, was able to narrow it down to 67 VECs within 28 different categories (46 bio-physical and 21 socio-economic).

Evidence of Cam Osler, October 29, Pages 2188 - 2189

The tremendous scope of this task can be demonstrated by looking at a few examples, starting first with the bio-physical.

As described earlier, there are over 400 bird species. Birds are ecologically and socially important and a strong component of the biodiversity in Manitoba. Those species had to be placed in six major groupings and distilled to the most vital by examining their domestic, cultural, recreational and community importance, their population status, and whether they were a species at risk – threatened or endangered.

Evidence of Robert Berger, October 29, Pages 2230 – 2231; Page 3326

When examining terrestrial ecosystems and vegetation in 2010, there were a number of eco-regions, 21 vegetation cover types, and 457 plant taxa identified. Over 29 locations for species of concern were observed and over 80 species of plants of traditional value found.

Evidence of Kevin Szwaluk, October 29, Page 2267

Mammals were studied by a wildlife biologist and his team and a number of different factors were considered:

- Mammals of importance to people for reasons such as hunting, trapping, cultural significance;
- Mammals considered of importance under current law, such as protected or critical habitats, or rare or endangered species;
- Keystone species that are critical in maintaining the structure of an ecological community impacting other species (such as beaver);
- Umbrella species that reflect the broad habitat requirements for many species (such as moose); and
- Indicator species that are indicators of a particular habitat niche (such as elk).

Evidence of Doug Schindler, October 30, Pages 2303 – 2304; Page 3325

From that analysis, a list of VEC species was developed, namely caribou, moose, American marten, beaver, elk, wolverine and grey wolf as a linkage species.

Evidence of Doug Schindler, October 30, Pages 2304 – 2305

Moose were selected as a VEC due to their importance for rights-based hunting and recreational hunting. They are particularly important to First Nations and Métis for personal community sustenance.

Evidence of Doug Schindler, October 31, Page 2639

Literature reviews were undertaken, government and historical data were reviewed including fur production records, field data was collected, and habitat modeling, surveys and monitoring were carried out, all to ensure the proper VECs were identified and the most appropriate route selected. Monitoring was carried out with the assistance of local trappers.

Evidence of Doug Schindler, October 30, Pages 2312 – 2314; Pages 2317 - 2319

The effects on the VEC species were examined, taking into account such concerns as overharvesting, habitat loss, alteration or fragmentation, proximity to linear developments, and sensory disturbance.

Evidence of Doug Schindler, October 30, Pages 2312 – 2314

A Socio-Economic Impact Assessment was also carried out to determine the appropriate VECs related to this Project. Such an assessment examines the effect of the Project on people in the vicinity who are part of the existing socio-economic environment. It was recognized that changes in both physical and bio-physical environment can affect the well-being of people, lands and the resources they use, and can affect their ways of life.

Evidence of Elizabeth Hicks, October 30, Page 2356

21 socio-economic VECs were selected by the team, falling under the following categories:

- Land Use - 6;
- Resource Use – 7;
- Economy - 1;
- Services - 2;
- Personal, Family and Community Life - 3; and
- Culture and Heritage - 2.

Evidence of Elizabeth Hicks, October 30, Pages 2356 – 2357

Chapter 8 of the EIS

Through the study of those VECs and the primary concerns surrounding them, additional areas to avoid were:

- Significant historical and cultural sites and burial grounds; and
- Key areas of concern for certain species both spatially and temporally such as habitats, nesting sites, calving areas, food sources, nesting, calving and denning periods.

In order to ensure that the right issues in agricultural Manitoba were identified and addressed, an agricultural specialist was retained. Information on soil types was gathered, both existing and new aerial photography was accumulated and assessed, the route was flown and driven several times to ground truth and determine key impediments, and the lines were developed over one and a half years of intensive work.

Evidence of Jim Nielsen, October 30, Pages 2467 – 2468

Extensive areas of similar soil types and high value cropland led to an initial selection of the shortest routes south of Winnipeg to minimize distance over these agricultural areas. While this makes sense from an agricultural perspective it is not always possible due to other considerations such as subdivisions and density of land development closer to Winnipeg.

Evidence of Jim Nielsen, October 30, Pages 2474 – 2476

Evidence of Pat McGarry, October 4, Page 766

Self-supporting structures were recommended to allow for farming operations to continue after tower placement, at an additional cost four to six times greater than guyed towers. This is much more difficult under guyed towers.

Evidence of Jim Nielsen, October 30, Pages 2481

In routing through agricultural areas, Manitoba Hydro used the relevant constraints and followed the general guidelines for routing.

EIS, Chapter 4, Pages 4-21 – 4-22

Evidence of Robert Berrien, November 19, Pages 5338 - 5339

Culture was selected as a single VEC, defined as a repertoire of behaviours and themes that identify the identity of a social group. It is described as a VEC in the EIS as it is an expression of the relationship between humans and the natural environment. The approach taken with respect to culture paralleled the methods and indicators identified by the UNESCO framework.

Evidence of Virginia Petch, October 30, Pages 2426 - 2427

Heritage resources were considered a VEC because they are a non-renewable resource. They are valuable for their archaeological, paleontological, cultural, pre-historic, historic, natural, scientific or aesthetic features. As of 2010, there were 5,012 registered heritage sites alone in the Project study area, including centennial farms, commemorative plaques, municipal and provincial sites, and archaeological sites.

Evidence of Virginia Petch, October 30, Pages 2435 - 2436

The importance of culture and heritage resources was also seen in the assessment of the route revisions requested by MCWS. Their existence and importance affected Manitoba Hydro's assessment of the Alternate Final Preferred Route in one section and their preference between the Final Preferred Route and Alternate Final Preferred Route.

Evidence of Pat McGarry, March 4, Pages 466

Where there was a pathway to potential health effects, and where concerns were expressed, Manitoba Hydro conducted further assessment, including electric and magnetic fields and noise. A human health impact assessment was not considered appropriate or necessary based upon the nature of the Project and its potential effects on health. Precedents provided by the Participant's expert were not at all comparable or applicable – for example, one of the assessments looked into concerns with chemical carcinogens found in liquid hydrocarbons, while another dealt with effects from an aluminum smelter operation.

Evidence of Dr. Lee, November 15, Pages 5102 - 5106

Through this extensive Site Selection and Environmental Assessment approach, and with the assistance of experienced professional experts, Manitoba Hydro was able to recognize the key issues in routing and was able to identify the most crucial VECs potentially impacted by the Project.

3. ARE MANITOBA HYDRO'S CONCLUSIONS REGARDING THE SIGNIFICANCE OF IMPACTS SOUND?

The Project itself and the route chosen were designed to achieve reliability without significant adverse effects. The route and site selection process allowed for early integration of potential environmental and socio-economic issues and provided considerable opportunities to avoid adverse effects where feasible, and allows the assessment to focus on areas where there are concerns regarding potential for measurable cumulative effects on VECs.

Exhibit 59, Slide 10 and 14

Evidence of Cam Osler, October 29, Page 2192

The assessment considers pathways of effect of each Project component on each VEC.

Evidence of Cam Osler, October 29, Page 2196

MH-59, slide 33

When the VECs have been identified and the pathways of effect determined, the next step is to consider the direction and nature of the effect on the VEC. Is it positive, negative or negligible in direction? How large is it? What is its geographical extent? Of what duration is it?

Evidence of Cam Osler, October 29, Page 2196

The VECs for the Project were screened in this fashion by the team of experts to determine the direction of their effects. This screening process looked at duration, magnitude and geographical extent of effects on each VEC in detail. Where there were potentially significant residual effects additional criteria were considered (i.e., frequency, reversibility and ecological and societal importance).

Evidence of Cam Osler, October 29, Page 2199

For those VEC's affected by the Project, the assessment was VEC focused, looking at whatever is affecting the VEC. The VECs sustainability and sensitivity were examined. For example, is it a threatened species? Are the people affected vulnerable?

Evidence of Cam Osler, October 29, Page 2196 - 2197

Where there was a potential adverse effect on a VEC that could not be avoided through route selection, mitigation measures proposed and discussed by Manitoba Hydro staff and specialists were applied to minimize or eliminate potential adverse effects.

Evidence of Cam Osler, October 29, Page 2196

Where there was a measurable adverse effect that could not be addressed through mitigation measures, and where appropriate, compensation has been offered. Two such examples are the Landowners Compensation Policy and the Trappers Notification and Compensation Policy.

Evidence of Cam Osler, October 29, Page 2198

A formal policy has not been established for outfitters. This is not intended to minimize the legitimacy and importance of the businesses being operated. However, as compared to landowners and trappers numbering in the hundreds, there are only two outfitters which have come forward with potential claims. Years of history, and considerable records, exist with respect to the income earned and the impacts on both of those groups (i.e. landowners and trappers), such that a fair, reasonable and consistent policy can and was established. To the contrary, the claims of the outfitters have not yet been established and contain many uncertainties still need to be considered. Many, if not all, of the potential impacts on outfitters can be mitigated. Manitoba Hydro has said it will entertain their claims if, and when, they do occur. It is not in any way rejecting their position and Manitoba Hydro will review each such claim on a case by case basis as they arise.

Evidence of Pat McGarry, March 12, Page 6800 - 6805

Exhibit WPG 17

The residual effects significance evaluation was undertaken after consideration of mitigation. Regulatory significance can potentially occur where there is still a residual adverse effect after mitigation. Determining the regulatory significance of the residual effects required specialist opinions on the effect (e.g., magnitude, duration, geographic extent) and the probability of the effect actually occurring, the degree of certainty in our present knowledge of the subject and the expected results of mitigation measures, continued follow-up monitoring and, in some cases, the development and implementation of follow up adaptive management plans to address uncertainties.

Manitoba Hydro's conclusions as to significance were based upon the extensive work done by numerous experts, all of whom prepared detailed technical reports, and most of whom attended at the hearing to be questioned on their work.

Once residual Project effects were identified, a cumulative effects assessment was carried out. During this hearing the matter of CEA framework and approach has received considerable attention. Appendix A of this Argument accordingly provides a summary regarding the CEA approach and clarifications on various specific issues. An overview of relevant points is provided below.

The cumulative effects assessment ("CEA") for the Project reflects current good practice and follows a method in alignment with the *Cumulative Effects Assessment Practitioners Guide* ("the Guide") prepared by the Cumulative Effects Assessment Working Groups for the Canadian Environmental Assessment Agency.

Evidence of George Hegmann, March 12, Pages 69 - 70

Evidence of Cam Osler, November 22, Page 5818

Appendix A

The CEA prepared in support of the Bipole III Project regulatory EIS filing follows a "project centric" approach, within which also lies the concept of the "residual effects trigger" as discussed in this hearing. CEA was conducted only for those VECs for which the Project results in a likely measureable adverse residual effect. This approach examined potential effects by the proposed Project on selected VECs, and through a cause-effect analysis evaluated significance of Project residual effects. This approach did not assess VECs unless they are affected by the Project, and also did not assess VECs where such effects of the Project are not adverse or measureable, and reflects understanding that Project contribution is critical to allow one to make judgment on the Project's effects and hence its acceptability. The Guide and the Canadian Environmental Assessment Act ("CEAAct") support this as a fundamental basis of assessment. This approach was the practice adopted in the 2009 New Nuclear-Darlington project CEA, and in the CEAs used by BC Hydro in all of its recent northern transmission line project assessments. As such, the Bipole III CEA using this approach reflects current and best practice and is not deficient in regards to VEC selection and assessment of effects.

Evidence of C. Osler, February 22, Pages 5818-5823; 5861-5863

Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2

Evidence of G. Hegmann, March 12, Pages 71-76

Appendix A

The words "cumulative effects assessment" have often been used interchangeably to mean two different things. A regional or strategic planning CEA has nothing to do directly with any one project application for regulatory review. Notwithstanding the potential benefits of having available a regional or strategic planning CEA in order to set context and (potentially) thresholds for overall effects on certain VECs in the region, the lack of such regional CEA studies does not in itself constitute deficiency in a CEA project assessment. Examples of where such regional or strategic CEA have been prepared, such as the oil sands region, confirm that such CEAs are supported by government responsible for overall resource and regional planning in the affected area. Dr. Noble and Dr. Gunn agreed that "regional strategic environmental assessment is ultimately the responsibility of government". To date, no such overall regional or strategic CEA has been prepared by government for the various regions affected by the Bipole III Project.

On this matter, the Bipole III CEA also complies fully with the Scoping Document (Section 8), i.e., it is based on CEAA guidelines as well as best and current practices in that it is required only to take into consideration any relevant regional and strategic environmental assessments available at the time the Bipole III EIS was prepared (and no such assessments were in fact available).

Evidence of G. Hegmann, March 12, Pages 6857-6859, 6887-6893

Evidence of Dr. Noble & Dr. Gunn, November 15, Pages 4963-4964

Evidence of C. Osler, November 22, Pages 5006-5007

Chapter 8 considered the cumulative effects of past and current projects when assessing the effects of the Project on each VEC. Chapter 9 built on the assessment in Chapter 8 by including a focus on future projects/activities where there is spatial or temporal overlap with residual adverse effects from the Project.

Exhibit 59, slides 17, 34, 46 to 56

All VECs with measurable adverse residual effects of the Project were carried forward for further analysis and consideration. Of the 67 biophysical and socio-economic VECs considered in the EIS effects assessment (Chapter 8), 64 VECs were considered in the cumulative effects assessment (Chapter 9). Two of the initial 67 VECs examined in Chapter 8 of the EIS were not examined in Chapter 9 due to the absence of a detectable adverse residual effect from the Project (Dakota Skipper and Groundwater Quality), and only one was not examined due to a residual positive effect (Economic Opportunities).

The CEA in Chapter 9 then screened VECs based on the geographic extent, magnitude and duration of effects in order to focus on key VECs where there was potential for non-negligible cumulative adverse effects. The CEA carried out in Chapter 9 for the remaining 64 VECs resulted in more detailed analysis of four VECs which were subject to further detailed analysis and consideration: Caribou (Wabowden herd), Community Services, Travel and Transportation and Public Safety (Gillam). Two further VECs were subject to more extensive consideration in the February 28 Supplemental Assessment Report: Moose (in GHA 14 [Moose Meadows] and GHA 19A and 14A) and Culture (in area of GHA 19A and 14A).

Response to CEC/MH-VI-347

Exhibit MH 59, Slides 7, 8, 16, 17, 33, 34, and 46 - 56

Evidence of Cam Osler, October 29, Pages 2172 – 2177, 2182 – 2184, Page 2191, Pages 2196 – 2197, Page 2199, and Pages 2206 – 2214

Evidence of Cam Osler, November 22, Pages 5861 – 5867

Evidence of George Hegmann, March 12, Pages 113 - 116

In carrying out the cumulative effects assessment, the Corporation:

- Determined if the Project would have an effect on the VEC;
- If a negative effect was demonstrated, determined if the incremental effects acted cumulatively with the effects of other actions (past, present and sufficiently known future ones);
- Determined if the combination of Project effects with other effects was going to cause a significant change now or in the future in the characteristics of the VEC after mitigation; and
- Tested whether the Project was incrementally responsible for the adverse effect and to what degree.

The cumulative effects assessment is not an assessment of past or future projects. Rather, it is the description of the overall, or cumulative, effects on the VEC and the extent to which Project is expected to be incrementally responsible for adverse effects. It examines potential overlaps of those effects with those from the Project on each VEC.

The assessment considers VEC context in light of effects from all sources - as addressed in detail in Appendix A to this Argument.

Three VECs with potentially significant effects were identified related to effects during the construction phase of the Keewatinoow Converter Station:

- Public safety in the Gillam area as a result of potential worker interaction;
- Traffic concerns to and from Gillam; and
- Community services such as hospitals and policing in the Gillam area.

Evidence of Elizabeth Hicks, October 29, Page 2386

Given the concerns identified, the proposed mitigation measures were revisited for those specific VECs. Additional work was done with both subject matter experts and members of the communities in and near the Gillam area and enhancements to the mitigation measures were proposed. Project plans and mitigation measures designed to minimize those effects include:

- The establishment of both start up camp and a main camp several kilometers away from the Town of Gillam, equipped with:
    - lodging and meals free of charge;

    - a separate ambulance service;
    - fire truck;
    - first aid building (in the case of the main camp);
    - a shuttle bus;
    - lounge and recreational facilities; and
    - access gates to allow for tracking and monitoring.
- Cultural awareness training of Hydro staff and contractors;
- Strictly enforced rules and security with respect to discipline, impaired driving and intoxication;
- Ongoing awareness initiatives regarding safe driving practices;
- Traffic signage on the access road and a traffic monitoring program; and
- Regular communication between Manitoba Hydro and the RCMP.

Evidence of Elizabeth Hicks, October 30, Pages 2380 - 2383

Residual adverse effects were also identified with respect to boreal woodland caribou. Thresholds for disturbance were reviewed that are available and provided in the National Recovery Strategy for Boreal Woodland Caribou in Canada. Caribou are a threatened species under both Provincial and Federal legislation and there are now in place both a national caribou recovery strategy and a Provincial one. Manitoba Hydro participates on three regional caribou committees and embarked upon a research project to contribute to caribou conservation in the future.

Evidence of Jim Rettie, October 31, Pages 2578 – 2579

Evidence of Mr. Schindler, MH-73

Evidence of Mr. Schindler, October 31, Pages 2623-2624

Manitoba Hydro convened an expert panel to conduct a formal risk assessment of the potential threat to woodland caribou from the Project. The assessment categories included forage loss and degradation, range fragmentation, predation, pathogens and direct mortality from humans.

Evidence of Jim Rettie, October 31, Page 2557 and Pages 2579 - 2580

Recommendations from the panel included a collaring and monitoring program to identify critical local range components, and a monitoring of local populations to determine the effects of linear disturbances on predation.

Evidence of Jim Rettie, October 31, Pages 2580 - 2582

The recommendations of the panel were implemented – a collaring and telemetry study was conducted, aerial surveys were carried out, habitat modeling took place, and new range maps created. The results of this detailed analysis were then used in the route selection to avoid the majority of ranges and habitats and to develop mitigation measures.

Evidence of Jim Rettie, October 31, Pages 2582 – 2588; Page 2591

Evidence of Doug Schindler, October 31, Page 2593

The majority of potential residual adverse effects on boreal woodland caribou were mitigated through this extensive study and analysis, and through the use of the pre-project monitoring, mainly through avoidance and the paralleling of existing infrastructure. There is not expected to be a decline in population as a consequence of increased predation due to the Bipole III Project.

Evidence of Jim Rettie, October 31, Page 2635

The AFPR changes in the Wabowden area reduced scientific uncertainty and concern regarding the potential residual effects of the Project on the Wabowden boreal woodland caribou evaluation range and increased the confidence in the prediction of residual effects and the overall assessment of significance for the boreal woodland caribou VEC

Exhibit MH-113

Evidence of Doug Schindler, March 4, 2013 pages 5983-5988

The use of thresholds is challenging as there are not many currently in existence. Not using thresholds does not necessarily represent a deficiency, so long as efforts are demonstrated to identify and apply if available.

Evidence of George Hegmann, February 18 Rebuttal, Pages 2

During the course of the hearing, and as new information became available, moose became more prominent as a VEC, necessitating further work and study, and a further cumulative effects assessment.   It had been determined at the time the EIS was drafted that the potential residual effects on moose of the Project, as a linear development, were not significant.

Evidence of Doug Schindler, October 30, Page 2312 – 2314

Due to additional information being provided by the Province and further concerns being brought forward on the decline of the moose population in certain Game Hunting Areas (GHAs) along the proposed route, there was a re-consideration of the route by Manitoba Conservation and Water Stewardship (MCWS) in GHA14 and in GHA19A/14A. Further field studies and review work were done by Manitoba Hydro to conduct an environmental assessment on the route alterations proposed by MCWS and to determine what, if any, effect the Project would have on the environment in those regions.

The February 2013 Supplemental Assessment concluded that with either the AFPR or the FPR for the HVdc transmission line component of the Project and mitigation as described in Chapter 6, the cumulative effects of the Project in combination with other past, current and future projects are not expected to result in any significant residual adverse effects on moose.

With respect to moose:

- In GHA 14, he AFPR crosses a larger amount of higher value moose habitat than the FPR, but does not change the significance evaluation from the EIS, as such either segment is viable.
- In GHA 19A/14A the AFPR has potentially significant issues (with respect to culture), so enhanced mitigation was proposed to allow re-adoption of the FPR while reducing or eliminating access issues to moose habitat.

Exhibit MH-113

March 4, 2013, page 5988-6037

The proposed AFPR change in the GHAs 19A and 14A areas will move the HVdc line construction and ongoing operation into a culturally sensitive area that is avoided by the FPR, and result in potentially significant adverse residual effects on the culture of Camperville, Pine Creek First Nation and Duck Bay. Aside from avoiding this area through routing the HVdc transmission line elsewhere (as was achieved with the FPR in the original EIS), Manitoba Hydro is not currently aware of mitigation measures likely to alleviate adequately these expected adverse residual effects on culture from the AFPR route change in the GHA 19A/14A area. Overall, the assessment concludes that the residual adverse effect of the AFPR in this area on culture is “not significant”; however, uncertainty is noted as to whether the ongoing adverse effect will remain moderate in magnitude and medium term in duration. The assessment of the FPR in this area had concluded that the residual adverse effects of the FPR on culture is not potentially significant.

Exhibit MH-112

Evidence of Virginia Petch, March 4, 2013 page 5972-5982

4. GIVEN THAT THE ROUTE BY THE ELECTORAL DECISION OF THE PEOPLE OF MANITOBA IS TO BE A WEST ROUTE, HAS MANITOBA HYDRO SUCCESSFULLY BALANCED ALL OF THE COMPETING RESTRAINTS OF SUCH A ROUTE?

It was acknowledged by Manitoba Hydro that one of the most common themes received during the consultation process pertained to the decision to route Bipole III on the west side of the Province, rather than on the east side.

Evidence of Pat McGarry, October 3, Pages 653 – 654

However, Manitoba Hydro cannot address that concern, based upon the decision reached by the Government of Manitoba in that regard in September of 2007.

Manitoba Hydro was then faced with the challenge of routing around, and in some cases, through areas of importance to particular groups, such as:

- Treaty Land Entitlement and reserve lands;
- Lands used for harvesting and domestic resources;
- Other lands of cultural and heritage importance;
- Intensive agricultural areas;
- Protected regions, Provincial Parks and Wildlife Management Areas;
- Critical habitats; and
- Regions already heavily developed with hydro, forestry and other projects.

Selecting a route on the western side of the Province was exceedingly challenging, given all of the impediments and the numerous competing interests, and given the distance the route had to cover – almost 1400 kilometers. As even Mr. Berrien conceded:

> "You guys had a huge job. I mean, it went up from all the way up in the shield all the way down into the Assiniboine flats and clay. It was a huge profile of land for sure."

Evidence of Robert Berrien, November 19, Page 5343

Focus was on the VECs relevant to the area being assessed. Where the VEC was not relevant to the section being evaluated, it was given a low or zero rating in the route selection matrix.

Evidence of Pat McGarry, October 4, Page 780

The task of balancing those interests, which were often at odds with each other, was a monumental one. During the evidence provided by Mr. McGarry and Mr. Dyck, they were able to demonstrate and depict visually the competing interests in one small section of the route through the display of the bottle neck map found in Chapter 8. The overlap in concerns and issues was staggering.

The extensive Site Selection and Environmental Assessment process, it has attempted to balance those competing interests and the various constraints revealed through both that process and through the EACP. Its use of numerous subject matter experts and a team approach was important to obtaining that balance.

Many of the remaining complaints raised by Participants and presenters with respect to aboriginal engagement arise out of issues with the Crown's constitutional duty to consult with First Nations and representatives of other Aboriginal communities and persons, including the MMF, and the alleged lack of progress on that Crown Consultation Process. With respect, issues arising out of that process are beyond the scope of this hearing, as the duty to consult has not been delegated to Manitoba Hydro. Further, environmental assessment in Manitoba is not designed to assess the impact on treaty or Aboriginal rights.

As already decided in a preliminary motion by Peguis First Nation, "it is not the Commission's job to tell the Crown how to conduct its business. This includes the content, the process and the timing of the Crown's consultations." It also stated that "in the absence of any legal authority which would require the Commission to consider the nature and adequacy of Crown consultations or of direction from the Minister in the Terms of Reference, the panel is of the view that no such obligation exists."

Decision of the CEC dated August 31, 2012

Concerns remain with respect to the Technical Advisory Committee ("TAC") process and the volume and substance of comments received from subject matter experts on that Committee. Again, those concerns cannot be addressed by Manitoba Hydro.

Evidence of Warren Mills, March 6, Pages 6443 - 6445

Throughout the hearing, we have heard from some landowners and farmers that they remain unhappy with the route selected and the residual effect the Project will have on their operations. The alternatives to the Project put forward by the Bipole III Coalition on their behalf are not acceptable from a reliability and cost perspective and cannot be implemented. To move the route elsewhere in southern Manitoba does not eliminate the concerns.

In the view of Mr. Nielsen, even with additional study and analysis, a better route through intensive agricultural land could not be found. It was reasonable routing which tried to avoid people, farm yards, residential areas and the like, and reduced diagonals. Moving the line elsewhere would only move the line to similar soil types and to someone else's farming operation.

Evidence of Jim Nielsen, October 30, Pages 2485 – 2487

The Bipole III Coalition introduced some potential alternate routing with agricultural Manitoba through Mr. Berrien. However, as he conceded, the "devil is in the detail". Many of his suggestions ignored routing constraints or impediments that were in existence, such as houses and shelter belts. There can be no substitute for the hours worked, and the kilometres travelled, in establishing a route that balances the needs and wants of the many landowners in the vicinity with the technical requirements of the Project.

Evidence of Robert Berrien, November 19, Page 5363 and 5365

In the final analysis, only 17.8 hectares of land will potentially be taken out of production as a result of tower placement, a tremendous feat given the length of the route and the necessity to go through western Manitoba.

Answer to Undertaking given at Page 2489 on October 30

Manitoba Hydro does, though, recognize and acknowledge the effect on such landowners. For that reason, it has a Landowners Compensation Policy to attempt to address the financial impact and has revised it over time to continue to address concerns that have been raised.

That program contains four components, made up of both one-time payments and "real time" payments to address specific impacts as they arise.

- Land compensation equivalent to 150% of the market value of the land taken for the easement, as compared to land acquired by way of expropriation (market value only).

Evidence of Curtis McLeod, October 30, Pages 2496 – 2500; Page 2505; Page 2519

- One-time structure impact compensation for the crop loss and related losses associated with the extra time and effort required to go around each tower, taking into the account the dominant land use in the past.

Evidence of Curtis McLeod, October 30, Page 2498

- Construction damage compensation negotiated post-construction for any kind of damage to property such as crops, land, or equipment

Evidence of Curtis McLeod, October 30, Pages 2497

- Ancillary damage compensation for direct or indirect impacts to the use of the property, such as impacts caused by an inability to aerial spray in one year; claims can be made by both landowners with towers on their property and by landowners in the vicinity of towers if they have been impacted.

Evidence of Curtis McLeod, October 30, Pages 2500 – 2501; Page 2506; Page 2520

In the one example provided – for one mile of right of way containing three or four towers and causing a minimal loss of cultivated land, a landowner would receive $111,000 of compensation.

Evidence of Curtis McLeod, October 30, Page 2502

It is not a "one size fits all" solution and has been customized to some degree. It will address individual impacts and can certainly be adapted over time to deal with unique issues that arise over time. It offers an upfront payment immediately and is also on par or better than that provided by electrical utilities in neighboring Provinces.

Evidence of Curtis McLeod, October 30, Page 2502; Page 2505; Page 2520

While annual payments have been suggested, *Expropriation Act* does not allow for annual payments in this regard, as conceded by Berrien.

Evidence of Robert Berrien, November 19, Pages 5260 - 5261

Another competing interest raised during the hearing is the conflict between blueberry harvesters and the Corporation's need to clear vegetation and manage it into the future. Although the experts have indicated that blueberries do better after disturbances such as fire or other clearing, further analysis has been done to address the concerns and minimize the conflict between these competing interests. Significant dollars have been expended on research and development, which includes research into blueberries.

Evidence of Kevin Szwaluk, October 29, Page 2266, Page 2270, and Page 2275

Evidence of James Matthewson, November 8, Page 4046

Assurances have been provided that no herbicides will be used during the construction process and its application later will be targeted, single plant applications. In many areas, construction will be done in the winter to ensure no damage is done to growing plants. Sensitive areas can be flagged during construction to ensure they are not disturbed and buffer zones established to address community members' concerns. This is yet another example of the attempts by Manitoba to find balance.

Evidence of Glenn Penner, March 12, Page 6786

Evidence of Wayne Ortiz, March 12, Page 6810

Routing through lower quality pasture land was seen as a routing opportunity and selected as the Alternate Final Preferred Route in the area of Moose Meadows through a bison ranch, thereby minimizing the environmental impact on moose and staying further away from the community of Pine Creek First Nation. However, this attempt to balance competing interests still has not addressed the visceral concerns of PCFN due to the incorrect perception that bison ranch operators could potentially receive compensation from Manitoba Hydro.

Evidence of Warren Mills, March 6, Page 6482 - 6483

Evidence of Pat McGarry, March 12, Page 6806

Through consultation with government resource managers, several suggestions were made in regard to routing which were adopted. For example a salt spring near Red Deer Lake was avoided and routing through Wildlife Management Areas minimized. The Round 4 consultation on the PPR also resulted in a number of route adjustments to adapt to specific landowner requests related to tower placement, irrigation and fence lines. An adjustment was also made to the PPR for proximity to a waterfowl area

Appendix 7B Chapter 7 EIS

The participation and contribution of many interested people and groups has helped locate a major transmission line project in a sustainable manner in a very large and diverse biophysical and socio-economic environment. The FPR (with adjustments) represents the compilation of many technical studies and the collective input of many stakeholders leading to a project route that has no significant impacts after mitigation and follow-up.

5. CAN MANITOBA HYDRO MANAGE THIS PROJECT RESPONSIBLY, PROFESSIONALLY AND SUCCESSFULLY GOING FORWARD?

Manitoba Hydro has developed an Environmental Protection Program which provides the framework for the implementation, management and monitoring of the environmental protection measures that are deemed necessary and important to the environment as the Project proceeds. Manitoba Hydro has made a written commitment to over 600 mitigation and monitoring measures designed to manage this Project responsibly professionally and successfully going ahead and to protect the environment as it moves forward.

Evidence of James Matthewson, November 8, Pages 4052 - 4053

The draft Project Environmental Protection Plan has been developed, but only after:

- a comprehensive review of its two most recent major projects (Wuskwatim Project and Riel Sectionalization) for lessons learned;
- a detailed literature review;
- a review of other North American Environmental Protection Plans for similar projects; and
- interviews with other utilities to gain from their experiences.

Evidence of James Matthewson, November 5, Pages 4050 - 4052

This demonstrates a commitment to using an Adaptive Environmental Management approach, one in which you plan, do, evaluate, learn, and adjust.

Evidence of James Matthewson, November 5, Pages 4117

The Environmental Protection Program has a number of key components which will also help Manitoba Hydro manage this Project responsibly professionally and successfully going forward, including:

- Monitoring Plans for both biophysical and socioeconomic elements;
- Management Plans for matters such as:
    - Access management;

    - Blasting;
    - Emergency preparedness and response;
    - Erosion protection and sediment control;
    - Rehabilitation/Remediation;
    - Vegetation; and
    - Solid waste/recycling;
- Environmental Protection Plans for construction, operations and maintenance, and decommissioning;
- A Heritage Resources Protection Plan;
- Inspection, Monitoring and Communication Programs;
- Continuing engagement of stakeholders;
- The use of the more innovative active Adaptive Environmental Management model;
- Use of a number of environmental officers/monitors and specialists with authority to inspect and monitor and, where necessary, shut down;
- Significant involvement of communities, including the hiring of local environmental monitors and community liaisons;
- Annual reviews and audits; and
- Annual Monitoring Reports hosted on the Manitoba Hydro website and submitted to MCWS.

Evidence of James Matthewson, November 8, Pages 4055 – 4117

One small example of this approach and commitment was provided by Dr. Petch as she described the many steps taken and the care exercised when two burial sites were discovered near the proposed Keewatinoow site. She described the considerable work done, in conjunction with Fox Lake Cree Nation, to protect and preserve these significant heritage resources, and to carry out further monitoring and work into the future.

Evidence of Virginia Petch, October 30, Pages 2444 - 2450

Manitoba Hydro is committed to a comprehensive Program of environmental protection. It is committed to engagement with communities, First Nations, the Métis, and regulators, and to their involvement in identifying/reviewing environmentally sensitive sites and corresponding mitigation measures throughout Program development. It is committed to being adaptive, to learning, and to evolving throughout the duration of the construction and operation of the Project. The Program and associated Plans have been designed to meet or exceed applicable government guidelines and industry best practices.

Evidence of James Matthewson, November 8, Pages 4117 - 4118

Evidence of Deirdre Zebrowski, October 3, Page 479

The Corporation has taken on the significant responsibility to ensure the Project is implemented with minimal effects on the environment and people. The Project and environmental protection only begin with licensing and, while it is end of the regulatory process, it is merely the start for Manitoba Hydro.

THE FINAL TASK BEFORE THE CEC

Manitoba Hydro takes the position that each of the 5 questions have been answered in the affirmative and, based upon the entirety of the evidence, this CEC can, in good conscience and with strong conviction, now recommend to the Minister that the Project be licensed.

Specifically, Manitoba Hydro is asking that the FPR be adopted as indicated in the original filing of the EIS on December 1, 2011, save and except for the following change found in the supplemental EIS filed January 28, 2013:

- The AFPR in the Wabowden area, as it reduces scientific uncertainty and concern regarding the potential residual effects of the Project on Wabowden woodland caribou evaluation range. Manitoba Hydro believes that mitigation measures can address the concerns of the mining interests.

With respect to GHA 14, Manitoba Hydro is of the view that both the FPR and the AFPR are acceptable based upon the environmental assessment, although the AFPR contains considerably more high quality moose habitat and will result in more challenging mitigation measures related to access along the AFPR.

Manitoba Hydro remains in support of the FPR for GHA14A/19A, because the AFPR may result in potentially significant adverse effects on the culture of Camperville, Pine Cree First Nation and Duck Bay.

The CEC's task, however, does not end with that recommendation. What conditions does it recommend be placed on that licence? What mitigation measures need to be put in place and what future monitoring is required?

The Corporation has committed to over 600 mitigation and monitoring measures so as to ensure that any possible anticipated residual effect is minimized. Those commitments are contained in a letter of commitment to the CEC dated October 29, 2012, and Manitoba Hydro recommends that those be adopted. They are detailed, extensive, and properly address any residual effects that have been caused by the Project. They also involve stakeholders extensively in future endeavours.

A requirement that the commencement of construction of Bipole III be subject to a "pre-condition", namely the successful negotiation of an agreement with a third party, such as suggested by the MMF and its expert, MSES, TCN, and others is not practical because it is not enforceable. There is no process or body, Court or government that can successfully compel two parties to "agree". If there is to be an agreement, the parties themselves have to negotiate it and conclude it. Just as judges have, continuously, declined to enforce "agreements to agree", they will be unable to compel a reluctant party to "agree" on any basis, be it assertions by the frustrated licence holder that the reluctant party is being unreasonable, or be it assertions by the third party that the licence holder is not negotiating in good faith or is not funding the third party's negotiation costs in a reasonable amount.

Transcript, October 19, Page 2122

Such a condition is also not appropriate in the context of an environmental hearing. This is not a hearing into the constitutional rights of the MMF or others. It is a hearing into the environmental impact on the Valued Environmental Components relevant to this Project.

The MMF has suggested that there is an obligation arising out of the Aboriginal Justice Inquiry Implementation Commission ("AJIIC") to negotiate an agreement or treaty with them prior to any natural resource development proceeding. With respect, the Bipole III Transmission Line Project is <u>not</u> a "natural resource development".

Manitoba Hydro also asks the CEC to carefully consider the practical application of any recommendation it is pondering in regard to Manitoba Hydro, and whether the contemplated recommendation can, in fact, be implemented by it. Although heartfelt and perhaps legitimate, many of the requests being made by the Participants are far beyond the scope and authority of Manitoba Hydro. Manitoba Hydro asks that any recommendations made be thoughtful, practical and well-explained.

Manitoba Hydro would like to thank the Clean Environment Commission, the Participants and the various presenters for their attentiveness, helpful input and insightful questions throughout the process. Manitoba Hydro has attempted to learn through this process, to adapt and respond to concerns expressed and the recommendations made, and to improve the assessment overall. A full environmental assessment is an iterative process and, as a result of the participation of all involved, the assessment process has been improved and the analysis of the Project more thorough. In the end result, the value of the hearing has been demonstrated and the end produce vastly improved. Manitoba Hydro will also take forward what it has learned from this experience and continue to improve upon its environmental assessments in the future.

APPENDIX A: SUMMARY RE: CUMULATIVE EFFECTS ASSESSMENT APPROACH

In response to issues raised by CAC and others during the hearing, Appendix A summarizes key points regarding the cumulative effects assessment approach and framework provided in the Bipole III Project EIS.

Compliance with *Cumulative Effects Assessment Practitioners Guide*

The cumulative effects assessment (CEA) for the Bipole III Project reflects current practice and follows a method in alignment with the *Cumulative Effects Assessment Practitioners Guide* (the "Guide"), prepared by the Cumulative Effects Assessment Working Group for the Canadian Environmental Assessment Agency (CEAAgency, 1999), and is therefore in compliance with the Guide and with good practice. Testimony to this was provided at the hearing by the lead author of the only current Canadian government guide available on CEA, the very Guide that Drs. Gunn and Noble themselves used and accepted as a benchmark. Mr. Hegmann's testimony on the matter of CEA current practice reflects his extensive and ongoing engagement in the authorship and/or management of project environmental assessments prepared for regulatory review and advice to governments and regulators, including for major linear pipeline projects in Canada that have relevance specifically to the CEA framework applicable to the Bipole III Project.

Evidence of G. Hegmann, March 12, Pages 6849-6850
Evidence of C. Osler, November 22, Page 5818

Clarifications on Specific Issues

1. **"Project-Centric Approach" and "Residual Effects Trigger" –** The CEA prepared in support of the Bipole III Project regulatory EIS filing follows a "project-centric" approach, within which also lies the concept of the "residual effects trigger" as discussed in this hearing, i.e., CEA was reviewed in Chapter 9 only for those VECs for which the Project results in a likely measureable adverse residual effect. This approach examines potential effects by the proposed Project on selected VECs, and through a cause-effect analysis evaluates significance of Project residual effects. This approach does not assess VECs unless they are affected by the Project, and also does not assess VECs where such effects of the Project are not measureable, and reflects understanding that Project contribution is critical to allow one to make judgment on the Project's effects and hence its acceptability. The Guide

and the CEAAct support this as a fundamental basis of assessment. This approach was the practice adopted in the 2009 New Nuclear-Darlington project CEA[2], and in the CEAs used by BC Hydro in all of its recent northern transmission line project assessments. As such, the Bipole III CEA using this approach reflects current and best practice and is not deficient in regards to VEC selection and assessment of effects.[3]

Evidence of C. Osler, February 22, Pages 5818-5823; 5861-5863
Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2
Evidence of G. Hegmann, March 12, Pages 6851-6856

2. **"Baseline" reflects World Without the Project -** "Baseline" in the Bipole III Project CEA reflects the "world without the Project", and is an essential requirement in defining the incremental residual effects of the Project as required for a "project-centric" CEA[4]. As such, this "baseline" differs from some "earlier time" or "natural" condition where there are no effects from other projects and activities that are considered in the CEA. For regulatory applications assessing the effects of a specific project, use of existing conditions to represent a baseline is an acceptable approach. Such baselines include present and past human actions, to the extent they may be mapped and otherwise identified. The Guide supports this as a fundamental basis of assessment of best practice and, as such, the Bipole III CEA reflects current practice and is not deficient in regards to use of baseline. Defining the "baseline" as the "world without the Project" does not preclude the ability to consider "earlier time" or "pre-development" conditions for some VECs, where this is feasible and useful for the overall assessment of cumulative effects on a VEC relative to a acceptable threshold, e.g., earlier time periods were considered in the Bipole III supplemental CEA filings with regard to caribou and moose.

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[2] Subject to the screening including VECs that were positively affected by the project.

[3] Mr. Hegmann discussed in his rebuttal and testimony that Dr. Noble and Dr. Gunn do not agree with the project-centric process followed in the Bipole III CEA and instead advocated an "ecosystem or ecologically or VEC based" approach based on health of ecosystem. It needs to be noted that a project-centric approach as recognized in current CEA practice and the Guide does not in any way mean that the CEA analysis does not also focus, where relevant, on the VECs themselves that are affected by the Project, including the context for the VEC absent and with the Project, and the sustainability of the VEC due to all factors affecting it, e.g., see Exhibit MH-59, slide 34 and related testimony of Mr. Osler. See also clarification #4 in this Appendix A.

[4] The concept of "non-static" or "evolving" baselines as discussed in the hearing recognizes the possibility that baseline conditions (i.e., the world without the Project) may change in the future due, for example, to natural phenomena, such as wildlife or climate change. Discussion of these issues does not affect the fundamental point that the Guide supports use of existing baseline conditions in CEA, and that this definition of "baseline" does not preclude consideration of other information for a specific VEC when relevant and feasible.

Exhibit MH-59, Slides 7 and 8
Evidence of C. Osler, October 29, Pages 2172-2177
Evidence of C. Osler, November 22, Pages 5863-5865
Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2
Evidence of G. Hegmann & C. Osler, March 12, Pages 6896-6901

3. **All VECs with detectable adverse residual effects of the Project are included in the CEA -** Contrary to the evidence of Dr Gunn and Dr Noble asserting that the CEA in Chapter 9 of the Bipole III EIS looked only at VECs determined in Chapter 8 to have significant adverse effects from the Project[5], the Bipole III CEA in Chapter 9 examined all VECs (namely 64 VECs) with detectable adverse residual effects of the Project as determined in Chapter 8, and, as such, did ***not*** look only at VECs determined in Chapter 8 to have significant adverse effects from the Project. Only two of the initial 67 VECs examined in Chapter 8 were not examined in Chapter 9 due to the absence of a detectable adverse residual effect of the Bipole III Project, and only one VEC examined in Chapter 8 was not examined in Chapter 9 due a residual positive effect. As a matter of record, this point was reviewed in detail in the response to *CEC/MH-VI-347*; further, review of Chapter 8 as well as the referenced interrogatory response confirms that in fact there were no VECs assessed in Chapter 8 to have 'significant adverse effects from the Project."

   As an additional related point of clarification, the Bipole III CEA includes Chapter 8 as well as Chapter 9. As stated in the EIS, VEC assessments in Chapter 8 in each instance considered the cumulative effects of past and current projects when assessing the effects of the Project on each VEC, i.e., the added CEA analysis of VECs in Chapter 9 focused on future projects/activities where there is spatial and temporal overlap with residual adverse effects of the Bipole III Project.

   The CEA carried out in Chapter 9 for the 64 remaining VECs resulted in more detailed assessment of four VECs (boreal woodland caribou in three ranges as affected by the HVdc

[5] This misunderstanding starts to occur around page 26 of the critique filed by Drs. Gunn and Noble, and permeates section 1.4 of Appendix A and reappears at page 39. The Chairman on March 12 at pages 6879-6880 noted that 'we had been led to believe that if there is no significant residual effect, then there's no need to go to the next step and do a cumulative effects assessment."

transmission line component, and three socio-economic VECs [namely community services, travel and transportation, and public safety] with regard to residual adverse effects from construction of the Keewatinoow converter station and associated facilities). Subsequent supplemental CEA analysis was provided separately for caribou (prior to the CEC hearing) and more recently for moose in western Manitoba (February 2013).

Response to CEC/MH-VI-347
Exhibit MH-59, Slides 16 and 17, 46 to 56
Evidence of C. Osler, October 29, Pages 2182-2184, 2206-2214
Evidence of C. Osler, November 22, Pages 5861-5867
Evidence of G. Hegmann, March 12, Pages 6893-6896

4. **Assessment considers VEC context in light of effects from all sources –** Notwithstanding analysis of incremental effects of the Project on each VEC, the Bipole III CEA considers the current and expected future context of each assessed VEC (i.e., including the effects on the VEC of other past, current and future activities) and, where available, any VEC thresholds. In this regard, the CEA examines the extent to which VECs are already disturbed and/or stressed by past actions and changing conditions (e.g., boreal woodland caribou listed as Threatened under federal and provincial legislation) and, where relevant, reasonably foreseeable future actions (e.g., public safety cumulative effects for Fox Lake Cree Nation and Gillam community members during construction of Keewatinoow converter station, Keeyask Generation and Conawapa Generation projects). In this regard, the Bipole III EIS structure in Chapter 8 assesses the CEA of Project residual effects combined with effects of past actions and existing projects/activities, and in Chapter 9 assesses the extent to which the Chapter 8 CEA determinations are modified for any VEC by consideration of Project effects combined with effects of other projects and activities not yet examined in Chapter 8, i.e., other future projects and activities as listed in Chapter 9.

Response to CEC/MH-VI-347
Exhibit MH-59, Slides 7 and 8, 33 and 34
Evidence of C. Osler, October 29, Pages 2172-2177, 2196-2197, 2206-2214

5. **CEA for Regional or Strategic Planning versus CEA for Project Regulatory Reviews –** The words "cumulative effects assessment" have often been used interchangeably to mean

two different things. A regional or strategic planning CEA has nothing to do directly with any one project application for regulatory review. Notwithstanding the potential benefits of having available a regional or strategic planning CEA in order to set context and (potentially) thresholds for overall effects on certain VECs in the region, the lack of such regional CEA studies or analytical approaches such studies may use does not in itself constitute deficiency in a CEA project assessment. Examples of where such regional or strategic CEA have been prepared, such as the oil sands region, confirm that such CEAs are supported by government responsible for overall resource and regional planning in the affected area, and Dr. Noble and Dr. Gunn agreed that "regional strategic environmental assessment is ultimately the responsibility of government". To date, no such overall regional or strategic CEA has been prepared by government for the various regions affected by the Bipole III Project.

On this matter, the Bipole III CEA also complies fully with the Scoping Document (Section 8), i.e., it is based on CEAA guidelines as well as best and current practices in that it is required only to take into consideration any relevant regional and strategic environmental assessments available at the time the Bipole III EIS was prepared (and no such assessments were in fact available).

The Guide also fully recognizes that regional "nibbling" effects of the type highlighted by Drs. Gunn and Noble and the "thousand cuts" imagery usually cannot be adequately dealt with on a project-by-project review basis, and that regional plans of the type discussed above (i.e., prepared by government) are required that clearly establish regional thresholds of change against which the specific actions may be compared.

Evidence of G. Hegmann, March 12, Pages 6857-6859, 6887-6893
Evidence of Dr. Noble & Dr. Gunn, November 15, Pages 4963-4964
Evidence of C. Osler, November 22, Pages 5006-5007

6. **Use of Thresholds in Bipole III CEA -** The Bipole III Project CEA uses thresholds to assist evaluation of significance where thresholds are available for VECs, e.g., CEA for woodland caribou. Absence of use of thresholds does not necessarily represent a deficiency, so long as efforts are demonstrated to identify and apply if available. The Guide does not support the view that the significance of a cumulative effect on a VEC cannot be assessed or commented

upon unless there is some established threshold for the affected VEC[6]. In this regard, the Bipole III CEA represents current practice and the Guide supports this view.

Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2

7. **Reliance in CEA on future management measures associated with other projects -** The Bipole III Project CEA's reliance on future management measures associated with other future Manitoba Hydro projects is a pragmatic and realistic recognition of one part of the long-term solution of cumulative effects within a given region. As such, mention of future measures supported by future projects does not represent a deficiency given that reasonable efforts are committed to by Manitoba Hydro regarding effects management. In this regard, the Bipole III CEA represents current practice and the Guide supports this view.

Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2

8. **Accidental events are not assessed in CEA -** The Bipole III Project CEA does not assess accidental events or malfunctions. As such, absence of such an assessment within this CEA does not represent a deficiency. There is no federal *guidance* that stipulates inclusion of assessment of accidents in a CEA[7]. Assessment of accidents, malfunction and upset events (AMUEs) is typically done separately within a regulatory application (Chapter 8, Section 8.4 of Bipole III EIS) due to the very different nature of such effects (compared to routine project effects) and the low likelihood (rarity) of such effects. In this regard, the Bipole III CEA represents current practice and the Guide supports this view.

Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2

9. **Study Areas for CEA -** The Bipole III Project CEA uses a very broad regional study area, and a Local Study Area that is 4.8 km wide centred on the route for the HVdc transmission

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[6] In this regard, the Guide does not support Dr. Noble's evidence as follows on this point (November 15, Page 4851): "The point is that unless you have some established threshold, you can't really identify or comment on the significance of the cumulative effect." If further guidance is sought on this matter, Section 3.5.3 of the Guide addresses what the practitioner can do in the absence of defined thresholds (including "acknowledge that there is no threshold, determine the residual effect and its significance, and let the reviewing authority decide if a threshold has been exceeded").

[7] In the hearing, Dr. Noble responded to a question from Mr. Beddome on this matter, saying (November 15, Page 5002) that the "operational policy statement for cumulative effects assessment at the federal level specifically requires catastrophic events to be considered, like major spills or risks, in good practice cumulative effects" and that "it's an important part of the consideration of cumulative effects." Mr. Hegmann's rebuttal confirms that there is no known support for Dr. Noble's testimony on this matter.

line and the area immediately surrounding other Project components; broader study areas beyond the Local Study Area are considered in the Bipole III EIS for the assessment of VECs as required and appropriate, and vary considerably based on the nature of the cause-effects on VECs. For linear projects such as transmission lines, use of a study area based on a linear corridor is common practice, and is commonly represented by a buffer along each side of the project right-of-way. As such, the use of the Local Study Area in the Bipole III CEA does not necessarily represent a deficiency. In this regard, the Bipole III CEA represents current practice and the Guide supports this view[8].

Evidence of G. Hegmann, Feb 18 Rebuttal, Page 2
Exhibit MH-59, Slides 20-21

10. **Regulatory Significance –** Following from experience working with First Nation partners on the Keeyask Generation Project EIS, the Bipole III EA and CEA uses the term "regulatory significance" to differentiate the technical and objective standard of significance required to be met by the CEAAct from other non-technical or non-regulatory interpretations, i.e., the CEAA guides on significance provide that significance determination is an objective exercise and not a question of personal point of view or public opinion. In relation to First Nation concerns in northern Manitoba, it is understood that the regulatory perspective of evaluating environmental effects of the Project that focuses on assessing the effects on certain VECs does not often fit with a holistic or Aski world view. – however, this difference in views has not stopped Manitoba Hydro from filing EISs (e.g., Keeyask Generation Project EIS) for new projects with First Nation partners and having these EISs include basically similar VEC selection, assessment and significance determinations as are provided in the Bipole III Project EIS. The material issues and concerns raised by affected northern Aboriginal communities such as TCN and FLCN are not readily or very appropriately addressed through VEC analysis in effects assessment – this includes issues of lack of trust, lack of involvement and a desire to be heard regarding past experiences with northern development and what has

[8] The definition of the Local Study Area in the Bipole III EIS did not prevent, where relevant, the assessment of Project effects on a given VEC from extending beyond the Local Study Area into the much broader Project Study Area, e.g., Chapter 9 and response to CEC/MH-VI-347 identify the relevant VECs in this regard (climate, boreal woodland caribou and several socio-economic VECs). Broader regional analysis was also done more recently for moose (and the technical analysis for various VECs also included consideration of context information beyond the Local Study Area). Defining study areas is a matter separate from the type of CEA analysis carried out for a VEC in the defined area on a VEC, and the evidence of Drs. Gunn and Noble on this issue often focuses on a preferred method of analysis such as use of landscape indicators.

been learned. These issues are being addressed by Manitoba Hydro on an ongoing basis through continued dialogue focused on developing an effective relationship with these communities.

Evidence of C. Osler pages 3099-3101 and pages 5824 to 5826.

11. **Scoping Future Projects into CEA -** Prospective future projects and human activities were defined in the Bipole III CEA as "not yet approved nor in a planning/approvals process preparatory to being constructed/carried out" and are listed in Table 9.2-3. This table includes prospective future transmission projects in southern Manitoba that have recently received a lot of discussion at this CEC hearing, namely the New International Transmission Line and prospect of further development of new transmission lines in southern Manitoba (e.g., Letellier/St. Vital line; St. Vital- LaVerendrye). Each of these projects were in early planning stages at the time the Bipole III EIS was filed and without adequate definition or other information to support any meaningful inclusion in the Bipole III CEA assessment. It was noted in Chapter 9 of the EIS for each of these transmission lines that the project would not occur without comprehensive route selection and environmental impact assessment (which has still yet to occur as at March 2013), extensive public consultation and approval and licensing by the relevant regulatory authorities.

Chapter 9, Table 9.2-3: Prospective Future Projects & Activities
CEC-MH-III-090; CEC-MH-III-091;
Evidence of C Osler, Pages 3216 to 3229

12. **Methods used to support regulatory CEA** - Although techniques such as the use of landscape or stream crossing indicators and computer based models are not required by the Guide to support a regulatory CEA, in the Bipole III EIS similar techniques were applied where appropriate. For example, technical studies were provided on Habitat Fragmentation, and the recent Supplemental Enhanced Assessment for Moose filed in February 2013 included analysis of linear disturbance on a landscape scale and the use of computer based models, confirming (page 47) that landscape and linear development do not explain moose decline in western Manitoba[9].

Habitat Fragmentation Technical Report (November 2011)
Enhanced Assessment for Moose (February 2013)
Evidence of G. Hegmann, Feb 18 Rebuttal, Page 3

[9] The critique by Drs. Gunn and Noble includes recommended studies that Manitoba Hydro does not see to be reasonable in the case of the Bipole III Project CEA, including (by way of example) the recommendation of a full CEA to all water crossings (pages 38 and 45) and wetlands (page 38 and 53-54). In the case of water crossings, the Project complies with strict and highly successful federal requirements such that no federal EIA is required regarding aquatic (fish and fish habitat) impacts due to the commitment to follow Department of Fisheries and Oceans operational statements as summarized in the December 2011 EIS (pages 8-48 to 8-51) and also reflecting the plan to focus construction in such areas during the winter season timing windows (which further minimizes any potential effects). In the case of wetlands, this is not a VEC for this project - for the reason that no material evidence has surfaced to suggest that this Project is likely to have any notable effect on wetlands.

Tab 21

MPA Morrison Park Advisors

Review of Updated Manitoba Hydro Development Plans

Prepared by Morrison Park Advisors
For

Manitoba Public Utilities Board

May 2014

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Contents

Tables

Figures

1. Introduction

Manitoba Hydro provided detailed information to the Manitoba Public Utilities Board (PUB) on its Preferred Development Plan and alternatives beginning with its Business Case, delivered in August 2013. Subsequent information was provided through IRs and supplementary information disclosures (some of which were commercially sensitive) to participants in the PUB's process.

Morrison Park Advisors reviewed and analyzed the information provided, and commented on it in its Report (January 2014), in various responses to IRs from the PUB and other participants, and in its presentation and verbal comments before the PUB (April 2014).

Coincident with the commencement of public hearings before the PUB, Manitoba Hydro began releasing updates to the Preferred Development Plan (PDP) and to various potential alternatives. These updates take into account both changes in the external environment (e.g., inflation rates and natural gas price projections), and changes in Manitoba Hydro management expectations (e.g., cost of construction for various proposed projects).

Given changes to multiple variables simultaneously, it is impossible to accurately predict the combined outcome on the relative attractiveness of the various alternatives presented by Manitoba Hydro absent testing of the new data. As a result, MPA updated its own models based on the new data provided by Manitoba Hydro, analyzed the outputs in detail, and presents its results in this supplementary report.

1.1. New Information Provided by Manitoba Hydro

Manitoba Hydro provided new information for the following Plans:

Table 1. Comparison of Updated to Original Plans

Plan	Elements (2013 version) (base DSM)	Elements (2014 version) (DSM level 2, no pipeline)
1	*All Gas* • Single cycle natural gas units added in 2022-23, 2025-26, 2028-29, 2034-35, 2047-48 • Combined Cycle natural gas units added in 2031-32, 2037-38, 2040-41, 2044-45	*All Gas* • Single cycle natural gas units added in 2031-32, 2035-36, 2039-40, 2047-48 • Combined Cycle natural gas unit added in 2042-43
2	*K22/Gas* • Keeyask Hydroelectric Generating Station in 2022-23 • Single cycle natural gas units added in 2029-30, 2032-33 • Combined Cycle natural gas units added in 2034-35, 2038-39, 2041-42, 2045-46	*K31/Gas* • Keeyask Hydroelectric Generating Station in 2031-32 • Single cycle natural gas units added in 2040-41, 2044-45, 2047-48

Plan	Elements (2013 version) (base DSM)	Elements (2014 version) (DSM level 2, no pipeline)
4	*K19/Gas24/250MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 250 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units added in 2024-25, 2029-30 • Combined Cycle natural gas units added in 2032-33, 2038-39, 2041-42, 2045-46	*K19/Gas40/250MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 250 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units added in 2040-41, 2044-45, 2047-48
5	*K19/Gas25/750MW(WPS Inv.)* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Interconnect will be partially owned and funded by a US investor • Single cycle natural gas units added in 2025-26, 2026-27, 2028-29, 2031-32, 2033-34, 2045-46, 2047-48 • Combined Cycle natural gas units added in 2042-43	*K19/Gas31/750MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units added in 2031-32, 2044-45, 2047-48
6	*K19/Gas31/750MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units added in 2031-32 (x2), 2032-33, 2034-35, 2043-44 • Combined Cycle natural gas units added in 2039-40, 2045-46	*K19/Gas40/750MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units added in 2040-41, 2044-45, 2047-48
14	*K19/C25/750MW(WPS Inv.)* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Interconnect will be partially owned and funded by a US investor • Conawapa Hydroelectric Generating Station in 2025-26 • Single cycle natural gas units added in 2041-42, 2044-45, 2046-47	*K19/C31/750MW* • Keeyask Hydroelectric Generating Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Conawapa Hydroelectric Generating Station in 2031-32

The original versions of the Plans, provided in August 2013, assumed the 2012 Manitoba load forecast, and a "base" level of Demand Side Management (DSM), as per the programs approved by the PUB at the time. The 2014 versions of the Plans assume the newer 2013 Manitoba load forecast and substantially higher "Level 2" spending on DSM. The difference is significant, and causes dramatic changes in the timing and composition of energy generation investments by Manitoba Hydro.

Investment in DSM (e.g., subsidies for efficiency measures such as improved lighting and motors, fuel switching for heating purposes from electricity to natural gas, subsidies for combined heat and power or waste heat electricity generation at industrial facilities, etc.) means that net load measured on the

Manitoba grid will be significantly reduced over time, as compared to current projections. This should have two impacts: more of Manitoba's Hydro's electricity production from existing facilities should be available for export (particularly in "wet" years), and new facilities to provide dependable energy will not be needed until later in the period under study. As a result, the revised plans include fewer single cycle and almost no combined cycle natural gas-fired generation units over the course of the next forty years.

Annual expenditures on DSM will be much higher throughout the period studied, but assuming the net cost of DSM investments is lower than the cost of the new generation being avoided, then Manitoba consumers as a whole should be better off.

[Note: this is an assumption made about Manitoba electricity consumers *collectively*. DSM programs by definition apply unequally across consumers when considered individually. DSM programs typically result in a higher price per unit energy because total demand is reduced, while system fixed costs – including DSM spending – do not fall with demand. Consumers who respond to DSM programs and reduce their consumption will benefit from the DSM investments, while consumers who do not participate in DSM programs and therefore do not reduce their power consumption will potentially pay more for their electricity. The rest of this paper focuses exclusively on collective customer rate impacts, and will not comment on the potential distributional effects of DSM within the Plans.]

As noted in Table 1, the additional load that may result from new interprovincial pipelines that might be built in the future was not included in the scenarios tested by MPA. According to Manitoba Hydro, such pipelines could increase Manitoba load by 1300 GWh by 2027 if they are built. This would reduce Manitoba Hydro's ability to export power, and may require changes in the timing of new generation units in certain plans.

Capital costs for the Keeyask and Conawapa projects have been increased, in accordance with the most recent construction contracts entered into by Manitoba Hydro.

The WPS Investment in the transmission interconnection with the United States that was assumed in certain Plans in 2013 is no longer assumed in any Plans. Manitoba Hydro is instead assumed to absorb the portion of the capital cost that was previously assigned to WPS, and recover those expenditures over time through other arrangements.

Common costs shared by all Plans (such as transmission, distribution and administrative costs) have been updated to match the recently released 2013 IFF and 2013 CEF.

Interest and inflation forecasts have also been updated. The following table highlights changes in the economic variables used in the analysis of the Plans:

1 **Table 2. Comparison of Updated Economic Variables**

Indicator		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020+**
Manitoba CPI Inflation (%)	2013	1.70	1.80	1.80	1.80	1.80	1.80	1.90	1.90
	2014	1.70	1.80	2.00	2.00	2.00	2.00	2.00	2.00
	Difference	0	0	+ 0.20	+ 0.20	+ 0.20	+ 0.20	+ 0.10	+ 0.10
Manitoba Hydro Long Term $CDN Debt Rate (%)	2013	4.15	4.30	4.85	5.55	5.95	6.15	6.30	6.30
	2014	4.15	4.50	4.85	5.20	5.95	6.40	6.75	6.75
	Difference	0	+ 0.20	0	- 0.35	0	+ 0.25	+ 0.45	+ 0.45
Manitoba Hydro Equity Rate (%)	2013	7.15	7.30	7.85	8.55	8.95	9.15	9.30	9.30
	2014	7.15	7.50	7.85	8.20	8.95	9.40	9.75	9.75
	Difference	0	+ 0.20	0	- 0.35	0	+ 0.25	+ 0.45	+ 0.45
Nominal Weighted Average Cost of Capital	2013								7.05
	2014								7.50
	Difference								+ 0.45

2

Taken together, all of these changes result in dramatically different Plans for consideration. Timing and extent of investments has changed, relative importance of exports vs. domestic load has changed (because of lower Manitoba demand), and capital costs have changed for both internal and external reasons. The only commonality between the “new” and “old” versions of the Plans are potential investments in Keeyask, Conawapa and transmission interties.

1.2. Scenarios

In August 2013 Manitoba Hydro provided data for and analysis of the various Plans in light of 27 different scenarios, based on High, Reference and Low forecasts for groups of variables relating to energy prices, capital costs and the economy. In addition, other cases were developed and examined relating to higher and lower demand expectations, and the possibility of droughts at different times in the future.

Comprehensive data for the 2014 updated Plans has been provided for a single scenario: reference economics, reference energy and reference capital costs (Ref/Ref/Ref).

Based on our model, MPA can and did test the impact of alternative interest costs (as a proxy for broader economic variables) and increased costs for construction of Keeyask and Conawapa (as a proxy for capital cost variables). This should be understood as sensitivity testing, rather than scenario analysis, however.

MPA could *not* test sensitivity to alternative energy prices. Changes in the price of electricity exports and natural gas purchases have important impacts on Manitoba Hydro’s expected behaviour at a plant level: depending on relative prices of exports, natural gas and domestic electricity rates, decisions are made whether to use or build up water reserves, and decisions are made between buying imported power and running domestic plants. These are the critical outputs of Manitoba Hydro’s SPLASH model. Data from Manitoba Hydro’s SPLASH model has been provided only for Reference energy prices, not for High or Low energy prices. MPA’s analysis of potential alternative energy price scenarios must perforce be restricted to conjectures based on the impact of energy prices on the 2013 Plans provided by Manitoba Hydro.

Also, while load forecasts are updated with respect to the 2014 versions of the Plans, Manitoba Hydro did not provide additional data from SPLASH model runs with higher or lower Manitoba demand. Again, MPA’s analysis must be restricted to comparisons with previously provided information.

1.3. New Analysis and Previous Conclusions

As summarized in MPA’s presentation to the PUB in April 2014, we ultimately came to the following conclusions based on all of the information provided to us based on Manitoba Hydro’s 2013 Plans:

a) In our view, there was no compelling commercial reason to not go ahead with the Keeyask and transmission interconnection projects, as described in the Preferred Development Plan and several other alternative plans;

b) Conawapa – which in our view is better understood as an ongoing development project rather than an immediate commercial opportunity as is Keeyask – faces a higher burden which does not appear to be met: it is not clearly commercially superior to alternatives, in fact appears to be less attractive than certain other alternatives, and therefore Manitoba Hydro should be required to demonstrate why it is appropriate to continue spending development capital on the project instead of pursuing alternatives.

In considering the new information provided by Manitoba Hydro, we were guided by these conclusions with respect to our further analysis:

- Does the new information suggest that alternatives are now clearly commercially superior to proceeding with Keeyask and the transmission interconnection?
- Is Conawapa now more attractive than alternatives as a development opportunity?

1.4. Note on Adjustments to the Model

MPA's financial model is identical to the version used to test the original data provided by Manitoba Hydro. No changes were made in order to ensure that new versions of the Plans can be compared to original versions.

A critical feature of the model is the domestic rate-setting mechanism. Manitoba domestic rates are set based on Manitoba Hydro's expected financial performance, as well as based on export prices and volumes. Crucially, changes from year to year are constrained to a maximum of two times the rate of inflation.

In the original data provided by Manitoba Hydro, long-term inflation in the Reference economics scenario was 1.9% per year. This resulted in a maximum change in Manitoba domestic rates of 3.8% per year (either up or down).

In the 2014 data recently provided, long-term inflation is assumed to be 2% per year, which would result in a maximum annual rate change in our model of 4% per year. The difference of 0.2% per year in maximum change in rates may not at first appear significant, but over the course of 20 years, that small difference in rates does become significant. For example, assuming an initial rate of 100, after 20 years of 3.8% increases the ending rate would be 210. If the rate of increase is instead 4%, then the ending rate is 219. Considered over large volumes of energy, such rate changes could have important impacts on Manitoba Hydro finances.

In order to provide insight to the potential impact of rate-setting decisions, MPA tested the model set to both a maximum change in annual rates of 3.8% and 4%.

2. Model Outputs

For each of the Plans (All Gas, 2, 4, 5, 6, PDP), MPA modeled the financial performance of Manitoba Hydro for each of the 99 hydrology patterns provided (the same patterns that were reviewed in our January report to the PUB). A variety of outputs were collected, including ratepayer costs, government revenues, export revenues, etc. In each case, raw outputs were summarized by averaging the results of the 99 hydrology patterns, recording high and low results, and the standard deviations around the mean (note that in an assumed "normal" distribution such as hydrology, approximately two thirds of cases should be within one standard deviation of the mean).

In addition, net present values for the results were calculated at both 6% and 10%.

2.1. Ratepayer Total Costs

Figure 1 below presents the total costs to Manitoba ratepayers over the life of the model, for the Ref/Ref/Ref Scenario. This calculation has been performed based on a 3.8% per year maximum change in domestic rates, consistent with MPA's January report.

Figure 1. Total Cost to Ratepayers at a 3.8% Maximum Annual Rate Change

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
Maximum	$40,915	$41,569	$40,561	$40,671	$40,816	$43,854
Minimum	$38,596	$39,282	$38,274	$38,571	$38,642	$40,815
Standard Deviation	$486	$485	$494	$465	$492	$708
Present Value						
NPV @ 10.00%						
Average	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322
Maximum	$22,406	$22,720	$22,561	$22,666	$22,736	$23,886
Minimum	$21,583	$21,787	$21,737	$21,864	$21,895	$22,961
Standard Deviation	$201	$257	$183	$168	$172	$225
Nominal Value						
Average	$161,316	$162,570	$151,161	$151,791	$151,794	$158,555
Maximum	$172,403	$176,999	$161,403	$164,331	$162,887	$172,101
Minimum	$153,275	$154,896	$141,117	$142,701	$142,824	$149,689
Standard Deviation	$4,568	$4,059	$4,278	$4,212	$4,449	$4,950

Some notable comparisons can be observed:

- The results for Plans 4, 5 and 6 (all of which include Keeyask but not Conawapa) are within 1% of each other across all cases (NPV at 6% or 10%, as well as nominal dollars, and also across maximum, minimum and average values).

- Plan 4, which includes Keeyask and a 250 MW intertie, is very slightly superior in all cases to Plan 5, which includes Keeyask and a larger intertie. However, the difference between the two Plans is approximately half of one percent, which is well within the margin of error that should be assumed for a model of this sort.
- Plan 2, which includes Keeyask but no transmission intertie, and is therefore a domestically focused Plan, is slightly inferior to Plans 4, 5, and 6 at an NPV of both 6% and 10%. However, in nominal dollar terms it is significantly inferior, which indicates that its costs to ratepayers are higher further out in the future.
- The All Gas Plan is competitive with Plans 4, 5, and 6 at an NPV of 6%, but slightly superior (by approximately 1%) at an NPV of 10%. However, in nominal dollar terms the All Gas Plan has the highest ratepayer cost of all Plans modeled, which indicates that its costs to ratepayers are significantly higher further out in the future.
- The PDP is approximately 5% inferior to Plans 4, 5 and 6 across all cases. It is the worst performing Plan in terms of NPV calculated at both 6% and 10%, but is superior to the All Gas Plan and Plan 2 in nominal dollar terms. The PDP also has the highest standard deviation, which suggests that it is the most sensitive to hydrology. Notably, there is no discount rate at which the PDP is superior to Plans 4, 5 and 6: they are superior to the PDP regardless of discount rate assumptions (note that nominal dollars are equivalent to a discount rate of 0%).

Figure 2 presents the same information as Figure 1, based on the application of a maximum 4% annual change in rates in the model.

Figure 2. Total Cost to Ratepayers at a 4% Maximum Annual Rate Change

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$39,687	$40,313	$39,454	$39,633	$39,699	$42,040
Maximum	$40,830	$41,497	$40,557	$40,581	$40,692	$43,533
Minimum	$38,652	$39,356	$38,273	$38,520	$38,651	$40,858
Standard Deviation	$493	$491	$498	$460	$479	$432
Present Value						
NPV @ 10.00%						
Average	$22,071	$22,285	$22,302	$22,400	$22,439	$23,507
Maximum	$22,409	$22,816	$22,695	$22,714	$22,759	$23,987
Minimum	$21,588	$21,860	$21,834	$21,958	$21,989	$23,115
Standard Deviation	$204	$256	$202	$170	$173	$141
Nominal Value						
Average	$160,890	$162,840	$150,881	$150,990	$150,948	$155,786
Maximum	$174,221	$176,603	$161,941	$164,688	$162,469	$165,868
Minimum	$151,390	$156,667	$141,592	$141,259	$139,321	$148,197
Standard Deviation	$4,851	$4,080	$4,333	$4,423	$4,674	$3,113

Some observations:

- As compared to the results with a 3.8% maximum change in rates, the NPVs at both 6% and 10% are slightly higher across all Plans when a 4% maximum change in rates rule is applied. However, total cost to Manitoba ratepayers in nominal dollar terms is lower. This impact is a result of higher rate increases in early years, and lower rates in later years, across all Plans.
- Rank ordering between the Plans has not changed despite the move from 3.8% maximum changes in rates to 4% maximum changes in rates. However, the gap between Plans has changed: the difference between the PDP and Plans 4, 5 and 6 has narrowed somewhat, as has the gap between Plan 2 and Plans 4, 5 and 6 when discounted.
- The standard deviation applicable to the PDP has significantly decreased. This suggests that more rapid increases in domestic rates and revenues, and the concomitant reduction in debt and interest charges that would result for Manitoba Hydro, are critical to reducing the sensitivity of the PDP to the hydrological performance of Manitoba's generation fleet.

2.2. Comparison to 2013 Plans

As noted in section 1.1. above, the updated versions of the Plans contain a number of significant changes from the versions provided in 2013. This has resulted in significant changes in the projected costs to Manitoba ratepayers. The Figure below summarizes the differences in NPV at 6% and 10%, based solely on the Ref/Ref/Ref scenario, with a maximum rate change of 3.8% per year.

Figure 3. Comparison of 2013 and 2014 Ratepayer Costs

Present Value of Domestic Revenue
Reference Economics, Energy and Capital
2013 Plans vs. 2014 Plans
(2015 - 2062)
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
2013 Average	$43,791		$42,878		$43,301	$44,230
2014 Average	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
Difference	-$4,132		-$3,438		-$3,605	-$2,231
%	-9.4%		-8.0%		-8.3%	-5.0%
NPV @ 10.00%	$23,623		$23,476		$23,633	$24,148
2013 Average	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322
2014 Average	-$1,624		-$1,251		-$1,288	-$826
Difference	-6.9%		-5.3%		-5.4%	-3.4%
%						

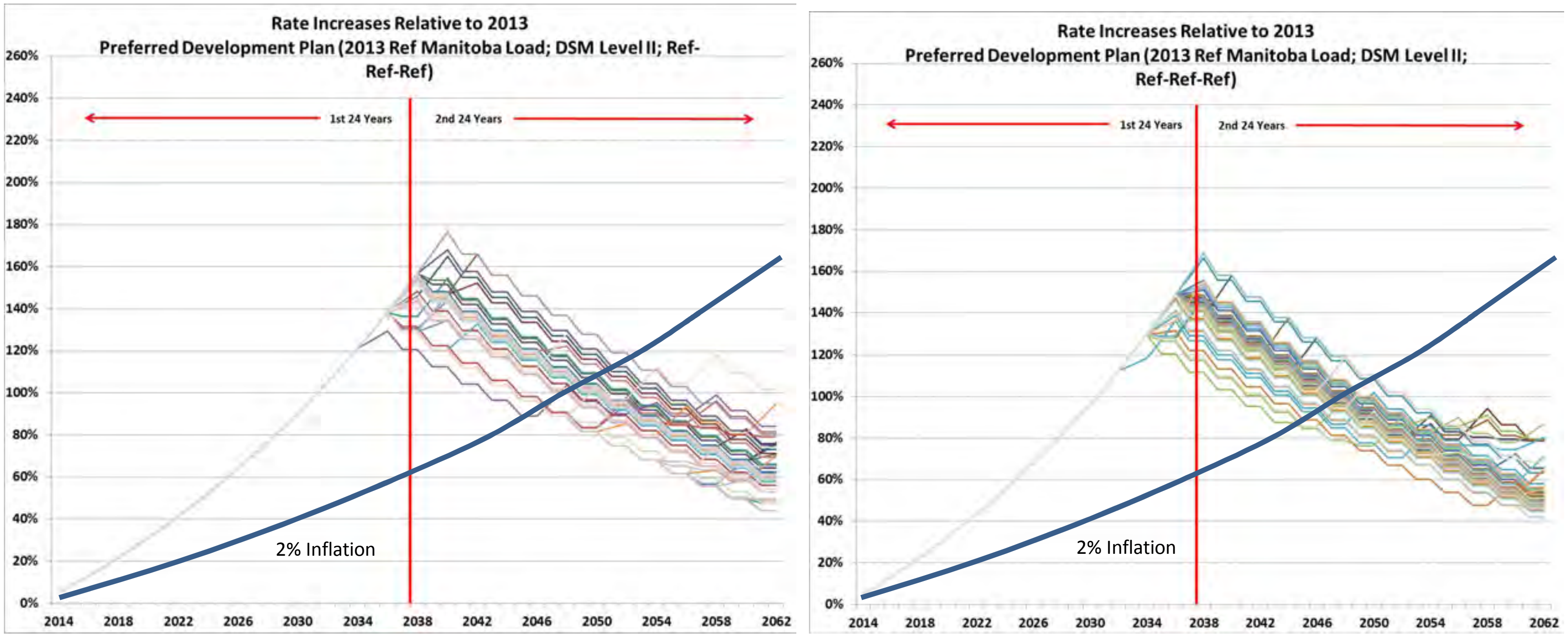
Across all Plans, projected total costs for Manitoba ratepayers have declined.

- It is notable that this decline has occurred *despite* the fact that expected interest rates have increased, capital costs for projects have increased, and inflation rates have increased slightly.
- The declines speak to the powerful impact of dramatically expanded DSM programs (4x the spending contemplated in the 2013 Business Case), which are expected to dramatically reduce Manitoba domestic load, and free up more capacity for export. Moreover, as noted above, the Plans themselves now contemplate a much reduced level of capital spending on generation projects (and generally later in time), though of course spending on enhanced DSM programs will begin almost immediately.
- The gap between All Gas and the Keeyask-based Plans has narrowed. All Gas is now marginally superior to Plans 4, 5 and 6 at a 10% discount rate, and essentially identical at a 6% discount rate. Based on the 2013 Plans, Plans 4 and 6 were superior to All Gas at 6%, and Plan 4 was also superior at 10%.
- The gap between the PDP and the other Plans has actually increased as compared to the 2013 versions of the Plans.

2.3. Rate Paths

Some of the observations made above with respect to ratepayer costs can be more easily illustrated by reference to projected rate increases in the future. For example, Figure 4 (below) presents rate increases for the PDP under 3.8% and 4% maximum annual rate changes.

Figure 4. Cumulative Rate Increases for the PDP under 3.8% and 4% Annual Rate Change Rules

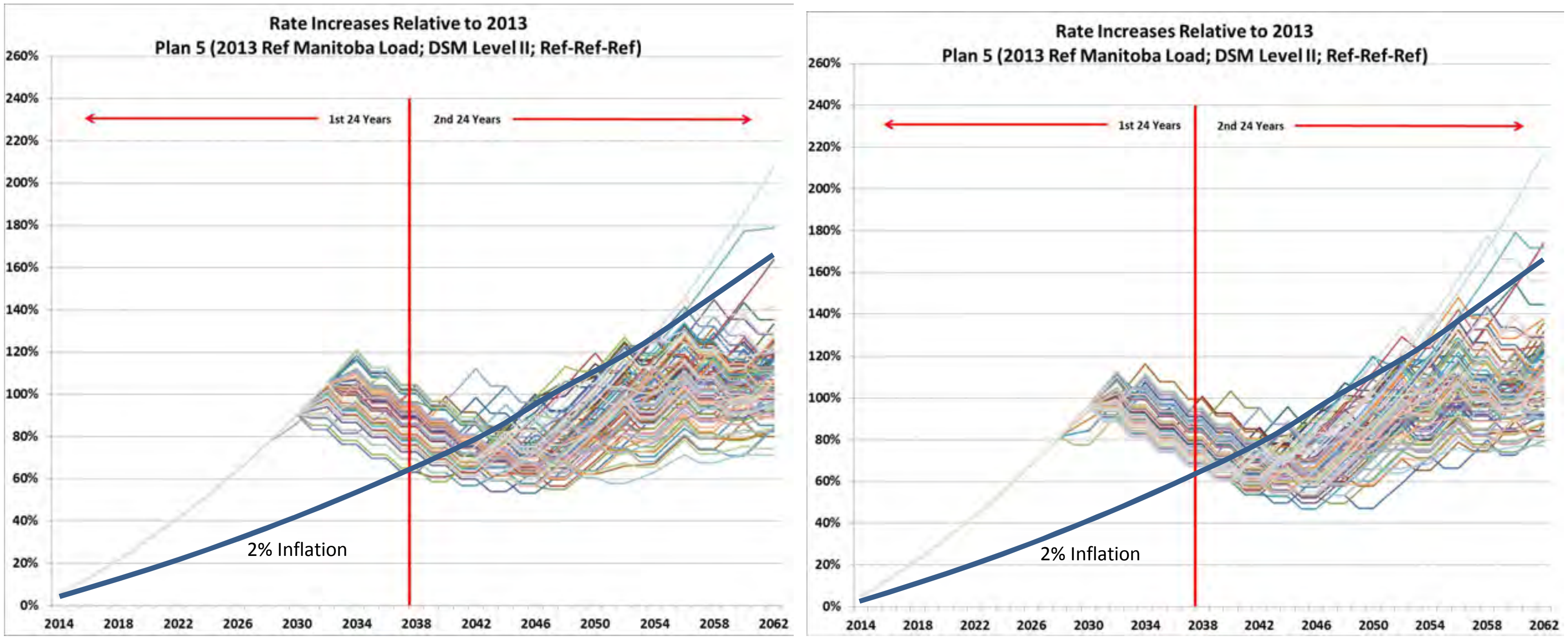


The graph on the left depicts the rate paths for the 99 hydrological patterns for the PDP under the Ref/Ref/Ref scenario, with the application of a 3.8% rule for maximum annual change in Manitoba domestic rates. On the right, the results are depicted for exactly the same assumptions, except for the use of a 4% maximum annual rate change rule. Since in both cases maximum annual rate increases are required for the first 20 years of the model, it can be seen that customer rates in Manitoba are approximately 9% higher in the year 2034 in the right hand graph. By the year 2038, the mid-point of the model period, rates in the right hand graph have peaked for virtually all of the 99 hydrological patterns tested, and rate declines have already begun in many instances. The left hand graph depicts that rates have not yet peaked in 2038 for many hydrological patterns, and the definitive turn downwards does not begin until 2040 or slightly later.

An observation that can be drawn from this comparison is that higher rates in the early years of the PDP would bring rates in later years down even further. However, such a change would simply accentuate the trade-off being made between the welfare of ratepayers in different periods of time.

Figure 5 (below) depicts the rate paths that would result from Plan 5 under the same conditions.

Figure 5. Cumulative Rate Increases for Plan 5 under 3.8% and 4% Annual Rate Change Rules

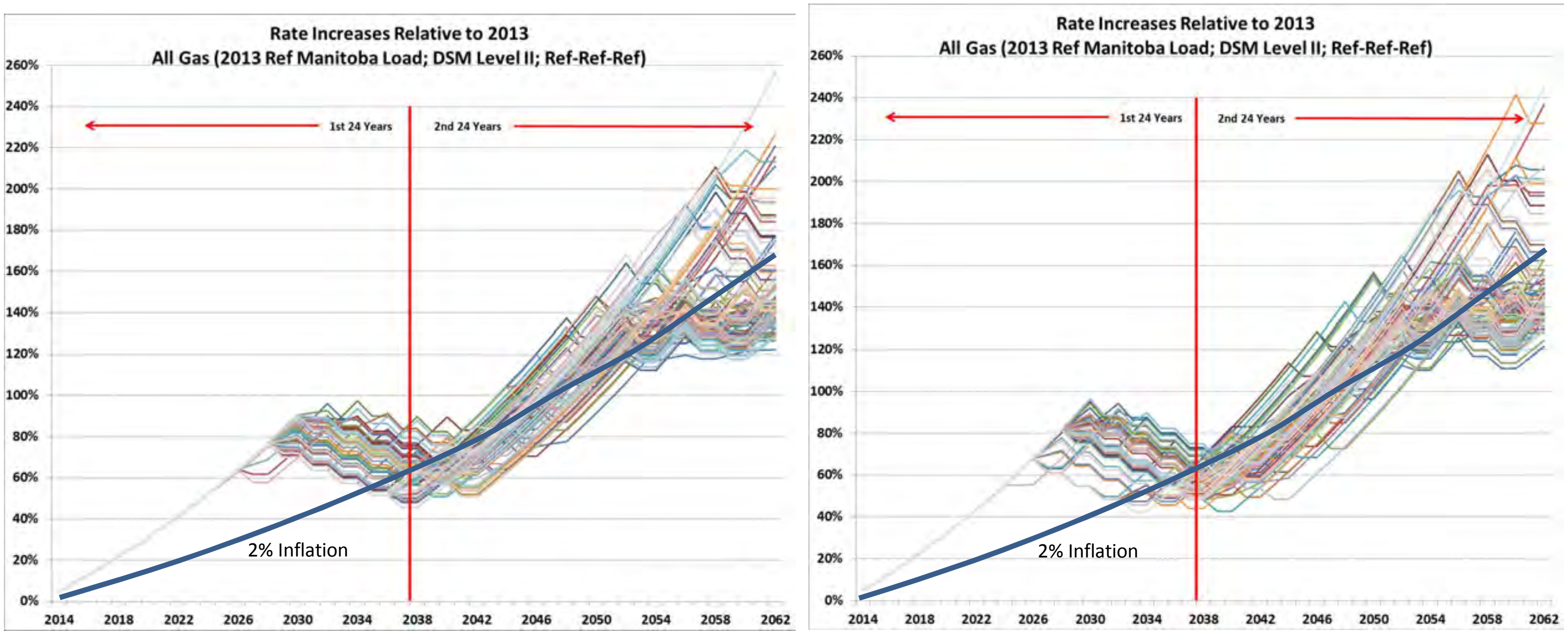


Cumulative rate increases for Plan 5 appear to peak in the early 2030s, before the mid-way point of the model is reached, then fall for approximately 10 years, and then rise again at a rate less than the maximum allowable (for all but a few hydrological patterns). With the higher allowable 4% change in rates, the peak appears to occur slightly earlier, as would be expected, and the distribution of the rate paths appears to be somewhat more compact until the late years of the model, suggesting that the higher domestic revenues resulting from higher Manitoba rates would reduce the sensitivity of Manitoba Hydro to financial stresses from hydrological patterns.

As compared to the PDP, the rate path is radically different, and represents a significantly different inter-generational choice with respect to the allocation of costs and benefits over time.

Figure 6 (below) provides the expected rate paths for the All Gas Plan.

Figure 6. Cumulative Rate Increases for All Gas under 3.8% and 4% Annual Rate Change Rules



The All Gas Plan represents yet another intergenerational allocation of costs and benefits, with cumulative Manitoba rate increases peaking in the late 2020s, then declining modestly for a decade, before strongly increasing again. This pattern is consistent with the results noted in Section 2.1, above, where the All Gas Plan was superior to the PDP at a NPV of 6%, and especially at 10% (because it entails lower rates in the earlier years of the model), but was significantly inferior to the PDP in nominal dollar terms (because of the impact of the very high prices under All Gas in the later years of the model). As compared to Plan 5, cumulative rate increases for All Gas are identical until the late 2020s, then All Gas rates are somewhat lower for approximately 10 years, before Plan 5 rates permanently fall below All Gas rates in the late 2030s.

The impact of the higher annual rate change limit, as with the other Plans, is to marginally shorten the initial period of maximum rate increases, and then to make the decline in customer rates more decisive, before allowing them to rise again.

2.4. Sensitivities

As noted above, Manitoba Hydro has not provided data for the updated Plans across the full range of 27 scenarios that were defined in August 2013. Absent SPLASH outputs for energy pricing alternatives, sensitivities of updated Plans to energy price changes cannot be calculated. This will be discussed further below. However, MPA's model provides the flexibility to test the sensitivity of the Plans to changes in nominal interest rates and to higher construction costs.

All sensitivities were calculated based on the 3.8% maximum annual change in domestic rates rule, in order to allow comparison to modeling work previously undertaken by MPA.

2.4.1. Interest Rates

As noted in section 1.1. above, Manitoba Hydro assumed long-term interest rates of 4.50% for 2014, rising to 6.75% for 2019 onwards. Changing these interest rate assumptions will raise or lower the projected debt interest costs to Manitoba Hydro, and will have a strong impact on the company's finances.

Typically, interest rate changes do not occur in isolation, since changes in interest rates are usually at least partly correlated with changes in inflation rates (as changes in interest costs permeate the economy they have an impact on prices for all goods, to a greater or lesser extent depending on a variety of elasticities of demand and price). However, in our model interest rate changes are isolated from inflation, so a 1% increase in interest charges does not affect assumed inflation (this is equivalent to a 1% change in "real" interest rates). Such a change could occur in the real world if, for example, the cost of debt to the Province of Manitoba (and hence Manitoba Hydro) were to rise or fall because the capital markets change their view of the Province's economic or fiscal performance. In such a case, underlying Canada interest rates would not change, and inflation would likely not be affected to any significant degree. As was noted in our January report, historically the "spread" between Manitoba and Canada has actually fluctuated substantially over time, without relationship to inflation, so this scenario is not far-fetched.

For the purposes of the current analysis, testing the sensitivity of the Plans to changes in interest rates is a proxy for the High/Reference/Low economic scenarios that were previously tested.

Figure 7 (below) summarizes the expected total cost to ratepayers from both an increase and a decrease in interest rates of 1%.

Currently, Manitoba's electricity system has the following output characteristics:

Figure 7. Sensitivity to Interest Rates

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

Sensitivity: + 1% Interest

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$41,424	$42,324	$41,916	$42,285	$42,338	$45,971
Maximum	$42,950	$43,821	$43,409	$43,575	$43,733	$47,659
Minimum	$40,028	$41,234	$40,464	$41,032	$40,994	$44,136
Standard Deviation	$609	$561	$659	$617	$661	$732
Present Value						
NPV @ 10.00%						
Average	$22,756	$23,172	$23,124	$23,287	$23,292	$24,461
Maximum	$23,240	$23,731	$23,548	$23,755	$23,711	$24,893
Minimum	$22,318	$22,702	$22,675	$22,898	$22,886	$23,966
Standard Deviation	$230	$265	$228	$205	$220	$193
Nominal Value						
Average	$168,986	$170,449	$165,237	$165,950	$166,785	$190,187
Maximum	$183,358	$183,264	$178,972	$178,760	$181,019	$205,753
Minimum	$158,243	$163,218	$154,544	$155,096	$155,654	$174,402
Standard Deviation	$5,070	$3,778	$4,845	$4,781	$5,049	$6,516

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

Sensitivity: - 1% Interest

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$38,076	$38,312	$37,506	$37,631	$37,701	$39,033
Maximum	$39,107	$39,485	$38,430	$38,527	$38,549	$40,118
Minimum	$37,185	$37,395	$36,415	$36,608	$36,707	$37,953
Standard Deviation	$445	$459	$441	$402	$420	$505
Present Value						
NPV @ 10.00%						
Average	$21,295	$21,342	$21,376	$21,458	$21,502	$22,283
Maximum	$21,694	$21,888	$21,739	$21,797	$21,827	$22,630
Minimum	$20,883	$20,829	$20,971	$21,035	$21,079	$21,918
Standard Deviation	$207	$235	$193	$167	$181	$205
Nominal Value						
Average	$154,164	$154,122	$143,351	$143,109	$143,104	$141,142
Maximum	$167,952	$165,362	$152,939	$154,959	$152,952	$148,757
Minimum	$146,923	$149,118	$136,304	$137,046	$136,294	$134,001
Standard Deviation	$4,248	$3,271	$3,604	$3,658	$3,786	$3,351

Interest rates have some clear impacts on total costs to Manitoba ratepayers:

- Changes in interest rates have the greatest impact on the PDP, which employs the greatest amount of debt capital, and the least impact on the All Gas Plan, which employs the least amount of debt capital.

- For Plan 5, a 1% increase in interest rates causes the NPV (at 6%) of Manitoba ratepayer costs to rise by approximately 6.5%. For All Gas this sensitivity is only 4.5%, while for the PDP the sensitivity is 9.5%.
- At lower interest rates the PDP becomes relatively more attractive, since the gap between the NPV (at a 6% rate) of the PDP and Plans 4, 5 and 6 has narrowed to approximately 4%. In nominal dollar terms the PDP actually has the lowest total cost to Manitoba ratepayers over the life of the model (which suggests that at a very low discount rate the NPV of the PDP would overtake the other Plans).
- Interestingly, at lower interest rates the difference between All Gas and Plan 2 (which includes Keeyask but no transmission intertie) essentially disappears.
- At higher interest rates the All Gas Plan is superior to all alternatives at both the 6% and 10% NPVs, but not in nominal dollar terms (which suggests that Plans 4, 5 and 6 would be superior to All Gas at a very low discount rate). However, it should be noted that the difference between the NPVs (at a 6% rate) of the All Gas and Plans 4, 5 and 6 are separated by slightly more than 1%, which is a barely significant difference.
- At higher interest rates the PDP is the most expensive Plan under all discount rates (including nominal dollars, which is a 0% discount rate).

2.4.2. Construction Costs

Figure 8 (below) presents the results of modeling for total ratepayer costs in the event that the construction costs of Keeyask and Conawapa are higher than currently forecast by $1 Billion (in 2014 $).

Note that this sensitivity is not a calculation of generally higher capital costs, but a calculation of the sensitivity of the Plans to specific project cost overruns. If construction costs are generally higher, then all Manitoba Hydro capital investments become more expensive, including those relating to transmission, distribution and administration. MPA does not have the means to calculate such a sensitivity since it does not have access to detailed Manitoba Hydro common cost information.

Figure 8. Sensitivity to Construction Cost Increases

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

Sensitivity: + $1 Billion for Keeyask, + $1 Billion for Conawapa (2014 $)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	$39,659	$40,937	$40,496	$40,729	$40,768	$43,975
Maximum	$40,915	$42,140	$41,738	$41,787	$41,927	$45,252
Minimum	$38,596	$39,903	$39,415	$39,751	$39,813	$42,549
Standard Deviation	$486	$504	$503	$462	$486	$526
Present Value						
NPV @ 10.00%						
Average	$21,999	$22,483	$22,641	$22,742	$22,756	$23,915
Maximum	$22,406	$22,900	$22,992	$23,037	$23,081	$24,276
Minimum	$21,583	$21,997	$22,252	$22,419	$22,439	$23,482
Standard Deviation	$201	$265	$168	$147	$145	$147
Nominal Value						
Average	$161,316	$166,224	$156,295	$156,941	$157,233	$173,282
Maximum	$172,403	$183,673	$168,821	$169,759	$168,430	$183,628
Minimum	$153,275	$158,664	$144,142	$147,314	$147,132	$163,259
Standard Deviation	$4,568	$5,068	$4,374	$4,366	$4,552	$4,358

The impact of higher construction costs is very similar to the impact of higher interest rates:

- This sensitivity has no impact on the All Gas Plan, since cost increases were tested only for the Keeyask and Conawapa projects.
- Adding $1 billion to the construction cost of Keeyask causes Plan 5 NPV (at 6%) of ratepayer costs to rise by slightly less than 3%. At this level, All Gas is approximately 2% superior to Plan 5 (or the other Plans including Keeyask in 2019). However, at lower discount rates Plans 4, 5 and 6 would still be superior to All Gas.
- The PDP is clearly inferior to all other Plans if both Keeyask and Conawapa construction costs are increased.

2.4.3. Energy Prices

As noted above, Manitoba Hydro did not provide SPLASH data for High and Low energy prices applied to the updated Plans, as they did for the 2013 Plans. As a result, it is not possible for MPA to examine in detail the potential impact on Manitoba ratepayers if energy prices were to fluctuate away from Reference assumptions. However, based on the work completed previously, and the new information available, it is possible to make “educated guesses” as to the sensitivity of the various Plans to energy prices.

In response to an information request from the PUB, in the record as PUB/MPA 1-004(a), MPA calculated the impact on various Plans of altering energy price assumptions while holding economics and capital variables at Reference assumptions. The following is a reprint of those outputs:

Figure 9. Excerpt from PUB/MPA1-004(a)

PV of Domestic Revenue
Comparison of Sensitivity to Energy Scenarios
Economic and Capital Scenarios at Reference
(in millions)

	6.00% Discount Rate					10.00% Discount Rate				
	Plan 1	**Plan 4**	**Plan 6**	**Plan 12**	**Plan 14**	**Plan 1**	**Plan 4**	**Plan 6**	**Plan 12**	**Plan 14**
High	$44,107	$41,868	$42,317	$42,409	$41,991	$23,441	$22,810	$22,991	$23,274	$23,268
Reference	$43,791	$42,878	$43,301	$44,727	$44,230	$23,623	$23,476	$23,633	$24,285	$24,148
Low	$43,695	$44,192	$44,585	$47,375	$47,037	$23,724	$24,017	$24,169	$25,122	$25,037
Sensitivity from Low to High	0.94%	-5.26%	-5.09%	-10.48%	-10.73%	-1.19%	-5.02%	-4.87%	-7.35%	-7.06%

In our work on the 2013 Plans, we concluded that energy prices had an inverse relationship to Manitoba ratepayer costs for those Plans which included Keeyask and Conawapa, but not necessarily for the All Gas Plan. In other words, High energy prices would lead to lower Manitoba ratepayer costs in the Plans based on the Keeyask and Conawapa projects.

One reason for this relationship is the higher export emphasis of those Plans. Recall that “energy prices” in the Manitoba Hydro scenarios consisted of a complex of four variables: electricity export prices (to the MISO market), electricity import prices (from the MISO market), natural gas prices (at delivered cost to Manitoba natural gas-fired electricity facilities), and carbon costs (as potentially imposed on fossil fuel-burning electricity generation facilities in the future). As these prices rise (in concert, as per Manitoba Hydro), Plans which include more gas-fired generation would suffer from higher natural gas fuel costs. On the other hand, Plans which emphasize hydroelectric production would not be affected by natural gas prices, but would benefit from higher export prices in the MISO market. Over the course of a 48-year model the picture is complicated by the fact that hydrology is different every year, and in droughts the impact of energy prices is reversed across Plans (high prices are bad for hydroelectric Plans in a drought because imports will be more expensive). However, since droughts are a relatively infrequent occurrence, they do not dominate the average impact across Plans.

Table 3 (below) compares the role of exports in the 2013 versions of the Plans with the role of exports in the updated versions (calculated from the 6% NPV figures).

Table 3. Export as % of Total Revenues – 2013 vs. Updated Plans

	All Gas	2	4	5	6	PDP
2013 Version	8.6%		14.2%		13.8%	17.3%
2014 Version	13.9%	16.1%	20.2%	21.4%	21.1%	27.5%
Change	+ 5.3%		+ 6.0%		+ 7.3%	+ 10.2%

The significant increases in revenues from exports for Manitoba Hydro across all of the updated Plans result from the much lower domestic demand in Manitoba due to Level 2 DSM programs. The updated All Gas Plan has an export orientation as strong as the 2013 versions of Plans 4 and 6. The updated versions of Plans 4 and 6 are now almost 50% more export oriented, and in fact are projected to generate more revenue from exports that the 2013 version of the PDP.

This suggests that ratepayer costs in all of the updated Plans are inversely proportional to energy prices, and likely quite strongly inversely proportional.

2.5. Inter-generational Impacts

In section 2.3. above, the depiction of rate paths for different Plans suggest strongly diverging treatment of Manitoba ratepayers over time.

- Regardless of the Plan chosen, ratepayers will face the maximum allowable rate increase for the next fifteen years under all Plans.
- After approximately 2030, the Plans diverge fairly dramatically, and continue to diverge for decades to come.

2.5.1. NPVs for Shorter Periods

MPA calculated the NPVs for domestic ratepayer costs for periods of 20 years and 30 years, as well as for 48 years. Figure 10 (below) presents these calculations for a 3.8% annual maximum rate change per year.

Figure 10. NPV of Ratepayer Costs for Alternative Periods

Present Value of Domestic Revenue
Reference Economics, Energy and Capital
20 year, 30 year and 48 year periods
($ in millions)

	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
2015 - 34	$24,244	$24,094	$24,911	$24,965	$24,993	$25,212
2015 - 44	$31,014	$31,728	$32,111	$32,314	$32,407	$34,694
2015 - 62	$39,659	$40,284	$39,440	$39,636	$39,696	$41,999
NPV @ 10.00%						
2015 - 34	$17,224	$17,133	$17,572	$17,599	$17,612	$17,721
2015 - 44	$19,900	$20,149	$20,440	$20,526	$20,566	$21,488
2015 - 62	$21,999	$22,248	$22,225	$22,312	$22,345	$23,322

A variety of observations can be made from this data:

- In the first 20 year period, Plan 2 is actually the least costly for ratepayers. This is likely the case because it does not involve writing off the costs sunk into Keeyask (as the All Gas Plan does), while new spending on Keeyask occurs relatively late in the period.
- The All Gas Plan represents the lowest ratepayer cost if the period examined is 30 years. In fact, the gap between the All Gas Plan and Plans 4, 5 and 6 is actually wider at 30 years than at 20 years, and the gap between All Gas and the PDP is also at its widest point.
- The gap between All Gas and Plans 4, 5 and 6 is never more than approximately 4%, regardless of the discount rate selected.
- When the examined period is 48 years, Plans 4, 5 and 6 have caught up to or surpassed the All Gas Plan, which suggests that ratepayers in that final 18 year period are dramatically better off under Keeyask-based Plans.
- While the PDP has the highest ratepayer costs under all periods, the gap narrows considerably over time. If the model were to progress beyond 48 years, then it is likely that the ranking of the PDP would continue to improve in nominal dollar terms. However, depending on the discount rate selected, the PDP might never catch up to Plans 4, 5 and 6. Higher discount rates dramatically reduce the present value effect of results so far in the future.
- From an inter-generational perspective, choice of Plans (considered solely from the perspective of ratepayer costs) is largely irrelevant to people who are likely to be ratepayers only for the next 15 years (e.g., older ratepayers, or businesses that do not foresee a long-term future in the province). However, beyond that point, the choice of Plans can have a very significant impact. Generational burdens, and the likely competitiveness of Manitoba electricity rates, will be very different depending on the choices made.

2.5.2. PUB Rate-setting Impacts

As noted above, MPA ran a financial model at both a 3.8% maximum annual change in domestic rates and a 4% annual maximum change. While the model was originally constructed to allow a maximum annual change of two times the projected rate of inflation (i.e., 2 x 2% = 4%), since the projected rate of inflation was previously 1.9% we ran the model both ways to ensure that comparisons could be made with previous results.

It is apparent that the setting of rates has important impacts on both total costs to ratepayers, intergenerational allocation of ratepayer costs, and the financial health of Manitoba Hydro.

In order to more clearly illustrate these issues, we ran the model at a maximum annual change in domestic rates of 5% for Plan 5 and the PDP. This is two and one half times the projected long-term rate of inflation, and represents a significant and noticeable annual increase in rates. At 5% growth per year existing rates would double in 15 years, and triple in 23 years, as compared to 18 and 29 years respectively for a 4% annual increase.

Figure 11. Manitoba Ratepayer Costs at 4% and 5% Maximum Annual Rate Change

Present Value and Nominal Value of Domestic Revenue
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

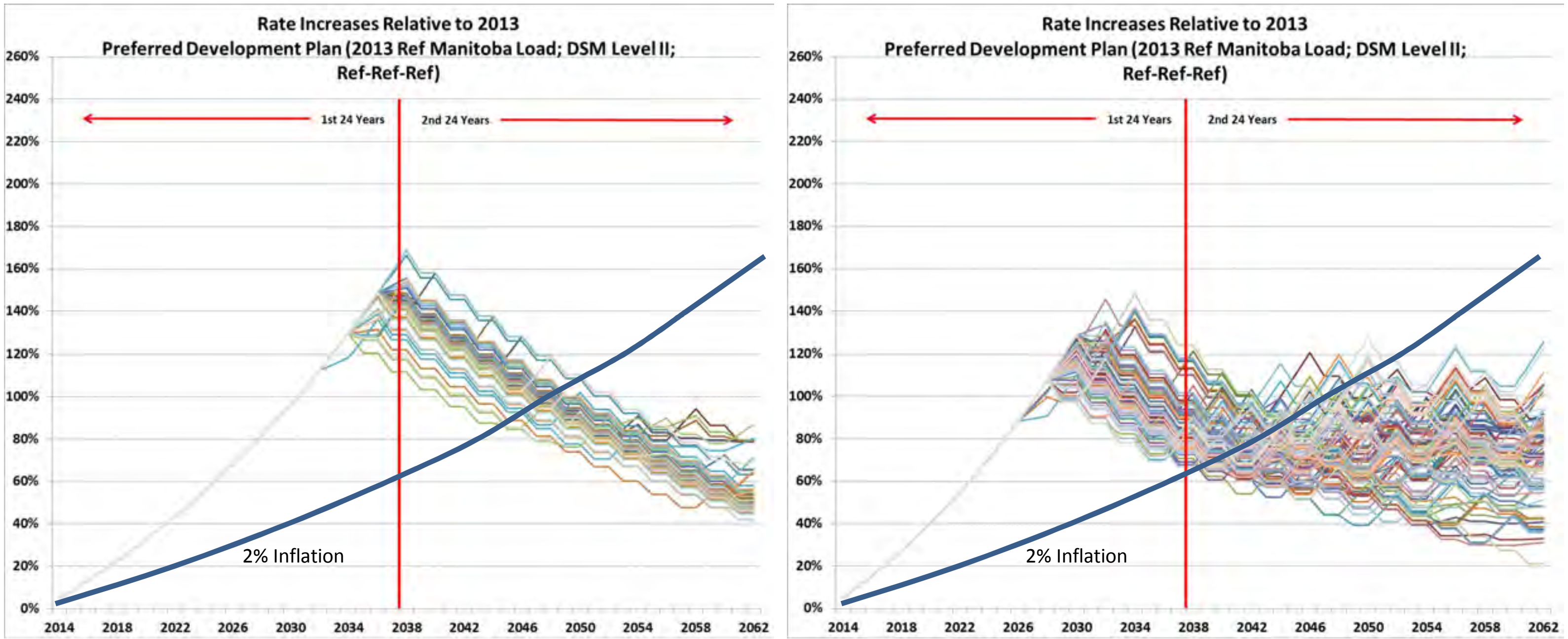
	5		**PDP**	
Present Value	**@4%**	**@5%**	**@4%**	**@5%**
NPV @ 6.00%				
Average	$39,633	$39,764	$42,040	$41,352
Maximum	$40,581	$40,775	$43,533	$42,591
Minimum	$38,520	$38,719	$40,858	$40,222
Standard Deviation	$460	$455	$432	$524
Present Value				
NPV @ 10.00%				
Average	$22,400	$22,824	$23,507	$23,682
Maximum	$22,714	$23,209	$23,987	$24,362
Minimum	$21,958	$22,221	$23,115	$23,138
Standard Deviation	$170	$175	$141	$227
Nominal Value				
Average	$150,990	$148,489	$155,786	$149,665
Maximum	$164,688	$163,013	$165,868	$160,936
Minimum	$141,259	$139,894	$148,197	$138,458
Standard Deviation	$4,423	$4,422	$3,113	$4,823

- As can be noted from the Figure, NPV results do not change dramatically for either Plan as a result of adopting a higher maximum annual rate change. While rates are rising faster in the early years of the model, the process of discounting the future (which makes earlier ratepayer costs more important) offsets the benefits achieved by Manitoba Hydro more quickly recovering costs.

- In nominal dollar terms, raising rates by 5% per year has a significant impact, particularly for the PDP, which sees total nominal dollar ratepayer costs fall by approximately 4% over the life of the model. At very low discount rates, this effect would also be noticeable.

Rate charts illustrate the impact of increasing the maximum allowed annual rate change.

Figure 12. Comparison of PDP Rate Paths with 4% and 5% Maximum Annual Rate Change Rule

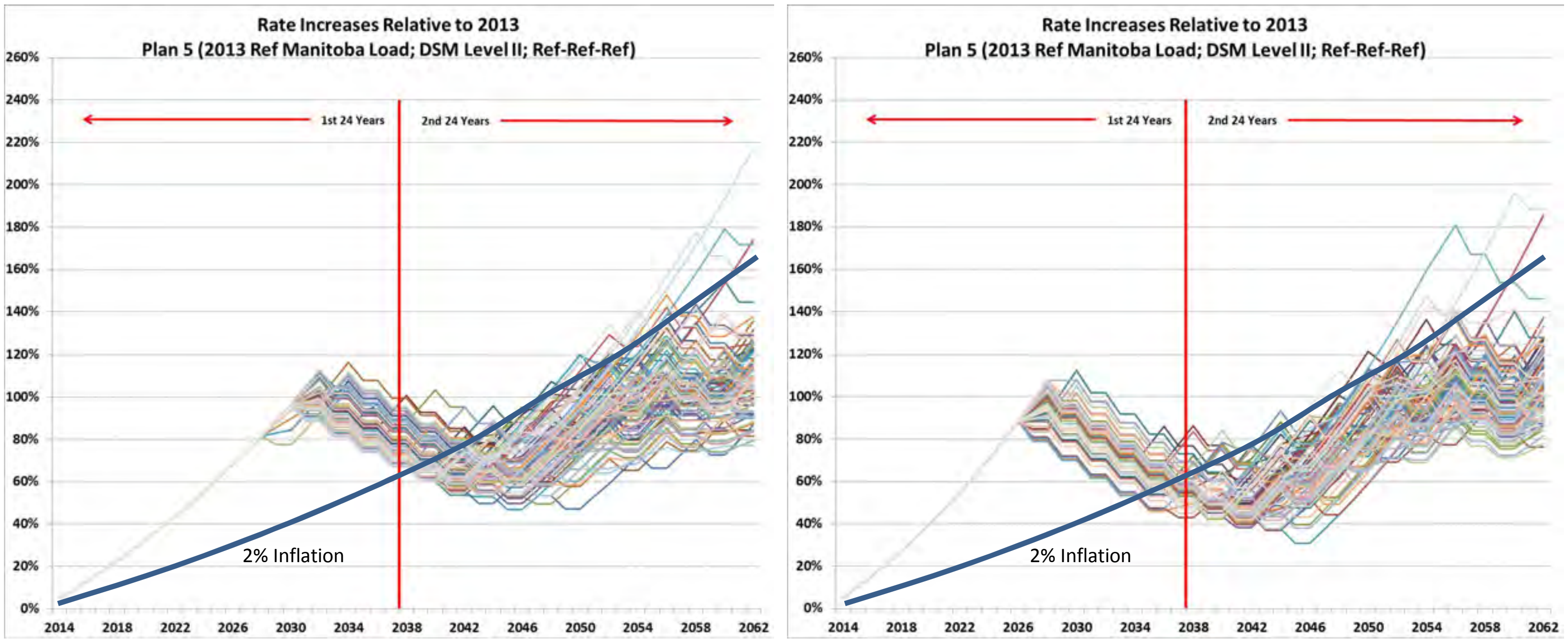


It is apparent from these graphs that raising rates at 5% per year versus 4% has a dramatic impact on rate path. While under 5% annual rate increases a doubling of rates is reached sooner, the rates peak earlier and at a lower absolute level before declining. The logic behind these differences centres on the fact that Manitoba Hydro would be generating significantly more revenue in the early years of the Plan, and hence would be taking on less debt, paying less interest over time, and more quickly paying down debt principal, which allows rate declines to be implemented.

Interestingly, the 5% graph demonstrates greater sensitivity to hydrological patterns (since the 99 lines are spread more widely after 2040). In the 4% graph, the spreading of the lines appears to begin in about 2055, suggesting that if the model were continued further into the future, a similar phenomenon would take place.

From an inter-generational perspective, the 5% path demonstrates more clearly than ever that the economic trade-off between ratepayers at different points in the future is crucially affected by the PUB's rate-making policies.

Figure 13. Comparison of Plan 5 Rate Paths with 4% and 5% Maximum Annual Rate Change Rule



For Plan 5, the cumulative rate impact of allowing 5% annual rate changes rather than 4% is less immediately apparent than for the PDP. However, it is clear that the first rate peaks occur earlier in the 5% case, and that the subsequent rate decline is deeper before rates resume their upward trajectory. For example, in 2038, rates in the 4% case are between 60% and 100% above the initial level, while in the 5% case rates are only 60% to 80% above the initial level.

Finally, it is interesting to note that after reaching their bottom, both rate paths essentially begin to follow an upward trajectory roughly consistent with inflation. This is very likely to be a reflection of the inflation-based assumptions embedded into the model further into the future. It perhaps suggests the essentially mechanical nature of the modeling exercise beyond the limits of the projects that can actually be planned in detail today.

2.6. Government Revenues

An important element of the review of the alternative Plans is the revenue that they are expected to deliver to the Government of Manitoba.

Government revenues were projected based on the 3.8% maximum annual rate change rule so that figures would be comparable to earlier modeling. Outputs are provided at a 6% discount rate, a 3% discount rate (which approximates the government's own cost of funds), and in nominal dollars.

Figure 14. Government of Manitoba Revenues

Average Present Value of Revenue to the Province of Manitoba
Reference Economics, Energy and Capital
Reference 2013 Manitoba Load; DSM Level II
(2015 - 2062)
($ in millions)

Revenue	**All Gas**	**Plan 2**	**Plan 4**	**Plan 5**	**Plan 6**	**PDP**
NPV @ 6.00%						
Water Rental	$1,606	$1,669	$1,768	$1,771	$1,769	$1,887
Capital Tax	$1,510	$1,756	$1,830	$1,856	$1,855	$2,247
subtotal	*$3,116*	*$3,425*	*$3,599*	*$3,627*	*$3,623*	*$4,133*
Debt Guarantee Fee	$2,370	$2,692	$2,838	$2,918	$2,908	$3,486
Total	*$5,486*	*$6,117*	*$6,437*	*$6,545*	*$6,531*	*$7,619*
NPV @ 3.00%						
Water Rental	$2,628	$2,780	$2,928	$2,931	$2,928	$3,207
Capital Tax	$2,635	$3,147	$3,166	$3,209	$3,207	$4,021
subtotal	*$5,263*	*$5,927*	*$6,094*	*$6,139*	*$6,135*	*$7,228*
Debt Guarantee Fee	$3,987	$4,642	$4,565	$4,701	$4,671	$5,646
Total	*$9,250*	*$10,569*	*$10,659*	*$10,840*	*$10,807*	*$12,874*
Nominal Dollars						
Water Rental	$5,103	$5,506	$5,745	$5,749	$5,744	$6,472
Capital Tax	$5,490	$6,679	$6,494	$6,572	$6,573	$8,440
subtotal	*$10,593*	*$12,185*	*$12,239*	*$12,320*	*$12,317*	*$14,912*
Debt Guarantee Fee	$7,998	$9,430	$8,561	$8,813	$8,727	$10,278
Total	*$18,591*	*$21,615*	*$20,800*	*$21,133*	*$21,045*	*$25,190*

Unsurprisingly, the PDP provides the Government with the most revenue: across each revenue source individually, in total, and regardless of the discount rate calculation. This should be expected since the PDP uses the most water, the most capital, and the most debt of all of the Plans.

From the Government's perspective, however, the benefits of additional revenue from Manitoba Hydro must be balanced against the higher costs to ratepayers that result from the PDP, and the potential economic drag that may result from those higher rates (higher costs for a staple such as electricity is roughly the equivalent of a reduction in disposable income for individuals and businesses, which results in lower tax revenue to the Government from sources other than Manitoba Hydro).

Government revenues can also be compared as between the 2013 versions of the Plans, and the updated versions.

Table 4. Government Revenues at 6% Discount Rate Ref/Ref/Ref – 2013 vs. Updated Plans

	All Gas	2	4	5	6	PDP
2013 Version	$5,866		$6,733		$6,775	$8,061
2014 Version	$5,486	$6,117	$6,437	$6,545	$6,531	$7,619
Change	- 6.5%		- 4.4%		- 3.6%	- 5.5%

Across all of the Plans, government revenues have declined with the updates made. In addition, the relative size of the gap between the PDP and most of the other Plans has narrowed slightly. Nevertheless, a gap continues to exist.

3. The Impact of Droughts

In our response to PUB/MPA 1-027, MPA provided a detailed description of the projected consequence of a “challenging” hydrological pattern. This pattern included two significant periods of drought, as well as a generally low average hydrology over an extended period of time.

In order to consider the impact of the updates made to the Plans, the same hydrological pattern was examined. Only the Ref/Ref/Ref scenario can be properly compared, as data for other scenarios (and in particular High and Low energy scenarios) has not been provided by Manitoba Hydro. Maximum annual rate changes are maintained at 3.8% to avoid adding a further difference.

Note that in the IR noted above MPA examined All Gas, Plans 4, 6 and 12, and the PDP. With the updated 2014 information, a slightly different set of alternatives was tested: All Gas, Plans 2, 4, 5, 6 and the PDP.

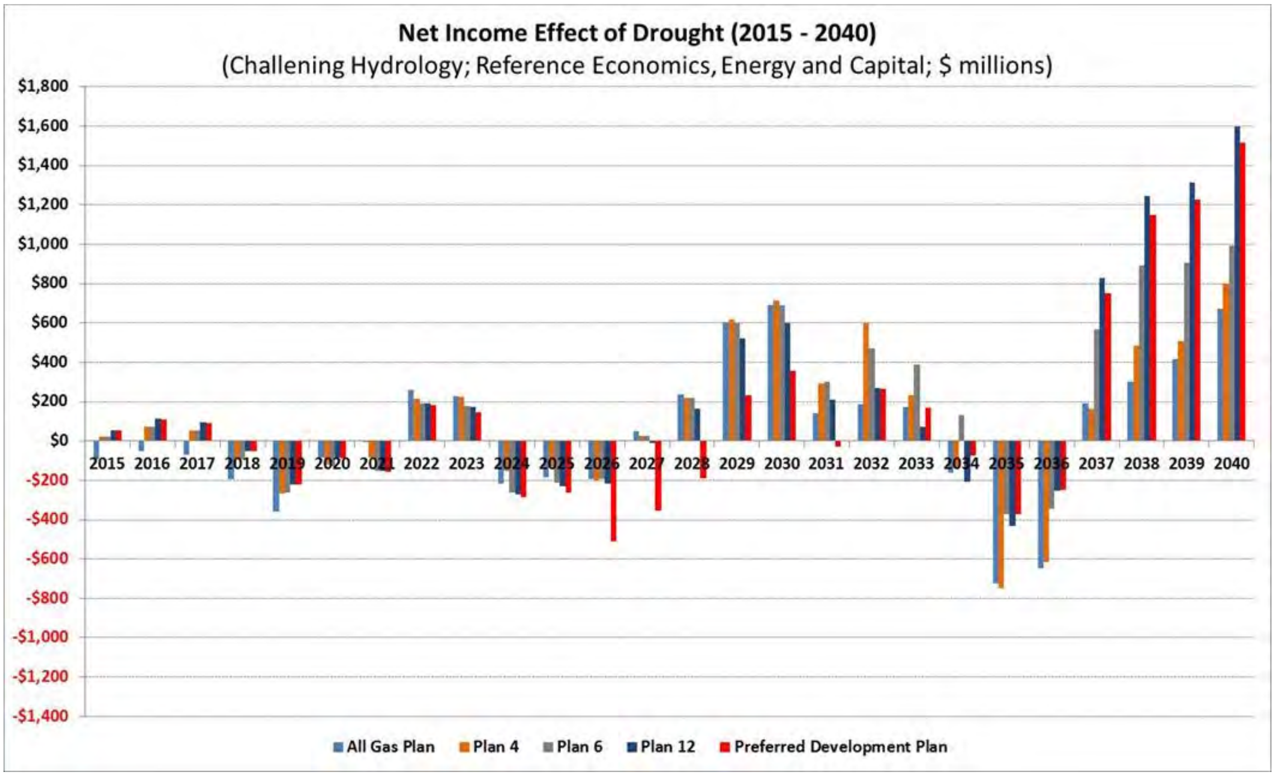
3.1. Net Income

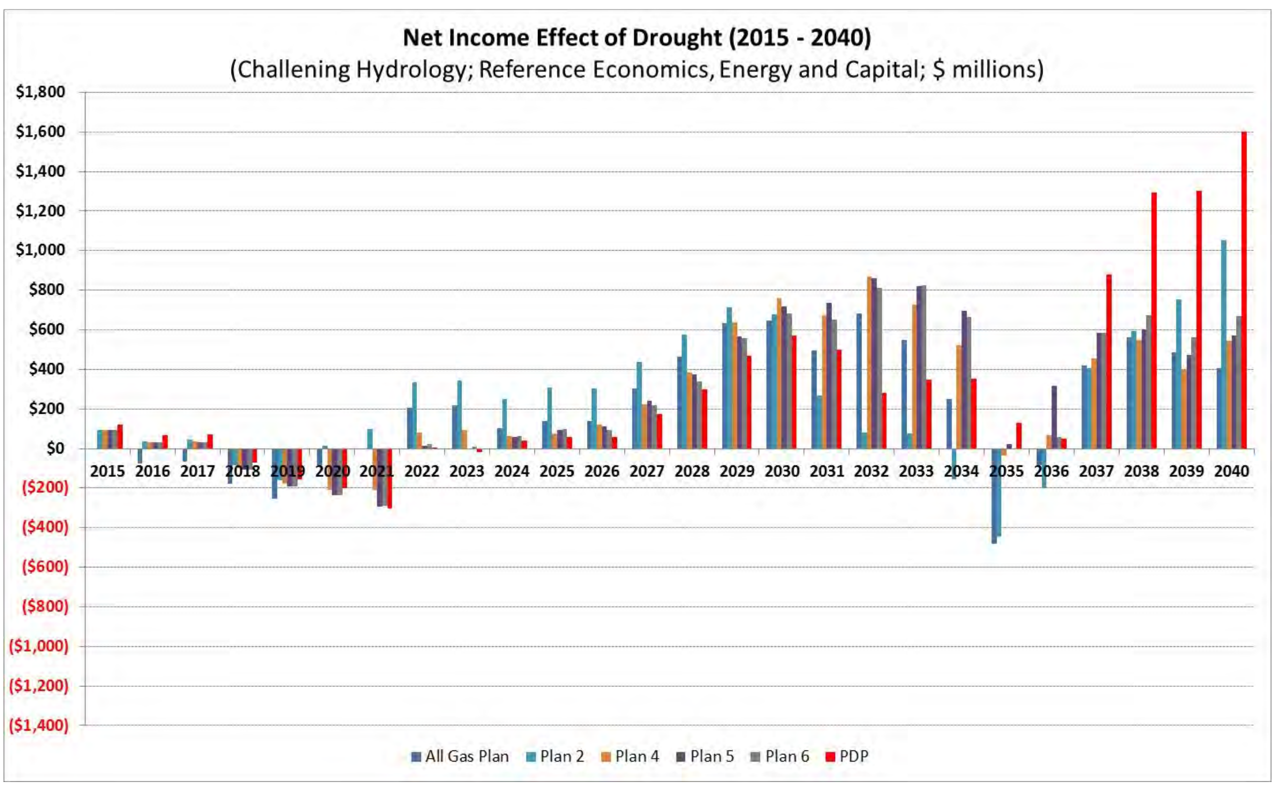
The following Figure compares the results of the 2013 Plans with the updated Plans.

Across all Plans it is immediately apparent that financial performance is now stronger. With the updated Plans, Manitoba Hydro is far less likely, even under very challenging hydrological conditions, to suffer negative net income. After 2021, only the All Gas Plan and Plans 1, 2 and 4 have any years with negative net income, notwithstanding the fact that Manitoba Hydro is presumed to be facing serious drought years in this projection.

A lower debt burden resulting from delayed generation projects (as compared to the 2013 versions of the Plans) clearly plays a role in these results.

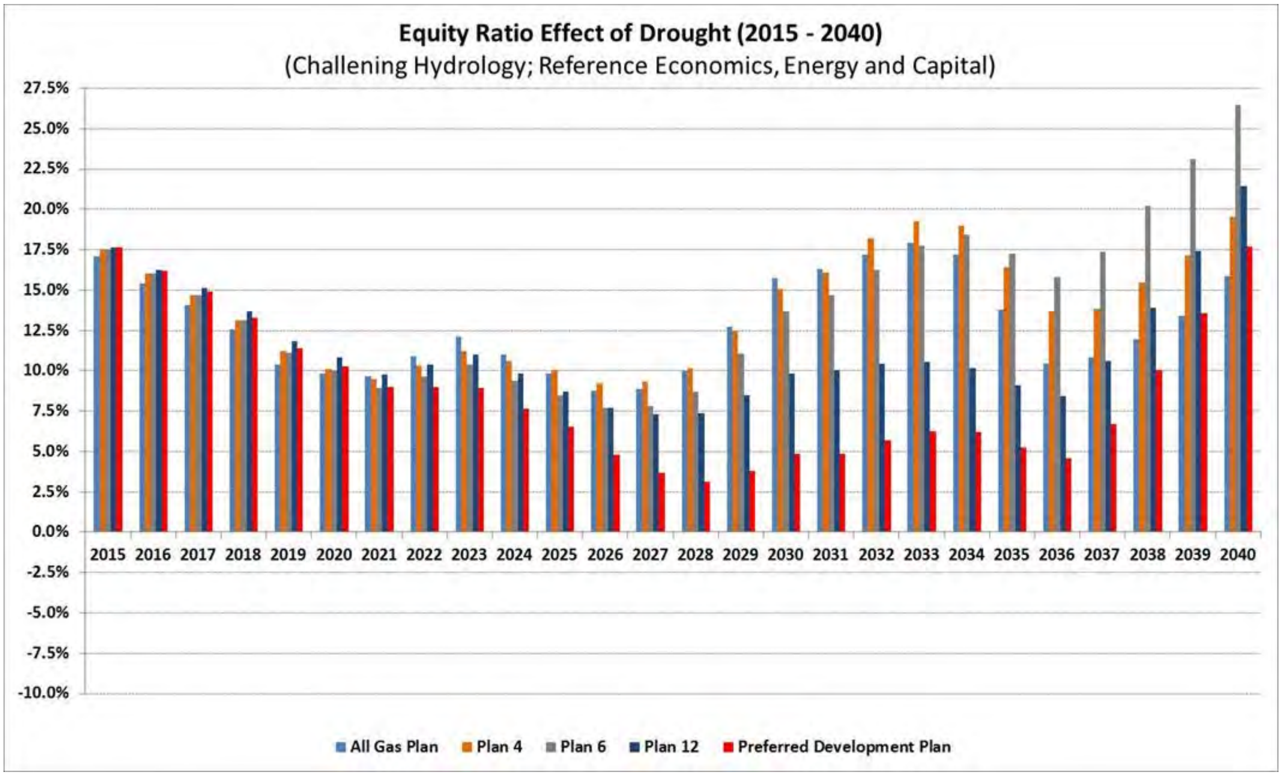
Figure 15. Net Income Performance Under Challenging Hydrology – 2013 vs. 2014

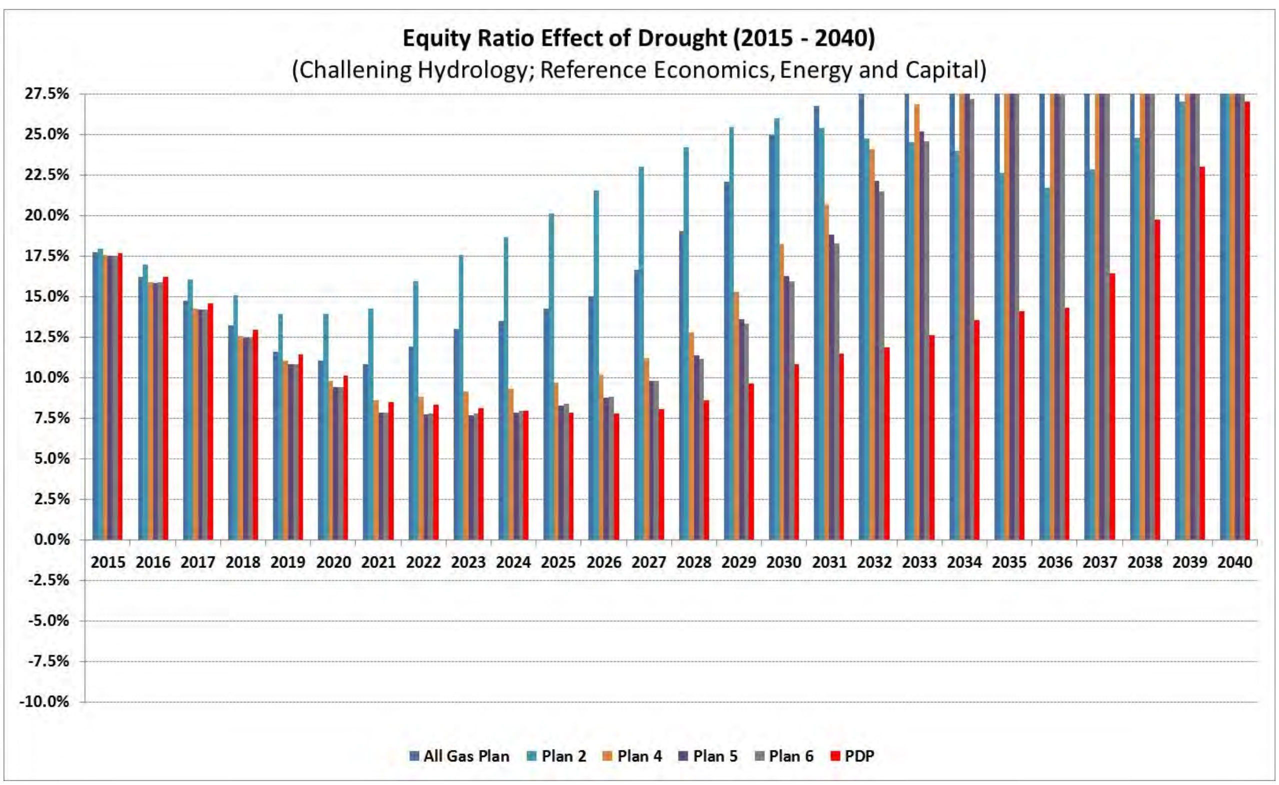




3.2. Equity Ratio

Figure 16. Equity Ratio Given Challenging Hydrology – 2013 vs. 2014





Note that Manitoba Hydro's equity ratio target is 25%.

The equity ratio results for the updated versions of the Plans are consistent with net income performance:

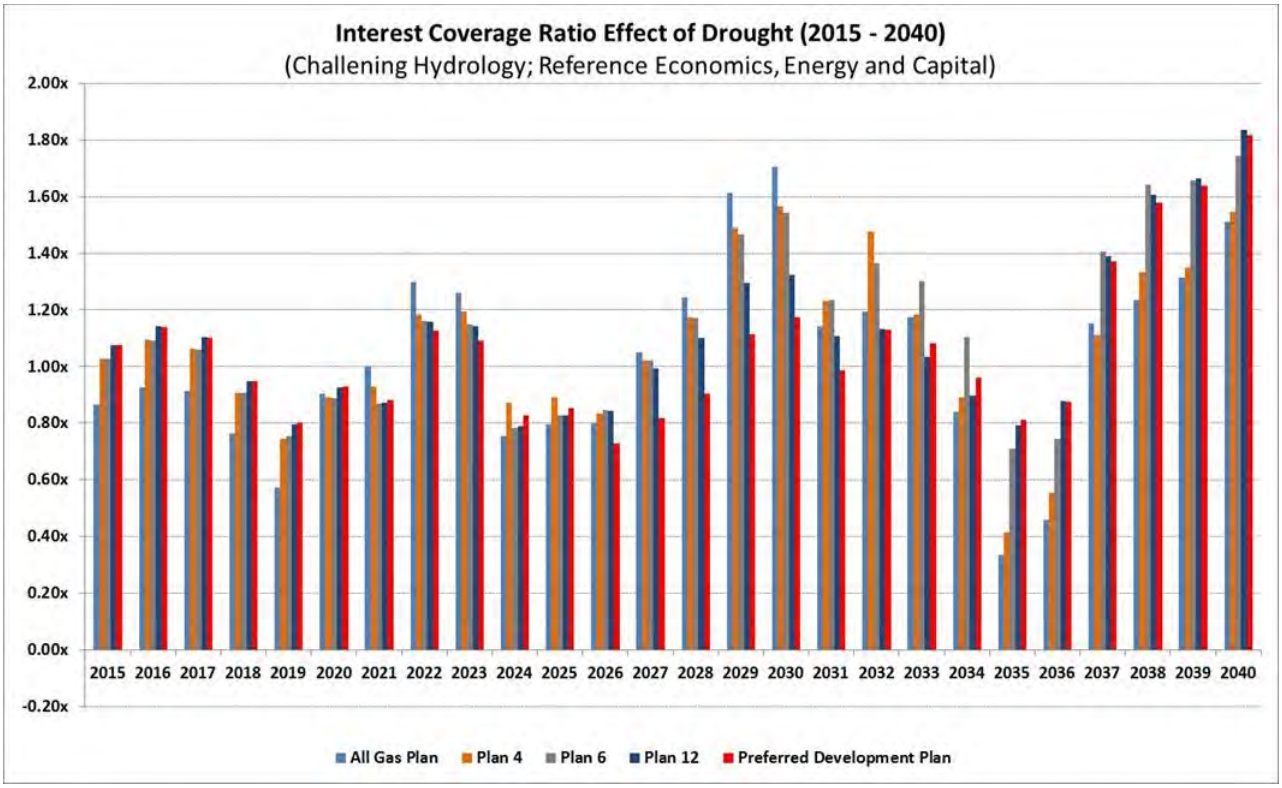
- For many of the Plans, the target equity ratio is met within 20 years, even under this challenging hydrology scenario.
- The PDP does not meet its equity ratio until 2040, but while its equity ratio falls below 10%, it never drops below 5%, as it did with the 2013 version of the Plan.
- For Plans 4, 5 and 6, the equity ratio is below 10% for less than a decade before improving strongly.

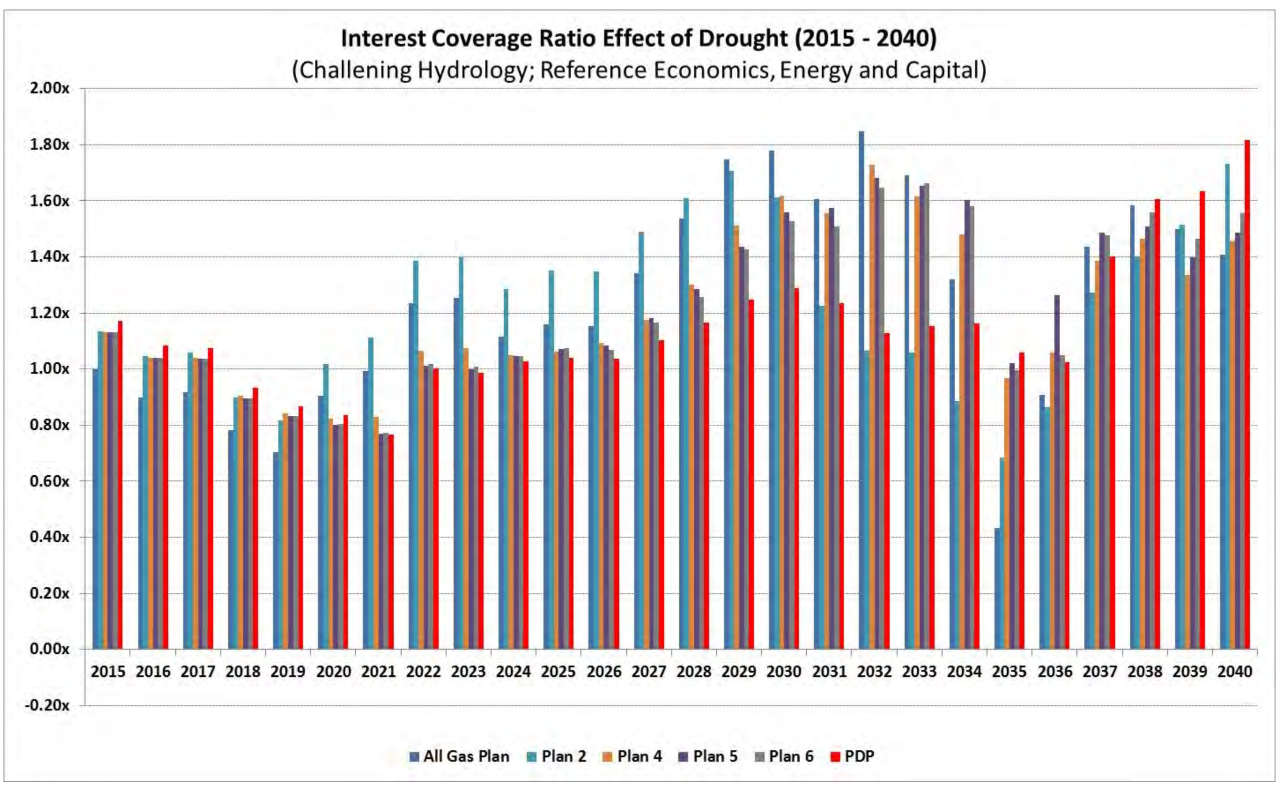
3.3. Interest Coverage Ratio

The improvement of the 2014 version of the Plans can be readily seen in the interest coverage ratio projection as well.

The 2013 versions of the Plans resulted in at least 10 years of interest coverage ratio below 1x for all Plans. In a few instances Plans actually fell below 0.5x for brief periods. The 2014 versions of the Plans are more robust, with few having interest coverage ratios below 1x for more than 5 years, and only one falling to 0.5x for a single year.

Figure 17. Interest Coverage Ratio Given Challenging Hydrology – 2013 vs. 2014





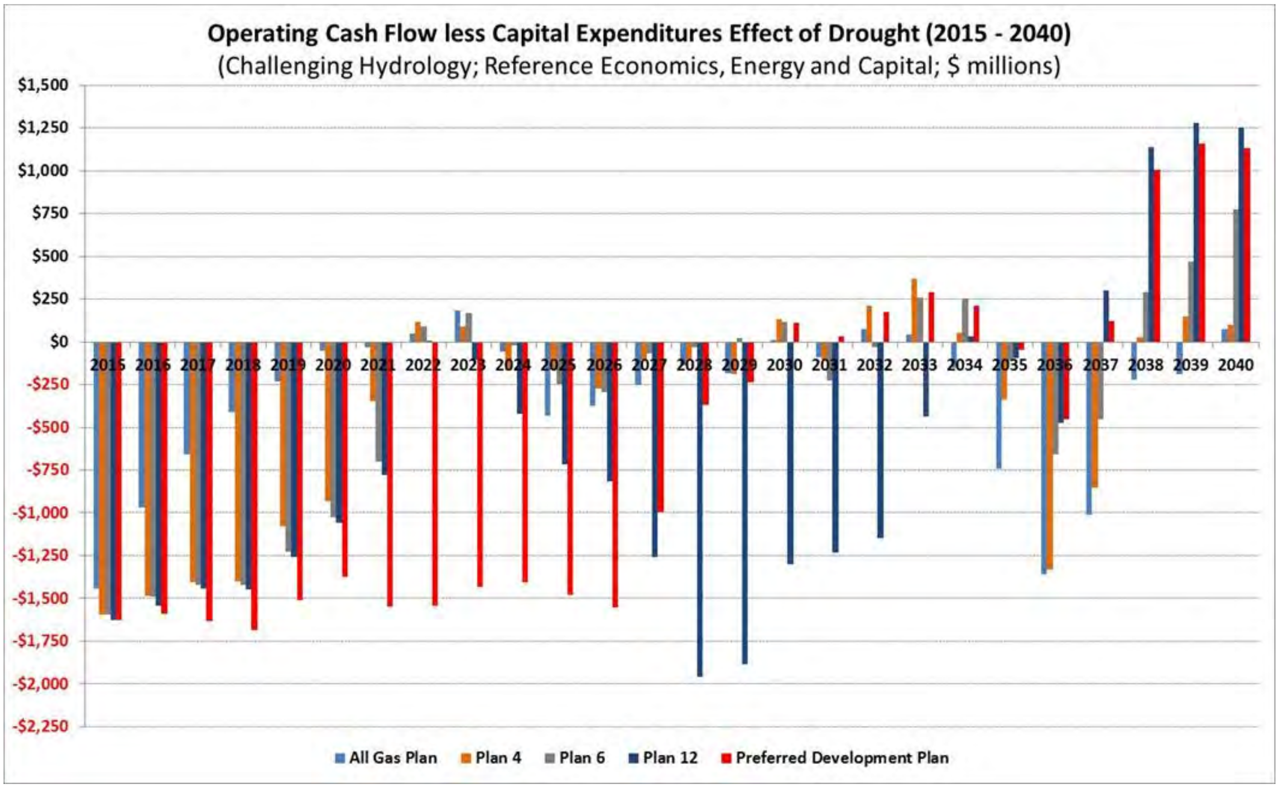
3.4. Operating Cash Flow Less Capital Expenditures

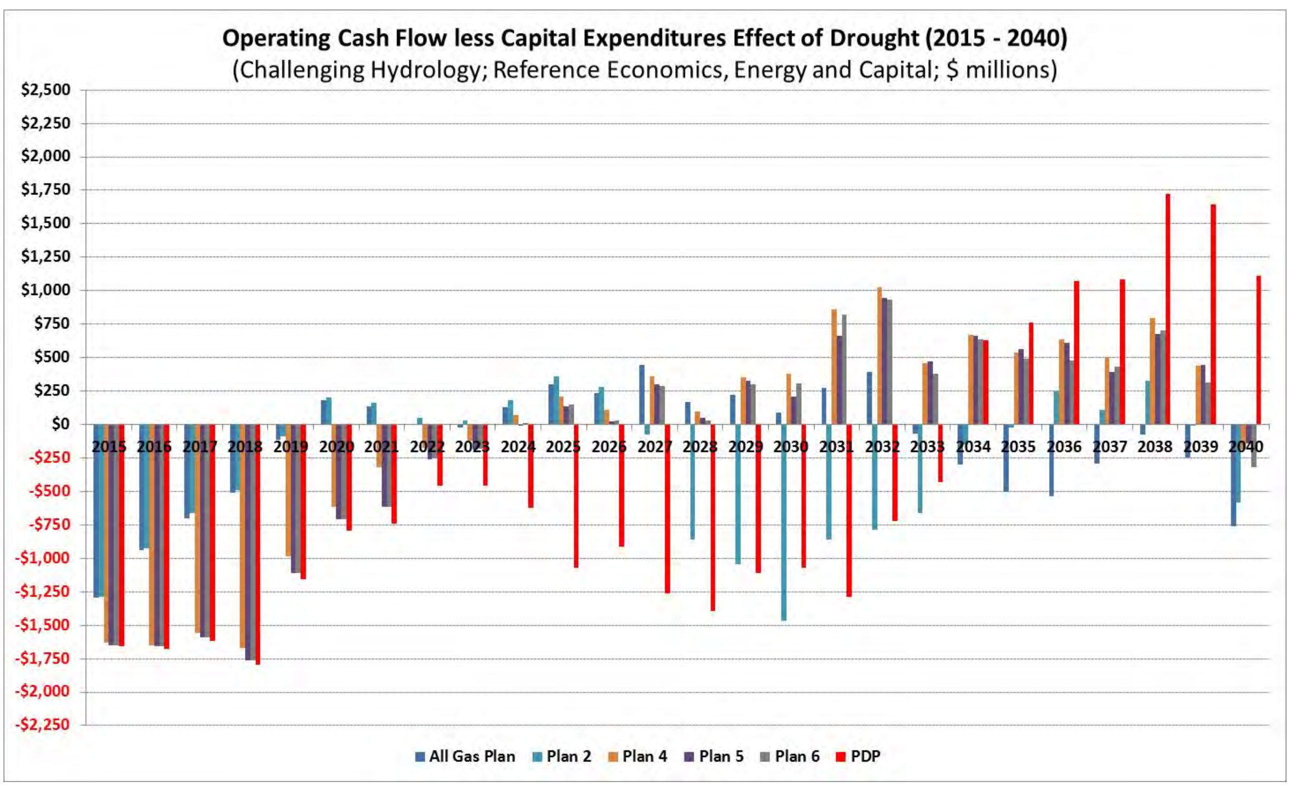
The principal financial difference between the 2013 and 2014 versions of the Plans is demonstrated by the calculation of cash flow less annual capital expenditures. The 2014 versions of the Plans require far less debt to be accumulated over time, across all Plans. This results in less debt, and hence less interest cost.

In addition, the repayment of debt principal begins much earlier in all Plans.

Despite a very challenging hydrology pattern, the 2014 versions of the Plans indicate no significant risk of perceived financial distress in a Ref/Ref/Ref scenario.

Figure 18. Cash Flow Less Capital Expenditures Given Challenging Hydrology – 2013 vs. 2014





3.5. Sensitivity

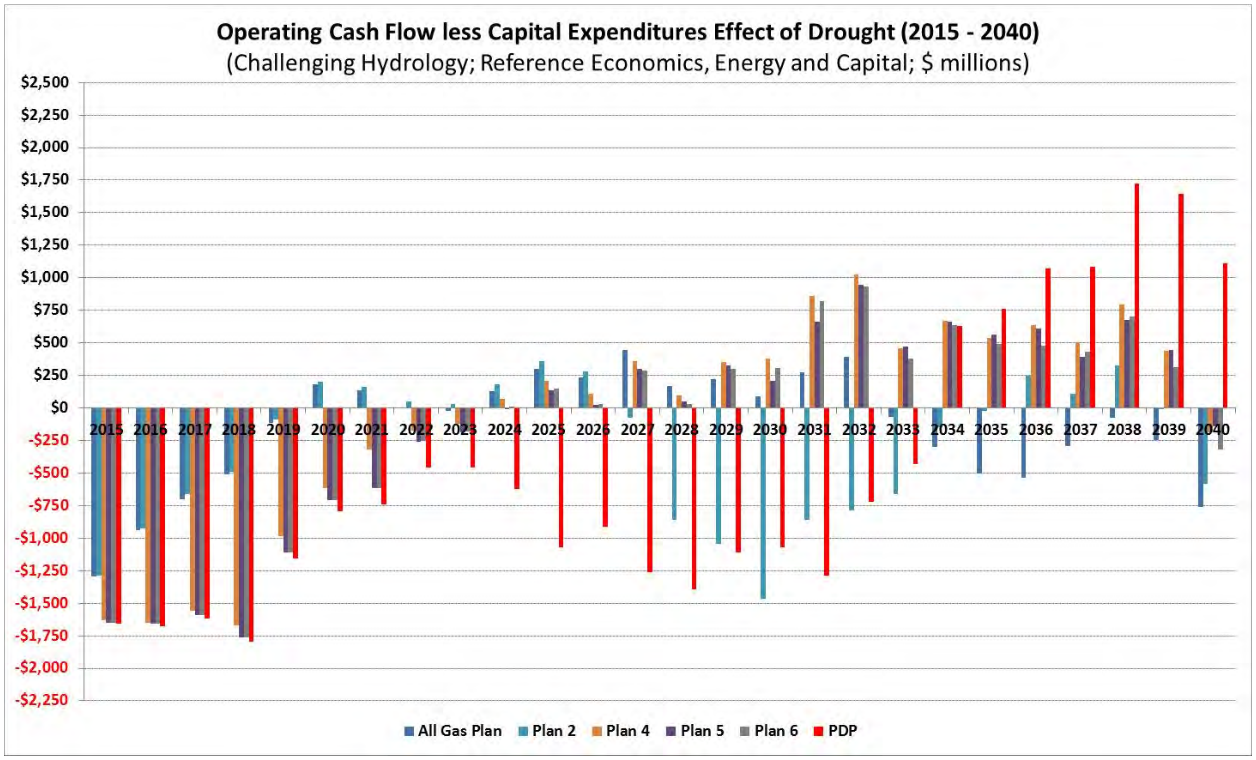
As was noted above, without detailed SPLASH model outputs it is not possible for MPA to produce valid projections in alternate scenarios. However, we were able to test Manitoba Hydro’s financial performance under this challenging hydrology pattern based on the sensitivities described above. Two examples appear to provide useful insights.

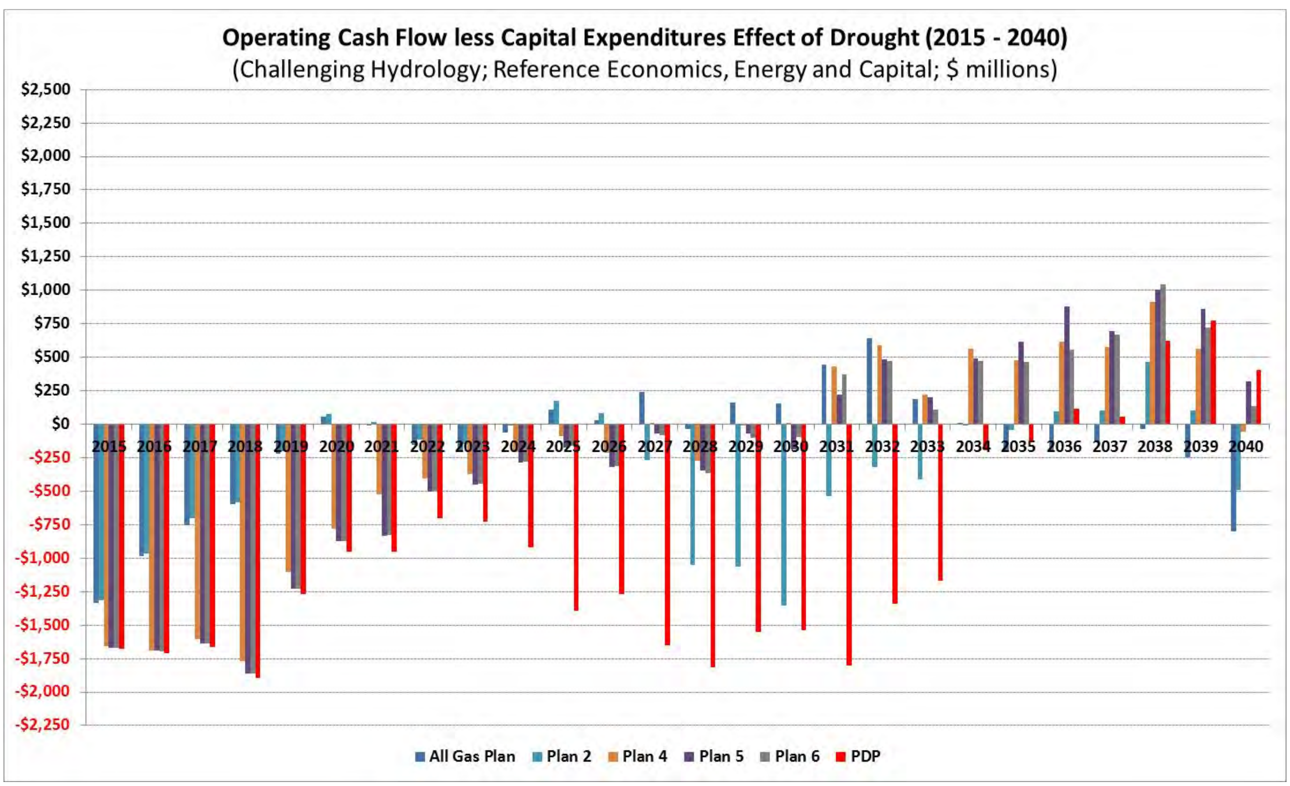
3.5.1. Higher Interest Costs

Increasing the rate of interest applied to Manitoba Hydro increases its net costs, reduces net income, and reduces its operating cash flow. The financial effect is similar to a reduction in revenue that might be caused by lower export prices.

In the challenging hydrology environment presented here, a one percent increase in interest rates causes all of the financial indicators to deteriorate. A comparison is provided below between the performance of the updated 2014 Plans at Ref/Ref/Ref and the same Plans at an interest rate one percent higher than projected in the Ref/Ref/Ref scenario.

Figure 19. Cash Flow Less Capital Expenditures Given Challenging Hydrology – Base vs. +1%





The effect of increasing the interest rate by 1% is reduced cash flow across all Plans.

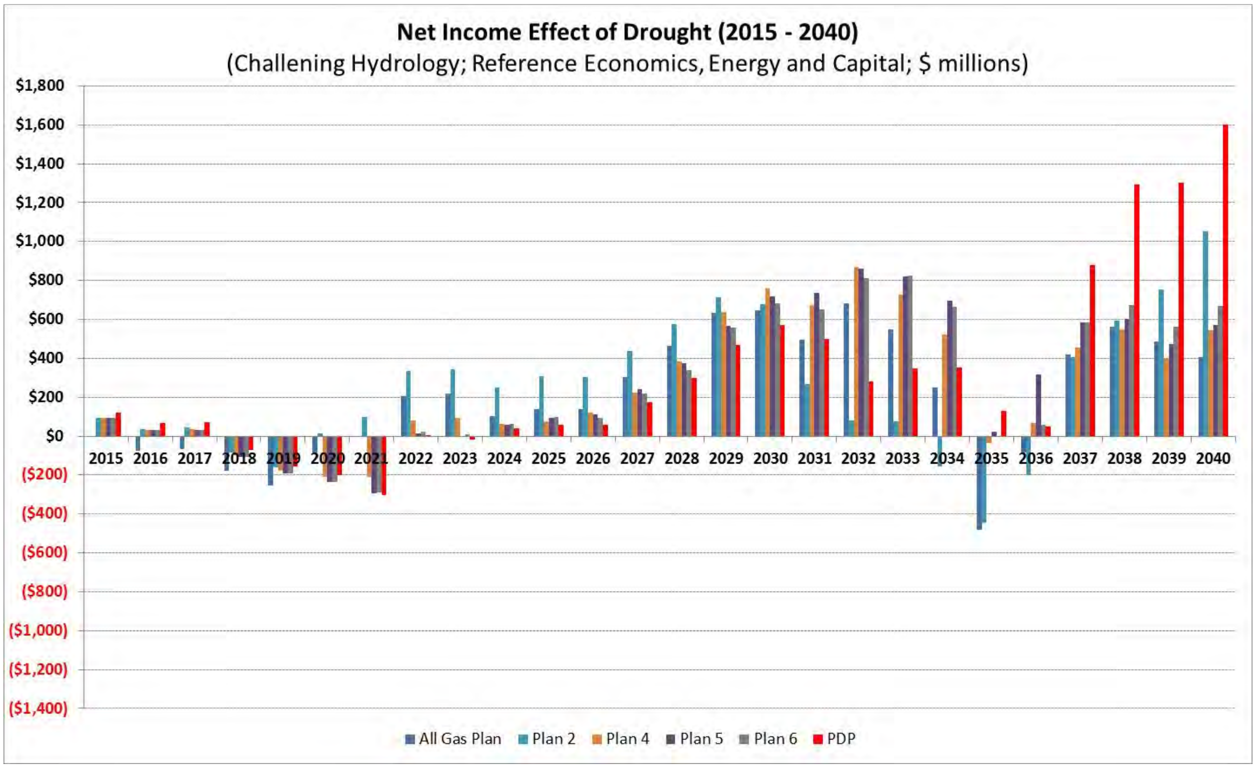
Those Plans that have greater capital requirements, and in particular the PDP, are particularly affected by the change in interest rates. Since the same Plans that are more capital intensive are more sensitive to export prices, as noted above, it should be assumed that a decline in export prices below the Reference projection would similarly affect the same Plans to a greater degree.

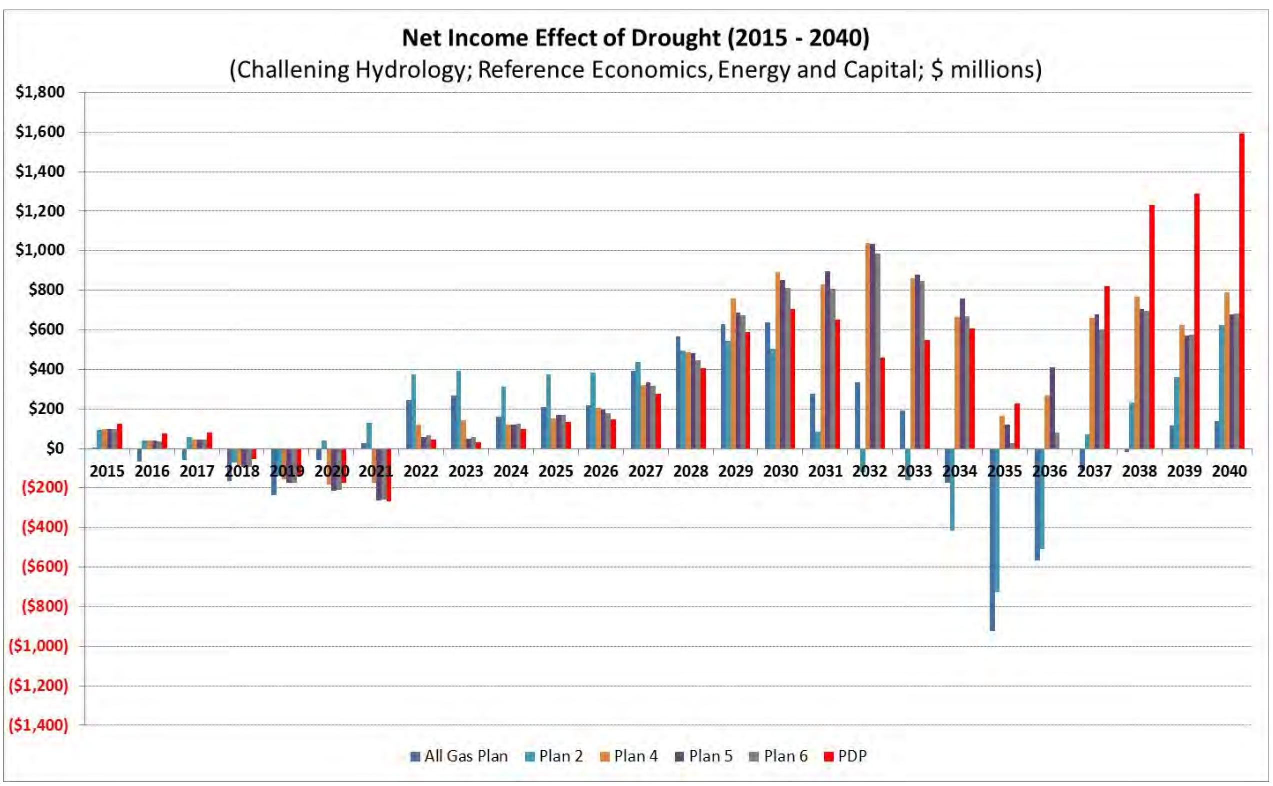
It is notable that cash flow in some Plans actually improves under the higher interest rate case in the late years of the model depicted on the graph. This is a result of the relationship between rate increases and the timing of droughts: in a lower interest rate environment, robust financial health at Manitoba Hydro allows for lower Manitoba domestic rates and greater reliance on exports. When drought sets in and exports are curtailed, however, this means that a greater drop in revenue results, and the limitation on the maximum rate increase subsequent to the drought limits the ability of Manitoba Hydro to quickly recover its financial position. In a higher interest rate environment, rates would not have been declining as rapidly, so the onset of drought would not have as great an impact on the company's finances, and recovery would be more rapid after the fact.

3.5.2. Higher Maximum Rate Increases

The financial robustness of Manitoba Hydro in the face of drought is to some degree in the hands of the PUB through its rate-setting policy. As part of its modeling exercise, MPA calculated the projected performance of Manitoba Hydro in the face of drought at both maximum annual rate changes of 3.8% and 4.0%. The impact of this difference is depicted below for the net income of the updated 2014 Plans.

Figure 20. Net Income Given Challenging Hydrology – 3.8% vs. 4% Maximum Annual Rate Increase

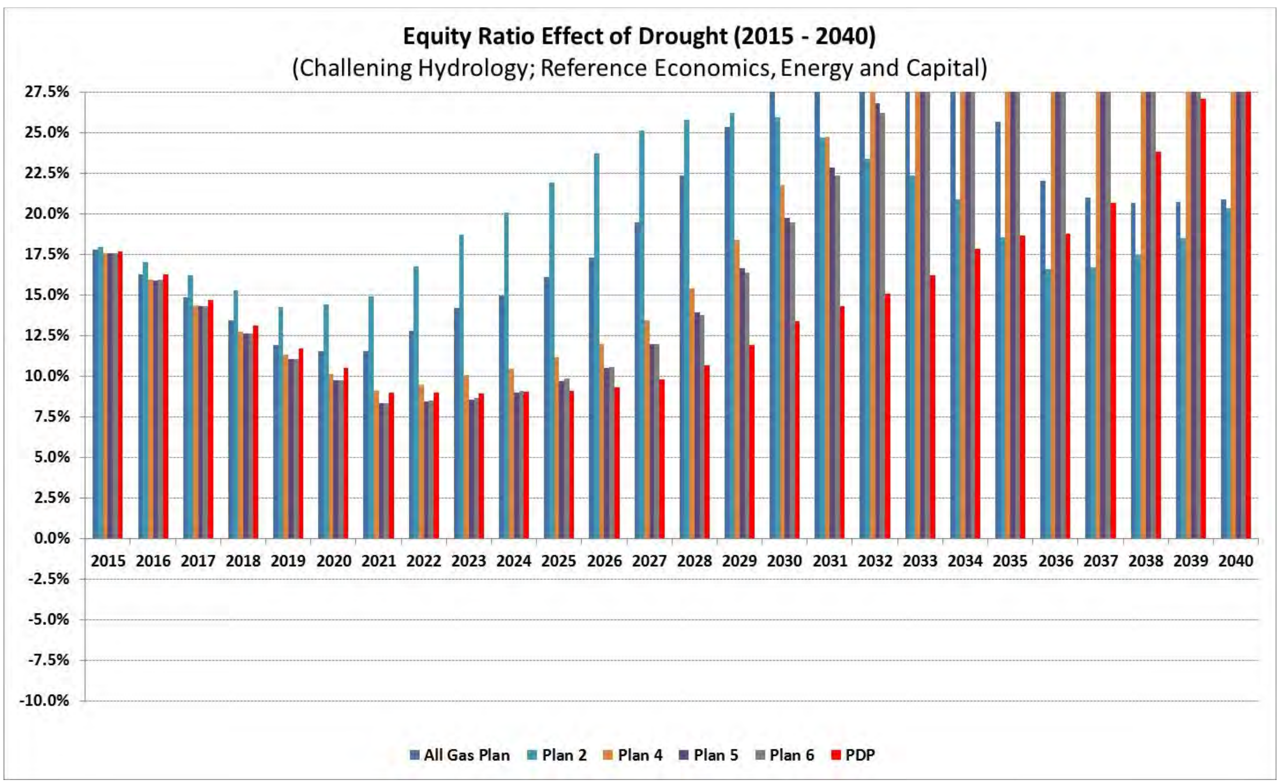




While the difference between a 3.8% maximum change in rates and 4% is small, it is nevertheless noticeable beginning in about 2020. Across all Plans net income rises to higher levels in the 2020s, as does cash flow, reducing the amount of debt that Manitoba Hydro must carry. By the early 2030s net income has improved by approximately $200 million per year for most Plans.

As can be recalled from Figures 4, 5 and 6, above, the difference between maximum rate changes of 3.8% and 4% allows domestic rates to peak earlier and then begin to decline. Given the mid-2030s timing of the major drought in this particular hydrological pattern being examined, several of the Plans would be caught by the limitation on rate increases. For example, Plan 1 would have had declining rates beginning in the late 2020s, but when the drought hits, the model only allows rate increases of 4%, despite very significant declines in net income caused by the drought. As a result, Manitoba Hydro's financial position worsens dramatically for a few years before recovering. However, as the graph below demonstrates, this is not a major financial risk, because Manitoba Hydro's finances have already become robust by that point. Notwithstanding the sharply negative net income resulting from the All Gas Plan during the drought of the 2030s, Manitoba Hydro's equity ratio does not fall below 20%.

<u>Figure 21. Equity Ratio Given Challenging Hydrology – 4% Annual Maximum Rate Change</u>



This demonstrates that there is a direct trade-off between inter-generational concerns in rate-setting policies, and the financial robustness of Manitoba Hydro to withstand challenging hydrology and other financially threatening events. The differences between the Plans suggests that this flexibility should be relied upon if Manitoba Hydro ultimately pursues a Plan that has a higher capital intensity, and is therefore more likely to be subject to significant financial shocks from drought or other causes during the next 20 years.

4. Conclusions

4.1. Keeyask and the Intertie

Does the new information provided by Manitoba Hydro suggest that alternatives are now clearly commercially superior to proceeding with Keeyask and the transmission interconnection?

As shown in Chapter 2 above, the gap between the All Gas Plan and Plans which include Keeyask 2019 and a transmission intertie, has narrowed somewhat. The Plans are essentially identical in their ratepayer impact for the first 15 years, but in the second 15 years All Gas appears to have an advantage, which it then gives up in the final period of our financial model.

However, this gap is not large enough overall to appear to be significant, given all of the caveats about assumptions and precision that must be recognized in any long-term financial modeling exercise.

As was noted by MPA before the PUB, Keeyask and the transmission intertie are immediate, real, actionable projects, which in our view should not be dismissed without clear evidence of commercially superior alternatives. Neither the All Gas Plan, nor Plan 2 (which does not include an intertie and schedules Keeyask for a later build) appear to satisfy that condition from the perspective of ratepayers.

From the government's perspective, the All Gas Plan provides the lowest revenues over time, and generates the least export revenue (in addition to fewer jobs and economic development, which is an issue outside our scope).

From the perspective of potential financial distress, neither the All Gas Plan nor Plan 2 can be demonstrated to be demonstrably different from Plans 4, 5 and 6 under a challenging hydrology scenario, as can be seen from the review of this issue in Chapter 3, above. While the exact timing of investments and potential drought or other distress events result in differences between Plans, it is not clear that there is any clear superiority or inferiority as between the Plans considered over a long period of time.

Based on this review of the new information, MPA sees no reason to modify our views as expressed before the PUB.

4.2. Conawapa

Does the new information provided by Manitoba Hydro suggest that Conawapa is now a more attractive development opportunity than alternatives, and therefore deserves expenditure of substantial resources to the exclusion of other opportunities?

As noted in section 2.1 above, the PDP is clearly inferior to Plans 4, 5 and 6 across all discount rates, including 0%. Increasing the maximum annual rate change from 3.8% to 4% does not change this conclusion. Even at a maximum rate change of 5% (2.5x the rate of inflation), Plan 5 is still superior to the PDP in a Ref/Ref/Ref scenario.

As has been noted in the past, the PDP is more sensitive to export prices and interest rates than other Plans. As a result, it is reasonable to believe that should interest rates fall below Reference projections, or export prices rise above Reference projections, then the gap between the PDP and alternatives could narrow.

From the government's perspective, it is unquestionable that the PDP delivers greater revenue than alternatives (as well as more jobs and economic development). However, does this benefit decisively outweigh the greater cost to Manitoba ratepayers that should be expected?

A final consideration is that according to the updated 2014 Plan presented by Manitoba Hydro, the PDP now contemplates Conawapa for an in-service date of 2031, with construction commencement more than 10 years away. Given this extended timeframe for continued development, it does not appear reasonable to assume that Conawapa should be an exclusive development priority superior to other alternatives.

MPA continues to support its comments to the PUB that Conawapa should be considered a development opportunity, competing with other potentially superior alternatives, and continued expenditures to develop Conawapa should be justified in that light.

Tab 22

BCG

REPORT

Review of Bipole III, Keeyask and Tie-Line Project

Manitoba Hydro Electricity Board

September 19, 2016

Introduction

This report summarizes the results of a review performed by The Boston Consulting Group ("BCG"), on behalf of Manitoba Hydro Electric Board("MHEB"), to evaluate the prudency and risk associated with Manitoba Hydro's ("Hydro") investments to build the Bipole III transmission project ("Bipole III"), the Keeyask generation station ("Keeyask"), and the MMTP/GNTL[1] projects ("Tie-line") [Exhibit 1]. The work was conducted between June and August 2016, using data provided by Hydro at the request of BCG, and through independent analysis performed by the BCG team based on its experience and expertise in the utility industry and with large capital projects.

The review performed sought to answer three key questions regarding the projects assessed [Exhibit 2]:

- Were the original decisions to invest the right ones to make?
- Is there further downside risk to the projects?
- Can the projects be stopped or paused without undue cost or risk?

Overview of Findings [**Exhibit 3**]

Through our analysis, we conclude that the decision to build a Bipole III was justified due to the significant and real reliability risks associated with relying solely on Bipole I, Bipole II, and Dorsey, and the societal impacts a catastrophic failure would carry. We also conclude that, while Bipole III East would have been the best option from an economic and execution standpoint, the decision to build along the West route was appropriate given the 2007 direction to the Chair of the Manitoba Hydro Electricity Board (MHEB) by The Minister of Hydro which deemed the East route inconsistent with environmental commitments and initiatives.

Conversely, the decision to build Keeyask and its associated infrastructure was an imprudent one due to a failure to fully assess the risks associated with moving forward. These included

- Financial modelling that did not fully reflect the specific project risks (e.g. construction execution, market prices, domestic demand)
- Discount rates that favored high capital projects over lower upfront cost projects
- The magnitude of the overall level of debt that both Hydro and the Province of Manitoba would ultimately be exposed to. This is especially true given the concurrent build of Bipole III, which is required for reliability purposes.

All three projects - a Bipole III, Keeyask, and the associated tie-line - should have been reviewed on an aggregate basis, instead of individually, to properly assess the collective risks of conducting all projects at once. While a Bipole III could have been pursued as a stand-alone project, the feasibility of Keeyask and the tie-line were both dependent on one another, and on construction of a Bipole III as well. Hence, separate reviews of the projects was not the best choice given their inherently interconnected nature.

[1] Manitoba Minnesota Transmission Project and the Great North Transmission Line together form the Tie Line project

Hydro took on undue execution risk by failing to fully obtain all the required approvals (notably the US Presidential and tie-line partner approvals) prior to commencement of construction of Keeyask, whose value is impacted by availability of the tie-line. Moreover, since the time the original analyses that supported proceeding with both projects was conducted, further downside risk associated with capital execution on both Bipole III and Keeyask has materialized.

Risks such as these have adversely impacted the economics of the projects and continued to put Hydro into a more and more difficult financial position, making construction of Keeyask and the tie-line in particular an even more questionable decision.

Despite our finding that the original decision by the Provincial Government and Manitoba Hydro to construct Keeyask and the tie-line was imprudent, given the current state of execution and the estimated incremental costs to cancel or delay the projects at this point, the most prudent decision – from an economic and strategic perspective – is to continue both projects to completion. However, continuing the projects will require a focus on mitigating any further downside impacts on costs and schedule to the extent they can be controlled.

Topic 1: Were the original decisions to invest the right ones to make? [Exhibit 4]

Bipole III

Manitoba Hydro's existing infrastructure of Bipole I & II and Dorsey carry significant reliability risks that have been untenable for a significant amount of time, but which should be immediately addressed upon completion of a Bipole III [Exhibit 5].
The impact of this risk is increasing [Exhibit 6] given several factors

- Approximately 70% of the Province's system's energy moves through this infrastructure
- The risks of significant incidence to these facilities are not negligible. For example, freezing rain and wind is estimated to impact Bipole I & II approximately once every 20 years, and fire risks at Dorsey are estimated to lead to reliability issues once every 29 years.
- Either of these types of events, or other significant events such as ground ice build-up or tornados, could lead to prolonged outages lasting weeks to months [Exhibit 7].
- Such events, while extremely rare, would result in an estimated $4 – 20B in negative societal impact, and hence must be planned for to avoid a catastrophic event at significant cost for multiple Hydro stakeholders [Exhibit 8].

While the decision to proceed with a Bipole III was a prudent action on the part of Hydro due to the reliability concerns of not building the asset, it should be noted that a Bipole III East route was deemed the most economic design, with funding requirements $900m[2] lower than alternatives. However, the East route option was not pursued following 2007 guidance from the Minister for Hydro to MHEB's Chair that the route would not be considered consistent with stated environmental commitments and initiatives [Exhibit 9]. The communication also stated the Corporation should

[2] As per 2007 Hydro Management West Route submission review presentation to the MHEB

move ahead with required consultations and planning for alternative routes. Of the options *ex*cluding Bipole III East, Bipole III West is the most cost effective [Exhibit 10].

Keeyask and tie-line

Unlike Bipole III, our analysis determined the accelerated commencement of construction of Keeyask with the tie-line to be an imprudent decision on the part of the provincial Government and Hydro leadership at the time of its initiation [Exhibit 4].

While new generation capacity will be needed for the region and system to ensure the ability to meet domestic load and capacity needs, this need does not consistently arise until 2027 [Exhibit 11]. Our analysis looked at the reasonability and soundness of several aspects of Manitoba Hydro's net demand and supply availability forecasts, in addition to various scenarios for Demand Side Management ("DSM") programs to identify the need for new generation [Exhibits 12, 13]. The earliest consistent need for new generation is 2027, and it is possible the need may not arise until as late as 2034 depending on actual gross demand and DSM impacts observed. This placed the originally planned 2019 Keeyask in-service date well in advance of the domestic need.

The decision to accelerate Keeyask to 2019 and build the tie-line, as opposed to building and completing construction by 2025/26 or pursuing alternative options such as gas generation, was based on an expected NPV analysis that measured the expected value versus alternatives [Exhibit 14]. Acceleration and the tie-line were of high value as they were projected to allow Hydro to meet a portion of the renewable energy needs of US customers, and hence earn attractively priced, contracted export revenues that would improve project NPV. The perception of a limited window of time to capture the benefits of the tie-line and export revenues significantly drove the decision to build on the originally planned schedule [Exhibit 15].

While this approach to offset capital costs was logical, the assumption that the window of opportunity for export to the US was closing should have been more closely scrutinized and tested. Specifically, the potential for additional future waves of renewable energy needs allowing for future export, driven not only by RPS[3], but also the US CPP[4] or other regulatory requirements, should have been more deeply assessed and considered as part of the analysis. In addition, the fact that acceleration of Keeyask led to commencement of construction prior to the tie-line receiving the required external approvals (US Presidential and the tie line partners), neither of which have been received to date, underscores the failure to perform all the important risk analyses associated with accelerating Keeyask to 2019.

Furthermore, while the expected NPV for Keeyask and the tie-line was estimated as being higher, the range of uncertainty around the expected NPV was also significantly larger than for alternatives [Exhibit 16]. This is due to larger project execution risks, industrial account electric load (i.e. demand) risks, export price and underlying hydrological risks.

[3] Renewable Portfolio Standards
[4] Clean Power Plan

Most importantly, given the financial outlook of the company (Hydro's equity ratio was expected to fall to 9% in a base case scenario) put forth during NFAT, consideration of the magnitude of project risks and their impact on the company's financial health should have been provided more weight and consideration in the evaluation [Exhibits17]. This is particularly true as Hydro already has less equity than most of its peers [Exhibit 18] and must be sufficiently capitalised to withstand the natural volatility of hydrological conditions and the impact on available energy. Further analysis of the risks related to the additional debt required to construct Keeyask and the tie-line in concurrence with a Bipole III should have also been performed prior to project initiation. In fact the level of debt being taken as part of Hydro's expansion program will dramatically increase the total level of debt taken on by and/or guaranteed by the Province [Exhibits 19].

Overall, a decision to further assess alternative options requiring less capital and lower risk profiles would have been more prudent than moving forward with Keeyask and the tie-line at the time the decision was made.

To the credit of Hydro, several aspects of the planning and decision process were conducted well. For example, the construction of Keeyask is an extremely complicated endeavor from technical, operational, and commercial perspectives. That the project was successfully designed and agreed to by multiple parties, stakeholders, and contract holders is a significant achievement that should not be overlooked in assessment of the project. Moreover, the fact that multiple highly favorable US export term contracts were negotiated prior to initiation demonstrates the attempts by project leadership to mitigate at least a portion of the financial and export risk associated with the project [Exhibit 20]. Further, Hydro conducted several analyses regarding potential risks to the project, including low water flows and changes to gas and CO_2 prices [Exhibit 21]. Although the ultimate acceptance of some of the risks identified is questionable, in particular with relation to acceptance of low equity ratios in future years, it is clear Hydro and the Province attempted to weigh several important risks related to the project.

Underlying Factors to Address

To help avoid similar situations in the future, our analysis has sought to trace back the underlying factors leading to the decisions to proceed with Keeyask and the tie-line. The decision can be traced back to systemic decision governance issues that must be addressed by Hydro and the Province of Manitoba. More specifically:

The Province, Hydro and the Regulator lack clear objective functions and criteria / constraints

- For example, it is unclear if the primary role of Hydro, on behalf of the Province (its owner), is to drive economic growth or serve domestic energy needs, which at times may come into conflict as a result of normal operations. In times of adverse operating conditions or capital expansion, this may leave the business with an insufficient or high risk equity base.
- With respect to the Regulator, there is a clear track record of favouring low rates, in accordance with AURAA[5], but less clear is the role they play in balancing responsible asset

[5] Affordable Utility Rate Accountability Act

stewardship by Hydro and setting reasonable reliability targets to manage both costs and system performance [Exhibit 22]. Clarification of the objective functions, specific criteria, and constraints on such criteria for both Manitoba Hydro and the Regulator would be of great importance in helping build transparency for planning and operation of the system.

Current rate-setting mechanisms do not link rates to an allowable return, disconnecting revenue recovery from the system investment plan [Exhibit 23].

- This in turn drives increased financial uncertainty at Hydro, which results in more precarious financial conditions (e.g., acceptance of a projected equity ratio that reaches as low as 9% in the near future).
- A revenue model more directly linked with Manitoba Hydro's cost to serve, the maintenance of its financial health, and its future investment needs to serve customers would be an important change in regulation that would more appropriately adjust to the ever changing needs of the system in order to provide reliable electric service.

The current project planning approach is iterative, instead of being consolidated in an upfront manner [Exhibit 24].

- This limits insight into the compounded execution and financial risks from running several major, simultaneous projects concurrently, even when they have clear interdependencies as is the case with Bipole III, Keeyask and the tie-line
- A more consolidated planning approach with respect to major projects – one that takes into account the combined opportunities and risks for the company and its stakeholders – would be more appropriate to implement.

Topic 2: Is there further downside risk to the projects? [Exhibit 25]

Our analysis identified six key factors that have a significant impact on overall economics of the projects and financial health of the business. Each of these was reviewed regarding the assumptions used, to define the probability of further downside risk to the projects. [Exhibit 26].

- **Water flows:** Remains the largest variable, for both the Keeyask and the existing generation assets. No change in the underlying risk range
- **Capital execution** The capital execution costs have already shifted in an unfavorable direction for Hydro
- **Export prices**: Expected opportunity sales (i.e. those sales exclusive of the favorably priced contracted volumes) have already trended toward the low end of MISO sales price range
- **Interest rates**: Short and long term rate expectations have moved favorably since the original assessment of the projects
- **Domestic electricity rates:** While still within the original risk range, the Provincial Utility Board (PUB) granted only a 3.36% domestic rate increase for one year vs. the requested 3.95% for multiple years in Manitoba Hydro's last filing, reducing revenue versus the baseline.

  Net domestic demand: There is no further change in the expected range of domestic demand

Despite the favourable movement in interest rates the adverse movements in capital execution versus the expected schedule and in export prices in MISO have negatively impacted the project economics.

With respect to capital execution, if mitigation initiatives are implemented to limit further slippage to cost and schedule, ~$1.0B in additional capital[6] [Exhibit 27] is expected to be required due to an expected 12 month delay in Bipole III [Exhibit 28], and 21 month delay in Keeyask [Exhibit 29]. Should the mitigation initiatives either not be implemented or prove to be less effective than expected, schedules could further slip by an additional 3 months for Bipole III and 11 months for Keeyask, requiring an additional ~$0.7B in capital [Exhibits 30, 31].

Regarding export prices, while contracted prices remain unchanged (at favourable levels), the 2016 "reference" scenario now includes opportunity sales at export price forecasts that are below the prior IFF '15 estimates (13-17%). For the non-contracted portion of export revenues, these adjustments will shift the risk range of the project NPV down [Exhibit 32].

Some of the risks above have materialized and impacted Manitoba Hydro's financial metrics [Exhibit 33]. The ultimate impacts could be even worse should additional downside risks – both controllable and uncontrollable by Manitoba Hydro – be experienced [Exhibit 34].

Topic 3: Can the projects be stopped or paused without undue cost or risk? [Exhibit 35]

Despite the finding that the Keeyask project was undertaken without sufficient review and consideration of the risks – some of which have materialized leading to cost overruns and lower revenue expectations upon project completion –on a 'go-forward' basis continuing the projects remains the lowest risk, lowest cost, highest value option.

An added consideration is the interdependent nature of the projects. Transmitting and exporting power from Keeyask will depend on the new transmission capacity provided by Bipole III and the tie-line. Cancelling the current Bipole III project would effectively strand much of the capacity of Keeyask and make it financially implausible that the project could be continued in its current form.

If the projects were stopped today, it is estimated that, in addition to the costs already incurred (~$5B across the projects), an additional ~$1B would be incurred for each of Bipole III and Keeyask, bringing the total project costs to ~$7B [Exhibit 36].

Stopping the projects would also result in no functioning assets being available to the system for the amount spent, continued significant and real reliability risks associated with Bipole I & II and the Dorsey station, the requirement to procure additional generation to meet Manitoba Hydro's load in the coming years (e.g., by 2027), and other undesired impacts to Manitoba stakeholders [Exhibit 37].

[6] Includes interest and escalation costs

Cancelling Keeyask would require near immediate commencement to build alternative generation options to avoid the risk of Hydro being unable to meet its domestic reserve capacity needs by 2027 when current generation capacity may prove insufficient[7].

Completing the projects is still expected to yield a net present value more favourable than rerouting to Bipole III East or switching to gas generation, by an estimated ~$4 - $6B [Exhibits 38,39].

Final Conclusions and Recommendations

Based on our analysis we believe building a Bipole III line was a reasonable undertaking for reliability purposes, despite the fact that the most cost-effective design to the East was not pursued. However, construction of Keeyask was an imprudent project to undertake in parallel without further consideration of the risks and impacts of concurrently executing the projects with a Bipole III. Some of these risks have begun to materialize, in particular those related to capital execution, creating further strain on the projects and underscoring the original need for enhanced review and analysis before the projects began construction. Notwithstanding these findings, it is our recommendation the projects continue, as, given the estimated costs to complete, the non-economic impacts, and the expected NPV versus alternatives at this point, continuation remains the best path forward for Hydro, the Province, and their stakeholders.

[7] In addition cancellation of Keeyask would cause Hydro to be unable to fulfill its existing interim contracted volumes, which are at favorable pricing. And it could make Hydro a less credible counterparty for longer term contracts in the future

Tab 23

SUBJECT: Contingency

REFERENCE: NFAT Technical Conference 09-06-2013 transcripts page 441 line 15, Manitoba Hydro has stated: "And it's Manitoba Hydro, our corporate policy, to use the P50 estimate in the contingency development."

PREAMBLE: While a corporate contingency guideline of 50 percent probability of overrun for projects that are part a total annual capital budget may be fine in incidences where numerous smaller capital projects make up a total annual budget and where cost variations on one project may be offset by that of another project, this may not be the case for large projects.

In an article, entitled "Monte Carlo Analysis: Ten Years of Experience" from Cost Engineering (a publication of the American Association of Cost Engineers) Vol 43/No. 6 June 2001 states: "The 50 percent probability guideline is not applied to very large projects or to strategic projects outside the annual capital budget. For these, the 10 percent to 20 percent probability of overrun is often acceptable. When applying MCA (Monte Carlo Analysis) to projects at a very preliminary stage, management usually requires a very low probability of overrun, possibly 5 percent."

QUESTION:

Please provide the probability distribution curve used to determine the P50 or alternatively please provide the P80, P90, and P95 values and associated contingencies.

RESPONSE:

Keeyask contingency amounts associated with requested P-values are as follows:

P-Value	Contingency Amount
P50	$527 million
P80	$848 million
P90	$950 million
P95	$1032 million

Tab 24

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

2017/18 and 2018/19

GENERAL RATE APPLICATION

PUBLIC HEARING

Before Board Panel:

Robert Gabor	-	Board Chairperson
Marilyn Kapitany	-	Vice-Chairperson
Larry Ring, QC	-	Board Member
Shawn McCutcheon	-	Board Member
Sharon McKay	-	Board Member
Hugh Grant	-	Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

January 22nd, 2018

Pages 5519 to 5839

APPEARANCES

Bob Peters		)Board Counsel
Dayna Steinfeld		)
Patti Ramage	(np)	)Manitoba Hydro
Odette Fernandes	(np)	)
Helga Van Iderstine		)
Doug Bedford	(np)	)
Marla Boyd	(np)	)
Matthew Ghikas	(np)	)
Byron Williams		)Consumers Coalition
Katrine Dilay	(np)	)
William Gange	(np)	)GAC
Peter Miller	(np)	)
David Cordingley	(np)	)
Antoine Hacault		)MIPUG
George Orle	(np)	)MKO
Senwung Luk	(np)	) Assembly of
Corey Shefman	(np)	) Manitoba Chiefs

LIST OF APPEARANCES (cont'd)

Kevin Williams (np)	) Business Council
Douglas Finkbeiner (np)	) of Manitoba
Daryl Ferguson (np)	) City of Winnipeg
Christian Monnin	) General Service
	) Small, General
	) Service Medium
	) Customer Classes
William Haight	) Independent Expert
William Gardner	) Witnesses
Kimberley Gilson (np)	)

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LIST OF EXHIBITS

LIST OF UNDERTAKINGS

LIST OF UNDERTAKINGS (CONT'D)

NO.	DESCRIPTION	PAGE NO.
56	Manitoba Hydro to provide the Board with an indication of how much Manitoba Hydro has paid KPMG since May the 2nd on the Keeyask project and, likewise, how much they've paid KPMG related to the Bipole III project. (TAKEN UNDER ADVISEMENT)	5709
57	To advise the Panel of Manitoba Hydro's calculation of the costs for stopping construction on Keeyask entirely, together with what, if any, rate impacts that would have.	5712
58	Manitoba Hydro to provide the Board with its current estimate of the additional costs of Bipole III being on the western side of the province compared to the eastern side of Lake Winnipeg; and to review the number that it put forward at the Clean Environment Commission proceeding, and confirm that it was accurate when given (TAKEN UNDER ADVISEMENT)	5781

LIST OF UNDERTAKINGS (cont'd)

NO.	DESCRIPTION	PAGE NO.
59	Manitoba Hydro to provide confirmation that the road costs that are attributable to Conawapa are not included in the $380 million that Manitoba Hydro wants to amortize over the thirty (30) years	5837

--- Upon commencing at 9:29 a.m.

RULING:

THE CHAIRPERSON: Morning, everyone. I apologize for the technical delay. Before we start today, the Board is going to issue a ruling in relation to Manitoba Hydro's request to give rebuttal evidence in response to Morrison Park Advisors.

In this proceeding, Intervenor expert witnesses and the independent expert consultants retained by the Board provided written prefiled evidence in the form of expert reports. Manitoba Hydro was given the opportunity to file written rebuttal evidence in response to the expert reports filed by Intervenor witnesses and the independent expert consultants and did so in response to the reports of the Intervenor expert witness -- witnesses; the Daymark expert -- export - independent expert consultants; the Daymark load - independent expert consultants; Dr. Adonis Yatchew; and MGF Project Services.

After providing written prefiled evidence, a number of the Intervenor expert witnesses and the independent expert consultants have given oral evidence in this proceeding. There are also still

Intervenor expert witnesses in independent expert Consultants scheduled to give oral evidence in the remaining two (2) weeks of the evidentiary portion of this hearing.

Morrison Park Advisors is an expert witness in this proceeding, and was jointly retained by the Consumers Coalition and the Manitoba Industrial Power Users Group. Morrison Park Advisors filed written prefiled evidence in accordance with the deadlines set by the Board. All parties had the opportunity to ask written Information Requests of Morrison Park Advisors, following which Manitoba Hydro responded to the written prefiled evidence in its written rebuttal.

Mr. Pelino Colaiacovo gave oral direct expert evidence in the oral evidentiary hearing on -- of this General Rate Application on January 15, 2018.

On January 16, 2018 during Manitoba Hydro's cross-examination of Mr. Colaiacovo, Manitoba Hydro reserved the right to call rebuttal evidence to respond to what was, in its position, new evidence raised in his oral testimony. This is found at page 5111 of the transcript and was further explained by Manitoba Hydro beginning at page 5140 of the transcript.

The testimony in question related to slides 17 and 18, of Mr. Colaiacovo's oral presentation marked as Consumers Coalition Exhibit 45. The testimony in question also related to a spreadsheet provided by him with his PowerPoint slide presentation, which was marked as Consumers Coalition Exhibit 46.

In cross-examination by Manitoba Hydro, Mr. Colaiacovo confirmed that the analysis on slides 17 and 18 of Consumers Coalition Number 45 and the spreadsheet marked as Consumers Coalition Number 46 was not included in his written prefiled evidence.

Manitoba Hydro's position is that as the calculations presented by Mr. Colaiacovo were not presented in his initial evidence, the Utility should therefore have the right to respond to the new analysis.

This request was not opposed by the Consumers Coalition or the Manitoba Industrial Power Users Group. As set out in the leading Sopinka, Lederman & Bryant text, The Law of Evidence in Canada, the right to call rebuttal or reply evidence is limited to new issues raised in the evidence and does not include matters which might properly be considered to form part of the Applicant's case in-chief.

Rebuttal evidence cannot be used under the guise of replying to confirm or reinforce the case which the Applicant was required to make out in the first instance. This ensures fairness for all those who are engaged in testing the Applicant's case.

The Board has determined that the analysis presented by Mr. Colaiacovo on slides 17 and 18 of his direct presentation and supported by the spreadsheet marked as Consumers Coalition 46 is new evidence, not previously raised in the written prefiled evidence of Morrison Park Advisors or responses to Information Requests. As such, it could not reasonably have been anticipated by Manitoba Hydro.

Manitoba Hydro can, therefore, properly address this evidence through calling rebuttal evidence on February 2nd, 2018, the day currently reserved in the schedule for that purpose. Should Manitoba Hydro's rebuttal evidence include new analysis or calculations performed by the Utility, such analysis or calculations must be provided to all parties by no later than 5:00 p.m. on January 31st, 2018. All parties will be given an opportunity to ask questions of the Manitoba Hydro witnesses called to give oral rebuttal evidence.

Based on the submissions of Manitoba Hydro, the Board has furthered determined that to date this matter is the only matter in this proceeding that is properly the subject of oral rebuttal evidence, unless another new matter is raised in the remaining scheduled oral testimony of Intervenor and independent expert consultant witnesses.

Manitoba Hydro's oral rebuttal evidence will be strictly limited to addressing only the evidence that formed the subject of this request as set out in page 5111 of the transcript.

This opportunity for the Utility to call oral rebuttal evidence cannot be used to attempt to reconfirm or reinforce its case in-chief, including any matters that could have reasonably been anticipated by the Utility. Should any further new evidence be raised in the oral testimony of the remaining scheduled witnesses that Manitoba Hydro wishes to respond to oral rebuttal evidence, Manitoba Hydro should make the appropriate request of the Board. Thank you.

Mr. Simonsen, if you could swear in the witnesses, please.

MANITOBA HYDRO PANEL 4 - MAJOR CAPITAL PROJECTS

JEFF STRONGMAN, Sworn
DAVID BOWEN, Sworn
LORNE MIDFORD, Sworn
DAVID CORMIE, Sworn
ALISTAIR FOGG, Sworn
GLENN PENNER, Sworn

THE CHAIRPERSON: Ms. Van Iderstine...?

MS. HELGA VAN IDERSTINE: Thank you, Mr. Chair. I would like to just enter before we start two (2) exhibits, the Capital Panel CVs should be entered as Manitoba Hydro Exhibit Number 118. And the presentation which you're about to hear should be entered as Manitoba Hydro 120.

MR. KURT SIMONSEN: Thank you.

--- EXHIBIT NO. MH-118: Capital Panel's CVs

--- EXHIBIT NO. MH-120: Capital Panel's PowerPoint presentation.

EXAMINATION-IN-CHIEF BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Thank you. And with that, I'd like to introduce Mr. Lorne

Midford, who is going to lead the presentation.

THE CHAIRPERSON: Sorry, for a second. Mr. Simonsen, we have it written down as 130, is it --

MR. KURT SIMONSEN: 120.

THE CHAIRPERSON: It's 120, okay, thank you. Sorry, Ms. Van Iderstine.

MS. HELGA VAN IDERSTINE: So with --

MR. KURT SIMONSEN: Sorry, just to backup, 119 is -- is a letter from Manitoba Hydro to PUB regarding the MGF redacted report.

(BRIEF PAUSE)

--- EXHIBIT NO. MH-119: Letter from Manitoba Hydro to PUB regarding the MGF redacted report.

THE CHAIRPERSON: Sorry, Ms. Van Iderstine...?

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: And with that, I'd like to introduce Mr. Lorne Midford who is going to lead the Keeyask portion of -- or who's going to lead the capital panel.

I would just caution you and let you know that as you saw when they're being introduced, we've got almost everybody up here. We have one (1) person who's in the back, so, they're going to move back and forward during the -- the presentation so that the appropriate person's in the front row.

And the other thing, just to let you know, is that we anticipate the Keeyask present -- portion of the presentation, which is the starting portion, will take up the majority of the time up until what you've got your scheduled breaks. So, we'll ask whether or not you want to proceed with a break at that point.

THE CHAIRPERSON: Thank you.

MR. LORNE MIDFORD: Good morning, Mr. Chairman, Madam Vice Chair, Board members, Board advisors, Intervenors, and our audience. I'm Lorne Midford and I am the vice-president of Generation and Wholesale at Manitoba Hydro. And since early 2016 I have executive responsibility for construction of the Keeyask generating station. And I also chair the Keeyask Hydropower Limited Partnership Board of Directors. It's a pleasure to be here.

Before I introduce our panel members, I'd just like to take a minute to pass on our condolences to the family of Todd Maytwayashing, who tragically lost his life last week following a workplace accident at a marshaling yard near the Limestone generating station on the lower Nelson River. Our thoughts and prayers go out to his family.

Beside me is David Cormie who I don't think needs any introduction. He's -- you're already familiar with Mr. Cormie. He's a part of the panel today through his involvement with both the Great Northern Transmission line and the Saskatchewan transmission line.

Glenn Penner behind us is the Director of Transmission Construction and Line Maintenance. Glenn is responsible for a diverse team of project managers, designers, engineers and lifeline workers. He has been with Manitoba Hydro for almost twenty-seven (27) years, much of that in transmission working in a variety of roles throughout including structural engineer and manager of transmission construction.

Beside David is Alistair Fogg. Mr. Fogg is the manager of the Converter Commercial and Controls Department in the Bipole III Converter Stations Division. Alistair is a professional engineer with a Masters of Business Administration and has a CMA designation. Alistair manages project control functions for the Bipole III project, including commercial support, contract strategies, project cost and schedule, change management and risk management.

Beside me is Dave Bowen. Mr. Bowen is the Director of the Keeyask project. Dave has over twenty (20) years of experience in both the consulting engineering and electric utility business. He's a registered professional engineer and has a Master of Science in Engineering. Dave's work experience has seen him taking on progressively senior roles as an engineering consultant in areas of infrastructure and within Manitoba Hydro, focused on the delivery of new generation projects. This has included work on the Wuskwatim generating station, Pointe du Bois spillway, Bipole III and Keeyask projects.

And beside David is Jeff Strongman. Jeff is the manager of the Keeyask Business Department. He's a civil engineer with over twenty (20) years of experience in the consulting, manufacturing and construction industries and prior to working on the Keeyask project, Jeff was a senior contracts negotiator working primarily on development of agreements with Minnesota Power on power export sales and a new transmission interconnection to the

United States. Prior to that, Jeff played a key role on the construction team during the Wuskwatim generating station build.

For myself, I am a professional engineer with thirty-two (32) years of experience in the electric utility business; about half in the transmission side of the business and half in the generating station side of the business.

So now I'd like to start the presentation. We're on slide 2. Nearly all of the electricity we produce each year is clean, renewable power generated at 15 hydroelectric generating stations on the Nelson, the Winnipeg, Saskatchewan, Burntwood, and Laurie Rivers.

We also operate two (2) thermal generating stations at Brandon and Selkirk which are, essentially, only used for backup power and four (4) small remote diesel generating stations at the off-grid communities of Brochet, Lac Brochet, Shamattawa and Tadoule Lake.

Our total generating capability is just under 5700 megawatts and Keeyask, once complete, will increase this capacity to just under 6400 megawatts. We also have wind power purchase agreements from independent windfarms at St. Leon and St. Joseph.

Manitoba Hydro's transmission system transmits electricity from generating stations around the province and also interconnects the Manitoba system with neighbouring provinces and states. Our major high-voltage transmission lines operate at 115,000 volts to 500,000. The high-voltage MR. DAVID CORMIE: lines shown in this picture are, essentially, an expressway for the majority of power that is generated in the north and transmitted to the south. The power that is generated in the north system is converted to high-voltage direct current at two (2) converter stations Radisson and Henday and transmitted over 1800 kilometres to Dorsey converter station just outside Winnipeg where it's converted back from high-voltage direct current to high-voltage alternating current.

We deliver electricity to our customers using over 18,000 kilometres of transmission lines and 68,000 kilometres of distribution lines.

Slide 3. Keeyask generating station is a collaborative effort between Manitoba Hydro and four (4) Manitoba First Nations working together as the Keeyask Hydropower Limited partnership. Our four (4) Cree nation partners are: Tataskweyak Cree Nation and War Lake First Nation acting as the Cree nation partners; York Factory First Nation and Fox Lake Cree Nation. The partnership is governed by the joint Keeyask Development Agreement, sometimes referred to as the JKDA, which outlines such things as the contractual investment terms for the partnership and outlines commitments in the form of training, employment and business opportunities during construction, as well as the ongoing governance structure.

Slide 4. The Keeyask Hydropower Limited Partnership has a Board of Directors with representation from all four (4) partners. The Board meets at least quarterly to review the project status, review any issues and concerns and, essentially, provides an ongoing and regular opportunity to meet and to talk and to provide feedback for the project.

I can tell you at a very personal level that I've come to better understand the Cree worldview. I've come to better understand the impact our legacy operations have had on these communities. And I've come to better understand the importance of reconciliation. And I continue to learn and to understand and I thank our Cree Nation partners for putting their confidence in me as chair of the Keeyask Hydropower Limited Partnership. Keeyask, and our approach to planning, constructing and operating this station like Wuskwatim is to Tataskweyak before it, is a cornerstone for Manitoba Hydro on behalf of the province to build a long-standing positive relationship with our Cree Nation partners based on respect and trust.

To reconcile the past, to work together for a better future, this will take some time. Reconciliation is a long journey. If the Tataskweyak is any indication, I'm very confident that we're on the right path and with time and openness, we will get there together.

I don't want to take too much time but this is so important to me personally and to the -- everyone involved in the project that I'd like to share a story with the Board, perhaps to provide some perspective.

In 2015 when the rock was being excavated for the powerhouse, essentially 100 foot rockface was drilled and blasted out of the rock, which is where the units will ultimately generate their power. In this rockface, there was a relief of a face in the rock that appeared that was perhaps ten (10) to fifteen (15) feet high. When I first learned of this by a photo that was circulating, I thought it was interesting, and frankly quite cool. But I can tell you that I didn't give it any more thought than that nor did others who did not grow up as the Cree have. Our Cree partners, on the other hand, had a very, very deep spiritual connection with this event and because of my and other's lack of acknowledgment and understanding, it created conflict and sadness with our Cree partners; that, of course, was unintentional.

We had emergency meetings with the Keeyask Hydropower Limited Partnership Board and through a lot of discussion and learning, we hosted several ceremonies both at site and within some of the communities to recognize the significance of this event. These ceremonies that I participated in were very moving. I can tell you that this is just one (1) example of how we are learning and continue to learn and to understand as we travel on this long journey of reconciliation.

The Keeyask Hydropower Limited Partnership Board also commissioned paintings from two (2) of the Cree nation communities to commemorate the rockface from Fox Lake Cree Nation and Tataskweyak Cree Nation which you can see on the -- on the screen in front of you. These lovely paintings hang on the wall at the check-in desk at the Keeyask camp and will, ultimately, find a home at the Keeyask generating station when it is complete. So when you visit the Keeyask site and you see these pictures hanging on the wall when you check-in, I hope you may reflect on this story. And understand that several Board members have had the opportunity to travel to Keeyask and look forward to future opportunities to host members of the Board as well at the site.

Slide 5. The Keeyask Hydropower Limited Partnership will own the Keeyask generating station. The Keeyask Hydropower Limited Partnership is structured as a limited liability partnership consisting of a general partner with .1 percent, a wholly owned subsidiary of Manitoba Hydro and four (4) limited partners with 99.9 percent. Manitoba Hydro, the Cree Nation partners made up of Tataskweyak and War Lake, Fox Lake Cree Nation Limited partnership and York Factory First Nation Limited Partnership.

The general partner manages the affairs of the Keeyask Hydropower Limited Partnership and has contracted with Manitoba Hydro to construct and operate the project. The general partner is managed by a Board of Directors consisting of seven (7) Manitoba Hydro reps and five (5) Keeyask Cree Nation reps, a monitoring advisory committee and a construction advisory committee provide advice to the Board. An advisory group on employment provides advice to the Manitoba Hydro project manager and also provides reports to the board. And an issues coordination committee, in turn, triages issues for discussion and direction to the Board of Directors.

Mr. Bowen is the director of the Keeyask project, and he reports directly to me. Dave has structured his team into areas of site construction manager, commercial contracts manager, engineering manager, and business manager.

The major projects -- slide 6. The major projects executive committee, which is Chaired by our President and CEO Kelvin Shepherd, oversees, directs, and makes strategic decisions on Manitoba Hydro's major capital projects. The executive committee was established in early 2016, with membership from the president and CEO, vice president of transmission, vice president, myself, generation and wholesale, vice president of HR and corporate services, vice president of Indigenous relations, and vice president of finance and strategy. The executive committee meets biweekly, or as often as required. Each operating group retains authority and accountability of the project within their scope of accountability.

I would now like to pass it over to Mr. Strongman.

MR. JEFF STRONGMAN: Thank you, Lorne.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Manitoba Hydro's Keeyask team is comprised of roughly two hundred and twenty (220) people split geographically between the Keeyask site and the corporate head office in Winnipeg. The site team, headed by the construction manager, is located at Keeyask and provides construction oversight and project management. The engineering, contracts management, and business teams are stationed in Winnipeg, as well as other corporate resources to provide the necessary support to the construction team at site.

Slide 8. So what are we building? We're building two (2) things. First, the 695 megawatt Keeyask Generating Station will be the fourth-largest generating station in the Province, providing 12 percent of Manitoba's renewable energy. It's clean, renewable energy that will benefit

Manitobans for more than one hundred (100) years. Secondly, we're building a stronger relationship with our First Nation partners.

The Keeyask project...

(BRIEF PAUSE)

MR. JEFF STRONGMAN: How's that? Is that better? Okay.

The Keeyask project includes a seven (7) unit powerhouse, a seven (7) bay spillway, an extensive network of dams and dikes, all-supporting infrastructure, which includes camp, access roads, and temporary infrastructure such as cofferdams, and all required transmission facilities. The Keeyask site is located on the Nelson River in northern Manitoba, roughly 700 kilometres north of Winnipeg, and 180 kilometres northeast of Thompson.

I understand that some of the members attended the site. I'll just give you a -- a rough roadmap of the road that you took once you landed in Gillam. Starting in Gillam, you'd proceeded east on the highway, away from the project site, in order to cross the Nelson River at the Limestone Generating Station, then back west towards the Keeyask site on

PR290. Then you turn left on the Keeyask access road, pass through the security gate, and finally arrived at the main camp after roughly two (2) hours.

Also note on this map the location of our partner communities and their close proximity to the site, Bird and Gillam on the right side are Fox Lake communities. On the left, Split Lake is the Tataskweyak First Nation community, York Landing is the York Factory First Nation community, and Ilford is the War Lake First Nation community shown.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: This aerial photo, you can see the project site before construction. The Nelson River flows from the left to the right in this photo, and is roughly 1000 metres wide as the river approaches the Gull Rapids. At that point, the river splits into three (3) channels, referred to the North, Central and South channel, with the North at the top. Through the rapids, the river drops 12 metres in elevation, which makes it an attractive site for the placement of a generating station.

Slide 10. This rendering shows the

layout of the principal structures at Keeyask with, again, the flow from the left to the right, and the top being North. The powerhouse is located on the north side of the river, and is a -- a mile from the spillway, separated by the Central dam. There will be short dams on the North and South side as well. Keeyask is constructed in relatively flat terrain, so it requires extensive diking, roughly 23 kilometres total.

The principal structures of the Keeyask Generating Station are the North and South dikes along the upstream shorelines, the North dam that connects the North dike to the powerhouse, the powerhouse complex constructed on the North side of the river, including an intake and tail race channel, a Central dam that will connect the powerhouse to the spillway, a spillway structure located on the North side of the Gull Rapids South channel, including the intake and -- and tail race channels, and the South dam that connects the spillway to the South dike.

Slide 11. This is an artist's rendering of the Keeyask powerhouse, once finished. In order to provide context on the size, the height to the top of the powerhouse is equivalent to -- pardon me. The height to the top of the Manitoba Hydro building is 88.6 metres, and the height of the powerhouse is 64 metres, which is roughly three quarters (3/4) of the height of the Hydro building. The powerhouse is 64 metres by 64 metres by 192 metres long. The total length is over two and a half (2 1/2) football fields.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: The second of the two (2) principal concrete structures is the spillway. And slide 13 is an artist's rendering of the Keeyask spillway, showing the completed version. Again, for context, comparing the spillway to the Manitoba Hydro building, the spillway is tall as the 17th floor of Manitoba Hydro. The spillway's dimensions are 60 metres high, 44 metres wide, and 119 metres long.

MR. JEFF STRONGMAN: Slide 15. The river management structures are the main features of this slide, and they are highlighted in green. In order to perform the construction work, the natural path of the North and Central channels of the river have been blocked by cofferdams, forcing the river to pass the construction site through the South channel. Inside these cofferdams, all the water has been pumped out so that the work can progress in dry conditions.

Slide 16 is a typical cross-section of a dam. The schematic depicts a typical permanent earthwork structure, such as what we were building in the North, Central and South dams. Shown are the impervious core and successive layers of rock designed for sufficient strength to hold back the pressure of the water on the west side of the dam. Not shown on this schematic is the variability of the underlying bedrock upon which the structure is built.

The top left picture in slide 17 is a -- a photo depicting the cleaning of the bedrock surface to what's referred to as dinner plate clean. The bottom left is the placement of dental concrete as a means of leveling the bedrock, and on the right, a portion of the central dam under construction in the summer of 2017.

Slide 18 shows the permanent structures of Keeyask overlaid on a map of Winnipeg. Again, this is designed to try to achieve context and perspective of the extent of the site. The South dike is 10 kilometres long, 22 metres high, roughly 10 metres wide at the top. The North dike is 11.6 kilometres long, 17 metres high, and roughly 10 metres wide at the crest. The North Dam is 320 metres long, 24 metres high, and 10 to 15 metres wide at the crest. The Central dam is 1,577 metres long, 28 metres high, and 15 metres wide at the top. And the South dam is 610 metres long, 22 metres high, and 15 metres wide at the top.

When you overlay the permanent structures on a map of Winnipeg and extend from -- there's -- they extend from Portage and Main almost to the west perimeter. Note that the North dike extends out of downtown, past Polo Park, continues to the James Richardson Airport, well into St. James, and the South dike extends out of downtown, through the Osborne junction, then west through River Heights, and into Charleswood, past Assiniboine Park, ending south of Wilkes.

Slide 20. We've taken the concrete structure of the powerhouse and overlaid it into a block of downtown. Similarly, the service Bay would take up a -- a similar footprint. The infrastructure required to support Keeyask include the following -- this is slide 21 -- 23 kilometre north access road, linking the Keeyask site to PR280, a 25 kilometre south access road linking the site to Gillam, a major bridge structure over the Looking Back Creek, and a two hundred (200) person start-up camp, and a twenty-four hundred (2,400) person main camp at either ends of the access road.

Slide 22 is the Keeyask transmission project, which has two (2) main components. The first is providing the power required for the current -- the construction of the Keeyask Generating Station, and the second is to transmit the power from Keeyask to the Manitoba Hydro Converter Stations linking and integrating the station into the Manitoba Hydro system. The Keeyask transmission project includes the construction of a power line and station, a switching station on the south side of the Nelson River, three (3) generation outlet transmission lines, four (4) unit transmission lines, and upgrades to the Radisson switching station.

Manitoba Hydro has incorporated lessons learned from previous projects, including Wuskwatim, at a cost of 1.4 billion, at Pointe du Bois, at a cost of 0.6 billion, into the delivery of Keeyask. The Corporation's project management capabilities have been built up over the last ten (10) years in preparation for delivering Keeyask and the Bipole project.

Lessons learned from past projects include: Early contractor involvement is valuable.

The contract model has to fit the circumstances and market conditions. Goals and incentives must be mutual and tied to project critical success factors. Independent third-party reviews are beneficial, providing independent perspective on the projects and processes enhances the opportunity for continuous improvement. Rigorous oversight is essential. Project integration is critical to success. Manitoba Hydro has to be active in managing the interface points between contracted work packages, and doing things as they have always been done does not work for complex projects that require constant innovation and a culture of collaboration.

Slide 24. Keeyask is a complex, multiyear Hydro construction project with suffic -- significant coordination and integration requirements. It's being developed at a remote Northern location with access from only one (1) Provincial highway that's -- and that's Provincial Road 280. Productivity of trades has been declining over the last twenty (20) and thirty (30) years.

On-site camp is required capable of accommodating the peak workforce of twenty-four hundred (2,400) workers. Seasonal constraints exist, and they limit the warm weather construction season significantly. Operating in a regulatory environment that includes necessary constraints such as environmental spawning windows that limit when certain construction activities occur.

River management is key. The Nelson River is over a kilometre wide, requiring significant earth structures for the variable flow conditions. Large earthworks projects with subsurface conditions within the former river channel can significantly impact the design and the construction of the project.

Slide 25, employment. Employment on the Keeyask project is a real success story, as the vast majority, 73 percent to date, of Keeyask workers are from Manitoba. As well, our project has enjoyed unprecedented employment from our partner communities, the First Nations within Manitoba. Midway through 2017, the project reached a significant milestone of 2 million person hours worked by our Keeyask partners and 4 million person hours worked by Indigenous people.

(BRIEF PAUSE)

MR. LORNE MIDFORD: In addition to the vast majority of project employees coming from

Manitoba, our project workers come from across the provinces of Canada and roughly half of the United States. In addition, project workers also come from Portugal, Italy, the United Kingdom, Australia, Chile, and Argentina.

Slide 27. A project site the size of Keeyask draws on global resources to fulfil its -- all of its requirements. Manitoba supplies the generator step-up transformers and trashracks. From across Canada the intake and spillway gates are supplied, as well as the powerhouse crane, intake, and draft tube cranes, turbine components, and the governors. From the United States we source the isolated phase bus and the exciter. And from Europe and Brazil we source the turbines, generators, and generator circuit breakers.

(BRIEF PAUSE)

MR. LORNE MIDFORD: Slide 28. The Keeyask project has a strong safety record for a large complex project in a remote location. However, last week a tragic accident took place. An employee of a contractor working for Manitoba Hydro near the community of Gillam suffered a fatal injury on January 17th, while securing tower steel bundles to a flat deck semi. The worker was an employee of Forbes Brothers, tasked with building the transmission line that will carry power from Keeyask to the Radisson converter station just out -- just outside of Gillam. Our hearts go out to the family. We cannot comment further until the investigation is complete.

To date, over 15 million person hours have been worked on the project to the end of 2017. The project is performing well compared to the construction sector in Manitoba. The lost time incidence rate for the project to date is less than one-tenth (1/10) of the provincial rate. The Keeyask project rate is zero-point-two-nine (0.29) lost time incidents compared to the construction sector average of four-point-two (4.2). The general civil contractor has gone over one (1) year without a lost time incident. Manitoba Hydro and all of our contractors will continue to work on our goal of zero injuries.

(BRIEF PAUSE)

MR. LORNE MIDFORD: Slide 29. The contracting model is specifically tailored for each contract and scope of work. This includes an evaluation of the market capacity, potential competition, constraints, and capabilities within Manitoba Hydro. This also involves allocating risk to the party who is best able to manage it.

There are variety of types of contracts. The four (4) main ones that are used on this project include cost reimbursable, where the contractor is paid for all of its allowable expenses plus a -- plus an additional payment for profit. The second is a target price, which is based on a cost reimbursable mechanism in which the contractor is reimbursed for actual costs subject to the application of a pain/gain formula at the end of the project based on performance.

A fixed-price contract is where a contractor is paid a predetermined price to complete the work regardless of actual costs. And the fourth type is a unit price contract where the contractor is paid a fixed sum for each unit of work complete.

Slide 31 shows the major contract types. This is a list of the Keeyask contracts whose value exceed 35 million. Note that there are total of two hundred and thirty-nine (239) contracts awarded to date, and that only the largest eleven (11) on the con -- on the project are shown on this slide.

Earlier when I spoke of the types of

contracts, you can see in the column on the right how all fit -- all four (4) main types are utilized in this project. For example, the turbines and generator contract to supply and install seven (7) units is a fixed-price because the scope of work is very clearly defined, while the service contracts, such as camp operations, are cost reimbursable largely because they are a function of time. The service contracts continue in duration for however long the construction phase requires to completion.

Slide 32, some remarks about the general civil contract. The general civil contract, or GCC as it's commonly referred, was awarded to BBE Hydro Constructors Limited Partnership in March of 2014. BBE is a tri-party consortium including Bechtel Canada, Barnard Construction of Canada, and EllisDon Civil Limited. It is by far the largest contract on the project, and includes the following key scopes of work: coffer dams, which are temporary river management structures; rock excavation; principal concrete structures, including the powerhouse and spillway; the earthwork structures, including the dams and dikes; and the electrical and mechanical work.

This contract was awarded as a single contract rather than a separate contract for the electrical and mechanical work, which was done on Wuskwatim, to minimize the interface risks and delays in coordinating other parties to take over the work from the general civil contractor as the concrete work progresses. This is subject to significant variability based on performance rates to completion.

Slide 33. In order to understand the context surrounding the decision to proceed with the general civil contract as a target price contract, we need to rewind the clock back five (5) years to 2012 when the procurement process was underway. At that time oil prices exceeded a hundred dollars per barrel and the North American megaproject market was hot, with dozens of capital expansion projects taking place in northern Alberta as well as LNG projects across the country.

In that environment megaproject contractors were not accepting hard money contracts where many risks such as labour productivity pass on to contractors without substantial and cost prohibitive premiums. This caused owners to proceed with alternative forms of contract sharing risk, where possible, and retaining them where they couldn't be passed on.

On the Wuskwatim project, Manitoba

Hydro attempted to tender the general civil contract as a unit price contract. However, the market was hot and unresponsive to hard money contract. As a result, Manitoba Hydro received only one (1) bid, which was cost prohibitive. Another lengthy procurement was undertaken, culminating in a responsive, competitive process and an award of a target priced cost reimbursable contract to O&E who performed the general civil contract work for Wuskwatim.

Slide 34. This is a timeline of the general civil procurement process. The procurement of the Keeyask general civil contract required a three (3) step process. The first step was market sounding to identify and open communications with potential parties interested in and capable of doing the work. This took place in early 2012.

The second step is the preq -- prequalification phase, where the market is invited to indicate interest in becoming prequalified to bid on the work. This took place in the second half of 2012. Seven (7) parties responded to Manitoba Hydro's invitation and four (4) proponents were qualified in early 2013.

The third and final step is the call for proposals from the four (4) qualified -- qualified proponents, which was done in the second half of 2013. All four (4) proponents responded to the call and submitted proposals. The submissions were evaluated on best value to Manitoba Hydro, and a contract award was made to BBE in March 2014. A third party was also retained to provide a reference proposal, in addition to the engineer's estimate, that also served as a reference point for comparison of the bids.

Slide 35. The general civil contract is a target price contract cost reimbursable contract with a pain/gain share formula that is intended to motivate the contractor to perform. The contractor's profit is at risk. However, their liability is capped at the profit. Once the profit is eroded all actual costs are 100 percent paid by Manitoba Hydro.

The target price contract model was used because the marketplace would not accept a fixed-price contract without a significant cost premium. In addition, all forms of contract require relief for changed conditions. This form of contract is intended to secure competitive bids in a competitive major project environment.

Slide 36 is a timeline showing the construction milestones that have been achieved. Starting with infrastructure, work including the access road, camp, and bridge over Looking Back Creek was built between 2012 and 2014. During NFAT this phase of work was referred to as KIP, or the Keeyask Infrastructure Project.

The general civil contract was awarded in March 2014 and in July of that year the milestone of first rocks in the river was achieved on July 16th, 2014, that signified the start of coffer dam construction which would continue through 2014 and 2015. The start of 2016 also saw the start of construction of the first permanent earthworks, followed by first concrete in the powerhouse in May of 2016. The construction of permanent concrete and earthwork structures has been the focus over the last two (2) years.

So that's looking backwards over the last five (5) years. Now looking forward we'll talk a bit about the future construction milestones. Slide 37 provides a look ahead for the next five (5) years required to complete the work. Starting at the left side of the slide with 2018, this year we'll see the start of turbine and generator installation at Keeyask. And, in fact, our contractor Voith has mobilized and begun work at the site.

Late summer of this year we'll see the

work advance sufficiently to divert the south channel of the river through the spillway. This is a major milestone as this signifies the transition of the river from its natural path through our control -- spillway control structure.

This also permits constru -- construction traffic crossing the river and utilizing the South Access Road to get to the Keeyask site, considerably -- considerably reducing travel time from Gillam. So in the fall of this year the travel from Winnipeg to the site will still be the two (2) hour flight to Gillam. However, rather than an additional two (2) hours on the highway it will be about a twenty-five (25) minute drive from Gillam. So if anyone's travelling a return visit, September-ish is a good time.

Looking ahead to the end of 2019, we'll see the enclosure of the full powerhouse. Currently only the service Bay and unit number 1 are enclosed, while the remaining units are under construction. Looking further to 2020, we would see impoundment of water up against the permanent earth structures followed by the first unit in-service date of August 2021, and the last unit by August 2022.

Slide 38 is another general

arrangement. 362,000 cubic metres of concrete are required to build the powerhouse and spillway. 2.2 kilometres of earth-filled dams are required to construct the North, Central, and South dams. 23 kilometres of dikes are required to build the North and South dikes along the Nelson River to contain enough water to produce power at Keeyask.

This rendering shows the layout of the principal structures at Keeyask. The river flows left to right with the north at the top. Again, the powerhouse is located on the north side of the river, is about one (1) mile from the spillway separated by the central dam. The short dams on the north and south side are also depicted. Keeyask is in a very flat area, so extensive diking is required, as I mentioned earlier, roughly 23 kilometres total.

Slide 39 is a powerhouse rendering. This is an artist rendering showing the powerhouse with the service bay on the right and the seven (7) units progressing leftwards.

Slide 40. This slide shows a time-lapse representation of the powerhouse. On the left and labelled "2015" is the powerhouse excavation progression. In the middle and labelled "2016" is the first year of concrete work showing the lower stages getting off the rock. And on the right and labelled "2017," you can see the service bay and the concrete work on the first three (3) units starting to take shape.

Slide 41. Shown on the left is the first concrete. Leveling and bay slab pours of the powerhouse are shown from early 2016. And shown on the right is the development of the draft to formwork for units 1 and 3. Unit 1 is on the right and unit 3 is on the left.

Slide 42. This is a shot of the powerhouse towards the end of the first year of construction in October 2016. You can see the five (5) tower cranes coloured in blue that serve the work face and are used to lift rebar, formwork, and any material requirements into place. I'd also want to point out the orange tarps that are visible. These are required as part of the heating and hoarding necessary to provide adequate temperatures for the working environment and for concrete curing.

Slide 43. This photo shows the powerhouse complex at the end of 2016, the first year of concrete construction at Keeyask. The model in the bottom half of the slide shows a rendering of the concrete pours completed within the powerhouse in that first year. Again, the service bay is on the right, and moving from the left you see the intake, and moving down you can see the units of the powerhouse, together with the tailrace pour shown on units 1 and 2.

Slide 44. This is another shot of the powerhouse looking upstream from the downstream side of the structure. This was taken in July 2017. You can see there are no orange tarps needed in the summer months. The service bay is on the right, and the units under construction are progressing on the left, starting with unit 1.

Slide 45 is an overhead bird's eye view of the powerhouse in the summer of 2017. You can see units 1, 2, and 3 identified by the circular draft to formwork in the middle of the shot. Progressing leftwards from there, you can see nothing in unit 4, 6, and 7. And the wooden formwork in unit 5 is visible but there's no concrete there.

Slide 46. This photo was taken just prior to Christmas on December 15th, 2017. At that time, you can see that the superstructure steel above units 1, 2, and 3 and the enclosure of the service bay in unit 1 on the right. By February of 2018 units 2 and 3 will be enclosed as well, to permit work continuing throughout the most extreme months of winter.

Slide 47. The previous series of pictures were of the powerhouse. Now I'll show you the spillway, starting with the artist rendering of the end product. You can see seven (7) bays in the spillway, each with its own gate that moves in the vertical direction. This is how we control the flow of the river by moving the gates up and down, increasing or decreasing the open area for water to pass. Also shown here are the upper and lower bridge decks that will connect with the South Access Road and the highway network leading to Gillam. Once construction is complete, the spillway bridge deck will become part of the highway as a river crossing.

Slide 48. This shot of the spillway shows the bay slab, which is the lowest lift of concrete progressing up from the bedrock. The rebar standing vertical and the formwork installation is underway for the first lift -- lift up off the bay slab, which will see the development of the piers starting to take shape. This was July 2016.

Slide 49. By the end of 2016 the spillway was about half complete, as you can see in the shot on the top left. The rendering on the bottom is dated December 17th, 2016, and you can see all of the piers are up off the bay slab, but only a few of them past the halfway point in reaching full height.

Slide 50. By August 2017 nearly all of the piers have reached full height. Preparations are now underway to finish the top lift, strip the forms, and prepare for the installation of the bridge deck.

Slide 51. This shot of the spillway was taken about a week and a half ago. It shows the completed spillway structure. The seven (7) bays are clearly defined and the top deck is in place. You can also see white tarps in the spillway bays providing a heated environment for the spillway gates and guides contractor who is preparing to do their work throughout the winter months.

Slide 52 is a satellite image of the Keeyask site taken in September of 2017. The previous series of slides, I showed you pictures of the powerhouse and spillway, located on this image to the right and on the bottom. They are connected by the central dam, which is the earthwork structure nearly a mile long linking the two (2) structures. The north dam is on the top, running from the powerhouse to the north dike. And the south dam will be on the centre bottom across the south channel linking the spillway to the south dike.

We have a short video prepared and I will pass off to Dave at this point.

(BRIEF PAUSE)

(VIDEO PRESENTATION PLAYED)

THE CHAIRPERSON: Mr. Bowen, I'm just wondering if this is the appropriate time to take the midmorning break.

MR. DAVID BOWEN: Sure.

THE CHAIRPERSON: Okay. So we'll break for fifteen (15) minutes. Thank you.

MR. DAVID BOWEN: Thank you.

--- Upon recessing at 10:34 a.m.

--- Upon resuming at 10:48 a.m.

THE CHAIRPERSON: Mr. Bowen...?

MR. DAVID BOWEN: Thank you, Mr. Chair. Mr. Strongman has walked us through the project features, construction completed in the past two (2) seasons and the basis of the general civil contractor procurement.

I would now like to spend some time describing our challenges with the construction, the permanent earthworks and concrete and what Manitoba Hydro's done and continues to do, deliver the project at the lowest cost and shortest schedule.

I will focus on what happened during the first months of concrete and earthworks construction. This is a time -- timeline from 2014 to spring of 2017. As Mr. Strongman mentioned during his portion of the presentation, the general civil contract scope includes the construction of all dams and dikes; what we've referred to as permanent earthworks and the concrete portion of the spillway and powerhouse; what we refer to -- referred to as the permanent structures.

A major milestone on any Hydro job is first concrete which signifies the start of a new phase, which is building the powerhouse complex. Almost all work prior to this is in support of the first concrete milestone. Concrete began at the beginning of May as planned. There was actually a small amount of concrete placed in the fall of 2015 to test the batch plant and systems. Besides the work, a senior off-site project review team was assembled to carry out a review of the general civil contract work in the spring of 2016 prior to first concrete to ensure that our contractor and Manitoba Hydro were doing everything possible to be successful.

Although this team identified areas of potential opportunity, they were not able to predict the soon-to-be-realized under performance. Concrete colonies were measured daily, and it was evident from the start that production was not meeting plan. At first it was believed that a lag in hiring was the source of the problem and the general civil contractor quickened the rampup of craft labour. It became evident in June that although this slowed the initial production, the plan productivity values were not being achieved.

In June, Manitoba Hydro formally requested a recovery plan which, in simple terms, states the contractor is not meeting their schedule and requires a plan back to get to their original schedule. This plan was developed by our contractor and was put into action in June. You can appreciate the contractor needs some time to prove out whether or not their plan can be achieved and demonstrate they've moved through the learning curve and -- and are able to make a marked improvement, which was expected. The rampup of concrete increased the contractor's workforce from roughly eight hundred (800) people to over fourteen hundred (1400) people in a few months, requiring specialized tradespeople from across Canada.

By the end -- end of July, it was becoming evident that it was less and less likely to occur for the contractor to achieve the original plan.

At the end of August both performance on concrete and earthworks were roughly one-third of where they should have been at this time.

Slide 55. As a result, Manitoba Hydro began to execute a much broader recovery plan which included three (3) parts. The question that needed to be an answer was to determine how do we move forward? Manitoba Hydro -- the Manitoba Hydro project team aggressively pushed our contractor to improve production, as well as developing an immediate and long-term recovery plan. During the fall, a recovery plan strategy was initiated that includes a call to action from BBE's project team, executive sponsors and CEOs. The immediate plan was focused on getting as much work done in the remainder of the 2016 season. This included a winter concrete plan to continue work up to the Christmas break and continue through the winter months.

The long-term plan was focused on what

needed to be done in 2017 going forward. Key work included identify any root causes that are impacting performance; initiating activities to re-forecast the cost and schedule for the project; undertaken an analysis around contractor's claims; supplementing the commercial expertise of our team. These key activities, our own support of helping us understand what to do next.

Slide 56. As noted previously at the end of August, the general civil contractor had achieved one-third of their plan. By the end of the 2016 season they had achieved 41 percent of the concrete plan and 65 percent of the earthworks -- earthworks plan demonstrating improvement, but certainly not where we need to be.

A separate task force was set up to understand the source of underperformance and that would -- then -- then what could be done to cause positive change. Multiple root causes were identified and mitigation measures were -- began to be developed. The main contributing factors were: Aggressive concrete production assumptions from the contractor's bid could not be achieved in the current marketplace; slower than plan progress during the rampup; and challenges that were posed by the geotechnical and geological conditions which impacted both concrete and earthworks.

In addition to these root causes, it was evidenced that we had lost the schedule advancement opportunity of nearly six (6) months that we had coming into the 2016 season, and that we could be facing a delay of two (2) to three (3) years or more.

Slide 57. This is a summary of the recovery plan implementation. There's a lot of content to -- to digest in this summary so don't feel like you need to read all. It summarizes the winter work plan, in other words, getting as much work done in 2016 and containing over the winter months when no concrete had been previously planned; understanding the root causes and a plan to develop mitigations and implement them; review of commut -- commercial options that I will describe on the next slide; understanding claims and contractor entitlement; key interactions with BBE senior leadership, which includes meetings with BBE ownership, accountable for the delivery of their contract which are titled sponsor meetings at the bottom of the page. And lastly, a re-forecast of the schedule and cost for both the general civil contract, and the entire Keeyask project.

Manitoba Hydro had to answer the fundamental question, which was: What is the most cost-effective way to proceed? Alternatives were developed. Manitoba Hydro sought out industry experts to provide advice and guidance from KPMG for the overall recovery plan; Revay for claims valuation and management; Borden Ladner Gervais LLP for legal support; and finally, validation estimating for project contingency development.

Slide 59. The thorough review of alternatives demonstrated the best course of action was to amend the existing contract with BBE. Alternatives were carefully examined based on the risks and impact to both project costs and schedule, and all alternatives guaranteed a substantive increase to costs, schedule, and risk. More detail on the evaluation will be provided tomorrow at the CSI session.

Slide 60. If we go back to the timeline, BBE was required to prepare an updated schedule, estimate and execution plan at the beginning of December in 2016. Manitoba Hydro and BBE -- BBE carried out a detailed review of the schedule first and cost second in December and January to ensure the most effective plan was developed.

This joint effort included the design change to extend the steel columns that support the walls and roof of the powerhouse nearly 10 metres deeper into the concrete. The net effect, to save the project well over one (1) additional year in schedule.

Slide 61. This slide shows the column extenders. On the left-hand side is the -- was the original design and on the right-hand side is the new design.

Slide 62. After the schedule and costs were developed, Manitoba Hydro and BBE were able to negotiate a mutual agreement that provides gives and takes from both parties. It is important to note that there was already a contract in place between Manitoba Hydro and BBE. Changing that contract required agreement from both parties. Manitoba Hydro could not unilaterally change the terms of the agreement without being in breach of contract. The net result lowered the overall costs and schedule risk for Manitoba Hydro and re-established a reasonable profit that BBE could earn back based on their future performance.

Foundational to the agreement was in alignment of both parties' interest to deliver at the lowest cost and shortest schedule.

Slide 63. An amending agreement

formalized these changes and included the following features: All potential claims for the contractor were erased or wiped clean; new schedule and cost incentive pools were established for BBE to provide them an opportunity to earn these incentives, at the same time, minimize project time and costs for Manitoba Hydro; general administration and overhead, which is a real cost for all businesses was capped for BBE at the new target price; for potential future claims the ability claim was narrowed; and finally, liquidated damages for late delivery were established.

Slide 64. Negotiations were completed in January and followed immediately with the update to the project control budget. The control budget is made up of two (2) basic parts: The base estimate and contingency. The base estimate includes all costs to build the work and is based on a realistic schedule, which does not consider all risks. The schedule and costs are then evaluated by a third-party expert, validation estimating, to deter -- to determine a possible range of outcomes and the P50, P75, P90 levels of confiden -- confidence are shown.

In early 2017, when Manitoba Hydro revised the control budget, the Keeyask project budget with a P50 contingency was selected. This established an $8.7 billion control budget to ensure Manitoba Hydro's was proceeding with the lowest cost for execution for the project.

Other alternatives were considered at the time, however, considering the completeness of the project, roughly halfway through the many key risks still remaining, the P50 contingency balances potential costs from the remaining risk and provides a challenge to the execution team.

This approach drives the lowest cost delivery and the most efficient outcome. In addition to contingency, low probability high-impact events were examined to include as project reserves, none were included.

Slide 65. This slide provides a summary of the changes to the Keeyask budget and was included as PUB-MFR-122. It shows a variance from our new control budget established in February 2017 to the control budget established during NFAT of $6.5 billion.

Slide 66. Significant changes were made to cause positive improvement in 2017 for both earthworks and concrete. The concrete works were much more complicated. For example, there was more curved formwork than flat formwork. The work was much higher off the ground and the amount of formwork was over 50 percent more for each placement than the work that occurred in 2016.

Overall, there was a 12 percent increase in concrete volume and a 90 percent increase in earthworks. In addition, the key milestone dates for concrete were achieved, however, despite achieving these milestones, there was a deficit of approximately 20 percent and 25 percent in volume for concrete and earthworks, respectively. And further improvement is required.

Slide 67. This table summarizes the three (3) milestones achieved in 2017, which include the spillway concrete completion, installation of powerhouse crane and in -- in closing the service bay and powerhouse unit 1.

The next two (2) key milestones are on track which include enclosure of units 2 and 3 by February; as well as work complete to divert the rul -- the river through the spillway which will begin in July after the Sturgeon spawn window closes and we could get back on the river again.

This is a photo of the spillway concrete complete in October. The next phase of work is to install the gates, guys and tower and bridge, which has been underway since October and is on track and was previous -- previously shown by Mr. Strongman.

Slide 69. This photo shows the installation of the two (2) powerhouse cranes. These cranes are required to install the turbine engine area parts.

Slide 70. This is the same photo that Mr. Strongman showed you on December 15th, just a different angle. It shows a service bay on the right and unit 1 which are enclosed with roofing and cladding. On the far left you can see the structural steel for units 2 and 3, which is nearly ready for roofing and cladding.

Slide 71. This is a photo from September showing the nearly completed first 600 metres of the central dam. On the top right of this photo you can see the tie-in to the spillway structure.

Slide 72. We have and continue to work with BBE to continually make improvements going forward. We know that we need to improve performance by a minimum 10 percent in the general civil contract to meet the control budget of $8.7 billion. And there is still risk to go. However, we've seen improvements in excess of 10 percent in 2017 and are confident that our team will deliver further improvement. Both Manitoba Hydro and BBE have continued to develop plans to cause positive change in 2018 and are actioning those plans as we speak.

We are not stopping there, and Manitoba Hydro has engaged former Hydro contractors to focus on the general civil contract execution and test these plans to ensure that BBE and Manitoba Hydro are doing everything possible to deliver at the lowest cost and shortest schedule.

As we look forward, the main contributor factors for success in 2018 will include: the 2018 winter work and south dike work which will core -- occur over this winter; continuing to learn from past experiences; earthwork foundation preparation is now complete for 2018 and that work is ready to go as we saw on previous photos from Mr. Strongman. The cold eyes review, which I just referred to, will ensure that we have the best plan going forward.

And finally, Manitoba Hydro and BBE's lead continue to drive improvement at their level of responsibilities for the work.

Slide 73. There are key risks that remain on the project. We are at the halfway point in terms of dollar spent to date and the halfway point for concrete quantity. There are two (2) critical years remaining for concrete and earthworks and more than four (4) years on the project.

Our top risk include successful execution of the general civil contract; loss of site access; work stoppages; unexpected geotechnical conditions. For example, we haven't uncovered the bedrock or the -- where the future south dam will be; and unseasonal weather. We need favourable spring and fall conditions to maximize the concrete window. We need minimal wind days that could potentially stop the crane from -- cranes from operating and minimal wet weather days that slow or stop the earthwork.

Slide 74. Looking at the project as a whole, our current forecast to completion it was with -- is within our control budget and we are currently forecasting the schedule to be four (4) to six (6) months in advance of the control date.

Slide 75. In summary, I'd like to leave -- I'd like to leave you with these thoughts. Manitoba Hydro is capable of the delivery of this project at the lowest cost and shortest schedule and has effective governance. The decision to amend the contract with BBE was the best path forward for the project, and yielded the lowest cost outcome and shortest schedule. Improvements were made in 2017 which saw BBE achieve the key milestones to provide the shortest schedule. Plans are being actioned to cause a 10 percent improvement or more, which is required to meet our control budget.

I would now like to pass it to Mr. Midford.

MR. LORNE MIDFORD: Thank you, Dave. So in summary, Manitoba Hydro has a number of capital projects underway with varying levels of -- of completion, and the project team is focused on managing the risks for the project. We've incorporated lessons learned from across the projects that we've been involved in up to this point.

I can tell you that there's a strong team in place which we've supported by external expertise as well. We're here to be open and transparent. We've shared as much information as we can with MGF and answered any questions that they've asked of us.

And we want the Panel, the Intervenors the public all to know where we are, what challenges we face and how we're addressing them. So, thank you.

MS. HELGA VAN IDERSTINE: And now Mr.

Fogg's going to address the Bipole transmission reliability project.

MR ALISTAIR FOGG: Thank you. Good morning, Panel. As mentioned, I would like to walk through the Bipole III transmission reliability project this morning.

On slide 2, just a quick presentation outline of what we'll cover related to the Bible III project. First, we'd like to go over what is HVDC or high-voltage direct current. We'll walk through the existing HVDC system that Manitoba Hydro has that Mr. Midford touched on briefly earlier this morning. We'll provide an overview of the Bible III project and what is included as part of that project. We'll then provide a status update on the project, and where things stand from a construction and commissioning perspective on Bipole III. We'll discuss the remaining risks on the Bible III project. And then the presentation will end with a quick video similar to that of Keeyask that provides some better context of the size and scope of the project itself.

So Slide 79. Why do we use HVDC or high-voltage direct current for a Bipole III project? HVDC is, essentially, a bulk transmission method. If you were to look at AC power, you know, as an example in the left side of the slide would be similar to that of truck transportation or air. Smaller volumes of material to move but move quickly and can execute from a specialized basis.

HVDC or DC power transmission is more akin to transporting materials on large cargo ships or rail. It's a larger bulk transportation method. There is additional infrastructure required associated with that. But in terms of carrying that amount of material or power, it's more efficient.

Slide 80. So for Bipole III why would we choose HVDC? Essentially, the decision comes down to a breakeven cost analysis on the distance the transmission line needs to cover from the source of the generation of power to where you're trying to deliver that power and the station costs difference between an AC power station and a MR. DAVID CORMIE: or HVDC power station. And what you see in the top left-hand corner of the slide is a picture of an existing HVDC converter station, whereas on the right-hand top corner of the slide is an AC switch yard or station. And as you can see, it provide -- there's a different level of infrastructure and size involved between those two (2) stations.

And considering those two (2) costs and

the distance of the line, essentially, between 600 and 800 kilometres of transmission line is the breakeven distance where HVDC is a more an effect -- cost-effective approach to transmitting power.

Slide 81. Recognizing some of that background on HVDC, we'd just like to walk through the existing Bipole I and II systems within Manitoba Hydro's infrastructure. Now, Bipole I and Bipole II provide a link to -- just around 70 percent of the province's generating capacity.

The picture in the top on the left are the existing Bipole I and II HVDC lines. They are constructed in the same right-of-way and as the picture shows, in some instances are essentially beside one another.

Now, in the picture you can see that each set of transmission lines has two (2) wires, if you will, or cables. Each one (1) of those represents a pole and that is why we would use the term Bipole for each one of those lines as they both carry those two (2) cables.

With -- with recognizing that -- that there's 900 kilometres for each of those lines, and they do traverse both difficult terrain and somewhat inaccessible terrain in the north as well, those lines terminate at a common station which is the Dorsey HVDC converter station.

Going to the next slide, Slide 82. Again, provides just in the -- reference to the province of Manitoba showing where the existing Bipole I and II lines originate in northern Manitoba near Gillam and terminate at the Dorsey converter station. As you'll note, we've essentially represented both Bipoles I and II, with the same line on the graphic as they are that near each other within the same corridor. You can also see on this picture, the location of the Bipole III project, which originates from the Keewatinohk converter station near Gillam and terminates at the Riel converter station just outside the city of Winnipeg on the east side.

Next slide, slide 83. When we look at Dorsey converter station, the terminus point for both of those existing Bipole III -- or sorry, Bipole I and II lines, we need to consider the reliability risk associated with that station. Because it is the single terminus point for those lines, it is susceptible to significant weather events, and in the vicinity of Dorsey, there have been such events in the past. The picture that we've included on this slide is the Elie F5 tornado which occurred approximately 40 kilometres from the Dorsey converter station. A loss at Dorsey could mean the loss of connection to the Northern generation for up to three (3) years to the specialized equipment involved at that station.

Slide 84 speaks to the supply -- potential supply deficit of a loss of either the Bipole I and II line in the winter, or similarly, a -- a loss of Dorsey. What the graphic is essentially showing is that without Bipole III, there would be a supply deficit of approximately 700 megawatts in the system if Bipole I and II or -- and II were lost in the winter of 2020. In comparison with Bipole III in place in such an event, there would be a 1300 megawatt surplus. In the context of -- of 700 megawatt loss, essentially what it would result in is rotating blackouts for about 140,000 homes, even in the event that we had the new 500 kV import line in place.

Slide 85 relates to that same supply deficit and risk, and what this covers is that the maximum percentage of power through a single facility, and by "facility," we would mean the Bipole I and II lines and the Dorsey converter station. Manitoba has the highest percentage of power concentrated in such a single facility for a major network in the world. It can be best described as too many eggs in one (1) basket. The graphic below compares Manitoba Hydro's current HVDC system against those of China, Brazil and Hydro Quebec, which are also hydroelectric-based operations and then shows the improvement in that concentration when Bipole III goes into service.

Slide 86. Really, as we've outlined in the preceding slides, Bipole III is related to increasing the reliability of Manitoba Hydro's system and providing a second corridor for the Northern generation. Bipole III would address the supply deficit of 700 megawatts that could occur with a loss of Bipoles I and II. It also provides the additional converter facility at the Riel converter station, eliminating the single-point risk of the Dorsey converter station.

The second benefit of Bipole III is it does also provide increased capacity of 2000 megawatts, and Bipole III will -- will allow for Keeyask and the associated power sales to be transmitted. Again, the pictures on these slides are showing the 1997 wind events near Dorsey. There was -- we were lucky in some respects, is that it occurred near the Dorsey converter station, just off of Highway 6, a relatively accessible area to address these damaged towers and restore connection to the Northern generation system.

Slide 87 provides an outline of what Bipole III actually includes. Starting from the left-hand side of the graphic, the power originates from the generating stations in Northern Manitoba. That power is collected or put on to five (5) 230 kilovolt lines, which are AC power lines, that bring that power from the generating stations to the new Keewatinohk converter station. The Keewatinohk converter station is -- is one (1) of two (2) stations that form part of Bipole III. It is the northern point on the Bipole III project, and it's about eight (8) -- 80 kilometres northeast of Gillam.

At Keewatinohk, the AC power generated from the generating stations is converted to MR. DAVID CORMIE: power for transmission, and is placed on the Bipole III HVDC transmission line. That transmission line is a 500 kilovolt line that is approximately 1,384 kilometres, which covers from Northern Manitoba to Southern Manitoba, and terminates at the Riel converter station, which is just east of Winnipeg.

At Riel, the power is converted back to AC power from MR. DAVID CORMIE: for use within either the system within the southern part of the Province, or for further transmission south. The other portions not represented in this picture that are important to note is there is a six hundred (600) person construction camp at the Keewatinohk converter station, and additional AC power infrastructure to allow the tie-in to the southern transmission system.

Slide 88 shows a picture of an actual converter station, and I'd just like to walk through some of the components of that converter station to actually show those different pieces and -- and how that functions to bring the power in and execute the conversion. And if we think about this is the Keewatinohk converter station, the power from the generating stations will come in through an AC switchyard, and that's the location where the power is received.

As part of that, we install equipment that are called harmonic filters. As their name suggests, essentially, what they're there for is to filter the AC power that is being received into that station and provide stability. The pow -- the AC power then goes through HVDC converter transformers. There are eight (8) of those transformers at each site, with two (2) spares at each site as well, so a total of twenty (20) of those transformers.

Those converter transformers pass the

power into the HVDC converter building, where the actual conversion from AC power to MR. DAVID CORMIE: power occurs. And the picture that you now see on -- on the slide shows what we would term converter valves, but simply are the pieces of equipment that execute the conversion from AC power to MR. DAVID CORMIE: power.

Once that has occurred, the power leaves the HVDC converter building through a MR. DAVID CORMIE: switchyard, and then is put onto the HVDC transmission line, or the Bipole III transmission line to be sent to the South to the Riel converter station. One unique aspect at Riel that isn't included at the Northern converter station are the synchronous condensers. There are four (4) synchronous condensers at the Riel converter station. They're essentially generators rotating on a horizontal axis to provide stability to the AC system and they're required because we don't have that rotating inertia, if you will, in the South as we do in the North where the conversion occurs right beside the existing generating stations in Northern Manitoba.

Slide 89 provides an outline of the transmission line. As mentioned, the Bipole III transmission line is a 500 kilovolts HVDC transmission line. There are three thousand and seventy-six (3,076) towers starting from the Keewatinohk converter station to the Riel converter station, and the length -- you'll note I've -- here, it states 1,388 kilometres. We noted earlier thirteen hundred and eighty-four (1,384). Thirteen hundred and eighty-eight (1,388) represents the actual constructed length now of the line as a result of a number of smaller group modifications that had to occur. So from plan distance to actual, there is an added 4 kilometres to for minor route adjustments that have occurred through the course of construction.

The five (5) collector lines, or 230 kilovolt AC lines are the lines that transfer the AC power from the stations and from the -- specifically from Henday and the Long Spruce generating station to Keewatinohk, from those five (5) lines, they total 165 kilometres, and there are three hundred and eighty-four (384) transmission towers.

Slide 90 shows a picture of the Keewatinohk converter station taken earlier in 2017. What you can see in this picture in the foreground is the AC switchyard that receives the power from the collector lines, then just beyond that are the converter transformers and the HVDC converter building, and beyond the building, just somewhat more difficult to see in this picture are -- is the MR. DAVID CORMIE: switchyard where the power will then be put onto the HVDC transition line, the Bipole III transmission line.

Slide 91 -- slide 91 shows a similar picture, but now with the Riel converter station, and you'll note quite a bit of similarity between those two (2) stations. Again, this -- this shows us somewhat of a closer picture of the HVDC converter building, where the converter valves are housed, and you can see in that picture as well a better representation of the HVDC converter transformers.

Slide 92 is a picture of the Bipole III transmission line, and in construction and stringing of that line itself, this would be more in the southern part of the Province. What you see in this picture along the ground would be matting, which would provide biosecurity to the crop areas. What it allows for is for trucks and the other vehicles to drive across that matting versus driving through the field itself. As they would exit or enter, they would -- the trucks would be cleaned to ensure that there was no contamination across field to field.

The next slide. This outlines some of

the scope of the history of the Bipole III budget. Shown here is the post-license control budget that was established in 2014 of $4.65 billion, and an in-service date of July 2018 -- end of July 2018. Within that budget, it was a complete project re-estimate from the previous budget for the project. It was based on an updated line routing, an Environmental Act license requirements that had been established at that point. There were updated land acquisition costs included within that budget. The key aspect was it established the LCC, or line-commutated converter HVDC technology that was based on vendor pricing that had been received.

Now, the term "LCC" really relates to just the technology type done for that conversion of AC to MR. DAVID CORMIE: , and would be the same technology used at the Dorsey converter station. As a result of that LCC technology, this budget also included four (4) synchronous condensers at the Riel converter station, and included costs for the community development initiative, or CDI that was part of Bipole III.

If we progress to the next slide, this outlines our current control budget for the Bipole III project of $5.04 billion, and it's still remaining at an in-service date of July 2018. The updates from the previous 2014 budget included actual transmission line construction costs or unit rates from the marketplace, updated transmission line material costs, and some southern route changes. There was further actual land acquisition cost included within this budget, and an increase to the project contingency from a P50 to a P75.

Next slide, slide 95. This outlines the Bipole III status currently. The converter station construction is 91 percent complete at this stage, and the transmission line construction is 84 percent complete. The Bipole III budget is 79 perspent -- percent spent, and is on target, and we remain on target for our in-service date the end of July 2018. At this stage, we have six (6) months of work left to test and energize thousands of components. And as such, right now, we would say the remaining risks are more an impact to schedule versus budget, and I say that largely as many of our contracts contain set dates with our contractors for completion, and liquidated damages or similar mechanisms to address costs if they do not achieve those dates.

So the next slide, slide 96 is a

further update on the Keewatinohk converter station status. At Keewatinohk, all of the HVDC equipment at the site has been installed, and the AC switchyard construction is all complete, and energization of that AC station is now underway. We've also completed the construction of what we would term auxiliary buildings, and those are buildings at the site that provide water for fire suppression systems, and other -- other similar supporting infrastructure.

The next slide is the Riel converter station current status. As with Keewatinohk, all of the HVDC equipment at Riel has been installed. At Riel, the AC switchyard was being expanded versus built from the ground up, and that expansion is complete, and the AC switchyard has been commissioned at Riel. For the Riel synchronous condensers, three (3) of those synchronous condenser units are on site and are under installation. The fourth synchronous condenser unit remains to arrive at Riel, and is just in the final stages of manufacturing.

Slide 98. This is the transmission line current status for Bipole III. Tower and anchor foundation, installation on Bipole III is at 99 percent complete, or essentially complete. With that tower, erection is at 84 percent complete as well.

The remaining focus on the line is tower -- is conductor stringing, and stringing is at 45 percent complete as of January 1st of this year. The transmission line construction will be complete in March of 2018.

Slide 99 provide a bit more context to what we would call the commissioning sequence, or the sequence with which the different pieces of equipment that we've covered are actually brought into service, and then the Bipole III system itself is turned on, if you will. But as I mentioned, at the Riel converter station, the AC switchyard is energized and commissioned already. At the Keewatinohk converter station, we're partway through the energization and commissioning of the switchyard, and by the end of this month, we'll have an operational AC switchyard at the Keewatinohk station.

Following the energization of the AC switchyard, between February and March of this year, we will commission the filters that we discussed earlier that are associated with both HVDC stations as well as the converter transformers, and two (2) of the four (4) Riel synchronous condensers will be commissioned and energized as well within that time frame. Then proceeding further into March of this

year, we will bring into service and commission the
MR. DAVID CORMIE: switchyard at both converter stations, and commission and energize the converter valves within both of the HVDC converter buildings. And by mid-March of 2018, the MR. DAVID CORMIE: line, or the Bipole III HVDC line, will be completed as well. So essentially, by the mid-March 2018 of this year, all of the infrastructure for Bipole III will be installed, commissioned, and energized, and the system will be in place that we will proceed to test.

Slide 100. As we proceed into that Bipole III commissioning, it's important to note the steps that have been taken well before the equipment actually arrives on the site to ensure that when it's turned on or put into service, that it -- it will operate as intended. We've installed quality insurance mechanisms to ensure that the manufacturing of all this equipment that we're receiving meets our technical specifications prior to it ever being placed in service. This includes equipment that is tested at the factories to ensure their technical compliance prior to them being shipped from overseas.

Once on site and once installed, each of those components of our equipment are tested on site and then subsystem tests, or smaller system tests are executed to verify their functionality before being connected to the Manitoba Hydro network. Finally, once that infrastructure is in place, we will energize the system and conduct numerous tests to integrate the Bipole III HVDC system into our existing HVDC network.

Slide 101. To talk -- to think about integrating Bipole III into the existing system, it's important to note what we're talking about is integrating a state-of-the-art, digitally-controlled Bipole III into a system that was designed and constructed in the mid-1960s, 1970s. So there -- there is some risk that goes with that, and we've -- taken the steps to mitigate those risks. That includes -- we've done a simulation of the operations of Bipole III at the factory level through over two thousand (2,000) tests through the control equipment before it was sent from Germany to Canada.

We will then conduct equipment and subsystem tests at the site. By equipment tests that would mean tests individually testing, say, the HVDC converter transformer. Whereas, a subsystem test would be a test of several components of equipment connected together. We will conduct over five hundred

(500) equipment tests, and four hundred and fifty (450) of these subsystem tests.

Once all that infrastructure has been tested at that level, and as -- in mid March 2018, we'll be proceeding to conduct system testing of the full Bipole III system, that is both converter stations and line. And there will be approximately two hundred and fifty (250) tests of that system together before it's brought into service. Finally, at the end of that there'll be a thirty (30) day trial operation which our contractor has to execute to ensure that the full system can be put into the Manitoba Hydro network.

Slide 102. As I mentioned earlier, there are remaining risks and they're primarily schedule risks. From the transmission line perspective the risks are related to both contractor performance and weather. We're in the last construction season of the transmission line. As noted, the transmission line needs to be completed by March of this year.

Therefore, there is risk related to ensuring that it's achieved both from a contractor performance or productivity perspective and weather. Weather can be both becoming warm too early, and making it difficult to construct in winter only construction zones. Or if it becomes too cold then it's difficult to actually stand the transmission towers.

From a converter station perspective, the risk is primarily related to the synchronous condensers and their completion. This is very much connected to a delay in transformers related to those syncs and their delivery. This is probably an important point to tell a small story about the kind of risks that -- that the projects can encounter. With these transformers for the synchronous condensers, they were to be delivered from Italy and there is four (4) of these transformers. These transformers were fully manufactured and the first two (2) were prepared to ship, and we were informed by our contractor that they were no longer able to obtain transportation permits for these transformers.

And on further inquiring learned that because of completely unassociated bridge collapses that had occurred in Italy, the government in Italy had decided to cease issuing transportation permits for larger loads until they could assess the source of those collapses and then also work through the responsibility between municipalities and the overall government of who would be res -- ultimately responsible for issuing such large load permits to allow the transformers to actually make it to the port.

After several months of working through this and developing mitigation plans our contractor, working with the manufacturer and working with Manitoba Hydro, were able to come up with alternatives to barge these transformers down local rivers and actually get to the sea transportation port which minimized the number of permits that ultimately had to be maintained. And they worked with each local community to obtain those -- that smaller number of permits. It was probably about a three (3) month delay, but ultimately it was mitigated to the point that it does not impact the in-service date of Bipole III.

Finally, from a schedule risk perspective is commissioning, and there is six (6) months of work to test and energized these over thousand components. And there is risk that some of those components still do not operate initially as intended. And we do have mitigation plans to address that as well.

So we'll just show a short video of

Bipole III that shows you both the converter stations and the transmission line and some of the infrastructure in its current state.

(VIDEO PRESENTATION PLAYED)

MR. ALISTAIR FOGG: So slide 104. In conclusion, construction is on schedule, and we are on schedule to be in service by July of this year. Budget is tracking to the control budget of 5.04 billion. This will be an asset that is in operation by the end of this year and will be part of the upcoming fiscal year as an asset in operation, and thus the capital cost will begin depreciating for the Bipole III asset this year.

Thank you. I'd just like to pass it over to an update on the MMTP project.

(BRIEF PAUSE)

MR. DAVID CORMIE: Yeah, I think for clarity we're going to do the GNTL project first. Dave, do you have the slides there for that?

(BRIEF PAUSE)

MR. DAVID CORMIE: Thank you. Thank you, Mr. Fogg. Good morning, panel. This section of the presentation will be on the Great Northern Transmission Line. Unfortunately, the bar has been raised and I won't be able to provide you with a video.

First, as background I think it would be helpful for me to explain the overall 500 kV Manitoba/US interconnection project, its components, its purpose, and how it fits into the -- the big picture. The new interconnection is a crucial part of our development plan to meet the future electricity needs of the province. The plan at its core involves the construction of Keeyask, the new interconnection, and several long-term firm export sales to US and Canadian utilities support the plan, improving its economics, reliability, and robustness.

The new interconnection consists of two (2) component transmission projects. In Manitoba the line being built by Manitoba Hydro is the Manitoba Minnesota Transmission Project, and Mr. Penner will speak to the project shortly. However, in Minnesota the Great Northern Transmission Line project is being built by Minnesota Power. In total, the capital cost for these two (2) projects is approximately $1 billion.

(BRIEF PAUSE)

MR. DAVID CORMIE: So slide 3. So what's the purpose of the new interconnection? From an import perspective, the interconnection will increase our firm import capability from 700 megawatts to almost 1,400 megawatts. To put that additional firm import capability into context. that additional megawatts apply capability from the United States is 25 percent greater than the new capacity that is being added to the system by the construction of Keeyask.

The new import capacity will allow us to access MISO market energy when needed in perpetuity. The new import capability will improve energy security during droughts. As a result, it will defer the need for additional dependable energy supplies in Manitoba in the future by as much as the construction of Keeyask will. The line will also improve day-to-day emergency response and system reliability, as we are strengthening our connection to the entire North American electric grid.

Immediately once it goes into service the line will reduce the cost of low water and drought to Manitoba Hydro. We will be able to buy significantly more energy at off-peak prices than we currently can. And the prices that we pay for purchased electricity at the border will improve as they will be more aligned with market prices seen in Minneapolis. These benefits will improve Manitoba Hydro's cost structure in perpetuity.

From an export perspective the interconnection will increase our export capability to the United States by 50 percent, from about 2,100 megawatts to about 3,000 megawatts. This increase will allow us to export more electricity, adding to Manitoba Hydro's income in higher water periods. As well, additional revenue will also be earned as a result of the line, because more of our surplus energy will be sold at on peak prices. In addition, export revenue will improve in almost all years as export prices at the border will be closer to the prices seen at the market in Minneapolis.

And lastly, additional firm export revenues will be generated each year, as firm export sales will not have to be interrupted during the routine interconnection outages we experience, as is now the case. And finally, the Great Northern Transmission Line will increase market access into

Wisconsin from about 100 megawatts that we currently have to 600 megawatts. And that will increase bilateral opportunities to a larger US customer base.

Slide 4. The Great Northern Transmission Line involves a forty (40) year deal with Minnesota Power, the foundation of which is the fifteen (15 year), 250 megawatt multibillion dollar power sale agreement. The deal is a complex arrangement involving several agreements between Manitoba Hydro, its subsidiary 6690271 Manitoba Limited and Minnesota Power. These cost-sharing agreements cover construction costs, property and capital taxes, operating costs, and sustaining capital.

As is it's not a Manitoba Hydro project, the construction cost contributions payable by 669 are not in Manitoba Hydro's capital expenditure forecast. However, they are included in the IFF. The cost will be capitalized as an intangible asset and amortized out over forty (40) years. To these annual costs are added 669's ongoing share of GNTL taxes and operating costs, and all of these costs are included in the IFF.

What is important from a risk perspective is that Manitoba Hydro is ultimately responsible for the majority of GNTL costs, 72 percent. And that -- and given that, most of the costs are incurred during construction. Now is the time during which we need to be most vigilant and active in protecting our interests, and we are doing that to our subsidiary 669.

Slide number 5. Manitoba Hydro established its subsidiary 669 for US tax and liability reasons related to the project. This company is responsible for representing Manitoba Hydro's interests in the development and construction of the line. It raises the capital it needs by issuing shares to Manitoba Hydro.

The GNTL is being built under a facilities construction agreement between Manitoba Hydro, the Midwest independent system operator, and Minnesota Power. The facility construction agreement commits Minnesota Power and 669 to pay for the up-front construction costs of the line.

The other significant agreement is the construction management agreement between Minnesota Power and 669. This agreement appoints Minnesota Power as the construction manager with the responsibility to physically build the line. Importantly, though, it establishes a governance structure for project decision-making that gives 669 significant oversight and control through consultation and ultimately veto rights, with the independent advice and help from an oversight engineer.

This is slide 6, and it illustrates the governance structure of the project. At the bottom on the left-hand side you can see Minnesota Power is the construction manager. The construction manager reports to the management committee, which has one (1) representative from Manitoba Hydro's subsidiary 669 and Minnesota Power.

The management committee has approval responsibilities in preconstruction, contracting, bidding, and construction areas. The independent third-party engineer also respor -- also reports to the management committee. Should there be a dispute at the management committee, the issue is raised to the executive level. If not resolved there the issue goes to binding arbitration.

Slide 7. As we sit here today, Minnesota Power is active in construction in northern Minnesota with a workforce of over four hundred and fifty (450) people working on all segments of the line. All major permits and approvals are in place. As a large portion of the right away is through very remote and wet terrain, the project is dependent on favourable winter constriction -- construction weather to minimize access costs. As a result, the project has -- has built an extra year into the schedule to provide for the option of delaying work if a mild winter occurs.

So far, the winter weather conditions have been ideal and significant process is being made on clearing and foundation work. The project is on schedule for in-service on June 1st, 2020. To date the project is on budget with approximately 10 percent of the funds spent. Manitoba Hydro has the expectation that the project will be under budget given the conservative nature of Minnesota Power's budgeting process.

With that I'd like to turn the mic over to Mr. Penner who will now speak about the Minnesota Manitoba transmission project.

(BRIEF PAUSE)

MR. GLENN PENNER: Thank you, Mr. Cormie. Good morning, panel. I would like to take a few minutes to explain a few more details around the Manitoba portion of the project, and as Dave explained we call the Manitoba portion of the project MMTP or Manitoba Minnesota Transmission Project.

The control budget for the MMTP is $453 million based on the final preferred route, the current schedule, and in service of June 2020. The picture shown here on this slide is the existing 500 kV transmission interconnection. The new line will look very similar using latticed steel structures.

The project consists of 213 kilometres of 500 kV line and modifications at three (3) stations: Dorsey, Riel, and Glenboro. The line begins at Dorsey and follows the existing corridor south of Winnipeg and east almost to Vivian where it takes a southeast path towards the RM of Piney where it crosses the international boundary.

Station modi -- modifications consist of the following: Dorsey, a500 kV line termination to connect the 500 kV line into the Manitoba Hydro system; at Riel, an additional transformer bank will be constructed; and at Glenboro phase shifting transformers and realignment of the transmission line. Glenboro is connected into Rugby, North Dakota, and is another interconnection. This phase shifting transformer is required to move power into the US once the MMTP project is in service.

The 500 kV line can be broken down into two (2) portions. The first is 92 kilometres on existing Manitoba Hydro owned corridor. It's beside other transmission lines. And the second is 121 kilometres in new right-of-way. The existing corridor will contain all self-supporting structures. The new right-of-way will contain approximately 50 percent of self-supporting structures and 50 percent of guide structures. Guide towers are used primarily in nonagricultural and in wetlands. Self-supporting structures are used primarily in agricultural land where a smaller footprint is required to access around the structures.

It is important for project success to have a project execution plan. The plan will define roles and responsibilities for the project and how Manitoba Hydro will deliver the project. The picture on this slide is of a Bipole transmission project during the stringing operation. The Transmission Projects Department at Manitoba Hydro is responsible for project management, which includes preparing and coordinating estimates, preparing schedules, and capital justification documents. They will be responsible to manage the ongoing activities to coordinate design and construction through project completion.

The Transmission Design Department at Manitoba Hydro is responsible for the design of the overall line, including structures and foundations. They are also responsible to develop all of the drawings, and tender all of the material required for the transmission line.

The Transmission Construction Department at Manitoba Hydro is responsible to put together the construction tender and then oversee the construction and ensure that the contractor hired constructs the project according to the design and meets the requirements and conditions of the environmental license. Station modifications will be designed within Manitoba Hydro and then the majority of the construction work will be completed by an external contractor.

The 2013 budget for the project was $350 million, which was revised to 453 million in 2016. There are a number of factors that influenced the decision to increase the budget. At the time, routing selection was complete, allowing a better estimate of required towers and tower types.

There -- there was an increase to self-supporting towers and a decrease in guide structures which resulted in a cost increase. Modifications to the phase shift transformers at Glenboro was that an increase to the cost. We updated the market prices based on results that we received from Bipole III, and so it reflected our most recent tender prices. And the estimate was increased from P75 probability estimate, which means that it has a 75 percent chance of being at or below the $453 million estimate.

In the transmission projects group at Manitoba Hydro, we are continually improving and adjusting how we do things based on past experiences. Bipole III is the latest project, which has been under construction for the past five (5) seasons. Prior to Bipole, the team was responsible for the construction of Wuskwatim transmission as well as Herblit transmission projects in the past ten (10) years.

Direct lessons learned, including changes to the routing methodologies, improved indigenous engagement, inclusion of bio-security in Bipole III and in MMTP, evaluating and changing how we do contracting models as well as construction methods. And we've also had opportunity to share some of these lessons learned with Minnesota Power and their GNTL project.

So where we are and where we've come

from. So between 2012 and 2015, we were involved in the environmental assessment and the public engagement process. In 2013 we received an Order in Council issued by the province to proceed with -- with the environmental assessment. In 2014 NFAT recommended this project to proceed. In 2015 we filed our environmental impact statement with the province. In 2016 we filed the application with the National Energy Board.

In 2017 we went through the clean environi -- sorry, the Clean Environment Commission hearing and review. In 2016 and 2017 we started detailed design, material procurement, and currently we are 10 percent of the budget spent, approximately $44 million. In 2017 we started property acquisition. In 2018 we will go through a National Energy Board hearing and review, and we anticipate a provincial license decision sometime in 2018. And we are estimating construction sar -- start sometime in 2018 or '19, depending on when we received regulatory decisions. And we have a June 2020 in-service date.

I will now pass the presentation back to Dave.

(BRIEF PAUSE)

MR. DAVID CORMIE: Thank you, Mr. Penner. This will be the last presentation, and it will be on the Manitoba/Saskatchewan transmission project. The need for a new transmission line between Manitoba and Saskatchewan is the result of an agreement reached in 2016 between Manitoba Hydro and SaskPower for the sale of 100 megawatts of system power. We first advised the Public Utility Board of the sale and the need for the line following the signing of the term sheet in September of 2015.

Energy deliveries will commence on June 1st, 2020, and will continue for twenty (20) years. To put the sale in perspective, it will require the equivalent of 18 percent of the capacity and 13 percent of the average energy production from Keeyask.

MS. HELGA VAN IDERSTINE: Mr. Cormie, can I just stop you for a second? Thanks. Does the panel have the presentation? Okay. Thanks.

MR. DAVID CORMIE: As the majority of the existing firm export capacity to Saskatchewan is reserved for other uses, transmission studies indicated that an additional transmission line was needed to make the sale feasible. The current schedule indicates that the in-service date won't be until June 1st of 2021, for that line which is a year later than the date when SaskPower needs the capacity and energy.

In the meantime, if the new line is actually delayed by a year the agreement allows for partial delivery using interim firm transmission service that's available to both companies. We are working on plans to ensure that as much of the hundred megawatts of capacity can be made available on June the 1st of 2020 as possible. In its review of the Saskatchewan sale agreement and transmission project, the Board's independent advisor, Daymark, has concluded that both the contract and the transmission line project remain economic.

In Manitoba, Manitoba Hydro will be responsible for building the Birtle transmission project. It's a relatively small project in comparison to Bipole III or the MMTP project. From a licensing perspective, it's a class 2, and Manitoba Hydro is engaged in significant public consultation for the line. The cost, based on a 2015 estimate, is $57 million.

Thank you. That completes my testimonial. I'll now let Mr. Midford summarize today's presentation.

MR. LORNE MIDFORD: Thank you, Mr.

Cormie and thank you to the Board for giving us the opportunity this morning to give you an update on all five (5) of these projects. I've had in my career the opportunity to work with each of these panel members in some way or another, and I can tell you that we are very, very fortunate to have this level of expertise working on our projects.

For all five (5) of these projects a common thread for all of them is that we're committed and -- and some might even say driven to providing these projects at the lowest cost possible, because we know that's the expectation of everybody in this room, and also of our customers as well.

For Keeyask, we are projecting to be on budget and on schedule. We're still four (4) ways away from being in service. And at this stage in the project we think it's appropriate the numbers that we've put forward for our control budget and schedule. We don't believe it's appropriate to overstate those potential costs and to reflect that in the rate base this early.

For Bipole III, as you've heard, we're on schedule and on budget for in-service July of this year. And, of course, that will impact the '18/'19 financials.

For MMTP we're on budget, with a projected in-service date of June of 2020. The Great Northern Transmission Line, you've also heard that the budget may be high, but we are on schedule at this early stage to meet the in-service of June of 2020.

And for the Saskatchewan transmission project, the budget is currently under review and our current in-service is June of 2021.

That concludes our presentation this morning, and if it's appropriate, I'd like to open it to questions.

THE CHAIRPERSON: Thank you, Mr. Midford. In fact, we'll take the lunch break at this moment. We'll break for lunch and return at one o'clock. Thank you.

--- Upon recessing at 12:06 p.m.

--- Upon resuming at 1:03 p.m.

THE CHAIRPERSON: Good afternoon. We're going to have questions from the Panel, Ms. Kapitany, I understand you wanted to proceed?

THE VICE-CHAIRPERSON: Thank you, Mr. Chair. I have a couple questions. One was alluded to by Mr. Strongman who is -- back in the front row. It was around labour productivity, I believe. You talked about productivity having declined over the last number of years. I just wondered if you could talk a bit more about that. It seems counterintuitive that productivity would've declined.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: So the remarks that were made -- I believe I made reference to productivity having declined in the last twenty (20) to thirty (30) years. The first thing to consider is that the remarks are made in reference to Keeyask, and there was a large gap in time between Manitoba Hydro's last generating station project that was a Conawapa -- excuse me, the Limestone project initiated in the '80s and completed in 1990 -- '92 I believe. And then the next station that was Wuskwatim started in 2006 and completed in 2012 and that fifteen (15) year gap led to a lot of people leaving Hydro industry following the completion of Limestone and not having generating stations on the books in terms of construction projects throughout Canada, actually, not just here in Manitoba, there was a gap in experience and -- and knowledge within Hydro construction.

So specific to productivity on Hydro stations that that's one (1) of the points. And the second is generationally the productivity issues are very different from the previous generation to now, with a wide range of more socioeconomic based explanations behind that. Higher regulatory obligations with respect to environment and -- and safety that has had an impact on productivity and something as simple as every person having an iPhone and not necessarily keeping it off until break time.

THE VICE-CHAIRPERSON: We call it NFAT. We did talk about the lessons learned from Waskwatim and some of those lessons -- Mr. Bowen, I think it might've been you spoke about that. Some of those lessons were then to be transferred to Keeyask.

Could you speak about that a little?

MR. DAVID BOWEN: Are you -- are you asking lessons learned specific to labour productivity?

So -- so in Wuskwatim, I think Jeff -- Mr. Strongman was trying to give us the context of the overall marketplace, and -- and not only in -- in the -- the type of work that happens on a generating station which is a heavy formwork type of work where there's many erosion of productivity that's happened right across Canada. But the same erosions happen if you look and studied the offshore gulf oil and gas work. It's -- it's the same erosion that's happened from the '80s onwards and it's -- it's -- it's at least a decline by half of the productivity was achieved.

But in terms of -- to your question about lessons learned Wuskwatim, the challenges we had at Wuskwatim were around the attraction/retention of -- of qualified craft labour and it was really in the generating station build phase. So, the time where we were doing the work we showed in the last two (2) years at Keeyask so the -- the -- constructing the concrete, the formwork, et cetera, and -- and a lot of back in the Wuskwatim time and just go back in -- in -- in history a little bit is that the Canadian marketplace was very hot and there was a great deal of competition right across the country for labour and -- and when you work at an isolated fly-in/fly-out facility, that -- it's -- it's -- that stress and strain on the marketplace is accentuated.

And so at -- at Wuskwatim we had -- our contractor had challenges with getting really good people there and keeping them there and, to some extent, we haven't had those same challenges at

Keeyask. We've had -- the execution challenges we've had at Keeyask are -- are -- are different and the same.

The -- the mitigating measures we put in place -- when we talk about attraction/retention is one of the first things we did for Keeyask back in 2014 was we actually did a study across all remote northern projects about the -- the labour piece. How much -- how much money is a craft labour worker going to put in their pocket on a weekly basis as they make the decision to either come to a job or stay. And -- and so we actually have a retention bonus that equalized -- raised the Manitoba rates which were the lowest in the country under the Burntwood Nelson Agreement to -- to something better. It wasn't the same as Alberta but it was better and it has an incentive to keep people here. That's one -- one mitigation.

I think other mitigation was this early contractor involvement process to -- to award the -- the scope as -- as Mr. Strongman stated for the earthworks and the concrete together as -- as one (1) contract that wo -- that scope was broken up during the Wuskwatim contract and it -- it was to allow the contractor almost two (2) years to plan out the work for the concrete, understand the marketplace and -- and -- and get ahead of the potential risk for not only attracting but retaining or training staff.

So those are -- those are two (2) mitigation measures in place that we -- that we put in place. Probably some of the most significant in terms of the strategy piece, in terms of the effectiveness while they haven't -- I guess from a Manitoba Hydro perspective, they haven't been as effective as -- as we had originally planned them to be.

THE VICE-CHAIRPERSON: Thank you. My second question is for you, Mr. Midford. It's from the last page in the slide deck that you presented this morning, under the Keeyask generating station section.

You've got a bullet in there that says:

"Several opportunities to reset for ratesetting purposes, if necessary."

You didn't speak to that bullet. Could you expand on what you meant by that?

MR. LORNE MIDFORD: What I meant -- so Keeyask in -- where it's at in terms of its phase of execution, there's four (4) years left until it's in-service, and we believe that -- there's a lot of talk about different classes of estimate, P50, P90, P75.

So I -- we believe that the P50 properly reflects the level of contingency at this phase in the project and that that level of our control should be reflected in terms of rate setting.

And the -- as the project continues if there is a requirement to revisit that, then they'll be those opportunities down the road. That was the point of that.

MS. HELGA VAN IDERSTINE: Ms. Kapitany, I think Mr. Strongman wanted to expand on the -- his answer after -- with respect to the first question you asked so if you don't mine.

MR. JEFF STRONGMAN: One (1) thing I would like to add is when we were talking about the -- the generational difference in productivity. One (1) of the key pieces of comparison is the -- the duration of rotation. A crew rotation going in and out of a remote site, historically, has been considerably longer than what current industry norms are. In previous projects that Manitoba Hydro has undertaken decades ago, thirty-five (35) days in a row and forty-two (42) days in a row were normal durations at site. And in the current environment that we're building Keeyask fourteen (14) and seven (7) and twenty-one (21) and seven (7) are the normal rotations.

So on a fixed period of time you have people away longer and greater travel expenses to get them back and forth from home and the -- the job site. So that, again, has an impact on group continuity and another things that erode productivity. Thank you.

THE CHAIRPERSON: Ms. McKay...?

BOARD MEMBER MCKAY: Just trying to understand the person hours that are listed because some are listed in person hours, some are percentages and wasn't quite sure what the total number of person hours was but you indicated on a later slide.

I just wanted to find out about the Indigenous employees, you have 4 million person hours listed, does not include the 2 million person hours for the KCN members?

MR. JEFF STRONGMAN: I -- I believe the -- the numbers that had been provided in the section of the Keeyask presentation that I provided had covered 15 million person hours to the end of 2017, of which 2 million hours were performed by our KCN partners and of which a total of 4 million out of that 15 was performed by Indigenous people.

BOARD MEMBER MCKAY: So let's 2 million plus the 4 million; is that what you're saying?

MR. JEFF STRONGMAN: Pardon me, I think it's slide 25. I'd just like to double-check with the reference.

BOARD MEMBER MCKAY: Yes, it is.

MR. JEFF STRONGMAN: Yes. So slide 25 shows 2 million person hours worked by our KCN partners, our members, and 4 million by the Indigenous employees of any location throughout Canada.

BOARD MEMBER MCKAY: Okay. So that's 6 million in total for Indigenous employees?

MR. JEFF STRONGMAN: Yes, the two is part of the four. Sorry, I wasn't sure that's what meant.

BOARD MEMBER MCKAY: Yeah, I kind of thought that. So, amongst your three (3) groups, there for Indigenous employees, all Manitobans and others? Your Indigenous employees would be the lowest number of person hours, correct?

MR. JEFF STRONGMAN: Sorry, I don't think I understand your question.

BOARD MEMBER MCKAY: Well, the question is, you have 73 percent total hires are Manitobans?

MR. JEFF STRONGMAN: That's correct.

BOARD MEMBER MCKAY: Okay. And 27

percent, I would presume are from outside of Manitoba?

MR. JEFF STRONGMAN: That's correct.

BOARD MEMBER MCKAY: That's 73 percent, I think works out to -- well, it's a total of 10,000 -- 10 million 50,000 so your Other would be 4 million 50,000 and your Indigenous employees would be six thousand (6,000) in total; if I was reading that right.

But it -- it might actually even be lower than because I was assuming that the Indigenous employees -- that the KCN members were not part of the 4 million, you were accounting for -- for Indigenous employees.

I'm just trying to clarify whether the Indigenous population has the lowest number of person hours on the site.

MR. JEFF STRONGMAN: Okay. Let me try and provide some clarification. On slide 28 we've stated that 15 million person hours have been worked on the project to the end of 2017 by all peoples.

Of those fifteen (15) 73 percent of them are Manitoba hires. That doesn't actually refer to the number of hours worked by Manitobans, but it's saying that for everybody hired on this job 73 percent of them have been Manitoba.

So I can't answer your question mathematically the way that you're asking it because we don't have the number of hours worked by the 73 percent of the employees ever hired. I think what you're trying to do is take 73 percent of those 15 million and say roughly 10 million. And then what percent of those are by the KCN and -- and Indigenous but we haven't calculate it that way and I can't confirm that that math is correct.

BOARD MEMBER MCKAY: Can we get an undertaking on that?

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Could you clarify what the undertaking would be?

BOARD MEMBER MCKAY: The breakdown of person hours for the 15 million person hours.

MR. JEFF STRONGMAN: Yes.

--- UNDERTAKING NO. 52: Manitoba Hydro to provide a breakdown of person hours for the 15 million person hours.

BOARD MEMBER GRANT: Can I just get a -- I think it's about the Bipole. I think it's slide 19 of the Bipole slides, sorry.

Now, you mentioned in-service date of July 2018. I was just comparing that to the last bullet where it's a -- whatever risks remain they're about scheduling as opposed to budgets.

So I guess it's two (2) questions. One: What is the risk of not hitting the in-service date of July 2018? And the second one it's just -- it's the juxtaposition of schedule and budget and I'm wondering if these are completely independent of each other. If you miss the in-service date, are there any budget implications whatsoever?

I understand with the generating station there are obvious ways in which a delay affects the budget but, in this case, are there any economic costs to not hitting that in-service date?

MR. ALISTAIR FOGG: Well, I think to -- to probably answer part 1 and part 2 of your question is -- both of those are and, really, in fact related to another.

So, if you would look at the comparison between budget impact and schedule impact, certainly, a project such as Bipole III from a cost-impact perspective were it to come into service later, would have additional costs, for example, related to interest and escalation or carrying costs before it was capitalized; very similar to a project such as Keeyask would have.

Where some of that may differ from a cost perspective is depending on contract model or contract type. For example, if converter station contracts would be in -- in the fixed-price arrangement, that contractor would still have -- be executing that under the same costs so there wouldn't be their overhead -- additional overheads for those additional time, plus they may be subject to penalty for being delayed, depending on the contract.

BOARD MEMBER GRANT: So if there is any -- so I guess going back to the first question then: What is the risk of not hitting the in-service date and then some order of magnitude or proportion of -- what would be the budgetary consequence; minor, large, sign -- you know?

MR. ALISTAIR FOGG: So in -- in terms of risk of not hitting in-service date, I guess, broadly speaking, the first risk starts to become continued exposure to reliability issues that we've been exposed to to date related to outages on Bipole I and II or she's at Dorsey. That -- that's what I would say is the -- the primary risk of not achieving the in-service date with Bipole III and extending that -- that risk out as time goes by.

Risks of not hitting that in-service date, otherwise, would -- really would be a balance between those -- those overhead -- sorry, interest and escalation costs counted against any potential amounts we can recoup from contractors for that.

BOARD MEMBER GRANT: Sorry, I wasn't clear in my question. What's the probability that you won't be ready to go by July 2018?

MR. ALISTAIR FOGG: I wouldn't have a specific probability assessment around that date; that being said, certainly based on where we stand right now construction progress wise and -- and the commissioning plan in place, we have a high degree of confidence of achieving that.

There's numerous months to allow for testing and potential issues that could arise during testing and to address those within that timeframe that we're working from today to July 2018.

BOARD MEMBER GRANT: And -- and if you were a month late, beside from interest and escalation, significant economic costs or --

MR. ALISTAIR FOGG: No, I would say in -- no, not significant. It would be some additional internal costs, project management costs. But again, I think we would be looking to recuperate some of that as well.

BOARD MEMBER GRANT: Okay, thank you.

MR. DAVID CORMIE: And, Dr. Grant, one (1) of the benefits of Bipole is the reduction of losses associated with Bipole III. And I'm -- I'm not sure what the megawatt amount was; something less than 100 megawatt. So, the earlier Bipole III comes in; the more power will be available for export.

If you used a thirty dollar ($30) a megawatt hour for a month would be a -- be a couple million dollars of -- of -- of reduced income that we had in the IFF associated with an in-service date of July. Let's say it was in-service date of August, that one (1) month of delay would mean that we would have less export revenue.

BOARD MEMBER GRANT: And sorry, that's because of less transmission loss?

MR. DAVID CORMIE: Losses, yes.

BOARD MEMBER GRANT: Okay, thank you.

MR. DAVID CORMIE: The -- the -- with Bipole III in-service, the MR. DAVID CORMIE:

transmission system is more efficient.

THE CHAIRPERSON: I have a few questions. I don't know who -- I'll just throw them out and whoever wants to answer them can answer them.

Bipole III you show a budget for 2016 of five billion 42 million (5,042,000,000) is that P50 or P75?

MR. ALISTAIR FOGG: That's P75.

THE CHAIRPERSON: Okay. MMTP 216, budget of 453 million. Is that P50 or P75?

MR. ALISTAIR FOGG: That's at P75.

THE CHAIRPERSON: Okay. Keeyask 8.7 billion is P50, correct?

MR. DAVID BOWEN: Correct.

THE CHAIRPERSON: We have evidence in this hearing that P90 is 9.6 to 9.9 billion, depending on the -- the delay, correct?

The evidence was if it's twenty-one (21) month delay it's 9.6 billion, if it's thirty-two (32) month delay it's 9.9 billion; that was -- that was put forward by Mr. McCallum.

MR. LORNE MIDFORD: Okay. From a project perspective, the 9 -- are P90 is 9.6.

THE CHAIRPERSON: Okay.

MR. LORNE MIDFORD: With -- with that

corresponding twenty-one (21) month delay.

THE CHAIRPERSON: Can you explain to me why -- so in your budgets then -- can you explain to me why certain things are shown in your budgets as P75, and other things, are shown as P50?

I'm having trouble understanding why Keeyask is shown as a P50, but these other projects are shown as P75.

MR. LORNE MIDFORD: I'll -- why don't I take a first crack at that and I'll leave it up to other panelists to -- to provide project-specific answers.

When a P50, P75, P90 estimate is developed, it's based on the risk assessment, various risks. There's a risk register for each of these projects given where they are at any given point in time, and each of those risks has a level of probability, and if you can think of it as a -- kind of a distribution curve as such.

So -- and then based on that, there's a mathematical analysis, Monte Carlo analysis, of all of those different permutations, commutations of those probabilities to derive what is perceived to be a P50 level estimate, P75 level, or a P90 level estimate.

So it's really a reflection of the

risks of each of the risk elements within each of the projects. And quite often it's based on understanding of what those risks are and exposure of those risks with -- for each of the different projects.

So for Keeyask, for instance, where we're at in terms of -- about 50 percent spend, and about 50 percent of the concrete that's been placed. With the risks moving forward and four (4) years of construction still ahead of us, we feel that the P50 is appropriate for where we're at in the project at this time.

These other -- some of the other projects are further along, and some of those risks and the risk profiles have changed as they get closer to -- to the in-service date or -- and so that -- so they do their own analysis and develop their own risk profiles.

THE CHAIRPERSON: Mr. Midford, do you have the geotech for the south dam? My understanding is you are still waiting. There's a -- there's a slide, I'm not going to look at it, that talks about that being one (1) of the biggest risk factors is that -- you haven't done the geotech for the south dam.

MR. LORNE MIDFORD: Yeah, the geotech underneath the existing waterway.

THE CHAIRPERSON: Right. So how is it a P50 then if you've got that kind of risk? I'm just -- I'm trying to figure out -- I understand the P50 and the P75 and it deals with risks and risk assessments, but you've identified the geotech as being one (1) of your biggest risks, but the budget given to us is still on a P50.

MR. DAVID BOWEN: I -- I'm going to try and answer the question.

THE CHAIRPERSON: Okay.

MR. DAVID BOWEN: I think you're asking the -- I'll -- I'll take a step back. So the -- the P50 value whether or not the geotech risks exist to the south dam and whether that quantum is 10 million or $100 million, that's what would vary based on the level of confidence. So knowing that that risk occur -- is -- is there just, for example, if that risk value at a P50 was $100 million, at a P75 the value carried in the budget would be something like, say, $140 million and a P90 would be something like $190 million.

So the -- the risk exists there, it's just -- it's how much money we -- we would carry in the budget at -- at a different confidence level. So I'm not sure if that answering your question.

THE CHAIRPERSON: So if you're -- if the geotech has a worst-case scenario, what you're saying is you've already assessed what that would be and relate that to the overall budget and determine whether it's P50 or P75?

MR. DAVID BOWEN: I guess -- almost. What -- what I'm saying is that we know that risk exists, that the amount -- the risk is the probability of occurrence times the impact.

So at a P50 level if the dollar amount in our budget would be the least amount and as we would increase in confidence of not overrunning, it would -- the dollar value would be higher. So that risk event, it's the same risk event that's carried but the dollar amount is higher as we move up from a P50, 75, 90, et cetera.

THE CHAIRPERSON: Okay. Can we --

MS. HELGA VAN IDERSTINE: Before we move on, I think that Mr. Penner might want to comment on --

THE CHAIRPERSON: Okay.

MR. GLENN PENNER: MMTP we do -- we're carrying a P75 estimate currently for it. And I guess the question could be begged that we are not as far along as Bipole III. However, given that we're working on the heels of Bipole III, we are very confident in what our construction contracts will be and tower steel prices are -- are -- have been pretty stable. So we feel that the P75 estimate is -- is something that -- that -- that makes sense to present at this time where it is in the project.

THE CHAIRPERSON: Thank you, Mr. Penner. Could we go to page -- I have it as number 10. I think it's probably 86. We're using different page numbers. No, sorry -- yeah.

This makes reference to 1997 Wind Events near Dorsey. Was that at -- at a level of an F5 or was that less than an F5?

MR. ALISTAIR FOGG: I don't believe it was specifically a -- a tornado event --

THE CHAIRPERSON: Okay.

MR. ALISTAIR FOGG: -- that occurred but it was -- it was a wind event, essentially, a large wind event that caused that issue.

THE CHAIRPERSON: Okay. And this is Bipole tower that went down? The mangled tower on top, is that a Bipole tower?

MR. ALISTAIR FOGG: Correct that wasn't -- that was in 1996 I believe.

THE CHAIRPERSON: Seven it says.

MR. ALISTAIR FOGG: 1997. And yes, there were nineteen (19) structures on both Bipole I and Bipole II that -- that came down. It was in September and it was a wind event that Environment Canada referred to as a microburst. They did not refer to it as a tornado.

THE CHAIRPERSON: And do you know how far from Dorsey it was?

MR. ALISTAIR FOGG: It was -- it was right at Highway 6 so it was probably 10 kilometres north of Dorsey, kind of in that range, little bit less.

THE CHAIRPERSON: Okay. Maybe you're the one to ask then, Mr. Penner, on page 83, the F -- that's an F5 tornado. It says:

"A loss at Dorsey could mean loss of connection to northern generation for up to three (3) years."

This was 40 kilometres from Dorsey. I assumed that if it gets that close to Dorsey we're looking at a major problem not only for the lines, but for Dorsey itself; is that correct?

MR. GLENN PENNER: If a tornado were to be a direct hit to Dorsey, there -- there would be major damage. It would be -- it's hard to predict how much damage, but -- but Dorsey is a very critical piece of infrastructure because until the Riel sectionalization was built, it was the only tie between the HVDC, the 500 kV AC interconnection and the 230 system that is the backbone at Manitoba Hydro.

THE CHAIRPERSON: So if you've got a tower -- if you've got towers within 40 kilometres, which is where this tornado was, and they got -- they were hip by the tornado, I assume that we -- we're going to have problems with those towers?

MR. GLENN PENNER: Correct.

THE CHAIRPERSON: Okay.

MR. ALISTAIR FOGG: And just -- just to add to that, the three (3) years at Dorsey references replacement of -- of equipment such as the converted transformers that we discussed previously. So due to their special nature, the lead time in remanufacturing and having those delivered to Dorsey could cause that three (3) years lost connection.

THE CHAIRPERSON: Okay. Page 82. You've got the map of Bipole and relation of Dorsey. How far is Bipole from Dorsey?

MR. GLENN PENNER: Are you referring to Bipole III?

THE CHAIRPERSON: Yeah, Bipole III,

the line that is west of Dorsey, how far away is that?

MR. GLENN PENNER: I'm not sure exactly how many kilometres but it was planned to be at a distance away and that's why it terminates at Riel and then travels east and south away from Winnipeg and Dorsey. It's certainly much further than 40 kilometres.

THE CHAIRPERSON: Okay. Elie is which direction from Dorsey? It would be west, wouldn't it?

MR. GLENN PENNER: Yes.

THE CHAIRPERSON: Okay. The tornado -- the Elie tornado came from the west; is that correct?

MR. GLENN PENNER: I'm not -- I'm not sure which direction it would've come from.

THE CHAIRPERSON: If I go up further north for Bipole III to immediately west of Jenpeg, what's the difference between Bipole -- what is the distance between Bipole III and Bipoles I and II?

MR. GLENN PENNER: I'm not sure what -- what the distance is between Bipole III and Bipoles I and II at that -- you're talking about that specific location where --

THE CHAIRPERSON: Yes.

MR. GLENN PENNER: -- they get closer.

THE CHAIRPERSON: Yes.

MR. GLENN PENNER: Correct. Yeah, I'm not sure -- I -- we would have to get an undertaking to get --

THE CHAIRPERSON: Well, if I could get an undertaking to determine the distance at that point. I think Mr. Penner --

MR. GLENN PENNER: Yeah, they were just giving you some background on the design requirements for that location. So, in those locations where we had to move as part of the -- the requirements to get closer to Bipole I and II, we pro -- we designed the structures to withstand a higher wind load. So the structures are reinforced in that area, but I -- I don't have the information as to exactly how close those structures are.

THE CHAIRPERSON: Well, could you provide an undertaking to determine what sort of wind it could take and -- and whether it could withstand a F5 tornado?

As I understand it, based on the information here, if an F5 tornado hits at that point, we've lost all the Bipoles, unless somebody tells me otherwise.

MR. GLENN PENNER: No -- I can -- I

can get an undertaking. But an F5 tornado, it -- it can -- it's a very specific and can be very focused in terms of its energy and I guess the best way to describe it is it's not -- it's not like a large wind event that -- that could take out multiple spans.

A tornado is a very specific type of storm and -- and it can be on the ground for very short periods of time. But I -- we can provide some information through an undertaking.

--- UNDERTAKING NO. 53: Manitoba Hydro to provide the distance between Bipoles III and Bipoles I and II at its point immediately west of Jenpeg. Then further to what level of resistance from when they've been built.

THE CHAIRPERSON: Okay. As I look at the -- as I look at the photo -- so the undertaking is that they will provide the distance between Bipoles III -- Bipole III and Bipoles I and II at its point immediately west of Jenpeg. Thank you and -- and I guess then further to what level of resistance from when they've been built.

Mr. Penner, when I look at the map on page 82, I guess the -- the actual map of the Riel converter station on the right is a better depiction than where it shows on the actual map? I mean, when I look at the -- the sort of the map on the left, it looks like Riel is south of Winnipeg. It's actually more east of Winnipeg, isn't it?

MR. GLENN PENNER: The map -- the air photo on the right is -- it's maybe a better depiction. I think the -- the word "Winnipeg" on that large-scale map may -- there's no dot indicating where Winnipeg is and I think that's -- that may be why -- there's a dot that indicates Selkirk, but there's no dot for Winnipeg.

THE CHAIRPERSON: Yes.

MR. GLENN PENNER: So it's -- it's -- if you -- it's just north of the Deacon's corner where the reservoirs are.

THE CHAIRPERSON: Okay and the -- and if I was going to the United States from Riel I'd go south or southeast of Riel to hook into the United States with GNTL and MMTP; is that correct?

MR. GLENN PENNER: MMTP actually

connects into Dorsey and it goes -- the -- the line actually follows -- it follows south of Winnipeg, but just south of Winnipeg, south of the perimeter and follows an existing corridor and then -- and then it actually comes up past Riel station and follows along an existing corridor just past Anola and you can see that on that page 82, and then it turns south/ southeast towards the RM of Piney.

THE CHAIRPERSON: Okay. Thank you very much.

MR. DAVID CORMIE: Mr. Chairman?

THE CHAIRPERSON: Yes.

MR. DAVID CORMIE: If I could add to the conversation about the risks of the Bipole -- associated with Bipole III. I think it was at our rate hearing last year, Dr. Swatek addressed this issue and provided a -- a comprehensive presentation on -- on -- on the probability of -- of -- of losses with and without Bipole III.

And I think it would help you understand the -- the change in risk profile that we have with Bipole I and II going to Bipole III. We would provide you that. It's -- it's -- it's quite illuminating.

THE CHAIRPERSON: Thank you, Mr.

Cormie, I'd appreciate that. Okay, Mr. Peters...?

MR. DAVID CORMIE: Yes, Manitoba Hydro will provide the presentation Dr. Swatek presented on the risks of reduction associated with the construction of Bipole III.

--- UNDERTAKING NO. 54: Manitoba Hydro will provide the presentation Dr. Swatek presented on the risks of reduction associated with the construction of Bipole III.

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Good afternoon to the Panel. I'd like to start by repeating an off-mentioned admonition that no questions of mine are to seek responses that contain information that Hydro believes is confidential or commercially sensitive.

My questions are only seeking to elicit succinct answers, but if you feel to answer my question properly for the Board that you have to include confidential information or information that Manitoba Hydro has not been required to put on the public record, please let the Board and your counsel know that you will respond fully to that question when we go in camera tomorrow.

Would that be understood and acceptable, Ms. Van Iderstine and Ms. Mayor?

MS. HELGA VAN IDERSTINE: Yes, that's acceptable, thanks.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And thank you. So I want to start my questions starting with Keeyask, and we're going to start in Board counsels' volume 6 of the book of documents on page 5. And to get us started, my questions will be for whoever chooses to answer from the panel, recognizing you have your -- your specialties.

The Public Utilities Board was told at the Needs For And Alternatives To review that Keeyask had a starting price at about $6.2 billion as would be seen by following the CEF-13 line item down to Keeyask where they intersect; is that correct?

MR. DAVID BOWEN: During the -- the NFAT, at the start of the NFAT hearing, the budget was indeed $6.2 billion. Before the -- the hearing was concluded, the budget was changed to $6.5 billion.

MR. BOB PETERS: And you told us that on your slide 34, that we don't need to go to Mr. Bowen, but it was during the course of the NFAT that Manitoba Hydro received its bids back from the four (4) contractors who were responding to Manitoba Hydro's tender; is that correct?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: And as a result of getting the four (4) bids back, Manitoba Hydro analyzed them, and Manitoba Hydro made a decision to accept a tender from a general civil contractor that resulted in the total cost of Keeyask coming in at 6.5 billion; correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And you told us on slide 32 of your presentation what's included in the general service contract -- general civil contract, it's the moving of the earth, the building of the earth structures, the building of the mechanical structures once the concrete is in place; correct?

MR. DAVID BOWEN: That's -- that's a good summary of the scope, yes, correct.

MR. BOB PETERS: And equally what's important is -- and I think you told us this as well, Mr. Bowen, that not included in the general civil contract for Keeyask would be what you referred to as the Keeyask Infrastructure Project, which included roads, power, there was a camp, as well as the turbines, the generators, the gates, the hoists, and the other hardware that engineers like?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: All right. That $6.5 billion, Mr. Bowen, was the total in-service cost and that includes interest that's been capitalized on all the money that's been paid out; correct?

MR. DAVID BOWEN: That's right, it was our P50 estimate --

MR. BOB PETERS: Yeah.

MR. DAVID BOWEN: -- at the time of the NFAT.

MR. BOB PETERS: All right, we'll -- we'll come to that a little bit later, but the -- the essence of looking now at -- back on page 5 of Board counsels' book of documents, and we can go over to your capital expenditure forecast number 14, follow it down, and we see 6.496 billion that we've rounded off to 6.5; correct?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: That 6.5 billion was supposed to be the all-in cost, if I can call it that;

correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And not only did it include interest, it included things like escalation, which was really analogous to an inflation adjustment over -- over the years?

MR. DAVID BOWEN: Once again it was our P50 value at that time.

MR. BOB PETERS: All right. And the 6.5 billion forecast included a first unit in-service on November 2019, if I recall?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: Now on page 6 of Board counsels' book of documents, we move past 2014, and there was no update, was there, and into 2015 and the capital expenditure forecast was not revised; was it, Mr. Bowen?

MR. DAVID BOWEN: Correct. There is no update in 2015.

MR. BOB PETERS: Why was there no update in 2015?

MR. DAVID BOWEN: There was no reason to update the control budget in 2015.

MR. BOB PETERS: Everything was looking at?

MR. DAVID BOWEN: I wouldn't say everything was looking good. A project like this has many risks but we didn't have any reason to believe that we were going too push past the 6.5 million in 2015.

MR. BOB PETERS: All right, but by mid-2016, Manitoba Hydro has engaged a group called the Boston Consulting Group.

You're aware of that?

MR. DAVID BOWEN: I'm aware that when the Manitoba Hydro Board was replaced, the -- one of the first things they did was to engage the Boston Consulting Group on behalf of the Board and that occurred I believe in the May/June timeframe of 2016.

MR. BOB PETERS: Would you be aware, Mr. Bowen, that at the same time the Manitoba Hydro Board or even before that, the Manitoba Hydro Board engaged KPMG Consulting Firm?

MR. DAVID BOWEN: I'm not aware that the Manitoba Hydro Board engaged KPMG.

MR. BOB PETERS: Was it Manitoba Hydro's management that in -- in -- Mr. Midford, can you help me out here?

MR. LORNE MIDFORD: I think you may be referring to the project team hiring KPMG to do a health check of the project perhaps.

MR. BOB PETERS: All right. And that was in May -- or sorry, that was in early 2016?

MR. LORNE MIDFORD: Yes.

MR. BOB PETERS: It's appended to your rebuttal evidence if you need a date but...

So the difference, Mr. Bowen, is it was Manitoba Hydro's Board of Directors that engaged the Boston Consulting Group, and it was the Manitoba Hydro executive that engaged KPMG at or about the same time.

Have I got that right?

MR. DAVID BOWEN: The -- the project team engaged KPMG.

MR. BOB PETERS: The project team is Manitoba Hydro?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: When you look on slide -- or page 6, I should say, of Board counsels' Exhibit 42-6 and Boston Consulting Group tells Manitoba Hydro that the cost of Keeyask will increase from 6.5 billion to 7.8 billion without any mitigation steps being taken by Manitoba Hydro and that will result in July '20/'22 in-service date; correct?

MR. DAVID BOWEN: Yes, that's what it says on -- on their slide.

MR. BOB PETERS: And you're aware that's what they told Manitoba Hydro or were you not aware of that?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: If Manitoba Hydro was to mitigate some of the concerns, Boston Consulting Group suggests that the in-service cost would still increase from 6.5 billion but would be more in the range of $7.2 billion with an in-service date probably in the August of '20/'21 range, correct?

MR. DAVID BOWEN: Yes, that's what -- that's what their analysis shows.

MR. BOB PETERS: You're aware of their analysis when they were doing it?

MR. DAVID BOWEN: They were working -- yes, they were working with my team at the time they were performing the analysis. However, our team did not perform this analysis. This is an analysis done by BCG.

MR. BOB PETERS: On slide -- sorry, on page 7 of book of documents 42-6, the Boston Consulting Group had some recommendations that would help mitigate the schedule.

You're aware of that, Mr. Bowen?

MR. DAVID BOWEN: Yes, I'm aware of

that.

MR. BOB PETERS: Did -- did Boston come up with those on their own or was it really Manitoba Hydro telling Boston that these are the steps that would mitigate the concerns?

MR. DAVID BOWEN: I would say the items identified here really came from our Manitoba Hydro team.

MR. BOB PETERS: All right. And not to get in any great detail but I think you mentioned in your slide this morning, Mr. Bowen, that to install powerhouse columns to enable parallel construction was really putting, and this is in my words, metal girders on cement at a lower stage of the cement construction so that something could be built on the top of those metal girders while somebody also worked underneath them on the cement -- or concrete?

MR. DAVID BOWEN: What I was just trying to say is that, yes, we could lower the elevation of the concrete and -- and for giving -- for correcting the structural steel columns and -- and really what -- what it enables to do for the site is that the -- the work is constrained by the winter months. So being able to get the columns up sooner and, of course, the cladding and roofing on sooner allows work to -- to continue over the winter months and allows us to mitigate schedule.

MR. BOB PETERS: And you told the Board this morning, Mr. Bowen, that that mitigated the schedule by as much as twelve (12) months?

MR. DAVID BOWEN: Yes, without -- without using column extenders we -- we would be facing another one (1) year delay or more.

MR. BOB PETERS: Was there a similar or some comparable time savings to using the backup power to replace the short-term need for the auxiliary building?

MR. DAVID BOWEN: It -- no, no, this was -- this is showing for the spillway structure and so, no, the -- the timesaving was not nearly as great.

MR. BOB PETERS: Was there, in fact, any timesaving to the overall schedule?

MR. DAVID BOWEN: I'd -- I'd have to -- to check to see what exactly that was. I don't have that answer on my fingertips.

MR. BOB PETERS: All right. Well let's look at the third -- the third performance improvement really focused on improving the general civil contractor's productivity and effectiveness; correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: How does Manitoba Hydro do that?

MR. DAVID BOWEN: That's a -- that's a really big question. And I -- so I think the question you're asking is: How does the Manitoba Hydro make sure that our contractor, in this case, a general civil contractor is providing the best result for Manitoba Hydro.

There's a number of things that we do and, really, I'll go back to the beginning and I'll go back to the GCC procurement. So I think what Mr. Strongman noted originally in his -- in his presentation was that at the time the general civil contract was put to tender, we went through an exhaustive two (2) year process. We engaged experts. We -- we attempted to match the risk that the marketplace would use -- would -- would be able to take at that time, and to ensure that we could get the best price for all -- all of Manitobans.

At the same time, we engaged a company called Chant Construction. Chant actually did a shadow bit at the same time to help validate our cost; to make sure that when those prices came in that they closed. There's -- there's one (1) example.

Really, other examples in terms of effect we manage risk. We -- we went through the process for the early contractor involvement where we brought our BBE, general civil contractor, in early in the process to help mitigate risks. It's -- it's -- it's hard to say -- because we don't have the project going on at the same time without doing the ECI compared to -- with the ECI, it's hard to provide an apples-to-apples comparison. But really, it's -- it's a best in class procurement methodology that's used in industry to help the contractor to mitigate risk and be ready for construction.

Those are just a few examples of what Manitoba Hydro is doing to provide the best value -- value for Manitobans.

MR. BOB PETERS: Thank you, Mr. Bowen, we'll come to some more of that. Before I leave page 7 of Board counsels' book of documents number 6, that chart, does that show the Board in a graphic how far behind the concrete placement was in those various years?

MR. DAVID BOWEN: So I believe you're referring to slide 7 in the book of documents --

MR. BOB PETERS: Yes.

MR. DAVID BOWEN: -- and you're --

you're referring to the graph on the bottom right corner, which shows the volume of concrete in April '16, May, et cetera.

So, yes, it shows, for example, if we look at May '16, there was plan to place 42,000 cubic metres of concrete at that time, and by month end we had 13,000. So it -- it shows that deficit, yes.

MR. BOB PETERS: All right, I've got some further questions about that, but I wanted to just cover the price at a high level, and we're going to leave the Boston Consulting Group prices of between 7.2 and 8.5 billion, Mr. Bowen, -- let me rephrase that.

It was Boston who quantified the in-service costs of Keeyask to be between 7.2 and 7.8 billion; correct?

MR. DAVID BOWEN: That's what the report says on slides -- slide 6, yes.

MR. BOB PETERS: And that's what they told Manitoba Hydro?

MR. DAVID BOWEN: Yes, that's what they told our -- our board.

MR. BOB PETERS: And your board didn't accept that because on page 8 of the book of documents, we see your board chair, I believe makes an announcement that the control budget of Keeyask is $8.7 billion, and that announcement was in approximately March 7th of 2017; correct?

MR. DAVID BOWEN: Yes, that's correct.

MR. BOB PETERS: Can you explain to this Board why the Boston Consulting Group's price forecasts were not accepted by Manitoba Hydro?

MR. LORNE MIDFORD: The board hired Boston Consultants to come in and they evaluated the -- the project in the very beginning of the construction where the concrete was being placed in May, June and part of July.

So Boston Consulting did a forecast based on that initial sliver of time looking at the productivity and they did their best to forecast where the project could end up.

That wasn't a change in the control budget or control schedule, that wasn't a detailed analysis of all the risks associated with the project, which is what the project team did at the -- at the end of the construction season. And then with that new information, they updated the control budget with a direct recommendation to our Manitoba Hydro Board with the -- with the new control of $8.7 billion.

MR. BOB PETERS: Thank you, Mr.

Midford. On page 11 of Exhibit 42-6, MGF Services provides what I'll call a waterfall diagram to depict what's happened in the Keeyask generating price going from 6.5 to $8.7 billion.

Do you see that, Mr. Bowen?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And the largest increase to get from 6.5 to 8.7 was due to which contract?

MR. DAVID BOWEN: The general civil contract.

MR. BOB PETERS: And we can see that on the next page as well, on page 12, that schematically the general civil contract was driving the majority of the cost increase taking Keeyask from 6.5 to $8.7 billion; correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: Now, Mr. Bowen, you personally didn't want to accept that $8.7 billion cost from the Manitoba Hydro Electric Board. So it looks like on page 13 of Board -- of Board counsels' book of documents that you challenged your construction team to bring Keeyask in at $8.2 billion, with only an eleven (11) month delay.

Do you see that? It's going to be on

the right-hand side of this -- and I'm not sure how --

MR. DAVID BOWEN: I see it, yes.

MR. BOB PETERS: All right. And -- and when I said "you," I guess it was personal you; was it not?

MR. DAVID BOWEN: This -- on Exhibit 13, this is what we call our Keeyask project manager -- project manager update. So Manitoba Hydro, as the project manager, provides this publication about quarterly mainly to our KCN partners to provide information on the project.

MR. LORNE MIDFORD: I might just add that this -- we consider this to be a stretched target for the project team and that was presented to our board at the same time that the new control budget was approved.

So the project team itself has a -- has a target to better the existing control budget and schedule.

MR. BOB PETERS: But Mr. Midford, it's not accepted by the Manitoba Hydro Electric Board?

MR. LORNE MIDFORD: It's considered a -- a stretch target.

MR. BOB PETERS: Okay. I'm not familiar with that concept, does that mean it's --

MR. LORNE MIDFORD: You're striving to achieve that, yes.

MR. BOB PETERS: Striving to achieve it. It's still considered realistic; is that correct?

MR. LORNE MIDFORD: (No Audible Response).

MR. BOB PETERS: As -- as we sit here today is that cost estimate still valid?

MR. DAVID BOWEN: By the math -- as I mentioned in my presentation, we require a 10 percent improvement in the general civil contract work this year. And we -- we can't have any major risk come true in order for it to -- for us to meet our control budget.

In order for us to do -- to push down towards $8.2 billion, that is significantly a -- a stretch goal, we would have to have upwards of a 30 percent improvement in our general civil contract to come close to that right now.

MR. BOB PETERS: So if we turn just quickly to page 50 of Board counsels' book of documents, we'll see a chart with a schedule of dates that was prepared not by Manitoba Hydro but I want to understand when we look at this schedule, Mr. Bowen, the October 17, 2020 in-service target is no longer the -- the stretch target or the plan date.

Would you accept that?

MR. DAVID BOWEN: Sorry, can you repeat the question?

MR. BOB PETERS: Let me ask it this way, Mr. Bowen. If your stretch target could be achieved and you've now indicated that to achieve it you'd need a 30 percent improvement in this next year, when would the first unit come in service?

(BRIEF PAUSE)

MR. DAVID BOWEN: I was just trying to make sure I got my math right here. So the -- we -- we would need over a 30 percent improvement, as I previously noted. The -- the stretch goal that we referred to, the 8.2 billion, has a first unit -- first unit in-service date of October of 2020.

MR. BOB PETERS: Would it be realistic at this point, Mr. Bowen, to conclude that that's not going to happen?

MR. DAVID BOWEN: Certainly from a -- from my perspective and our team's perspective, we are going to continue to drive to have the lowest cost and shortest schedule. I guess it depends who you ask whether or not it's realistic. It is a very tough goal that we are going to continue to work at, and I'd be happy to report back here at the end of this construction season and -- and give you a real answer of how realistic it is or not.

MR. BOB PETERS: All right, we'll make a date. No, it's certainly not an undertaking.

In the discussion you had with the Chair just after the lunch recess today, the understanding is that the $8.7 billion is the P50 number, and you stressed that repeatedly, Mr. Bowen; correct?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: And just for the record, the -- the designation P50 indicates that there's a 50 percent chance the cost will be lower, and also a 50 percent chance the cost will be higher than 8.7 billion?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And catching up to what the Chairman talked with your President and CFO about on page 15 and 16 of Board counsels' book of documents, maybe we'll see it over the top of 16, we can see that with no in-service delay beyond '20/'21, the P90 would be 9.6 billion but that would increase to 9.9 billion if there was a further delay; correct?

MR. DAVID BOWEN: Yes, that's what's shown here.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Bow -- sorry, Mr. Bowen, your slide 64 from your presentation this morning...

(BRIEF PAUSE)

MR. BOB PETERS: I just want to make sure the -- the Board here is clear that going from Manitoba Hydro's P90 on page 64, your slide 64, that contemplates a delay of not only eighteen (18) months, but an additional eleven (11) months as noted above that, correct?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: So that's a twenty-nine (29) month delay from what was first estimated?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And if -- if the P90 number was calculated based on what I believe was being spoken about in response to this information request of a further delay or a thirty-two (32) month delay, that thirty-two (32) month delay is, in essence, only three (3) additional months from Manitoba Hydro's P90 of April 22 -- April of 2022, and a nine point six (9.6) number?

MR. DAVID BOWEN: So -- so to clarify, the -- the P90 value provided on slide 64 has a twenty (20) minu -- twenty-nine (29) month delay. In the reference books of documents here on -- on item 16, there is a farther three (3) month delay noted to move the twenty-nine (29) month delay to thirty-two (32) months, and there is additional interest and escalation that that would attract. I haven't run the numbers personally, but the -- the values show here that it would increase from 9.6 to $9.9 billion.

MR. BOB PETERS: Thank you. And you -- you answered better than I asked it, but you can confirm that to go from Manitoba Hydro's P90 of $9.6 billion to the P90 at $9.9 billion, that's an additional three (3) months and only three (3) months, according to the information?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: Thank you, sir. Mr. Bowen, is Manitoba Hydro in the process of updating its Keeyask cost estimate?

MR. DAVID BOWEN: No. No, we have -- we have monthly construction cost reports, and we have our contract -- our -- our staff are continually projecting, but we're not going through a formal update at this time.

MR. BOB PETERS: Is there an update being done for the schedule?

MR. DAVID BOWEN: Yes. Yes, the schedule is driven by the general civil contract work. Because there's been change in the schedule, it impacts the entire job. Right now, as we speak, our Manitoba Hydro site team is working with BBE to update the Keeyask schedule based on expected progress for 2018. Once that occurs for the general civil contract work, of course, there is a knock-on effect to other site contracts, and that work will happen and exp -- expected to happen and be complete in -- in the next month.

MR. BOB PETERS: By the end of February, 2018?

MR. DAVID BOWEN: Correct.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Bowen, can you

through your counsel undertake to provide that information to the Board when it's received?

MR. DAVID BOWEN: It's -- just want to confirm what you're asking. You're asking for our updated control schedule at the end of February?

MR. BOB PETERS: Or as soon as it's received, yes.

MR. DAVID BOWEN: I -- we -- we can provide that.

MR. BOB PETERS: Thank you, sir. Mr. Bowen, your undertaking was to -- to provide through your counsel the Public Utilities Board with an update of Manitoba Hydro's schedule for the completion of Keeyask?

MR. DAVID BOWEN: Yes. Yes.

--- UNDERTAKING NO. 55: Manitoba Hydro to provide the PUB with an update of Manitoba Hydro's control schedule for the completion of Keeyask at the end of February or as soon as it's received

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And, Mr. Bowen, if that schedule either adds more days or subtracts more days, does that impact the cost?

MR. DAVID BOWEN: Absolutely.

MR. BOB PETERS: And will Manitoba Hydro take steps to update its Keeyask cost estimate after it gets its schedule estimate?

MR. DAVID BOWEN: So the -- the schedule I'm referring to, we have our control schedule, and -- and I think everyone recognizes what the control schedule is. So our first in-service date is -- for our control is August of 2021. We have what we call a working schedule, and the working schedule is dynamic, and this working schedule is the schedule I was referring that's being developed with the general civil contractor as we speak.

This schedule will outline the work that's going to happen this year in the 2018 sea -- season. Once -- once the -- we establish what work happens under the general civil work, we'll then look at what work happens under the turbine engineer work with Voith. We'll look at the intake, et cetera, to make sure everything is knitted together, and -- and we have all the logic ties, right? So -- so normally we would not do an update of our cost estimate unless there was a significant change to the working schedule. From -- from what I know right now is that we -- we were -- the -- the change is going to be such that we do not plan to do an update of our costs based on the schedule.

MR. BOB PETERS: Thank you for that, Mr. Bowen. If we turn to page 50 again in Board counsel's book of documents, Exhibit 42-6, Mr. Bowen, I want to make sure the panel is with you on that last answer. Manitoba Hydro's control data is shown as August 2021, correct?

(BRIEF PAUSE)

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: And that's for the first unit to be in-service and operational?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: Even with this updated schedule done with the general civil contractor, Manitoba Hydro is not planning to change the control date of August, 2021?

MR. DAVID BOWEN: I just want to make sure we're -- we're talking correctly, the terminology. The control date references our $8.7

billion control budget. Our working schedule is that our team's goal is to achieve the work -- to finish the work as quickly as possible to mitigate costs. Of course, we're not going to give up on safety, the environment, quality, and our -- and our commitments under the JKDA. So -- so I would expect the information that I received back from our construction team will be in advance of the control date, because that's what everyone's working to is to -- to come in at the -- the shortest amount of time.

MR. BOB PETERS: Thank you, sir. I'd like to turn to an issue to explain to this panel the increase in prices for Keeyask that wen -- went from 6.5 to 8.7 billion with my next questions. And probably the best way to start, Mr. Bowen, is to pick up some of your comments by looking at page 25 of Board counsel book of documents. At the end of 2016, Mr. Bowen, there were problems that were identified by Hydro by the Boston Consulting Group, and I suppose by KPMG, correct?

MR. DAVID BOWEN: Yes, it was evident at the end of 2016 that we had done -- like it says here, it was actually about 40 percent of our planned concrete work, and about 60 percent of our planned earthworks.

MR. BOB PETERS: And when we try to drill down with this question as to what was the reasons for that, Manitoba Hydro had three (3) main reasons. The first was the labour productivity was a problem. There was also a slower than planned ramp-up on site, and then there was some geotechnical issues and concerns, correct?

MR. DAVID BOWEN: That's correct. And -- and if -- if the Board likes, I'd be prepared to talk at more detail on -- on these items tomorrow.

MR. BOB PETERS: All right. You're inviting the Board to -- you want to provide something to the Board -- and that wasn't very cryptic, but in the -- in the in-camera session?

MR. DAVID BOWEN: Yes, I'd be willing to provide greater level of detail tomorrow.

MR. BOB PETERS: All right. So I'll just ask Ms. Van Iderstine, or Ms. Mayor to make a note of that and they will ask you the appropriate question in-camera. That would be acceptable. Thank you.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Yes, we will

do so.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: On the public record, Mr. Bowen, which of these three (3) main issues is the largest driver of the increase in costs of Keeyask going from 6.5 billion to 8.7 billion?

MR. DAVID BOWEN: I would say let me look at these three (3) -- three (3) bullets. The -- the difference between the bid and the actual production achieved -- product to be achieved is the -- is the largest driver.

MR. BOB PETERS: So that's the productivity factor that's mentioned in -- in one (1) of those three (3) bullets?

MR. DAVID BOWEN: Yes. Yes, in the first bullet.

MR. BOB PETERS: And is it the productivity for both the startup of the concrete placement in 2016, and also the actual productivity for concrete placement once the contractor got mobilized in 2016?

MR. DAVID BOWEN: The -- the actual productivity achieved from startup right through the season was -- was far greater than what was expected.

MR. BOB PETERS: I'm sorry, I'm not sure I heard your answer correctly.

MR. DAVID BOWEN: The -- the productivity rates achieved, the person hours per unit of work, they were much larger than the bid from the start of the construction season throughout the entire construction season.

MR. BOB PETERS: What you're saying is Manitoba Hydro's expected productivity never materialized from the general civil contractor?

MR. DAVID BOWEN: Well, what I'm saying is that both Manitoba Hydro's expectation and our contractor's expectations were not achieved.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Bowen, where did Manitoba Hydro get its expectations as to productivity with concrete and earthworks?

MR. DAVID BOWEN: In terms of where -- where we derive our productivity rates from, it comes from our past historical experience. So from Limestone, Wuskwatim, Pointe du Bois. It comes from working with other utilities across Canada, and it also comes from, in this case, I mentioned the -- the shadow estimate that was done during the general civil contractor bid. So it comes from all those different areas.

MR. BOB PETERS: Did Manitoba...

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Bowen, can you indicate whether Manitoba Hydro, in its original contract with the general civil contractor, use the same productivity rates for concrete and earthworks that Manitoba Hydro actually achieved when it constructed Wuskwatim?

MR. DAVID BOWEN: No. The rates for lower.

MR. BOB PETERS: Manitoba Hydro's expectation of productivity was lower -- let me rephrase the question. Manitoba Hydro expected there to be greater productivity on Keeyask than Manitoba Hydro achieved on Wuskwatim?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: So where in Manitoba Hydro's past history did Manitoba Hydro achieve the productivity rates that it was expecting in its contract with the general civil contractor on Keeyask?

MR. DAVID BOWEN: The -- the rates provided by the general civil contractor would have been during the Limestone era.

MR. BOB PETERS: So for the panel to understand, the general civil contractor included in that bid productivity levels that were similar to what would have been achieved by Manitoba Hydro in the Limestone construction?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: Did Manitoba Hydro verify how the general civil contractor could achieve those productivity levels?

MR. DAVID BOWEN: During the -- the bid analysis phase, this was a -- obviously a -- a topic of concern and discussion. It was one (1) of the reasons why we carried a significant labour reserve in our original control budget, albeit it -- in hindsight, it wasn't adequate, but yes, yes, we looked at that in -- in earnest.

MR. BOB PETERS: What you're telling this Board is that when you received the general civil contractor's bids for productivity, a red flag went up that caused Manitoba Hydro to want to check into that further?

MR. DAVID BOWEN: Correct. As part of

our bid evaluation, we -- we look at the prices, and -- and certainly this one was a concern for -- for the team doing the analysis during the procurement phase.

MR. BOB PETERS: And the contract, the general civil contractor that Manitoba Hydro -- Hydro hired was a joint venture consortium of -- you told us this morning -- Bechtel Canada, Barnard Canada, and EllisDon, correct?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: Have -- and -- and it's all -- its shown as BBE, and perhaps that's the legal name that they use? Is that how it's known?

MR. DAVID BOWEN: Yes. It's much easier to say.

MR. BOB PETERS: Thank you. Did BBE construct other Hydro projects that Manitoba Hydro could verify their productivity levels on?

MR. DAVID BOWEN: Bechtel was part of a joint venture that was involved with Limestone, so that was a Bechtel/Kumagai joint venture. Barnard has done some Hydro work, albeit quite a bit smaller in -- in the US. And -- and EllisDon, they're -- they don't have direct experience within the -- the Hydro marketplace, but certainly, they have more experience within the Canadian construction marketplace.

MR. BOB PETERS: And the three (3) of them haven't joined together to do any Hydro project that Manitoba Hydro is aware of?

MR. DAVID BOWEN: I'm not aware of that JV doing any other -- other Hydro projects like -- like this, no.

MR. BOB PETERS: So help the Board understand that once Manitoba Hydro saw that the productivity level being quoted in the general civil contract proposal by BBE, was it -- was it -- was similar to what was achieved back in the Limestone days, what investigations did Manitoba Hydro do to determine whether that was reasonable going forward?

MR. DAVID BOWEN: I think the -- the largest investigation we did was bringing on -- doing a -- the shadow estimate that I talk -- just talked about by having a contractor do a shadow estimate on the bid to help verify those values.

MR. BOB PETERS: Was that shadow contractor doing that work before the bids were received from the four (4) proponents?

MR. DAVID BOWEN: Yes. I -- you're -- you're testing my memory, but I believe that the estimate from the shadow estimate was received at the same time that the bids were -- were closed.

MR. BOB PETERS: And you're prepared to share what those bids are tomorrow with the panel?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: All right. Thank you for that, sir. Mr. Bowen, in some discussion you had just after lunch -- lunch with the Vice Chair, you've previously told not only the Vice Chair, but the members of the Board who were on the Needs for and Alternatives rou -- review panel that there were lessons that Manitoba Hydro had learned from the Wuskwatim construction, and that was going to give Manitoba Hydro greater confidence when it embarked on Keeyask, correct?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: And one (1) of the -- and I'm looking on page 34 of Board counsel's book of documents. One (1) of the reasons for that greater confidence was because dealing with Keeyask, Manitoba Hydro had already awarded the general civil contract by the time the Needs for and Alternatives review was being conducted. Do you recall that?

MR. DAVID BOWEN: Yes, I do.

MR. BOB PETERS: And the essence of that, Mr. Bowen, is because the general civil contract had been issued for Keeyask and was included in that

$6.5 billion number, that gave the Utility, Manitoba Hydro, greater confidence that this project would come in close to $6.5 billion?

MR. DAVID BOWEN: I think, as discussed with the other projects here today, one (1) of the first risks of any major -- major project is getting -- securing pricing from contractors. At this point in time, the general civil contract, it's the largest risk on Keeyask. We had secured that price, and it gave us more confidence in the potential outcome.

MR. BOB PETERS: With the benefit of hindsight, we can say that that really didn't turn out the way it was expected correct?

MR. DAVID BOWEN: Yes. We're at 50 percent complete right now. Our control budgets increased from six point five (6.5) to eight point seven (8.7). We are doing everything we can to come in lower than that, and that's what we'll keep doing, But -- but yes, we look back over the last two (2) years, that's -- that's exactly right.

MR. BOB PETERS: Another one (1) of the concerns -- or lessons that was learned from the Wuskwatim project was that from the point in time in which the general service contractor had been engaged until the end of the project, costs increased between 10 and 13 percent on the Wuskwatim project, correct?

MR. DAVID BOWEN: Yes, it was in that ballpark.

MR. BOB PETERS: And back on page 31 of Board counsel's book of documents, the -- the suggestion then, Mr. Bowen, is because for Keeyask the general service contract had already been awarded, the cost increases that you saw in Wuskwatim after the general civil contract was awarded would lead you to believe that the risks would probably be less than 10 or 13 percent more for Keeyask?

MR. DAVID BOWEN: Correct. At that time, we -- we believe that -- that the risk represented here, and what we knew, we would be within our control or -- or much closer to control. But as you've already mentioned, is that hindsight is 20/20, and the -- the project has incurred a -- a substantial cost increase.

MR. BOB PETERS: And if we -- if we go back, Mr. Bowen, to page 11 and look at that waterfall in the MGF project services report, leaving aside the general civil contract, and I suppose the contingency, a lot of the other contracts fluctuated, but probably within the percentage range that you were expecting

after Wuskwatim. Would that be fair?
MR. DAVID BOWEN: The general civil contract drives the project -- the schedule for the work drives the project, so if we're on site longer, if we have more person hours and more people in camp for longer, generally all our costs go up because of running the -- operating the town of Keeyask, if you like. So -- so, yes, there's a knock-on effect, and -- and it's driven through being there longer and -- and more person hours driven by this work.
MR. BOB PETERS: All right. I -- I appreciate the clarification. What you're telling this panel is that because the general civil contract was the largest source of cost increase and delay in schedule increase, that had a -- an effect on many of the other items that are listed on page 11 in the -- the waterfall?
MR. DAVID BOWEN: That's right.
MR. BOB PETERS: All right. I've got your point. Thank you. Now for Wuskwatim, Mr. Bowen, do you recall if Manitoba Hydro included a labour reserve or an escalation reserve?
MR. DAVID BOWEN: I don't believe we had either for Wuskwatim.
MR. BOB PETERS: But you did have for

Keeyask, correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And you had both a labour reserve and an escalation reserve?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And as you've previously told me about ten (10) minutes ago, that labour reserve just turned out to not be large enough in -- in light of the productivity challenges that the project has faced?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: One (1) of the other mitigating factors that Manitoba Hydro was thinking would give a higher level of confidence was because it had a comprehensive schedule that linked the design, procurement, and construction together.

Do you recall that?

MR. DAVID BOWEN: Sorry, can you repeat the question?

MR. BOB PETERS: The essence of the question is that Manitoba Hydro had confidence in its Keeyask price because with Keeyask, it had a comprehensive schedule that linked design, procurement, and construction?

MR. DAVID BOWEN: Yes, we had a -- a

well-developed schedule that links all the different parts of the work together, and -- which is required for any of this work, and -- and the -- yes, it -- it's fundamental to carrying out any estimate and providing confidence in what you're doing.

MR. BOB PETERS: And Wuskwatim didn't have that, did it?

MR. DAVID BOWEN: I -- I didn't say that. Wuskwatim had a comprehensive schedule developed as well.

MR. BOB PETERS: To the same degree as Keeyask's?

MR. JEFF STRONGMAN: If you don't mind, I'll jump in on the Wuskwatim question.

MR. BOB PETERS: Absolutely, Mr. Strongman.

MR. JEFF STRONGMAN: Wuskwatim's schedule was not as well-developed as Keeyask. We certainly learned a lot in -- in the scheduling aspects of executing Wuskwatim, and we incorporated many of those lessons into what we're now doing for Keeyask. So the status of our Keeyask schedule is certainly an improvement upon what we had for Wuskwatim.

MR. BOB PETERS: Even though the

comprehensive schedule existed, Mr. Strongman, it -- it was such that it -- it hasn't been complied with such that a new schedule's had to be developed?

MR. JEFF STRONGMAN: Are you referring now to Keeyask?

MR. BOB PETERS: I was, yes.

MR. JEFF STRONGMAN: Yes. Well, I think referring to the BCG chart that I identified, the variance between plan versus actual concrete production, the order of magnitude of the variance was such that the schedule was very quickly no longer effective in managing the work in 2016.

MR. BOB PETERS: All right. You're referring back to pag -- page 7 of Board counsel's book of documents, and you're telling this Board at the bottom right-hand corner, there is a chart, and the performance on -- and the productivity on concrete got behind so much, so quickly, so early that Manitoba Hydro wasn't able to recover from that?

MR. JEFF STRONGMAN: Precisely.

MR. BOB PETERS: Now, with Keeyask in the general serv -- civil contract, Manitoba Hydro had a labour risk strategy that included a premier camp to attract and retain the craft labour, Mr. Bowen, and you talked about that with the -- with the panel after lunch today?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: Was that labour risk related to productivity?

MR. DAVID BOWEN: I'll be more specific. The labour product -- productivity risk, it's about attraction and retention, so we wanted to provide a top-quality camp so people working away from home in a remote environment would -- would stay not only state our job, but come to our job. So, yes, that was part of our attraction and retention strategy, which is highly important for anyone whose care network and a remote project department anywhere in the world.

MR. BOB PETERS: Has the labour risk strategy been successful or unsuccessful with the hindsight?

MR. DAVID BOWEN: Some of it's been successful, and some of it hasn't.

MR. BOB PETERS: What part has not been successful?

MR. DAVID BOWEN: The part that hasn't been successful was that we are spending more person hours per unit of work than we originally planned.

MR. BOB PETERS: Mr. Bowen, on page 37

of Board counsel's book of documents, on the transcript from the Needs for and Alternatives to review, the Wuskwatim labour productivity was lower than expected, correct?

MR. JEFF STRONGMAN: The Wuskwatim labour productivity was definitely less than what was expected.

MR. BOB PETERS: And even with that knowledge, Mr. Strongman, the productivity rates in the Keeyask contract were greater than what was in the Wuskwatim arrangement?

MR. JEFF STRONGMAN: I -- I just want to caution it's -- for clarity purposes, it's actually misleading to say greater than or less than when -- man hours per cubic metre of concrete. As you spend more man hours per cubic metre of concrete, you're actually less productive. So just to try to help with that basic understanding.

MR. BOB PETERS: Thank you for -- I think you were correcting me. I thought I had said it actually correctly, but however many person hours are needed at Wuskwatim, even more person hours ended up being needed at Keeyask. Have I said that right?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And even though

Manitoba Hydro knew that the person hours used at Wuskwatim weren't meeting the target, the target for Keeyask was for fewer person hours than it was at Wuskwatim, correct?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: Turning to page 40 of Board counsel's book of documents, this was a slide presentation made to Manitoba Hydro's Board of Directors. And I take it, Mr. Midford, you were probably a part of that? Or maybe Mr. Bowen, I don't know.

MR. LORNE MIDFORD: Sorry, what's the -- the date of this presentation?

(BRIEF PAUSE)

MR. BOB PETERS: We -- we're arguing over it. I think it's November of 2013. Does that help?

(BRIEF PAUSE)

MS. LOIS MORRISON: So, at that time, I wasn't -- I wasn't there at that time.

MR. BOB PETERS: Okay. Thank you,

sir. Let's not dwell on the date unless it's important to the witnesses, and -- and certainly, we'll -- we can try to track that down. But on this slide presentation, there's a contingency breakdown provided, and labour productivity is identified as a concern, but it's not included in the contingency. Have I -- have I got that right?

(BRIEF PAUSE)

MR. DAVID BOWEN: It doesn't appear to be here. I'd have to -- I -- I'd say yes, but subject to check.

MR. BOB PETERS: Okay. I'll accept that. Thank you, Mr. Bowen.

(BRIEF PAUSE)

MR. BOB PETERS: If we turn the page to page 41, a provision was added for Keeyask for a labour reserve as part of a management reserve, correct?

MR. DAVID BOWEN: Yes, that's correct.

(BRIEF PAUSE)

MR. BOB PETERS: So the labour productivity concern was not going to be addressed by the contingency, but it was going to be addressed by what is called a management reserve?

MR. DAVID BOWEN: Again, subject to check, I've been told by my colleague that this presentation was provided to our Hydro Board back in February of 2014. At that time, it clearly indicates that we're looking to -- may potentially have to access a labour reserve. I don't know whether or not contingency monies were allocated for labour at that time.

MR. BOB PETERS: Thank you.

(BRIEF PAUSE)

MR. BOB PETERS: Did Manitoba Hydro seek to get the productivity performance of the contractors that were constructing --

MS. HELGA VAN IDERSTINE: Mr. Peters, I just wanted to correct the date on that presentation. It appears to have been November 2013, so.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And -- and thank you, Ms. -- Ms. Van Iderstine. If we scroll ahead to page 59 of that same document, we see that there's a similar presentation using the same graphics made in February of 2014, correct?

MR. JEFF STRONGMAN: That appears to be correct, and that the timeline that we're referring to right now, it -- it proceeds involvement of each of the three (3) panelists in their current positions, just for clarification.

MR. BOB PETERS: Okay, thank you -- thank you very much. That's helpful, Mr. Strongman. And before Ms. Van Iderstine's point, I was asking the witnesses whether Manitoba Hydro contacted the general civil contractors constructing other Canadian Hydro dams to find out the productivity levels that were being achieved in the Canadian market?

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Would you please repeat the question?

MR. BOB PETERS: Mr. Strongman, the -- I'm wondering if Manitoba Hydro, on receiving the productivity quotes from the general civil contractors, contacted any other Canadian utilities or Canadian general civil contractors working on programs of Hydro construction for their productivity rates.

MR. JEFF STRONGMAN: So yes, Manitoba Hydro is in -- in communication and collaboration with other Hydro utilities across Canada on a regular basis. Specifically referring to the time in question, I don't know specifically if the receipt of bids had prompted any communication, but certainly, we have tracking of project metrics across Canada from other utilities that would have served as a basis for comparison.

MR. BOB PETERS: Did any of those comparisons show as favourable as those bid by the BBE joint venture?

MR. JEFF STRONGMAN: So let me qualify my answer before making it. The information that we're getting into right now is -- is considered to be highly confidential, and each of the utilities across Canada that would have been a part of the communication would have taken steps to ensure protection of the information that would delve into a great level of detail. So, really, just high-level productivities would have been subject to discussion and -- and breakdowns or specifics would have been avoided at that time.

MR. BOB PETERS: All right. Thank you. I accept that, Mr. Strongman.

Mr. Bowen, one (1) of the other reasons that Manitoba Hydro gained confidence in the Keeyask project costs that were disclosed at the Needs for and Alternatives to review was because Manitoba Hydro had essentially locked down 80 percent of the contracts, correct?

MR. DAVID BOWEN: Yes, that's correct.

MR. BOB PETERS: And that really meant there was only 20 percent left to be tendered and to be awarded, and so that, Manitoba Hydro expected, would minimize the need for any increase in costs?

MR. DAVID BOWEN: As I spoke of earlier, one (1) of the major risks, again, is the tender of -- of contracts. And yes, we had got through our big ones at that time, and we were confident at that time.

MR. BOB PETERS: Manitoba Hydro for Keeyask also had a much better estimating process, would you accept that, than it did for Wuskwatim?

MR. DAVID BOWEN: I would -- I would say yes. We continued to improve, and -- and we continue to apply lessons learned and refine our --

our estimating process. So, yes.

MR. BOB PETERS: And another factor, Mr. Bowen, was that the regulatory review of the Wuskwatim project, that was conducted by the Clean Environment Commission, correct?

MR. DAVID BOWEN: I wasn't personally involved in that process, so I -- I believe that's correct, but I --

MR. BOB PETERS: And that -- that review happened -- Mr. Williams remembers that, but -- or at least his younger brother does. That Wuskwatim review happened much earlier, or actually years earlier, before the actual construction started compared to Keeyask, correct?

Ms. Mayor may be the one who has to assist on that.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Yeah, we'd have to get back to you on that. I'm not sure that anybody's got that information at their -- at fingertips.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, Ms. Van Iderstine. I'm not going to ask for that as an undertaking, but the point I want to try to see if Mr. Bowen agrees, or Mr. Strongman agrees is for Wuskwatim, there was a lag between getting the regulatory approval and putting shovel in the ground.

Do you accept that as correct, that leg could have been several years?

MR. DAVID CORMIE: Mr. Peters, I was involved in this -- this process, and I -- your -- your premise is correct.

MR. BOB PETERS: And so, Mr. Bowen, with the Keeyask project, it looked like the ink was barely dry on the PUB's Needs for and Alternatives review before there was something being done in the river, the cofferdam was being constructed, correct?

MR. DAVID BOWEN: Our first -- our -- our start of construction in 2014 was pushing the first rock in the river, which happened on July 15th, which was very close to when the NFAT process closed.

MR. BOB PETERS: Within a matter of a few weeks after the Board's issued its -- its NFAT report?

MR. DAVID BOWEN: That's -- that's my recollection.

MR. BOB PETERS: All right. And Mr. Bowen, the whole point of going here is that gave Manitoba Hydro confidence that because of the relative duration between the regulatory approval and the actual construction, that, too, would serve to keep construction costs lower than they otherwise could be?

MR. DAVID BOWEN: Correct. I think -- I think what your -- point you're trying to make is that any delay to the construction would push back the contr -- the -- the project schedule, and there is a very large and significant cost for interest and escalation, and -- and yes, it would make it cost more.

MR. BOB PETERS: All right. Thank you, sir. Mr. Chair, if this suits the Board, this would be an appropriate time for an afternoon break.

THE CHAIRPERSON: Thank you. We'll break for fifteen (15) minutes.

--- Upon recessing at 2:47 p.m.
--- Upon resuming at 3:06 p.m.

THE CHAIRPERSON: Mr. Peters...?

MR. BOB PETERS: Thank you, sir.

MS. HELGA VAN IDERSTINE: May I just

jump in. We have -- at the outset of the hearing this afternoon Panel Member McKay had asked a question which seemed quite simple to answer and we're having a challenge with it, but it actually was a little more complicated, which is why we waited and now Mr. Strongman has the answer.

MR. JEFF STRONGMAN: So I believe the question was relating to the number of hours worked. So I've -- I've got the data handy to respond to the question.

The milestone that was celebrated back in June of 2017 of 2 million hours and 4 million hours for KCN employees and Indigenous employees respectively that, as I said, was the summertime. By year's end of 2017 the total KCN hours worked was 2.3 million and the total Indigenous hours worked in -- on the project by the end of 2017 was 5.8 million, on a total -- total labour hours worked of 15.3 million.

So the Indigenous proportion of the total was close to 40 percent, and the remark that I'd made previously was that this proportion is unprecedented in megaproject work within Canada.

I believe that was responsive to the question you'd asked.

THE CHAIRPERSON: Mr. Peters...?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you. On slide 56 of Manitoba Hydro Exhibit 120, one (1) of the issues raised for the cost overruns related to geotechnical issues, correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: In one (1) of the reports that was obtained, it was in the MGF report specifically by the contractor KCB, Klohn Crippen Berger, they found that the quantities of earthworks and excavations were close to forecast.

Do you recall them saying that, Mr. Bowen or Mr. Strongman?

MR. JEFF STRONGMAN: Yes, I recall that. I think the comment was in relation to concrete work. They were remarkably close and on earthworks the net sum was very close with some expected deviation according to different classes of excavation.

MR. BOB PETERS: Your memory's better than mine. And on that note, then, Mr. Strongman, why did the geotechnical issues cause problems if, as KCB found, the quantities were very close to what was forecast?

MR. JEFF STRONGMAN: Good question.

In the slide deck that I presented earlier this morning, I attempted to lay the groundwork, if you done mine the pun, for the answer to that question. There's a couple of slides and one (1) of them made reference "to dinner plate clean." It's on slide deck number 17.

Do you see the pictures here? You can see on the left that the -- the undulations of the bedrock are quite substantial and as the people are standing in the high and low spots there's a variation of -- of a number of feet in this picture and many metres over a long stretch of -- of ground.

On the right side you can see a picture showing where rock material has been placed at the base and in the -- in the foreground of that shot where there has yet to be any material placed. And with such significant variation on the bedrock, one of the means of leveling the surface before preparing it for the high-volume machinery with higher productivity levels would be to add in what we call dental concrete. Dental concrete is a lien mix of concrete. It's -- it's less expensive than structural concrete. There's less cement there, but it's really used to fill up all the voids.

And our estimation of -- of how much

dental concrete was going to be required on this job was minimal and as the ground conditions have dictated, it's been one (1) of those concrete -- sorry, one (1) of those quantities where substantially more has been required to date.

MR. BOB PETERS: Can you quantify the dollar and schedule impacts from that dental concrete issue?

MR. JEFF STRONGMAN: The dental concrete issue itself, I can quantify saying that we assumed 1 or 2000 cubic metres of concrete and I think by the end of the second year we had already used at least 10,000 with two (2) more years of earthworks to go. I'd have to check to confirm those numbers, but those pop to mind.

The actual cost impact of that? I would hold back from quantifying because I don't have certainty on what the number is.

MR. BOB PETERS: But in term --

MR. JEFF STRONGMAN: Probably what is more significant is the impact to the overall productivity of having to spend considerably more time getting off the rock -- sorry, is that better?

(BRIEF PAUSE)

MR. JEFF STRONGMAN: So I tried to quantify the -- the volumes. I'm not sure if that was well understood. In any event, the -- the impact from volume and costs is substantial but probably even more impactful is the schedule delay associated with taking considerably more time than planned to clean the surface of the rock to ensure that the base of the earth structures are well founded, and that there is no potential water path or seepage path once the impoundment takes place.

MR. BOB PETERS: While you haven't put a dollar value on the record, Mr. Strongman, by how many weeks, months was the project delayed because of difficulty in getting this dental concrete in place?

MR. JEFF STRONGMAN: It's a good question. Before being able to answer the question, there needs to be an understanding that there is multiple parallel paths of critical work happening. So the earthworks that's taking place, if we just talk about earthworks in exclusivity, we would be measuring the delay experience from getting off the rock in a number of months. On the North dam, for instance, which is nearing completion, we might have spent three (3) to six (6) months longer than planned in preparing the base before we could work up.

The central dam which is approximately a third completed, we would've had a similar impact there.

And for the south dam which has yet to be constructed because that's currently the path of the -- the river and won't be constructed until, at the very earliest, after next year, there's no measurable delay there yet.

Now, as the earthworks are proceeding we're also building concrete works and concrete has had its own different challenges. So saying what the effect of this earthworks issue has to the overall project schedule, it's happening at the same time as -- as we're experiencing some delays on concrete. So it's -- it's hard to be specific about exactly what that number is.

MR. BOB PETERS: Is Manitoba Hydro attributing any of the delay in the schedule to the dental concrete?

MR. DAVID BOWEN: If I could just add to Mr. Strongman's comments, the -- the concrete works right now is driving the schedule, the critical path. So -- so right now the earthworks is a shorter duration and -- and we should not be waiting for the earthworks structures to water up and -- and to energize our -- our units.

So if that assumption holds true for the remainder, then the earthworks will not delay our critical path because the concrete path is longer.

MR. BOB PETERS: Were the cost increases addressed for this dental concrete in the original contingency amount set aside for the original general civil contract?

MR. DAVID BOWEN: I would say that, no, there's been a lot more dental concrete work that's been performed than originally anticipated.

MR. BOB PETERS: So that answer really means, Mr. Bowen, that the original contingency amount was insufficient for this -- for this problem?

MR. DAVID BOWEN: Correct. The -- the undulations shown here, I believe that some of the Panel members, when you -- they came to site this past summer on the central dan, we -- there was a -- a pretty significant fault that was right in the middle of the central dam where we've had to go around that -- those conditions to the act -- that -- to that extent weren't anticipated and -- and -- and they're costing more than we originally anticipated.

MR. BOB PETERS: All right. Let's

move us along the timeline, gentlemen, that before the end of the 2016 construction season Manitoba Hydro's management and Board of Directors had concerns about the -- the productivity at Keeyask; that's correct?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And we know that Manitoba Hydro engaged KPMG in May approximately of 2016 to help address some of the problems; correct?

MR. JEFF STRONGMAN: That's correct. The KPMG engagement was self-directed assessment of the Keeyask project's systems and processes to identify opportunities for improvement and then act on those recommendations.

MR. BOB PETERS: And in mid to late 2016 -- 2016, the Manitoba Hydro Board of Directors made a decision to proceed with both Bipole III and Keeyask?

MR. LORNE MIDFORD: Yes, that's right.

MR. BOB PETERS: And that was after Manitoba Hydro's Board of Directors considered whether they should cancel construction on both of those megaprojects; correct?

MR. LORNE MIDFORD: Yes.

MR. BOB PETERS: And moving forward, Manitoba Hydro developed the BBE recovery roadmap in late 2016; is that also correct, Mr. Midford?

MR. LORNE MIDFORD: Yes, that's -- that's correct.

MR. BOB PETERS: And then as a result of that recovery roadmap, a recovery plan was prepared by Manitoba Hydro in late 2016 or early 2017?

MR. LORNE MIDFORD: Yes, that's -- that's accurate.

MR. BOB PETERS: And I understand from previous answers that the consulting firm KPMG, who's provided a letter as appendix A to Manitoba Hydro's rebuttal, KPMG provided the services to help with that recovery plan?

MR. DAVID BOWEN: That's right.

MR. BOB PETERS: Is KPMG still providing services on Keeyask?

MR. DAVID BOWEN: Yes, they are.

MR. BOB PETERS: Can you tell the Board briefly what KPMG is doing?

MR. DAVID BOWEN: KPMG's providing advisory services to the pro -- to project management for the construction of Keeyask and so much like Mr. Peters has just stated, they were heavily involved with the recovery plan, which began initiated back in September 2016, but they're providing ongoing support to our team for various issues as they arise on the -- on the construction.

MR. BOB PETERS: Did KPMG also assist on the assessment of the Bipole III project?

MR. ALISTAIR FOGG: Sorry, Mr. Peters, in terms of the Bipole III project from the proceed or not proceed perspective or...?

MR. BOB PETERS: Mr. Fogg, I understand that KPMG was engaged on approximately May the 2nd, 2016. Can you accept that as accurate?

MR. ALISTAIR FOGG: For Keeyask or for -- for Bipole III?

MR. BOB PETERS: No, for the engagement of KPMG engagement entirely. And maybe what I could do is I could ask Diana to find Manitoba Hydro's rebuttal evidence and we'll turn to I guess 59 might be the first page of the -- it might be a KPMG letter. No. If we follow page 58 of 58, a couple more pages ahead, Diana, please. All right, thank you.

(BRIEF PAUSE)

MR. BOB PETERS: This is what I was thinking of is that KPMG was engaged by Hydro on May the 2nd and they provided a review of the Keeyask generating station project and they talked about development and implementation of a recovery plan, correct? Mr. Strongman or Mr. Midford?

MR. LORNE MIDFORD: Yes, that's correct.

MR. BOB PETERS: My question then, Mr. Fogg, was: Did KPMG also have any role to play since May the 2nd, 2016, in respect to Bipole III?

MR. ALISTAIR FOGG: KPMG has not have -- had an active role on Bipole since May 2nd; earlier to that they were involved on Bipole III conducting, I believe the term has come up, for a health check on the project processes and services.

MR. BOB PETERS: Are these -- Mr. Fogg, was this an extensive health check? Is this an annual medical or is this just a walk-in clinic view?

MR. ALISTAIR FOGG: I wouldn't context it as a trip to the ER necessarily. It was a thorough review of our processes and standards for Bipole III and with some areas of recommendations for improvement.

MR. BOB PETERS: All right. Perhaps the better way for the Board to assess the duration and the scope of their involvement, Mr. Midford, could you undertake to provide the Board with an indication of how much Manitoba Hydro has paid KPMG since May the 2nd on the Keeyask project and, likewise, how much they've paid KPMG related to the Bipole III project?

MS. HELGA VAN IDERSTINE: We'll take that under advisement, Mr. Peters.

MR. BOB PETERS: All right, thank you.

--- UNDERTAKING NO. 56: Manitoba Hydro to provide the Board with an indication of how much Manitoba Hydro has paid KPMG since May the 2nd on the Keeyask project and, likewise, how much they've paid KPMG related to the Bipole III project. (TAKEN UNDER ADVISEMENT)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Any costs of these third-party consultants would be included in the control budget; is that correct, Mr. Midford?

MR. LORNE MIDFORD: Yes, that's right.

MR. BOB PETERS: Thank you. In this

process, Mr. Midford, did Manitoba Hydro management consider the cost to walk away from the Keeyask project, in essence, shut it down?

MR. LORNE MIDFORD: I'm not sure what you're -- are you referring to the KPMG engagement or the BCG from the Board? Sorry.

MR. BOB PETERS: Let me rephrase the question. During this review process and just prior to preparing the recovery roadmap and the recovery plan, Manitoba Hydro, as I understood the evidence of your president, had considered on a couple of occasions whether to stop construction on Keeyask entirely; correct?

MR. LORNE MIDFORD: The Manitoba Hydro Board hired BCG in, as you know, in '16 to -- to review the projects and -- and provide that recommendation to them in terms of the -- the economics of continuing or looking at other alternatives going forward. And so that was the main focus of the BCG review. So that was provided to the Manitoba Hydro Board towards the end of '16, I believe.

Since then, internally we've done a refresh of that review which I think was provided in earlier testimony with the new control budget of the

$8.7 billion. And so -- so I believe what our CEO was referring to was the refresh of that analysis in the spring of 2017 by Manitoba -- internally by Manitoba Hydro staff.

MR. BOB PETERS: Has Manitoba Hydro calculated what the cost of stopping work on Keeyask would be and what it would mean for ratepayers?

MR. LORNE MIDFORD: Sorry, Mr. Peters, can you just repeat that.

MR. BOB PETERS: I'm wondering, Mr. Midford, whether Manitoba Hydro had calculated the cost of discontinuing work on Keeyask, together with any ratepayer impacts that might have?

MR. LORNE MIDFORD: Yes, I believe that was done.

MR. BOB PETERS: And are those -- is that information something that Manitoba Hydro can provide to this Board on the public record?

MS. HELGA VAN IDERSTINE: I think -- I think we -- yeah, I don't think the detail of that has been provided, Mr. Peters. It was provided at a high level I think, in -- either in an MFR or an IR, so, we'd have to check into that and whether that's determ -- we can provide more detail.

MR. BOB PETERS: All right, if you

could undertake then, Ms. Van Iderstine, to advise the Panel of Manitoba Hydro's calculation of the costs for stopping construction on Keeyask entirely, together with what, if any, rate impacts that would have.

That would be appreciated.

MS. HELGA VAN IDERSTINE: Excuse me, if that -- if that's been done then I -- we'll look into it and if it's possible to produce it, we will. But I'm not entirely certain it's been done in that entire -- in that detail.

MR. BOB PETERS: Thank you.

--- UNDERTAKING NO. 57: To advise the Panel of Manitoba Hydro's calculation of the costs for stopping construction on Keeyask entirely, together with what, if any, rate impacts that would have.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: In terms of Manitoba Hydro's recovery roadmap, one (1) of the options to go forward was to start with a new general civil contractor; is that correct?

MR. DAVID BOWEN: That -- that's what's shown there, yes, on slide 57 of my presentation this morning.

(BRIEF PAUSE)

MR. BOB PETERS: Is it correct for this Board to understand, Mr. Bowen, that when Manitoba Hydro was developing the recovery roadmap, the general civil contractor that we've called BBE was not interested in continuing under the old contract?

MR. DAVID BOWEN: I'd like to provide the most complete answer today, but I would request that be able to provide more information tomorrow. Certainly BBE was aware of the challenges they were having and, certainly, they wanted to do everything they could to -- to help Manitoba Hydro and continue with the project.

MR. BOB PETERS: But it's a matter of public record, is it, Mr. Bowen, that one (1) of the options considered by Manitoba Hydro was to part company with BBE and proceed in a different direction?

MR. DAVID BOWEN: Yes, that's what's shown on slide 57.

MR. BOB PETERS: The other option would be to reduce the scope of work for BBE and bring in some additional contractors to help?

MR. DAVID BOWEN: We -- we considered descoping, yes.

MR. BOB PETERS: And descoping for those of us who aren't all that familiar with the word really means, put a new contract together with BBE but also bring in somebody else to do some of the work that BBE wasn't given in the new contract?

MR. DAVID BOWEN: More -- more or less, it would -- it would change the scope of work they had and would bring in different parties to execute portions of that work.

(BRIEF PAUSE)

MR. BOB PETERS: Let's jumped to when Manitoba Hydro decided to continue the relationship with BBE as the general civil contractor, Mr. Bowen; that meant Manitoba Hydro had to, in essence, renegotiate with them to continue?

MS. HELGA VAN IDERSTINE: Excuse me, Mr. Peters, I just --

MR. BOB PETERS: I'm sorry.

MS. HELGA VAN IDERSTINE: -- wanted to have a quick chat with -- with Mr. Bowen. I -- I know he's concerned at this point to some of the questions are getting quite close to things that he'd be concerned about relating -- that affect the relationship with some of the parties and would otherwise be CSI so.

We want to be as open as we can in this process so that the public is aware of what's going on and response of -- it's getting too close.

MR. BOB PETERS: Since that, Ms. Van Iderstine, and I move to a new topic if -- if that permit -- but if I am encroaching and that sensitivity arises again, please, don't hesitate to -- to let us know.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: I wanted to turn, Mr. Bowen, to Manitoba Hydro having made the decision to continue with BBE as the general civil contractor; that meant that there had to be a new negotiation with that contractor; correct?

MR. DAVID BOWEN: Correct, based on the -- the challenge we had and -- and the problems that, yes, we need to negotiate a new path forward.

MR. BOB PETERS: And I'll put the question out and you'll tell me if I'm getting too close to the line, but under the original contract the cost overruns due to the productivity problems had a negative impact on BBE's profits?

MR. DAVID BOWEN: I'd like to discuss that tomorrow --

MR. BOB PETERS: All right.

MR. DAVID BOWEN: -- if I may.

DR. BYRON WILLIAMS: Mr. -- Mr. Chair, just -- Byron Williams for the Consumers Coalition. I'll just note that if one goes to the KPMG letter attached to Manitoba Hydro's rebuttal evidence, there's a fair bit of information in there and -- and certainly our client always is interested in as much information on the public domain as possible.

I'm not as confident as Manitoba Hydro that we are coming close to -- close to that line. This is important public information.

THE CHAIRPERSON: Thank you, Dr. Williams, and -- and I'm sure that in your cross-examination, if it's on the record already, you may go to it.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Bowen, in late 2016 or early 2017 both Hydro and BBE signed what is known as Amending Agreement Number 7?

MR. DAVID BOWEN: Yes, that occur -- occurred in early 2017.

MR. BOB PETERS: And essentially, that's the new general civil contract going forward and that's the one that's in place today?

MR. DAVID BOWEN: Correct, that agreement amended the existing original contract.

MR. BOB PETERS: And under this Amending Agreement 7, there was a recalibration of the productivity required from BBE and the profit to be allowed to BBE?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: And there was a new target price for the completed contract?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And there was a new profit amount determined that would be available to BBE?

MR. DAVID BOWEN: Correct.

MR. BOB PETERS: Can you indicate whether BBE would also receive overheads and general

administrative cost allowance?
MR. DAVID BOWEN: Yes, general administration, overhead applied.
MR. BOB PETERS: Would be fair for this panel to understand, Mr. Bowen, that the new contract with BBE looked a lot like the old contract?
MR. DAVID BOWEN: Well, certainly, the -- the technical scope and the scope of work was -- was mostly unchanged. The commercial points of it, though, there are some pretty substantive changes.
MR. BOB PETERS: And those are the points you're going to tell the Panel about tomorrow?
MR. DAVID BOWEN: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: All right. Are you able to tell the Board today, Mr. Bowen, that in addition to any contingency reserve in the Amending Agreement 7 whether there are management reserves?
MR. DAVID BOWEN: As I noted in my presentation, there were no management reserves contained in the control budget.
MR. BOB PETERS: Can you indicate why that's the case?

MR. DAVID BOWEN: I -- I tried to articulate that earlier. The -- the reason for -- management reserves are low probability/high-impact events and one (1) event could be if there was a major safety incident that, basically, stopped work in the powerhouse complex for months on end, which would have a direct impact on the scheduled date completion, of course, lots of costs.

At this point in the contract, in the project, we chose not to -- to choose these events to -- to put in the budget because of their large dollar value and -- and the low likelihood of occurrence.

MR. BOB PETERS: Keeping it at a high level, Mr. Bowen, we can fast-forward to the MGF services report in these proceedings, and there is an extract on page 43 of Board counsels' book of documents and MGF -- I'm sorry, I suggested it was a report, it's actually in response to an Information Request.

MGF indicates that the Amending Agreement Number 7 is not being performed at an acceptable level. And as an example, more money is being spent for less process -- progress and revised productivities in Amending Agreement Number 7 are not being met.

Do you see that?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: Is that factually accurate?

MR. DAVID BOWEN: In -- in my presentation today, we talked about the -- the quantity deficits for both concrete and earthworks. So if we go back to the -- remind everyone of that conversation is that, we saw improvements to concrete production and to earthworks, but we had a deficit of 20 percent in the concrete and 25 percent in the earthworks.

The -- the work on the concrete, the -- the costs are higher than the amending agreement right now, and certainly we've seen some cost growth in other areas of the contract. So, those are some challenges that we're actively working on with our general civil contract as we speak to -- to bring those costs back in line with -- and improve upon them based on what was signed in the amending agreement.

MR. BOB PETERS: And so with that answer, Mr. Bowen, you're acknowledging as said by MGF that revised productivities in Amending Agreement Number 7 are not being met; correct?

MR. DAVID BOWEN: I'm -- I'm

qualifying the answer. In earthworks this year, we -- we saw an improvement overall. In -- in concrete we did see an improvement. I would -- I would characterize that improvement as a 20 percent improvement overall but if you look at the person hours, the dollars per person, yes, it's cost more than the -- than the amending agreement, but there is a complexity factor to consider as well.

MR. BOB PETERS: All right, thank you. And to complete the Keeyask cost estimates that are on the public record, MGF on page 45 of Board counsels' book of documents indicates that the order of magnitude estimate range to complete Keeyask, according to MGF, is between 9.5 billion and 10.5 billion.

You see that, sir?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And Manitoba Hydro understands that the $9.5 billion number from MGF is if MGF -- is if Manitoba Hydro takes some mitigation steps that MGF has indicated are needed in the MGF report?

MR. DAVID BOWEN: The first thing I'm always concerned about, various consultants throwing out range of values. I think we've seen a history of that on the Keeyask project to date. We --we've -- we've provided -- Manitoba Hydro's provided our best estimate of where the project could end up. Certainly others can have other opinions and -- but it's -- it's -- it's challenging and dangerous to make opinions based on limited knowledge.

MR. BOB PETERS: I'll take that as a polite way of Manitoba Hydro disagreeing with MGF's view and you provided your written reasons in Manitoba Hydro's rebuttal, Mr. Bowen?

MR. DAVID CORMIE: Well, to be clear, the -- the P90 value for Manitoba Hydro's control budget was 9.6 billion which is in the range. We -- we did look at reserves with our budget and -- and certainly we're not disputing that we can -- the project has risks that could put us in this range. So I'm not disputing that fact, but I -- I don't -- we have difficulty understanding how MGF arrived at these numbers.

MR. BOB PETERS: All right, I have your point. Thank you. Now, you've already in your last few answers repeated what we heard in your presentation to the effect that more concrete was placed in 2017 than in 2016 and, likewise, more earthworks were completed in 2017 and 2016, correct?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: And you'll agree with me that -- and I think your answer may have contained the germ of the point I'm getting to -- is that just because more quantity of concrete and earth was placed in the prior years that doesn't mean Manitoba Hydro and BBE were more productive than in 2016; does it?

MR. DAVID BOWEN: To be clear, we saw a productivity improvement on the earthworks. The -- the earthworks is very easy to measure. For the concrete, the concrete work this year if we go back to the slides that Mr. Strongman showed of the work completed in 2016 compared to 2017. In 2016 we were metres off the ground. Whereas in 2017, we were tens of metres and lots of work was accessed by scaffolding. So it -- the work was higher, more -- more complex. The formwork we saw the draft to forms and we saw the top of the scroll case, all that formwork surround -- circular formwork compared to flat formwork.

So the complexity of the work, what I was trying to illustrate was the complexity of the work in 2017 was a fair bit more complex than in 2016. So overall, the productivity values, the dollar -- the person hours per unit to work, it did cost more, but when you weigh it with the complexity factor, there was certainly improvements that were made.

MR. BOB PETERS: Even with those improvements, Mr. Bowen, 2017 productivity for both concrete and earthworks were below the targets in the 2017 Amending Agreement Number 7?

MR. DAVID BOWEN: So I'll just -- I'll just correct the language for the -- for the record. The production targets which means the total volume of work completed were both less for concrete and earthworks and that was a 20 percent deficit for concrete and a 25 percent deficit for earthworks.

MR. BOB PETERS: From a productivity perspective, Mr. Bowen, was both the productivity for concrete and earthworks below target levels set in Amending Agreement Number 7?

MR. DAVID BOWEN: The earthworks improved and the concrete eroded based on the complexity factor I noted.

MR. BOB PETERS: And the complexity factor you note, and this is a non-engineering explanation, but you're telling the Panel that it was harder to pour the concrete in 2017 than it was in 2016?

MR. DAVID BOWEN: I'll try not to be

too much of an engineer. If you imagine each concrete placement, basically, you're putting up a wood box. You're putting in rebar. You're putting in a -- a water stop to prevent water from leaking through the dam. You're putting in a bunch of pipe, mechanical pipe. That whole cycle from starting with forming to actually placing the concrete in there and letting it harden, that's a whole cycle. So -- so, yes, that whole cycle was more challenging in 2017.

MR. BOB PETERS: Mr. Bowen, if productivity continued exactly going forward as it did in 2017 for both concrete and earthworks, does it mean that the MGF cost estimate is a possible result?

MR. DAVID BOWEN: We require a 10 percent improvement in our productivity for GCC and no major risk materialized to reach our control budget. If we saw a 0 percent increase, so just straight line, it would -- it would push us north of $9 billion and -- and would push us closer to the bottom of the MGF range.

MR. BOB PETERS: That 10 percent increase by the general civil contractor was for both concrete and earthworks?

MR. DAVID BOWEN: The -- the 10 percent improvement's required across the board. So I would characterize it as improving the productivity so the person hours per unit of work improving the production, so getting more volume of work, and improving the costs. So overall, the costs come down by 10 percent.

MR. BOB PETERS: And there's no management reserve for productivity in Amending Agreement Number 7, is there, Mr. Bowen?

MR. DAVID BOWEN: No, no, as I noted earlier, the -- there's no management reserve in our control budget and there is no management reserve in the amending agreement with the general civil contractor.

MR. BOB PETERS: So a lack of productivity drives up the cost just like it did when Manitoba Hydro had to go from the original BBE contract to the Amending Agreement Number 7?

MR. DAVID BOWEN: Certainly, the -- the productivity rate will dictate whether the costs goes up or down for -- for this work, yes.

And -- and as I noted earlier, we have a number of mitigation plans in place with BBE, our contractor, and Manitoba Hydro to improve upon those results and drive down the costs.

MR. BOB PETERS: Let's turn, if we

could, to discuss the types of contracts in a bit more detail. Starting on page 54 of Board counsels' book of documents, we have an extract from the MGF report. I don't know if it's a colloquialism or something, but it -- in construction time is money. In traditional fixed contracts time is the contractor's money and in cost reimbursable contracts, time is the owner's money.

Do you see that, Mr. Bowen?

MR. DAVID BOWEN: Yes.

MR. BOB PETERS: Have you heard that before?

MR. DAVID BOWEN: Yes, I've heard it from a few engineers in the past.

MR. BOB PETERS: Is it true?

MR. DAVID BOWEN: It's in there -- it's a very narrow view. Certainly at face value, yes, it's absolutely true. In the context it's presented, the -- we do not have a cost reimbursable contract. We have a target price contract and so I -- I think in the context it's presented that it's -- it's misleading.

MR. BOB PETERS: Okay, let's -- let's go there. In terms of which of those three (3) most closely aligns or which -- sorry, which of those two

(2), the fixed contract or the cost reimbursable aligns with Hydro's original contract with BBE. Most closely, it would be the cost reimbursable contract; would you accept that?

MR. DAVID BOWEN: I'd say it's somewhere in between --

MR. BOB PETERS: All right and what about --

MR. DAVID BOWEN: -- the fixed --

MR. BOB PETERS: -- the Amending Agreement Number 7, is that closer to a cost reimbursable contract --

MR. DAVID BOWEN: Yes --

MR. BOB PETERS: -- than a fixed contract?

MR. DAVID BOWEN: Pardon me, it's -- it's somewhere in between.

MR. BOB PETERS: Would you be more comfortable, Mr. Bowen, if Manitoba Hydro's contract was called a cost reimbursable contract with a target price?

MR. DAVID BOWEN: Yes, that's indeed what it's called.

MR. BOB PETERS: On page 55 of Board counsels' book of documents, there are some slides that were presented at one (1) of the meetings with Manitoba Hydro's Board of Directors.

So, Mr. Midford, if you saw it it was probably this February 14th version. Have you seen it before?

MR. LORNE MIDFORD: Yes.

MR. BOB PETERS: All right. So let's -- subject to anybody checking, and I'm not sure it matters, but this was a presentation made to the Manitoba Hydro Electric Board of Directors; correct?

MR. LORNE MIDFORD: That's my understanding.

MR. BOB PETERS: All right, did anybody on this panel present it to the Board of Directors? I'm seeing shaking heads so --

MR. LORNE MIDFORD: No.

MR. BOB PETERS: All right. I'd like to move quickly through it, but I want the panel, the witness panel, to explain to the Board Panel exactly how a cost reimbursable contract with a target price works. So we start on page 55.

And on this chart, the actual cost of work is on the bottom axis and what the contractor is paid is cont -- is identified on the vertical axis, correct?

MR. JEFF STRONGMAN: I'll attempt to answer your questions in this region.

MR. BOB PETERS: All right.

MR. JEFF STRONGMAN: However, having said that, I'm -- I'm not familiar with the references to these charts. But certainly I can explain the contract model.

MR. BOB PETERS: And that's -- that's really what I want to do is explain it with these documents, if I could, Mr. Strongman --

MR. JEFF STRONGMAN: Okay.

MR. BOB PETERS: -- and to the extent you can help. So on page 55, we start off, there's the initials TP or -- that stands for Target Price up at the top of the chart?

MR. JEFF STRONGMAN: Agree.

MR. BOB PETERS: And that's Manitoba Hydro's target price that would intercept the horizontal access at some dollar value, correct?

MR. JEFF STRONGMAN: Correct.

MR. BOB PETERS: And we knew that that dollar value was $6.5 billion when the first contract was -- was let.

MR. JEFF STRONGMAN: Just to be clear, the -- the project budget was 6.5 billion, but the contract value would have been considerably less than that, given it was a component of the overall project.

MR. BOB PETERS: All right, I perhaps didn't word the question properly.

What you're telling the Panel is the general civil contract is only a portion of the total $6.5 billion total price?

MR. JEFF STRONGMAN: That's right, in my earlier presentation, I think I said there was two hundred and thirty-nine (239) contracts awarded; of those, the general civil contract is the largest and it is the form of contract that we're currently discussing.

MR. BOB PETERS: All right, on page 6 -- 56 of Board counsels' book of documents, we progress along a time continuum here and we see that the contractor has been paid their actual cost of work, correct?

MR. JEFF STRONGMAN: Page 56 we're just presuming some hypothetical cost of work component?

MR. BOB PETERS: Yes, we are.

MR. JEFF STRONGMAN: Yep.

MR. BOB PETERS: And so you're agreeing that the contractor has been paid their cost of work?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: That's the actual cost that the contractor would charge to Manitoba Hydro, if this applied to Manitoba Hydro?

MR. JEFF STRONGMAN: Yes, this theoretical example appears to be so.

MR. BOB PETERS: It's not tied to a unit or a -- or a fixed price, it's based on what the actual cost is by the contractor?

MR. JEFF STRONGMAN: But the actual cost of the work that complies with the cost reimbursable requirements within the contract.

MR. BOB PETERS: What you're telling the Panel is there's a maximum amount this contractor's going to receive under a cost reimbursable contract with a target price. But until that -- that target price is met, the contractor is going to be paid their actual cost of doing work?

MR. JEFF STRONGMAN: That's right.

MR. BOB PETERS: So maybe let me try it this way and let's bring it back to Keeyask. We've heard of evid -- excuse me, we've heard evidence that the contractor was not meeting the productivity levels in the placement of concrete; correct, Mr. Strongman?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: Even though the contractor wasn't meeting those productivity levels, that means the contractor was actually taking longer to do what they were supposed to be doing?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And by the contractor taking longer to do work, the contractor was getting paid more because that was their actual cost of work?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: So even though the contractor was -- had a productivity target, they weren't meeting it, they were still getting paid for their actual cost of work?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: And on top of being paid for their actual cost of work, the contractor was also getting a separate cheque representing their profit?

MR. JEFF STRONGMAN: The provisions within the contract specify the general administrative and overhead expenses that are a potential markup on top of the cost, subject to limitations, as well as a profit percentage that would be a markup on top of the actual cost of the work, subject to a separate range of limitations.

MR. BOB PETERS: All right, and that's what this is showing on page 56 is that the actual cost to work being done is being reimbursed to the contractor and the contractor's getting on top of that some profit and what's not shown is the overheads and general administration costs?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: And so now on page 57, there is a continuing actual cost of work being done by the -- by the contractor and while the contractor is doing more work, they're still being paid the same as they were on the slide 56?

Mr. Strongman, that's your understanding?

MR. JEFF STRONGMAN: One moment please.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Mr. Peters, if -- if you don't mind, I'll take a crack at explaining the basics of the contract without making specific reference to the charts because I find them less than clear in terms of the questions that you're asking me.

I think I can give you the information that you're seeking if you don't mind. Okay.

MR. BOB PETERS: Let's try.

MR. JEFF STRONGMAN: In a cost reimbursable target price contract, Mr. Peters, was explaining that the contractor is reimbursed for costs incurred to do the work.

How the target price comes into play is the contractor's bid for all the different units of work and the quantities to be performed times the prices that he submitted as his estimate to do the work creates an extension of all the line items, fifty (50) or sixty (60) odd different line items times the prices that he's quoted and that becomes the target price.

So if we just assigned a number to it, let's say, it's $100. Through the execution of the work, the contractors entering monthly invoices of one (1) or two (2) or three dollars ($3) a month all the time performing work and being reimbursed for those costs.

We're constantly comparing the unit costs that the contractor's engaging in and comparing those to what the bid price was to understand long before we're at the end of the job whether or not there is a positive variance happening, a negative variance or they're on track.

So, if the contractor's work is happening and it's costing more expensive than what their bid price is, we are obligated to reimburse them according to the terms of the contract but we're very quickly tracking the fact that we're seeing a variance take place and should things continue to the end, there would be a projection of an overrun and, therefore, the provisions of the contract would indicate that the contractor's expected profit would be eroded by that overrun.

Our contract says that for every dollar overrun we experience the contractor's cost beyond the target price, their profit would be eroded by eighty cents ($0.80) on the dollar. Conversely, if they proceed to spend and incur less cost to complete the work, and they end up saving us money, then Manitoba Hydro pays less for the work to be accomplished, and we also share in the savings with the contractor. So we give them, in effect, an incentive to reduce cost and -- and perform better than planned.

I think what Mr. Peters is driving at is through the course of execution of the work, the contractor is reimbursed for the cost. They also have their markup for general admin, and overhead, and profit, and that all works out fine unless you start seeing a variance. And then you account for that variance by either triggering the general admin and overhead provisions that cap, or a profit erosion looks to be probable, and then you start modifying how the profit would be paid. And there's a reconciliation at the end of the job on the assumption that those are all close.

In our case, through 2016, the variance between plan and actual was so significant, we didn't need to wait to the end of the job to know that the variance was causing a problem on simply executing the work. And that triggered many of the recovery plans, and development and implementation of the recovery, and -- and negotiation of the contract terms that we've been describing today.

How was that, Mr. Peters?

MR. BOB PETERS: That was, I'll say, excellent and I appreciate that. So to help the Board understand your -- your latter comments on Tab 60 of the Board counsel -- or page 60 of Board counsel book of documents. And if this is -- this is an example where there's a cost underrun, and if you're not comfortable, Mr. Strongman, answering it, I don't want you to go there, but in an example of a cost underrun between the actual cost of work done and the target price, there's a sharing of the surplus monies, correct?

MR. JEFF STRONGMAN: Yes. If we use the hundred dollar job cost, that I threw out there, if the contractor's cost of doing the work is only ninety (90) at the finish and they, therefore, save ten (10), Manitoba Hydro would keep eight (8) of that ten (10), and give the contractor two (2) of it as an incentive for beating the target price on the work.

MR. BOB PETERS: So let's take that, Mr. Strongman, and let's go to page 61, in an example where there's a cost overrun. And how does that work under this cost reimbursable arrangement with the target price?

MR. JEFF STRONGMAN: Okay. So if we had the same hundred dollar target price, but this time, the actual cost of the work exceeds, and it costs us a hundred and ten (110), Manitoba Hydro has paid the hundred and ten (110) as an incurring cost to do the work, but the contractor's profit will be eroded at a rate of 80 percent of that ten dollar ($10) overrun, such that Manitoba Hydro is effectively clawing back cost of work payments that have already been made but to reconcile on the profit to ensure that the terms of the contract relating to profit are fulfilled. That would probably be done at the end of the project, but we're still talking in a hypothetical.

MR. BOB PETERS: All right. And while the contractor would bear the pain of that 80 percent of the cost overrun, Manitoba Hydro would bear the other 20 percent of that pain?

MR. JEFF STRONGMAN: That's right. So when we paid out a hundred and ten (110) to get the work done, we would then recover eight (8) out of the ten dollar ($10) overrun by removing that from the contractor's profit entitlement. We would still be out a couple dollars beyond the hundred dollar project budget, because that was our 20 percent that we own from the contract term.

MR. BOB PETERS: All right. And the example I -- I want to turn to is on page 62. And in the situation in which the actual cost of work exceeds the target price and also exceeds the profit that was to be paid to the contractor, what happens in that instance?

MR. JEFF STRONGMAN: Okay. Well, this is the scenario that most closely relates to Keeyask in 2016 prior to amending agreement number 7. However, just to qualify that comment, we were basing on a projection because we were nowhere near the end of the job, but the job was projecting to be in the situation that is described here on page 62, where actual cost of the work exceeded the target price as well as the limitation of liability from the contractor's profit.

So in other words, the job costs were going to be so far beyond the plan that even after clawing back the contractor's profit, we would still be incurring costs that we had no recourse for.

MR. BOB PETERS: Could you repeat that last -- last response? You'd be clawing back --

MR. JEFF STRONGMAN: We would be recovering a portion of the costs from the contractor's exposure to liability by reducing their profit, but -- and once that profit was fully recovered, the contractor's limit of liability is no more. We have no recourse to penalize or effectively recover any costs. We were on the -- on the hook for the 100 percent of the costs beyond the contractor's profit. It's a scenario that clearly, we did not envision and see as a -- a likely outcome. However, we found ourselves there.

MR. BOB PETERS: Mr. Strongman, we saw in Manitoba Hydro's slides that contracts for things like -- I think it was the -- the turbines and generators were a fixed-price contract. Are you aware of that?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: But even if there's a fixed-price contract, that may end up costing Manitoba Hydro more money if the project is delayed, as I understood you when we were talking about the waterfall?

MR. JEFF STRONGMAN: Right. So the form of contract does not necessarily insulate you from changed conditions or substantial deviations from plan.

MR. BOB PETERS: That wasn't my question. My question was: You're now going to have to pay somebody to -- with whom you've entered into a fixed-price contract more than the fixed-price contract because the general civil contractor caused a delay.

MR. JEFF STRONGMAN: Pardon me.

MR. BOB PETERS: Do you understand my question?

MR. JEFF STRONGMAN: Okay. Sorry. I

understand your question now.

MR. BOB PETERS: All right. And in that instance, Mr. Strongman, who is responsible for paying that additional cost under the fixed-price arrangement?

MR. JEFF STRONGMAN: The owner would be responsible.

MR. BOB PETERS: That doesn't get charged back to the general civil contractor who caused the delay that caused the fixed-price contract to escalate?

MR. JEFF STRONGMAN: Not typically. That would typically be an interface that the owner retains responsibility for. So earlier, Dave talked about the knock-on effect when a -- the general civil schedule has affected and impacted other work subsequent to the concrete and earthwork structures being completed.

The service contracts that are a req -- a requirement for our -- our construction site, providing security, catering, et cetera, they're all function of time. So when the schedule takes six (6) months longer than expected, all of those contracts' duration are extended by six (6) months, and we would then incur costs equivalent to six (6) months' extension.

If we had a -- a fixed-price contract like a gates, guides, and hoist installation, if that would be impacted by the work of a previous contractor, we would then need to work out some form of resolution with the impact.

MR. BOB PETERS: Mr. Strongman, on page 63 of Board counsel's book of documents is an extract from the MGF project services report. This is a portion that was, I believe, authored by Klohn Crippen Berger -- Berger? Do you have that, sir?

MR. JEFF STRONGMAN: I have page 63 in front of me.

MR. BOB PETERS: And -- well, you know them as KCB, do you, as --

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: And that's the company that constructs Hydro dams?

MR. JEFF STRONGMAN: Yeah. I don't have much direct experience with them, but I understand them to have worked a fair amount of Western Canada.

MR. BOB PETERS: On Hydro generating stations?

MR. JEFF STRONGMAN: Yeah.

MR. BOB PETERS: And in their review of the 2014 contract, they too called it a cost-reimbursable model, and your -- you'd like that to be corrected to say cost-reimbursable with a target price?

MR. JEFF STRONGMAN: Yes, I believe that's how we addressed our rebuttal.

MR. BOB PETERS: And in this particular review, KCB was trying to understand how the project could be as far over budget, because the variances and quantities didn't appear that high, and the initial unit prices were, in fact, low.

Do you see their statements?

MR. JEFF STRONGMAN: I see them highlighted here, yes.

MR. BOB PETERS: And you've already told this panel that the variances and quantities was not that high, correct?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: But on the next page, 64, KCB focuses on a section of the contract where it seems that actual costs that are paid to the contractor by Manitoba Hydro is not qualified by the quantities times the unit prices. Do you see that?

MR. JEFF STRONGMAN: I do.

MR. BOB PETERS: And so when KCB speaks of the actual costs, you've already acknowledged that Manitoba Hydro had to pay BBE the actual costs for the work that they actually did?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And that actual cost was not tied to any specific quantity times a unit price?

MR. JEFF STRONGMAN: Save for the explanation I -- that I gave to how the cost of the work compares to the target price and the profit component.

(BRIEF PAUSE)

MR. BOB PETERS: KCB, then, in the middle of page 64, focuses in on the all actual indirect and direct costs incurred by the contractor or BBE in performing the work are reimbursed to the contractor, correct?

MR. JEFF STRONGMAN: That is definitely what it says.

MR. BOB PETERS: And they're quoting from the contract that Manitoba Hydro has with BBE?

MR. JEFF STRONGMAN: I presume so, but

I haven't confirmed.

MR. BOB PETERS: All right. Will you take that subject to check?

MR. JEFF STRONGMAN: Sure.

MR. BOB PETERS: All right. It -- and then want to take you to below the quote of that section. Their comment from KCB that there's no connection between actual costs and the quantities and unit prices in the bill of quantities, that's accurate, is it not?

MR. JEFF STRONGMAN: Well, I would say the same response as I did a moment ago. I -- I don't feel it's a hundred percent accurate, because in a target price contract, the linkage is through the comparison of actual cost to the target price and then the influence on the contractor's profit and GA & O as -- as an outcome. So I -- I disagree with that. It demonstrates to me that KCB did not fully understand the target price component of the contract.

MR. BOB PETERS: So long as the general civil contractor is below or underneath the target price, this statement would then be actual -- would be factual, correct?

MR. JEFF STRONGMAN: Well, not necessarily just below, below or above, within the range of influence from the provisions relating to the profit, that 80 percent, plus or minus.

MR. BOB PETERS: Once the target price has been exceeded, and the profit margin has disappeared for the general civil contractor --

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: -- is there any incentive for BBB -- BBE to actually perform the work?

MR. JEFF STRONGMAN: No. The incentive perversably (sic) flips. In other words, there -- there appears to be more incentive to drag it out as opposed to finishing, subject to limitations on the GA & O cap.

MR. BOB PETERS: And that perverse incentive is because by dragging it out, BBE would be paid their actual costs of construction?

MR. JEFF STRONGMAN: Correct.

MR. BOB PETERS: They wouldn't be getting additional profit at that point in time?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: But they would be getting paid their actual costs of their workers?

MR. JEFF STRONGMAN: Yes. They would also get an -- a GA & O markup until that ran out, as well.

MR. BOB PETERS: Right, and you haven't put on the public record when that happens, but that would be a factor that would determine at what point they're totally -- have little incentive to perform the work?

MR. JEFF STRONGMAN: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Midford, I don't know if you can answer this, but did Manitoba Hydro have a preference for a unit price contract for Keeyask rather than the cost reimbursable contract with the target price?

MR. LORNE MIDFORD: The original contract or the amending contract?

MR. BOB PETERS: Let's start with the original contract.

MR. LORNE MIDFORD: I'm -- I think that both Mr. Bowen and -- and Mr. Strongman provided kind of the environment when that contract was awarded, and based on the market conditions at the time, I think they've stated that there was -- and based on their experience in the award of Wuskwatim, that the unit-based approach wasn't an approach that they thought would be successful.

MR. BOB PETERS: In that answer, Mr. Midford, are you telling this panel that Manitoba Hydro did not put out a unit price contract tender for Keeyask?

MR. LORNE MIDFORD: Yes, that's my understanding.

MR. BOB PETERS: Did Manitoba Hydro put out a tender for Keeyask other than a cost reimbursable contract with a target price?

MR. LORNE MIDFORD: No.

MR. BOB PETERS: Now, in Manitoba Hydro's rebuttal, Mr. Midford, Mr. Bowen, and Mr. Strongman, I believe pages 6 and 7 of 58, there's an explanation that Manitoba Hydro did try to put out -- or did, in fact, put out a unit price contract when Wuskwatim was going out to tender, correct?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And that yielded, Mr. Strongman, one (1) and only one (1) bidder that came back with a proposal?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: Manitoba Hydro wasn't obligated to accept any bid, and did not accept that one (1) bid, did they?

MR. JEFF STRONGMAN: That's right.

MR. BOB PETERS: Now, in the rebuttal, there's an indication that the unit price bid would have nearly doubled the engineer's estimate. Do you recall that being in your rebuttal?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: At what stage was the engineer's estimate back in, I suppose it was 2001 or 2002, as the Wuskwatim review was filed before the Clean Environment Commission sometime in 2003? Do you know?

MR. JEFF STRONGMAN: No, that predates my involvement by about a decade. Let me check.

MR. BOB PETERS: I indicated earlier that Mr. Williams's younger twin brother would be able to answer that, but...

(BRIEF PAUSE)

MR. BOB PETERS: Were you able to determine whether or not the engineer's estimate was at a refined stage, or was it just a preliminary calculation?

MR. JEFF STRONGMAN: I have not been able to definitively --

MR. BOB PETERS: All right.

MR. JEFF STRONGMAN: -- provide that, no.

MR. BOB PETERS: Can you tell this Board how the unit price bid for the general civil contract on Wuskwatim compared to the actual final price paid by Hydro on the general civil contract?

MR. JEFF STRONGMAN: Yes. I can say that the -- the bid provided values considerably more than the final cost outcome.

MR. BOB PETERS: So for the general civil contractor on Wuskwatim, had Manitoba Hydro proceeded on a unit price basis, they would have paid more than they actually did under a cost reimbursable with a target price contract?

MR. JEFF STRONGMAN: Yes, that's correct.

MR. BOB PETERS: And are you able to say how much more?

MR. JEFF STRONGMAN: I can't with certainty. My recollection is between 50 and 100 million more.

MR. BOB PETERS: So when we go back to -- I hate to do this, but back to page 5 of Board counsel's book of documents, and we look for

Wuskwatim, and let's just look at the very top line on this chart, because that's the Wuskwatim generating station, correct, not including the transmission?

MR. JEFF STRONGMAN: Okay. Page 5?

MR. BOB PETERS: Yes.

MR. JEFF STRONGMAN: Could you repeat the question?

MR. BOB PETERS: I'm suggesting that to -- to understand your last -- or second last answer to me, we have to look at that Wuskwatim GS line, or generating station line at the top of the chart on page 5 of Board counsel's book of documents?

MR. JEFF STRONGMAN: Okay.

MR. BOB PETERS: And by the time this project had gone to the Clean Environment Commission in 2003, Manitoba Hydro had already determined, did it, that it was not going to go out on a unit price contract?

MR. JEFF STRONGMAN: So I joined the project in 2009, approximately two (2) weeks before the first concrete by the general civil contract, O-N-E, on Wuskwatim. And the history prior to 2009 predates me, but I had done some checking in anticipation of this question, and I found that Manitoba Hydro tendered for the general civil contract in 2006, and received the one (1) bid for unit price in early 2007, determined that bid to be cost prohibitive and did not proceed. Then we went to a second procurement process through 2008 for the general civil contract. We had four (4) prequalified vendors who submitted proposals, and ultimately we selected one (1) to proceed.

MR. BOB PETERS: All right. Let's go back, then, Mr. Strongman, to 2006. That's the year in which the unit price contract was put -- a tender was put out and one (1) party responded, correct?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And that response was considered unacceptable because it was nearly double the engineering estimate for what the general civil contractor should have been asking for?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And so of that $1.1 billion, are you able to indicate the approximate percentage of that that would have been related to the general civil contractor, or is that something that can't be put on the public record?

MR. JEFF STRONGMAN: I would just be guessing. I -- I can't recall the exact engineer's estimate of the proponent --

MR. BOB PETERS: All right, but --

MR. JEFF STRONGMAN: -- or the percentage.

MR. BOB PETERS: -- on the generating station, the general civil contract was the largest contract for that project?

MR. JEFF STRONGMAN: It might be a third (1/3), 40 percent-ish?

MR. BOB PETERS: Okay. So if we say it's $300 million, are you with me on that?

MR. JEFF STRONGMAN: As a ballpark, yes.

MR. BOB PETERS: As a ballpark. If -- even if that bid had come back and was an extra hundred million dollars, it would have meant that you would have paid $400 million for the general civil contractor, correct?

MR. JEFF STRONGMAN: Are you talking about a hundred million worth of change conditions and executing the work?

MR. BOB PETERS: I was using the hundred million that you gave me about five (5) minutes ago.

MR. JEFF STRONGMAN: Okay. Well, we should also account for the change conditions in executing the work if we're going to take the theoretical path of proceeding with a lump sum contractor or a unit price contract right out of the gates.

MR. BOB PETERS: Okay, but let's -- let's stick with this unit price bid. Would it not be correct for this panel to look at the cost in 2006 of $1.1 billion and say, Even if it was an extra hundred million dollars, that's still coming in considerably lower than what it otherwise would have cost?

MR. JEFF STRONGMAN: Okay. Let me back up, then. So in the 2006 time frame, where the project budget was one point one (1.1) our engineer's estimate would've been a third (1/3), so we would have expected roughly a general civil contract value of in the neighbourhood of three hundred (300). And as the procurement process evolved and only one (1) bid was received, we would have considered that noncompetitive. But the value for that one (1) bid was exceedingly expensive, and by that, I mean close to double, so we would not have chosen to proceed.

Had we proceeded, we would have then made an award for a contract somewhere between 5 and 600 million, and through the execution of the work, we would have had to account for change conditions, and that would have increased the price through the three (3) to four (4) year construction phase.

(BRIEF PAUSE)

MR. BOB PETERS: And so, cut to the bottom line, it -- it came in at 1.4 billion. What would it have been under the hypothetical, had you accepted the unit price with those change conditions?

MR. JEFF STRONGMAN: So we finished the project just under 400 million with the general civil contract. I think three ninety-six (396) is the number that comes to mind, but I'd -- I'd have to confirm that.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: We're trying to compare two (2) scenarios where one (1) is actual and the other is a hypothetical. So to the degree that we can, we're trying to make them comparable where change conditions may or may not affect the execution.

MR. BOB PETERS: And that's exactly correct, Mr. Strongman, and I have your -- I have your point, and --

MR. JEFF STRONGMAN: Okay.

MR. BOB PETERS: -- I think you've helped us understand that I may have misunderstood a -- a previous answer of yours that led to that clarification. So thank you.

MR. JEFF STRONGMAN: Okay.

MR. BOB PETERS: Back to Keeyask, is Manitoba Hydro able to indicate to this Board whether BBE has been paid for general, administration, and overheads in 2016?

MR. JEFF STRONGMAN: Are you referring to the period of time prior to amending agreement number 7?

MR. BOB PETERS: I am.

MR. JEFF STRONGMAN: Yes, GA & O would have been paid.

MR. BOB PETERS: It's not clawed back?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: Was it paid prior to the renegotiation of amending agreement 7?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: Can you indicate on the public record whether BBE has been paid any amount for profit on the 2014 original contract?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: You can, and yes, they have?

MR. JEFF STRONGMAN: That's correct. Both.

MR. BOB PETERS: Does the fact that BBE received profit on the original contract indicate that Manitoba Hydro took remediation steps before the contract was in a -- an -- a cost overrun position?

MR. JEFF STRONGMAN: Let me just confer with someone who has the details.

MR. BOB PETERS: Thank you.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: I'm prepared to answer.

MR. BOB PETERS: Thank you. I was asking whether BBE was paid any amount for profit on the original 2014 contract?

MR. JEFF STRONGMAN: Yes. So through 2014, '15, and most of '16, the profit markup would have been included in the contractor's monthly draw. Towards the end of the year, when Manitoba Hydro recognized the need for implementing the recovery plan, the profit payment was stopped, and further than just stopping it, a clawback took place in advance of the end of the year. I believe it was November 2016. So the profit that was viewed as having ove -- been overpaid was reconciled with one (1) of the monthly draws sub -- subsequent to October 2016.

(BRIEF PAUSE)

MR. BOB PETERS: So, Mr. Strongman, you've been good at helping this panel navigate some hypothetical questions, but if we go forward from today from amending agreement number 7, and perchance if the target price in that document is exceeded, and again, there is no more profit for BBE to earn, does Manitoba Hydro have a -- a plan to renegotiate a further amending agreement with a new target price?

MR. JEFF STRONGMAN: So no. The first question is no, we don't have a -- a plan to renegotiate another amendment, but a more fulsome answer is the possibility of a repeat of what has already taken place was in our minds during the negotiations of the amending agreement number 7, and we attempted to narrow the window of possibility for that, having come to light. We are prepared to talk a little bit more about those details as the provisions that were negotiated in-camera tomorrow.

(BRIEF PAUSE)

MR. BOB PETERS: Do I take from that answer -- and thank you, Mr. Strongman -- that Manitoba Hydro is, instead of negotiating a -- a revised agreement on top of the amending agreement number 7, is prepared to expend up to the P90 number under the current arrangement?

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Would you clarify the question?

MR. BOB PETERS: Well, certainly. What -- there have been the different cost estimates put on the record of these proceedings, and you've already seen the one that MGF project services has put on the record, and -- and what I'm asking is, rather than renegotiate a revision to amending agreement number 7, should this Board take Manitoba Hydro's strategy be -- to be to continue it through recognizing that the P90 number is -- is something Manitoba Hydro is prepared to pay rather than restructure the agreement yet again?

MR. JEFF STRONGMAN: One (1) moment, please.

MR. BOB PETERS: Certainly.

(BRIEF PAUSE)

MR. JEFF STRONGMAN: Manitoba Hydro is not intending on renegotiating another amending agreement.

(BRIEF PAUSE)

MR. BOB PETERS: Thank you. I'm going to turn to a new area, unless the panel wants a short recess at this time. And I'll keep going.

I want to turn ahead to page 114 on Board counsel's sixth book of document -- number 6 book of documents. This relates to a -- a matter, Mr. Strongman, you and Board member McKay were discussing, and it also talks about breakdown of the -- the total number of hires.

And on page 114, Mr. Strongman, this is the information Manitoba Hydro has with respect to the Keeyask project, correct?

MR. JEFF STRONGMAN: The numbers look correct, yes.

MR. BOB PETERS: And when Manitoba Hydro says, as they do on page 114 of Board counsel's book of documents, that there's been a total of thirteen thousand one hundred and sixty-five (13,165) hires, that doesn't mean there's been thirteen thousand one hundred and sixty-five (13,165) different people involved, does it?

MR. JEFF STRONGMAN: That's -- no, you're right. It doesn't.

MR. BOB PETERS: And does that imply, then, that one (1) person could be hired multiple times?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And on the Keeyask project, I suppose the chart at the bottom of the page might be better than what I can see on the pie charts at the top. What you were telling the Board before was of the total hires, Manitoba Hydro has the data to determine if that individual was hired and it was a member of one (1) of the KCN partners, correct?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: And -- or some other Indigenous peoples rather than KCN, correct?

MR. JEFF STRONGMAN: Yes.

MR. BOB PETERS: And is that done on the basis of the self-declaring, or is there a -- a questionnaire that's provided, or how -- how is that determined?

MR. JEFF STRONGMAN: We have a contractor employment database that relies on information provided to Manitoba Hydro from the contractors executing the work, where on a monthly basis, they provide reports on who is on their payroll and various other pieces of data.

MR. BOB PETERS: All right. Can we go to the -- the pie chart at the top of page 114, please. Scroll back up to the top of the page. Please scroll back up to the top of the page.

And of these hires, the database from the human resource personnel are able to determine how many of the hires come from Northern Manitoba and how many come from other parts of Manitoba?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: And for the Northern Manitoba, again, this is where the data has been broken down specifically for KCN members and for Northern Manitobans that are non-KCN members, but other Indigenous peoples?

MR. JEFF STRONGMAN: That's correct.

MR. BOB PETERS: The same information I think is on page 112. We might as well do it right now, Mr. Bowen, dealing with Bipole III, although Mr. Mr. Fogg might want to weigh in here as well.

Sir, again, on Bipole three, the twelve thousand three hundred and fifty-two (12,352) hires on the project do not represent individual people. It could be the same person hired more than once?

MR. ALISTAIR FOGG: That's correct. It could be a rehire.

MR. BOB PETERS: Can you give an example as to why a person would be hired more than once on the -- on a -- on a project?

MR. ALISTAIR FOGG: There are a couple situations where that could occur. The best example I could think of is a person would be rehired if they were working for one (1) contractor on a phase of work, that work was completed, they applied for a position with the contractor doing the subsequent phase of work, so they'd be rehired to the project with that other contractor.

MR. BOB PETERS: And the same breakdown in terms of the hires for Bipole III is provided as it was for Keeyask, Mr. Fogg?

MR. ALISTAIR FOGG: Correct.

(BRIEF PAUSE)

MR. BOB PETERS: In someone's presentation today, there was mention that the hiring was done as a result of the Burntwood Nelson agreement, correct?

(BRIEF PAUSE)

MR. DAVID BOWEN: Yes, the -- the Bursment -- Burntwood Nelson Agreement applies to both Keeyask and the Keewatinohk converter station, and the Burntwood Nelson agreement is effectively the -- what we call the project labour agreement for -- for the work, and all craft labour that contractors use on both those project sites, there's hiring preferences within the -- the BNA that they need to follow.

MR. BOB PETERS: That BNA, or Burntwood Nelson agreement that you're referring to doesn't apply to Bipole III, does it?

MR. ALISTAIR FOGG: To clarify, that applies to the Keewatinohk converter station as part of Bipole III -- the Bipole III transmission line is under the transmission line labour agreement, and then the Riel converter station does not have a labour agreement.

MR. BOB PETERS: Did the Board understand your evidence correctly, if the -- understood that the wages in the Burntwood Nelson agreement are above the market rates in Manitoba?

MR. DAVID BOWEN: For -- for Keeyask, the wages in the Burntwood Nelson agreement generally piggyback the wages of the collective -- the CLRA in Southern Manitoba. Early on in -- for the Keeyask project, in the -- towards the end of the 2014 year, we did a analysis of wages for remote projects across the country, and what we found is that the wage rates for -- in the BNA were amongst the lowest in the country, and the that's when I mentioned that we -- we provided a -- an increase. I believe the increase was about 13 percent, and it's -- it's only earned if -- if the person continues employment for a -- and renewed quarterly, so that's -- that's what I was referring to.

MR. BOB PETERS: Can you indicate, Mr. Bowen, whether the Burntwood Nelson agreement has contributed to the cost overruns on Keeyask?

MR. DAVID BOWEN: Certainly, I'd be

willing to explore this in farther detail tomorrow, but labour is a -- a major cost for the Keeyask project, and -- and there -- there have been some challenges to date.

MR. BOB PETERS: I'm going to turn to some questions on the Bipole III, and Mr. Penner, I don't have a direct line of sight, which you don't have to complain about, but if -- if you're comfortable there, or else I could ask that --

MS. HELGA VAN IDERSTINE: If you've stopped asking questions of Mr. Strongman, he can slip into the back row and we can bring him --

MR. BOB PETERS: No, I liked his answers. He -- he gives good answers, Ms. Van Iderstine, maybe he should -- well, he can -- he can slip back for a minute. I'm going to turn to the Bipole, and then hopefully move into the MMTP, and maybe touch a couple of Mr. Cormie's as well.

(BRIEF PAUSE)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Fogg and Mr. Penner, I want to talk about Bipole III, and I want you to appreciate that this is a project that hasn't been before the Public Utilities Board for a Needs for and Alternative review. Is that your understanding?

MR. ALISTAIR FOGG: Yes, that's my understanding.

MR. BOB PETERS: Is it also your understanding, Mr. Fogg, that the in the beginning, Bipole III was to bring down power from Northern Manitoba related to what no doubt Mr. Cormie had a hand in, which was selling energy from Conawapa to Ontario Hydro?

MR. ALISTAIR FOGG: I'm somewhat aware, probably not as much as Mr. Cormie, of some of the history of -- of that --

MR. BOB PETERS: And he's certainly welcome to assist in any way he can.

And Mr. Penner, you were probably an engineer in training way back then, but the initial routing for the Bipole was to come to -- on the east side of Lake Winnipeg? Do you recall that?

MR. GLENN PENNER: Yes, yes, I do.

MR. BOB PETERS: And when the Ontario sale didn't continue, Conawapa didn't continue, and then Bipole III, at that point in time, didn't continue either, did it?

MR. GLENN PENNER: That is my

understanding.

MR. BOB PETERS: All right. And the while we think one (1) of your slides today was misdated, but in approximately September of 1996, there was a inclement weather, or a wind event, I think was the word used, that affected the Bipoles I and II, correct?

MR. GLENN PENNER: Yes, that's correct. The slide said 1997, and -- and my recollection was nine -- September 5th, 1996.

MR. BOB PETERS: All right. So we'll blame the person who prepared the slide. The purpose of the Bipole III is to provide redundant transmission line to mitigate the risks of the outages, correct, outages on Bipoles I and II?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And way back when, and on page 5 of Exhibit 42-6, Board counsel's book of documents, I think the earliest indication here on this chart was Bipole III, under the capital expenditure forecast in 2003, was -- was penciled in at $360 million on an East side routing. Was that your understanding?

MR. ALISTAIR FOGG: Yes, that --

that's correct. And -- and just to clarify, it was a Bipole III East side routing, and did not include any converter stations at that point in time.

MR. BOB PETERS: And -- and that's an interesting comment, Mr. Fogg, because would Bipole III need converter stations regardless of whether there was additional generation in Northern Manitoba?

MR. ALISTAIR FOGG: I think that the key aspect of that question relates to the single terminus point at the Dorsey converter station, and without -- Bipole III would still require the Riel converter station to truly provide the redundancy that we're -- we're seeking to provide the reliability.

MR. BOB PETERS: Well, the redundancy is that -- Dorsey is the redundancy for Riel, and Riel is the done -- redundancy for Dorsey. Would you understand it that way?

MR. ALISTAIR FOGG: I guess I would explain it as Riel provides a -- a second point -- a separate point, or terminus point for a Bipole III line. So essentially, yes.

MR. BOB PETERS: So when I asked was a converter station needed regardless of the routing of the Bipole, and regardless of whether there's a new generating station in Northern Manitoba, your answer is, It has to end at a converter station somewhere?

MR. ALISTAIR FOGG: That's correct. It -- as an HVDC transmission line, it would need to end at a converter station.

MR. BOB PETERS: And I'm sure technically, it was possible for it to terminate at Dorsey, but Manitoba Hydro made a decision that rather than put, I think your words are, All their eggs in one (1) basket, you were going to move over and build the Riel converter station on the other side of the city?

MR. ALISTAIR FOGG: I believe to terminate at Dorsey still would have required additional infrastructure to accommodate Bipole III. However, you're correct in saying that from a reliability perspective, the decision would be to build Riel and the second terminus point.

MR. BOB PETERS: All right. And on that page 5 that's in front of us, we see that in that the capital expenditure forecast in 2005, the Bipole has about a 1.8 or $1.9 billion placeholder, at least, correct?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And at this point in time, Mr. Fogg, it includes a Northern and a Southern converter station, correct?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And at this point in time, it also includes a Western Manitoba routing as opposed to an Eastern Manitoba routing?

MR. ALISTAIR FOGG: I believe it -- this estimate does include a -- a Western routing, however, I -- I would believe it would be contexted as a -- as a placeholder value, as it has not been significantly analyzed in terms of the costs associated with that routing. This would have been an initial point of changing from an East side to a West side, and an initial value would have been put into the estimate before me -- more detailed costs could be assessed.

MR. BOB PETERS: What you're telling the panel is Manitoba Hydro's engineers were -- were doing planning as if it was going to be an East side routing, but they also came up with a placeholder if it was going to be a West side routing?

MR. ALISTAIR FOGG: I think what -- just to clarify what I'm saying is that Manitoba Hydro's engineers would be planning an East side Bipole III but had been asked to look at alternatives to that, and that -- at that point in time, in 2005, it would have looked at a placeholder cost of what a West -- West side Bipole III would look like.

MR. BOB PETERS: And if we go back to page 124 of Board counsel's book of documents...

(BRIEF PAUSE)

MR. BOB PETERS: Let's make that page 130. That's the end of a letter that Manitoba Hydro's Board of Directors received from the minister responsible for Manitoba Hydro, on or about September 20th of 2007, Mr. Fogg?

MR. ALISTAIR FOGG: Yes, that's correct.

MR. BOB PETERS: And the essence of that was that there was a policy decision by the Manitoba government that Bipole III should be rooted on the west side of the province, correct?

MR. ALISTAIR FOGG: My understanding would be a decision requesting alternatives to an east side Bipole III line be examined.

MR. BOB PETERS: And so those alternatives could have been the west side of the province or they could have been through the Interlake corridor?

MR. ALISTAIR FOGG: The alternatives could been a west side line or other alternatives for fal -- to provide the anticipated reliability, be it gas generation or other options such as that.

MR. BOB PETERS: So did Manitoba Hydro pursue a natural gas generator in southern Manitoba?

MR. ALISTAIR FOGG: The specific analys -- economic analysis of that would have been before my involvement on the project. But my understanding is those options were considered along with a western rooted Bipole III, and it was found that the western rooted Bipole III remained the most economical option to provide the required reliability improvements.

MR. BOB PETERS: And so while the provincial government was saying, in essence, don't use an eastern or east side of Lake Winnipeg routing, find an alternative routing, or alternative to even the Bipole III.

Manitoba Hydro determined that the best option was a Bipole III, but routed on the west side of the province?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And we see on page 131 a sketchy little map of the province that shows an east side routing or a west side route, as well as in Interlake corridor route, correct?

MR. ALISTAIR FOGG: That's what it shows, that's correct.

MR. BOB PETERS: And at this point in time -- this, Mr. Fogg, I should've identified was -- I believe it was -- it was in the Boston Consulting Group report, although the source of it indicates, in the bottom left-hand corner, at Teshmont, 2006?

MR. ALISTAIR FOGG: That appears to be what it states, yeah.

MR. BOB PETERS: And you're familiar with Teshmont being an engineering firm in the city?

MR. ALISTAIR FOGG: Yes, I am.

MR. BOB PETERS: As a result of the west side routing, it appears that the physical distance is longer. And I know you put on the record this morning the exact distance, but it's clear on this map that Bipole III on the east was 855 kilometres, and the Bipole III on the west side would be 1,341 kilometres, correct?

MR. ALISTAIR FOGG: Yes, I believe the graph says 885 kilometres for the -- the eastside, and then 1,341 kilometres for the west.

MR. BOB PETERS: Thank you, if I

misspoke, for correcting me. And I believe, but I don't have the number handy, it was within a few kilometres, the actual length, correct?

MR. ALISTAIR FOGG: Sorry, for the -- the current west side line?

MR. BOB PETERS: Yeah --

MR. ALISTAIR FOGG: It would be a 1,388 kilometres actual -- actual built length, correct.

MR. BOB PETERS: And it stands to reason that longer distance will mean more towers, more conductors, or longer conductors and wires, correct?

MR. ALISTAIR FOGG: Correct.

MR. BOB PETERS: And as a result of those decisions to go down the west side, what does Manitoba Hydro estimate to be the increased costs for Bipole III as a result of the west side routing and not a routing on the east side of Lake Manitoba?

MR. ALISTAIR FOGG: If you could just give me one (1) second.

MR. BOB PETERS: Certainly.

(BRIEF PAUSE)

MR. ALISTAIR FOGG: Mr. Peters, I don't have that number specifically at hand. That was -- would be something I'd have to look into. But gen -- generally speaking, you could look at those distances and -- and you would expect a longer distance would be more expensive.

MR. BOB PETERS: While you don't have those numbers at hand, Mr. Fogg, do you -- are you able to undertake to provide them to the Board?

MS. HELGA VAN IDERSTINE: I'll jump -- I'll jump in. We'll take it under advisement at the moment. I'm not certain that those numbers are available or if they are relevant to the hearing at this moment, so.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Well, Mr. Fogg, on page 132 of Board counsels' book of documents, again, it's a slide from the Boston Consulting Group.

Were you familiar with that?

MR. ALISTAIR FOGG: Yes, I am.

(BRIEF PAUSE)

MR. BOB PETERS: And on this page,

halfway down on the left side, the cost estimate used in 2011 EIS, do you know what that was?

MR. ALISTAIR FOGG: Yes, the Environmental Impact Statement.

MR. BOB PETERS: And that was prepared by Manitoba Hydro?

MR. ALISTAIR FOGG: Correct.

MR. BOB PETERS: And is it correct that Manitoba Hydro quantified the route on the west side to be approximately $900 million more expensive than the east side of Lake Winnipeg?

MR. ALISTAIR FOGG: That's what the slide say.

MR. BOB PETERS: And I'm asking you if that was -- if that's factual.

MR. ALISTAIR FOGG: I'm not specifically familiar at that number. I would -- that would have to be confirmed.

MR. BOB PETERS: You'll take that subject to check?

MR. ALISTAIR FOGG: Yes.

MR. BOB PETERS: And so when you're looking to tell this Board whether Manitoba Hydro has an estimate for the additional costs for Bipole III to be on the west side of Manitoba, as opposed to the east side, you can indicate whether this $900 million number that Manitoba Hydro provided in their environmental impact statement is also accurate.

Would be acceptable?

MS. HELGA VAN IDERSTINE: I'm just going to clarify, what do you mean by "accurate" in this context? I mean, if that's the number that -- I wasn't at the environmental impact -- the -- or didn't -- involved in that environmental impact statement. But I'm presuming if the number was presented at that time, it was accurate at that time.

MR. BOB PETERS: That's what we want to confirm, if we could, Ms. Van Iderstine --

MS. HELGA VAN IDERSTINE: You're not looking --

MR. BOB PETERS: -- and if you --

MS. HELGA VAN IDERSTINE: -- for anything else?

MR. BOB PETERS: Pardon me?

MS. HELGA VAN IDERSTINE: But you're not looking for anything else?

MR. BOB PETERS: Not related to this number, no. But I did ask Mr. Fogg earlier if Manitoba Hydro had a -- a calculation at this point in time of what that number would be, and you we're going to take that under advisement.

MS. HELGA VAN IDERSTINE: Yes. I'm -- I'm pretty concerned about relevance, so.

MR. BOB PETERS: All right. Thank you.

(BRIEF PAUSE)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: On page...

(BRIEF PAUSE)

MR. BOB PETERS: I've been asked to -- to put on the record, Mr. Fogg, Ms. Van Iderstine, what the request was that the Manitoba Hydro has agreed to take under advisement. And I was asking Manitoba Hydro to provide the Board with its current estimate of the additional costs of Bipole III being on the western side of the province compared to the eastern side of Lake Winnipeg.

And included in that was a request to review the number that Manitoba Hydro put forward at the Clean Environment Commission proceeding, and confirm that it was accurate when given.

MS. HELGA VAN IDERSTINE: That's a whole -- a whole bunch of questions. I'm going to take all of them under advisement. And I suspect that we'll be able to answer the ones that I have identified earlier, but rather than try to parse them now, I think that's the easiest way to address it.

MR. BOB PETERS: All right. Let's proceed then.

--- UNDERTAKING NO. 58: Manitoba Hydro to provide the Board with its current estimate of the additional costs of Bipole III being on the western side of the province compared to the eastern side of Lake Winnipeg; and to review the number that it put forward at the Clean Environment Commission proceeding, and confirm that it was accurate when given. (TAKEN UNDER ADVISEMENT)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Fogg, on page 137 of Board counsels' book of documents, Manitoba Hydro responded to an Information Request at a prior General Rate Application, and carried forward the cost of Bipole III from $3.2 billion to $4.65 billion, correct?

MR. ALISTAIR FOGG: Correct.

MR. BOB PETERS: And in this -- in this Information Request, Manitoba Hydro was able to break down the transmission lines and keep that separate from the converter station costs. Also correct?

MR. ALISTAIR FOGG: That's what it shows us, correct.

MR. BOB PETERS: And then, in terms of the converter station costs, let's keep that 2.6 or $2.68 billion number in mind and turn to page 140 of Board counsels' book of documents. Actually make that page 141.

The converter station costs that are now on Manitoba Hydro's capital expenditure forecast have gone up from the $2.68 billion, they've gone up by $105 million, Mr. Fogg?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And I'll come back to that point. But let's do the same here on the transmission line, on page 140.

The transmission line was initially budgeted at $1.65 billion, and that has gone up another $302 million, correct?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And so that puts the overall project for Bipole III increasing from $4.65 billion to $5 billion?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And the causes of the converter station increase, I think can be seen on page 144, Board counsels' book of documents. Well, it can't be seen that well.

Below the redacted waterfall chart from the MGF report, Manitoba Hydro indicates that contributing to the converter station costs were costs that Manitoba Hydro had to pay to upgrade a couple of provincial roads.

Is that correct?

MR. ALISTAIR FOGG: There were costs that were -- were previously assumed to be shared with the Conawapa project that is not proceeding, that were now to be funded by the Bipole III project for those provincial roads, yes.

MR. BOB PETERS: We can scroll down to the bottom half of the page.

Mr. Fogg, I understood your answer to say Manitoba Hydro had to upgrade Provincial Roads 280 and 290, correct?

MR. ALISTAIR FOGG: We contributed funds to the upgrading of those provincial roads, yes.

MR. BOB PETERS: And you contributed funds because you wanted to use that road should Conawapa come in-service, but you also needed it for the Bipole III project?

MR. ALISTAIR FOGG: The Provincial Road 280 -- upgrades, Provincial Road 280, serves the Bipole III project and also the Keeyask project. So there would be upgrades required to that road to address construction traffic for those projects.

Provincial Road 290 serves the Bipole III project and would've served the Conawapa project, as well. And that road, similarly, as a result of Keewatinohk construction, would require upgrades due to the construction traffic.

MR. BOB PETERS: So whatever was included on the Conawapa side of the ledger, you've transferred that all to the Bipole III side?

MR. ALISTAIR FOGG: Correct.

MR. BOB PETERS: And on the Provincial Road 280, are all of the costs on Bipole III, or did some of that stay with Keeyask?

MR. ALISTAIR FOGG: I believe Keeyask has some of those costs as well.

MR. BOB PETERS: And when you talk about the Conawapa access road upgrades, those again were costs that used to be on Conawapa's ledger, but are now transferred over the Bipole III?

MR. ALISTAIR FOGG: Those would have been shared costs with the Conawapa project. That is the private road that Manitoba Hydro owns that accesses the Keewatinohk site, that would've also accessed proposed Conawapa generating station site.

MR. BOB PETERS: And the Chairman talked with you about this as well earlier after lunch today. One (1) of the reasons for increasing the converter station costs was to increase to a confidence level of -- of P75, correct?

MR. ALISTAIR FOGG: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: In turning to the

causes for the $300 million increase on the transmission line, I'd like to go to page 147 of the book of documents, please, and below the chart.

What we're telling the public here, Mr. Fogg, is that the $300 million of additional costs were in some way related to increases for the transmission line itself, correct?

MR. ALISTAIR FOGG: I believe, yes, there were increases to the transmission line costs. I believe, on page 148, the reasons for those increases are further documented.

MR. BOB PETERS: And that includes the line being longer, more land needing to be acquired, more legal fees being incurred?

MR. ALISTAIR FOGG: Mr. Peters, I -- I'm not sure I would say more land needing to be acquired, necessarily, but the actual costs to acquire that land was incorporated into the budget.

MR. BOB PETERS: And when you say Bipole III transmission line vehicles, what additional cost is that for?

MR. ALISTAIR FOGG: Those would be construction site vehicles.

MR. BOB PETERS: And again, on the contingency, we're talking about additional costs on the line going from a P50 to a PS75?

MR. ALISTAIR FOGG: Specific to the line, when we've looked at the contingency for the Bipole III project, we have looked at converter stations and transmission line separately, and then have combined them together as a whole.

Bipole III project -- as it notes here, there is an increase to the transmission line contingency from P50 to what would amount to P80, but essentially the Bipole III project perspective that's a -- it's a P75 estimate currently.

MR. BOB PETERS: Turning to page 150 of Board counsels' book of documents.

The risks that materialized for Bipole III that contributed to the $400 million overall increase in costs, Mr. Fogg, only one (1) of the risks identified had a dollar impact in excess of $20 million, and more than a six (6) month delay in the project.

Is that correct?

MR. ALISTAIR FOGG: That's what the table shows, yes.

MR. BOB PETERS: And that unforeseen risk was geotechnical?

MR. ALISTAIR FOGG: That's correct.

It was a geotechnical risk at the Keewatinohk converter station.

MR. BOB PETERS: That schedule -- that schedule risk was mitigated, and there's no delay as a result of this, is that also true?

MR. ALISTAIR FOGG: That's correct there. The -- the scheduled risks associated with this, these unforeseen conditions, was mitigated, and there's no impact to the Bipole III schedule.

MR. BOB PETERS: But there was an impact to the Bipole III budget?

MR. ALISTAIR FOGG: There is a cost impact to this risk event, and -- and the final value of that impact is still being assessed and negotiated.

MR. BOB PETERS: On Bipole III, Mr. Fogg, it appears on page 155 of Board counsels' book of documents, that Manitoba Hydro used at least three (3) forms of contracts, that being a lump sum, a unit price, and cost reimbursable, correct?

MR. ALISTAIR FOGG: That's correct. The project uses all three (3) of those forms of contracts.

MR. BOB PETERS: And that's for both the converter station as well as the transmission line?

MR. ALISTAIR FOGG: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: Before we leave that tab, on page 156, the conclusions and recommendations from MGF were that Hydro's choice of compensation mechanisms was appropriate for the contracts required. And that was for the converter stations, and was a sensible allocation of risk as between Hydro and its contractors.

Do you see that?

MR. ALISTAIR FOGG: Yes, I see that.

MR. BOB PETERS: Manitoba Hydro doesn't disagree with that, does it?

MR. ALISTAIR FOGG: We don't disagree with that, no.

MR. BOB PETERS: Okay. On page 163 of Board counsels' book of documents is a chart, in terms of the completion, out of one of Manitoba Hydro's quarterly reports.

(BRIEF PAUSE)

MR. BOB PETERS: On page 162. I

apologize.

We see at the right side of this schedule, Mr. Fogg, the in-service date that you told us about is -- we're seeing July of 2018?

MR. ALISTAIR FOGG: It would be the end of July, 2018, yes.

MR. BOB PETERS: And MR. DOUGLAS SMITH: you told the Board earlier this morning, that schedule is still valid?

MR. ALISTAIR FOGG: That's correct. That's -- we are still on target to achieve that in-service date of July, 2018.

MR. BOB PETERS: And the transmission line itself is to be completed in March of 2018, if I read this correctly?

MR. ALISTAIR FOGG: That's correct.

MR. BOB PETERS: And one (1) of the risks related to the transmission line was weather. But, perhaps, in the perverse or inverted way, Manitoba Hydro needs cold weather in which to construct the Bipole III line.

Is that correct?

MR. GLENN PENNER: We need cold weather, but not too cold.

MR. BOB PETERS: Why do you need cold

weather?

MR. GLENN PENNER: Most of the northern access is on a winter trails, and warm weather tends to make it very difficult to get between sites.

MR. BOB PETERS: And so the weather risk is Manitoba Hydro needs cold weather to complete the northern portions with frozen ground or frozen earth?

MR. GLENN PENNER: That's correct.

MR. BOB PETERS: And we're in the middle of January. Is everything running according to schedule at this point in time, with respect to the transmission line construction?

MR. GLENN PENNER: We are targeting March 1 on many of our segments, which gives us a few weeks buffer. We feel that usually -- we can usually expect winter weather until the end of March, so we are currently on schedule.

MR. BOB PETERS: On page 112 of Board counsels' book of documents is an extract, I believe -- no...

(BRIEF PAUSE)

MR. BOB PETERS: On page 16 -- on page 165, Board counsels' book of documents, MGF raises a risk, Mr. Penner, and that relates to the performance of one (1) of your contractors on the Bipole III line, correct?

MR. GLENN PENNER: That is correct.

MR. BOB PETERS: Have those performance concerns manifest themselves?

MR. GLENN PENNER: Yes, we -- we descoped a portion of the Rokstad's contract, and we have awarded that to a -- a third contractor. So there is now another contractor working on a portion of Bipole.

MR. BOB PETERS: And so on -- on page 168 of Board counsels' book of documents, in the top part of the page, MGF raises a concern that if the construction was not completed, it will cost on the schedule an additional year, correct?

MR. GLENN PENNER: That's what they have said, yes.

MR. BOB PETERS: And because Manitoba Hydro has descoped one (1) of your contractors and hired a -- an additional contractor, has all of that risk been mitigated?

MR. GLENN PENNER: We are continuing

to closely monitor all of the work on the project, and I think we -- we continue to -- to make decisions to ensure that we will be complete by the end of this winter season.

MR. BOB PETERS: That meeting March 2018?

MR. GLENN PENNER: Correct.

MR. BOB PETERS: Is there an additional cost component as a result of descoping one (1) contractor and engaging another?

(BRIEF PAUSE)

MR. GLENN PENNER: There are additional costs to -- to add another contractor. However, we had sufficient contingency within the current control budget to cover that.

MR. BOB PETERS: So the real risk is for schedule, as opposed to cost?

MR. GLENN PENNER: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: At page 49 of Exhibit 42-6, Board counsels' book of documents, we see from the MGF report for the Bipole III transmission line, that the critical paths for both of two (2) contractors are slipping, which jeopardizes completion in August of 2018, correct?

Mr. Penner, do you see that?

MR. GLENN PENNER: I do see that, yes.

MR. BOB PETERS: This raises not only one (1) contractor but two (2) of the contractors.

Have -- have -- has whatever work been slipping been corrected?

MR. GLENN PENNER: Our other contractor is on track to -- to completion, and we don't have significant concerns about their performance.

MR. BOB PETERS: Thank you. I want to turn to the Manitoba-Minnesota Transmission Line. And perhaps to orient the panel, if we flip back to page 5 of Board counsels' book of documents, we can see at the bottom of the chart, near the bottom of the chart, the price for the Manitoba-Minnesota Transmission Project was $350 million in Capital Expenditure 13, which would have been used at the Needs For And Alternatives To review.

Is that correct?

MR. GLENN PENNER: That is correct.

MR. BOB PETERS: And what level of project definition was that $350 million based on?

MR. GLENN PENNER: Can you clarify?

MR. BOB PETERS: Well, we've seen in some of the other evidence, that Manitoba Hydro's capital projects are quantified under various levels or degrees of estimates and planning.

Are you aware of that?

MR. GLENN PENNER: And so, in -- in general terms, I would say it was a -- it was a -- a higher level estimate without a probability associated with the contingency.

MR. BOB PETERS: That means that -- well, let's turn to page 171 of Board counsels' book of documents.

Here's some Manitoba Hydro rebuttal, this time to the METSCO company, and it talks about at the time certain projects were conceived the process required the budget to be estimated and approved prior to any engineering or planning being done to define the project scope. Hence, the initial budget estimate was created without a clear definition of scope.

Do you see that in the rebuttal from Manitoba Hydro?

MR. GLENN PENNER: Yes, I see that.

MR. BOB PETERS: Does that apply to the Manitoba-Minnesota Transmission Line Project, back in 2013?

MR. GLENN PENNER: One (1) moment.

(BRIEF PAUSE)

MR. GLENN PENNER: So for the $350 million estimate, we -- we didn't have a final preferred route, we didn't have any of the environmental conditions, and we didn't have any design work completed on it. So you -- you could say it was -- was a more preliminary estimate.

MR. BOB PETERS: And just so this panel understands that, Mr. Penner, those preliminary estimates are still submitted for approval to the executive of Manitoba Hydro through the capital proce -- project justification process?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And Manitoba Hydro's executive is aware as to what level those costs have been engineered or -- or planned?

MR. GLENN PENNER: Yes, they would be.

MR. BOB PETERS: In the file -- in the

September of 2017, if we go to page 172, we see that the cost of the Manitoba-Minnesota Transmission Line Project increases up to $453 million, correct?

MR. BOB PETERS: That's correct.

MR. BOB PETERS: And that's your most current cost estimate?

MR. GLENN PENNER: That is our most current cost estimate.

MR. BOB PETERS: And that 30 percent increase is partly related to a more and a better refined scope and engineering for the project?

MR. GLENN PENNER: Correct. We have -- we have a final pref -- or a final preferred route. We -- we know more about the construction costs based on our most current Bipole III construction tenders.

MR. BOB PETERS: And we see on page 175, the capital project justification addendum, that increases the cost up to -- up a hundred million dollars to 453 million, and the various components of it, correct?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: Now, it appears that licensing and environmental assessment went up $17 million, on page 175, correct?

MR. GLENN PENNER: Correct.

MR. BOB PETERS: That was before the National Energy Board decision requiring Manitoba Hydro to pursue a certificate rather than a permit for this project?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: Can you tell this Board how much more it will cost for certificate than a permit?

MR. GLENN PENNER: One (1) moment.

(BRIEF PAUSE)

MR. GLENN PENNER: We don't have those additional costs. However, we don't expect that they -- they will be as significant as the -- the CEC hearing process.

MR. BOB PETERS: Sorry, I didn't understand that. The -- the additional cost to get a certificate will be less than it would be if you had to do a Clean Environment Commission proc -- proceeding in Manitoba?

MR. GLENN PENNER: Yes, because what we did -- we started in 2012, and we did all of our --

our CEC process begins long before the hearings. And we do our -- our public consultation, we do our environmental assessments, and we submit that information. And then we go through the hearing process.

All of that work is -- at least my understanding is that that work is submitted as evidence into the NEB process. So we're not doing, at this point, any additional environmental studies, and all those kinds of things.

So we're -- we're going through now an IR process with the NEB, leading up to a hearing sometime this spring.

MR. BOB PETERS: On page 179, flipping over to 180, is the Clean Environment Commission Report on the Manitoba-Minnesota Transmission Project correct?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And there are recommendations that have been reproduced, starting on page 180, carrying through to 182.

You're familiar with those?

MR. GLENN PENNER: Yes.

MR. BOB PETERS: Have all of those

recommendations been accepted by the Government of Manitoba.

MR. GLENN PENNER: We have not heard yet.

MR. BOB PETERS: If any of those recommendations are accepted and required to be done by Manitoba Hydro, does that mean Manitoba Hydro has to spend more money on the Manitoba-Minnesota Transmission Project.

MR. GLENN PENNER: No, we've reviewed these recommendations and -- and feel that, for the most part, they're within the -- the within the budget and typical are expected.

MR. BOB PETERS: Did the Clean Environment Commission recommend any changes in the route?

(BRIEF PAUSE)

MR. GLENN PENNER: I'm not aware that the CEC made any recommended changes to the route. However, it's pointed out to me that nine point four (9.4) is an open-ended recommendation that -- that could cause some problems around planting trees to -- to screen the view of -- of the transmission line.

MR. BOB PETERS: Manitoba Hydro hasn't taken that into account in the project cost?

MR. GLENN PENNER: No, it's not taken an account in -- in the project cost.

MR. BOB PETERS: Is it covered by the P75 figure?

MR. GLENN PENNER: It's an open-ended recommendation that we don't fully understand.

MR. BOB PETERS: All right. Let's turn to page 173 and look at a map. I think we saw this in your slide deck as well, Mr. Penner. The bottom of the page there's a map for the Manitoba-Minnesota Transmission Project.

That's the projected route, is that correct?

MR. GLENN PENNER: Yes.

MR. BOB PETERS: And I believe in conversations with the Chairman after lunch today, you indicated that the transmission starts over at Dorsey, on the west side of Winnipeg, goes around the south end of the city, close to the Riel station, and then heads straight west, correct?

MR. GLENN PENNER: Correct.

MR. BOB PETERS: And when we look at that line going straight west of Riel, it's to approximately to -- as far as a Anola, correct?

MR. GLENN PENNER: Yeah, just past -- just east of Anola.

MR. BOB PETERS: How many kilometres or miles would that be?

(BRIEF PAUSE)

MR. GLENN PENNER: I would estimate it's about 30 kilometres.

MR. BOB PETERS: I'm sorry, I was not listening.

MR. GLENN PENNER: I am estimating approximately 30 kilometres without doing any measurements.

MR. BOB PETERS: All right. Thank you. I was listening now.

I'm looking at this map on the screen, and the Board will note that there is a dotted black line that also comes out of this solid blue line of the MMTP route, correct?

MR. GLENN PENNER: That's correct.

MR. BOB PETERS: That dotted line represents the -- is it the Dorsey-Forbes line or whatever it's now called?

MR. GLENN PENNER: Yes, it -- it used to be known as Dorsey to Forbes RD602F, and now it -- it terminates at Riel, and now it's referred to as M602F.

MR. BOB PETERS: In any event, regardless of what it's called, it appears to be how -- how far apart is it from the MMTP project?

MR. GLENN PENNER: It lies in the same corridor for that distance.

MR. BOB PETERS: So for the 30 kilometres or so that you estimated, those two (2) transmission lines are in the same corridor or just metres apart?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: Why would you prefer that routing to something separate, when the whole theory of the Bipole routing is to provide separation as between major transmission lines?

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Chair, while the witnesses are conferring on this topic, I would beg indulgence for another thirty (30) minutes, if the

Board was so inclined. But if the Board had other commitments, I will try to find the time tomorrow morning after my colleagues opposite have had the microphone.

I apologize for not raising it sooner. I would like to cover a couple more topics, but if not today, then tomorrow. And if the panel would like to stand down for a short break, I'm amenable as well, but that's fine.

THE CHAIRPERSON: Yeah, we'll -- we'll break for ten (10) minutes.

MR. BOB PETERS: All right. Thank you.

--- Upon recessing at 5:28 p.m.

--- Upon resuming at 5:40 p.m.

THE CHAIRPERSON: Mr. Peters...?

MR. BOB PETERS: Thank you, Mr. Chairman.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Penner, you were seeking some counsel with your colleagues at the time of the recess, did you have an opportunity to discuss with them?

MR. GLENN PENNER: Yes.

MR. BOB PETERS: And your answer then to the information you were seeking?

MR. GLENN PENNER: So yes, while it does parallel existing infrastructure, it -- it -- it was looked at very carefully by our system planning engineers and it meets in their reliability standards and some of the factors that weighed into that were that it's an east-west portion of the line. Most of the weather events occur with a westerly winds, so, there's a -- there's a change in -- in that and so that's significant.

And the other component to it is -- that it's very easy to access and very quick to have to go back in and -- and put transmission towers up, if they were to come down as a result of a major storm.

MR. BOB PETERS: So compounding that answer, Mr. Penner, is Manitoba Hydro has in that one (1) corridor -- you gave it a fancy number M602F.

Have I got that right?

MR. GLENN PENNER: Yes.

MR. BOB PETERS: Do you guys really give it numbers like that, that's incredible. That's how it's known?

MR. GLENN PENNER: That's correct. The 'M' and the 'F' refer to the stations that it starts and stops and the -- the digits in between kind of -- can tell you what line designation and the voltage class.

MR. BOB PETERS: Obviously. But on this same map that we're looking at where we see the blue line coming from Riel going as far as -- just past Anola, is the Panel correct in understanding that Bipole III is also going to join that corridor?

MR. GLENN PENNER: Bipole III is also in that corridor for a short duration as well.

MR. BOB PETERS: So a short duration, shorter than 30 kilometres?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And so now you've got two 500 kV and the Bipole III all on the same corridor?

MR. GLENN PENNER: That's correct.

MR. BOB PETERS: Thank you. Couple of quick -- let me finish...

You told the Chairman after lunch that the $453 million in-service cost was at a preliminary stage because that's before any shovels are in the ground; correct?

MR. GLENN PENNER: No, I think I referred to the three fifty million (350) as a preliminary budget. We refer to the four hundred and fifty-three (453) now as a P75 estimate.

MR. BOB PETERS: All right but that P75 estimate or that $100 million increase from three fifty-four (354) to four fifty three (453) is before any contracts are signed for any of the work to begin on the construction of the MMTP line?

MR. GLENN PENNER: Yes. So there are no construction contracts. They haven't been signed. We haven't even put the construction contracts out to tender yet.

MR. BOB PETERS: If we compare the stage that this project is at to where Bipole III is at, isn't it correct that once the Bipole III bids were received between the bids to the actual price there was a 17 percent increase in the transmission line?

You take that subject to check?

MR. GLENN PENNER: We tendered the project in phases and the last piece -- the last half of the project was -- was actually awarded after the -

- the budget was raised to the 5.04.

MR. BOB PETERS: Okay, I've got your point on that. We heard that Hydro is committed to the June 2020 in-service date for this MMTP; correct?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And we talked about the National Energy Board requiring Manitoba Hydro to seek a certificate; correct?

MR. GLENN PENNER: Yes, that's correct.

MR. BOB PETERS: And typically how long will it take to get a certificate compared to how long it would take to get a permit?

MR. GLENN PENNER: Maybe I could answer the question this way. The -- the process that the NEB has identified is that there -- they have fifteen (15) months, and they've deemed that -- their -- their timeline to be March 2019.

MR. BOB PETERS: That is, the project will be -- will have gone through the certificate process and will have been concluded by March 2019?

MR. GLENN PENNER: Yes, they have fifteen (15) months from the time they deemed that the documents are complete to the time that -- that they need to prepare a recommendation.

MR. BOB PETERS: Can Manitoba Hydro construct the Manitoba Minnesota transmission line in thirteen (13) months?

MR. GLENN PENNER: I think it would be difficult. We are, however -- however, hopeful that once the -- the hearing is complete sometime later this spring or early summer that we would get a recommendation sooner than the March 2019 date and -- and so that we -- we are hoping that that's a possibility.

MR. BOB PETERS: Well, I had heard earlier that hope is not a plan but you're telling me that that's what you're relying on now for the Manitoba Minnesota transmission line is hopefully getting an early ruling?

MR. GLENN PENNER: I wouldn't say we're relying on it. We are not prepared to change our June 2020 in-service date until we determine that we cannot achieve a 2020 -- a June 2020 in-service date. And so we have to look at all of the factors as we move forward. Right now, it's -- it's a hypothetical to determine other than that June 2020 in-service date.

MR. BOB PETERS: All right. I've got

your point. On page 183 of Board counsels' book of documents, in the MGF report Manitoba Hydro's costs were measured against a benchmark provided by MGF and Stanley Consulting.

You're aware of that?

MR. GLENN PENNER: Yes.

MR. BOB PETERS: You're aware of the industry benchmarked used by Stanley Consulting and MGF?

MR. GLENN PENNER: I have had a look at their -- their industry benchmark, yes.

MR. BOB PETERS: Do you agree with the industry benchmark that was used?

MR. GLENN PENNER: I think it can be difficult to determine exact line -- per kilometre line costs. I -- I think it's -- it's very hard to compare the different lines across North America.

MR. BOB PETERS: Can you explain to this Board, why Manitoba Hydro's cost is 25 percent lower than the benchmark?

MR. GLENN PENNER: I think historically Manitoba Hydro has been able to build transmission lines for less than -- than other Utilities. Primarily it -- transmission lines can vary in cost depending on the density of population if it's travelling in -- in urban areas. If there's a lot of line angles and it. So there's -- there's a variety of -- of different factors that -- that weigh into it. The type of structures that are used.

In this case where we use guide structures, I think our transmission line costs are -- are less expensive than -- than typical industry standards.

MR. BOB PETERS: In my haste I glossed over page 115 of Board counsels' book of documents and we should go back and if it was Mr. Strongman who has to give an answer, I'll -- I'll let the panel decide.

On page 115, there's an indication and I'll just read into the record that:

"Manitoba Hydro advised MGF that they have had great success with local Aboriginal labour. However, they have exhausted all availability."

Have I read that correctly? Mr. Bowen or Mr. Strongman from the back?

MR. JEFF STRONGMAN: Hi. I see the quote that is being referred to. In fact, this quote was subject of some discussion between Manitoba Hydro and MGF because Manitoba Hydro believe that although

MGF advised that they had been -- they had received this as a direct quote from one (1) of our project staff, Manitoba Hydro's view of this topic is that while we have had some success with some of the smaller communities within our partnership, Manitoba Hydro's position is that we continue to look for more opportunity and that we have not necessarily exhausted all availability.

So Manitoba Hydro believes that going forward we will continue to review with our partners employment opportunities and that we are not at the point where we can't do better. We will continue to do better.

MR. BOB PETERS: What efforts has Manitoba Hydro taken to source all available local Aboriginal labour?

MR. JEFF STRONGMAN: Within the Joint Keeyask Development Agreement, there are three (3) subcommittees that are active on a monthly basis. One of which is dedicated specifically to employment and Manitoba Hydro and the four (4) partners meet regularly to identify people within the communities that are currently looking for work and Manitoba Hydro and its contractors intend to act on those as opportunities.

MR. BOB PETERS: So Manitoba Hydro is of the understanding that there is still available employment in northern Manitoba with local Aboriginal labour being available?

MR. JEFF STRONGMAN: Yes, that's correct. I mentioned earlier that with some of the labour hours that we had quoted, roughly, 40 percent of our labour hours worked on this job by the end of 2017 were performed by Aboriginal employees and that statistic is unprecedented across Canada. We still believe that we can do better.

MR. BOB PETERS: And what steps are you taking to do better?

MR. JEFF STRONGMAN: Could I confer with my colleagues? I'm at the different table here.

MR. BOB PETERS: Yes, absolutely, Mr. Strongman, I appreciate. Thank you.

MR. DAVID BOWEN: I'll just add to Mr. Strongman's answer. He spoke about the AGE committee, the Advisory Group on Employment. So that's one (1) committee that has all our contractors. It has the folks that work at the job referral service. So really, the -- if you want to apply for a job for Keeyask, you have to submit your name within the -- what's called the JRS, the job referral service.

It has that within each of our -- our four (4) partner committees, there's a JRS worker who's -- is really for -- for lack of better words, look -- hoping to source the talent within that community to link with the province and the JRS with our contractors hiring and, of course, our Manitoba Hydro staff help that process. So that -- that is at -- continuing -- continually at work.

Some of the other efforts that are -- are other ways that -- we've typically in the last two (2) years have gone to each of the four (4) partner communities to do a job fair with the contractors working at site to make sure people are aware of what the job opportunities are and -- and help -- help get people to the site.

Other examples, we've had, of course, high school students come to site. We've actually had -- I believe it's for a -- don't quote me on this one, but it's a -- there's a work experience option where we had about just over ten (10) -- ten (10) people from the communities come to Keeyask for -- for a number days to see what it's like to -- to be at camp, see what it's like to potentially work at the camp and so -- so those are just some of the -- the efforts that are being weighed -- made to -- to increase the employment for our partner communities and, of course, Indigenous people in the north.

MR. BOB PETERS: Mr. Bowen, maybe your last comment covered this, but I understood there was a job referral service worker from each of the four (4) KCN partners; is that what I've understood?

MR. DAVID BOWEN: That's correct.

MR. BOB PETERS: And so the question becomes: For the communities that aren't part of the KCN partnership, how is Manitoba Hydro recruiting additional Aboriginal workers?

MR. DAVID BOWEN: Our -- our focus is certainly on our partner communities, and that's -- that's our -- that's our primary focus. Certainly, there's -- there's word of word-of-mouth. We have linked -- the other piece that I didn't mention was that we have linked with the -- what's called the -- the trades coordinator for the -- Partnership Manitoba. We -- there's an Aboriginal coordinator within the Thompson area to -- to get the word out and to help -- help potential people looking for work to -- to get employment Keeyask.

MR. BOB PETERS: All right. Thank you. If in your discussions with Mr. Strongman you have additional information to add, I'd ask you to put that on the record. I won't ask for that as an undertaking but you can discuss with him when you're in closer proximity than you are now.

Would you do that, sir?

MR. DAVID BOWEN: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: Thank you for that. Mr. Cormie, finally, six o'clock. Thank you for patience.

In the information provided at page 195 of Board counsels' book of documents, are the Great Northern transmission line project information as provided; correct?

MR. DAVID CORMIE: Yes. Yes, I see that.

MR. BOB PETERS: And in this -- in this document, the capital cost estimate is at $677 million as of December 31st, 2015 and if we could go to the top of the page we'll see, Mr. Cormie, what I was referring to in terms of the quarterly update?

MR. DAVID CORMIE: Yes, that's the publicly available estimate that Minnesota Power has provided Manitoba Hydro.

MR. BOB PETERS: And can you tell the Board if that cost estimate includes an amount on account of contingency?

(BRIEF PAUSE)

MR. DAVID CORMIE: Yes, Mr. Peters, that includes the -- the contingency and that's the amount that's included in the facility's construction agreement.

MR. BOB PETERS: Turning to tab -- to page 197, Mr. Cormie, MGF in their report has benchmarked the costs of the Great Northern transmission line against Manitoba Hydro's Minnesota -- Manitoba/Minnesota transmission project, as well as a -- an industry benchmark.

Do you see that?

MR. DAVID CORMIE: Yes, I see that.

MR. BOB PETERS: And likewise, on page 202 of Board counsels' book of documents, we see just on the screen in front of you, based on the metrics the Great Northern transmission line project is significantly higher than those project metrics seen for other projects; correct?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And can you indicate to the Board at this time, why Manitoba Hydro's costs appear to be significantly higher than metrics for other projects that are benchmarked?

MR. DAVID CORMIE: Were you asking me whether Manitoba Hydro's project or Minnesota Power's projects?

MR. BOB PETERS: I have your clarification. I'm going to -- I'm talking about the Great Northern transmission line project. And you correctly are reminding me that that's Minnesota Power's project?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: So in terms of the information that Manitoba Hydro has provided and in terms of its comparability to other transmission lines, is Manitoba Hydro able to provide an answer as to why the cost, according to MGF, for the Great Northern transmission line appear higher than other similar industry projects?

MR. DAVID CORMIE: Yes, I can provide that. Minnesota Power always intended their estimate to be conservative and at the time the estimate was prepared it -- like, with the MMTP project, they did not have a final route, and they recognized that there was a long period of time between the time and the estimate was prepared and the in-service date.

And so they deliberately chose a -- a conservative number for the purposes of the forecast. And we believe now that -- that that -- that number is -- still believe that that number is conservative. Minnesota Power has yet to finalize some of its contract costs. And once those contract costs are finalized, we will be updating the budget to recognize market prices, but as of now we're comfortable to have a cushion in our -- our budget and we're -- we believe that we'll leave -- leave that there -- Minnesota Power will leave that there until they're more confident in what their actual costs will be.

MR. BOB PETERS: When you say "conservative," Mr. Cormie, you mean that the Minnesota Power's costs for the Great Northern transmission line are on the high side of what will actually come in?

MR. DAVID CORMIE: Yes. To date, the contracts that have been let by Minnesota Power have been as forecast or underforecasts. But as I indicated in my direct testimony this morning, only about 10 percent of the cost of the projects have been spent to date and we believe it's premature to assume that we can rely on that in order to lower the estimate. Better to be underforecast than to be caught short.

MR. BOB PETERS: I'm not sure I -- I agree with your -- your terminology, Mr. Cormie. "Better to be underforecast," what you mean to say is better to have your forecast showing a higher price than what you expect will actually come in.

MR. DAVID CORMIE: Yes, unfortunately, Minnesota Power doesn't use the probability based. They haven't given us a probability associated with their forecast. They've indicated it is a conservative forecast. So they -- they believe and our -- our analysis of their estimate is that -- that it is probably conservative and, with time, we will get a revised estimate that will be more -- more likely to be closer to what we actually expect to spend.

MR. BOB PETERS: Mr. Cormie, while the revisions, if any, to the in-service costs of that budget are considered confidential in these proceedings, Manitoba Hydro's public position is that if the capital costs of the Great Northern transmission line exceed $1 billion, then Manitoba Hydro will not proceed.

You're aware of that?

MR. DAVID CORMIE: I think you're referring to my testimony at NFAT where I indicated that if the cost of the Great Northern line came in at $1 billion, the project would not be viable. We are not anywhere close to spending $1 billion on the Great Northern transmission line.

MR. BOB PETERS: And -- and Mr. Cormie, I was quoting you put on page 204 of Board counsels' book of documents, it was from the 2015 General Rate Application, but other than that, I'll accept your answer, if that's satisfactory to you, sir.

MR. DAVID CORMIE: Yes, I stand corrected.

MR. BOB PETERS: Now, Mr. Cormie, in September of 2016 the Boston Consulting Group was asked to review the business case on the Great Northern transmission line.

You're aware of that?

MR. DAVID CORMIE: Yes, we contracted with them to help us make a final decision -- commitment to construct the line in the fall of 2016, and -- and given that they had worked through the summer for our board on the Keeyask project, they were well capable of providing that service.

MR. BOB PETERS: And on page 231 of Board counsels' book of documents, we see the engagement letter; correct?

MR. DAVID CORMIE: Yes, I see that.

MR. BOB PETERS: And on page 235 of Board counsels' book of documents one (1) of the benefits associated with the Great Northern transmission line project, Mr. Cormie, is Manitoba Hydro's access to the Wisconsin markets; correct?

MR. DAVID CORMIE: Yes, the --

MR. BOB PETERS: And -- I'm sorry.

MR. DAVID CORMIE: When we requested transmission service associated with the Great Northern transmission line, MISO provided us access -- additional 500 megawatts of export access into Wisconsin as -- as part of our transmission request.

MR. BOB PETERS: And from your evidence this morning, the suggestion was that Manitoba Hydro should be able to extract higher export prices if they ship energy into Wisconsin?

MR. DAVID CORMIE: What I indicated in my testimony was that in the bilateral market for the long -- sale of long-term firm power, Wisconsin is a higher cost market than Minnesota and so it creates opportunities for Manitoba Hydro to sell long-term firm power over the firm transmission associated with the -- with the project. So those are the opportunities.

Spot market electricity is priced at the border, whether it goes into Wisconsin or Minnesota. So the opportunity market doesn't make any difference, but from a bilateral perspective, it -- it provides more -- a larger customer base.

MR. BOB PETERS: Mr. Cormie, have the higher prices for bilateral agreements in Wisconsin been reflected in Manitoba Hydro's export revenue forecast?

MR. DAVID CORMIE: There are two (2) contracts in the export revenue forecast for the sale of firm power to Wisconsin public service. One that we're currently engaged in delivering to, and one that commences in 2021 as a result of the construction of Keeyask. Those are very attractive prices for Manitoba Hydro.

MR. BOB PETERS: Those prices are included in the export price forecast?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And so are there any additional bilateral agreements in Wisconsin included in the export forecast other than the two (2) that you've referenced?

MR. DAVID CORMIE: No, we're -- we're building -- building the market in Wisconsin as we speak.

MR. BOB PETERS: Mr. Cormie, on your slide, which I think is part of Manitoba Hydro Exhibit 120, I believe it's on page 117, if I've got this right. I don't.

I'm looking for the Great Northern transmission line project, Mr. Cormie, and your slide number 3. I don't know if you gave that as a separate -- a separate PDF. It would relate to the...

(BRIEF PAUSE)

MR. BOB PETERS: Perhaps 106, if we could try that page. All right, we are -- one more page forward I believe will be where we want to go.

MR. DAVID CORMIE: The US interconnection objectives?

MR. BOB PETERS: Yes.

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: Thank you very much, Diana, with putting up with my searching.

On this page, this morning, Mr. Cormie, you talked about reducing import costs once the Great Northern and the Manitoba/Minnesota lines are constructed; correct?

MR. DAVID CORMIE: Yes, Mr. Peters.

MR. BOB PETERS: And that reduction in import costs occurs for what reason?

MR. DAVID CORMIE: It -- it occurs when we're importing. There is congestion between the MINNHUB price and the Manitoba border. And so prices at the Manitoba border are higher than if we were to buy that electricity in Minneapolis.

Now, you're build -- you're building a bigger transmission network, so, power can more easily flow from Minneapolis to the border, therefore, the price at the border is lower when we're purchasing. So import costs are reduced. And conversely, the same thing happens when we're exporting because you have now a larger transmission network delivering electricity in Minneapolis, the price at the MISO node, the pricing note at the border, goes up and approaches the price that you would receive at the market.

Right now there's about a -- on average, a 2 to 5 percent difference in those prices and so they'd be price improvement for exports and price reductions for imports which add value to all of Manitoba Hydro's exports and reduces the costs for all our reports.

MR. BOB PETERS: Has that 2 to five percent difference in the value that that spins off, Mr. Cormie, been included in Manitoba Hydro's export price forecasts?

MR. DAVID CORMIE: I don't believe so. I believe that we are still relying on the historical ratio between -- that exists on the existing interconnection. We have not yet reflected in the IFF the additional revenue that would be associated with that improvement.

MR. BOB PETERS: All right. On the bottom part of this page in front of us, the increased export capability, an extra 900 megawatts, has that been included in Manitoba Hydro's export price forecast?

MR. DAVID CORMIE: It's in the IFF because the export capability doesn't change the price, it just makes -- allows us to export more electricity rather than spill it when the existing transmission line is fully loaded.

MR. BOB PETERS: All right, thank you.

Mr. Cormie, I want to turn with you to the last subject that I have today is the SaskPower sale and transmission line.

The matter you spoke to this morning as well, sir?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: Currently, Manitoba Hydro has a 25 megawatt sale to SaskPower on the books from 2015 to 2022?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: A seven (7) year contract, sir?

MR. DAVID CORMIE: I think it's six (6) years.

MR. BOB PETERS: Okay, and it's on existing transmission?

MR. DAVID CORMIE: Yes, it is.

MR. BOB PETERS: Is it also correct that Manitoba Hydro has a 500 megawatt term sheet with SaskPower?

MR. DAVID CORMIE: No, that is incorrect. We have a 500 megawatt Memorandum of Understanding that allows the companies to explore opportunities.

MR. BOB PETERS: And that Memorandum

of Understanding is that related to both energy, as well as transmission interconnections?

MR. DAVID CORMIE: Yes, it has quite a broad scope, including a lot of different activities, including the exporting of surplus electricity and the study of additional transmission facilities.

MR. BOB PETERS: It is, Mr. Cormie, for nonlegal terms, it's -- it's just a precursor to possible future agreements.

Would that be how you understand it?

MR. DAVID CORMIE: Yes. One (1) of the purposes of a Memorandum of Understanding is to define the scope of the discussions that take place between the Utilities and to create a confidential context so that we agree to share our confidential information and -- and allow those conversations to take place.

But there is non -- it's a nonbinding, nothing can happen under that agreement, except the study.

MR. BOB PETERS: Is this 500 -- sorry, is this 100 megawatts sale that you've spoken about with SaskPower between June of 2020 and May of 2040 part of that 500 megawatt Memorandum of Understanding?

MR. DAVID CORMIE: Yes, it's a child

of that process.

MR. BOB PETERS: I take it you're the father? Mr. Cormie, to complete the 100 megawatts sale, each Utility is responsible to construct the transmission in their respective provinces?

MR. DAVID CORMIE: That is correct.

MR. BOB PETERS: Does the power flow both ways on this transmission line?

MR. DAVID CORMIE: Contractually the power is only designed to be exported. The -- the power flow will be in both directions, depending upon the -- the -- the network flows a power at the time. So it -- it -- it is designed as an export line, it's not designed to provide any firm import capability into Manitoba.

MR. BOB PETERS: And on page 251 of Board counsels' sixth book of documents, the project cost, Mr. Cormie, is quantified at $57 million, perhaps now $56.5 million?

MR. DAVID CORMIE: Yes, that was our estimate in 2015. And I believe that estimate is under review, and the -- and the -- we expect an update in that in the next capital expenditure forecast.

MR. BOB PETERS: All right, thank you

for that. On page 253 of Board counsels' book of documents, would the Board be correct in understanding, Mr. Cormie, that Manitoba Hydro in 2015 conducted an economic evaluation of this sale?

MR. DAVID CORMIE: Yes, as part of the approval process for sales, something that outside of my scope of responsibility is an economic evaluation and that was done.

MR. BOB PETERS: And the economic evaluation was done on both a 100 and a 140 megawatt sale option?

MR. DAVID CORMIE: Yes, we offered SaskPower the option of taking an additional 40 megawatts, and so we had to be prepared for them to accept the -- the extra 40 megawatts, and so the valuation was done on that basis as well.

MR. BOB PETERS: And both options required new transmission lines?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And the economic evaluation included both capacity and energy charges, Mr. Cormie?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And the environmental attributes were transferred to SaskPower and included in the price?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And we see on page 258 of the Board counsels' book of documents that Manitoba Hydro's evaluation or mini NFAT, or Needs For an Alternative review on this project, it looked at three (3) scenarios, sir?

MR. DAVID CORMIE: That is correct.

MR. BOB PETERS: Has Manitoba Hydro's executive committee, and Manitoba Hydro's Board of Directors, provided approvals for this, Mr. Midford or Mr. Cormie?

MR. DAVID CORMIE: Yes, these -- this sale agreement was approved by the Manitoba Hydro Electric Board.

MR. BOB PETERS: Was Manitoba Hydro required to obtain approval from the government of Manitoba to proceed with the transmission line and the sale agreement?

MR. DAVID CORMIE: All sales agreement that require the construction of capital projects requires approval by the province of Manitoba.

MR. BOB PETERS: And that approval is provided by way of the province borrowing money tp support the project?

MR. DAVID CORMIE: No, there'd be an Order in Council associated with the sale agreement.

MR. BOB PETERS: When does construction begin, Mr. Cormie?

(BRIEF PAUSE)

MR. DAVID CORMIE: I'm sorry, Mr. Peters, I didn't hear the question.

MR. BOB PETERS: I was asking when Manitoba Hydro will begin construction on the transmission line.

(BRIEF PAUSE)

MR. GLENN PENNER: After the CEC approval. We have the probably a year or maybe more to construct.

MR. BOB PETERS: Has the Clean Environment Commission process been established?

(BRIEF PAUSE)

MR. GLENN PENNER: We haven't submitted yet. So no, the dates have not been completely identified.

It's a Class 2. So typically Class 2 would not require a hearing, so there is time.

MR. BOB PETERS: On page 262 of Board counsels' book of documents, Daymark Energy advisors, who are probably in town right now and coming here tomorrow, have indicated -- and I thought, Mr. Cormie, you put that in one of your presentations, that Daymark concluded that it is in the best -- it is in the interest of Manitoba Hydro and its ratepayers to proceed with the project, correct?

MR. DAVID CORMIE: Yes. Daymark did a -- quite a robust review of the -- of the project, and came to the same conclusion that Manitoba Hydro did.

MR. BOB PETERS: And you say a robust review based on the report that you reviewed?

MR. DAVID CORMIE: No, it was based on an updated information of the report that -- that we referred to previously was done at the time the sale was recommended to the Manitoba Hydro Board. Daymark has re -- has reviewed it in the current context.

MR. BOB PETERS: Yes, and you said it was a robust review. So let's just make sure the Panel understands that Manitoba Hydro's initial review was back I believe in 2015, Mr. Cormie?

MR. DAVID CORMIE: Yes.

MR. BOB PETERS: And in 2015, Manitoba Hydro was making various assumptions and those assumptions have changed under current conditions?

MR. DAVID CORMIE: Yes. I think Manitoba Hydro's load forecast has changed. Our export price forecast has changed. And there been changes to the cost estimate of the project. And so we reflected all the up-to-date information, and provided that to Daymark for their analysis.

MR. BOB PETERS: All right. On page 263 there is indication that even if the project is delayed, Mr. Cormie, the power agreement provides for interim deliveries for most of the power on the existing transmission system.

Do you see that?

MR. DAVID CORMIE: Yes, I do.

MR. BOB PETERS: You spoke to that this morning and can you explain to the Panel for how long this agreement would remain valid if the project was delayed?

MR. DAVID CORMIE: As I indicated in my testimony this morning, the Utilities have allocated the existing transmission service available between Manitoba and Saskatchewan for other uses. For short-term purposes, they are willing to relax those uses in order to make available as much of the hundred megawatts of power as possible.

And in our conversations with Saskatchewan Power, the -- we believe that most, if not all, of the power can be delivered using interim arrangements and we have talked about a -- doing that for a year. We haven't talked about doing it for in perpetuity, but it -- it is something that we know that in order to meet the construction schedule that Manitoba Hydro has there will have to be a little bit of flexibility in the use of the existing transmission service. And -- and so far with the 2021 in-service date that Manitoba Hydro is projecting, we're able to agree to -- to that interim service use.

MR. BOB PETERS: Thank you, Mr. Cormie. Before I close off the microphone, Mr. Chair, I would like the assistance I believe I'm going to pick on Mr. Midford.

To go back to Board counsel, page 144 with my last question, and it deals, Mr. Midford, with something we talked about on the Conawapa. We talked about Conawapa and -- and Bipole III, and the costs related to it.

In earlier portions of this hearing,

Mr. Midford, we have heard from Manitoba Hydro who has proposed a method to deal with what I'll call the sunk costs of the Conawapa generating station.

Are you generally familiar with that, sir?

(BRIEF PAUSE)

MR. LORNE MIDFORD: I'm not intimately involved in that, Mr. Peters.

MR. BOB PETERS: No and I -- I greatly appreciate that. Manitoba Hydro has put before this Board a future proposal as to how Manitoba Hydro wants to deal with the costs related to Conawapa.

Would you -- are you generally aware that that's the case?

MR. DAVID CORMIE: Is that the amortization over thirty (30) years, Mr. Peters?

MR. BOB PETERS: Yes.

MR. DAVID CORMIE: Yes, I'm aware of those.

MR. BOB PETERS: And -- and my only question, Mr. Cormie, and it may result in an undertaking is that we heard related to Bipole III that the costs that were previously attributed to

Conawapa were going to be brought over to Bipole III and not charged through on Conawapa.

Do you remember hearing that this afternoon?

MR. DAVID CORMIE: Yes, I remember the discussion.

MR. BOB PETERS: And so we would like confirmation, please, that the road costs that are attributable to Conawapa are not included in the $380 million that Manitoba Hydro wants to amortize over the thirty (30) years.

Could you take that as an undertaking and find somebody on the revenue requirement panel to assist you with that?

MR. DAVID CORMIE: Yes, we will -- we will undertake to determine what those Conawapa road costs are and how they're being handled.

MR. BOB PETERS: That would be satisfactory if your counsel agrees and I thank you for that.

MR. DAVID CORMIE: Okay.

--- UNDERTAKING NO. 59: Manitoba Hydro to provide confirmation that the road costs that are

attributable to Conawapa
are not included in the
$380 million that Manitoba
Hydro wants to amortize
over the thirty (30) years

MR. BOB PETERS: Mr. Chair, it's been a long day, and I've contributed to the -- the duration. So I want to thank the Board Panel for their indulgence. I also want to thank the witnesses from Manitoba Hydro for their responses to my questions.

I will be turning the microphone over in the morning to Dr. Williams, but only after counsel for the General Service Small, General Service Medium and KAP have their fifteen (15) minutes of questions of this panel first thing at nine o'clock tomorrow.

After the Consumers Coalition will be -- the Consumers Coalition is estimating approximately no more than forty-five (45) minutes and likewise, Manitoba Industrial Power Users group is estimating approximate forty-five (45) minutes.

So the in-camera session would begin tomorrow from 11:00 till perhaps as late as 12:30

tomorrow and we should be relatively on track to hear from Daymark on the SaskPower matter which we expect will not take the balance of the day as long as it has been today.

THE CHAIRPERSON: Thank you all. It's been a long day. Thank you very much and we'll adjourn until nine o'clock tomorrow morning.

(PANEL RETIRES)

--- Upon adjourning at 6:26 p.m.

Certified Correct,

____

Cheryl Lavigne, Ms.

Tab 25

Manitoba Hydro
~~Privatization~~

Tories open to private-sector Hydro deals

WS

√f p 5

NOV 13 2006

ROCHELLE SQUIRES
Legislature Reporter

A Tory government would consider involving the private sector in financing and building more hydroelectric generating stations in Manitoba.

Opposition leader Hugh McFadyen said his party will be conducting a rigorous analysis into the public-private partnerships (P3s) funding model as a way to expand hydro capacity in the province.

"We would look at involving the private sector to finance hydro projects, much the way they do in B.C. and Ontario and other provinces," said McFadyen. "(If elected), we would adopt a pragmatic approach, and if we thought there was a benefit to consumers we would adopt it. If that case wasn't made, then we'd stick with traditional financing models."

The issue will undoubtedly be fiercely debated in the next provincial election.

The NDP government, still seething over the privatization of Manitoba Telecom Services Inc. by former Tory premier Gary Filmon, said McFadyen's ploy to use private money to expand Manitoba Hydro is a stepping stone toward selling off the utility.

Strong rating

"It's a back-door route to privatization," said Finance Minister Greg Selinger.

The minister said his government won't consider public-private partnerships to expand the utility because it's cheaper to use public dollars, not private money.

"It costs more money because the borrowing costs are higher. Our position, with our strong credit rating, is that nobody has been able to beat our rates," said Selinger.

Selinger said the utility must remain under the control of government, not a private board.

"The private sector would maximize shareholder value at the expense of the consumers of the service," he said.

McFadyen said the NDP government is being hypocritical because it used the P3 model to develop wind power.

He also denied any intention of privatizing Manitoba Hydro.

"We're not going to sell off Manitoba Hydro. MTS was a completely different case," said McFadyen. "We would never consider selling Manitoba Hydro. There's no reason to privatize a monopoly."

Private-public partnerships have flourished across the country as governments are finding them to be viable alternatives to borrowing for capital projects.

A 300-bed hospital in British Columbia, a courthouse in Calgary and a major highway in New Brunswick are all being built using a mix of private and public dollars.

Adrienne Batra, provincial director for the Canadian Taxpayers' Federation, said Manitoba's high debt is just cause for examining the P3 model further.

"The province should establish a long-term policy that would ensure core services are paid for without borrowing millions of dollars and adding to the debt," said Batra.

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2.0 NEED AND ALTERNATIVES

2.1 INTRODUCTION

Manitoba Hydro is under a statutory obligation to ensure the availability of a supply of power adequate to meet the needs of the Province. Without improvement, Manitoba's system is extremely vulnerable to weather or other emergency events which could interrupt the use of either the existing Bipoles I and II high voltage direct current (HVdc) lines located on the Interlake corridor or the single southern converter station (Dorsey). This chapter describes the urgent need to ensure the reliability and security of Manitoba's power supply and reviews the various alternatives for meeting that need.

In arriving at the conclusion that the Bipole III Project is the best alternative for meeting the province's reliability requirements, the chapter considers and analyzes the following questions:

- Why is the Project needed and what load serving requirements will it have to meet in order to sufficiently enhance system reliability?
- What options aside from new north-south transmission are available for addressing system reliability and what criteria were used to evaluate such options?
- Given that the construction of new north-south transmission has been determined to be the best reliability option, what alternative means of transmission can be built in order to carry power from the north to the south?

The chapter identifies that the best solution to meet the reliability needs of the Province is a new overhead north-south HVdc transmission line. Alternative routes for the transmission line are considered in Chapter 7.

2.2 NEED FOR AND SIZE OF THE PROJECT

2.2.1 Overview of Manitoba Hydro System Reliability Issues

Manitoba is heavily reliant on hydroelectricity, approximately 70%[1] of which is generated in plants in northern Manitoba in the form of alternating current (ac). This power is fed into the northern ac transmission system which is known as the Northern Collector System. In order to supply southern Manitoba today, power in the Northern Collector System must be converted from ac to HVdc for transmission over the exceptionally long distances to southern Manitoba, and then re-converted to ac form in southern Manitoba for transmission to customers via the Southern ac System.

At present, the overall Manitoba Hydro system depends on two converter stations in the north (Radisson and Henday), two HVdc lines (Bipoles I and II) running south along the same Interlake corridor, and the single Dorsey converter station in the south. The single Interlake corridor carries about 70% of Manitoba's entire generation supply. Manitoba is the only system in the world with such a concentration (of percentage) of supply along one corridor and in one converter station.

Manitoba's HVdc system is extremely vulnerable to weather or other events which could damage the Bipole I and II lines in the Interlake Corridor or Dorsey Station. The potential consequences of such an outage of the existing HVdc transmission system are exacerbated by the very long estimated repair times. Wide front windstorm, fire, or tornado damage at Dorsey Station could cause an outage that shuts down the HVdc system for up to three years because of the time required to repair or replace equipment of such complexity. The duration of a similar outage of the Bipoles I and II lines, although not as severe and dire as a failure at Dorsey Station, could still easily cause an outage of six to eight weeks.

In the event of an extended HVdc outage, supply would be restricted to the generation connected to the ac system and the possible imports on the ac interconnections with the United States and neighbouring provinces. Such a restricted supply of power would be significantly inadequate to meet provincial demand, particularly in the winter, and could necessitate rotating blackouts for months. The potential shortfall has been growing steadily over the years, as increased demands for power from new and existing customers have increased the system load requirement.

---

[1] The Northern Collector System generation totals 3570 MW, which is 70.9% of the total Manitoba Hydro hydroelectric generation of 5033 MW.

The potential effects of such an event present a risk that is unacceptable to Manitoba customers, particularly in the very cold months when the loss of power for extended periods could have serious effects on health, safety and security. The loss of Dorsey Station for up to three years could have a disastrous impact to the province and its economy.

The extensive rotating blackouts would leave affected neighbourhoods without power for extended stretches of time on a daily basis meaning that day to day requirements such as lighting, refrigeration, heating/cooling would be unavailable on a rotating schedule. Similarly, businesses would also be without power to operate their facilities forcing them to close during such outages, and causing business disruptions.

The types of events that could occur to put system reliability at risk in Manitoba include forest fires, fire at a converter station, weather events such as downburst/wide front winds, tornados and ice storms. The probability and potential duration associated with these potential catastrophic events is discussed in the following section.

2.2.2 Probability and Durations of a Catastrophic HVdc Outage

The potential of catastrophic failure of either the Bipole I and II lines or Dorsey Station due to fire and extreme weather events has been evaluated by Manitoba Hydro, in consultation with experts in the field.

Studies (Teshmont 2001) have shown that with respect to Dorsey Station, there is a 1 in 29 year probability of outage due to fire and a 1 in 200 year probability of outage due to wide front winds. While mitigation measures have been put in place, which partially address fire vulnerability at Dorsey, there is little that can reasonably be done to mitigate vulnerability to wind and other weather events. The same studies (Teshmont 2001) revealed that the probability of the loss of the Interlake corridor is 1 in 17 years from a tornado, 1 in 50 years from icing and 1 in 250 years from wide front winds.

Several "near-miss" experiences in Manitoba have highlighted the need for a major system reliability enhancement. Two examples are outlined below, each of which could easily have caused greater damage and led to more severe consequences.

Manitoba Hydro Wind Event, September 1996

On September 5, 1996 a downburst wind event caused the failure of 19 Bipole I and II transmission towers just two km north of Dorsey Station. Had this event occurred closer to Dorsey Station, it could have also taken down the Dorsey-Forbes 500 kV interconnection which would have in turn reduced the amount of power that could be imported from the United States. It took over four days to restore one HVdc line. Bipole I and II converters were then operated on this one line until the second dc line was repaired.

Photo 2.2-1: Damaged Towers of (TWG #1991) Bipole I and II Lines by Downburst Winds in 1996

Due to the time of year (September), the load was relatively low. Manitoba Hydro managed to serve the entire load during this event by relying heavily on arranged imports of up to 985 MW of power from the USA and neighbouring provinces, as well as by appealing to the public to reduce consumption. Had the event occurred just a month or two later in the year when load levels would have been higher, rotating blackouts would have been unavoidable.

Elie Tornado, June 2007

On June 22, 2007, a level 5 tornado (the strongest confirmed tornado in Canadian history) flattened buildings and the electrical infrastructure in the town of Elie just west of Winnipeg. Extensive damage caused by the tornado left thousands of customers without electricity until service was restored two days later. Damage to towns and communities from a separate storm system farther west was more severe, leaving many more thousands of customers without power for even greater periods.

Photo 2.2-2: Elie F5 Tornado and the Aftermath Damage

The Elie tornado was on the ground for about 35 minutes, and traveled a distance of approximately 5.5 kilometres (km). Damage occurred throughout a swath of land that reached widths of up to 300 meters. At their most intense, the tornado wind speeds were estimated to have reached between 420 and 510 km/h. An entire two-story home was swept off its foundation and tossed 75 feet in the air before rotating around the tornado and being obliterated.

Dorsey station is only 30 km north of Elie. A tornado of this or even lesser magnitude at Dorsey would have leveled the station, causing the kind of catastrophic failure discussed throughout this chapter.

2.2.3 Potential Load Shortfall and Required Size for Reliability Project

The chart set out below in Figure 2.2-1 depicts the available power supply and peak load in the event of loss of the Bipoles I and II transmission lines. With Wuskwatim generation in service, in the event of a catastrophic outage, the 2011/2012 system shortfall at winter peak is about 1400 MW, and will increase steadily with the growth in load to approximately 1500 MW by 2017 and 2000 MW by 2025, even after the 300 MW improvement associated with Riel sectionalization. The supply which would be available under such outage conditions is based on existing thermal generating capacity, generation connected to the ac system and the ability to import 900 MW of power from outside of Manitoba. The 1500 MW shortfall would be equivalent to the power demand of over 300,000 average residences based on an average peak demand of 5 kVA/household.

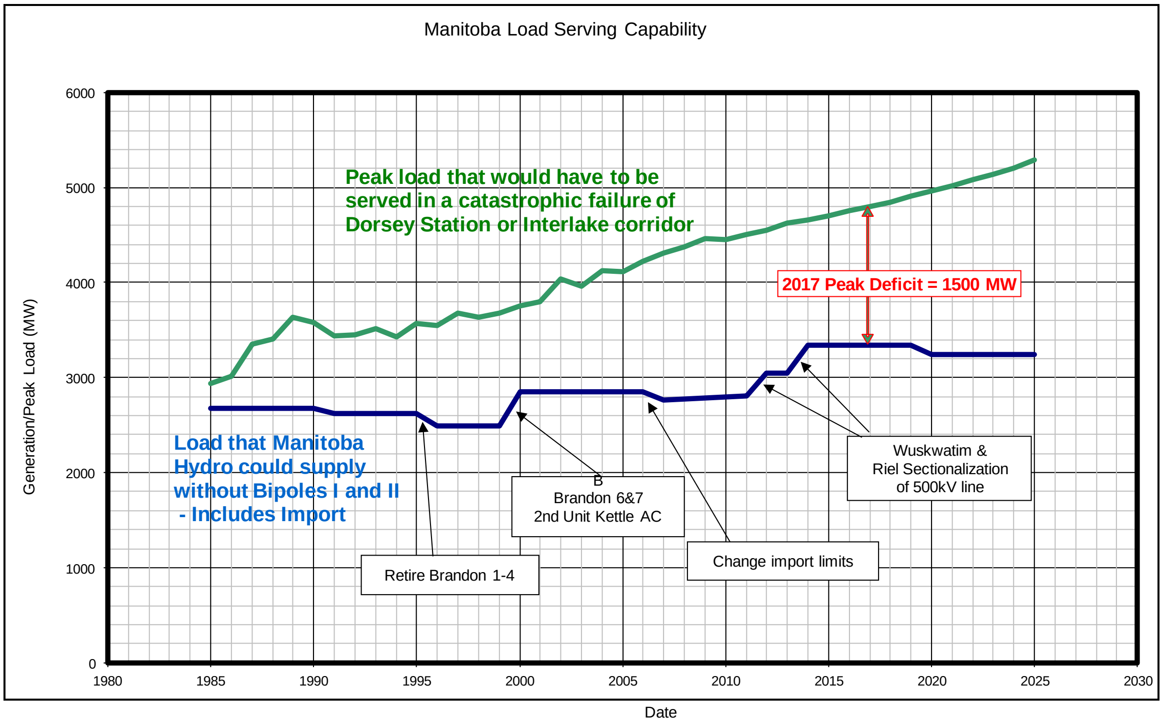

Figure 2.2-1: Load Serving Capability without Bipoles I & II

The deficit has been growing despite the various system improvements that have been made over the years, demonstrating the need for a reliability initiative that would address the deficit in full for a reasonable time frame in to the future.

Recognizing that the system is not always operating at peak load requirement, additional data must be considered to evaluate the consequences on a broader basis. Given that loads vary with both time of year and time of day, these variables must be taken into account when evaluating the loss of transmission capacity. Figure 2.2-2 depicts this analysis showing that in 2017/18, if Bipoles I and II were unavailable, Manitoba Hydro would be unable to meet provincial demand for approximately one third of the time during that period.

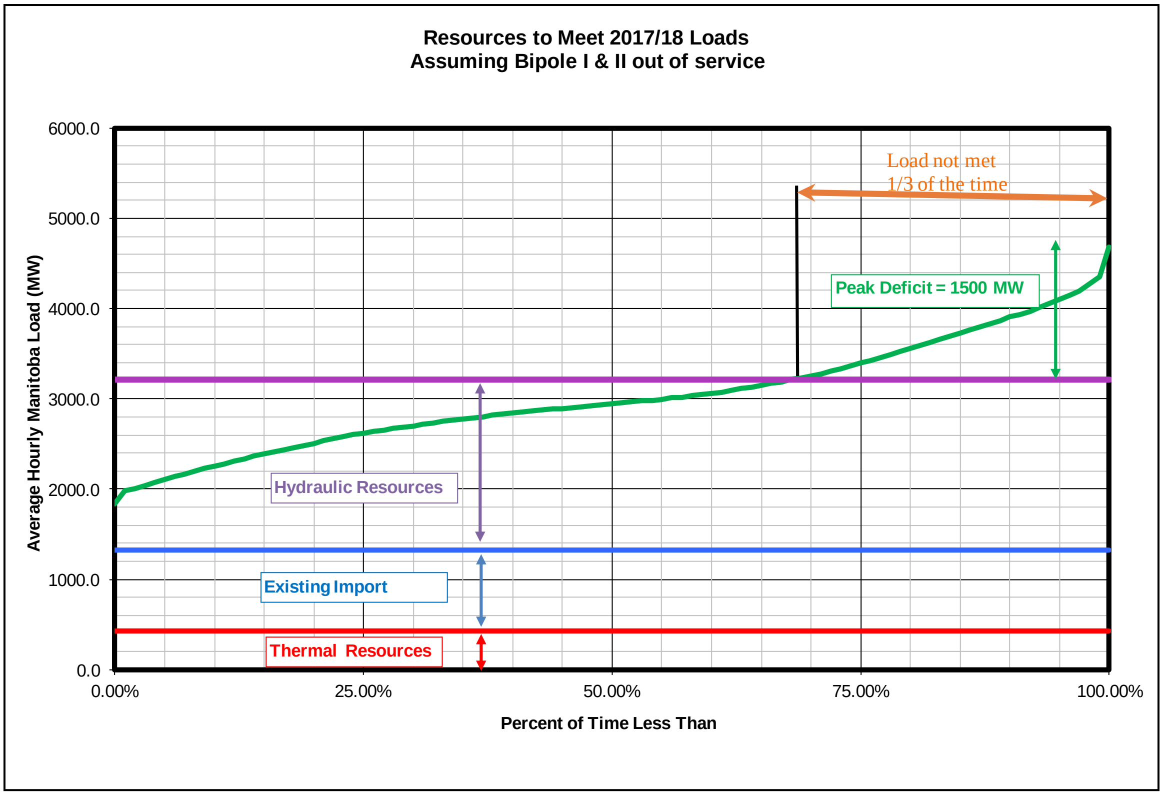

Figure 2.2-2: 2017/2018 Load Duration Curve for a Catastrophic Outage of HVdc

If an outage occurred in January 2017, be it at the Dorsey station or on the HVdc lines, as depicted on Figure 2.2-3, Manitoba Hydro would not be able to meet demand for 85% of the time during that month.

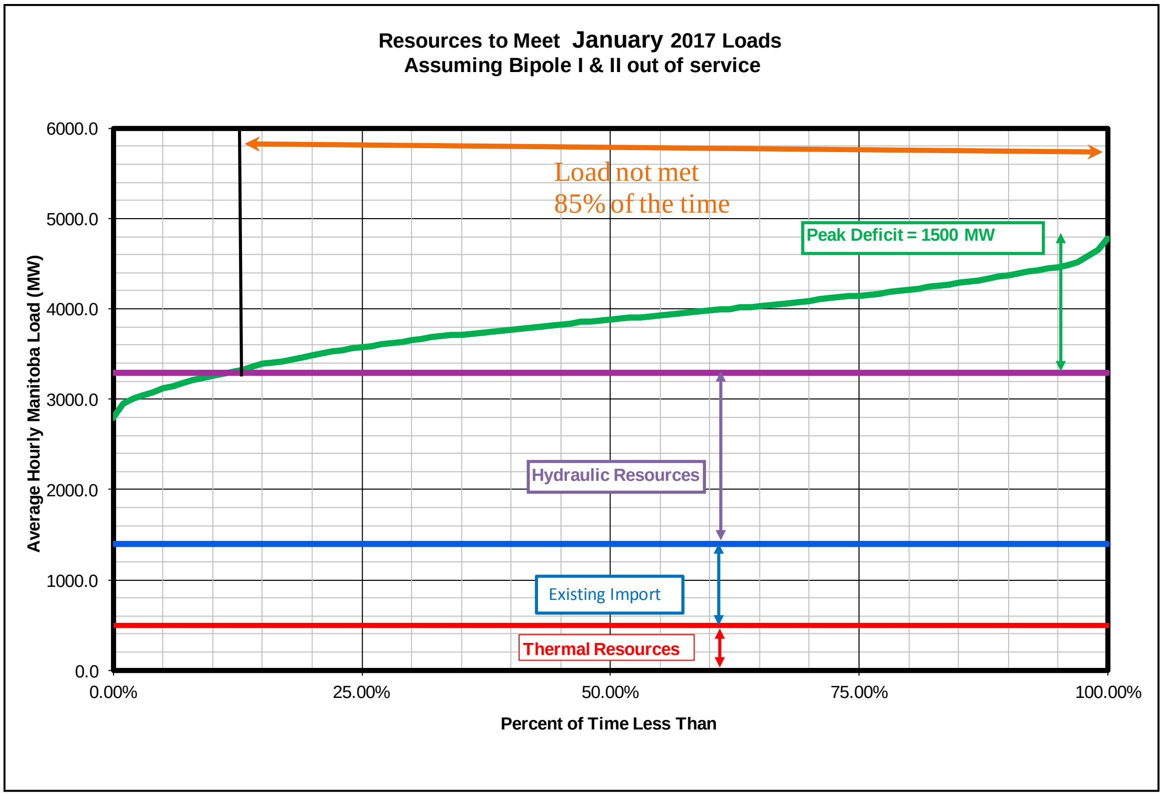

Figure 2.2-3: 2017 January Load Duration Curve for a Catastrophic Outage of HVdc

Given the significant consequences to Manitoba Hydro customers of an extended HVdc outage, the preferred reliability option should be able to minimize the unserved domestic load resulting from a catastrophic HVdc outage beyond the year it is put in service. A major factor considered in the selection of the 2000 MW Bipole III rating was the requirement to provide excess capacity beyond the 1500 MW deficit expected in 2017, the Bipole III in-service date, considering the extended time and outages required to add capacity in stages once the Bipole III is placed in service. A second important factor considered was compatibility with the existing system.

2.3 PROJECT ALTERNATIVES TO ADDRESS SYSTEM RELIABILITY

Alternatives to the project are the functionally different ways to meet the need for the Project and to achieve the Project's purpose. The following three alternative project options for enhancing the reliability of the Manitoba Hydro system were identified and evaluated:

1. The addition of 2000 MW of north-south HVdc transmission to continue to supply power from existing hydraulic generating sources in the north.
2. The addition of up to 2000 MW of gas turbines in southern Manitoba.
3. The addition of up to 1500 MW of new import tie lines to the United States (USA) to provide access to firm US generation, which is assumed to be comprised mainly of natural gas-fired generation, plus the addition of another 500 MW of natural gas-fired generation in southern Manitoba.

Other alternatives were considered to meet the Project's purpose, but were quickly ruled out as viable options. For example, some consideration was given to strengthening the existing HVdc transmission lines and converter stations to withstand higher stresses than those for which they were originally designed. While such work could lessen the vulnerability of the system, the probability of catastrophic outage associated with major events would still be too great to warrant strengthening as a solution on its own and, accordingly, it was not further evaluated. Staging of Bipole III was ruled out as being most costly due to the 1500 MW supply deficit and the minimal time between the initial stage and the completion stage.

2.3.1 Evaluation Criteria for Project Alternatives

Each of the three reliability improvement alternatives was planned and designed to meet the objective of continuing to serve Manitoba load in the event of an extended HVdc outage. The main criteria by which the project options were assessed are as follows:

1. *Project Cost* – The overall capital cost of each project alternative is a consideration for Manitoba Hydro in assessing project viability. Project cost was the main factor in the alternative evaluation.
2. *Implications to Manitoba Hydro during an extended catastrophic HVdc outage* – Given the potentially long repair times associated with potential catastrophic outages, each

project option was assessed having regard to the additional costs which would be incurred during such outages.

Implications to Manitoba Hydro during non-catastrophic outages and normal operation – The HVdc system currently has very little spare transmission capability (only about 300 MW). In the event of a more commonly occurring non-catastrophic HVdc outage such as a valve group or pole outage, this spare capacity is insufficient to transmit all available northern generation. Under this circumstance export curtailments or power imports may be necessary to meet load requirements. Accordingly, each reliability alternative has been evaluated for its ability to minimize additional costs and maximize value to Manitoba Hydro by providing coverage for planned/forced non-catastrophic HVdc outages.

Ability to facilitate future system expansion and enhance operational flexibility – Manitoba's growing domestic load will require future expansion of Manitoba Hydro's system generation capability. Over the last forty years, Manitoba Hydro has made huge investments in northern hydroelectric facilities and it is anticipated that future domestic load, as well as export requirements, will be met through additions to such infrastructure. Each of the three reliability options has also been assessed having regard to their ability to enhance operational flexibility as well as facilitate the choices available for future supply options.

Table 2.3-1 in Section 2.3.5 reviews the project alternatives relative to the project criteria. The discussion below reviews each project option studied and their respective evaluation.

2.3.2 Alternative 1 - Additional HVdc North-South Transmission

With respect to project cost, the construction of the proposed Bipole III is currently estimated at $3.28 billion in-service dollars. As noted in the previous section, the sizing of the Project is an important consideration. It has been sized for 2000 MW which will meet the projected reliability shortfall and enhance operational compatibility.

Long distance north-south transmission can be implemented using ac or dc transmission and the costs and operational attributes will vary according to the technology selected to carry out the project (see Section 2.4 below). Ultimately, the preferred means of HVdc overhead transmission is the most reliable, cost effective and technically viable option that also offers the greatest operational flexibility. The HVdc transmission line can be integrated into the Northern Collector System allowing operational flexibility of the three Bipole system. The addition of a third north-south HVdc line will increase efficiency of the north-south transmission system under normal operation, saving line losses of approximately 76 MW by splitting the generation from the Northern Collector System amongst three lines instead of two (Bipoles I and II).

Bipole III is the most attractive project alternative to protect the long-term supply of power, in that it continues to utilize existing northern hydraulic generation. The development of Bipole III also has the significant additional benefit of protecting Manitoba Hydro's options for future expansion of northern generating facilities both for domestic load and for export purposes, by adding additional transmission capacity into the system. While the primary driver of the project is system reliability, there is significant ancillary value to Manitoba Hydro in protecting and supporting the major investments it has made in northern generation facilities, as well as any future investments in northern hydroelectric resources. Moreover, failing to strengthen Manitoba Hydro's ability to transmit power from the north will reduce its attractiveness as a supply option to those export markets which Manitoba Hydro may in turn have to rely on for imports in an emergency situation.

2.3.3 Alternative 2 - Building Natural Gas-Fired Generation in Southern Manitoba

The second project alternative which has been assessed in the context of the potential load shortfall is the construction of approximately 1500 MW of natural gas-fired generation in southern Manitoba for 2017, and a further addition of 500 MW by the year 2025. The total cost of this gas turbine alternative has been estimated to be nearly $700 million (2010$) higher than that of the current estimate for the Bipole III Project on a present value basis.

The costs associated with this project alternative during any kind of outage would be significantly higher than the costs associated with transmission given that it would burn natural gas to generate power as opposed to utilizing northern hydraulic generation.

Gas capacity installed for system reliability would mostly be used for contingency situations; and accordingly, the capital investment will be used primarily as a "stand-by" source of power. The total project cost is comprised of the installation of gas turbines as well as the cost of ensuring a large firm gas supply on demand. The cost of the turbines themselves (2000 MW) is estimated to be $2.99 billion (2017$). Ensuring access to sudden and extensive demand for gas requires a firm gas supply for any given year throughout the 35-year planning horizon. An average cost of $181 million per year (in-service$) is required to secure a firm gas supply and consists primarily of a pipeline reservation fee with an additional cost for arrangements for the provision of fuel in the event that it is needed. It should be noted that the above cost of securing gas supply does not include the significant additional fuel costs that would be incurred when the gas turbines are operated during an outage.

In the event of a planned or unexpected outage, substantial operating, maintenance and fuel costs would be incurred for the natural gas-fired generation alternative. While idling in "stand-by" mode, gas turbines are required to run five percent of the time to ensure operational readiness. This in turn results in an additional annual fuel cost independent of turbine utilization.

During a catastrophic outage, the fuel, operating and maintenance costs associated with the supply of emergency power will be substantially higher for this option, and could be exacerbated by natural gas price volatility. There could also be delays associated with bringing the gas turbines from "stand-by" mode to full operational capacity. Use of non-renewable fossil fuels will increase the carbon foot print of this option in comparison to a transmission option linked to existing hydroelectric generation. In addition, this option would require the development of new transmission connections, with the possible exception of an installation near the Riel site, which would then require the construction of a gas pipeline to Riel.

Finally, this option significantly limits the potential for overall system development and enhancement given the lack of transmission connection to the major northern source of power from hydroelectric generating stations.

2.3.4 Alternative 3 - Importing Power

The third alternative involves the construction of a new high capacity transmission line between Winnipeg and Minneapolis, making it possible to import firm generation from a US supplier during an emergency. A 1500 MW interconnection of this nature is estimated to cost approximately $1.5 billion. In addition to this capital cost, this alternative requires firm power purchases in order to secure a reliable supply of import power, as well as 500 MW of natural gas-fired generation installed in Manitoba to meet growing load thereafter. A proxy for the cost of firm power purchases is the capital cost of adding 1500 MW of natural gas-fired generation in Manitoba, a standard proxy for new generation. Consequently, the total cost for the import alternative would consist of approximately $1.5 billion for building an interconnection and the capital cost of adding 2000 MW of natural gas-fired generation ($2.99 billion [in-service dollars]) plus operating costs. Accordingly, this option has the added cost of approximately $1.5 billion for building an interconnection but provides no additional benefits over the all-gas option.

The costs associated with this option during an outage will be similar or greater than the costs identified for the southern gas turbine alternative and would again expose Manitoba Hydro to natural gas price volatility.

A significant challenge associated with this project option is the need to engage US partners to construct the necessary generation and tie line facilities in the US. Building transmission outside of Manitoba and Canada is an unprecedented venture for Manitoba Hydro and would inherently have considerable risks involved. Given that Manitoba Hydro has been a supplier of significant amounts of firm clean energy to US customers for the past few decades, the concept of Manitoba Hydro requesting the US utilities to construct firm natural gas-fired generation for purchase by Manitoba Hydro would be a daunting request.

As with the gas supply option, this option significantly limits the potential for future opportunities for export sales as it does not enhance the transmission connection to the major northern source of hydroelectric power.

2.3.5 Recommended Alternative

The above discussion provides a description of the alternatives considered for improving Manitoba Hydro system reliability. Having regard to the criteria identified in Section 2.3.1, the Bipole III north-south transmission alternative is clearly the superior reliability solution at the least capital cost. In addition, it provides the greatest flexibility in operation and system expansion, with the least cost of emergency power during HVdc outages, catastrophic or otherwise. Furthermore, it is the only alternative that does not utilize energy generated from a non-renewable source and makes full utilization of the hydro-based generation system that Manitoba Hydro has developed over the past 50 years. The summary of the analysis of the three viable options having regard to the project criteria is set out below in.

Table 2.3-1: Evaluation Criteria for Project Alternatives

Objectives	Alternative 1 North-South dc Transmission	Alternative 2 Manitoba Natural Gas fired Generation	Alternative 3 Importing Power
Cost	Capital Cost (in-service dollars) $3.28 billion Fixed and variable annual cost $0.01 billion/yr	Capital cost amounts to $696 million more than Alternative 1 (Bipole III) on a present value basis Gas turbine installation cost $2.99 billion (in-service $) Fixed and variable annual cost $0.181 billion/year + variable costs	Capital Cost approximately $4.49 billion (in-service $) Annual costs subject to contract terms and variable costs
Savings/costs additional to the above	Reduction in transmission losses – approximately 26 M/year (2010$)	Annual cost of maintaining standby readiness	
Minimize unserved load during an extended HVdc outage	Meets reliability requirements until 2025. In the early years additional capacity available over the peak demand can reduce the import requirement costs	Meets reliability requirements until 2025 But heavily reliant on import from inception in 2017	Meets reliability requirements until 2025 Very high import dependency
Minimize costs to Manitoba Hydro during an extended HVdc outage	No additional costs	Significant fuel, operation and maintenance cost	Significant power purchase costs
Minimize costs to Manitoba Hydro during non-a catastrophic outage of HVdc	No additional costs	Fuel, operation and maintenance cost	Power purchase costs
Facilitate future system expansion and operational flexibility	Facilitates a reliability solution and an outlet for northern hydro development as soon as 2017	Provides only the reliability solution	Provides reliability solution and future potential for expansion of export access to US market

2.4 "ALTERNATIVE MEANS OF" CARRYING OUT THE PROJECT

Alternative means are the various technically and economically feasible ways the project can be implemented or carried out (CEAA 2007). Bipole III (overhead north-south dc transmission) was identified as the best alternative to meet the project need and purpose both economically and technically. A number of other means of carrying out the project were identified and evaluated. The alternative means identified included:

- ac versus dc transmission;
- Overhead lines versus underground option; and
- Overhead lines versus underwater option.

As discussed below, none of these alternative means were deemed to be viable options for this project. Alternative routes for the transmission line are reviewed in Chapter 7.

2.4.1 HVdc versus HVac Transmission

High voltage direct current (HVdc) transmission and high voltage alternating current (HVac) transmission are the two options for providing additional transmission capacity. The HVdc option requires a third transmission line from north to south that includes new converters at both ends. The HVac option would require new high voltage transformer stations and switchyards at both ends of the line and one or more stations at the intermediate points (voltage compensation) of the line for the transmission lengths in consideration.

The point to point distance from the Nelson River northern collector system to the load centers close to Winnipeg exceeds 800 km (Rudervall *et al* 2000; Seimens 2008; New England Power Service Company 1997).

The reason for development of HVdc systems was in part to deal with the excessive energy losses incurred over long distances when transmitting ac power. The use of dc transmission entails lower energy losses over distance but requires costly converter stations at each end of the system. Transmission losses on an HVdc transmission line are about 75% of the losses of an equivalent ac transmission line (New England Power Service Company 1997). Based on industry cost comparisons for HVdc and HVac transmission, HVdc transmission is most economical for distances exceeding on the average about 600 km (Rudervall *et al* 2000; Seimens 2008). Estimated loss savings with HVdc transmission can be more than 40 MW at full capacity utilization of the proposed transmission scheme.

A double circuit ac transmission on a single tower is considered to provide comparable capacity and availability to a bipolar HVdc transmission system. Due to their complexity, the capital costs for HVdc converter stations are higher than for high voltage ac substations. On the other hand, the transmission line costs are lower for HVdc transmission, given that only two sets of conductors are required as opposed to six for double circuit three phase ac transmission lines. Significantly smaller towers are required for HVdc versus ac. A 500 kV ac double circuit tower that provides adequate clearances and structural strength would be about 35% taller and much wider (Figure 2.4-1). One further major deterrent to using ac transmission is the need to connect the ac transmission line to the Northern Collector System. The greatest operational flexibility arises from a new transmission scheme that connects directly to this system, where power transfer between Bipoles I and II and the new scheme can be controlled without switching operations. This is easiest to achieve with HVdc due to its compatibility with Bipoles I and II.

In contrast, an ac line cannot readily be connected to the Northern Collector System without major and potentially very costly system changes. Since the existing north-south transmission is all HVdc, the Northern Collector System is isolated from (asynchronous to) the southern Manitoba interconnected ac system. This is unique to the Manitoba Hydro system and enables several special protection systems that enhance system stability, operability and export capability. A permanently connected ac line between the Northern Collector System and the south will disrupt this unique configuration. A north-south ac line permanently connected to the Northern Collector System will not be readily compatible with the existing system configuration without major reengineering of the existing protection and control schemes and the possible addition of new special protection systems (SPSs). An ac line left disconnected from the northern collector system will normally have the undesirable effect of delaying the process of power transfer to and from the ac transmission scheme, as it would involve switching generation onto the ac line and out of the northern collector system, and vice versa.

In essence, the analysis means that there are significant operating complexities and costly upgrades that would be required to make the ac transmission option viable. Even with such upgrades there will be switching delays in activating this transmission when required for system operations.

500kV 500kV Double Circuit

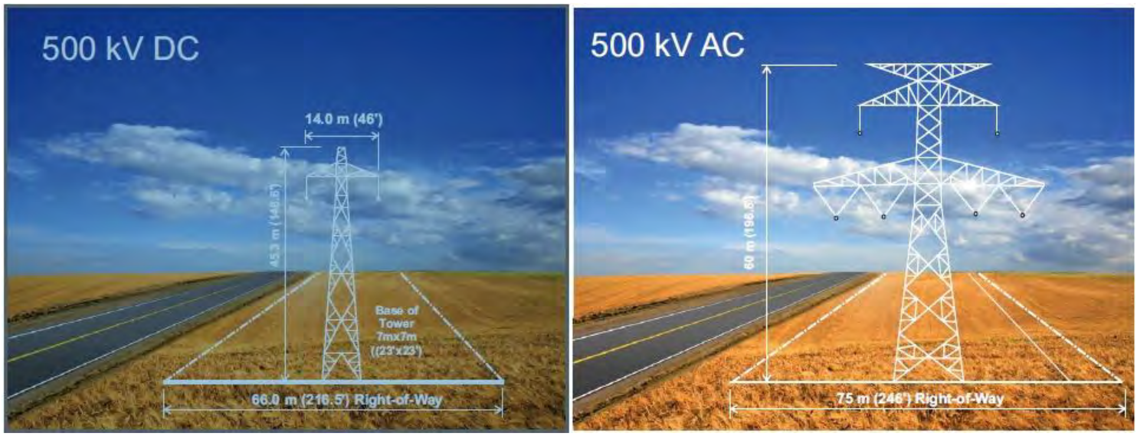

Figure 2.4-1: Typical Transmission Line Structures for 500kV 2000MW HVdc and AC Schemes

The double circuit ac line requires a significantly wider right-of-way (ROW), about 15% more than for HVdc as estimated by Manitoba Hydro. A 15% increase in ROW over a line length greater than 1300 km is significant, adding cost and requiring more land clearing (Table 2.4-1) to accommodate a 75 m wide ROW.

In summary, HVdc transmission is less expensive, less complex and provides the greatest operational flexibility with the existing Bipoles I and II. The ac transmission option is less desirable in the context of the reliability initiative; due to cost considerations and the additional complexity of operation it would impose on the Manitoba Hydro major transmission system as a whole.

2.4.2 Overhead Transmission Lines versus Underground or Submarine Cable Transmission

The point to point transmission distance from the northern collector system to the load centers close to Winnipeg exceeds 800 km. The actual transmission distance exceeds 1300 km for the west-side route that has been proposed. Overhead transmission is the most economical and technically mature technology for such long lengths of transmission. Underground ac cables require intermediate stations to control voltage along the line, which adds to the cost and operating complexity and reduces reliability. As a result, there is no bulk power transmission scheme in the world that uses underground ac cable technology for lines longer than 100 km in length.

Underground or underwater HVdc cables are rarely used where overhead transmission is technically viable. In fact, worldwide, there is no high power, long distance underground cable transmission; underwater dc cable transmission is used because it is the sole transmission choice for crossing large bodies of water and they are usually accessible to large ocean going cable laying ships. Underground or subsurface transmission at the 500 kV voltage level, even in favourable terrain conditions, is on average five to six times more costly than overhead transmission. Even if it were otherwise feasible, underground transmission requires a cleared right-of-way and does not eliminate concerns about the loss of vegetation and habitat, or about increased access (two of the principal concerns encountered with transmission lines in northern Manitoba) or disturbance to agricultural lands in southern Manitoba.

Underwater (submarine) cables laid in trenches in the lake bed of Lake Winnipeg have also recently been investigated conceptually as an alternative form of transmission for future transmission projects (Farlinger *et al* 2011).

A review panel consisting of multi disciplinary experts both within and external to Manitoba Hydro has investigated the potential use of the submarine or underground cables for long distance electricity transmission in Manitoba. The report was completed early this year and reviews the various potential routes, costs and performance issues associated with the application of these technologies to Manitoba (Farlinger *et al* 2011).

According to the above report, the current technology for cable transportation is limited to short cable lengths and therefore requires hundreds of splices (cable connections). It also identifies the life expectancy of underground and submarine cables as half of that of overhead lines. The failure rates are high (failure every 3 to 17 years). Repair times would be longer and costs would be higher considering the long winter months in Manitoba when Lake Winnipeg is ice covered. The report concludes that it is premature to consider submarine or underground cables as a means of delivering this project at this time.

2.4.3 Recommended Means

The above discussion provides a brief description of the alternative means considered for carrying out the preferred project of additional north-south transmission with overhead HVdc transmission being the recommended means. This option is by far the least cost alternative, is technically feasible, and provides excellent reliability. The comparison of the various north-south transmission options is set out below in Table 2.4-1.

Table 2.4-1: Comparison of North-South Transmission Options

	Overhead HVac	Overhead HVdc	Underground HVdc	Underwater Hvdc
Cost	Very high for the considered length of transmission	Least cost	5-6 times more than the HVdc	Highest
Feasibility	Feasible	Feasible	Feasible for short distances	Not currently feasible in Manitoba situation
Reliability	Generally technology offers excellent reliability However, for this application there is compromise due to operational complexities	Excellent reliability	Not as reliable due to frequent and long repair times, due to the many splices in U/G cables. Shorter life time than O/H lines Maintenance in winter months can be difficult	Not as reliable as even the U/G due to short cable pieces spliced together as demanded by the cable laying technology Maintenance in the winter months can be prohibitive

2.4.4 North-South Transmission Alternative Corridors

Once north-south HVdc overhead transmission was selected as the preferred means for addressing system reliability, several alternatives were considered in selecting a corridor to route the preferred transmission option. The geography of Manitoba essentially forms three corridors between northern and southern Manitoba: east of Lake Winnipeg, the Interlake Region, and west of Lakes Manitoba and Winnipegosis.

The eastern corridor had been under consideration early in the planning stages. However, a policy decision was made by the Provincial Government that the reliability project should not be routed within this corridor. A copy of the letter from the Minister responsible for Manitoba Hydro providing this policy direction to Manitoba Hydro is attached as Appendix 2A to this chapter.

The Interlake corridor is the location of the existing Bipoles I and II and is unacceptable as a location for Bipole III. In order to meet reliability criteria, physical separation from the existing major HVdc transmission facilities is required. Separation is the only effective way to reduce the risk of common outage of all three lines at the same time. Given the over concentration of transmission in the Interlake corridor, the third transmission line must be located within a corridor well separated from Bipoles I and II in order to obtain maximum reliability benefits (Teshmont 2006). As such a separation is not feasible within the Interlake corridor; this corridor was rejected for Bipole III routing.

As a consequence of the above analysis, the western corridor was selected for routing the Bipole III Project. Several studies have quantified the reduction in risk of common outage for the various routing options (Teshmont 2006). In general a significant improvement in reliability can be gained by the western routing option as compared to the Interlake corridor. Routing options within the western corridor are reviewed in Chapter 7.

2.5 SUMMARY OF RECOMMENDED PROJECT AND RATIONALE FOR SELECTION

The existing vulnerability of the Manitoba Hydro transmission system to extreme weather and other events which would result in an inability to serve a large portion of the Manitoba load over extended outage durations clearly justifies the need for the project. The over dependence on a single transmission right-of way in the Interlake or a single Dorsey converter station for transmitting about 70% of the hydroelectric generation in Manitoba to southern load centers has long been seen as unacceptable for reliably meeting the needs of Manitoba Hydro customers. Any extended loss of power of this magnitude, would have disastrous consequences for the Province of Manitoba and its residents.

- The recommended option to address the energy supply reliability of the Manitoba Hydro system is the 2000 MW Bipole III alternative. This is the most cost effective alternative that meets the entire supply shortfall in the event of an extended HVdc outage with minimal risk and the most effective operating flexibility. The Bipole III alternative is about $696 Million (2010 present value dollars) less costly than the natural gas-fired generation alternative.
- The 2000 MW Bipole III provides the required capacity to meet load in the event of an extended HVdc outage of Dorsey Station or the Interlake corridor. This option has minimal operating cost to Manitoba Hydro during such an outage, as it would continue to utilize the low cost northern hydraulic generation, as opposed to gas generation or imported power considered in the other alternatives (Manitoba Hydro 2011).
- Bipole III would also provide the much needed north-south spare transmission for normal day to day operation and provides significant savings in transmission losses. The estimated potential savings in losses are 76 MW at maximum generation

approximately amounting to 243 GWh/year, which can have a value of $26 million/year to Manitoba Hydro (Manitoba Hydro 2011).

- The availability of spare transmission also results in minimizing the cost of non-catastrophic outages of the HVdc system, by minimizing the curtailment of firm export power and/or the need for import to serve domestic load. The planned or forced non-catastrophic outages would result in significant additional operating costs for the gas or import alternatives (Manitoba Hydro 2011).
- Bipole III is the only alternative that facilitates reliable and economical system expansion for serving future load growth. Thus it has the most potential to meet reliability needs, as well as increases to domestic load and/or export requirements in future years with minimum cost. The gas or import options inhibit future participation in the export market which has historically enhanced Manitoba Hydro's ability to maintain low electricity rates.

2.6 CONCLUSION

A system reliability initiative, Bipole III is needed to provide a back-up transmission path, recognizing the existing vulnerability of Bipoles I and II, which share a common transmission line corridor and a single terminus at Dorsey Station. Based on both technical and economic feasibility, as well as environmental considerations, overhead high voltage direct current (HVdc) transmission is the best technology to provide the reliability and security of power for the province.

The process to select the route itself is described in greater detail in Chapter 7 of the EIS.

2.7 REFERENCES

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Tab 27

DECISION
of the
Manitoba Clean Environment Commission
On the Motion of the
Bipole III Coalition, Applicants
August 29, 2012

For the Applicant: Brian Meronek, Q.C.
Ivan Holloway
Intervenor: James Beddome
For the Respondent,
Manitoba Hydro: Doug Bedford

Decision

The Motion requesting an adjournment of the Hearings is dismissed.

Issue

The Applicant, by way of a motion made pursuant to Section 2.08 of the Clean Environment Commission *Process Guidelines Respecting Public Hearings*, requested an order directing the proponent to answer specific Information Requests, as well as an adjournment of the start of the Commission's public hearings to an unspecified date from the scheduled date of October 1, 2012.

Background

In December 2011, the Minister of Conservation issued a request that the Clean Environment Commission (CEC) hold public hearings on Manitoba Hydro's proposal to construct the Bipole III transmission line project.

In May 2012, the Bipole III Coalition was granted funding under the Participant Assistance Program (PAP) and, thus, became a registered participant for the CEC proceedings.

Commission's Authority

Subsection 6(8) of *The Environment Act* allows the Commission to make rules governing its procedure.

Section 2.08 of the Clean Environment Commission *Process Guidelines Respecting Public Hearings* provides:

> The Commission will accept motions respecting procedural matters from the Proponent and those designated as Participants.
>
> ………
>
> On hearing the motion, the Commission may allow, dismiss or adjourn the motion, in whole or in part, and with or without terms.

The Supreme Court of Canada reinforced this authority in a 1989 decision:

> As a general rule, these tribunals are considered to be masters in their own house. In the absence of specific rules laid down by statute or regulation, they control their own procedures subject to the proviso that they comply with the rules of fairness and, where they exercise judicial or quasi-judicial functions, the rules of natural justice. Adjournment of their proceedings is very much in their discretion[1]

Accordingly, the Commission does have the authority to decide whether or not to grant the requested adjournment.

The Manitoba Court of Queen's Bench, in *Candeias v. Manitoba (Residential Tenancies Commission)*, 2000 MBQB 216, considered the matter of a request for an adjournment of an administrative proceeding.

The judge quoted from a decision of the Supreme Court of Canada in identifying the principle to be followed by an administrative body in making such a decision:

> "… there is, as a general common law principle, a duty of procedural fairness lying on every public authority making an administrative decision which is not of a legislative nature and which affects the rights, privileges or interests of an individual: ...
>
> "The question, of course, is what the duty of procedural fairness may reasonably require of an authority in the way of specific procedural rights in a particular legislative and administrative context and what should be considered to be a breach of fairness in particular circumstances. ..."[2]

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[1] *Prassad v. Canada (Minister of Employment and Immigration)*, [1989] 1 S.C.R. 560
[2] *Cardinal et al. v. Director of Kent Institution* (1985), 16 Admin. L.R. 233 (S.C.C.)

Relief Sought

1. An Order or Direction of the CEC to Manitoba Hydro to respond to those Information Requests submitted to the CEC by the Coalition on July 19 and 20, 2012, as listed in attachment A to this Motion;

2. An adjournment of the Hearing scheduled to commence on October 1, 2012 to a date sufficient to enable the Information Requests to be answered; a second round of Information Requests to be submitted by the participants and answered by Manitoba Hydro; and, expert reports to be prepared in time before the commencement of the hearing; in accordance with the schedule, in attachment B to this Motion.

Applicant's Grounds

From Notice of Motion, filed August 8, 2012.

The Applicant's arguments focus on the fact that a number of its Information Requests were not submitted to the proponent for response. It argued that:

1. The Information Requests are relevant.

2. A review of the EIS demonstrates that the Information Requests are necessary in order to determine:

   a. The need at this time for Bipole III at all regardless of location;
   b. The reliability concerns alleged by Manitoba Hydro to be the motivating consideration behind Bipole III;
   c. Whether there are alternatives to the construction at this time of Bipole III in terms of environmental impact, cost and sustainable development specifically by relocating Bipole II to the La Verendrye S.S. (or perhaps the Riel S.S.).

3. All Information Requests are within the scope of the Terms of Reference to the CEC established by the Minister of Conservation on or about December 5, 2011.

4. All Information Requests directly relate to matters and issues specifically advanced by Manitoba Hydro in the EIS.

5. Natural justice requires that Information Requests which are clearly inside the Terms of Reference be allowed to be asked of the proponent without first having to be vetted and pre-approved by the CEC or its staff.

6. Natural justice requires that a tribunal not pre-judge the requirement for evidence without the proponent first putting the relevancy and admissibility of such evidence into question before the tribunal.

7. Environmental law recognizes that there be a meaningful need for and alternative to (NFAAT) assessment of a project in order for the tribunal to discharge its obligations in making recommendations to the Minister.

8. The proponent has put into question NFAAT in its EIS.

9. The timing of the receipt of IR responses; the need for a second round of IRs and responses thereto; and the ability of the Coalition's experts to adequately review the responses and prepare their report all militate in favour of an adjournment of approximately two months.

10. The state of the Record is inadequate to permit the hearing to commence on October 1, 2012 as scheduled.

11. There is nothing on the record submitted by Manitoba Hydro which would require the hearing to be held on October 1, 2012.

Proponent's Response

From Response of Manitoba Hydro, filed August 13, 2012.

According to the Brief filed by the Bipole III Coalition, it no longer seeks answers to a number of the IRs it submitted and has answers to others it submitted because they were duplicative of questions asked by other participants which were sent to Manitoba Hydro and which have been answered by Manitoba Hydro. With respect to the residual questions, to date, unanswered because they were found to be out of scope, Manitoba Hydro responds as follows.

1. The Terms of Reference given to the CEC by the Minister of Conservation do not direct the CEC to determine if there is a less costly way for Manitoba Hydro to meet, through existing facilities, its need to improve reliability. Questions seeking data or reports or alternative spreadsheet modeling intended to assist in determining the foregoing are out of scope for this hearing.

2. The Terms of Reference do not ask the CEC to determine whether Bipole III has to be built "at this time". Accordingly, questions that seek data or reports or alternative spreadsheet modeling intended to assist in proving that the Bipole III Project is not needed "at this time" are out of scope for this hearing.

3. While acknowledging that the EIS does have a chapter explaining the need for the Project and alternatives to it, the proponent is of the view that the Minister of Conservation, in his request that the EIS be "reviewed", did not intend that the CEC investigate whether Bipole III is needed "at this time" or whether there are cheaper, better alternatives.

4. Courts and tribunals are entitled to set aside, in summary fashion, documents filed with them that do not follow prescribed procedures or which are, on their face, out of scope. Not every decision made by every decision maker must necessarily be accompanied by 'notice' and 'an opportunity to be heard'. In any event, to be practical, the Bipole III Coalition is going to be heard on the issues raised in its Motion, notwithstanding that it is in effect "appealing" a decision to the CEC that it has already made.

Other Participants

Mr. Beddome of the Green Party of Manitoba spoke in support of the motion.

CEC Findings

The members of the Commission have carefully reviewed the written briefs filed by the applicant and by the proponent in response. We have also considered the oral arguments presented.

The applicant asked for two different remedies in this motion:

- an order directing the proponent to respond to specific Information Requests submitted by the applicant; and
- an adjournment of the commencement of the hearing to a date sufficient to enable the Information Requests to be answered; a second round of Information Requests to be submitted and answered; and, expert reports to be prepared in time before the commencement of the hearing.

In addressing the first remedy, counsel for the applicant argued that all of the information requests in question are relevant, that they relate directly to matters in regard to the "needs for and alternatives to" the project (NFAAT). Counsel argued that the Terms of Reference issued to the Clean Environment Commission are very clear that NFAAT issues are to be reviewed in the public hearings.

The applicant dismissed suggestions by the proponent's counsel that the Commission seek a clarification of the Terms of Reference from the Minister. The applicant argued that there is no ambiguity in the terms of reference and, thus, no need for clarification.

In his response, counsel for Manitoba Hydro argued that the Minister did not specifically ask the Commission to investigate matters relating to NFAAT. He argued further that, if the panel were to engage in considering NFAAT matters, it would be at the expense of environmental issues, which he stated is our area of expertise.

The conflicting positions presented on this matter made it clear to the panel that a clear and wide divide exists among parties on the matter of reviewing NFAAT matters during the hearings.

While an NFAAT consideration is a requirement of environmental reviews conducted under the federal *Canadian Environmental Assessment Act,* it is not required by provincial statute and has not been a part of provincial reviews.

The one exception to this was the review process for the two Wuskwatim projects – the generating station and the transmission line. Rather than subject the projects to two separate and potentially lengthy reviews, it was decided to have a joint Clean Environment Commission-Public Utilities Board review, with members of both bodies sitting on the review panel. The Terms of Reference issued by the Minister specifically stipulated reviews of both NFAAT and environmental matters.

Wuskwatim was a distinct, one-time process. The Clean Environment Commission, in stand-alone hearings, has not undertaken NFAAT reviews.

In order to resolve this divide among the parties, the panel elected to write to the Minister seeking clarification as to his intent in regard to the Commission's review of NFAAT, as it relates to Bipole III.

The Minister has responded that it was not his intention that we engage in an NFAAT review.

Accordingly, the first remedy sought is not granted.

The second remedy sought by this applicant asked for an adjournment of sufficient time to allow for the completion, receipt and analysis of certain information. Co-counsel for the applicant, in arguing this matter, spoke of the large scale of the project, the large amount of information filed and the tight timeframes for the participants to prepare prior to the commencement of the hearings.

This argument shares some elements of that put forward by the Consumers' Association of Canada.

The panel recognizes that the Bipole project is not insignificant in its size and in the amount and scope of the materials provided. The panel also recognizes that there is much work involved in preparing for the hearings.

However, the amount of time for the Bipole proceedings is not out of line when compared with other recent CEC hearings. For the Wuskwatim hearings, the period from the filing of the EIS by the proponent to the start of the hearings was eleven months; for the Floodway Expansion, it was six months. For Bipole III, the proposed start date for the hearings is ten months after the filing of the EIS.

During the course of the hearings, the applicant, along with all of the other participants, will be given every reasonable opportunity to pose questions to the proponent. It will be incumbent on the proponent to respond adequately to all such relevant questions. There is no fixed end-date to the hearings.

Further, it is open to participants to argue against the issuance of an environmental license or to argue that any license should be subject to conditions.

If the Commission concludes, after hearing all of the evidence from the proponent and the various participants, that there remain unanswered, relevant questions, the Commission can emphasize such conclusions in its final report.

In such a case, the Commission would have the authority and the mandate to consider a number of alternatives available in making recommendations to the Minister.

The decision in regard to the second remedy is to dismiss the application and to confirm that the hearings will commence on October 1, 2012.

The Commission has set out a process that will allow testing by participants of the EIS filed by the proponent and is confident that the concerns expressed by the applicant can be addressed through the hearing process.

The Commission remains of the view that the process, upon which we have embarked, balances the needs of all of the parties to have an efficient, fair and transparent process, and allows sufficient opportunity to test the relevant information.

Disposition

On the application for an Order or Direction of the CEC to Manitoba Hydro to respond to those Information Requests submitted to the CEC by the Coalition on July 19 and 20, 2012, as listed in attachment A to this Motion, the decision is to dismiss; and

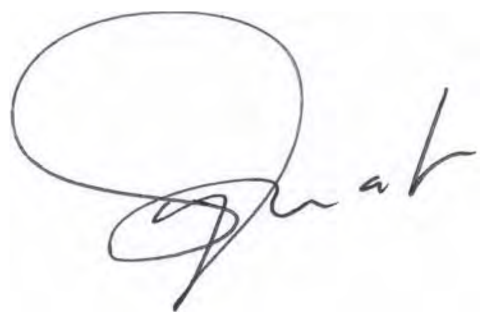
On the application for an adjournment of the Hearing scheduled to commence on October 1, 2012 to a date sufficient to enable the Information Requests to be answered; a second round of Information Requests to be submitted by the participants and answered by Manitoba Hydro; and, expert reports to be prepared in time before the commencement of the hearing; in accordance with the schedule, in attachment B to this Motion, the decision is to dismiss.

Conclusion

Given the decision on this application, the Commission confirms that the hearings will commence on October 1, 2012.

DATED this 29th day of August, 2012.

MANITOBA CLEAN ENVIRONMENT COMMISSION



Terry Sargeant, Chair

On behalf of the Panel: Ken Gibbons, Brian Kaplan, Patricia MacKay, Wayne Motheral

Manitoba CLEAN·ENVIRONMENT™ COMMISSION

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August 20, 2012

Honourable Gord Mackintosh
Minister of Conservation
Room 330 Legislative Building
Winnipeg, MB R3C 0V8

Dear Minister:

I am writing to seek clarification with respect to the Terms of Reference for the Manitoba Hydro Bipole III Transmission Line Project, specifically in regard to the review of the "need for and alternatives to" the project (NFAAT).

On August 16, 2012, the Commission considered motions presented by registered-Participant groups in advance of the hearings. During the presentation of positions, it became apparent that a clear and wide divide exists among Parties as to how deeply the Clean Environment Commission should go in reviewing NFAAT matters during the hearings.

On the one side, the Proponent, Manitoba Hydro, is of the view that, since the Terms of Reference issued to the Commission in December 2011 do not specifically identify a review of NFAAT, the Commission has no authority to enter into such considerations.

On the other side, at least two Participants are of the view that the NFAAT review should be a full PUB-style deliberation, considering whether or not the project is necessary.

Both sides may be looking to the Wuskwatim review in 2004 as an example.

The Wuskwatim project involved two separate, but obviously connected, proposals: the generating station and a transmission line. In an effort to streamline the regulatory process, it was decided that, rather than subject the projects to separate and potentially lengthy reviews by both the Public Utilities Board and the Clean Environment

Manitoba

Commission, the two would be combined into one proceeding. To that end, two members of the PUB were cross-appointed to the CEC. Terms of Reference were issued by the Minister of Conservation, which specifically addressed both sides of the review.

The Participants may be of the view that the Wuskwatim precedent is the “new normal”, calling for a full-NFAAT review; while Hydro takes the view that, in the absence of specific directions on NFAAT as in Wuskwatim, there should be no such review at all.

While an NFAAT consideration is a requirement of environmental reviews conducted under the federal *Canadian Environmental Assessment Act,* it has not been a part of provincial reviews. Except for the Wuskwatim example, the Commission, in past proceedings, has not undertaken NFAAT reviews.

The Panel is caught in a dilemma on this issue. In order to resolve this, we ask that you clarify your intent in regard to the Commission’s review of NFAAT, as it relates to Bipole III.

Minister, time is of the essence. Without resolution of this matter in short order, there could be significant impacts on the scheduled hearing and its timely completion. It will be necessary to issue decisions on the August 16 motions by the end of this week.

Sincerely,

Original signed by

Terry Sargeant
Chair

cc: Bipole Panel

MINISTER OF
CONSERVATION AND WATER STEWARDSHIP

Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

AUG 23 2012

August 23, 2012

Mr. Terry Sargeant
Chair
Clean Environment Commission
305-155 Carlton St.
Winnipeg MB R3C 3H8

Dear Mr. Sargeant:

Thank you for your August 21, 2012 letter requesting clarification of the Terms of Reference for the CEC's review of Manitoba Hydro's Bipole III Transmission Line Project. In response to your specific question about a Needs For And Alternatives To (NFAAT) review, the Terms of Reference, which were issued in December 2011, do not include instruction for the CEC to conduct an NFAAT.

I trust this clarifies this matter.

Yours sincerely,

Gord Mackintosh
Minister

CC. Fred Meier
Dan McInnis
Tracey Braun

Tab 28

Bipole III, Keeyask and Tie-Line review

September 19, 2016

The Boston Consulting Group

Exhibit 1: Assessment of complex program of three projects

Each with standalone objectives and integrated benefits

	Bipole III	Keeyask	Tie-line[1]
	Endorsed on reliability need	*Preferred generation option*	*Acceleration opportunity*
Project objective	**Mitigate longstanding system reliability risk** • Ensure reliability against losing Bipole I & II lines or Dorsey converter station	**Satisfy future Manitoba energy need** • Meet future domestic energy need • Leverage Manitoba's clean hydro resource	**Secure cost-effective dependable energy** • Reduce future need for domestic generation • Expand market access in MISO (MN & WI)
Secondary considerations	**Strengthen physical transmission capability** • Additional peak capacity (enabling new generation) • Redundancy for maintenance	**Leverage resource attributes to cover part of costs through export** • "New hydro" to satisfy US tie-line requirement • Leverage increased peak capacity from Bipole III	**Increase value of domestic resources** • Reduce Bipole corridor reliability requirement • Improve Keeyask value generation potential

1. Tie-line = MMTP plus GNTL

Exhibit 2: Core questions being addressed in this effort

1. **Were the original decisions the right ones?**

2. **Is there further downside risk?**

3. **Can they be stopped or paused without undue cost or risk?**

Exhibit 3: Summary of key messages

1 Original decision on Bipole III justifiable but Keeyask (in hindsight) a less prudent decision

- Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but the Province directed Hydro not to consider it
  - Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas
- Keeyask (with US Tie-line) long-run economics attractive on paper, but financial and execution risks not fully considered
  - Rationale existed for accelerating Keeyask, e.g.: sustainable energy solution that capitalizes on expiring export opportunity
  - However, several factors suggest decision imprudent, e.g.: lower / delayed capex alternatives (e.g. gas) not fully explored, costly constraints not fully challenged, permits not in place ahead of proceeding, discount rates did not reflect project risk
- Imprudence can be traced to systemic decision governance issues, e.g.: lack of clear objective function and criteria/constraints of Hydro and regulatory body, rates not linked to allowable returns, iterative (vs. upfront) approach to investment decisions

2 Based on current outlook, project economics expected to worsen and remain sensitive to key uncertainties

- Capital execution will likely overrun and export price assumptions expected to worsen (outside of carbon constrained scenario)
- Equity ratios dip into single digits - similar to 1970-1995, but Province with 30%+ net debt/GDP vs. ~20% before

3 Despite these challenges, cancelling in flight projects to shift to alternatives is not a realistic option

- ~$5B already sunk on Bipole III and Keeyask with cancellation costs of ~$1B each, bringing effective total to ~$7B
- ~$3.2B cost to complete Bipole III West clearly more favourable vs. ~$4.5B rerouting costs of Bipole III East
  - Furthermore, decision to reroute Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- ~$4.7B cost to complete Keeyask yields an NPV $3-5B more favourable vs. switching to gas option, and avoids strategic risks

Exhibit 4: Were the original decisions the right ones?

Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but was refused

- Reliability risk associated with Bipole I&II and Dorsey has been untenable for a long time: High concentration (e.g., 70% of energy), high incidence risk (e.g.,1/20 years), high societal impact (~$4-20B), major political implications
- Bipole III East lowest cost option but Provincial decision not to pursue based on environmental grounds
- Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas

Original decision on Keeyask (with Tie-line) an imprudent decision

- New generation capacity required to meet domestic demand … but not until 2024+
- Keeyask project represents 2019 acceleration option to leverage US Tie-line import and export opportunity
- On paper, represents most favourable NPV option vs. delayed Keeyask (without Tie-line) or delayed gas
- Hydro generation deemed favourable vs. gas considering fuel price volatility and regulatory (e.g. CO_2) risk
- But assessment did not fully consider execution risks and sensitivities, e.g., project risk, industrial account risk, export price risk
- Additional downside financial risks of additional leverage (with Bipole III running concurrently) and associated discount rates to account for these risks did not appear to be fully factored into decisions
- Fuller assessment of lower capital and lower risk options would have been more prudent action at the time
  - Gas alternative
  - More aggressive challenging of costly constraints, e.g., regulatory requirement of Tie-line
  - Greater scrutiny of scope and design decisions

Imprudence can be traced to systemic decision governance issues

- Lack of clear objective function and criteria/constraints of Hydro, Government and Regulator, e.g., role of Hydro to drive economic growth vs. service domestic needs; role of regulator to maintain low rates vs. govern responsible stewardship of assets
- Ineffective rate-setting regime, e.g., rates not linked to allowable return, creating disconnect with system investment plan
- Iterative (vs. upfront) approach to investment plan decisions, e.g., ensuring full project scope considered holistically (Bipole III, Keeyask, US Tie-line) to appropriate capture compounded execution and financial risks

Exhibit 5: Mitigating risk of Bipole I&II, Dorsey a necessity

Represent unusually large contingencies

Bipole I&II carry majority of MH electricity
- ~70% of energy (MWh)
- ~50% of generation capacity[1] (MW)

Unable to meet winter demand without Bipole I&II
- 1500MW short of peak demand in 2017
- Assumes max. imports and running all thermal plants

Significant and real risk of catastrophic failure

Fire significant risk to Dorsey
- 1/29yr expected frequency[2]

Tornado at Dorsey unlikely but catastrophic
- 1/4000yr; Ellie[3] was scare
- Could take years to rebuild

Freezing rain and wind significant risk to Bipole I&II
- 1/20yr expected frequency

Ground ice buildup also risk to Bipole I&II
- Near-miss with shifted tower bases

~$4-20B societal impact of prolonged outage

Outage likely to last weeks to months
- 5-8 weeks for Bipole I&II
- Weeks to year(s) for Dorsey

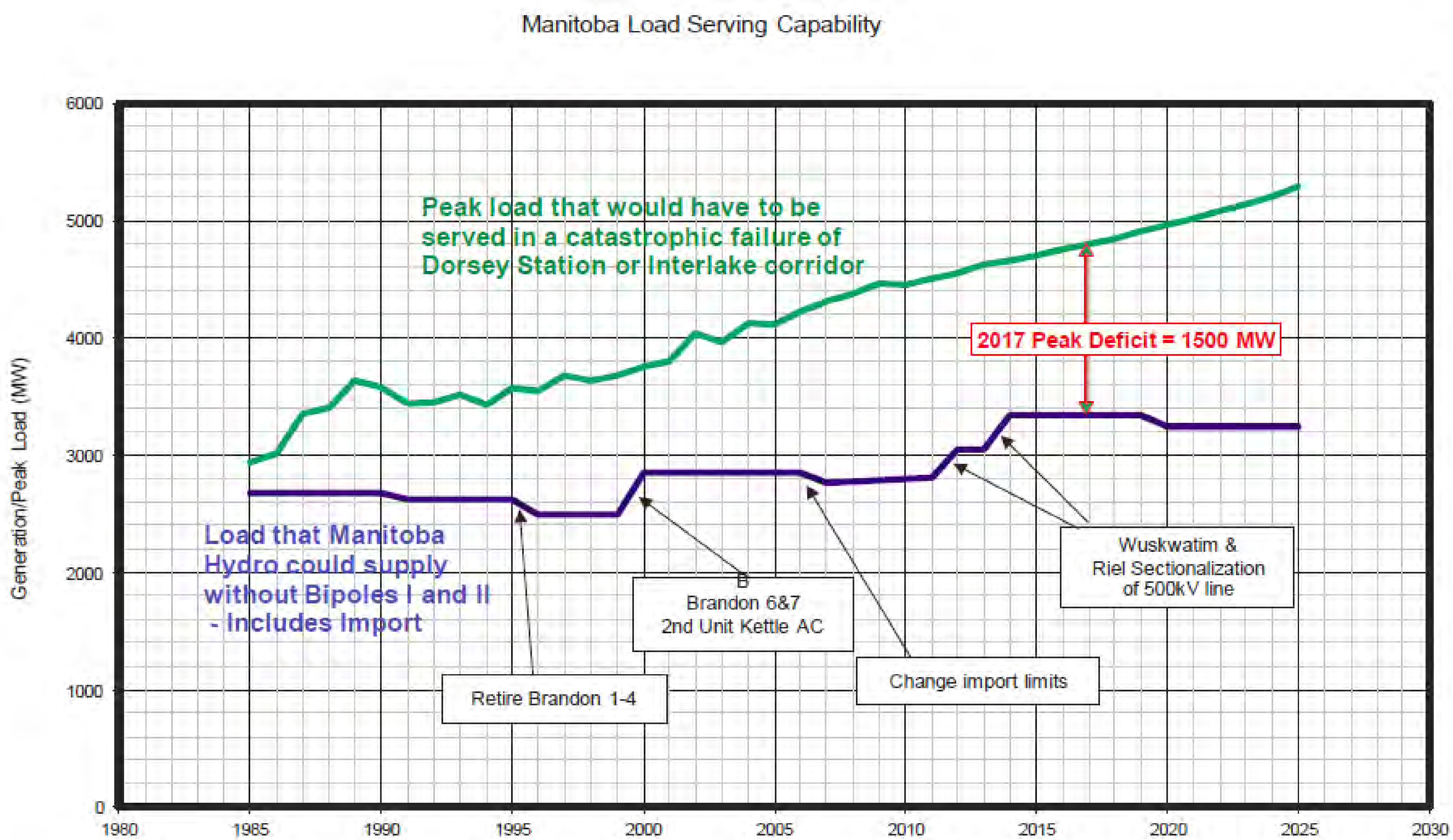
Rolling blackouts and/or demand curtailment
- Must force demand down to supply limit

~$4-20B cost depending of type and time of outage
- ~$10/kWh that fail to supply
- ~$4B for Jan. line outage
- ~$20B if full year

Popular backlash against MH and government likely
- Failure to honor Hydro Act

1. Total (100%) includes both generation and import line capacity. 2. After hardening of relay building in 2011 risk may be lower than stated in the reports.
3. Strongest tornado in Canadian history, 25km away.
Source: Teshmont (2001, 2006, 2012)

Exhibit 6: Peak load growth making loss of Dorsey or Bipole I & II consequences more severe (1.5 GW peak shortfall in '17)



Source: Reliability Alternatives for Mitigating the Risks of a Dorsey or Interlake Corridor Outage (2011)

Exhibit 7: Probabilistic studies show risk to Dorsey and Bipole I & II, and there have been several near misses

Threat	Dorsey[1]	Bipole I & II
Tornado, downburst	**1/4000yr** (summer) Down ***month to year(s)*** • 3km away (Sep. '96) • 25km away[2] (Jun. '07)	**1/17yr** (summer) Down ***days to weeks*** • 19 towers destroyed (Sep. '96)
Fire	**1/29yr** Down ***week to months*** • Exploding transformer	**N/A**
Wide-front wind	**1/200yr**	**1/90yr** Down ***week to months***
Freezing rain & wind	**1/50yr**	**1/20yr** Down ***week to months***
Ground ice buildup	**N/A**	Unknown; **likely significant** • Tower bases shifted from the ground
Sabotage	**Unknown**	**Unknown**

1. After hardening of relay building in 2011 several of the risks to Dorsey are likely lower than stated in the reports. 2. Elie; strongest tornado in Canadian history
Source: Teshmont (2001, 2006, 2012)

Exhibit 8: Societal impact of loss of Bipole I & II or Dorsey for month of January ~C$4B, and ~C$20B for full year

Low societal impact ↔ High societal impact

Short-term outage	Dorsey / Bipole I & II	Severe weather outage
Temporary (minutes–hours) inability to serve load • Black/brown-out	**Prolonged (week–year) inability to serve load** • Rolling blackouts • Shed industrial load • Prioritize residential heating	**Prolonged (day–week) inability to supply power** • Black-out until repair
MISO Value of Lost Load (VoLL) estimates: • Residential[1]: US$2/kWh • Small C/I: US$42/kWh • Large C/I: US$29/kWh	**MH VoLL estimate:** • C$10/kWh • Very unusual situation with uncertain long-term effects	**1998 Canada ice storm** • C$9/kWh **2012 Superstorm Sandy** • ~US$20B; 8.5M lost power

Bipole I & II transmission lines (for January)
- Un-served January demand * C$10/kWh = **~C$4B/mo**

Dorsey converter station (for a year)
- Un-served annual demand * C$10/kWh = **~C$20B/yr**

1. Likely higher for customers reliant on electric heating, and may underestimate modern reliance on electronics

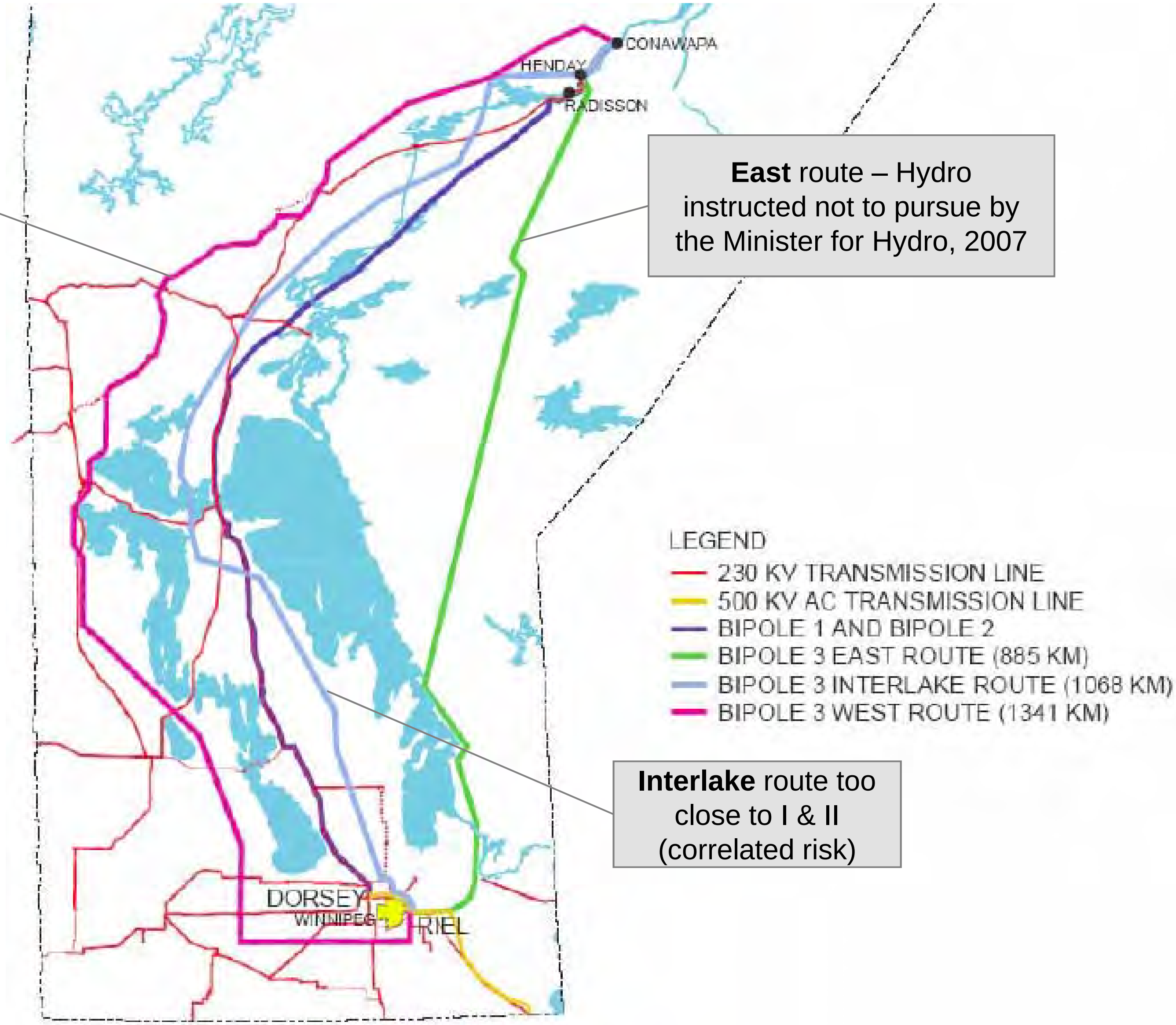
Source: "Estimating the Value of Lost Load", London Economics (2013); "Manitoba Customer Interruption Cost Evaluation", R. Billington, PowerComp Associates (2001); "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages", Executive Office of the President (2013)

Exhibit 9: Bipole III West route chosen to minimize risk correlation with Bipole I & II

West route longer but satisfies requirements

East route – Hydro instructed not to pursue by the Minister for Hydro, 2007

Interlake route too close to I & II (correlated risk)



Source: Teshmont 2006

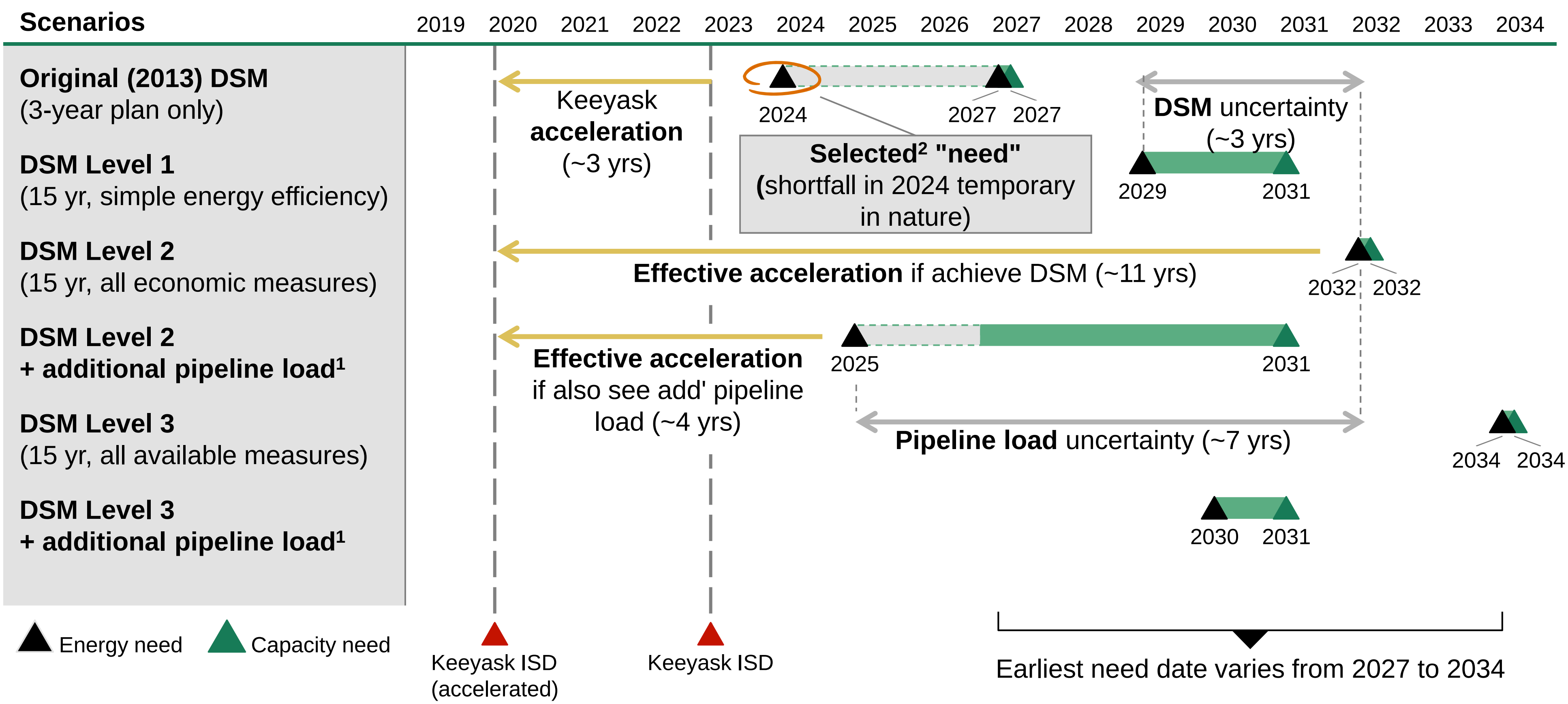
Exhibit 10: Bipole III East the most favourable option

But directed not to pursue by previous government, hence Bipole III West pursued

	Lowest cost, not selected **Bipole III East**	*Selected option* **Bipole III West**	**All-gas**	**Import + gas**
Description	**Alternative access to northern hydro** • 2000MW line • Could stage (line first, conv. stations later[1])	**Alternative access to northern hydro** • 2,300MW line • Cannot stage line and converter stations	**Backup generation** • 2000MW gas in the South	**Import line + backup generation** • 1500MW US line • 500MW gas
Cost estimate used in 2011 EIS[4]	Not formally assessed but estimated to be $900m less expensive • Staged converter station build • 700-900km shorter	**~$3.3B** (capital cost in-service dollars) **~$10M/y** annual cost	**~0.7B** more than BPIII on PV[2] basis **~$3B** gas turbine **~$181M/y** pipeline reservation fee + variable costs	**~$4.5B** (capital cost in-service dollars) Annual costs subject to contract terms and variable costs
Additional benefits	**$28M/yr from reduced losses[3]** **Additional capacity for new hydro**	**$26M/yr from reduced losses[3]** **Additional capacity for new hydro**	**More dependable energy**	**Larger import/ export potential** **More dependable energy**
Risks	**Route through Boreal forest**	**No specific risk**	**Environmental risk, pipeline reservation fee**	**Environmental risk, future price of securing capacity**
Verdict	**In 2007 the province directed MH to study Western routes**	**Lowest cost of available options**	**Higher cost, CO_2-emitting**	**Higher cost, CO_2-emitting, difficult to secure US partner**

1. Line primary concern, given low probability of Dorsey destruction. 2. Present Value. 3. Current Bipole I&II transmission losses 8.6%; Bipole III West 6.4% to 7.0%; Bipole III East 6.0% to 6.4%.
4. Environmental Impact Statement (2011)
Source: Manitoba Hydro, BCG analysis

Exhibit 11: Timing of domestic requirements



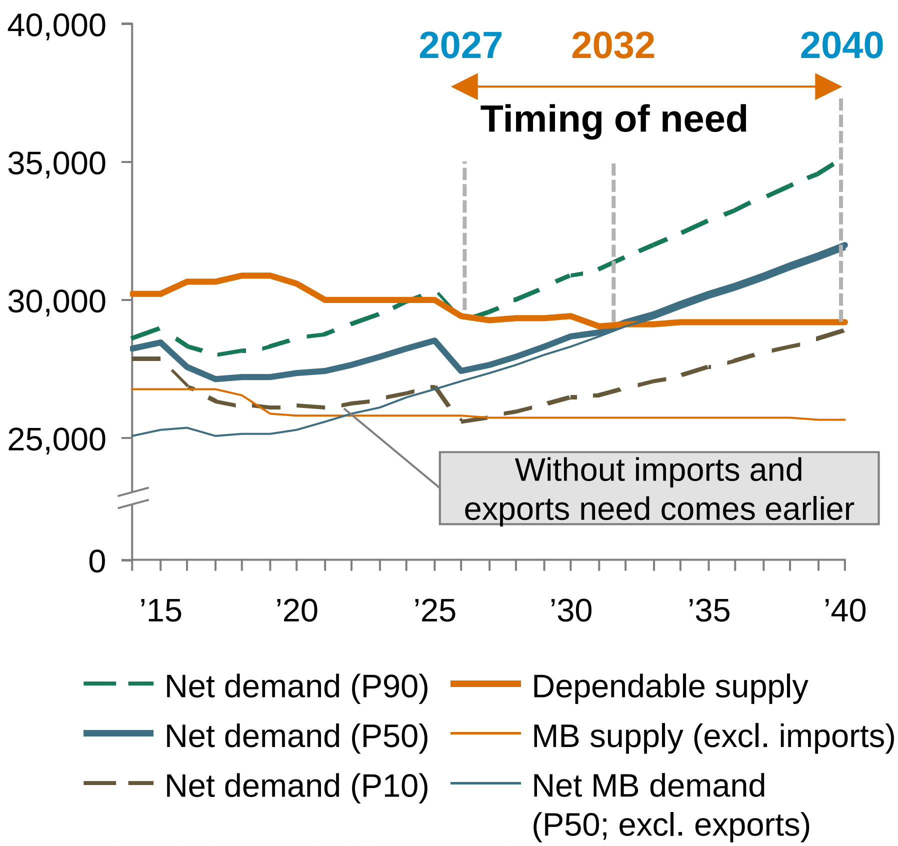
Realistic DSM pushed need date out, but expected additional pipeline load pulled it back to ~2027

1. 1700MWh additional load planned by pipeline customers. 2. Put forward by MH, and accepted by NFAT panel (partly because they expected additional pipeline load to materialize).
Source: NFAT Final Report

Exhibit 12: New generation capacity required, although not until 2027 or beyond

NFAT: Supply vs. net demand[1]

Dependable energy supply vs. net demand (GWh)



1. Gross demand minus DSM, including exports unless noted
Source: Manitoba Hydro (NFAT)

Timing subject to forecast uncertainty

Gross demand forecasted to grow by 1.5% p.a.
- ***Residential segment:*** Population growth and increased penetration of electric heating
- ***Mass market segment:*** GDP growth (2%) and population key drivers
- ***Top customers segment :*** 17 companies, "Potential Large Industrial Loads" longer term

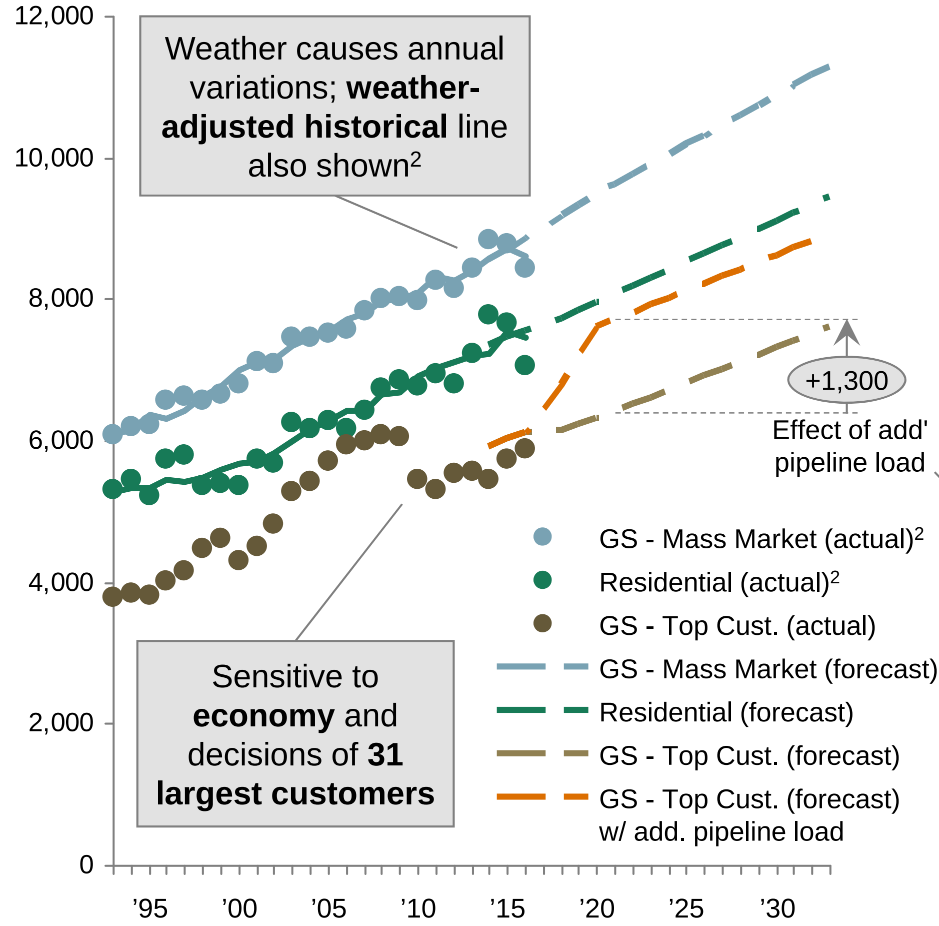
Demand Side Mgmt. (DSM) expected to offset 66% of demand growth over 15 years
- ***Conservation rates:*** MH proposed higher rates for electricity beyond threshold
- ***Fuel switching:*** Switch to gas heating
- ***Load displacement:*** Industrial self-generation

Uncertainty for both gross demand & DSM
- Decisions of larger industrial customers (e.g., pipeline load)
- DSM adoption may be lower than in other markets due to low retail rates

Exhibit 13: Gross demand forecast sensitive to Top Customers

Forecast methodology sound, but inherent risk in lumpy Industrial demand

Customer segment gross demand[1] (GWh)



Demand forecast by customer segment

Methodology to forecast demand by segment

- ***General Service – Mass market:*** GDP and residential customer number drive demand
- ***Residential segment:*** Population, electric heating penetration, etc. drive demand
- ***General Service – Top Customers:*** Individual forecasts for top 31 drive near-term demand; annual PLIL[3] increment beyond that

Historically, demand forecast accurate for General Service and Residential

Top Customers largest source of uncertainty

- Sensitive to largest customers and economic cycles
- E.g., expected 1700GWh add' pipeline load (+1300GWh over PLIL[3]) but only ~500GWh now expected to materialize

1. Gross MB demand shown; net demand is gross demand minus DSM, plus net exports. 2. Weather-adjusted line also shown (N/A to Top Cust.). 3. Potential Large Industrial Loads
Source: Manitoba Hydro

Exhibit 14: NPV & upside favoured Keeyask by 2019 + Tie-line

But at substantially higher capital risk vs. delayed gas option

Selected option

Criteria	Gas generation 2022+	Keeyask 2025/26	Keeyask '19 + Tie-line
Resource type	***Fossil*** *(CO_2 emitting; fully dispatchable)*	***Renewable*** *("new hydro"; dispatchable subject to water)*	***Renewable*** *("new hydro"; dispatchable subject to water)*
Cost structure	***Variable cost intensive*** *CAPEX (PV[1]): ~$2.8B* *Variable cost: ~$40-62/MWh* *LCOE[3]: ~75-265 $/MWh[4]*	***Capital intensive*** *CAPEX (PV[1]): ~$4.4B* *Variable cost[2]: ~$3-4/MWh* *LCOE[3]: ~68 $/MWh*	***Capital intensive*** *CAPEX (PV[1]): ~$6.2B* *Variable cost[2]: ~$3-4/MWh* *LCOE[3]:~68 $/MWh[5]*
NPV (NFAT)	***Reference case***	***–$38M*** *benefits to MH and* ***$591M*** *payments to province compared to gas reference*	***+$386M*** *benefits to MH and* ***$1148M*** *payments to province compared to gas reference*
Upside and risk	*Higher or lower* ***gas and CO_2 prices*** *than forecast* *Federal or provincial* ***restrictions on CO_2***	*Increased export prices from* ***US Clean Power Plan****, etc.* ***Cost*** *and* ***schedule overrun***	*Increased export prices from* ***US Clean Power Plan****, etc.* ***Cost*** *and* ***schedule overrun****, and tie-line* ***permitting***

1. Present Value of capital expenditure for scenario (including late-time gas generation) 2. Only water rental included here 3. Levelized Cost of Electricity. 4. Varies by utilization. 5. Keeyask only.
Source: NFAT, BCG analysis

Exhibit 15: Tie-line a key source of value for Keeyask project

Greatly improves economics of Keeyask given potential for export to subsidize low domestic rates

Minnesota Power needed rapid path to reduce CO^2

The problem

- MP legally mandated to achieve 26.5% RPS by 2025
- MP had set its own target to produce 1/3rd of current 1900 MW from renewables
- CPP may require MP to reduce 30% CO^2 from coal by ~2030
- Can only import <u>new source of renewable power</u>

MP were looking for a near-term solution

MP had several options to solve CO^2 challenge

Several options to solve

- Build out wind
- Wait for utility scale PV to drop in price (as per trend)
- Start build out of gas
- Lock in new source of hydro power to import (Keeyask provided the option)

Keeyask one of several viable options considered

Building Keeyask and tie line had benefits for MH

With the tie line, MH gets

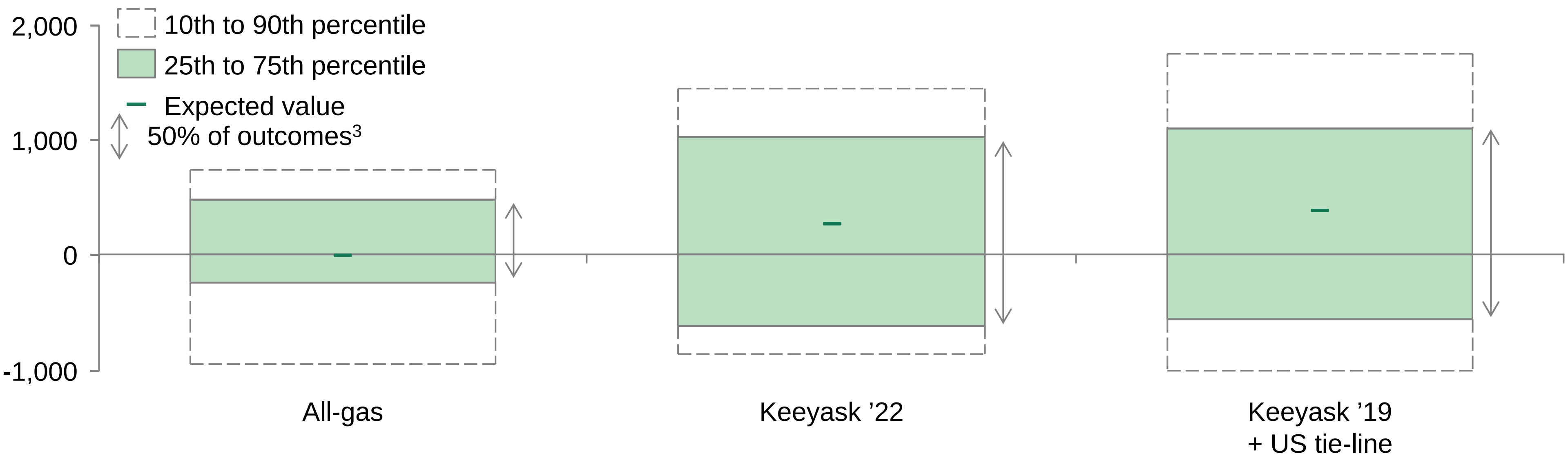
- ~3 TWh new cost-effective dependable energy
- Import capacity of ~700MW dependable capacity to offset hydro risk
- 885MW increase in export capacity used to offset construction cost of Keeyask

MH built early to capture benefits in a closing window

Exhibit 16: Gas carried less uncertainty, but Keeyask with tie-line had higher expected incremental NPV[1]

Gas generation 2022+	Keeyask 2025/26	Keeyask '19 + Tie-line
Smaller and staggered capital costs, with future fuel expense	**Large capital investment**	**Large capital investment and early additional export rev.**
Key sensitivities (discount rate, energy prices, capital costs) can vary NPV by -$1B to +$0.7B	**Expected incremental NPV ~$0.3B, but more sensitive (ranges from -$0.8B to + $1.4B)**	**Highest expected incremental NPV (~$0.4B), but also most sensitive (largest up/downside)**

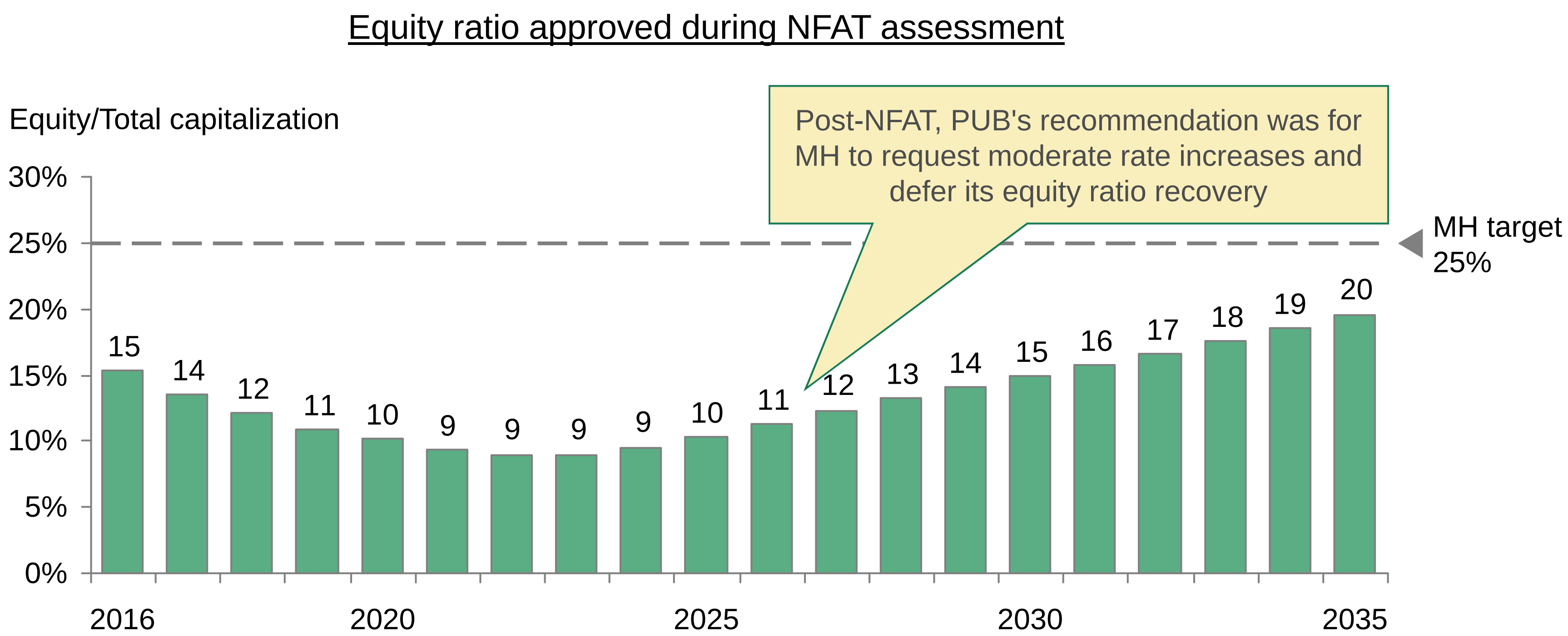
Incremental NPV[1] over all-gas reference case[2] ($M)



1. Having sunk $1.2B. NPV benefit to Manitoba Hydro only (excluding water rental and capital tax and guarantee fee payments) 2. All-gas reference case with reference values for discount rate, energy prices, and capital costs. 3. Considering uncertainty in discount rate, capital costs, and energy prices. Note: Manitoba Hydro did not update this analysis to reflect final DSM level 2 demand forecast
Source: NFAT final report

Exhibit 17: Implied equity ratios of NFAT submissions

NFAT and PUB supported equity ratio falling to 9%

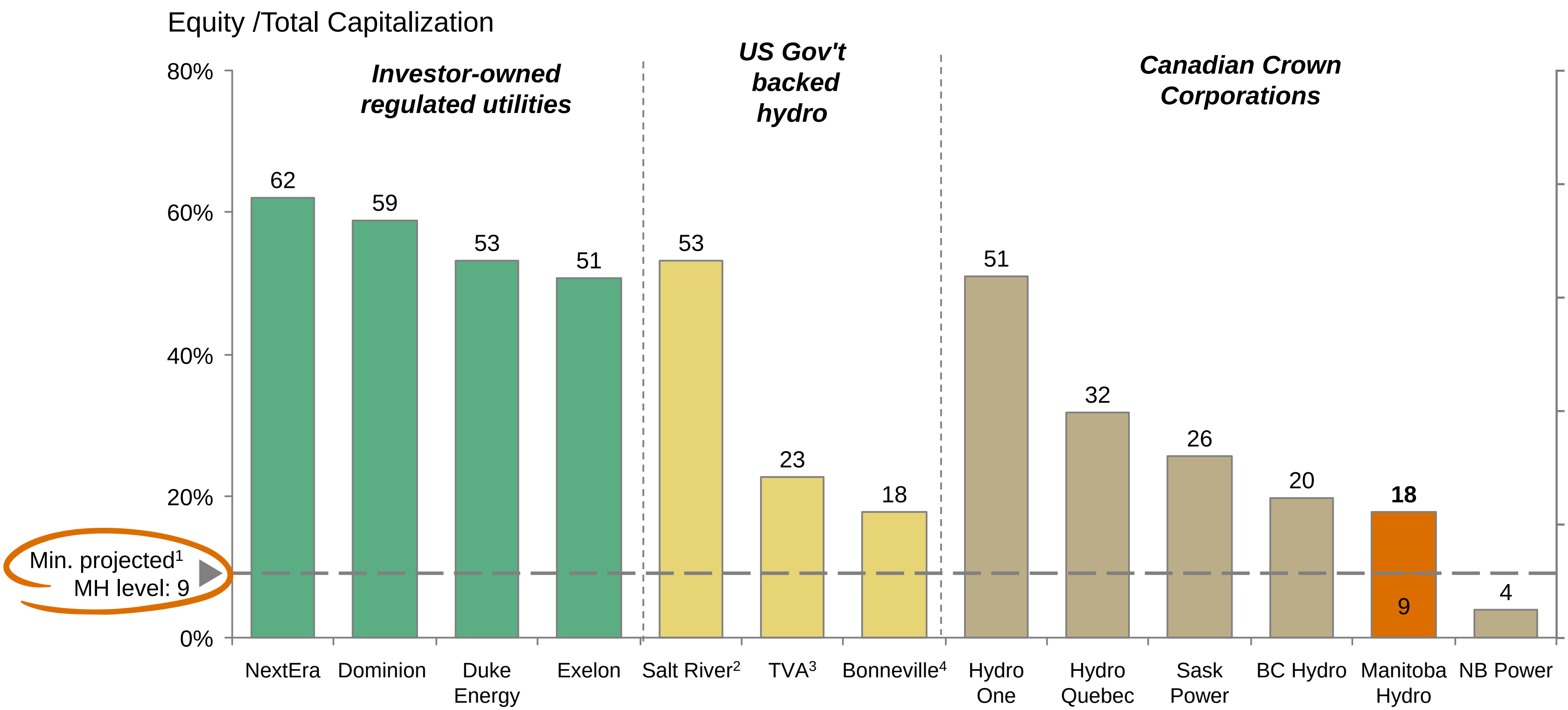


Single digit equity ratios were not highlighted as a significant risk when projects approved

Source: IFF '15; NFAT Projected Financial Statements for Plan K19/Gas/750MW – DSM Level 2

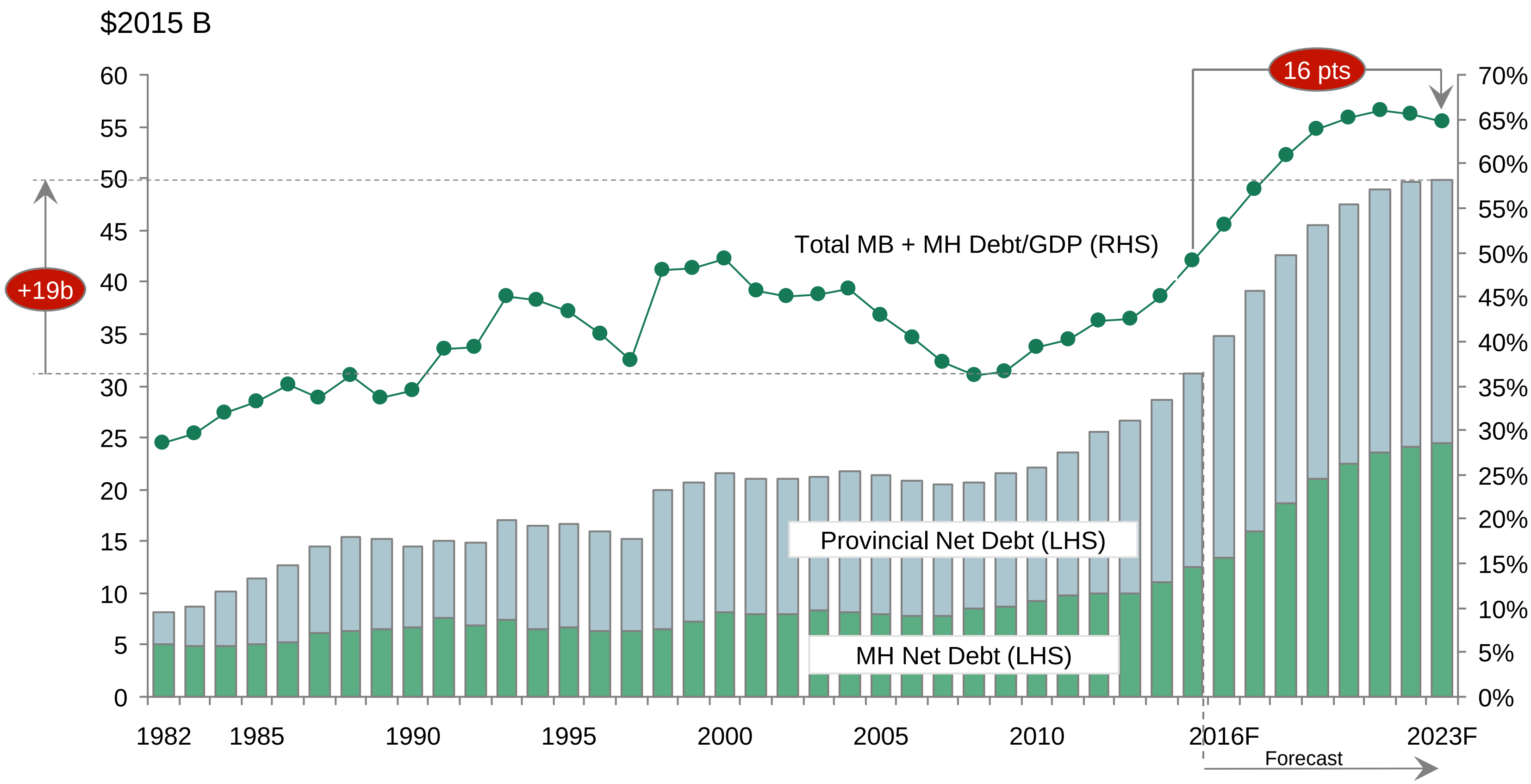
Exhibit 18: Equity ratios well-below most peers

Capital structure and credit rating for US and Canadian gov't and investor-owned regulated utilities



1. 2022 Expected Equity Ratio on NFAT Base Case 2. Salt River Project an entity of the State of Arizona 3. Federally owned corporation 4. US Federal administration within Dept. of Energy
Source: 2015 Audited Financial statements, SNL

Exhibit 19: Hydro debt included, total debt-to-GDP ratio forecast will increase to 65%



2015 Debt/GDP
(including utility[4])

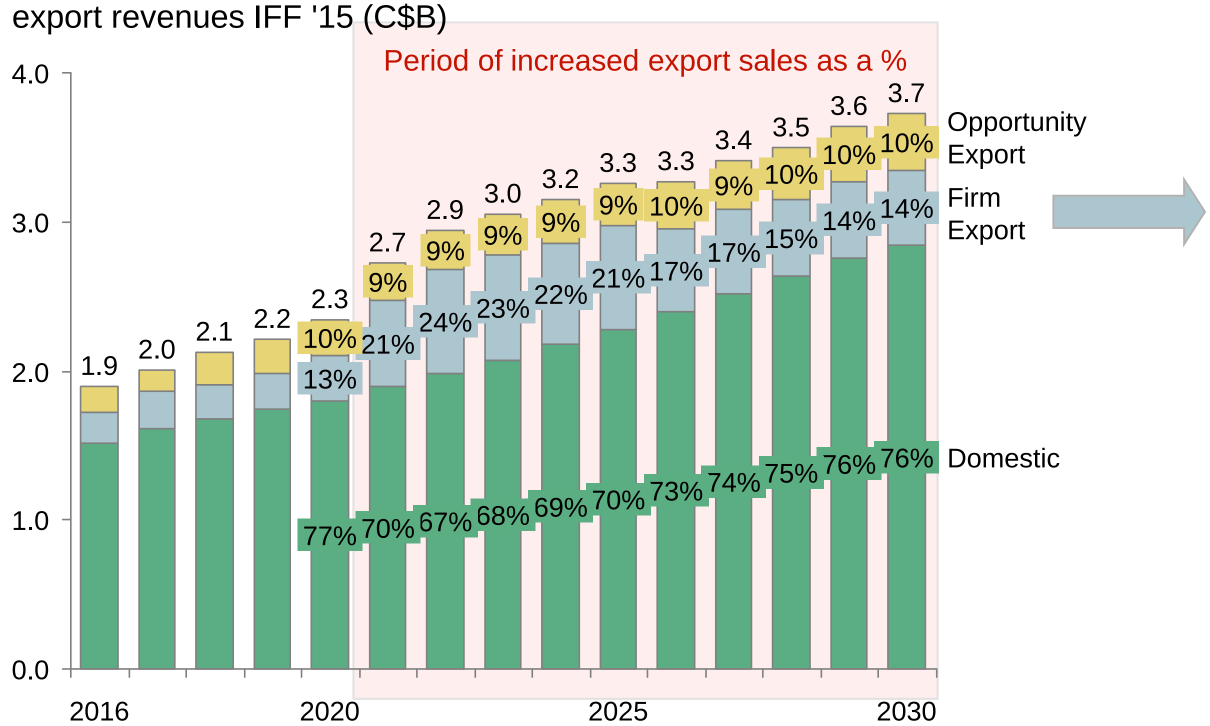
Limited capacity for the Province to provide debt backstop

Source: Canadian Department of Finance, Manitoba Hydro Debt Management Strategy Report, RBC, 2015 Utility Annual Reports
1. Total Debt calculated as Provincial Net Debt + Manitoba Hydro Net Debt in base case. 2. Debt to GDP ratio from RBC report; excludes Manitoba Hydro debt 3. Provincial debt forecasts modeled based on Provincial target to close budget gap within 8 years 4. Provincial net debt with utility crown corporation debt included 5. Ontario Provincial debt plus OPG debt (including asset removal and nuclear waste management liabilities)

Exhibit 20: Firm export volumes and prices benefit economics

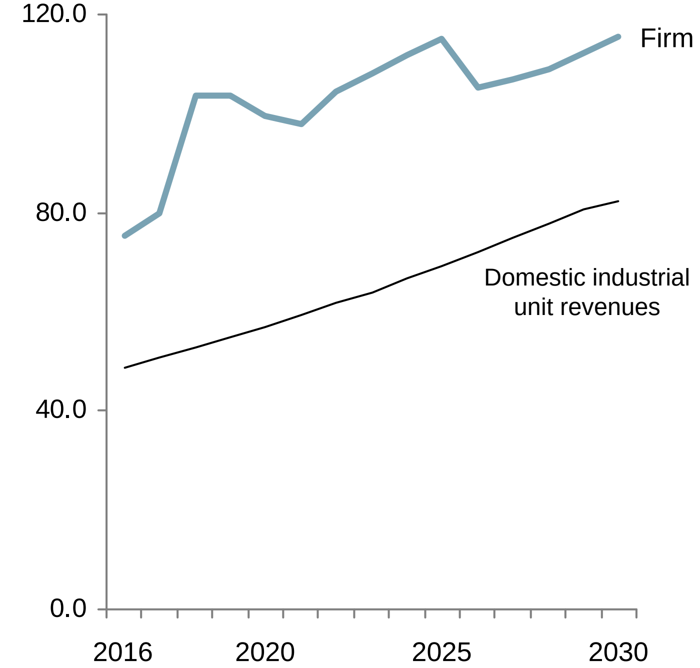
Revenue mix expectations: Firm export expected to grow to 20%+

Forecasted domestic demand and export revenues IFF '15 (C$B)



Price expectations: Firm export at 15% premium

Unit revenues IFF'15 ($C/MWh)



Source: Manitoba Hydro, BCG analysis

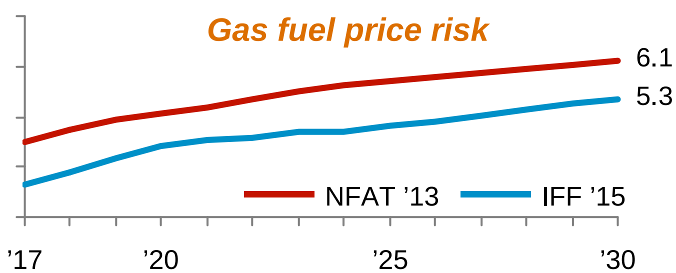
Exhibit 21: Gas & CO_2 price risk vs. Hydro & Export price risk

Manitoba's resources and the current regulatory model better fits with the hydro based risk profile

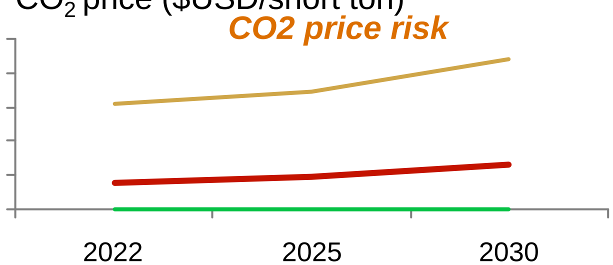
Selected option

Criteria	Gas generation	Hydro generation & US Tie-line
Risks	*Domestic price & fuel price volatility* *Environmental regulation risk incl. CO_2* *Fuel import dependency*	*Risk related to water levels* *Domestic & export price levels* *Execution risk (e.g. project complexity)*
Increase of Gas & CO2 prices with upward impact on Export prices and hence benefitting MH's hydro assets		

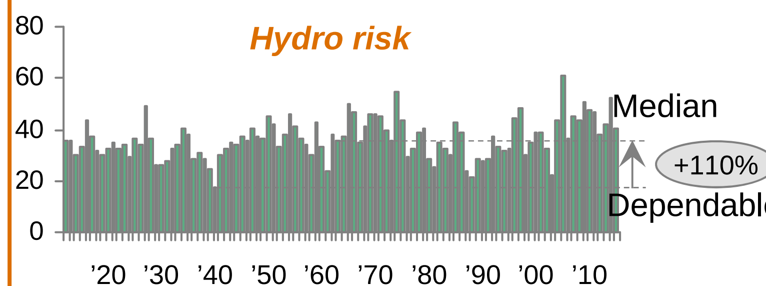
Price ($2015 USD/MWh)



CO_2 price ($USD/short ton)



Energy from water flow (TWh)



MISO Minnesota price forecasts ($/MWh)

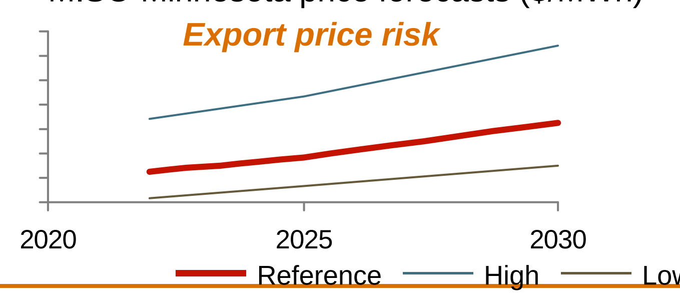


Exhibit 22: Manitoba Hydro's regulatory framework oriented towards maintaining consistent, low price increases

Hydro Act	**Outlines Manitoba Hydro's core purpose: to provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently** • Regulatory framework allows for exports of power **Directs that prices be set such that MH can recover operating and interest costs and build sufficient reserves to fund replacement of assets and new investment in property or plant** • Act also outlines MH's ability to borrow under Provincial guarantee
+	
PUB	**PUB mandate exclusively to review the price of power; no supervisory authority granted** **Track record of PUB to prioritize low, stable increases over time rather than implement lumpier price increases timed with capital expenditures**
+	
Provincial Cabinet	**Province reviews capital plans, export contracts and interconnect agreements** • Province may direct PUB to review other elements of MH's operations on its behalf
+	
Other legislation	**MH also subject to other legislation that influences PUB and public attitude towards price:** • Affordable Utility Rate Accountability Act requires Manitoba to have lowest combined price of gas, electricity and auto insurance among provinces • Clean energy legislation governing development of renewables prioritizes low rates

Exhibit 23: Manitoba regulatory construct different from traditional utility cost-of service model on several dimensions

	Manitoba PUB "Modified" Cost of Service	Traditional Cost of Service
Rate framework	**Price of power set based on PUB judgment** **PUB considerations:** • Operating expenses • Retained earnings reserves • Proposed capital plans • Smooth trajectory of rate increases	**Revenue requirement = Operating Expenses + (Gross value of the utility's tangible and intangible property – Accrued depreciation) * Allowed Return on Rate Base**
Objective function	• **Provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently**	• **Maximize return within regulatory bounds**
Investor	• **Government**	• **Institutions and individuals**
Return on equity	• **Outcome of rate setting process** • **Varies with revenue increases**	• **Primary lever of rate setting process** • **Set at level to attract private capital**
Capital Plan	**PUB informed of plan but no formal approval**	**Regulatory approval of CapEx required before addition to rate base**
Supervisory Authority	**PUB lacks supervisory authority**	**Regulatory supervisory authority granted**
Allowance/ disallowance	**No disallowance authority from PUB**	**Regulatory authority to disallow expenditures from rate base**

Exhibit 24: Decision making more iterative than consolidated

Reliability	*Energy and Capacity*		*Rate application*
Clean Energy Commission '13	**PUB in the NFAT '13-14**		**PUB rate process '15**
Bipole III West Route for 2018 ISD	**Keeyask 695MW Hydro for 2019 ISD**	**750MW US Tie Line for 2020 ISD**	**Increase Manitoba rates by 3.95%**
Bipole III East Route	All Gas (various types and ISDs)	250MW US Tie Line for 2020 ISD	Various rate increase scenarios presented
Gas	Keeyask 695MW Hydro for later ISD (2022)	DSM included in all options	
Import and Gas	Conawapa 1485MW later than 2026 ISD	Other resources (e.g. wind, solar)	
Import only	Increase of import and change planning guidelines[1]	Push out ISD of US tie-line for later	Efficiency measures

Current option

Alternatives considered

Alternatives not considered

1.Import can account for up 10% of Manitoba load plus export, overall capped at 50% of the off-peak load
Source: BCG analysis

Exhibit 25: Is there further downside risk?

Outlook under current assumptions already highly sensitive to performance across 6 key factors:

1) **Water flows / Hydro risk: No change to existing range of uncertainty for near term-impact**
   - High variability in range of possibilities

2) **Capital execution costs**: **Both projects likely to exceed P90**
   - Bipole III expected to run over by $0.3B with 12 month delay and Keeyask expected to run-over by $0.7B with 21 month delay, including interest
   - For Bipole III, transmission line construction productivity in winter and tower steel availability the main drivers

3) **Export prices: Expected to worsen (outside of longer term carbon constrained scenario)**
   - Most recent forecasts represent a ~13-17% decrease in long-term export prices vs. IFF '15
   - Firm energy premium reducing up to 10%

4) **Interest rates: Favorable movement since NFAT in long term rate**
   - Assumptions of long term rates fall from 6.3% to 4.4%, reducing debt service levels and discount rate

5) **Domestic rates: Potentially lower than forecast initially**
   - PUB granted 3.36% vs 3.95% as requested (partially due to lower interest rate and debt servicing cost)

6) **Net domestic demand: No change to expected case**

Equity ratios expected to dip to single digits, creating a potentially precarious position for the province

- Falls to <12% in expected scenario
- Under extreme sensitivities (severe capex overrun, sustained drought), feasible for equity to go below 5%
- While single-digit equity ratios observed 1970-1995, Province with 30%+ net debt/GDP vs. ~20% before

Exhibit 26: Project economics expected to worsen

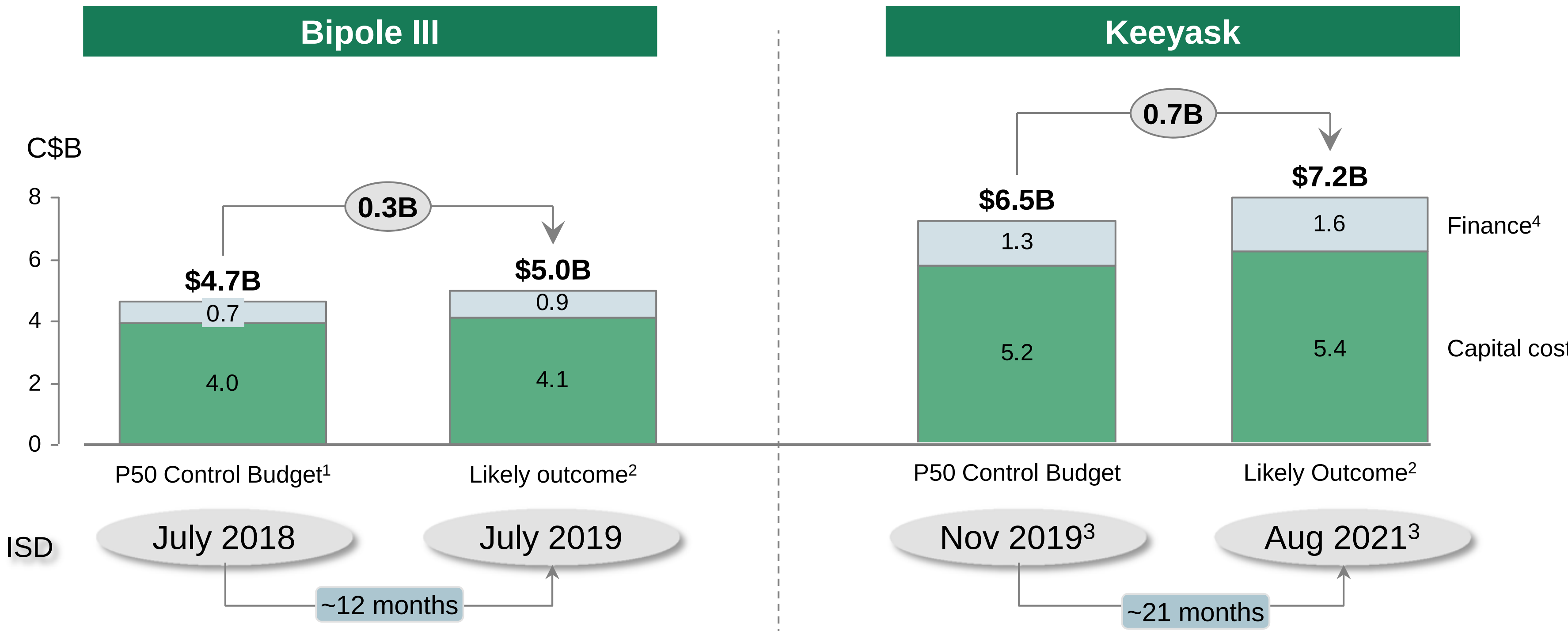
And remain sensitive to key uncertainties

		BCG view on assumptions
Water flows / Hydro risk	**Hydro risk influences total supply which drives opportunity sales** • 102 scenarios various sequences of drought and flood time periods • Climate change not explicitly modeled (impact unclear)	*Range of uncertainty unchanged*
Export prices	**Revenues sensitive to fluctuations in export price levels:** • Reference scenario below previous forecasts	*Adverse movement in MISO*
Capital Execution	**Cost and schedule overruns at one or both large projects can lead to increased borrowing and deterioration of capital profile:** • Scenarios modeled for cost and schedule overruns at Keeyask and Bipole	*Adverse movement in both projects*
Interest rates	**Canadian long-term interest rates influence MH borrowing costs** • +/- 100 bps change	*Favorable movement from NFAT to today*
Domestic Rates	**Domestic rates increases influence how quickly MH recoups its capital investments:** • 3% vs. 4% vs. 5% annual growth rate	*Range of uncertainty unchanged*
Net domestic demand	**Revenue and export quantities sensitive to domestic demand:** • Three levels considered: P50 (base) vs. P90 (high gross demand) vs. P10 (lower gross demand)	*Range of uncertainty unchanged*

Note: Exchange rate sensitivity limited given the company's internal FX net position, therefore there was no specific sensitivity analysis performed
Source: Manitoba Hydro

Exhibit 27: Capital cost & project schedules have deteriorated

~$1.0B in additional capital, ~12 month delay for BPIII and ~21 month delay for Keeyask



Transmission line construction productivity in winter main driver of schedule – 17% more than baseline must be completed in two remaining seasons

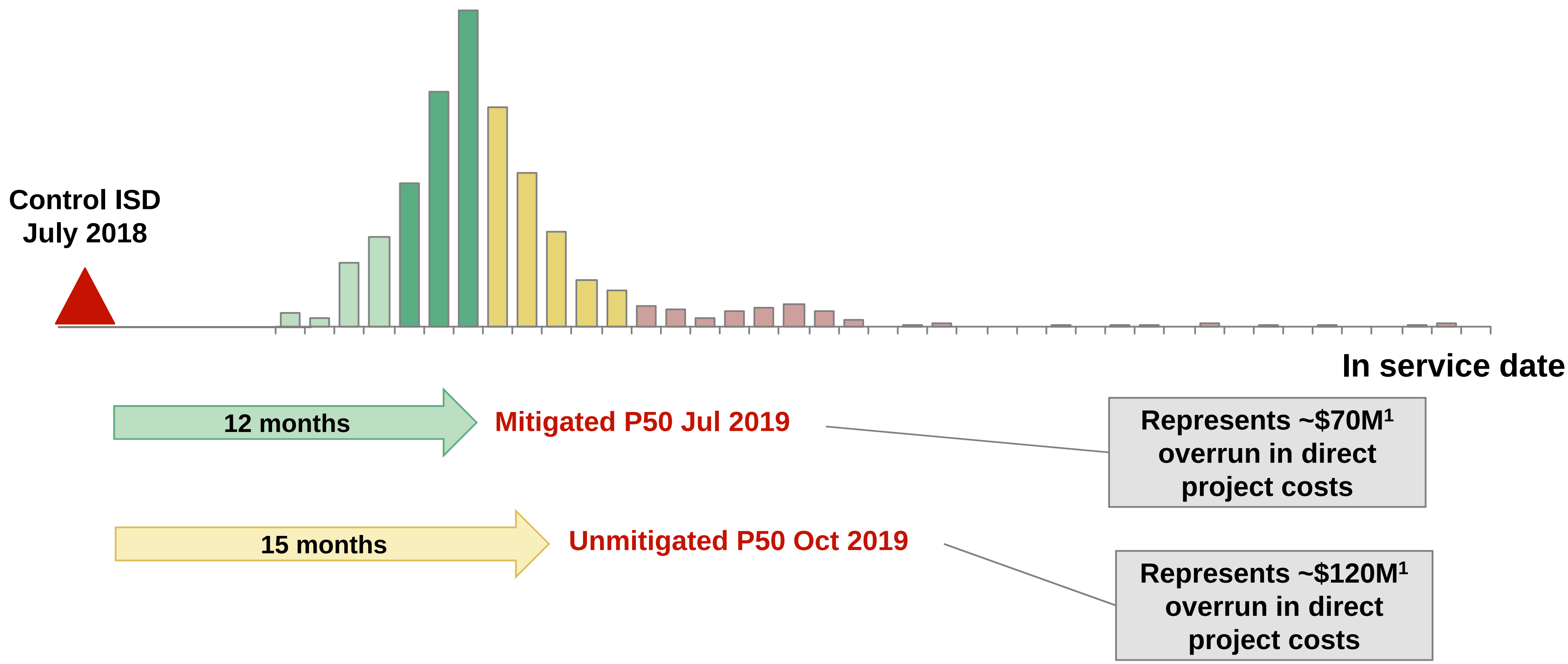
Loss of 1 complete summer construction season likely due to GCC contract underperformance, especially related to earthworks (at ~70% vs target) and concrete productivity (at ~40% vs target)

Sources: 1. Manitoba Hydro control budget. 2. BCG Analysis 3. First unit ISD 4. Includes interest & escalation

Exhibit 28: Bipole III 12 month delay is the most likely outcome

Bipole III ISD distribution

Based on current performance to date incorporating schedule mitigation activities



1. Excludes interest (Additional $0.2B in finance costs)
Note: This is based on mitigated estimates (August 15, 2016). Based on 1000 simulation runs
Source: MH durations estimates

Exhibit 29: Mitigated project delay expected to be ~21 months

Estimated in-service cost equal to ~$7.2B

Keeyask schedule distribution

Control ISD
Unit 1: Nov 2019

21 months — **Mitigated P50 Aug 2021**

Represents ~$0.4B[1] overrun in direct project costs

32 months — **Unmitigated P50 Jul 2022**

Represents ~$0.6B[2] overrun in direct project costs

1. Excludes interest (Additional $0.3B in finance costs)   2. Excludes interest (Additional $0.7B in finance costs)
Note: Activity durations and mitigation plans determined in conjunction with Manitoba Hydro. Based on 10000 simulation runs on 12-Aug-2016
Source: MH durations estimates. BCG analysis

Exhibit 30: Expected case $250M over control budget (incl interest), assumes some acceleration of construction

All numbers in nominal C$ B

	Control Budget P50	Current performance without mitigation (Downside case)	Mitigated schedule (Base case)
Spend to date	**1.8**	**1.8**	**1.8**
Transmission Line	0.6	1.1[2]	1.0
Converter Stations	1.1	1.2	1.2
Collector Lines	0.1	0.1	0.1
Community Development Initiative	0.0	0.0	0.0
Contingency	0.35	-	-
Escalation	0.2	0.1	0.1
Total project capex (excl interest)	**4.1**	**4.3**	**4.2**
Interest on incremental overrun	-	0.2	0.2
Interest on Control Budget P50 project cost	0.5	0.5	0.5
Total interest capex			
Total project capex (incl interest)	**4.65**	**5.0**	**4.9**
% of P50 control budget	**100%**	**108%**	**105%**
Schedule over run (months)	-	15 months	12 months
Project completion	July 2018	October 2019	July 2019

Excludes capitalized interest

~$15M/mo burn rate[1] for delay

Changed escalation rate reduces costs

*Potential **~$50-100M savings** through mitigations to manage schedule overrun. Preliminary est. of mitigation cost = $8M*

1. $15M/month burn rate applied to 12 months for Downside case and 9 months for mitigated case, with the remaining overrun charges relating to internal costs of the commissioning team and scaled down T-Line and Converter Station teams as needed. Includes $350M contingency allocation in addition to burn rate 2. Number rounded up to nearest billion

Source: MH control budget, CEF 2015, BCG analysis

Exhibit 31: Fully loaded project cost overrun forecast ~$700M

~$250M project capex benefit from schedule mitigation activities

(All numbers in nominal C$ B)	**Control Budget P50**	**Current trajectory without mitigation**	**Mitigated schedule**
Spend to date excl interest[1]	**2.1**	**2.1**	**2.1**
Generating Station (to-go)	2.4	3.3	3.1
Generating Outlet Transmission (to-go)	0.2	0.2	0.2
Contingency & Reserves (remaining)	0.3[2]	-	-
Escalation (total)	0.2	0.2	0.2
Total project capex (excl. interest)	**5.2**	**5.8**	**5.6**
Interest on incremental overrun[3]	-	0.7	0.3
Interest on Control Budget P50 project cost	1.3	1.3	1.3
Total capitalized interest	**1.3**	**2.0**	**1.6**
Total project capex (incl interest)	**6.5**	**7.8**	**7.2**
% of P50 control budget	**100%**	**120%**	**111%**
Schedule over run (months)	-	32	21
Unit 1 ISD date	November 2019	July 2022	August 2021

*Potential **~$250M benefit** from mitigations and avoided interest*

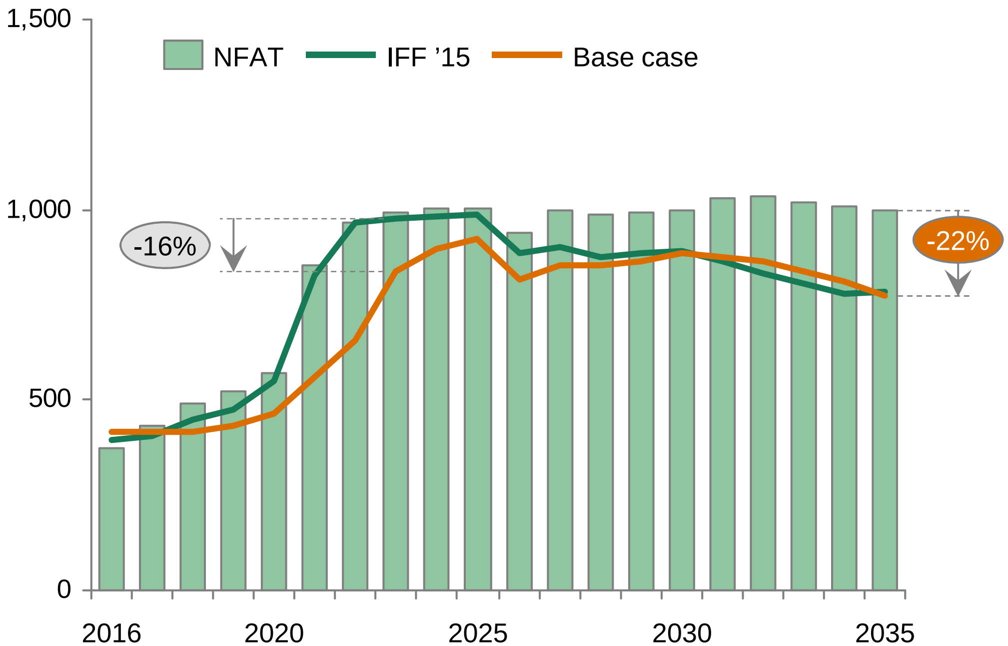
1. As at March 2016. 2. Original cont./reserves of $0.7B for project costs already partially allocated to contracts – $0.3B remaining. Assumed will be used up completely for overruns 3. Includes compounding effect due to schedule delay + additional interest on incremental project spend.
Note: Cost over run in fixed price, milestone based contracts (mainly equipment supply & install) reduced from previous phase due to greater certainty on risks (e.g. GGH contracts >50% complete, better SPI=0.94 vs 0.7 from previous phase on T&G, etc)
Source: MH control budget, CEF 2015, BCG analysis

Exhibit 32: Keeyask delay and low export prices impact revenue

Reducing latest forecast of export revenues by 19-28%

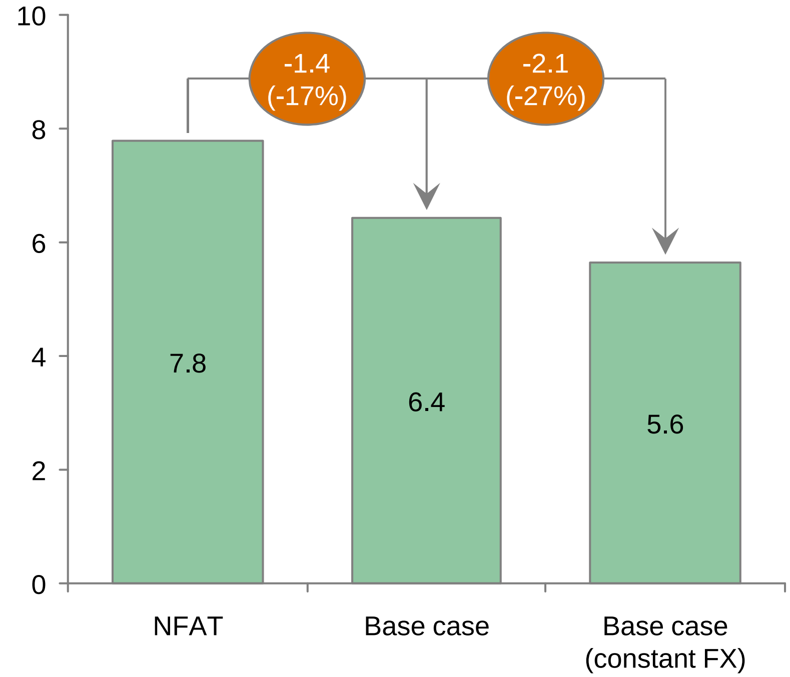
Export revenue forecasts have been revised downward since NFAT

Export Revenues ($C M)



Expected export revenues reduced by 19% to 28%

2017-2026 Total Export Rev. ($CB)



Secured firm contracts (30% of revenue[1]) reduce further downside; upside expected in case of Clean Power Plan approval

1. Including current contracts and term sheets, but not available uncommitted firm energy which could be contracted (17% of revenue).

Source: Manitoba Hydro, BCG analysis

Exhibit 33: Expected case equity ratios sustained at <15% through 2030

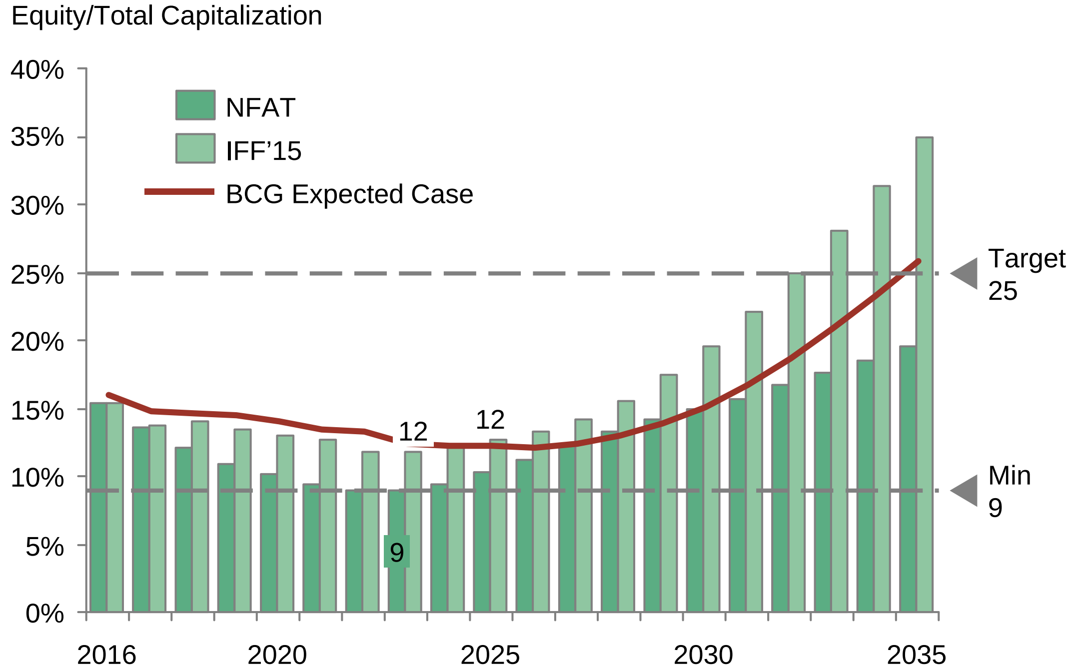
Key assumptions

NFAT
- Bipole in '19, Keeyask in '21, Tie-line in '20
- Level 2 DSM
- 2013 Interest rates

IFF '15
- Unchanged ISDs
- Reduced export price and slightly reduced demand
- Lower, 2015 interest rates

BCG Expected Case
- 12 mos. Bipole III delay
- 21 mos. Keeyask delay
- $1B total cost overrun
- Lower, 2016 reference export prices
- Lower, 2016 interest rate forecasts

Projected ratios have decreased materially under revised capital and price assumptions



Additional risks

- Additional project CapEx overrun
- Further export price deterioration
- Hydro risk
- Increasing interest rates
- Lower domestic rate increases

Exhibit 34: Stress test shows significant impact if further downside risk experienced – equity % dips to low single digits

Downside scenario modelled

Water flow	Low flow scenario
Capital project overruns *Schedule (months)*	Keeyask: 32mth delay BPIII: 15mth delay
Interest rates *Long range forecasts*	ST~3.85% LT ~5.4%
Export prices	Peak and off peak spot curve as per IFF'16 (no premium and reduced base)
Cost inflation *Overall OM&A cost increase*	2% in 2016-17 3.5% pa 2018 - 2021

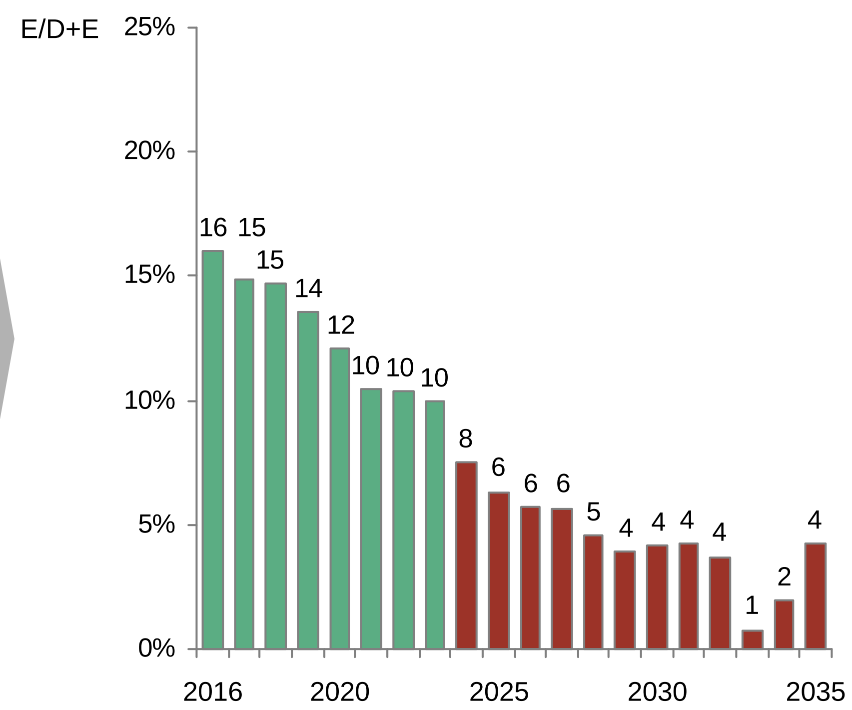


Exhibit 35: Can the projects be stopped / paused?

Bipole III and Keeyask are already well advanced in their construction with $5B already sunk

- Bipole III $2.5B (53%) spent of $4.7B control budget
- Keeyask with $2.5B (39%) of $6.5B control budget spent, including completion of milestones that prevent contractual cancellation

Cancelling Bipole III and Keeyask would bring total spend up to ~$7B

- In addition to sunk costs, Bipole III and Keeyask would both incur cancellation costs (e.g., breakage, remediation) of ~$1B each
- Decision to just cancel (or reroute) Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- Implication of cancelling both projects is ~$7B capital spent without completion of any functioning assets

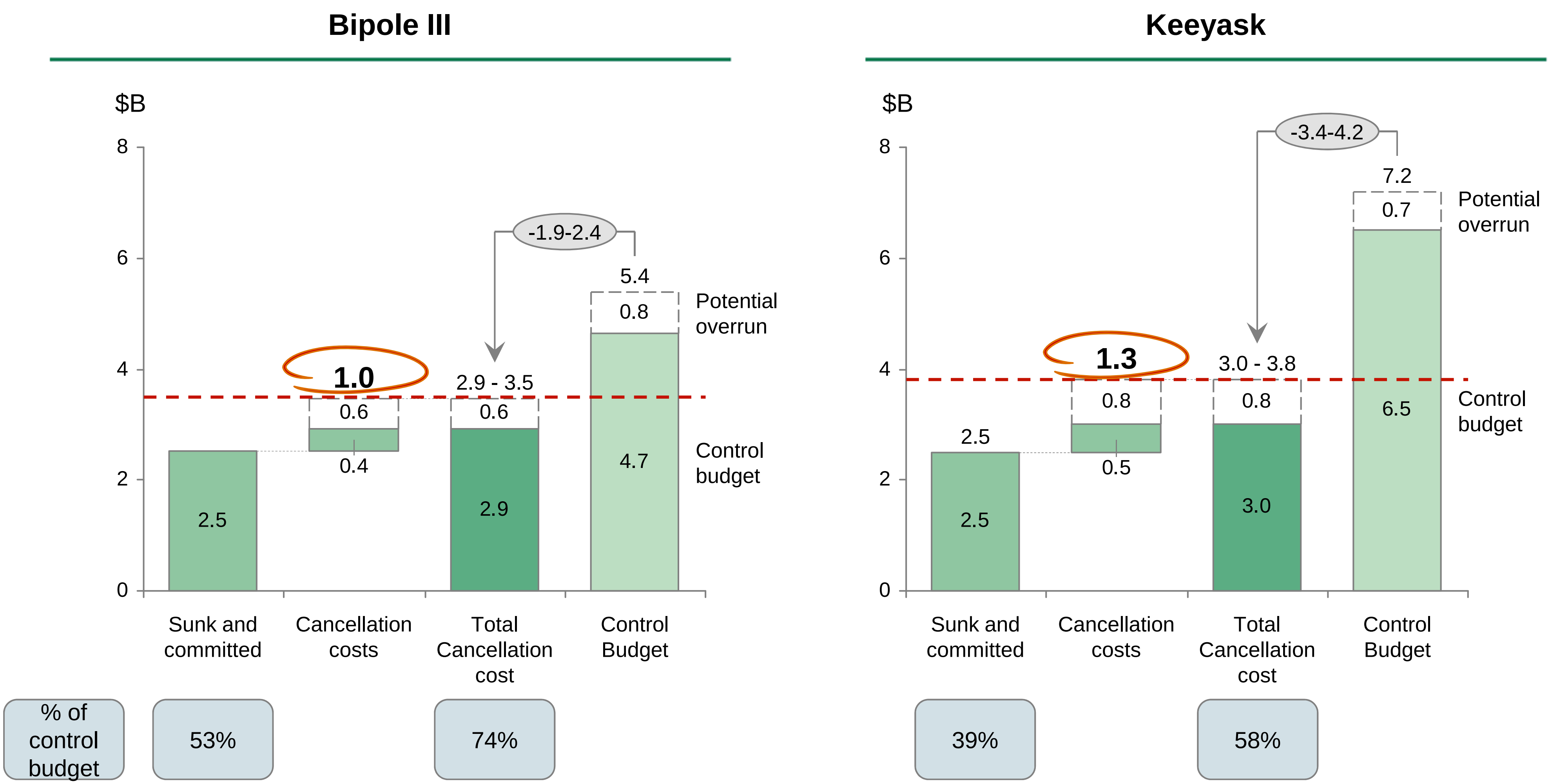
Economics remain in favour of continuing both projects when compared to alternatives

- ~$3.2B cost to complete Bipole III <u>West</u> clearly more favourable vs. ~$4.5B rerouting costs of Bipole III <u>East</u>
  - Construction cost of Bipole III <u>East</u> ~$3.0-3.5B on top of ~$1B Bipole III <u>West</u> cancellation costs
- $4.7B cost to complete Keeyask yields an NPV $3-5B more favourable vs. switching to gas option
  - Gas option with incremental $11.9B spend (including cancellation and capitalized cost of gas supply)

Further, several strategic risks to consider for stopping or pausing Keeyask

- Considerable trust and relationship damage with four First Nations partners likely to impede any future Hydro project
- Market risk of inability to supply MISO plus requirement to add domestic reserve
- Direct GDP impact of ~0.5%, particularly impacting First Nations communities

Exhibit 36: Cancellation of either project brings to bear significant further cost



Source: Manitoba Hydro estimate of cancelation; BCG analysis

Exhibit 37: Strategic impacts of cancellation potentially severe

Bipole III: Major risks relate to future reliability

- Continued system reliability risk: failure at Dorsey C.S. or on Bipole I or II will jeopardize the Province's energy supply
- Limited capacity and decreasing operational reliability on BP I & II
- Cancellation or rerouting of Bipole III strands Keeyask and likely implies cancellation due to deterioration of economics

Keeyask: Significant stakeholder impacts

- Considerable trust and relationship damage with four First Nation partners likely to impede any future Hydro project – social license to operate many years in the making
- Market risk of inability to supply MISO plus requirement to add domestic reserve
- Direct GDP impact of ~0.5%, particularly impacting First Nations communities

Source: Manitoba Hydro estimate of cancelation; BCG analysis

Exhibit 38: Completing Bipole III is the best go-forward option

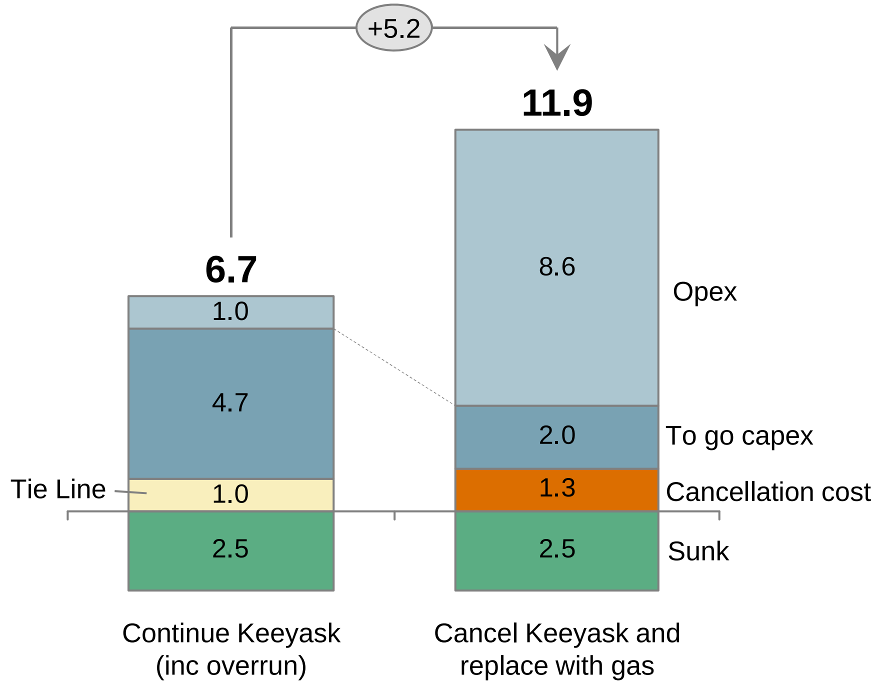
Shifting to the east route would be more costly and require at least 5 years for approvals

	Go Forward Option	Verdict	Rationale	Incremental Cost	Likely ISD
	Cancel Bipole III West	✗	• System still lacks redundancy and exposed to major outage risk • Strains relationship within MISO and risks exports	• **$400M to $1B** to cancel, wind-down and remediate	• N/A – no solution implemented
Selected option	**Continue Bipole III West**	✓	• Fastest way to improve reliability • Supports Keeyask and future hydro generation	• **$2.2 – 3.2B** to complete	• 2018 – 2019
	Shift to East Route	✗	• More costly with later in-service date • Negative environmental and First Nations impacts along east route	• **~$3.4 -4.5B+**, (~$2.3 – 3.4B for new East route work)[1]	• 2025 – 2026
	All-Gas	✗	• Future input price volatility (gas, imports) • Loss of export revenue through lack of capacity for new Keeyask power • Damage to relationships with US partners and First Nations groups	• **$3.4-4.1B**[2] (NPC[3] of gas + Bipole III cancellation + addt'l O&M)	• 2021 – 2022
	Import + Gas	✗		• **$4.9-5.5B**[4] (capital cost + Bipole III cancellation)	• 2021 – 2022

1. Assumes some work on collector lines and convertor stations continues. Estimate is purely factored at low levels of maturity 2. Based on MH and BCG scenario analysis, with contingency and over-run factors applied 3. NPC = net present cost 4. Capital cost from Manitoba Hydro Bipole III EIS + BCG analysis of Bipole III cancellation cost

Exhibit 39: Economically, continuing Keeyask is most attractive option

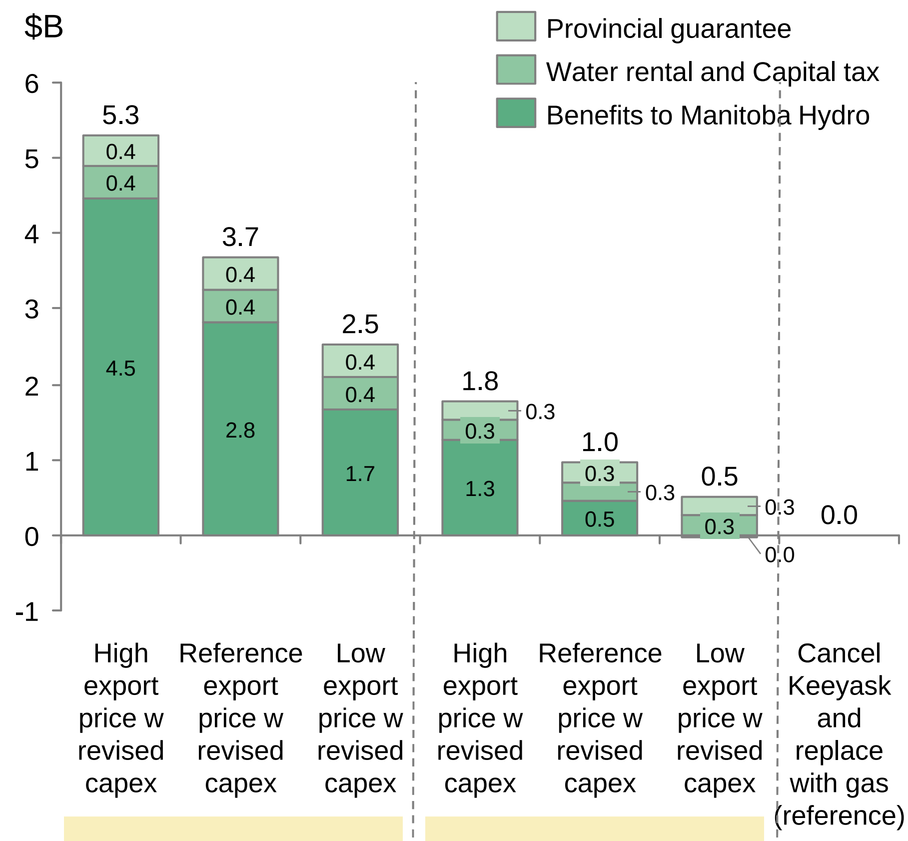
Forward capital and operating cost of gas vs Keeyask is ~$5B higher



Hydro = High upfront capital, low, stable opex

Gas = Low upfront capital, high, volatile opex

Relative NPV of continuing is $3-5B greater than replacing with gas



Base assumption @4.15% real disc rate

Sensitivity @8.0% real disc rate

Source: Economic Bar Charts, Manitoba Hydro, BCG analysis

Tab 29

CAC/MH II-47

Subject: Capital Expenditures
Reference: PUB/MH I-90 c)

a) The response to part (c) makes reference to a risk assessment associated with the consequences of a capital project's deferral. Is such an assessment undertaken for each project? If so, please provide risk assessment for each project in CEF11 with total costs of $100 M or more.

ANSWER:

A risk assessment associated with the consequences of a capital project's deferral is not undertaken for each project. Please see Manitoba Hydro's response to CAC/MH II-47(b) for additional information.

CAC/MH II-47

Subject: Capital Expenditures
Reference: PUB/MH I-90 c)

b) Is there a formal process/framework for assessing the relative risks of various capital projects? If yes, please provide the assessment underlying the projects set out in CEF11.

ANSWER:

The Capital Project Justification ("CPJ") framework is used to summarize technical, economic and financial information for a project that is being proposed or revised for inclusion in the capital program. Information provided in the CPJ includes the business case, risk assessment, resourcing requirements and other pertinent details.

The Justification section of the CPJ provides the rationale for proceeding with the project, including the reasons why the selected option was recommended, the degree of urgency and how the project supports corporate and specific business unit goals and plans. This section also addresses efficiencies that may be lost or negatively impacted as a result of deferral.

The Risk Analysis section of the CPJ addresses any unusual or special risks associated with proceeding with the recommended alternative. Risks can include scheduling, resourcing, construction uncertainties, with or without financial impacts.

The Summary of Alternatives section summarizes the alternatives studied including the most significant criteria and why the recommended alternative was selected. It includes an economic comparison of the costs and benefits for each alternative.

The purpose of the CPJ is to provide management with information to review and evaluate the technical merits and economic justification for a project. Proposed CPJ's are reviewed and approved by Executive Committee and actions are taken where necessary to mitigate risks and address prioritization.

The prioritization of the overall capital portfolio considers safety, reliability, customer requirements, compliance with regulation, environmental and financial impacts including risk of deferral. Varying methods of prioritization are used by the business units to assist the Executive in making decisions for the allocation of capital dollars and resources including the use of asset condition assessments and ranking tools to evaluate projects using common criteria.

CAC/MH II-47

Subject: **Capital Expenditures**
Reference: **PUB/MH I-90 c)**

c) If not, what process is used to prioritize capital projects and how are the risks associated with each project taken into account?

ANSWER

Please see Manitoba Hydro’s response to CAC/MH II-47(b).

Tab 30

PUB MFR 155
Bipole III

Provide the original Capital Project Justifications (2001) and all subsequent addenda for the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative, Bipole III Western Route, and Converter Upgrade to 2300 MW. Include any CPJ addenda recommended for implementation but not approved by Executive Committee or MHEB.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a letter seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The following CPJ / CPJ Addenda documents prepared for Bipole III are provided as Attachment 1 to this response.

Document	Date	Approval
Original CPJ	2001.06.13	Executive Committee, 2001.09.05
Addendum #01	2003.05.08	Executive Committee, 2003.08.19
Addendum #02	2003.11.12	Executive Committee, 2003.09.30
Addendum #03	2004.04.06	Executive Committee, 2004.06.01
Addendum #04	2005.06.23	Executive Committee, 2005.09.13
Addendum #05	2007.05.15	Manitoba Hydro Board of Directors, 2007.09.20
Addendum #06	2009.08.18	unapproved
Addendum #06a (Trans Line)	2011.03.30	Executive Committee, 2011.03.31
Addendum #06b (Converter Stns)	2011.03.29	Executive Committee, 2011.03.31
Addendum #06c (Collector Lines)	2011.03.30	Executive Committee, 2011.03.31
Community Development Initiative	2013.07.19	Executive Committee, 2013.08.20
Addendum #07a (Trans Line)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07b (Converter Stns)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07c (Collector Lines)	2014.09.24	Executive Committee, 2014.10.21
Addendum #07d (Comm Dev Init)	2014.09.26	Executive Committee, 2014.10.21
Addendum #08a (Trans Line)	2016.10.14	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08b (Converter Stns)	2016.10.12	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08c (Collector Lines)	2016.10.14	Manitoba Hydro-Electric Board, 2016.10.26
Addendum #08d (Comm Dev Init)	2016.10.dd	Manitoba Hydro-Electric Board, 2016.10.26 .

ORIGINAL CPJ

Dated 2001.06.13

Approved by Executive Committee on 2001.09.05

CAPITAL PROJECT JUSTIFICATION
FOR

RADISSON to RIEL ± 500 KV HVDC LINE

ORIGINATING DIVISION: Transmission Planning & Design

W.B.S.: ~~1.1.2.1.2.1~~ 1.5

MAJOR ITEM X **DOMESTIC ITEM**

PREPARED BY: J.B. Davies/K.L. Kent

DATE PREPARED: 2001 06 13

REPORT NO.: SPD-01/7

FILE NO. (Optional):

REVIEWED BY:
(Originating Department Manager)

NOTED BY: (if applicable)

Designing Division:

Constructing Division:

Financial Department:
(for capital item over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Originating Division Manager: V.J. Stecink

Business Unit Vice-President:

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 900.11

DATE: 2001 09 05
MANAGEMENT SERVICES

			ORIGINATING

Project Description
An 800 km, ±500 kV dc transmission line is constructed between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site. A dc paralleling line is constructed between the proposed Riel site and Dorsey Station to provide HVDC transmission during an Interlake corridor loss. Before Bipole III is in service, the new line will be used for Bipole II and the existing Bipole I & II lines are paralleled for Bipole I, resulting in loss savings of about 78 MW at maximum generation.

Recommendation
Build an 800 km, +/-500 kV dc transmission line between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site, and build a dc paralleling line between the proposed Riel site and Dorsey station.

Project Scope
Includes the 500 kV dc transmission line from near Radisson to Riel, and a paralleling line from Riel to Dorsey.

Background
This project is being recommended based on the economics of up to 78 MW of HVDC transmission power loss savings and reliability benefits discussed in the report, Manitoba Hydro Transmission System Reliability and Enhancement Options, which will be released in the fall of 2001.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
This transmission only alternative provides increased reliability to the Manitoba Hydro system. In normal steady-state operation, this item provides an increase in southern power of about 78 MW at full load due to decreased HVDC transmission losses.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	10%	

Recommended Option	NPV
800 km, ±500 kV dc transmission line is constructed between the proposed Bipole I and II emergency paralleling site near Radisson and the proposed Riel site.	zero

Other Alternatives Considered	NPV

Other Alternatives Considered	NPV

Risk Analysis

Risk Analysis was documented in System Planning and Resource Planning and Market Analysis joint report on Manitoba Hydro Transmission System Reliability and Enhancement Options.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements

Total Budget

2002/03	$ 2,500,000
2003/04	$ 4,586,000
2004/05	$ 13,063,000
2005/06	$ 13,533,000
2006/07	$ 12,269,000
2007/08	$149,096,000
2008/09	$ 46,111,000
2009/10	$ 62,373,000
2010/11	$ 57,248,000
Total	$360,779,000

Proposed Schedule

Work start date: 2002/04/01
In service date: 2010/10/31

Related Projects

SECTIONALIZATION OF LINE D602F AT RIEL

Reference Documents

This project is recommended in the report, Minimum Transmission Requirements for HVDC Bulk System Reliability, which also recommends Sectionalization of the 500 kV line D602F at Riel.

These two projects are the first recommendations to which come out of

Reference Documents

the work associated with the report, Manitoba Hydro Transmission System Reliability and Enhancement Options, which will be released in the fall of 2001.

ADDENDUM #01

Dated 2003.05.08

Approved by Executive Committee on 2003.08.19

D1878(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 01

REVIEWED BY:
(Owning Dept Manager)
Ron Mayer

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department: Nieuwenburg 2003 08 05
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Ron Mayer / for G.N.

Business Unit V.P.: [signature] 03 08 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 993.03

DATE: 2003 08 19
MANAGEMENT SERVICES

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$351,916,000
REVISED BUDGET $: (Total Net Cost)	$360,161,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2010 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.1.2.2.1

W.B.S. NUMBER: P4218, P4220, P4221

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J.B. Davies / K.L. Kent

DATE PREPARED: 2003 05 08

REPORT NUMBER:

FILE NUMBER (Optional):

-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).
Change the location of the northern termination of the dc transmission line, from Radisson to Henday, thereby increasing the line length by 20 km for a revised length of 820 km. The revised total net cost of the complex is now $360,161,000, an increase of $8,245,000 over the previously approved budget.

Project Scope (This section is be filled out only if there is a change to the scope).
Build an 820 km, ±500 kV dc transmission line between Henday and the proposed Riel site, rather than an 800 km line between Radisson and Riel.

Background (This section is be filled out only if there is information relevant to the recommendation).
The original northern termination of the line at a remote site near Radisson was consistent with an earlier plan to locate the Bipole III rectifier at the future Gull generating station site. Further studies have resulted in a recommendation that the Bipole III rectifier be located at the future Conawapa generating station site, since it is more consistent with the ultimate 2000 MW rating of Bipole III. The HVdc Task Force at the May 9, 2003 meeting approved this recommendation. Since the Bipole III HVdc line was justified based on loss saving while connected to Bipole II, the line presently only needs to be built to the Bipole II rectifier site at Henday. The line would then be extended to the Conawapa generating station site when the Bipole III converters are installed at that site. The future location of the Bipole III rectifier at Conawapa can still accommodate a possible Gull generating station first generation development sequence.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).
The termination of the Bipole III HVdc line at Henday reduces the risk associated with outages of the Bipole I & II HVdc lines, because the connection of Bipole I & II converters to the Bipole III line can be done in a staffed station with switches, rather than at a remote location with manual connections made by a line crew. The termination of the Bipole III HVdc line at Henday does not lead to the risk of all three HVdc lines crossing at one point, which is a difficult and expensive risk to mitigate.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget (after Rollover to CEF02-2)	Current CEF Budget (after Rollover to CEF02-2)	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664 *	$ 1,664 *	$ 1,664 *	$ 0	$ 0
2003/04	$ 5,422	$ 5,422	$ 4,462	($ 960)	($ 960)
2004/05	$ 13,063	$ 13,063	$ 12,914	($ 149)	($ 149)
2005/06	$ 13,533	$ 13,534	$ 13,349	($ 184)	($ 185)
2006/07	$ 12,269	$ 12,269	$ 13,055	$ 786	$ 786
2007/08	$149,096	$101,273	$ 79,390	($ 69,706)	($ 21,883)
2008/09	$ 46,111	$ 76,331	$ 78,976	$ 32,865	$ 2,645
2009/10	$ 62,373	$ 84,329	$ 99,425	$ 37,052	$ 15,096
2010/11	$ 57,248	$ 44,031	$ 56,926	($ 322)	$ 12,895
Total	$360,779	$351,916	$360,161	($ 618)	$ 8,245

* as per SAP (does not agree with the March 2003 Capital Expenditure Report)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

Memorandum from K.L. Kent to J.B. Davies, BIPOLE III TRANSMISSION LINE – BIPOLE III NORTHERN CONVERTER LOCATION, 2002 11 19, System Planning File 6-7G.

ADDENDUM #02

Dated 2003.11.12

Approved by Executive Committee on 2003.09.30

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 02

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

- Designing Division:

Constructing Division:

Financial Department: (if over $1 million) Nieuwenburg 2003 11 13

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: Anl Snyder 03 11 14

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 999.05

DATE: 2003 09 30
MANAGEMENT SERVICES

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$360,161,000
REVISED BUDGET $: (Total Net Cost)	$360,157,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2010 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.1.2.2.1

W.B.S. NUMBER: P4218, P4220, P4221

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: C.A. Nieuwenburg

DATE PREPARED: 2003 11 12

REPORT NUMBER:

FILE NUMBER (Optional):

01	2003 05 08	Change northern termination from Radisson to Henday, increasing line length by 20 km and costs by $8,245k.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).

Defer $2,462,000 worth of budget requirements from 2003/04 to future years.

Project Scope (This section is be filled out only if there is a change to the scope).

Background (This section is be filled out only if there is information relevant to the recommendation).

Reduction to 2003/04 was made to help offset an unexpected over-expenditure on one of Transmission & Distribution's other complexes, namely Communications (complex #1.1.2.6.2.1 – project #P2993 – Interlake and Nelson River Communications-Fibre).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis

Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget (after Rollover)	Current CEF Budget (after Rollover to CEF02-2)	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664	$ 1,664	$ 1,664	$ 0	$ 0
2003/04	$ 4,462	$ 5,422	$ 2,000	($ 2,462)	($ 3,422)
2004/05	$ 12,914	$ 13,063	$ 13,529	$ 615	$ 466
2005/06	$ 13,349	$ 13,534	$ 13,965	$ 616	$ 431
2006/07	$ 13,055	$ 12,269	$ 14,286	$ 1,231	$ 2,017
2007/08	$ 79,390	$101,273	$ 79,390	$ 0	($ 21,883)
2008/09	$ 78,976	$ 76,331	$ 78,973	($ 3)	$ 2,642
2009/10	$ 99,425	$ 84,329	$ 99,424	($ 1)	$ 15,095
2010/11	$ 56,926	$ 44,031	$ 56,926	$ 0	$ 12,895
Total	$360,161	$351,916	$360,157	($ 4)	$ 8,241

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

ADDENDUM #03

Dated 2004.04.06

Approved by Executive Committee on 2004.06.01

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

HENDAY – RIEL ± 500 KV HVDC LINE

Addendum Number 03

REVIEWED BY:
(Owning Dept Manager)
Ron Mayer
2004/05/14

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department: C. Nieuwenburg 2004 05 25
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G. Neufeld

Business Unit V.P.:

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1030.05

DATE: 2004 06 01
MANAGEMENT SERVICES

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$360,157,000
REVISED BUDGET $: (Total Net Cost)	$387,620,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 10
REVISED ISD: (Last Major In-service Date)	2012 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.1.2.2.1

W.B.S. NUMBER: P4218, P4220, P4221

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J.B. Davies / K.L. Kent

DATE PREPARED: 2004 04 06

REPORT NUMBER:

FILE NUMBER (Optional):

02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900-11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Henday-Riel ±500 kV HVDC Line

Recommendation (This section is required for all Addendums).
The extended environmental process has resulted in a delay in the expected license date by two years and thus it is recommended that the in-service date be delayed by two years from 2010 10 to 2012 10.

Project Scope (This section is be filled out only if there is a change to the scope).

Background (This section is be filled out only if there is information relevant to the recommendation).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).
The Henday-Riel ±500 kV HVDC Line provides additional southern generation through loss savings, and also a reliability benefit to the Manitoba Hydro system. Any delay to the ISD means additional risk to the system for the duration of the delay. Riel station and Bipole III share common elements, so the environmental strategy must be considered as a whole.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget	Current CEF Budget	Revised CPJ Budget	CPJ Increase (Decrease)	CEF/ Revised CPJ Increase (Decrease)
Prev.	$ 1,664	$ 1,664	$ 1,664	$ 0	$ 0
2003/04	$ 2,000	$ 2,000	$ 907	($ 1,093)	($ 1,093)
2004/05	$ 13,529	$ 13,530	$ 2,147	($ 11,382)	($ 11,383)
2005/06	$ 13,965	$ 13,966	$ 3,961	($ 10,004)	($ 10,005)
2006/07	$ 14,286	$ 14,286	$ 12,761	($ 1,525)	($ 1,525)
2007/08	$ 79,390	$ 79,389	$ 14,568	($ 64,822)	($ 64,821)
2008/09	$ 78,973	$ 78,975	$ 66,866	($ 12,107)	($ 12,109)
2009/10	$ 99,424	$ 99,424	$ 64,647	($ 34,777)	($ 34,777)
2010/11	$ 56,926	$ 56,927	$ 71,478	$ 14,552	$ 14,551
2011/12	$ 0	$ 0	$ 89,424	$ 89,424	$ 89,424
2012/13	$ 0	$ 0	$ 59,198	$ 59,198	$ 59,198
Total	$360,157	$360,159	$387,620	$ 27,463	$ 27,461

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

ADDENDUM #04

Dated 2005.06.23

Approved by Executive Committee on 2005.09.13

.J1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

HENDAY – RIEL ± 500 KV HVDC LINE
Renamed to:
BIPOLE III WESTERN ROUTE
Addendum Number 04

REVIEWED BY:
(Owning Dept Manager) Ron Mazur 2005 08 29.

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department: (if over $1 million) Nieuwenburg 2005 08 29

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2005 08 29

Business Unit V.P.: 05 08 29

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$387,620,000
REVISED BUDGET $: (Total Net Cost)	$1,879,896,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	Multi - 2010 10
REVISED ISD: (Last Major In-service Date)	Multi - 2017 10
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.1.2.2.1

W.B.S. NUMBER: P4218, P4220, P4221, P10155, P10157

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: System Planning Department

DATE PREPARED: 2005 06 23

REPORT NUMBER:

FILE NUMBER (Optional):

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1090.06

DATE: 2005 09 13
Capital Plans, Corp Budget Services

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III with the HVdc line routed west of Lakes Winnipegosis and Manitoba.

Recommendation (This section is required for all Addendums).

Manitoba Hydro has been asked to look at other alternatives for routing the Bipole III transmission line from the east side of Lake Winnipeg. In the interim, a west side of the province (west of Lakes Winnipegosis and Manitoba) routed Bipole III transmission line from Conawapa Station to Riel Station with 2000 MW of HVdc converters at both stations is being advanced as a placeholder in the budget. In October 2006, a recommendation for an alternative to the east-side of Lake Winnipeg routed Bipole III line for Manitoba Hydro system reliability will be made. Also, the recommendation will address the reliability of equipment associated with common mode HVdc station outages in addition to common mode outages of the HVdc lines. The October 2006 recommendation may be quite different from the above.

Project Scope (This section is be filled out only if there is a change to the scope).

The Bipole III scheme as a placeholder in the budget includes:

- An HVdc transmission line of a minimum length of 1295 km from Riel Converter Station to Conawapa Converter Station.
- A converter station with 2000 MW of converters at Conawapa.
- Six ac transmission lines approximately 30 km long to connect the Conawapa Converter Station to Henday Converter Station (three of these lines are not necessary with Conawapa generation development).
- A converter station with 2000 MW of converters at Riel, including 3 synchronous compensators

A paralleling line between Dorsey Converter Station and Riel Converter Station is not required as paralleling with Bipole II will not be possible and the western-routed Bipole III line will not be usable by Bipole I or Bipole II.

Background (This section is be filled out only if there is information relevant to the recommendation).

A Bipole III transmission line routed on the east side of Lake Winnipeg was originally recommended and approved (I.M. Node Number 1.5.1.2.2.1). The Board of Manitoba Hydro has directed that alternative transmission line (Bipole III) routes other than the east side of Lake Winnipeg be evaluated.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

Due to the severe critical risk to the Province and Corporation of not mitigating an Interlake (Bipole I&II) corridor outage or a Dorsey station common mode outage, this budget item is being included as a placeholder pending an October 2006 recommendation of an alternative to an east-side of Lake Winnipeg routed Bipole III line.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
An East-side routed Bipole III line.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The risks associated with this project are as follows:

1) Technically inferior solution to the eastern-routed Bipole III line with converters; less load served on average in situations for which the line is to be built.
2) Less reliable solution since the west side scheme would still only provide an outlet of 2000 MW of northern generation in the event of another Bipole I&II corridor outage, while an east side Bipole III line would allow the paralleling of Bipole I&II converters on the Bipole III line providing the outlet of 3300 MW of northern generation. Also the longer line length associated with a western route increases exposure to outages on Bipole III.
3) A delayed ISD over an eastern routed line, placing Manitoba customers at greater risk for a longer period of time. A western line will likely take longer for conducting environmental assessment/public work consultation and will take more time to build. The earliest date for initiation of environmental work is after the October 2006 recommendation of an alternative to the east of Lake Winnipeg Bipole III line.
4) Justification at a public hearing by Manitoba Hydro of the westerly routing concept vs. an easterly route concept will be problematic.
5) Although 1265 km is used as a proxy minimum for the line length, it is likely the actually built line will be considerably longer with more cost and losses, due to efforts to maximize separation from the existing HVDC right of way.
6) The siting of Bipole III in a western corridor would make the placement of the next north/south transmission line very problematic with the east of Lake Winnipeg routing being blocked and the Interlake routing presenting significant risk of a common mode outage.

There is a risk of further delays in the expected in-service date as the siting of the southern station at Riel may need to be re-evaluated with a western routing of Bipole III

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

To be determined.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget	Current CEF Budget	Revised CPJ Budget	CPJ Increase (Decrease)	CEF Increase (Decrease)
Prev.	$ 2,571	$ 2,571	$ 2,571	$ 0	$ 0
2004/05	$ 2,147	$ 2,147	$ 2,357	$ 210	$ 210
2005/06	$ 3,961	$ 3,961	$ 1,040	($ 2,921)	($ 2,921)
2006/07	$ 12,761	$ 12,761	$ 956	($ 11,805)	($ 11,805)
2007/08	$ 14,568	$ 14,568	$ 1,862	($ 12,706)	($ 12,706)
2008/09	$ 66,866	$ 66,866	$ 2,877	($ 63,989)	($ 63,989)
2009/10	$ 64,647	$ 64,647	$ 9,067	($ 55,580)	($ 55,580)
2010/11	$ 71,478	$ 71,478	$ 12,559	($ 58,919)	($ 58,919)
2011/12	$ 89,424	$ 89,424	$ 23,388	($ 66,036)	($ 66,036)
2012/13	$ 59,198	$ 59,197	$ 118,975	$ 59,778	$ 59,778
2013/14	$ 0	$ 0	$ 266,921	$ 266,921	$ 266,921
2014/15	$ 0	$ 0	$ 349,682	$ 349,682	$ 349,682
2015/16	$ 0	$ 0	$ 503,939	$ 503,939	$ 503,939
2016/17	$ 0	$ 0	$ 456,655	$ 456,655	$ 456,655
2017/18	$ 0	$ 0	$ 123,990	$ 123,990	$ 123,990
2018/19	$ 0	$ 0	$ 3,056	$ 3,056	$ 3,056
Total	$ 387,620	$ 387,620	$1,879,896	$1,492,276	$1,492,276

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

To be determined.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #05

Dated 2007.05.15

Approved by Manitoba Hydro Board of Directors 2007.09.20

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

BIPOLE III WESTERN ROUTE

Addendum Number 05

REVIEWED BY:
(Owning Dept Manager)
KLK 26 JUN 07 Ron W. Mazur 2007-06-26

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million) Nieuwenburg 2007/07/05

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2007 06 27

Business Unit V.P.: 07 07 19

Approved By MH Board of Directors
MINUTE # 786-07-05

DATE: 2007 09 20
Capital Plans, Accounting, Research & Capital

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,879,896,000
REVISED BUDGET $: (Total Net Cost)	$2,247,835,000
START DATE: (1st Cost Flow)	2002 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	Mult - 2017 10
REVISED ISD: (Last Major In-service Date)	Mult - 2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 1 (160 pts)
INVESTMENT REASON:	

OWNING DIVISION: Transmission Planning & Design

I.M. NODE NUMBER: 1.5.1.2.2.1

W.B.S. NUMBERs: P4218, P4220 (old), P4221, P10155, P10157

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: A.A. Poulin / J.B. Davies / K.L. Kent
AAP 2007/06/13

DATE PREPARED: 2007 05 15

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies/K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies/K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies/K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III with the HVdc line routed west of Lakes Winnipegosis and Manitoba.

Recommendation (This section is required for all Addendums).
Increase the proposed budget for the Bipole III western route budget placeholder by $367,940,000 to $2,247,835,000.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change.

Background (This section is be filled out only if there is information relevant to the recommendation).

The estimate is higher due to:

- an increase in line length for the western route as refined for the October 2006 report, from 1296 km to 1341 km;
- moderate increases being experienced in transmission line material costs due to price volatility in the marketplace (approx. 20%);
- considerable increases being experienced in transmission line construction costs, doubling since Addendum #04 due to market conditions (approx. 40% increase applied in late 2005 due to factors such as increased labour and fuel costs, and a further 50% increase applied in 2007 due to recent experience with tendered prices for the Wuskwatim-Birchtree transmission line and further upward trends in construction costs across western Canada), and
- resultant increases in interest and escalation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
No Change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	**% For current corporate rates see G911**	**For clarification on hurdle rates, contact Economic Analysis Department**

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**
No Change.	

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**
No Change.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

No Change.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

To be determined.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 6,141	$ 6,141	$ -
2006/07	$ 1,472	$ 1,472	$ -
2007/08	$ 1,174	$ 1,875	$ 701
2008/09	$ 2,877	$ 2,901	$ 24
2009/10	$ 9,067	$ 9,298	$ 231
2010/11	$ 12,559	$ 12,994	$ 434
2011/12	$ 23,388	$ 25,115	$ 1,727
2012/13	$ 118,975	$ 172,475	$ 53,501
2013/14	$ 266,921	$ 331,532	$ 64,611
2014/15	$ 349,682	$ 420,146	$ 70,464
2015/16	$ 503,939	$ 579,614	$ 75,675
2016/17	$ 456,655	$ 535,141	$ 78,485
2017/18	$ 123,990	$ 145,948	$ 21,959
2018/19	$ 3,056	$ 3,184	$ 128
Total	$ 1,879,896	$ 2,247,835	$ 367,940

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #06

Dated 2009.08.18

Unapproved

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III WESTERN ROUTE 500kV HVDC TRANSMISSION LINE & 2000MW CONVERTERS
Addendum Number 06

REVIEWED BY:
(Owning Dept Mgr - Transmission)

(Owning Dept Mgr – Power Supply)

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Financial:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$2,247,835,000
REVISED BUDGET $: (Total Net Cost)	$3,953,749,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 pts)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Mgr – Transmission:

Owning Div. Mgr – Power Supply:

Vice-President – Transmission: H. Tymofichuk 2009.09.10

Vice President – Power Supply: [signature] 09 09 10

OWNING DIVISIONs: Transmission Planning & Design; New Generation Construction

I.M. NODE NUMBER: 1.5.2.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14363 P:14364, P:14518, P:15533 - P:15537, P:15540 – P15544, P:15696, P:15697

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: K.L. Kent (Complex Owner); A.A. Poulin (Complex Manager); H.S. Jhinger (Proj. Mgr, Converters)

DATE PREPARED: 2009 08 18

REPORT NUMBER:

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Route 500kV HVdc Transmission Line & 2000MW Converters

Recommendation (This section is required for all Addendums).

Increase the budget for the Bipole III complex by $1706 million to a revised total of $3954 million, in order to incorporate the following:

- review of estimates for all components of the complex (total increase of $739 million to the base estimate, 2009$),
- inclusion of contingency for all components of the complex (total increase of $525 million to the base estimate, 2009$), and
- the resultant changes to interest and escalation (increase of $442 million).

Project Scope (This section is be filled out only if there is a change to the scope).

No change to the high-level concept at this time. Potential future changes to scope (cost and schedule) that may be forthcoming in a subsequent CPJ Addendum (i.e., are not part of this submission) are as follows:

- Changes to the existing transmission network or at existing generation facilities that may be necessary as a result of the Bipole III transmission line and converters being added to the system.
- Changes that may be necessary for an HVdc transmission line and converters rated at 2500MW.
- Application of Transmission Development Fund (TDF) and/or Adverse Effects policies that may be recommended for the Bipole III complex.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was a placeholder only, pending completion of studies by System Planning, and was based on a 2001 estimate prepared by Teshmont Consultants.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost of licensing, property and converters were not updated at that time, nor was contingency identified in that estimate.

This CPJ Addendum #06 covers re-estimates that have been prepared since either the 2001 Teshmont report or the May 2007 CPJ Addendum, for all components of the Bipole III complex. These re-estimates result in an increase of $739 million to the base estimate, detailed as follows (all amounts are in 2009$).

TRANSMISSION-RELATED ITEMS (total increase of $142 million to base estimate):

a) <u>500kV dc Transmission Line</u>
The base estimate for the transmission line has increased by $72 million due to a design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize flashovers, and by $25 million due to the application of the Transmission Line Agreement (TLA), or unionization of labour.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Northern 230kV Collector Lines
Reflects increases since 2001 to both construction material and labour costs ($23 million). Also reflects an increase of 39km to the overall length of transmission line construction required ($9 million). In addition, the line from Limestone to Conawapa, previously assumed to be established with the construction power for the Conawapa G.S, is now required first for construction power of the Northern Converter Station ($9 million).

c) Licensing & Environmental Assessment
Costs have increased by $2 million due to more comprehensive aboriginal and community consultations.

d) Sectionalize 230kV Transmission Line R49R at Riel
This is a new item, estimated at $2 million. R49R sectionalization is required to accommodate and reliably transmit a 2000MW Bipole III at Riel. This had been recommenced with the Riel Sectionalization project but was deferred to coincide with Bipole III converters.

In addition to the above, the risk assessment yielded a contingency estimate of $143 million (see the Risk Analysis section for details). These changes, along with an increase of $57 million for interest and escalation, make the total net increase equal to $343 million and the revised total net cost equal to $1477 million, for the transmission-related portion of the complex.

CONVERTER-RELATED ITEMS (total increase of $596 million to base estimate):

e) Riel Converter Station
Converter and HVdc equipment costs remain relatively unchanged; however, the costs for synchronous condensers have more than doubled. Studies have also recommended the addition of a fourth synchronous condenser for the 2000MW Bipole ($193 million combined increase). Other increases to the base estimate include: higher construction management, project management and engineering costs, which were not fully considered in the 2001 placeholder ($49 million); and increase in site size, development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($29 million).

f) Northern Converter Station at Conawapa
Converter and HVdc equipment costs remain relatively unchanged. Changes to the base cost are as a result of: inclusion of the construction camp previously assumed to be built and covered by the Conawapa G.S. Project ($38 million); higher construction management, project management and engineering costs not fully considered in the 2001 placeholder ($61 million), and site size increase of 2.2 times that assumed in 2001 and the associated increase in site development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($54 million).

g) Riel Site Development for Converters & 230kV Switchyard
Part of the switchyard will be established under a separate project, Riel Sectionalization; however, the concept was developed to more easily accommodate the future HVdc requirements (5 bays and 12 breakers vs. just 3 bays and 9 breakers) and reconfiguration to accommodate a transfer bus scheme, therefore 50% of the equipment costs are included in this estimate ($33 million). An expansion of the 230kV switchyard is required with Bipole III to output the 2000MW, establishing 4 new bays and 11 breakers, and required terminations for HVdc equipment are included in the base estimate ($51

Background (This section is be filled out only if there is information relevant to the recommendation).

million). Half of the site development costs at Riel are included here as attributable to the Converter Station and 230 Switchyard, whereas the 2001 report did not have any site development costs (assumed it would be developed at Riel prior to Bipole III). Like the northern converter station, the site size at Riel has increased (approx. 2.6 times) due to maintenance and security requirements, changes to oil spill containment systems, and planning the layout to accommodate for future additions to the station (i.e. paralleling line and additional 500kV and 230kV AC lines). The associated site development and infrastructure costs have increased ($28 million).

h) Northern 230kV Switchyard
Estimate has increased by $25 million to accommodate the following scope changes: two temporary additional AC lines required to transmit a 2000MW Bipole in the interval when Bipole III is in service before Conawapa G.S. (due to the change in generation sequence), and three lines for future Gilliam Island addition, for a total of 8 bays and 32 breakers.

i) Property for the Riel Converter Station
Not previously included in the estimate. Includes $6 million worth of station site properties and $12 million worth of buffer properties, all purchased from private owners.

j) Construction Power Station for Northern Converter
This item was not previously included, as it had been assumed to be part of the construction of the Conawapa Generation Station. Due to a change in sequencing this complex will be the first to require construction power, and hence the estimated cost of $15 million is now part of this complex.

k) Electrode Lines and Stations
Other components not previously included that have now been estimated are for the electrode lines and stations for both the Northern and the Riel Converter Stations, for a total of $2 million.

In addition to the above, the risk assessment yielded a contingency estimate of $382 million (see the Risk Analysis section for details). These changes, along with an increase of $384 million for interest and escalation, make the total net increase equal to $1363 million and the revised total net cost equal to $2477 million, for the converter-related portion of the complex.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

On July 4th, 2001 a System Planning report entitled "Minimum Transmission Requirements for HVDC Bulk System Reliability" (SPD 01/7) was issued and subsequently approved. A major recommendation of that report was for a Bipole III transmission line routed east of Lake Winnipeg. Converter capacity to be connected to the line would be considered in subsequent studies.

At the request of the MHEB, System Planning examined reliability alternatives to an eastern routed Bipole III line. The report entitled "Manitoba HVDC Reliability Alternatives" (SPD 2006/11) was issued on October 4th, 2006, and concluded that Bipole III routed west of Lakes Winnipegosis and Manitoba with 2000 MW of converter capacity was the leading reliability alternative to an eastern routed line.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

Based on the conclusions of this report, a recommendation was made by the Executive to the MHEB to proceed with Bipole III, routed west of Lakes Winnipegosis and Manitoba, and with 2000 MW of converter capacity.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability-Outage Related	Operational Enhancement	New Asset Addition	60%	$2,372,250,000
Reliability-Load Related	Capacity Enhancement (for domestic load)	New Asset Addition	20%	$ 790,750,000
Reliability-Load Related	New/increased Generation Delivery (for domestic load)	New Asset Addition	20%	$ 790,750,000
				$3,953,750,000

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	**For current corporate rates see G911** **For clarification on hurdle rates, contact Economic Analysis Department**

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Contingency (total of $525 million in base 2009$):

The contingency estimate is based on risk assessments that were conducted to identify areas of uncertainty or potential fluctuation, and is detailed as follows:

TRANSMISSION-RELATED ITEMS (total contingency of $143 million or 15% of the base costs):

a) 500kV dc Transmission Line (total contingency = $116 million or 15% of the base costs)
   - A potential change to the detailed route selection or line length of up to 10%, as the final route has not yet been determined ($87 million).
   - Related to lack of geotechnical information, uncertainty with soil conditions calls for the purchase of extra foundation types to allow for flexibility during the tight construction window ($15 million).
   - Potential premiums in association with maximizing aboriginal content ($10 million).
   - Higher compensation to property owners for damages during construction, based on National Energy Board (NEB) compensation settlements recently experienced in Alberta ($4 million).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

b) Licensing & Environmental Assessment (total contingency = $13 million or 21% of the base costs)
- Greatest risk for licensing is in the costs for aboriginal and community consultations ($9 million).
- Potential for even more extensive environmental monitoring and assessments, based on our experiences with the Wuskwatim project ($4 million).

c) Northern 230kV Collector Lines (total contingency = $10 million or 12 % of the base costs)
Design uncertainty and exact location of the northern converter station could increase the total line lengths assumed.

d) Property for 500kV dc Transmission Line (total contingency = $4 million or 18% of the base costs)
Potential increases in land values, by as much as 50%, based on the NEB compensation settlements recently experienced in Alberta. Note however that this risk estimate does not include any costs for expropriation of land and the associated legal expenses.

CONVERTER-RELATED ITEMS (total contingency of $382 million or 26% of the base costs):

e) Riel Converter Station (total contingency = $200 million or 39% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters and $100 million for synchronous condensers).

f) Northern Converter Station (total contingency = $135 million or 18% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters); and potential for higher costs associated with northern work ($35 million).

g) Riel Site Development for Converters & AC Switchyard (total contingency = $25 million or 19% of the base costs)
Final Design for Phase A of the Riel Switchyard won't be available from the engineer and procure contract until January 2010, while final design for Phase B is three to six years away. There is also uncertainty with line protection, cyber security, and building strength. Re-work is anticipated for site preparation, as construction will be started ahead of final design to protect against the risk of a wet summer delaying the construction progress.

h) Northern 230kV AC Switchyard (total contingency = $15 million or 31% of the base costs)
Based on a Range Estimating session, recommend contingency for potentially higher costs associated with northern work.

i) Construction Power Station for Northern Converter Station (total contingency = $4 million or 27% of the base costs)
Design and construction estimate are based on a conceptual Single Line Diagram (SLD) only; the site size and exact location of the Converter Station is not yet confirmed.

j) Northern and Riel Electrode Lines (total contingency = $3 million or 36% of the base costs)
The length of the lines is not certain, as Electrode sites have not yet been determined. Also provides for the use of steel towers if necessary (base estimate assumes wood).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Management Reserve (total of $334 million in base 2009$):

Also identified during the risk assessment but not included in the contingency estimate at this time, are the management reserve items listed below. Though each of the components covered by this list has a contingency amount included within the project estimate, there is potential for further increases above those contingency amounts, for the following factors:

- Premium if basing the converters estimate on pricing received from the most experienced supplier ($102 million, high probability).
- Uncertainty on the northern interconnecting station modifications at Henday Converter Station and Long Spruce Generating Station, as the scope is not well defined at this time ($20 million, high probability).
- Allowance for greater requirement for engineering, project management and construction management on the Northern Converter Station and the Riel Converter Station projects ($14 million, high probability).
- Allowance for poor soil conditions during construction of the Northern Converter Station ($12 million, high probability)
- Market conditions for transmission line construction labour may increase costs by as much as 20% ($70 million, low probability).
- Market conditions for transmission-related materials or commodities (e.g., towers, hardware, conductor, insulators, foundations, communications equipment) may increase by 10-25% ($61 million, low probability).
- Increase to design, supply and install (construction) costs for the Northern 230kV AC Switchyard if a gas-insulated station (GIS) is chosen instead of an air-insulated station (AIS), due to unknown soil conditions ($55 million, low probability).

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:

- The detailed route selection must be finalized by December 2010.
- An Environmental Licence must be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the Western route is based on having five winter seasons for access and construction. The southern portion of the Western route can be built year-round, however it is subject to more property and land access issues.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 7,613	$ 7,613	$ -
2007/08	$ 1,875	$ 1,955	$ 80
2008/09	$ 2,901	$ 17,878	$ 14,977
2009/10	$ 9,298	$ 33,037	$ 23,739
2010/11	$ 12,994	$ 80,542	$ 67,548
2011/12	$ 25,115	$ 110,970	$ 85,855
2012/13	$ 172,475	$ 271,913	$ 99,438
2013/14	$ 331,532	$ 671,609	$ 340,077
2014/15	$ 420,146	$ 691,071	$ 270,926
2015/16	$ 579,614	$ 823,189	$ 243,576
2016/17	$ 535,141	$ 866,711	$ 331,570
2017/18	$ 145,948	$ 375,335	$ 229,387
2018/19	$ 3,184	$ 1,926	$ (1,258)
Total	$ 2,247,835	$ 3,953,749	$ 1,705,914

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

ADDENDUM #06a (Transmission Line)

Dated 2011.03.30

Approved by Executive Committee 2011.03.31

ADDENDUM #06b (Converter Stations)

Dated 2011.03.29

Approved by Executive Committee 2011.03.31

ADDENDUM #06c (Collector Lines)

Dated 2011.03.30

Approved by Executive Committee 2011.03.31

D1876(A)

CAPITAL PROJECT JUSTIFIC
FOR

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

Bipole III Western Routed T/L & 2000MW Converters
TRANSMISSION LINE
Addendum Number 06a

REVIEWED BY:
(Owning Dept Manager) Ron Mayer 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: S. Railey 2011/03/30

Constructing Div:

Designing Div.:

Financial: Nieuwenburg 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld 2011 03 30

Business Unit V.P.: 2011.03.30

PREV. APPROVED BUDGET $: (Use S value from approved CPJ or last approved CPJ Addendum)	$1,081,923,000
REVISED BUDGET $: (Total Net Cost)	$1,259,915,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Project Owner: Pei Wang
Project Manager: Adele Poulin

DATE PREPARED: 2011.03.30

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $177,991,000 for the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,259,915,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the HVdc transmission line, and of the licensing and environmental assessment for the overall complex (total increase of $152,122,000);
- inclusion of contingency for the above-mentioned components (total increase of $49,353,000); and
- the resultant changes to interest and escalation (decrease of $23,485,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinoow Converter Station to the Riel Converter Station, approximately 1341km in length.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).
- Property acquisition and/or easements for the 500kV HVdc transmission line.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost estimates for licensing, property and contingency were not updated at that time.

This CPJ Addendum #06a covers a budget increase of $177,991,000 in association with the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>500kV HVdc Transmission Line (base increase of $140,714,000):</u>
   - Design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize the likelihood of anomalous flashovers that have been experienced on the existing bipoles in the past 20 years.
   - Incorporation of the Transmission Line Agreement for unionization of construction labour.
   - Application of the revised corporate policy for compensation for private property.

b) <u>Licensing & Environmental Assessment for the Bipole III complex (base increase of $4,912,000):</u>
   - More comprehensive aboriginal and community consultations.
   - Additional studies related to converter size.

Background (This section is be filled out only if there is information relevant to the recommendation).
c) Property Acquisition and/or Easements for the Transmission Line (base increase of $6,497,000): ▪ More privately-owned land associated with the western route. d) The revised budget also includes contingency at $49,353,000 (Project Risk Analysis section contains details). The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in a net decrease of $23,485,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).
A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	**NPV Benefits (Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits (Costs)**

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).
A total of $49,353,000 of contingency (approximately 6% of the base estimate) is included in the budget amount for CPJ Addendum #06a, to cover the following: a) 500kV HVdc Transmission Line (contingency of $39,967,000 or 5% of the base estimate): Potential changes to the detailed route selection or line length. b) Licensing & Environmental Assessment (contingency of $9,386,000 or 15% of the base estimate): Potential for greater requirements for aboriginal and community consultations, and for more extensive environmental monitoring and assessments during construction.

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The following risks create a potential for additional costs:
- Market conditions for transmission line construction labour, materials or commodities.
- Unforeseen geotechnical conditions.
- Further changes to corporate policy for private property compensation.

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:
- Environmental License to be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the line is based on having five winter seasons for access and construction.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 17,207	$ 24,613	$ 7,406
2010/11	$ 5,801	$ 16,118	$ 10,317
2011/12	$ 10,235	$ 24,830	$ 14,595
2012/13	$ 146,630	$ 59,866	$ (86,764)
2013/14	$ 181,825	$ 162,043	$ (19,782)
2014/15	$ 201,556	$ 298,935	$ 97,379
2015/16	$ 216,344	$ 318,454	$ 102,110
2016/17	$ 227,477	$ 234,575	$ 7,098
2017/18	$ 71,665	$ 120,055	$ 48,390
2018/19	$ 3,184	$ 426	$ (2,758)
2019/20	$ -	$ -	$ -
Total	$ 1,081,923	$ 1,259,915	$ 177,991

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).
No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFICA
FOR

Bipole III Western Routed T/L & 2000MW Converters
CONVERTER STATIONS
Addendum Number 06b

REVIEWED BY:
(Owning Dept Manager)
BA FOR RME

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Designing Div.:

Financial:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,104,197,000
REVISED BUDGET $: (Total Net Cost)	$1,828,532,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

11 03 30

OWNING DIVISION: NEW GENERATION CONSTRUCTION

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY:

DATE PREPARED: 2011.03.29

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $724,335,000 for the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,828,532,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the Riel and Keewatinoow Converter Stations and 230kV Switchyards (total increase of $474,226,000);
- inclusion of contingency for the above-mentioned components (total increase of $138,926,000); and
- the resultant changes to interest and escalation (increase of $111,183,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of the 2000 MW Riel Converter Station and 230kV AC Switchyard.
- Design and construction of the 2000 MW Keewatinoow Converter Station and 230kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinoow Converter Stations.

The proposed budget assumes use of voltage source converters for both the Riel and Keewatinoow Converter Stations without synchronous condensers at the Riel Converter Station.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the converter stations, nor was contingency included for the converter stations, as these components had not yet been reviewed in detail.

This CPJ Addendum #06b covers a budget increase of $724,335,000 in association with the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Riel Converter Station and 230kV AC Switchyard (base increase of $169,355,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

b) <u>Keewatinoow Converter Station and 230kV AC Switchyard (base increase of $286,069,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

Background (This section is be filled out only if there is information relevant to the recommendation).
▪ Site development costs have increased for the following reasons: the previous budget assumed that the Conawapa Generating Station infrastructure would be built ahead of Bipole III and therefore costs associated with a construction camp and work areas would be covered by that project's budget; mechanical services such as fire, water, sewer and oil containment, along with security and environmental requirements, were not considered in the 2001 estimate; the site size has increased and soil conditions are worse than identified in the 2001 estimate; the transformer change-out method and the emergency response buildings were not included in the 2001 estimate. c) Property Acquisition and/or Easements for the Converter Stations (base increase of $18,802,000): Property costs for Riel and Keewatinoow Converter Stations were not included in the 2001 estimate. Costs for the Riel site are more substantial than the Keewatinoow site, and include $6.4 million for station site properties, and $12.3 million for buffer properties that have been purchased from private owners. In addition to the above, the revised budget also includes the introduction of contingency at $138,926,000 (Project Risk Analysis section contains details). The changes to the base estimate and inclusion of contingency, along with the change in base dollars from 2007 to 2010, result in an increase of $111,183,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).
A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of aDorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	**For current corporate rates see G911**

Recommended Option	**NPV Benefits (Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits (Costs)**

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $138,926,000 of contingency (approximately 11% of the base estimate) is included in the budget amount for CPJ Addendum #06b, to cover the following:

a) Keewatinoow Converter Station and 230kV AC Switchyard (contingency of $71,960,000 or 12% of the base estimate):
   - Potential changes to equipment costs due to a limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Potentially higher costs due to northern work conditions.

b) Riel Converter Station and 230kV AC Switchyard (contingency of $66,966,000 or 11% of the base estimate):
   - Potential changes to equipment costs due to limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Uncertainty with protection, cyber security and building strength (physical security).

The following risks create a potential for additional costs:
- Potential for greater requirement for engineering, project management and construction management.
- Potential for poor site conditions during construction.
- The potential requirement for synchronous condensers at the Riel Converter Station.

The assumed use of new technology in the form of voltage source converters at both the Keewatinoow and Riel Converter Stations represents an additional risk factor. Confirmation or otherwise of the feasibility of this technology is expected by late 2011.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 4,243	$ 30,423	$ 26,181
2010/11	$ 6,812	$ 46,255	$ 39,443
2011/12	$ 14,092	$ 59,696	$ 45,604
2012/13	$ 24,477	$ 148,883	$ 124,406
2013/14	$ 141,783	$ 300,258	$ 158,475
2014/15	$ 207,019	$ 290,185	$ 83,166
2015/16	$ 344,041	$ 294,281	$ (49,759)
2016/17	$ 291,378	$ 308,460	$ 17,082
2017/18	$ 70,351	$ 347,692	$ 277,341
2018/19	$ -	$ 2,398	$ 2,398
2019/20	$ -	$ -	$ -
Total	$ 1,104,197	$ 1,828,532	$ 724,335

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFIC FOR

Bipole III Western Routed T/L & 2000MW Converters
COLLECTOR LINES
Addendum Number 06c

REVIEWED BY:
(Owning Dept Manager: Ron Mazur) Ron Mazur 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: Shane Mailey S. Mailey 2011/03/30

Constructing Div:

Designing Div.:

Financial: Nieuwenburg 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld 2011 03 30

Business Unit V.P.: 2011.03.30

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$61,715,000
REVISED BUDGET $: (Total Net Cost)	$191,438,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534 - P:15537, P:15542, P:15543, P:15696, P:15697

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Project Owner: Pei Wang
Project Manager: Adele Poulin

DATE PREPARED: 2011.03.30

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $129,722,000 for the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $191,438,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the 230kV collector lines for the Keewatinoow Converter Station, the construction power for the Keewatinoow Converter Station, the sectionalization of 230kV transmission line R49R at the Riel Converter Station, and the electrode lines for the Riel and Keewatinoow Converter Stations (total increase of $73,222,000);
- inclusion of contingency for the above-mentioned components (total increase of $17,203,000); and
- the resultant changes to interest and escalation (increase of $39,297,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of three permanent and two temporary 230kV collector lines for the Keewatinoow Converter Station.
- Construction power substation for the Keewatinoow Converter Station.
- Design and construction for the Riel and Keewatinoow electrode lines.
- Sectionalization of 230kV transmission line R49R at Riel.
- Property acquisition and/or easements for the collector and electrode lines.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the northern collector lines, the two electrode lines, the related property, or contingency.

This CPJ Addendum #06c covers a budget increase of $129,722,000 in association with the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Keewatinoow 230kV Collector Lines (base increase of $35,756,000):</u>
The 2001 estimate included only three collector lines, while this estimate has two more (temporary) collector lines. The two temporary lines are required in lieu of an earlier introduction of additional generation in the northern collector system. At the time of the 2001 estimate, the planned in-service for the Conawapa Generating Station (GS) was only two years after Bipole III. Now that the in-service for Conawapa GS is planned for several years later, two temporary lines are required in order to permit full use of a 2000MW rating for Bipole III in the event of a Dorsey Station or Bipole I / II outage.

In addition, the cost of transmission line material and construction has increased since 2001.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Keewatinoow Construction Power (base increase of $23,381,000):
The 2001 estimate did not include the requirement for a construction power substation, as it was assumed it would have already been built for construction of the Conawapa GS. With the change in the sequence, the Bipole III project will now be the first development to require this construction power substation.

c) Property Acquisition and/or Easements for the Collector and Electrode Lines (base increase of $10,732,000):
The 2001 estimate did not include any property costs for the Keewatinoow collector lines or the Riel and Keewatinoow electrode lines.

d) Sectionalization of 230kV Transmission Line R49R at Riel (base increase of $1,955,000):
This had been included in the Riel Sectionalization project but was deferred to coincide with the Bipole III converters. It is required to accommodate and reliably transmit a 2000MW Bipole III at Riel.

e) Riel and Keewatinoow Electrode Lines (base increase of $1,398,000):
The cost of line material and construction has increased since 2001.

f) The revised budget also includes contingency at $17,203,000 (Project Risk Analysis section contains details).

The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in an increase of $39,297,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $17,203,000 of contingency (approximately 15% of the base estimate) is included in the budget amount for CPJ Addendum #06c, to cover the following:

a) Keewatinoow Collector Lines (contingency of $8,952,000 or 13% of the base estimate):
Provides for potentially higher costs for material and construction labour.

b) Keewatinoow Construction Power (contingency of $5,451,000 or 23% of the base estimate):
Estimates are based on a conceptual Single Line Diagram only. The site size and exact location are not yet finalized. Backup power requirements are currently under review.

c) Riel and Keewatinoow Electrode Lines (contingency of $2,800,000 or 34% of the base estimate):
Line lengths are uncertain, as the Electrode sites for Riel and Keewatinoow have not been finalized. Also provides for use of steel towers if necessary for reliability.

The following risks create a potential for additional costs:
- Potential for poor site conditions during construction.
- Potentially higher costs due to northern work conditions.
- Further changes to corporate policy for private property compensation.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 237	$ 0	$ (237)
2010/11	$ 381	$ 2,121	$ 1,740
2011/12	$ 788	$ 19,917	$ 19,130
2012/13	$ 1,368	$ 52,709	$ 51,341
2013/14	$ 7,924	$ 30,141	$ 22,217
2014/15	$ 11,571	$ 30,927	$ 19,357
2015/16	$ 19,229	$ 34,255	$ 15,026
2016/17	$ 16,286	$ 13,549	$ (2,737)
2017/18	$ 3,932	$ 7,818	$ 3,886
2018/19	$ -	$ -	$ -
2019/20	$ -	$ -	$ -
Total	$ 61,715	$ 191,438	$ 129,722

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).
No change.

Reference Documents (This section is be filled out only if changed).
No change.

COMMUNITY DEVELOPMENT INITIATIVE

Dated 2013.07.19

Approved by Executive Committee 2013.08.20

D1876

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1453.03

DATE: 2013 08 20
Financial Planning

CAPITAL PROJECT JUS[illegible]
FOR

Community Development Initiative

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: [signature] 2013/08/15

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☒ Efficiency
- ☐ Environmental

BUDGET $: (Total Net Cost)	$60,782,000
START DATE: (1st Cost Flow)	2014 03
IN-SERVICE DATE: (Last Major In-service Date)	2017 10
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	Tier 2 (950 points)
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: Aboriginal Relations

I.M. NODE NUMBER: 1.5.2.1.1.2

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Louis Demers

DATE PREPARED: 2013 07 19

REPORT NUMBER:

FILE NUMBER (Optional):

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Bipole III Community Development Initiative – **TRANSMISSION LINE**

Recommendation

Establish budget to incorporate Bipole III Community Development Initiative ("CDI") that was approved by the Manitoba Hydro-Electric Board in May 2010.

Project Scope

Estimate based on the net present value of a 10-year program valued at up to $6 million per year.

Background

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03). Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

The requested budget increase is planned as a 2013/14 expense based on all regulatory approvals being received no later than December 2013.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The CDI program remains inclusive of a variety of interests; is strongly linked to the Bipole III facilities; and will be an effective means of promoting community support for hosting the Bipole III project facilities.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis

No change.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2013/14	$	53,937
2014/15	$	2,157
2015/16	$	1,979
2016/17+	$	2,709
Total	$	60,782

Proposed Schedule

No change.

Related Projects

No change.

Reference Documents

Executive Committee Board Recommendation for the "Bipole III Community Development Initiative" (document approved under EC minute # 913-10-06 - plus revision of August 12, 2013 (revising the distance from the line to 40km) EC minute # pending.

ADDENDUM #07a (Transmission Line)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07b (Converter Stations)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07c (Collector Lines)

Dated 2014.09.24

Approved by Executive Committee 2014.10.21

ADDENDUM #07d (Community Development Initiative)

Dated 2014.09.26

Approved by Executive Committee 2014.10.21

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AD FOR

Bipole III Project
TRANSMISSION LINE
Addendum Number 07a

REVIEWED BY:
(Owning Dept Manager)

Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/01

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,259,915,000
REVISED BUDGET $: (Total Net Cost)	$1,655,371,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $395 million for the Transmission Line components of the Bipole III Project, to a revised total of $1,655 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:
- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk (Keewatinoow) Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).

Changes to scope include: revised line length of final approved route, issued Licence & Conditions, revised landowner compensation strategy and policy, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based on a preferred routing of the line prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. Also since the last estimate, the project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line and change to project in-service of July 2018.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for market uncertainty risk for transmission line construction work.

P50 Estimate:

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $363 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Changes to the finalized route (increased length, additional towers and increased right-of-way width)
- Updated land acquisition costs
- Recommended contingency of [redacted] (increase of $61M) to address remaining uncertainty. See

Background (This section is be filled out only if there is information relevant to the recommendation).

Risk Analysis section.

Reserves:
A Management Reserve has been established to address significant risks related to bidding market and pricing uncertainty for Transmission Line construction work (increase of $100M). See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project is $395M (31%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	**% For current corporate rates see G911**	**For clarification on hurdle rates, contact Economic Analysis Department**

Recommended Option	NPV Benefits/(Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Additionally, this portion of the Bipole III Project includes a recommended Management Reserve of \$100M associated with bidding market and pricing uncertainty for Transmission Line construction work. This remains the greatest area of uncertainty for Bipole III and the potential cost variation associated with this risk is best addressed through the inclusion of Management Reserve funds.

An additional, significant area of uncertainty is the potential impacts to schedule due to further delays in acquisition of private lands. A Management Reserve for this risk has not been recommended as part of the project budget. However, there will be cost impacts to the project should the risk occur.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 24,613	$ 24,613	$ -
2010/11	$ 16,118	$ 19,002	$ 2,884
2011/12	$ 24,830	$ 18,350	$ (6,480)
2012/13	$ 59,866	$ 25,091	$ (34,775)
2013/14	$ 162,043	$ 54,276	$ (107,767)
2014/15	$ 298,935	$ 203,458	$ (95,477)
2015/16	$ 318,454	$ 360,455	$ 42,001
2016/17	$ 234,575	$ 381,047	$ 146,472
2017/18	$ 120,055	$ 493,821	$ 373,766
2018/19	$ 426	$ 75,257	$ 74,831
Total	$ 1,259,915	$ 1,655,371	$ 395,456

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

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2675083

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A
FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 07b

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,828,532,000
REVISED BUDGET $: (Total Net Cost)	$2,675,083,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ Customer Service
- ☐ System Supply
- ☐ Efficiency
- ☒ System Reliability
- ☐ Environmental

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $ 846.5 million for the Converter Station components of the Bipole Project, to a revised total of $2,675 and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:
- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.

Changes to scope include: Selection of LCC HVdc technology requiring the inclusion of Synchronous Condensers, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based largely on historical and budgetary pricing from vendors as well as an assumption of VSC technology for the HVdc Converter and therefore no requirement for synchronous condensers.

The revised estimate is based on LCC HVdc technology as this was the technology bid by all vendors and incorporates the bid pricing received. The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

P50 Estimate:

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $649 million to the P50 Estimate as a result of the following:

- Incorporation of contract costs for the Keewatinohk 230kV AC Switchyard, Keewatinohk Site Development, Keewatinohk Camp and Keewatinohk Camp Services
- Incorporation of bid price for the Keewatinohk and Riel HVdc Converter Equipment contract
- Inclusion of Synchronous Condensers in the scope of work as a result of LCC technology for the HVdc equipment
- Incorporation of allocated portion of actual costs for Riel Sectionalization project
- Incorporation of updated costs for the Riel 230kV AC Switchyard Expansion

Background (This section is be filled out only if there is information relevant to the recommendation).

- Recommended contingency of [redacted] (decrease of $16M) to address remaining uncertainty.

Reserves:
No Management Reserve for the Converter Stations component of the project is recommended to include in the estimate at this time.

In-Service Costs:
The overall increase to the in-service cost of the project is $846.5 (46%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 30,423	$ 30,423	$ -
2010/11	$ 46,255	$ 28,069	$ (18,186)
2011/12	$ 59,696	$ 36,417	$ (23,279)
2012/13	$ 148,883	$ 79,718	$ (69,165)
2013/14	$ 300,258	$ 144,153	$ (156,105)
2014/15	$ 290,185	$ 221,051	$ (69,134)
2015/16	$ 294,281	$ 580,792	$ 286,511
2016/17	$ 308,460	$ 828,733	$ 520,273
2017/18	$ 347,692	$ 507,689	$ 159,997
2018/19	$ 2,399	$ 195,085	$ 192,686
2019/20	$ -	$ 18,432	$ 18,432
2020/21	$ -	$ 4,520	$ 4,520
Total	$ 1,828,532	$ 2,675,083	$ 846,551

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

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26026

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A[illegible]
FOR

Bipole III Project
COLLECTOR LINES
Addendum Number 07c

REVIEWED BY:
(Owning Dept Manager)

Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

[signature] 2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: [signature] 2014/10/02

Business Unit V.P.: Bruce Smith 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$191,438,000
REVISED BUDGET $: (Total Net Cost)	$260,150,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P:20790, P:21201, P:23816

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $68.7 million for the Collector Lines components of the Bipole III Project, to a revised total of $260.2 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:
- Design and construction of three permanent and two temporary 230 KV collector lines for the Keewatinohk (Keewatinoow) Converter Station.
- Construction power substation, 138 KV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station.
- Design and construction of the Riel and Keewatinohk electrode lines.
- Sectionalization of 230 KV transmission line R49R at Riel and associated modifications at Ridgeway and Rosser stations.
- Property acquisition and/or easements for the above components.
- Design and construction of a new bay and modifications at existing Long Spruce 230 KV AC switchyard for the new collector line to Keewatinohk Converter Station.
- Design and construction of a new bay and modifications at existing Henday 230 KV AC switchyard for the four new collector lines to Keewatinoow Converter Station.
- Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Changes to scope include: the issued Licence & Conditions, double circuit requirement for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts, inclusion of Long Spruce and Henday 230 KV station expansions/modifications, inclusion of breaker replacements, and revised schedule and project in-service date to July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2009/10, based on conceptual scope of collector line components, prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, increased scope (new items in this component), as well as up-to-date market information. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. In addition, new items were included in the current scope for this component.

Background (This section is be filled out only if there is information relevant to the recommendation).

This resulted in an increase of $83 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Change to include a double circuit requirement for the Keewatinoow to Long Spruce AC collector line
- Incorporation of increased reliability design for both electrode lines
- Change to assume Clearing, 230kV AC transmission line construction and Construction Power contracts as Direct Negotiated Contracts (DNCs)
- Inclusion of new items – Long Spruce and Henday 230 KV station expansions/modifications and breaker replacements projects
- Recommended contingency of [redacted] (increase of $800K) for this component, to address remaining uncertainty. See Risk Analysis section.

<u>Reserves:</u>
No Management Reserve for the Collector Lines components is recommended to include in the estimate at this time. See Risk Analysis section.

<u>In-Service Costs:</u>
The overall increase to the in-service cost of the project for this component is $68 M (36%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date and increase in the recommended contingency. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 0	$ 0	$ -
2010/11	$ 2,121	$ 386	$ (1,735)
2011/12	$ 19,917	$ 2,075	$ (17,842)
2012/13	$ 52,709	$ 4,394	$ (48,315)
2013/14	$ 30,141	$ 26,265	$ (3,876)
2014/15	$ 30,927	$ 58,432	$ 27,505
2015/16	$ 34,255	$ 75,516	$ 41,261
2016/17	$ 13,549	$ 51,722	$ 38,173
2017/18	$ 7,819	$ 36,708	$ 28,889
2018/19	$ -	$ 4,653	$ 4,653
Total	$ 191,438	$ 260,150	$ 68,711

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI FOR

Bipole III Project
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 07d

REVIEWED BY:
(Owning Dept Manager)
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:
2014/10/14

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$60,782,000
REVISED BUDGET $: (Total Net Cost)	$61,954,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.7.1

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 26

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

-	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1453.03)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **COMMUNITY DEVELOPMENT INITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).
Increase the budget by $1.2 million for the Bipole III Community Development Initiative ("CDI") fund, that was approved by the Manitoba Hydro-Electric Board in May 2010, to a revised total of $62.0 million

Project Scope (This section is be filled out only if there is a change to the scope).
Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project

Background (This section is be filled out only if there is information relevant to the recommendation).

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03).

Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

Justification (This section is required for all addendums).
The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No Change	

Other Alternatives Considered	NPV Benefits/(Costs)
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ -	$ -
2013/14	$ 53,937	$ 53,863	$ (73)
2014/15	$ 2,157	$ 2,291	$ 134
2015/16	$ 1,979	$ 1,979	$ -
2016/17	$ 1,787	$ 1,787	$ -
2017/18	$ 922	$ 1,581	$ 659
2018/19	$ -	$ 453	$ 453
Total	$ 60,782	$ 61,954	$ 1,172

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

Identify any additional reference documents (relative to those already listed in the previous CPJ/Addendum) that support or provide background on this recommendation.

ADDENDUM #08a (Transmission Line)

Dated 2016.10.14

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08b (Converter Stations)

Dated 2016.10.12

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08c (Collector Lines)

Dated 2016.10.14

Approved by Manitoba Hydro-Electric Board 2016.10.26

ADDENDUM #08d (Community Development Initiative)

Dated 2016.10.dd

Approved by Manitoba Hydro-Electric Board 2016.10.26

D1876(A)

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
TRANSMISSION LINE
Addendum Number 08a

REVIEWED BY:
(Requesting Dept Manager) Adele Poulin 2016/10/19

NOTED BY:
(if applicable)

Responsible Division: 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) C Bell oct.19/16.

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,655,371,000
REVISED BUDGET $: (Total Net Cost)	$1,957,616,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Mailey 2016/10/20

REQUESTING DIVISION:	Transmission Construction & Line Maintenance
I.M. NODE NUMBER:	1.5.2.1.1.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817, P:23622, P:25505, P:25508 - P:25511, P:18767

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Adele Poulin / Ryan Bilcowski

DATE PREPARED: 2016 10 14

REPORT NUMBER:

FILE NUMBER (Optional):

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

See list of Addendums next page.

07a	2014 10 21	Revised estimate for inclusion of final approved route, issued Licence & Conditions, revised landowner compensation, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.	Alastair Fogg / Adele Poulin	Executive Committee (Minute #1503.02)
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Total net in-service cost has increased by $302.245 million, from $1,655.371 million to $1,957.616 million from the last approved CPJ addendum, with the in-service date to remain at July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope for this portion of the Bipole III complex includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e. including the Converter Stations and AC Collector system).
- Contingency for this Transmission Line project.

Changes to scope: awarded contracts and compressed schedule, CEC prescribed route finalization, additional tower steel suppliers, biosecurity measures implementation in the south and some helicopter tower erection for a portion of the line.

Background (This section is be filled out only if there is information relevant to the recommendation).

The previous project re-estimate was completed in 2014 and was based on a P50 confidence level. The recommended budget is based on a P80 estimate for the Transmission Line, that includes all base costs and contingency at an 80% confidence level.

The revised estimate incorporates actual costs to date as well as awarded contracts and reflects current market conditions. The estimate is based on maintaining a project in-service date of July 2018. The resultant revised P80 point estimate of $1,751 million from $1,400 million (an increase of $350 million relative to the current approved budget) is a result of the following changes:

- Incorporation of actual construction costs and awarded values as a result of higher market rates for anchor and foundations as well as tower assembly erection and stringing contracts than planned; incorporated delay claims (weather and material) experienced to date, construction schedule compression; and increased equipment and vehicles to support construction.
- Incorporation of additional materials required for CEC prescribed southern route changes, delays in materials, premiums to accelerate materials and associated engineering.
- Incorporation of property costs for CEC prescribed southern route, inclusion of LVAC (Land Valuation Appraisal Council) certification and legal fees.
- Incorporation of greater material management costs, project management and construction management.
- Inclusion of greater than planned costs for indigenous relationships management and agreements, as well as actual licensing costs and required project environmental monitoring as a result of the licence conditions.

Background (This section is be filled out only if there is information relevant to the recommendation).
• Recommended [redacted] contingency for remaining risks and schedule acceleration (as the previously approved $210 M , of which included $100 management reserve, has been allocated and spent for the above increases in point estimate; remaining risks are detailed in the Risk Analysis portion of this CPJ addendum). <u>In-Service Costs:</u> The overall increase to the in-service cost of the project is $302 million (18%), from $1,655.4 million to $1,957.6 million. This increase to the in-service cost is due to the increases in the P80 base estimate as noted above ($350 million). These increases are offset by reduced interest and escalation costs ($48 million reduction).

Justification (This section is required for all addendums).
A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system). The DC converter rating was increased from 2000MW to 2300MW in the 2014 CPJA. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outages, the most frequently occurred events based on operation experience.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No Change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The revised estimate includes a recommended Transmission Line project contingency at a P80 confidence level to address remaining areas of uncertainty to the completion of the project and maintain desired in-service date of July 2018.

The previously approved Management Reserve ($100 million) for this portion of the Bipole III complex has been allocated or spent, no further management reserve is not considered necessary at this time.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The Transmission Line components require a revised contingency amount of [redacted] for remaining risks and for schedule protection of the July 2018 in-service date. The previously approved $210 million for a P50 (2014) estimate has been allocated as noted in the point estimate (see Background section of this CPJ addendum above). The $100 million in management reserve was approved to be allocated to the two major transmission line contracts for awarded values, and for increases as a result of changes to the Burntwood Nelson Agreement as part of the Converter Stations project.

Remaining risks identified for [redacted] include:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 141,332	$ 141,618	$ 286
2014/15	$ 203,458	$ 125,584	$ (77,874)
2015/16	$ 360,455	$ 345,779	$ (14,676)
2016/17	$ 381,047	$ 549,625	$ 168,578
2017/18	$ 493,821	$ 426,982	$ (66,839)
2018/19	$ 75,257	$ 356,283	$ 281,026
2019/20	$ -	$ 9,676	$ 9,676
2020/21	$ -	$ 2,069	$ 2,069
Total	$ 1,655,371	$ 1,957,616	$ 302,245

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No Change.

Related Projects (This section is be filled out only if changed).
1.5.2.1.2.1 Bipole III Project – Converter Stations 1.5.2.1.3.1 Bipole III Project – Collector Lines 1.5.2.1.7.1 Bipole III Project – Community Development Initiative

Reference Documents (This section is be filled out only if changed).
No Change.

D1876(A)

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 08b

REVIEWED BY:
(Requesting Dept Manager)
A. Fogg 2016/10/19

NOTED BY:
(if applicable)

Responsible Division: 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) 2016/10/18

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Rodey 2016/10/19

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$2,675,083,000
REVISED BUDGET $: (Total Net Cost)	$2,780,691,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

REQUESTING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837

MAJOR ITEM X **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg

DATE PREPARED: 2016 10 12

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- X System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: X **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

07b	2014 10 21	Revised Converter Stations estimate to incorporate numerous updates including LCC HVdc technology, Synchronous Condensers, BPIII rating to 2300MW, ISD from 2017 10 to 2018 07.	A.A. Poulin / A. Fogg	Executive Committee (Minute #1503.02)
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc.	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)

-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $106 million for the Converter Station components of the Bipole Project, to a revised total of $2,781 with the in-service date to remain at July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope for this portion of the Bipole III complex includes the following major components:

- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.
- Design & Construction of the Riel Synchronous Condensers.

Changes to scope include: Provincial Road 280, Provincial Road 290 and Conawapa Access Road upgrades.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2014 and incorporated a majority of the project's contract costs and scope updates. The 2014 estimate was based on a P50 confidence level.

The revised estimate incorporates previously out of scope provincial road upgrades and an increase in contingency levels to a P75 confidence level to better address project risks to the completion of the work. There are no other scope changes from the 2014 estimate.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The DC converter rating was increased from 2000MW to 2300MW. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outages, the most frequently occurred events based on operation experience

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The revised estimate includes a recommended project contingency at a P75confidence level to address remaining areas of uncertainty to the completion of the project.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 318,781	$ 318,781	$ -
2014/15	$ 221,051	$ 198,269	$ (22,782)
2015/16	$ 580,792	$ 468,260	$ (112,532)
2016/17	$ 828,733	$ 955,621	$ 126,888
2017/18	$ 507,689	$ 593,197	$ 85,508
2018/19	$ 195,085	$ 237,967	$ 42,882
2019/20	$ 18,432	$ 8,024	$ (10,408)
2020/21	$ 4,520	$ 574	$ (3,946)
Total	$ 2,675,083	$ 2,780,691	$ 105,609

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule remains unchanged with an in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1. Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

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26026

APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
COLLECTOR LINES
Addendum Number 08c

REVIEWED BY:
(Owning Dept Manager): Adèle Poulin 2016/10/19

NOTED BY:
(if applicable)

Coordinating Division: Glenn Penner 2016/10/19

Constructing Division:

Financial Department:
(if over $1 million) C Bell Oct. 18/16.

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Glenn Penner 2016/10/19

Business Unit V.P.: A. Manley 2016/10/20

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$260,150,000
REVISED BUDGET $: (Total Net Cost)	$246,567,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: Transmission Construction & Line Maintenance

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P20790, P21201, P23816, P27469

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Ryan Bilcowski / Luc Collet

DATE PREPARED: 2016 10 14

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

See list of Addendums next page.

07c	2014 09 24	Revised estimate for increase double circuit requirements for one collector line, increased reliability design for electrode line, inclusion of Long Spruce and Henday station expansion/modifications and breaker replacements. Revised schedule and project in-service date to July 2018.	A. Fogg / A.A. Poulin	Executive Committee (Minute #1503.02)
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Decrease the budget by $13.6 million for the Collector Lines components of the Bipole III Project, to a revised total of $246.6 million, with the in-service date to remain at July 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project remains the same as the previous estimate, with the addition of a secondary communications link between the Keewatinohk CS and Henday.

Background (This section is be filled out only if there is information relevant to the recommendation).

The previous project re-estimate was completed in 2014 and was based on a P50 confidence level.

The revised estimate incorporates a detailed scope based on the actual construction progress to date, reflects current market conditions, and includes the changes noted below. The estimate is based on maintaining a project in-service date of July 2018. The recommended budget for the Collector Lines project is based on a P75 estimate that includes all base costs and contingency at a 75% confidence level.

The Total Net Cost decrease of $13.6M relative to the current approved budget is a result of the following changes:

1. Decrease of $13.0M to forecast escalation and interest.
2. Decrease of $11.0M due to savings in accommodation costs for Long Spruce generating station (GS), Henday converter station (CS) and the AC Collector lines.
3. Decrease of $6.0M in the steel structure costs due to competitive bidding for the AC Collector lines.

These net decreases are slightly offset by the following scope changes:

4. Increase of $6.0M to the construction costs for the installation of the dead end tower footings. Final design was not complete at the time of the contract award; additional towers were required resulting in higher construction costs.
5. Increase of $3.6M for scope changes in the project (several in small amounts) now incorporated.
6. Increase of $2.8M to the construction costs as there was a change in strategy from internal resources to external contracts for the high voltage cable installations and steel modification work at Long Spruce GS, primarily due to the lack of internal resources and expertise for the given scope.
7. Increase of $2.4M for the incorporation of secondary communications link between the Keewatinohk CS and Henday CS.
8. Increase of $1.6M in construction costs as there was a change in strategy from internal resources to external contract for the steel assembly, erection, switch installation and bus modifications at Henday CS, due to the lack of availability of internal resources.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter

Justification (This section is required for all addendums).

Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The DC converter rating was increased from 2000MW to 2300MW. The additional 300MW converter rating is a pre-investment to allow for economical transmission options for future generation development and to maintain adequate HVDC spare capacity to cover the valve group outage, the most frequently occurred events based on operation experience.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	
Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended Collector Lines project contingency at a P75 confidence level to address remaining areas of uncertainty, and has decreased from the previously approved contingency.

Inclusion of a Management Reserve for this portion of the Bipole III Project is not considered necessary at this time.

The Collector Line components require a reduced contingency amount of $1M from [redacted] to [redacted] in contingency as the project components are further along in construction and reflect remaining risks.

Remaining significant risks identified include:

- $3.2M for potential market rates for the Electrode Lines and R49R Sectionalization.
- $3.0M for potential weather delays increasing construction costs.
- $2.0M for skywire replacement with buried grounding conductor outside of Henday CS to accommodate new overhead lines.
- $2.0M for additional modifications to the Gas Insulated Switchgear at Long Spruce GS.
- $2.0M for additional crews at Long Spruce GS and Henday CS to support the overhead work.
- $1.0M for potential additional costs for 500kV line crossings.
- $1.0M for potential additional costs associated with the installation of the High Voltage cables at Long Spruce GS.
- $0.7M for potential additional construction support from design groups.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 33,120	$ 33,120	$ -
2014/15	$ 58,432	$ 34,218	$ (24,214)
2015/16	$ 75,516	$ 63,240	$ (12,277)
2016/17	$ 51,722	$ 60,752	$ 9,030
2017/18	$ 36,708	$ 33,974	$ (2,733)
2018/19	$ 4,653	$ 21,264	$ 16,612
Total	$ 260,150	$ 246,568	$ (13,583)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change to the in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

No change.
1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

Reference Documents (This section is be filled out only if changed).

No change.
1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

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APPROVED BY MHEB
MINUTE # 872.07

DATE: 2016 10 26
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III PROJECT
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 08d

REVIEWED BY:
(Requesting Dept Manager)
Adele Poulin 2016/10/19

Oct 20/2016

NOTED BY:
(if applicable)

Responsible Division: 2016/10/19

Constructing Division:

Financial Department: CBell Oct. 19/16.
(if over $1 million)

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$61,954,000
REVISED BUDGET $: (Total Net Cost)	$56,647,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 07
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2016/10/19

Business Unit V.P.: A. Bailey 2016/10/20

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION: Transmission Construction & Line Maintenance

I.M. NODE NUMBER: 1.5.2.1.7.1

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY:

DATE PREPARED: 2016 10 dd

REPORT NUMBER:

FILE NUMBER (Optional):

07d	2014 10 21	Inclusion of Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project	Alastair Fogg / Adele Poulin	Executive Committee (Minute #1503.02)
	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1145.03)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **COMMUNITY DEVELOPMENT INTITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).
Total cost has decreased from $62 million to $56.7 million from the last approved CPJ addendum. [redacted] These costs are now captured in 1.5.2.1.1.1 Transmission Line (in P:04221).

Project Scope (This section is be filled out only if there is a change to the scope).
No change.

Background (This section is be filled out only if there is information relevant to the recommendation).
The total decrease of $5.3 million is as a result of a revaluation of the Present Value of the payments, [redacted] These costs are now captured in 1.5.2.1.1.1 Transmission Line (in P:04221).

Justification (This section is required for all addendums).
The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No Change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).
No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 53,863	$ 53,863	$ -
2014/15	$ 2,291	$ 2,065	$ (226)
2015/16	$ 1,979	$ (5,470)	$ (7,449)
2016/17	$ 1,787	$ 2,588	$ 801
2017/18	$ 1,581	$ 2,698	$ 1,117
2018/19	$ 453	$ 903	$ 450
Total	$ 61,954	$ 56,647	$ (5,307)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No Change.

Related Projects (This section is be filled out only if changed).

No Change.
1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

Reference Documents (This section is be filled out only if changed).

No change.

Tab 31

MANITOBA	**Board Order 7/03**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**February 3, 2003**

Before: G. D. Forrest, Chair
R. A. Mayer, Q.C., Vice Chair
Dr. K. Avery Kinew, Member

A FILING BY MANITOBA HYDRO TO PROVIDE AN INFORMATION UPDATE REGARDING FINANCIAL RESULTS, FORECASTS, METHODOLOGIES, PROCESSES, AND OTHER MATTERS RELATING TO SALES RATES CHARGED BY MANITOBA HYDRO

Table of Contents

Executive Summary

The Manitoba Hydro-Electric Board ("Hydro") filed a status update with The Public Utilities Board ("the Board") on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board determined that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition may have a significant impact on the future overall operations of Hydro.

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because of the robust export markets and favourable water conditions, which underpinned Hydro's strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its longer term financial objectives. Hydro also stated domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenues as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

During the course of the public hearing, the Board examined a number of specific areas related to Hydro's operations including operating results and financial projections, financial targets and risk, capital expenditures, extra provincial revenues, payments to the Province of Manitoba, operating, administrative and finance expenses, transmission tariffs, load forecasts and overall revenue requirements. As a result of this review, the Board identified a number of areas of concern, and made a number of recommendations including:

- Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and focus on reducing long-term debt.
- Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba.
- Hydro continue to monitor and control operating and administrative expenses.
- Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy.

In addition to the above recommendations, the Board directed Hydro to:

- File an updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
- File a detailed debt management strategy;
- Undertake a study to quantify specific reserve provisions required to cover major risks and contingencies;
- Undertake a study on the merits of implementing an inverted rate structure for all customer classes;

- Undertake a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;
- Undertake a study which considers time of use rates for General Service classes based on a seasonal, weekly, daily, and hourly basis;
- Identify and specifically account for all export-related capital expenditures in its capital forecasts to ensure that export revenues are appropriately matched against the full cost of production;
- Undertake a study on the methods and impacts with respect to the classification of generation costs in the Cost of Service Study;
- Re-examine the current level of Demand Side Management programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board;
- Consider the use of wind power in remote diesel electric communities and file a report with the Board; and

A considerable amount of time at the hearing was directed towards a review of the various cost of service studies filed by Hydro, and in particular, the proposed changes in methodology from the methodologies previously approved by the Board. The most contentious issue, and the issue with the greatest impact on cost of service results, is the allocation of net export revenues between customer classes. In this Order, the Board has not accepted Hydro's proposed cost of service methodology. The Board has directed Hydro to file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects a number of specific directives as set out in the Order including the cost treatment of export classes.

Although Hydro is not seeking any change to firm rates currently charged to customers, the Board noted that certain customer classes have consistently paid rates higher than their allocated costs. Therefore, the Board has directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 that reflects:

(a) A 1% rate decrease for General Service Small customers;

(b) A 2% rate decrease for General Service Large ("GSL") customers greater than 30 kV; and

(c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

The Board understands that this change will likely bring the General Service Medium class and the GSL <30 kV class closer to unity. Therefore, no further rate adjustment will be ordered for this class.

Given that uniform rates have provided recent rate decreases to some residential customers and the residential class revenue to cost coverage ratio has been consistently below unity (i.e., subsidized by other classes), no further rate changes are ordered for the residential rate class at this time.

The Board also directed Hydro to file a separate application for approval of an open access transmission tariff by no later than June 30, 2003.

The Board approved the Curtailable Rate Program, confirmed as final a number of interim ex parte Orders, and approved extending the Limited Use Billing Demand Rate option to March 31, 2004.

The Board also directed Hydro to establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings even if no rate changes are required. This timeframe will improve the efficiency, effectiveness and timeliness of the regulatory process.

Subject to these and other specific rate directives contained in this Order, the Board has confirmed Hydro's remaining existing rate schedules to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

1.0 Appearances

R. Peters K. Kalinowsky C. McNicol	Counsel for The Manitoba Public Utilities Board ("the Board")
M. Murphy O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board ("Hydro")
J. Feldschmid	Counsel for Canadian Centre for Energy Policy Incorporated ("CCEP")
B. Williams B. Froese	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. ("CAC/MSOS")
T. McCaffrey	Counsel for Manitoba Industrial Power Users Group ("MIPUG")
M. Anderson	Representing Manitoba Keewatinowi Okimakanak Inc. ("MKO")
E. Fleming	Representing Provincial Council of Women of Manitoba, Inc. ("PCWM")
M. Buchart	Counsel for Time to Respect Earth's Ecosystems/Resource Conservation Manitoba ("TREE/RCM")
C. Henderson	Counsel for Indian and Northern Affairs Canada ("INAC")

2.0 Witnesses for Hydro

V. Warden	Chief Financial Officer, Vice President, Finance & Administration
L. Wray	Division Manager, Business Analysis & Regulatory Affairs
R. Kirk	Corporate Controller
H. Surminski	Section Head, Resource Planning and Market Analysis
R. Wiens	Manager, Rates Department
B. Poff	Manager, Transmission Services
G. Rose	Vice-President, Customer Service and Marketing

3.0 Intervenors of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc.

The City of Winnipeg

Manitoba Industrial Power Users Group

Communications, Energy and Paperworkers Union of Canada

Provincial Council of Women of Manitoba Inc.

Canadian Centre for Energy Policy Incorporated

Manitoba Keewatinowi Okimakanak Inc.

Time to Respect Earth's Ecosystems/Resource Conservation Manitoba

Subsequent to the City of Winnipeg registering as an Intervenor, Hydro entered into negotiations with the City of Winnipeg to purchase all of the assets of Winnipeg Hydro. As a result of this transaction, the City of Winnipeg withdrew from active participation as an Intervenor in this hearing.

4.0 Intervenor Witnesses

4.1 CAC/MSOS

J. Todd	President, Econalysis Consulting Services, Inc.
B. Harper	Manager, Econalysis Consulting Services, Inc.

4.2 MIPUG

J. Osler	Principal Consultant & Manager, InterGroup Consultants Ltd.
P. Bowman	Consultant, InterGroup Consultants Ltd.

4.3 TREE/RCM

J. Lazar	Consulting Economist, Micro Design Northwest
P. Miller	Professor, University of Winnipeg
B. Wild	Homesteader, Lake Winnipegosis

4.4 MKO

F. Mills	Manager, Program Planning and Allocation, Funding Services Directorate, INAC

5.0 Presenters

J. Knowles	Chief Financial Officer Hudson Bay Mining and Smelting Co. Ltd. ("HBMS")
W. Schroeder	Chief Power Engineer, Inco Limited, Thompson "Inco")
C. Weiss-Bundy	Systems Engineer, Simplot Canada, Brandon Complex ("Simplot")
B. Turner	Plant Manager, Nexen Chemicals Canada Limited Partnership, Brandon Plant ("Nexen")
Dr. C. Nicolaou	Member, Canadian Centre for Energy Policy ("CCEP")

6.0 Background

Hydro filed a status update with the Board on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001. The last time Hydro sought a general rate increase was in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96.

Hydro sought final approval of a new Curtailable Rate Program and numerous interim ex parte Orders dealing mainly with setting the monthly reference discount prices for curtailable service program customers, establishing weekly spot market replacement energy rates under the former dual fuel heating surplus energy to self-generators and industrial surplus energy programs, and establishing weekly spot market replacement energy rates for surplus energy program customers. Hydro also requested final approval extending the Limited Use Billing Demand Rate Option.

A pre-hearing conference was held on January 14, 2002 to define the scope of the hearing, and to establish a timetable for the orderly exchange of information. As a result of the hearing, the Board issued Order 9/02 in which the Board found that, in light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, one purpose of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

A public hearing was held on various dates between May 27 and September 30. The Board heard final arguments on June 11, 2002 to deal with the revenue requirement aspects of the application and September 30, 2002 to deal with Cost of Service and Rate Design.

A separate hearing was held to review matters related to the Integration of Centra Gas Manitoba Inc. and Hydro. Order 208/02 dated December 6, 2002 addresses Integration matters.

7.0 Operating Results and Financial Projections

7.1 Comparison of Actual Operating Results with IFF 95-2

The Integrated Financial Forecast ("IFF 95-2") reflected the forecasted financial results of the Board's decisions in Order 51/96. Hydro's actual operating results from 1996 to 2001 and forecast results for 2002 through 2006, as stated in IFF MH 01-1, are compared to IFF 95-2 in the following table:

Statement of Operations & Retained Earnings ($millions)	*Actual*						*Forecast IFF 01-1*				
	1996	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Revenues											
Domestic	740	756	745	757	748	793	796	802	832	857	885
Export	246	268	297	326	376	480	628	553	528	467	454
	986	1,024	1,042	1,083	1,124	1,273	1,424	1,355	1,360	1,324	1,339
Expenses:											
Finance	426	418	419	411	402	387	496	504	507	493	497
Depreciation	169	178	191	198	215	227	237	256	269	280	286
Operating & Administrative	224	226	214	226	234	245	254	262	266	268	273
Water Rentals	47	51	56	50	51	56	112	101	97	97	97
Tax Expense	36	37	37	39	41	43	40	41	41	42	42
Fuel & Power Purchased	14	13	14	59	33	48	65	81	89	86	75
	916	923	931	983	976	1,006	1,204	1,245	1,269	1,266	1,270
Net Income	70	101	111	100	148	267	220	110	91	58	69
IFF 95-2	59	49	31	11	42	41	60	89	129	126	66
Annual Difference	11	52	80	89	106	226	160	21	(38)	(68)	3
Retained Earnings Balances											
Opening Retained Earnings	284	354	455	566	666	814	1,081	1,151	1,186	1,214	1,272
Net Income	70	101	111	100	148	267	220	110	91	58	69
Special Payment to Province	-	-	-	-	-	-	(150)	(75)	(63)	-	-
Retained Earnings - MH01-1	354	455	566	666	814	1,081	1,151	1,186	1,214	1,272	1,341
Retained Earnings - IFF 95-2	343	392	423	434	475	516	576	665	795	921	987
Culmulative Difference	11	63	143	232	339	565	575	521	419	351	354

Hydro's operating results since 1996 have been substantially better than forecasted in IFF 95-2. Hydro attributed the improvement in financial position to increased export revenues coinciding with periods of above average water flows, and controls over operating and administrative costs relative to inflation. Actual net income for each of the years 1996 through 2001 exceeded that forecast in IFF 95-2, by $11 million in 1996 to $226 million in 2001. The better than expected operating results have provided retained earnings forecast at $1.15 billion at the end of fiscal

2002, compared to the retained earnings forecast for 2002 in IFF 95-2 of $576 million. On an overall basis, Hydro is now forecasting to have $1.341 billion in retained earnings by March 31, 2006 in IFF MH 01-1 compared to the amount forecasted in IFF 95-2 of $987 million at March 31, 2006.

7.2 Integrated Financial Forecast ("IFF MH 01-1")

Hydro filed its most current financial forecast (IFF MH 01-1) for its electric operations, which included a projected operating statement, balance sheet, financing requirements and financial ratios, as well as a capital expenditure forecast (CEF 01-1) for the eleven-year period 2002 to 2012. The purpose of the IFF and CEF was to provide an indication of Hydro's long-term financial direction and for use in future planning. The forecast was revised during the hearing to reflect the impact of a $288 million payment to the Province and accounting policy changes related to foreign currency transactions including the Exposure Management Program.
IFF MH 01-1 and CEF 01-1 are attached as Appendix A and B to this Order.

IFF MH 01-1 reflects no requested rate increases for fiscal 2002 or 2003, but includes a rate increase scenario of 2% annually for fiscal years 2004 to 2009. Hydro is not seeking approval from the Board for any rate changes in this application, but will file a future rate application with the Board for its approval if rate changes are subsequently determined to be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition will have a significant impact on the future overall operations of Hydro. The impact of this transaction is not reflected in IFF MH 01-1.

8.0 Financial Targets

8.1 Background

In September 1995, Hydro adopted the following financial targets, which were reviewed by the Board at the 1996 General Rate Application ("GRA").

1. To achieve and maintain a minimum debt to equity ratio target of 75:25 by no later than 2005/06.

2. To achieve and maintain an annual gross interest coverage ratio in the range of 1.20 to 1.35 as soon as possible.

3. To fund all capital construction requirements from internal resources, except during periods when major new generation and/or major transmission facilities are being added to the system.

At that time, Hydro stated that in adopting its financial targets, a number of factors were considered including the following:

- A cushion is required to absorb the impact of negative events so as to maintain rate stability for customers;

- Risks faced by Hydro have been increasing in complexity and size, noting that a major drought could cost in the range of $1 billion;

- Credit rating agencies rely on Hydro's status as a self-supporting utility in determining the Provincial credit rating; and

- Hydro's financial targets are not out of line with the financial position and performance of several other Canadian government owned electric utilities.

These financial targets are consistent with the financial targets included in Hydro's Corporate Strategic Plan for 2002.

8.2 Risks

Hydro has identified a number of specific domestic risks that could have serious financial impacts on its operations including:

- Drought;
- Economic downturn;
- Lower than forecast domestic load related to weather;
- Decreased water flows from increased Alberta and Saskatchewan usage;
- Higher interest rates;
- Higher escalation rates; and
- Transmission or generation system outages.

During a drought, some of Hydro's non-firm export sales would be curtailed, and Hydro could be required to import power to satisfy domestic and firm export load requirements. Imported power would be significantly more expensive. An extended five-year drought has happened three times in the last 86 years. It is Hydro's position that the five-year drought scenario is the most substantial risk, with a possible $1.3 billion negative impact on retained earnings. Other risks could increase this financial impact, especially if they occur concurrent with drought. However, other risks may be non-related, and hence not totally additive. In addition to the threats of water flows, weather, economic and market conditions, erosion of domestic load, major equipment failures, and increased government payments, Hydro's financial position could also be seriously impacted by competition and deregulation in the US.

Hydro has identified a number of specific export revenue risks that could also have a serious financial impact including:

- Economic downturn;
- New gas and coal generating stations coming on line in the US;
- Increased protectionism in the US;

- Changing US legislation and regulation;
- Transmission constraints, mainly in export markets;
- Lower export prices; and
- Open access transmission.

Since export revenues are approximately 40% of total revenue, any risks to export revenues must be considered seriously. With a drought, export revenues will be significantly diminished.

In response to the suggestion of CAC/MSOS witnesses that Hydro prepare a quantitative risk analysis, which would indicate an appropriate amount for required reserves, Hydro noted the breadth and complexity of its risks are vast, and to quantify each risk would be a near impossible task. Furthermore, Hydro stated its many risks are already evaluated and managed throughout Hydro on a day-to-day basis.

According to Hydro, the suggested aggregation of risks goes against including a reserve provision only for foreseeable and measurable contingencies. The nature of risk is precisely that it cannot be foreseen and measured perfectly. While the costs of drought are estimated at over $1.3 billion today, the actual costs of a financial downturn may be greater, depending upon other factors such as domestic load, market prices, supply availability and transmission conditions at that time. In addition, other risks may occur simultaneously with the drought and all costs may have to be recovered through future rate increases. According to Hydro, the current financial targets are designed to provide a cushion to absorb the expected costs of foreseeable measurable risks, with some room to cover unforeseeable contingencies.

8.3 Debt to Equity Ratio

Hydro had a debt to equity ratio in 1996 of 91:09. The ratio has improved to 80:20 in 2001. The improvement is attributable to a growth in retained earnings, rather than a reduction in the level of debt. Total debt, net of sinking fund, increased from $4.8 billion in 1996 to $5.5 billion in

2002, while retained earnings increased from $354 million in 1996 to $1.15 billion in 2002, due primarily to increased operating profits over that forecasted in IFF 95-2.

In its credit rating report dated October 21, 2001, Dominion Bond Rating Services stated, “Hydro continues to generate sufficient cash flows to finance capital expenditures, but there’s little surplus available for debt reduction. … The challenge is that high debt levels weaken most financial ratios.”

Hydro attributed the high-debt level to its significant capital program and that internally generated funds first pay operating costs and then are allocated towards the capital construction program. Furthermore, the acquisition of Centra Gas Manitoba Inc. (“Centra”) and the construction of the Brandon combustion turbine increased debt by $748 million during this period.

Hydro has achieved and exceeded the debt equity ratio forecasted in IFF 95-2 as illustrated in the following table:

	Actual						**Forecast**				
Fiscal Year	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Actual/IFF MH 01-1	91:09	88:12	86:14	84:16	83:17	80:20	77:23	78:22	78:22	77:23	77:23
IFF 95-1	91:09	91:09	90:10	89:11	88:12	87:13	86:14	85:15	82:18	80:20	79:21

In IFF MH 01-1, Hydro originally forecasted to achieve its target debt equity ratio of 75:25 by fiscal 2006 with a 74:26 debt equity ratio. After reflecting the $288 million special payment to be made to the Province, the debt equity ratio in fiscal 2006 is now forecasted to be 77:23, and Hydro will not achieve a 75:25 ratio until 2008. Hydro stated that the current target is not attainable and that there would likely be a recommendation presented to its Board of Directors to establish a new target when the IFF is updated in the fall of 2002.

8.4 Interest Coverage

The Hydro Board of Directors revised the interest coverage target in 2001 from "a range of 1.20 to 1.35" to "maintaining a minimum gross interest coverage level greater than 1.20." Hydro stated that it was important that it operated with a gross interest coverage ratio of 1.20, noting that if it operated at break even, with no margin for adverse events, losses or unexpected costs, Hydro would be required to undertake additional borrowing for interest payments. According to Hydro, capital markets would not have a positive view of an interest coverage lower than 1.20, and operating at a break-even could have a negative impact on rate stability.

Hydro achieved its interest coverage ratio target of 1.20 in fiscal years 1997 to 2000, and exceeded the target in 2001 with an interest coverage ratio of 1.66. The actual results for fiscal 1996 to fiscal 2001 were significantly better than that projected in IFF 95-2 as illustrated in the table below:

	Actual						Forecast				
Fiscal Year	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Actual IFF MH 01-1	1.16	1.23	1.25	1.23	1.35	1.66	1.41	1.21	1.18	1.12	1.13
IFF 95-2	1.13	1.10	1.06	1.02	1.08	1.08	1.12	1.18	1.27	1.27	1.14

The interest coverage ratio is projected to fall below the 1.2 target in 2004 for the remainder of the forecast period as a result of the additional financing costs related to the $288 million special payment to the Province. The gross interest coverage ratio over the 11-year period 2002 to 2012 in IFF MH 01-1 ranges from a high of 1.41 forecast for fiscal 2002 to a low of 1.12 in fiscal 2005, ending at 1.13 in fiscal 2012.

8.5 Capital Coverage

Hydro's target is to fund all capital construction requirements from internal cash resources, except during periods when major new generation or major transmission facilities are being added to the system.

Since 1996, Hydro has funded all capital expenditure from internally generated funds. However, at the end of fiscal 2001, its overall debt had increased by approximately $750 million. Hydro noted that its goal was to fund all capital construction, except major generation and transmission, from internally generated funds. However, there were other expenditures that fall outside the definition of capital construction expenditures that required financing such as inventory, mitigation expenses, vehicle purchases and the acquisition of Centra.

9.0 Capital Expenditures

9.1 Comparison of CEF 01-1 to CEF 95-1

Hydro's Capital Expenditure Forecast CEF 01-1 summarizes an eleven-year program of capital expenditures totalling $3.75 billion, ranging from $425 million in 2002 and declining to $239 million in 2012. This compares with CEF 95-1 total program forecast expenditures of $2.7 billion over the eleven-year period from 1996 to 2006. Over the same eleven-year period, Hydro's actual capital expenditures for 1996 to 2001 and projected expenditures for 2002 through 2006 is $3.6 billion, approximately $848 million greater than that forecast in CEF 95-1, as illustrated in the following table:

Capital Expenditures ($ millions)	**Actual**						**Forecast/Projected**					
For the years ended March 31	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**Total**
Actual/ CEF 01-1 Capital Expenditures	256	297	252	308	310	335	425	367	376	338	330	3,594
CEF 95-1	314	297	285	239	222	207	204	207	220	229	322	2,746
Difference	(58)	0	(33)	69	88	128	221	160	156	109	8	848

At the 1996 GRA, capital expenditures averaged approximately $250 million per year. In CEF 01-1, capital expenditures average approximately $350 million per year.

In CEF 01-1 capital expenditure estimates in later years are less than in earlier years since future capital projects have not yet been identified. Hydro believes that in the absence of fortuitous events, capital expenditures in the later years of the forecast period will be significantly higher than forecast since new projects will be identified. According to Hydro, the higher level of annual expenditures has been, and will continue to be driven, in large part, by distribution system expansions and upgrades, and the repair and replacement of an ageing distribution system.

The capital expenditures forecast in CEF 01-1 do not include Wuskwatim, Gull or Notigi generating stations which are expected to come into service over the next 8-20 years. Hydro has already incurred approximately $367 million in expenditures related to these future capital projects. These expenditures and related financing costs are deferred and will not be depreciated or amortized until the plant or facility is put into service.

9.2 Major Expenditures

Included in Hydro's current capital forecast are the following major projects:

Project	**Total Costs ($ million)**
Brandon Combustion Turbine	183
Brandon Unit #5 Life Extension for Coal	23
Selkirk Conversion to Natural Gas	32
Selkirk Life Extension	29
Interconnection to Rugby ND	25
Radisson-Riel HVDC Line	352
Riel Station	98
Microwave Radio Replacements	141
Planning Studies (2002-2012)	130

Hydro has installed a new 260 MW natural gas combustion turbine at the existing Brandon generating station site. Hydro also plans to upgrade the coal-fired generator to extend its useful life to 2019, beyond its scheduled closing date. Whereas the coal facilities will assist in servicing the domestic load in Southwestern Manitoba, the new natural gas combustion turbines are largely to provide necessary reserve power to facilitate extra provincial sales. The investment in the Brandon combustion turbine is primarily based on increasing the value of Hydro's surplus hydraulic energy that would have otherwise been exported into the short-term opportunity market as interruptible power. After firming up this energy, it can be sold into the more lucrative forward market. The primary benefit of the Brandon combustion turbine is to provide backup power when hydraulic generating capability is reduced during drought or equipment outages. It is expected to operate only 10-16% of the time, while hydraulic generation operates 65-80% of the time.

Citing environmental reasons, Hydro is converting the Selkirk generating station from a coal-fired to a natural gas-fired source of generation, in addition to extending its operating life. Selkirk is also scheduled to operate approximately 16% of the time.

Hydro is also embarking upon an ambitious transmission project which, when totally completed, will result in an additional HVDC line and converter stations on the east side of Lake Winnipeg. The new HVDC line ($352 million) will stretch from the Radisson Converter Station to the proposed Riel Station ($98 million) located outside Winnipeg. An HVDC paralleling line will be constructed to the existing Dorsey HVDC converter station. This will increase reliability and provide an additional 78 MW of capacity due to decreased line losses. This additional power may be sold on the export market. Ultimately two new converter stations will be added at an estimated costs of $400-$500 million each. These are not included in CEF 01-1 since their in-service date is beyond 2012. The total estimated costs for Bipole III are approximately $1.35 billion.

Hydro has forecast spending $130 million from 2002 to 2012 on planning studies for major new generation and transmission projects. In cross-examination, Hydro acknowledged paying for planning study costs commissioned by First Nations communities which will have an equity interest in the future generating stations. Planning studies are capitalized and attract carrying costs that may be significant since these studies are typically undertaken several years in advance of the planned in-service date of the project.

Costs associated with mitigation of environmental and social impacts are not included in the capital forecasts, but are included as a separate expense line item. To ameliorate the adverse effects of hydro-electric projects on the Churchill River Diversion and the Lake Winnipeg Regulation, Hydro has incurred approximately $471 million in mitigation costs. Four of the five First Nations have signed final agreements for compensation under the Northern Flood Agreement, and negotiations for settlement with Cross Lake First Nation are ongoing.

9.3 Justification and Prioritization

Hydro justified its capital expenditures within the following categories:

Justification Category	% of Capital Costs
Capacity	3.5
Load/Reliability	26.5
Safety	0.5
Reliability/Rehabilitation	10.0
Service	2.0
Efficiency	4.5
Other	4.0
Domestic Items*	48.7
	100.0

* Domestic items are non-specific domestic consumer-related expenditures.

Hydro has not attempted to specifically allocate capital costs associated with servicing the export market. Many of the existing capacity and load reliability items (i.e., connection to Rugby, North Dakota) may have an export component and future new generation may be built primarily for the export market. To date however, only the Brandon Combustion Turbine has specifically been justified solely for export purposes. Hydro stated that the majority of capital expenditures in CEF 01-1 have benefits associated with both export and domestic markets.

10.0 Extra-Provincial Revenues

10.1 Industry Changes Impact on Hydro

Over the past six years the North American electricity industry has changed significantly with the introduction of competition at the wholesale level. In response to the issuance of Orders 888 and 889 by the US Federal Energy Regulatory Commission ("FERC") in 1996, open access conditions were made mandatory for transmission carriers, along with a non-discriminatory wholesale tariff, which enabled wholesale competition in the electric industry in the US. By Order 2000, FERC mandated utilities to join Regional Transmission Operators ("RTOs").

The restructuring of the electricity industry in the US resulted in significant opportunities for Hydro, which prompted changes in Hydro's operations to better respond to increased deregulation. In 1996 Hydro reorganized its operations into three business units (Power Supply, Transmission and Distribution, and Customer Service and Marketing) and two support groups (Finance and Administration, and Corporate.)

Hydro's governing legislation was also changed by statutory amendments in 1997, expanding the mandate to include the marketing and supply of power outside the Province. Previously, Hydro's mandate was limited to supplying power adequate for the needs of the Province and promoting economy and efficiency in the generation, distribution, supply and use of electricity.

In response to the new opportunities, Hydro became an active member of the Mid-Continent Area Power Pool ("MAPP"), an electric reliability region and power marketing pool based in St. Paul, Minnesota. With MAPP unable to successfully transform into an RTO, Hydro then joined the Midwest Independent System Operator ("MISO"), which has become an RTO, serving 35 states.

The main consequences to Hydro resulting from electricity restructuring in the US include the following:

- Hydro now sells its transmission service under an open access transmission tariff;
- Significant increases in both the price and quantity of electricity exported;
- Annual export revenues have increased significantly;
- US customers have increased to more than 50 from 5;
- The operation of the main transmission grid is under the oversight of MISO which is responsible for operational reliability; and
- Standards of conduct limit the free flow of transmission information between the transmission operations with Hydro and the wholesale marketers within Hydro.

10.2 Extra-Provincial Revenues - 1996 to 2001

For the fiscal year ended 1996, extra-provincial revenues accounted for $246 million or 25% of total revenues. For the fiscal year ended 2001, extra-provincial revenues were $480 million representing over 40% of total revenue. The major increase in extra-provincial revenues since 1996 was primarily due to the changes in the electric industry with the evolution of competitive wholesale electricity markets discussed above. In addition, the shortage of generation supply caused spikes in prices during the high demand summer periods. This created the opportunity for Hydro to enter into forward contracts for export sales at higher prices. High natural gas prices also added to the volatility of the electricity prices.

Hydro maintains a mixed portfolio of export sales to reduce risk. These export products include long-term firm contracts and short-term opportunity sales. The opportunity sales are dependant upon water flows and can vary greatly from year-to-year.

The table below summarizes export revenues from 1996 to 2001:

Year	Opportunity Export Revenues	Long-Term Firm Export Revenues	Total Export Revenues
	Export Revenues ($ Millions)		
1996	105	141	246
1997	126	142	268
1998	149	148	297
1999	146	180	326
2000	146	230	376
2001	219	261	480

The export revenues, GW.h exported and average sales price per kW.h for the years 1996 to 2001 are as follows:

For the years ended March 31	1996	1997	1998	1999	2000	2001
Revenue $ million(s)	246	268	297	326	376	480
GW.h	10,496	12,531	14,341	10,694	10,776	12,082
Average sale price ¢/kW.h	2.34	2.14	2.07	3.05	3.49	3.97

10.3 Extra-Provincial Revenues - Future Outlook

Hydro stated that price volatility in the MAPP marketplace decreased significantly in 2001 due to the addition of new generation. In addition, the spike in natural gas prices subsided as a result of a downturn in the US economy. With much of the new electricity generated by natural gas combustion turbines, the resulting forward price of electricity decreased significantly in the last months of fiscal 2002. Hydro noted that with a continuance of the downturn in the US economy and lower natural gas prices, it is expected export prices will remain at lower levels in the near term. However, export prices are expected to increase gradually in the long term because of the greater reliance on generation from natural gas-fired combustion turbines in MAPP, rather than generation from coal fired plants with lower fuel costs. In addition, the price of natural gas is forecast to increase in the long term due to high projected demand for natural gas, particularly in the electricity generation sector.

Extra-provincial revenues are forecast to increase to $628 million in fiscal 2002. The major increase forecast for 2002 over 2001 was due primarily to a change in the exchange rate used for translating US extra-provincial revenues, discussed later in this Order. Of the $148 million increase in 2002 over 2001, approximately $110 million relates to the change in the accounting for US export sales. The remainder, approximately $38 million, is due to forecast increases in volumes.

Longer-term sales volumes are forecasted at average levels with revenues of $400 to $500 million/year. Hydro did not provide a breakdown of its future export revenues forecast nor GW.h information for fiscal years 2002 through 2012, since it considers the information to be commercially sensitive.

11.0 Payments to the Province

As a Crown Corporation, Hydro does not pay income tax, provincial sales tax or the Goods and Services Tax. Hydro does, however, pay the Provincial Corporations Capital Tax, similar to other privately held corporations employing capital in the Province. The Province of Manitoba also levies a number of other fees to be paid by Hydro. At the 1996 GRA, annual payments made to the Province from Hydro were in the range of $96 million. Payments to the Province have now increased to $128 million in 2001 and are forecasted to be $354 million in 2002.

The total payments to the Province from 1996 through 2004 are summarized as follows:

	Actual ($ millions)						Forecast ($ millions)		
For the year ended March 31	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Debt Guarantee Fee	25	26	29	31	40	49	65	62*	61*
Water Rental Rates	46	50	53	46	46	50	107	96	92
Corporations' Capital Tax	25	26	26	27	29	29	31	31	32
Sinking Fund Service Charge	0	0	0	0	0	0	1	1	1
Special Export Profit Payment ($288 million)	0	0	0	0	0	0	150**	75**	63**
Total	96	102	108	104	115	128	354	265	249

* The impact of the required borrowings related to $288 million special payment to the Province is not reflected.

**Subsequent to the hearing, Hydro's 2002 financial statements indicated that the special export profit payment will be paid out in 2003 and 2004. The first instalment will be $150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income for that year. In accordance with the legislation, the total distribution to the Province of Manitoba over the two-year period will not exceed $288 million.

11.1 Special Export Profit Payment

In the April 2002 Provincial budget, the Province announced a special export profit payment by Hydro to the Province of $288 million, payable in the amount of $150 million in 2002, $75 million in 2003 and $63 million in 2004. These payments are to be funded from the high export profits Hydro is experiencing and is forecast to continue experiencing. Hydro indicated that general rates would not increase as a result of these payments.

Hydro intends to finance the $288 million payment to the Province since its cash on hand is insufficient to make the payments. The interest costs to finance the payments are estimated to be an additional $276 million during the eleven-year forecast period from 2002 to 2012. As a result of the special payment and additional finance charges, retained earnings is forecast to be over $534 million less in 2012 than that originally forecast prior to the payment. When questioned as to whether Hydro had considered alternatives to financing these payments, Hydro responded it had only considered removing monies from its sinking fund. Hydro had not considered reductions to its capital expenditures nor revisions to its operations, maintenance and administration budgets.

The effect of the special export profit payment on the financial targets is to delay achieving the 75:25 debt equity ratio from 2006 to 2010, and to not achieve the interest coverage ratio target of 1.20 after fiscal 2003 through the remainder of the forecast period to 2012. Subsequent to the completion of the hearing the Hydro annual report for fiscal 2002 indicates that the $288 million will now be taken out in fiscal 2003 and 2004. The first instalment will be $150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income. Total distributions to the Province are limited to $288 million, under the legislation.

11.2 Water Rental Payment

Hydro pays water rental rates to the Province for the use of water resources in the operation of its hydroelectric generating stations. Under *The Water Power Act* water rental rates increased by over 105% from $1.6285/MW.h to $3.34/MW.h effective April 1, 2001. The effect of this increase was to more than double the water rental fees from $50 million in 2001 to $107 million in 2002.

Hydro had previously negotiated an agreement with the Province whereby water rental rates would be frozen from 1989 to 2001 in exchange for Hydro undertaking a number of northern development initiatives. The total costs to Hydro of such initiatives were $154 million over the 12 years. While Hydro noted the freezing of water rental rates was beneficial to Hydro, it did not plan to negotiate a similar agreement in the future.

11.3 Debt Guarantee Fee

Hydro pays the Province a debt guarantee fee in return for the Province guaranteeing Hydro's long-term debt. Previously set at 0.5% of the outstanding debt guaranteed by the Province, the fee was increased to 0.65% effective April 1, 2000 and 0.95% effective April 1, 2001. This increases the debt guarantee fee from $25 million in 1996 at the last GRA to $65 million in 2002.

Hydro stated that it receives a benefit of 15 basis points in Canadian capital markets and 75 basis points in US capital markets by financing with the backing of the provincial guarantee. All credit rating agency reports point to the provincial debt guarantee as a favourable factor in the credit rating of Hydro.

11.4 Sinking Fund

A sinking fund service charge of 0.075% of the sinking fund is paid to the Province for managing and servicing Hydro's sinking fund balance. This amounts to approximately $1 million per year.

12.0 Finance Expenses

Finance expenses were $426 million in 1996 representing over 46% of total operating expenses. Finance expenses declined to $387 million in fiscal 2001. For the fiscal years 1996 through 2001 actual finance expenses were over $226 million lower than that forecast in IFF 95-2 a result of declining long-term interest rates during the period.

Hydro has forecast finance expenses to increase in fiscal 2002 by $109 million to $496 million or 41% of annual operating expenses. The increase is attributable to an accounting policy change related to the Exposure Management Program ("EMP"), discussed below, additional debt related to the payment of the special payment to the Province, as well as an increase in the debt guarantee fee paid to the Province.

12.1 Exposure Management Program ("EMP")

Hydro employs an EMP which acts as a hedging program intended to limit the Corporation's net US dollar exposure within defined policy limits. Debt denominated in US currency is not subject to foreign exchange fluctuations as the exchange rate used has been fixed in accordance with the EMP. The program is necessary since $2.9 billion or 45% of the Corporation's $6.5 billion in long-term debt at March 31, 2001 is payable in US dollars.

As a result of the EMP, Hydro does not recognize gains or losses related to changes in the US currency exchange rate on its long-term debt or sinking fund. The EMP limits Hydro's exposure to foreign currency changes, and the sinking fund and export revenues act as a natural hedge for the retirement of the US denominated debt. Hydro has estimated that its US cash inflows will exceed the cumulative US cash outflows for interest, thermal fuel and sinking fund payments and will be sufficient to retire the existing US debt by March 31, 2023.

As a result of the program, the long-term debt and sinking fund were recorded at a designated exchange rate of ($1.00 US = $1.17 Cdn), rather than a year-end rate of ($1.00 US = $1.56 Cdn) at March 31,2001. If long-term debt had been recorded at the year-end rate it would have been approximately $1 billion greater than that reflected in Hydro's financial statements. The balance of the sinking fund would have been approximately $200 million greater. US extra-provincial revenues and finance expenses were also recorded at the lower designated rate rather than current exchange rates.

Hydro revised its EMP to reflect a new accounting policy whereby revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollar equivalents at exchange rates in effect at the transaction dates except to the extent revenues are used to hedge future long-term foreign debt obligations. Revenues used as formal hedges are firm US revenues which are translated at the embedded exchange rates of the respective US debt obligations to which the firm revenues are linked and for which they, together, form an effective hedge.

Previously, the US based transactions including net export revenues, interest revenues on US sinking fund investments, finance expenses on US debt and fuel purchases were translated at a designated exchange rate of $1.00 US to $1.17 Cdn, an exchange rate significantly lower than the rate of exchange prevailing during the year.

As a result of these changes, Hydro's export revenues increased from $480 million in 2001 to $628 million in 2002. Approximately $110 million of the $148 million increase was due to the change in accounting policy and the remainder, $38 million was due to a forecast increase in the volume of extra provincial sales. In addition, net long-term debt increased by over $403 million in 2003 and finance expenses also increased during the forecast period.

13.0 Operating and Administration Expenses

Operating and administration expenses include the costs associated with operating, maintaining and administering Hydro. Over 72% of these costs relate to labour costs including employee benefits. Hydro reorganized its operations into a business unit structure effective April 1, 1997, resulting in no practical means of comparing individual operating and administrative expense items for fiscal 1996 and 1997 to current expenses. The operating and administrative expenses for fiscal years 1998 to 2002 are as follows:

Operating & Administrative Expenses
($ thousands)

For the years ending March 31,	**1998**	**1999**	**2000**	**2001**	**2002**
Wages, salaries and overtime	205,299	213,732	219,702	259,162	274,079
Employee benefits	46,516	46,782	44,145	49,664	53,963
	251,815	260,514	263,847	308,826	328,042
Travel	18,301	19,992	20,327	22,146	23,302
Material & tools	18,089	18,280	18,674	22,135	22,212
Building and property services	13,967	13,393	13,410	17,221	17,493
Motor vehicle	11,045	12,050	13,048	15,052	12,785
Office and administration	8,358	9,299	9,858	13,604	12,624
Consulting and professional fees	8,151	9,515	8,413	9,229	9,290
Construction and maintenance services	7,765	10,691	8,482	10,242	10,797
Computer services	5,868	5,471	3,920	4,513	4,234
Purchased services	3,897	4,176	6,321	6,794	6,588
Customer and public relations	3,211	4,731	2,436	2,970	3,272
Equipment maintenance	2,761	2,870	3,730	5,096	5,760
Communication systems	1,545	1,586	2,133	2,211	2,242
Consumer services	1,109	1,203	1,339	5,533	5,656
Collections	1,054	1,329	1,445	3,260	2,757
Contingency	-	-	-	-	(1,632)
Operating expense recovery	(11,833)	(5,722)	(7,723)	(11,415)	(11,583)
	345,103	369,378	369,660	437,417	453,839
Less: Capital order activities	(87,280)	(91,617)	(88,065)	(99,660)	(107,814)
Centra costs of operations	-	-	-	(44,000)	(44,900)
Electric costs of operations	257,823	277,761	281,595	293,757	301,125
Less: Capitalized overhead	(45,209)	(54,846)	(53,373)	(50,758)	(46,805)
Total	212,614	222,915	228,222	242,999	254,320

Total operating and administration expenses have increased from $213 million in 1998 to $254 million in 2002. Over the same period of time, Hydro's workforce has increased by 911 equivalent full-time ("EFT") employees, and labour costs have increased by $76 million. This increase in staffing levels and related gross labour costs was largely due to the acquisition of Centra by Hydro and the integration of Centra's employees into Hydro's operations.

13.1 Operating and Administration Costs Per Customer

In the 2002 Corporate Strategic Plan, one of Hydro's stated goals is to improve corporate financial strength. One measure of this goal is to achieve an operating and administration cost per customer (electric) of $600 by March 2003. Hydro stated that the target is a stretch target, calculated based on the average costs per customer in the proceeding five years. By relying on the average of the proceeding five years in calculating the target, productivity increases are automatically built in and accounted for in the target.

IFF MH 01-1 indicates that over the eleven-year forecast period 2002 to 2012, operating and administration expenses per customer are projected to increase from $584/customer to $664/customer. Hydro has stated that to meet the target set out in the 2002 Corporate Strategic Plan, the operating budgets of the various divisions will be scrutinized on an overall basis to ensure the target is met.

13.2 Staffing Levels

Hydro indicated that between 1998 through 2003, staffing levels are projected to increase by 887 effective full time ("EFT") employees, from 4,030 to 4,917 EFT employees. The largest increase in EFT employees occurred in 2001 when staffing levels increased by 704 EFT employees, largely attributable to the acquisition of Centra and the integration of approximately 650 Centra employees.

According to Hydro, the projected level of EFT employees in 2002 and 2003 is optimistic and the actual increase projected for these years may be less. Hydro indicated that the number of EFT positions is closely monitored to maximize efficiency within the Corporation. Hydro stated that any new position has to be approved by the President and is subject to a rigorous process to make sure the position is justified.

13.3 Cost Control Process

According to Hydro, cost control measures are continuous through the utilization of a formalized cost control process that includes planning, budgeting, monthly reporting and variance analyses, which ensures costs and resource allocations are consistent and in line with operating and capital plans. Hydro uses this process to allow management to prioritize programs and projects; manage changing conditions; provide changes in corporate direction; establish communication regarding performance; and react to unforeseen conditions on a timely basis.

13.4 Capitalization of Operating and Administration Expenditures

Hydro segregates costs between operating activities, which are a direct charge against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of a respective project. Hydro indicated that employees timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, Hydro also capitalizes overhead by applying the predetermined overhead rates to all capital projects.

Operating and administrative expenses were approximately $454 million in 2002 before capitalized activities and overhead. Hydro indicated that approximately 25% or $107 million would be charged to capital order activities and approximately 10% or $46 million to capitalized overhead. Hydro stated that capitalizing approximately 35% of the total operating and administration expenses was reasonable and was the norm within the industry.

14.0 Transmission Tariffs

14.1 Hydro Transmission Tariff

To ensure access to the lucrative American export market, Hydro complies with certain FERC initiated demands, including reciprocity. Just as Hydro is able to obtain open access to other utilities' transmission systems in the US, Hydro now offers an open access transmission service and levies a transmission tariff to provide for the movement of electricity through Manitoba on its transmission grid. Offered as a service since 1997, the Transmission Tariff has been utilized, on occasion, by other entities and Hydro itself. Under Hydro's standards of conduct, the transmission function is separated from other functions and bills the other business units for use of the transmission facilities. Revenues have been received from use of this Transmission Tariff.

Hydro's Open Access Transmission Tariff has never been submitted for approval by the Board or the National Energy Board, but its associated rate schedules have been filed with FERC in the US. This tariff is based on the FERC pro forma Open Access Transmission Tariff. Approval of this tariff varies across other jurisdictions. Some provincial regulators, such as the British Columbia Utilities Commission, have approved open access transmission tariffs. In the restructured Alberta and Ontario marketplaces, provincial regulators approve provincial based open access transmission tariffs.

14.2 MISO Transmission Tariff

MISO also has its own open access transmission tariff to provide for the movement of electricity from Manitoba into, through, and from a MISO destination. Based on licence plate pricing, whereby the rate charged is that of the destination load zone, this tariff is also a FERC pro forma tariff. The MISO tariff does not apply to the Hydro transmission facilities – rather, it applies south of the border.

This MISO tariff has been approved by FERC, but has not been filed with either the Board or National Energy Board for approval.

14.3 Hydro's Position on Jurisdiction

Hydro noted the legislation is silent as to explicit approvals of transmission tariffs. Hydro argued the MISO tariff was beyond the provincial realm of constitutional division of powers. With respect to the Hydro Open Access Transmission Tariff, the only users are Hydro and parties outside of Manitoba. To retain the flexibility Hydro stated it must respond to rapid changes in the US markets, therefore the tariff should not be subject to direct PUB approval. Instead, the Board would review the tariff at a GRA to the extent that the tariff may affect domestic rates.

15.0 Load Forecasts and Power Resources

15.1 System Load

Hydro's domestic system load forecast is estimated at approximately 3,700 MW net peak demand, and 21,000 GW.h energy for 2003. This is forecast to increase to approximately 4,100 MW peak demand and 24,000 GW.h energy for 2012. Hydro's system load forecast has projected an increase of approximately 18% for energy and 13% for demand for the next 10 years. Over the last 16 years, actual domestic loads have been significantly below base forecasts in 13 of the last 16 years. In the other three years, actual loads have marginally exceeded base forecasts.

With relatively low generating costs and favourable export markets, Hydro is in a relatively advantageous situation to compete on the open market for the sale of power. Therefore, firm contracts negotiated by Hydro provide additional system load demands over and above domestic loads. Available power not required by domestic or firm contract export customers can also potentially be sold in the export market as opportunity sales.

15.2 System Capacity

Hydro currently has approximately 5,400 MW (winter demand) and 25,000 GW.h (annual energy) capability within its hydraulic generation and thermal plants. Hydro has sufficient resources to supply domestic loads and existing firm export sales to the year 2019 under expected load growth conditions.

The capacity criterion for the Hydro system requires that planned generation capacity must not be less than forecast annual firm peak demand plus a reserve requirement of 12% of forecast firm loads. The energy criterion requires that the Hydro system be capable of a dependable supply of energy to meet forecast firm load demands. Specifically, there must be sufficient firm energy sources to meet firm energy demand in the event of a repeat of the lowest historic water flows.

Even with a 12% demand reserve requirement, the demand capability will not be exceeded until after 2020 for domestic load and energy capability will not be exceeded until 2014. Firm exports impose only a modest (100 to 200 MW in demand and 500 to 1,000 GW.h in energy) addition to system capacity and energy demand because the nature of Hydro's firm export contracts (often involving an off-setting import commitment).

15.3 New Power Resources

In accordance with its mandate to pursue sales in the export market, Hydro is bringing new capacity online in 2003 including the Brandon Combustion Turbine. This facility will provide a total installed capacity of 260 MW.

As mentioned in the capital expenditures section of this Order, Hydro intends to embark upon an ambitious construction program over the next two decades with construction of several new generating stations: Wuskwatim (200 MW), Gull (650 MW), Notigi (100 MW), and possibly Conawapa (1,230 MW) which Hydro indicates will be subject to a separate hearing. It is Hydro's contention that new hydraulic generation should be viewed as "green" energy since it produces little or no greenhouse gases. As such, their new hydraulic facilities will contribute significantly to greenhouse gas reductions as contemplated in the Kyoto Protocol. Hydro is committed to maintaining the cumulative average net greenhouse gas emissions since 1990 at 6% below 1990 levels.

Hydro did not distribute its Power Resource Plan citing confidentiality due to the increased competitive nature of electricity trading in the US. Hydro has no wind generation in its current power resources nor plans to install any over the next decade. Witnesses for Hydro agreed the efficiencies and reliability of wind generation have increased substantially while costs have dropped simultaneously over the past few years. However, as yet, wind generation is more costly than Hydro's hydraulic generation, although there may be some other additional environmental and social benefits.

16.0 Revenue Requirement and Current Rates

16.1 Current Level of Rates

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because the robust export markets and favourable water conditions, which underpinned the strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its financial objectives.

Hydro also believes domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenue as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

In IFF 01-1 Hydro has forecast a 2% rate increases in 2004 and each year thereafter until 2009. Hydro indicated these future actual rate increases are at risk of being higher than those projected in the long range forecast in the absence of fortuitous events, such as higher export revenues or higher water flows. Furthermore, according to Hydro, a short-term decrease in rates may simply have to be recovered in future years, potentially leading to rate instability for customers. As rate stability was one of the overriding parameters, reducing and then subsequently increasing rates was not desirable. In response to the suggestion that rates should be set at a break-even level, Hydro stated domestic rates would have followed a widely fluctuating pattern with large rate decreases in 2001 during the windfall years followed by huge rate increases in the subsequent years. As such, it would be neither stable nor predictable.

17.0 Cost of Service Study

17.1 Purpose of a Cost of Service Study

A cost of service or cost allocation study is a tool used to assist in setting appropriate rates to be charged to each class of customer. The Cost of Service Study analyzes the components of Hydro's costs and assigns them to the various customer classes. The purpose of this analysis is to compare assigned costs to revenue by customer classes. The relationship of the revenues from a particular customer class to the assigned costs for that class is the revenue to cost ratio. A customer class where the revenues are equal to the assigned costs, would have a revenue to cost ratio of one. In Order 51/96, the Board stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05" for all class revenue to cost coverage ratios. The results are used to provide guidance in establishing the rate levels and designing the rate structures for each customer class so that each customer class pays its fair share of costs incurred by Hydro to deliver service.

17.2 Methodology

Fully embedded cost of service studies generally employ a three-step process of cost analysis as follows:

(a) <u>Functionalization</u> of costs according to services (or functions) performed by the utility. The major functions by which costs are assigned are generation, transmission, distribution and ancillary services.

(b) Classification of each function's costs according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of the following:

- Demand-related costs - Allocated among the customer classes on the basis of demand imposed on the system during specific peak hours, and the maximum size (capacity) of facilities required to service the demand of customers.
- Energy-related costs - Allocated among the customer classes on the basis of energy which the system must supply to serve the customers.

- Customer-related costs – Allocated among the customer classes on the basis of the number of customers, the weighted number of customers, or costs per customer.

(c) Allocation of each functional and classified cost component to specific customer classes based on each class's contribution to the specific cost driver selected.

17.3 1997 Cost of Service Study

Hydro's 1997 Cost of Service Study generally follows the standard three-step process of functionalization, classification and allocation of costs to customer classes. The methodology was last reviewed in conjunction with Hydro's Application for 1996 and 1997 rates. In the resulting Order 51/96, the Board directed Hydro to make some methodology changes, to review a number of other matters, and to report to the Board by no later than the next GRA on a number of issues including the following:

(a) An alternate method of solving the persistent problem of certain subclasses (e.g. Zone 3 Residential and General Service Large ("GSL") being outside of the zone of reasonableness.

(b) The merit of considering GSL customers (over 100 kV) as a separate customer class for cost of service purposes.

(c) An actual cost of service study for 1996/97 on Area and Roadway Lighting to determine actual conditions including the real coincident peak ("CP") factor.

(d) The implications of using incremental versus embedded costs as they would apply to Hydro's rate design, including the impact on various customer classes.

(e) Directly assign DSM costs for General Service Small ("GSS") and General Service Medium ("GSM") customers in future cost of service studies.

(f) Continue with the present net export revenue allocation for cost of service purposes.

(g) Develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off-peak and seasonable rates. The study was also to include the implication of the phase out of the winter ratchet.

17.4 November 2001 Cost of Service Study

Hydro revised its cost of service methodology in the Cost of Service Study filed in November 2001 to:

- Recognize the changes in export energy markets that have taken place in the last several years;
- Recognize the significance of Hydro's participation in these markets to the pricing of its energy and transmission resources;
- Recognize the unique circumstances of Hydro's wholesale customer – The City of Winnipeg; and
- Address issues arising out of Orders 51/96 and 91/00.

17.5 March 2002 Cost of Service Study

Prior to the commencement of the hearing, Hydro indicated it was unable, for reasons of commercial sensitivity, to provide the information necessary to support its November 2001 proposed cost of service methodology. Also, subsequent to the original filing, Hydro and the City of Winnipeg entered into negotiations for Hydro to purchase the net assets of Winnipeg Hydro. Completion of this transaction would eliminate Winnipeg Hydro as a separate customer class and impact the cost of service analysis. As result, on March 27, 2002, and in accordance with Order 52/02, Hydro filed a revised cost of service study that included a number of modifications to its November 2001 filing. The Revenue Cost Average Analysis is attached as Appendix C and the Revenue Cost Variance Analysis is attached as Appendix D.

17.6 Functional Changes

17.6.1 Transmission Assets

In Hydro's 1996 cost of service methodology, all transmission lines and stations (including HVDC facilities) were included in the transmission function and, subsequently, allocated on the basis of both demand and energy. In the March 2002 Cost of Service Study, Hydro proposed a number of changes in the functionalization of transmission assets:

- Hydro's HVDC facilities (with the exception of the Dorsey Converter Station which is considered transmission) are functionalized as generation;
- Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function;
- Four sets of AC transmission lines that serve as part of the HVDC collection system in the north to bring the power to the converter stations at Henday and Radisson are functionalized as generation;
- Radial (one way) transmission facilities, including those with voltages greater than 100 kV, are treated as sub transmission and included as part of distribution assets; and
- Local power lines and stations are treated as distribution.

The transmission lines and stations excluded from the transmission function continue to be treated as generation.

17.6.2 Ancillary Services

In its proposed cost of service methodology, Hydro has introduced a new function to capture the facilities and costs associated with providing the following ancillary services:

- Scheduling, System Control and Dispatch
- Reactive Supply and Voltage Control from Generation Sources
- Regulation and Frequency Response
- Energy Imbalance
- Operating Reserve-Spinning Reserve
- Operating Reserve-Supplemental Reserve

In previous studies the costs associated with these services were "bundled" as part of generation and transmission costs. To determine the costs of ancillary function, the assets and expenses associated with providing each of the above services were identified.

17.7 Classification Changes

17.7.1 Generation

Hydro's pre-2001 cost of service methodology classified generation and transmission between energy and demand on the basis of system load factor. The methodology proposed in Hydro's November 2001 study classified generation, transmission and ancillary service separately. Generation costs were classified into four categories: winter energy, winter capacity, summer energy and summer capacity. The classification ratios were to be derived by multiplying the domestic energy and demand forecast by a five-year levelized forecast of Hydro's marginal costs, which, in turn, reflected the export value of capacity and energy.

In its March 2002 revised cost of service methodology, Hydro generally returned to the pre-2001 approach and classified total generation and transmission (along with ancillary services) costs on the basis of system load factor. However, in the revised Cost of Service Study, transmission and ancillary services are classified wholly as demand-related. The balance of the demand-related costs is assigned to generation and all other generation costs are classified as energy related. The result is that 21.2% of generation costs are classified as demand-related.

17.7.2 Transmission

Both the November 2001 and March 2002 cost of service studies classified all transmission costs as demand-related as opposed to classifying then on the basis of system load factor, as previously done by Hydro.

17.7.3 Ancillary Services

Hydro proposes to classify these costs on the same basis as transmission function costs - entirely demand-related.

17.8 Allocation Changes

17.8.1 Generation, Transmission and Ancillary Services Costs

Hydro's pre-2001 cost of service methodology allocated energy-related generation and transmission costs on the basis of annual energy use, including losses between the meter and the generators. Demand-related generation and transmission costs were allocated on the basis of each customer class' contribution to the coincident peak (where coincident peak was defined as the average load during the highest 50 hours of the year). Ancillary services were not separately identified in the previous Cost of Service Study.

In Hydro's March 2002 cost of service methodology:

- Energy-related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak Methodology);
- Demand-related generation costs are allocated to customer classes on the basis of each customer class' share of the average of the top 50 coincident load hours during the months of December, January and February and June, July and August (2 Coincident Peak Methodology);
- Transmission costs are all classified as demand-related and allocated to customer classes based upon their monthly demands at the time of the system's monthly peaks, with all months given an equal weighting (12 Coincident Peak Methodology);
- Ancillary services costs (all considered to be demand-related) are allocated on the same basis as transmission costs (12 Coincident Peak Methodology).

17.8.2 Export Revenues

Hydro's net export revenues have grown from 17% of total revenues in 1993 to 43% of total revenues as forecast for 2002. As a result, the Cost of Service Study treatment of net export revenues now plays a significant role in the determination of revenue to cost coverage ratios for the various customer classes. For example, the revenue to cost ratio of the "GSL" customer class, based on the proposed methodology in the March 2002 Cost of Service Study, is 1.00, and allocated export revenues are approximately 39% of allocated costs. Alternatively, if export revenues are allocated to the GSL customer class using the methodology consistent with the Board's decision in Order 51/96, the revenue to cost ratio is approximately 1.12, and the allocated export revenues are approximately 49% of allocated costs. Different methodologies for allocation of export revenues can significantly impact customer class revenue to cost coverage ratios.

The previous cost of service methodology employed by Hydro in 1996, and approved by this Board, allocated export revenues as a credit to the various customer classes, based on the generation and transmission costs allocated to each customer class. The previous methodology was based on the premise that it was only the generation and transmission functions which support the export of Hydro's surplus capacity and energy. The revised cost allocation study proposed by Hydro allocates net export revenues on the basis of each class of customer's share of all allocated costs (generation, transmission and distribution).

There was much discussion and debate during the hearing concerning the merits or otherwise of creating a separate export revenue customer class. While acknowledging that creation of an "Export Class" is theoretically possible, Hydro has not fully studied the matter and indicated there were issues, such as the identification of embedded costs, that would need to be determined and whether it is appropriate to include only long-term sales, all firm sales or all export sales in an "Export Class".

Hydro suggests its proposed change in the allocation of net export revenue yields results that:

- Are less distorting of the economic price signals for generation and transmission; and
- Address the Board's concerns as expressed in Order 51/96, including the concerns about class revenue to cost ratios falling outside of the "zone of reasonableness."

17.8.3 Winnipeg Hydro

The November 2001 cost of service filing by Hydro had proposed a number of modifications to the way generation and transmission costs were allocated to Winnipeg Hydro. However, as a result of the acquisition of Winnipeg Hydro, the revised cost of service methodology filed with the Board in March 2002 resulted in the following changes:

- Removal of Winnipeg Hydro as a class of service from the Cost of Service Study;
- Allocation of the costs formerly allocated to Winnipeg Hydro to all the retail classes on the basis of the appropriate allocators; and
- Allocation of the revenues anticipated from Winnipeg Hydro to all the retail classes on the same basis as export revenues.

Hydro's interim adjustment, to the Cost of Service Methodology, for costs and revenues associated with Winnipeg Hydro, was in recognition that the retail customers of Winnipeg Hydro will be incorporated into Hydro's retail classes in future cost of service studies. However, the load and cost data from Winnipeg Hydro was not available to permit such treatment in the March 27, 2002 amended methodology.

Both CAC/MSOS's and MIPUG's pre-filed evidence criticized Hydro's March 27, 2002 amended methodology for the treatment of Winnipeg Hydro as being inconsistent in its treatment of costs and revenues.

In its rebuttal evidence, Hydro acknowledged the inconsistency and suggested that a more appropriate interim cost of service methodology to exclude Winnipeg Hydro as a customer class, would be to subtract all costs expected to have been billed directly by Hydro to Winnipeg Hydro, from generation and transmission costs. Hydro also suggests it would be consistent with the balance of all costs incurred by Hydro's current customer classes.

Hydro has indicated that there is sufficient information available to revise the most recent Cost of Service Study and roughly assign Winnipeg Hydro data to the appropriate classes with a view to illustrating, on a directional basis, the impacts of the Winnipeg Hydro acquisition. A more precise prospective cost of service study for 2003/04 will be prepared.

17.8.4 Implications of Proposed Cost of Service Methodology

The March 2002 proposed Cost of Service Study includes the above-mentioned methodology changes. The results are at considerable variance from the results obtained under the methodology previously approved by the Board. The Revenue to Cost Coverage ("RCC") results under the proposed methodology are significantly affected by the proposed treatment of export revenues and the acquisition of Winnipeg Hydro. The RCC results by overall major customer class are shown in the following table:

Class	RCC Using Previous Methodology (51/96) For Year Ended March 31, 2002	RCC Using Proposed Methodology (March 2002) For Year Ended March 31, 2002
Residential	.884	.965
General Service Small (non-demand)	1.058	1.095
General Service Small (demand)	1.061	1.047
General Service Medium	1.073	1.044
Winnipeg Hydro	1.173	not applicable
Area and Roadway Lighting	.976	1.019
General Service Large	1.108	1.000

17.8.5 Zone of Reasonableness

One product of a cost of service study is a revenue to cost ratio by customer class, where unity, or revenue to cost ratio of 1, indicates that the costs allocated to a class is equal to the revenue earned from that class. The "zone of reasonableness" refers to the revenue to cost ratio range above and below unity that is acceptable. That is, the degree to which each customer class either underpays or overpays their share of allocated costs. Prior to 1996, the zone of reasonableness target was initially 0.85 to 1.15, then 0.90 to 1.10. In Order 51/96, the Board Findings stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05."

The attached table summarizes revenue to cost ratios by major customer classes over the ten year period 1992 to 2002, and highlights certain customer subclasses that have consistently been outside of the zone of reasonableness for a considerable period of time.

Revenue to Cost Coverage – Various Customer Classes
1992 to 2002

PCOSS	1992	1993	1994	1995	1996	1997	1999	2000	2001	*2002
Res Z1	93.2	90.9	92.5	96.5	100.5	102.5	96.3	97.0	92.4	100.6
Res Z2	96.2	93.7	93.7	95.2	96.6	96.0	99.9	101.0	98.6	102.1
Res Z3	85.5	83.0	82.6	82.7	81.8	81.6	83.7	83.1	83.9	89.0
GSS	103.8	103.2	105.6	105.3	106.2	104.5	107.7	105.8	105.4	107.1
GSM	109.3	110.5	110.1	106.1	102.4	102.4	105.5	108.4	109.4	104.4
GSL<30kV	109.0	109.7	109.5	105.2	98.5	100.9	101.4	101.2	102.6	96.8
GSL 30-100kV	122.5	117.5	114.8	111.8	109.4	108.1	110.3	112.0	118.8	109.4
GSL>100kV	110.9	111.8	111.6	110.9	109.5	111.1	110.8	111.0	116.7	100.1
GS Curtail	_	_	_	_	_	_	107.5	110.3	114.5	99.2

* Hydro's March 2002 proposed Cost of Service Study includes some methodologies, which have not been accepted by the Board.

18.0 Rate Design

18.1 Background

As part of its Status Update filing, Hydro is not seeking any change to firm rates currently charged to customers. Hydro's position is that any Board directed changes and modifications to the Cost of Service Study may impact rate design, and accordingly, the issue of rates should be deferred for future discussions at another hearing. However, Hydro agreed that this regulatory review was a good time to examine rate design issues on a purely principled basis, because Hydro was not requesting any rate changes.

In Order 51/96 the Board directed Hydro to "undertake a study and report to the Board by no later than the next GRA to develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off peak and seasonal rates. This study should include consultation with interested parties and consideration of implications of the phase out of the winter ratchet." It was Hydro's position that matters relating to the problems of subclasses being outside the zone of reasonableness requires regulatory resolution before any other issues related to rate policy and strategy are considered. Hydro also indicated it has no intention of planning any major rate design changes over the next five years.

18.2 Uniform Rates

With the introduction of uniform rates by way of legislation in November 2001, rate zone distinctions for customers on the inter-connected grid were eliminated and all rates in the previous zones 2 and 3 were reduced to be the same as the rate charged in zone 1, which includes the City of Winnipeg. The financial impact of uniform rates is a decrease in revenues of approximately $14.8 million in 2003, the first full year of implementation.

18.3 Residential Rates

The residential rate has a declining block structure which includes a higher energy charge for the initial 175 kW.h and a lower charge for the remaining block. Additionally a basic monthly charge of $6.25 is intended to partially recover costs which do not vary with either demand or energy but which are incurred merely by being a customer on the system. These costs include those associated with billing, customer service, metering, meter service reading, and some portion of the distribution system. Currently the basic monthly charge recovers less than half of these actual costs, the balance of such costs being recovered by way of the energy charge.

18.4 General Service Small Demand and Non-Demand

These customers are the least homogenous of all rate groups. GSS customers are generally small retail and commercial operations. The basic monthly charge of $14.00 for single-phase power or $20.86 for three-phase power recovers substantially more customer related costs than does the residential basic monthly charge. The energy charge is also a declining block rate structure. GSS customers that exceed 50 kV.A are also subject to a demand charge.

18.5 General Service Medium

These rates contain a basic monthly charge, in addition to both demand and energy charges.

18.6 General Service Large

This customer class is broken into three different rate groups, depending upon consumption levels. There are no basic monthly charges for customers in this class. Those customers with the highest consumption levels are charged the lowest rates, because the largest consumers are served off the main transmission system, thereby not using sub-transmission or distribution facilities.

18.7 Time of Use Rates

A time of use rate varies according to the time in which the consumption occurs. During peak periods, customers are charged higher rates and are charged lower rates during off-peak periods. Time of use rates vary seasonally, weekly, daily, or hourly, and even extend to real time pricing. These rates provide a signal to customers of the variable costs of power.

In Order 51/96 the Board directed Hydro to undertake a comprehensive rate design study and include consideration of time of use rates, amongst other things. No such report has been prepared and no movement towards time of use rates is planned by Hydro in the near future. Hydro indicated it is planning to attach specialized meter reading equipment on more customers below the 1,000 kV.A threshold, namely the 250-1,000 kV.A level, of GSL and GSM, which will enable these customers to access time of use rates should Hydro develop such rates in the future. In doing so, this will remove a practical impediment to implementing time of use rates.

18.8 Winter Ratchet

As part of the demand billing process, the monthly billing demand for general service customers is based on actual demand, with a minimum demand equal to 80% of maximum previous winter monthly demand measured in December, January or February. The rationale for the winter ratchet is to signal to customers the high costs of winter capacity and to ensure full winter demand costs are recovered. This issue is problematic for those customers with low off-peak energy usage relative to maximum demand.

The Board is aware that certain customers have been pressing Hydro for a waiver of demand charges during scheduled maintenance shutdowns. Their argument focuses on Hydro's ability to sell this available power on the opportunity export market. Under appropriate constraints with respect to timing and pricing, there could be merit in Hydro offering such a waiver to certain customers.

A report prepared by Hydro investigated alternatives to the winter ratchet including:

- Elimination or substantial reduction of the winter ratchet;
- Gradual reduction of the winter ratchet;
- Replacement of the winter ratchet with higher seasonal and/or peak prices; and
- Waive of the winter ratchet during selected periods.

If the winter ratchet were to be eliminated, the financial consequences would be approximately $3-4 million less revenue annually for Hydro.

18.9 Limited Use Billing Demand

In seeking to address some issues with the winter ratchet, Hydro introduced the Limited Use Billing Demand ("LUBD") rate option in 2000. This allows eligible customers with low energy use relative to demand use to choose an alternate billing process. Under the LUBD program, customers may opt for a lower demand charge in exchange for a higher energy charge. The energy rate for a GSM firm customer is 2.12¢/kW.h whereas a LUBD customer pays 6.92¢/kW.h. The demand rate for that same firm customer is 8.32¢/kV.A whereas a LUBD customer pays 2.08¢/kV.A.

Originally approved for two years commencing June 30, 2000, Order 118/02 extended the LUBD on an interim ex parte basis so it could be considered in this hearing before the Board. Hydro is seeking final approval of Order 118/02 and to make the LUBD rate option a permanent rate offering.

The LUBD rate option is utilized by approximately 120 customers.

18.10 Surplus Energy Program

The Surplus Energy Program ("SEP") replaced the Dual Fuel Heating ("DFH") and Industrial Surplus Energy Programs ("ISE") in 2000. The rationale for those programs was that as a predominantly hydraulic utility, Hydro must plan to have sufficient energy capability to meet the demand of firm customers under the most adverse water conditions. As droughts occur intermittently, Hydro normally has surplus energy available most years. Hydro markets this surplus energy to Manitoba eligible consumers at rates comparable to export prices for similar energy services to enhance pricing options.

The ISE program permitted customers to obtain an alternate supply of energy through spot market energy when Hydro interrupted their supply. The spot market price was based on market conditions considering such factors as import and thermal costs, foregoing export revenues, transmission losses, a margin to account for overhead and administration, and a contribution to retained earnings. A minimum spot market replacement energy rate was in place, in addition to a varying weekly Energy Cost Adjustment and when the Energy Cost Adjustment was required Hydro would file such an application with the Board, on a weekly basis for interim ex parte approval.

The prices for the SEP are based on a forecast of the expected source of energy and associated costs. These are submitted to the Board on a weekly basis for interim ex parte approval, with rates broken into peak, shoulder, and off-peak hours.

At the time of closing arguments, a total of 116 interim ex parte weekly orders had been approved for the DFH and ISE programs, and 96 orders had been approved on an interim ex parte basis for the SEP. Hydro requested final approval of all orders issued on an interim ex parte basis prior to the Board issuing this order. No Intervenors addressed these orders in the hearing. A list of all ex parte orders relating to these programs is attached as Appendix E to this Order.

18.11 Curtailable Rates

Hydro has applied for approval of a new Curtailable Rate Program ("CRP") to supercede the existing Curtailable Service Program ("CSP"). The existing program, originally set to expire November 30, 2001, was extended to February 28, 2002 by Order 150/01 and then again by ex parte Order 55/02, until this Order was released. Hydro proposes the new CRP have a relatively short duration of until November 30, 2003 because the unknown impact of MISO's requirement for and value of reserves.

The CRP allows Hydro to curtail a portion of a large industrial customer's peak load in exchange for reduced rates on that same portion of the load when it was not curtailed. The objective of the CRP is to cut back on the electrical loads during specific periods when the overall electrical system was being taxed to its maximum capacity. As part of the Demand Side Management Program, the CRP reduces Hydro's peak load and assists in maintaining the essential power capacity reserves required for domestic and export operations.

Currently, nine curtailable rate options exist for customers, based on duration and notice for curtailment, in addition to price. Three customers now subscribe to the program, with a total subscribed load of approximately 100 MW. In 2001, the two customers who subscribed to the curtailable rates program saved $1.96 million and $380,000 respectively. Under the proposed CRP, five curtailable rates options will be offered to customers.

Under the proposed CRP, the rationale for curtailments will be altered to only instances required to meet reliability of the system and obligations to maintain operating reserves. There will be no curtailments to enable Hydro to make a high value opportunity sale; curtailments may, however, be made for firm export sales. Additionally, curtailments could occur for forecast errors, loss of facility, and restoring the operating reserve. Curtailments will not be conducted for peak shaving. In 2001, the overwhelming majority of curtailments (26 of 29) were for peak shaving and reducing imports. Since neither of those will be reasons for curtailment in the future, Hydro expects only two to three curtailments per year under the new program, although there will be a maximum ceiling of 3 to 18 curtailments per year depending upon the option chosen.

The financial case for the CRP is based upon an expectation of 150 MW subscribed annually, for a $4.3 million revenue savings to customers. With approximately $1 million attributable to benefits easily quantifiable, the remaining $3.3 million is attributable to reliability benefits not easily quantifiable according to Hydro witnesses. In 1998 (Order 153/98) Hydro presented an application to the Board to alter and extend the Curtailable Service Program. At that time, Hydro indicated there would be $10.4 million in savings to ratepayers if the CRP were extended for a decade. With compounding effects, this would increase to $26 million over that 10 year period. At this hearing, Hydro was unable to provide any tangible evidence whether part of this benefit had been achieved since 1998, noting that by their very nature, these benefits are difficult to quantify and reconstructing decisions made based upon existing circumstances at that time is nearly impossible with intervening events.

The proposed CRP has a reference discount which varies by percentage for each program option. Previously, the benefits had been calculated using the marginal cost values of capacity. The benefit of capacity curtailed over the winter peak was estimated to result from the ability to improve reliability and thus defer the timing of resource requirements. For summer, the benefit of capacity curtailed was estimated to result in increased revenues corresponding to short-term firm capacity sales. Previously the reference discount varied monthly, based on the US – Canadian dollar exchange rate.

In this application, Hydro has applied for a fixed reference discount of $2.75/kW per month, to be adjusted annually for the Consumer Price Index. Hydro has also changed the calculation of the reference discount since Hydro now believes marginal costs are commercially sensitive information and the determination of a value was difficult. Now, Hydro is attempting to use reasonable judgment to balance the lowest value Hydro judges to be necessary to attract sufficient curtailable load to make the CRP work, with the expectation that the load will be available in the long term where the capacity values to Hydro are expected to be higher. Accordingly, Hydro proposes the reference discount be ascribed a value of a reasonable relationship to an alternative least cost resource of capacity, namely a natural gas combustion turbine. In this instance, at $2.75/kW, it is approximately 42% of the levelized cost of the combustion turbine.

With the reference discount previously subject to monthly fluctuations in currency exchange rates, Hydro had filed a number of interim ex parte applications for the CSP. In this application Hydro seeks final approval of the ex parte Orders listed in Appendix E of this Order.

18.12 Diesel Rates

There are approximately 800 customers in the four remote communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, who are provided electrical service by diesel generation. These customers are not connected to the main grid due to remoteness of location. In 1997 nine other remote communities previously on diesel service were connected to the main grid. Recent upgrades have permitted the four remaining diesel communities to have similar residential service to those on the main grid with the exception of a prohibition of space and hot water heating.

The current full cost rate for providing diesel service was estimated at 35.9¢/kW.h. Residential diesel customers are charged the same rates as residential grid customers, thereby creating a shortfall of approximately 29¢/kW.h sold. Non-government General Service customers are charged the same rate as grid customers for the first 3,000 kW.h consumed per month and the full cost rate thereafter. Government customers pay the full cost rate. In addition to these full cost rates, all government customers pay a government surcharge intended to recover the deficit incurred by providing grid based rates to non-government diesel customers. The surcharge has been in effect since 1984 and has escalated dramatically to 44.8¢/kW.h. This surcharge is in addition to the full cost rate of 35.9¢/kW.h.

Notwithstanding the government surcharge, a shortfall of $250,000/month is accumulating since the costs of providing service greatly exceed the revenues generated. Up until 2001, the total revenue shortfall was $7.4 million, with a $3.2 million shortfall in 2001 alone.

Since November 2000, in response to a request by MKO, Hydro has billed all First Nations accounts, including government surcharges, directly to Indian and Northern Affairs Canada. In response, Indian and Northern Affairs Canada maintains it provides funding through a formula to the Bands to assist in paying their electricity bills, and returned the unpaid bills to Hydro.

Hydro filed an application for rates for diesel service dated December 2, 2002 and a public hearing is scheduled to commence on March 3, 2003.

19.0 Intervenors' Positions

19.1 CAC/MSOS

19.1.1 Financial Targets

CAC/MSOS questioned the need for Hydro to attain a 75:25 debt equity target to acquire capital at reasonable rates. CAC/MSOS stated the evidence presented by its witnesses, Mr. Todd and Mr. Harper, had confirmed that neither the debt equity ratio nor interest coverage ratios are determinative of Hydro's ability to access capital at reasonable rates. Rather, the key factor in establishing the credit rating is the health of the Provincial finances coupled with the sufficiency of the actual potential revenue streams. Mr. Todd stated neither the interest coverage ratio nor the debt equity ratio should impact Hydro's debt rating nor change Hydro's ability to issue debt, since Hydro's rating is primarily based on the existing Provincial debt guarantee. Mr. Todd noted Hydro's capacity to raise rates, if circumstances warrant, is the key indicator of its ability to meet its obligations in the event of a catastrophe, without posing a burden on the Province.

Further, as confirmed by Standard & Poors, "the existence of a strong and supportive Government and regulatory environment, including a debt guarantee fee, can outweigh somewhat weaker financial indicators." CAC/MSOS noted this was supported by the fact that Hydro's debt rating had remained unchanged, while its debt equity ratio has consistently improved, noting Manitoba still benefits from the same "A" rating now as in 1995 when its debt equity ratio was substantially weaker at 92:8.

Mr. Todd stated there was an inconsistency in Hydro setting an interest coverage ratio of 1.20 to collect an additional $100 million cushion each year, when current reserves of over $1 billion give Hydro sufficient financial protection from a drought. Mr. Todd further stated Hydro need not keep earning net income of $100 million or more annually to be fiscally responsible and that instead of maintaining an interest coverage ratio of 1.20, building reserves even further, Hydro could establish an interest coverage ratio of 1.0, resulting in lower rates set roughly in line with break even over the long run.

19.1.2 Risks

Mr. Todd stated that with more than $1 billion in retained earnings, and 400,000 customers, each customer on average had contributed $2,500 towards that retained earning. As a form of rate stabilization insurance, this was rather expensive according to Mr. Todd, and Hydro is seeking to increase the amount by another 50% to $1.5 billion by fiscal 2008.

Mr. Todd stated it was not sufficient to justify seeking reserves of over $1.5 billion on the basis of a cursory listing of risks. To determine analytically the extent to which it is appropriate to build financial reserves by setting rates that recover more than the normally allowed costs, it is necessary to define clearly the risks being mitigated. Defining the risks involves not only identifying them, but also quantifying the range of possible financial impacts of the relevant risk factors and the likelihood of different possible outcomes. In addition, it is necessary to understand clearly the purpose of mitigating the risk, so an assessment can be made of the appropriate risk tolerance to be adopted for purposes of establishing appropriate financial targets. According to Mr. Todd, risks which cannot be anticipated and built into the forecast should be the only risks requiring reserves.

CAC/MSOS suggested that Hydro's risk analysis consisted of identifying the financial impact of drought at $1.3 billion and then merely listing other risks with no indication as to their impact or likelihood of occurring. Accordingly, such a superficial approach should be rejected in favour of a more vigorous quantitative risk analysis. CAC/MSOS supported its witnesses' recommendations on examining the risks to set an adequate reserve provision by undertaking the following:

1. Determine which risks require reserves – namely unanticipated and therefore not built into the forecast;

2. Consider the magnitude and probability of that risk occurring and recognize the relationship between the risks;

3. Consider the tolerable rate increase should the risks be realized; and

4. Ensure the risk analysis can justify the reserve provision.

19.1.3 Capital Expenditures

CAC/MSOS further suggested the current levels of reserves encourage higher than necessary capital expenditures and that Hydro could operate with a 5% lower capital budget without seriously impacting system capacity and reliability. Furthermore, Hydro's response to a worsening financial situation should be a decrease in capital expenditures rather than merely a requested rate increase.

19.1.4 Operating and Administrative Expenses

The evidence of Mr. Harper, on behalf of CAC/MSOS, suggested Hydro be encouraged to pursue aggressive cost control through productivity improvements to control operating and administration expenses. CAC/MSOS adopted the position of Mr. Harper in closing argument and advocated that Hydro should be evaluated on whether it could achieve annual productivity improvements of 1.5%. CAC/MSOS also suggested there exists opportunities for Hydro to reduce the operating and administration costs per customer.

Mr. Todd and Mr. Harper stated in their evidence that the target level for operating and administration cost per customer for rate setting purposes for the years 2000 to 2012 should be set at $620/customer. Mr. Harper stated the $620 benchmark would reflect a level of productivity typically expected of other regulated activities. Mr. Harper acknowledged Hydro has built in a productivity factor in setting the operating and administration cost per customer target, but suggested that the bar be set higher, more in line with general industry expectations.

CAC/MSOS witnesses stated Hydro's performance in terms of operating costs per customer was in the middle to upper end of the cost range when compared to Hydro Quebec and BC Hydro. They also examined the operating and administration costs in IFF MH 99-1 and IFF MH 01-1, and suggested Hydro has room for improvement.

19.1.5 Load Forecast and Power Resources

CAC/MSOS witnesses highlighted that Hydro has adopted as an energy supply planning criteria that its system be capable of supplying sufficient energy from its thermal and hydraulic stations, under low flow conditions, to meet firm load demands (including firm exports). CAC/MSOS noted forecast export prices should be reflective of the price of natural gas. The cost of gas-fired generation is expected to increase with resulting increased opportunities for Hydro to export power, according to CAC/MSOS witnesses.

19.1.6 Revenue Requirement and Rates

CAC/MSOS argued that although a rate decrease would have been justified prior to the announcement of the special export profit payment, it would now be difficult to recommend one taking into consideration the impact of the payment on the net income of Hydro. CAC/MSOS suggested the Board consider a modest one-time only dividend of approximately 4% to reduce the net income forecasted for 2003.

19.1.7 Cost of Service

CAC/MSOS argued that one of the key questions in the proceedings is whether the Board should accept the narrow view of cost causation supported by MIPUG, or a broader view adopted by Hydro and supported by CAC/MSOS and CCEP. CAC/MSOS pointed out that historically, export revenues were small relative to domestic revenues and costs, and at that time, export prices were less than domestic rates. Under that scenario, applying the principle of cost causality, efficiency, stability and public acceptability made some sense, as did the allocation of export revenues to generation and transmission only. Given the relatively low level of export revenues, this methodology was not distorting and was reasonably reflective of total costs.

CAC/MSOS pointed out that in the recent past, the export market has changed considerably, both in terms of the magnitude of sales, access to the market and Hydro's planning perspective. Net export revenues now offset over 52% of total generation and transmission costs. Mr. Harper stated the costs of generation and transmission allocated to customers have been increasingly underwritten by export revenues, causing an increasing disparity between costs allocated to high-voltage customers served off the transmission system and lower-voltage customers served off distribution.

Export sales now play a more prominent role in the planning and installation of generation and transmission resources, and rates from export sales are now higher than domestic rates in terms of dollars per megawatt hour. As a consequence, all things being equal, an increase in domestic loads will result in required increases in rates to the extent that export sales are reduced. This change in circumstance raises a fundamental question as to the fairness of the cost allocation process, and in the view of CAC/MSOS, a cost allocation methodology conceived in a far different time cannot endure. Mr. Harper stated since all customer classes contribute to the costs of covering risks associated with export revenues, it would be appropriate that all customer classes share in the benefit from net export revenues. Mr. Harper further noted Hydro's proposed methodology accomplishes this and eliminates the significant distortion the previous methodology created between the costs of generation and transmission versus distribution.

CAC/MSOS recommended not pursuing a separate export class at this point of time, suggesting two fundamental problems. The first problem was an analytical weakness, being that the export rates are set by the market, and since the Board has no jurisdiction over these rates, there is a disconnect between the purpose of cost allocation, which is ultimately connected to the setting of rates based on embedded costs. The second problem was a technical weakness, being the difficulties and issues around the question of how to identify and allocate costs between export and domestic customers. This issue is further complicated by issues around commercial sensitivity of certain data related to export revenues and costs. CAC/MSOS acknowledged that although the concept of an export class of customer did not appear feasible or analytically defensible at the present time, that may change when future generation is built for export purposes.

Mr. Harper agreed with Hydro that capacity is the primary factor in determining the overall investment in transmission facilities and agreed that it was appropriate to classify transmission costs as 100% demand related.

CAC/MSOS also supported the allocation of demand related generation costs on a two CP method, which, in their view, is a major improvement in terms of cost causality. Given concerns regarding confidentiality to eliminate the need to rely on marginal costs and export prices to support the Cost of Service Study, Mr. Harper stated that it might also be appropriate to consider using the 12 CP method to allocate demand related generation costs.

CAC/MSOS also supported its witnesses recommendations for the Board to:

- Approve separating the costs of ancillary services from those associated with generation and transmission;
- Direct Hydro to study and report on whether these are alternative approaches to classifying and allocating generation costs that are more reflective of cost causation; and
- Accept the classification of ancillary services as 100% demand related and their allocation on the basis of 12 CP.

Mr. Harper further stated given the materiality of generation in the overall Cost of Service Study and the changes required with the integration of Winnipeg Hydro, it would be appropriate for Hydro to address the allocation of generation before the next GRA. Mr. Harper urged the Board to direct Hydro to study and report whether there are alternative approaches to classifying and allocating generation that are more reflective of cost causation. Mr. Harper further noted it would be inadvisable to adjust the relative rates of the retail customers based on the RCC results presented in the current Cost of Service Study.

19.1.8 Rate Design

With respect to the Curtailable Rates Program, CAC/MSOS adopted the four concerns of its witness:

1. The current reference discount price cannot be justified over the short, intermediate or long term, in terms of net benefit to firm customers;

2. The process for studying the reference discount price is excessively judgmental, which leads to issues of transparency;

3. The application of the load factor is overly generous and overcompensates customers, especially in light of the potential for new customers whose current patterns of usage may differ and diverge materially from the current customers; and

4. Given the uncertainty with MISO, it would be a more prudent regulatory course to continue with the current program until the position of MISO is more apparent.

CAC/MSOS recommended that the reference discount level be set such that it provides real financial benefits to firm customers over a defined period of not more than 10 years, that the reference discount should be benchmarked relative to a publicly available cross-reference that allows the continuing value of the program to be objectively monitored. Mr. Harper urged the Board to direct Hydro change its methodology for calculating the load factor adjustment basing it strictly on the load factor of the curtailable load. Mr. Harper further urged the Board to direct

Hydro to clarify the implications its association with MISO will have on the value of reserves and required terms and conditions, and file a proposal that reflects the anticipated value of the CRP program. CAC/MSOS further recommended that the current CRP should be extended to November 30, 2003, and no further.

On the subject of Uniform Rates, CAC/MSOS recommended that subclasses within the residential and general service categories be maintained, and there be a specific allocation of export revenues to the residential and general service classes to address the class revenue shortfalls arising from the implementation of uniform rates, sufficient to equate the revenue to cost ratios for zone 2 and zone 3 to zone 1.

Dealing with inverted rates, CAC/MSOS acknowledged that although an interesting concept whose time might come, the debate for inverted rates raises more questions than it resolves, and the time for inverted rates has not come yet. CAC/MSOS therefore recommended that the Board should direct Hydro to report back on the feasibility of adopting alternative rate designs, including inverted rates, for all customer classes that would encourage the efficient use of electrical energy, including an implementation plan for those alternatives considered appropriate.

19.2 CCEP

19.2.1 Capital Expenditures

CCEP agreed with the evidence of witnesses of CAC/MSOS that there appears to be less discipline being exercised over the level of capital expenditure as the overall financial position of Hydro improves. CCEP argued that when constrained by increased payments to the province and wanting to maintain financial targets, one option Hydro could explore, other than increasing rates, would be to control the level of capital expenditures. CCEP argued Hydro's capital budgetary requirements could be lowered if targets for export revenues were lowered and environmental initiatives such as the Selkirk fuel switching to natural gas project were deferred until required by legislation. The justification for certain projects was not rigorous enough and as such, some other justifiable projects might be dropped.

Given the potential savings in operating and administrative expenses and capital expenditures and the potential for better than forecast export revenues, CCEP stated there is a possibility that there would be more funds available to provide rate relief to ratepayers.

19.2.2 Extra Provincial Revenues/Operating and Administrative Expenses

CCEP stated Hydro, since the last GRA, consistently underestimated export revenues citing evidence of CAC/MSOS that export revenue projections are likely conservative and Hydro will likely outperform its current financial forecast. CCEP also stated that Hydro could fare better than forecast and realize some $100 million in savings if operating and administrative expenses were held to a benchmark of target $620 per customer in 2012 as proposed by the witness for CAC/MSOS, rather than $664 per customer currently forecast by Hydro.

19.2.3 Payments to the Province

Although outside the Board's jurisdiction, CCEP urged the Board to consider the financial effects of the increased payments to the Province. At $354 million, just over 25% of Hydro's gross revenues are paid to the Province of Manitoba – amongst the highest in Canada. CCEP further stated the Province, as the shareholder of Hydro, has a role to play in assisting Hydro in reaching its appropriate targets without unduly or adversely affecting ratepayers.

19.2.4 Revenue Requirement And Rates

CCEP argued if the Province and Hydro are confident increased payments to the Province are sustainable, then a modest rate decrease of 1% to 2% to the benefit of ratepayers should also be included. This small rate reduction will still provide Hydro with sufficient reserves to face its greatest risk, the possibility of a five-year drought.

19.2.5 Transmission Tariff

In assessing the Board's jurisdiction over the wholesale Transmission Tariff, CCEP urged the Board to view the legislation broadly, and argued that the provision of power should include a transmission tariff as a necessary component of electrical power.

19.2.6 Cost of Service

CCEP stated that they have taken on the mandate of representing the interests of the GSS customer class, a non-residential customer class, whose demand and energy profiles are often similar to residential customers. CCEP also has a mandate to promote better energy policy and understanding of relevant energy issues. Accordingly, although CCEP advocated on behalf of the GSS customer class, it does not do so to the exclusion of improved energy policy.

In CCEP's view, the principles of equity and improved energy policy, in particular the principle that customer classes should pay rates in accordance with the costs of serving that class, require some redress at the earliest opportunity in favour of the GSS class. CCEP pointed out that the revenue to cost "zone of reasonableness" for Hydro customers has been established by the Board between 0.95 and 1.05, and the different cost of service studies reviewed show the GSS customers to be above the zone of reasonableness. The revenue to cost ratio for the GSS customer class, as a whole, is 1.07, and the non-demand sub-class, representing in excess of 40,000 customers, is 1.09. Since the GSS customer class has been outside the zone of reasonableness for some time, and is the only major customer class that remains outside the zone of reasonableness in accordance with the March 2002 study, CCEP strongly advocates immediate redress.

CCEP accepted Hydro's position that the entire Hydro system, including those portions of the system built to support export sales, are built at the risk of all Hydro domestic customers. It is therefore appropriate to allocate export revenues to all functions of the Cost of Service Study, even though the position of the GSS class is nearly unaffected by the methodological change. Accordingly, CCEP disagrees with the MIPUG argument that the GSL customer class pays rates which are even greater than the GSS class, relative to cost of service, since this argument by MIPUG is based on the former methodology of allocating export revenues. CCEP also discounted the argument by certain MIPUG members that electricity costs comprises a large portion of their costs, arguing that issues of economic development and employment policy should not be an issue for cost of service and rate design proceedings.

CCEP argued that if the Board accepts the position of Hydro, supported by CAC/MSOS and CCEP, that Hydro's proposed COS methodology changes, including allocation of export revenues, are appropriate, then the only class continuing to pay more than their cost of service is the GSS class. CCEP further argued that Hydro's proposal to rebalance rates at the next GRA was unacceptable because the ultimate timing of that application was uncertain. Therefore, CCEP requested the Board to direct Hydro to institute a rate decrease to the GSS class at the conclusion of this proceeding of $5.3 million, or 3.8%, in order to bring the GSS class to the top of the zone of reasonableness of 1.05. Alternatively, a rate reduction in the range of $17.7 million or 12.5% would be required to bring the GSS class to unity. CCEP argued that such a rate decrease could be implemented without changing the rates of other customer classes, and with no adverse effects on other revenue to cost ratios.

19.3 MIPUG

19.3.1 Financial Targets

In MIPUG's view, achieving a 75:25 debt to equity ratio and an interest coverage target of 1.20 were laudable goals from an internal corporate perspective. However, they were not appropriate from a cost of service regulatory perspective. The issue to be considered is whether domestic ratepayers should contribute towards achieving Hydro's internal goals beyond that required to enable Hydro to provide safe and reliable electrical service. MIPUG further noted although existing reserves exceed $1 billion, the debt equity ratio would be impacted by the additional debt related to the purchase of Centra, and as a result, rate increases may be required to maintain the debt equity target.

19.3.2 Risks

MIPUG argued that evidence presented by its witnesses demonstrated the existing reserves are more than adequate to achieve the regulatory goals of running the utility and providing a safe and reliable electrical service, and agreed with the witnesses of CAC/MSOS that the existing reserves are beyond what is necessary to protect against the material risks faced by Hydro and are now more than adequate to deal with the risk of drought.

19.3.3 Capital Expenditures

MIPUG argued Hydro's capital program mirrors the rise in export revenues, and capital expenditures increase when export profits are high. MIPUG stated Hydro's capital expenditures have exceeded their 1996 forecast and are now expected to result in $1 billion more in capital assets by 2006 than was expected at the time of the last GRA. MIPUG argued that given the strong export markets, the trend towards acquiring more and more capital assets is likely to continue, and there is not the same level of restraint in controlling capital expenditures that would be required in lean years. MIPUG stated Hydro's decisions about the amount of capital spending increases the burden on domestic ratepayers due to increased interest costs and depreciation in future years.

19.3.4 Operating and Administrative Expenses

The witnesses for MIPUG noted Hydro has been diligent in operating cost control through most of the period under review and that there have not been any increased operating costs, with the exception of fuel expenses, to parallel the increases in revenues. Mr. Osler and Mr. Bowman indicated throughout most of the period since the last GRA, Hydro has functioned with less operating expenses than in the IFF H 95-2 forecast. The witnesses indicated the forecast future increase in fuel expenses is related to exports because the large amount of fuel to be used by the Brandon Combustion Turbine and the Selkirk Generating Station is used to produce power for export purposes.

19.3.5 Load Forecasts and Power Resources

MIPUG expressed concerned about the potential shift in prioritization within Hydro from a domestic supply-oriented utility to an export sales-oriented utility, which discourages domestic use. MIPUG further stated Hydro is first and foremost here to serve Manitobans and low electrical rates can have the benefit of attracting more industry and associated job opportunities to Manitoba. MIPUG urged the Board to be vigilant, noting Hydro has signalled a shift away from a domestic focus, discouraging the use of power in Manitoba in favour of selling into the more lucrative extra-Provincial markets.

19.3.6 Payments to the Province

MIPUG agreed with CAC/MSOS that Hydro's risks are somewhat overstated and Hydro likely will continue to exceed its current revenue targets. MIPUG noted Hydro is nowhere near becoming a risk to the Province. Mr. Osler, who presented evidence on behalf MIPUG, stated that there has been a substantial improvement in Hydro's forecast revenues and financial situation, compared to the forecasts that were provided in the last GRA. Hydro had exceeded its 1996 forecast export revenues over the 10-year period 1996 to 2006 by some $1.63 billion. MIPUG noted the biggest beneficiary from this improved financial position continues to be the Government of Manitoba rather than domestic ratepayers. MIPUG noted that payments to the Province have increased by $800 million over the 10-year period 1996 to 2006, approximately half of the additional $1.6 billion in export revenues, of which only 11% had actually gone to the general benefit of customers through foregone rate increases.

MIPUG suggested increasing payments to the Province is another risk faced by Hydro and that given the increased payments, the Province does not appear overly concerned with the current progress Hydro makes towards reaching its financial targets. MIPUG is satisfied Hydro could adequately address its risks, even with these increased payments to the Province, and further noted that increased equity levels would likely benefit the Province and not the ratepayers - something MIPUG urged the Board to consider in setting rates that may contribute to increased equity levels.

19.3.7 Revenue Requirement and Rates

MIPUG argued when forecasts are scrutinized, it is apparent that rates should not be increased. In addition, MIPUG argued there is some room for a rate decrease based on the fact that the future outlook suggests that the financial expectations of Hydro will be surpassed and that the current reserves are sufficient to protect customers without requiring them to contribute unnecessarily to the achievement of financial targets. Further, MIPUG argued Hydro has not discharged their onus of establishing that the overall level of rates are just and reasonable.

MIPUG argued that the revenue requirement was overstated by Hydro, the existing level of reserves are more than adequate, and rate decrease in the amount of approximately $15 million could be achieved without increasing rates to other customer classes.

19.3.8 Transmission Tariff

MIPUG argued that since power was not part of the transmission service, the Board's jurisdiction over the tariff did not exist because the Board's jurisdiction was confined to reviewing rates for service for the provision of power.

19.3.9 Cost of Service

MIPUG asserted that Hydro's sales rates have long been set based on the principle of cost causation, and the Board, in fulfilling its responsibility to determine whether the rates charged by Hydro are just and reasonable, must consider the evidence in support of Hydro's revenue requirement and Cost of Service Study. MIPUG further stated that the principle of cost causation has long been used in this jurisdiction because it works, and because it satisfies the ratemaking principles of rate stability, predictability, transparency and public acceptability. MIPUG further argued that the cost causation principle has been refined over the years, has stood the test of time, and there is no reason to depart from that principle today.

With historic revenue to cost ratios generally exceeding 1.05, MIPUG argued for a rate reduction of $15 million to comply with Order 51/96 and to bring the "GSL greater than 100 kV sub-class into the zone of reasonableness. MIPUG argued that a rate freeze does not address the problem of a sub-class paying rates that chronically exceed costs. The witnesses for MIPUG stated there is a demonstrable need and opportunity to provide substantive rate relief to industrial customers who have been paying rates above costs for more than a decade. MIPUG believes the time for solution is now, not only because rate relief for the sub-class is overdue, but also because Hydro's favourable financial situation at the present time creates an opportunity to make progress in bringing the sub-class towards the zone of reasonableness without negatively impacting other customer classes. MIPUG argued that there should be no further delay in rate relief.

MIPUG supported its witnesses' position that some changes to Hydro's Cost of Service Study have departed from cost causation, most notably the treatment of export revenues. The change in the methodology to allocate export revenues is also based on the premise that domestic rates in Manitoba are already as low as they need be, which in MIPUG's view, is a premise that has not been tested or accepted by the Board. MIPUG further argued that no other regulated jurisdiction sets rates other than on cost based principles, and that cost based principles are resilient enough to apply to a range of changing circumstances, including a large increase or decrease in export revenues, and the future construction of Wuskwatim for export purposes. The witnesses for MIPUG stated that it is apparent that the revised methodology has mathematically achieved what Hydro has been unable to achieve through rate revisions over the past decade. MIPUG believes that a primary motivation for Hydro to depart from a cost based allocation methodology is Hydro's desire to bring the revenue to cost ratios for all subclasses closer to unity without having to reduce rates.

In MIPUG's view, the established practice of allocating net export revenues to generation and transmission is consistent with the costs of getting those export sales in the first place. Since generation and transmission are the only functions responsible for supplying the power to the export market, the revenues earned from the export market should be used to offset those costs. In addition, since all Hydro customers use the generation and transmission assets, all customers do receive a benefit from the export revenue allocation, in proportion to each customer classes use of those assets.

MIPUG stated that the non export revenues related changes to Hydro's cost of service methodologies have a relatively minimal impact on the revenue to cost ratios of the subclasses in comparison to the changes in allocation of the net export revenues. The witnesses for MIPUG stated the proposed changes to the Cost of Service Study methodology dramatically redefines the measurement of costs to service customer classes and serves to shift material net costs away from residential customer classes onto industrial customer classes.

MIPUG does not support the creation of a separate export customer class, noting the difficulty in identifying the embedded costs associated with earning the export revenues. MIPUG suggested that the Board could direct Hydro to study further the issue of embedded costs for export revenues, but noted that Hydro was directed to do this in 1999 and did not do so. MIPUG requested that the Boards decision on this matter should not delay the issue of immediate rate relief.

The witnesses for MIPUG noted there is a minimum basis to adopt any of the proposed changes to the Cost of Service Study methodology and that the past cost of service practice remains suitable for the present domestic situation, and therefore recommended retaining the previously approved cost of service approach. The witnesses further stated that the classification of transmission costs on a basis of 100% demand (based on a continued allocation using a 1 CP methodology) may have merit. In addition, they recommended the assignment of some level of "system dividends" to all customers limited to net export revenues net of all embedded costs to serve these loads. However, MIPUG stated the proposed changes to not functionalising HVDC to generation, changes are perhaps not necessary, they can be supported by cost causation, and therefore, MIPUG is not opposing the proposed change. MIPUG also believes that the previous method of classifying each of transmission and generation on the basis of system load factor is preferable over the complicated and unprecedented two-step classification approach proposed by Hydro.

MIPUG also argued that there is only one key time of the year which drives the costs on the Manitoba system, and that is winter. Therefore, under the cost causation principle, the only approach that relies on established principled rationale is the retention of the 1 CP method, based on winter peak load, for both transmission and generation.

With respect to the treatment of Winnipeg Hydro costs and revenues as export sales, MIPUG's witnesses stated this ignores that Winnipeg Hydro's costs and revenues are matched with both entirely related to generation and transmission. Instead, Hydro's proposal results in the costs previously allocated to Winnipeg Hydro's being reallocated back to other customers on the basis of generation and transmission, while the revenues are reallocated back to other customers on the basis of generation, transmission and distribution. This fails to maintain the matching of costs and revenues and fails to reflect cost causation. Accordingly, there is no basis to adopting this interim approach.

19.3.10 Rate Design

With respect to the CRP, the witnesses for MIPUG stated the CRP continues to be the most substantial capacity related Demand Side Management program offered by Hydro and continues to provide value to the utility and its customers in terms of reliability and support of increased high-value firm export sales. MIPUG argued that although the program is relatively small program compared to Hydro's firm rate offerings, it is none the less an important program for certain large industrial customers and strongly supported approval of the Curtailable Rates Program on a permanent basis, subject to the reference discount being adjusted to remove the 12% reduction, to revert to an 80% equivalency factor, and to re-introduce the U.S. exchange rate for the summer generation portion of the benefits.

19.4 TREE/RCM

19.4.1 Capital Expenditures

TREE/RCM argued that Hydro's capital requirements could be lowered if appropriate incentives for reduced energy usage were put in place. With enhanced energy efficiency major new transmission and generation would be unnecessary.

19.4.2 Extra Provincial Revenues

TREE/RCM commended Hydro for its efforts in expanding export sales and stated Hydro had been successful in exploiting opportunities in the North American energy market through their initiative and would like to see Hydro apply such similar talents and skills to an aggressive demand side management policy. TREE/RCM noted that an aggressive demand side management policy and the inverted rate structure may be unduly harsh on the 35% of households in Manitoba reliant on electric heat and that some revenues would be required to mitigate these effects in the short run. Accordingly, some revenues from the export market should be used to enhance energy efficient installations in Manitoba homes.

19.4.3 Load Forecast and Power Resources/Revenue Requirement and Rates

TREE/RCM argued the Board should consider the conservation interest and sustainable development in its rate-setting, and realize that low rates are not necessarily the only or even prime consideration in determining rates. TREE/RCM argued for an overall rate increase to enhance the revenue requirement such that the additional monies could be used for conservation purposes, to enhance DSM programs for residential customers, and, in particular, to finance the transition to the inverted rate structure, especially for residential customers reliant upon electric heat.

19.4.4 Rate Design

The intervention by TREE and RCM was to examine Hydro's operations and rates for their impact on energy conservation and consequent impacts on local and global eco-systems. TREE/RCM stated that Hydro has sales rates that are amongst the lowest in the world, and generally speaking, low rates have a negative impact on energy efficiency because it is affordable to waste energy. Peter Miller, a witness appearing on behalf of TREE/RCM, noted because of the low rates, it is more cost effective, or at least affordable, for the consumer to waste energy than to spend money on energy conservation. TREE/RCM's objective is to get Hydro to adopt policies that better promote principles of sustainability, emphasizing energy conservation and environmental impact reduction and mitigation. Peter Miller, on behalf of TREE/RCM, stated in setting rates Hydro should interpret its mandate as being to secure the best possible "triple-bottom-line" including social, environmental and economic outcomes in its operations. TREE/RCM argued that despite well-expressed intentions, Hydro has not been aggressive in their DSM efforts and in promoting conservation and efficiency.

TREE/RCM brought forward Mr. James Lazar, a regulatory consulting economist, as a witness to address the benefits of adopting an inverted rate structure for residential customers. This would have an initial rate inversion based on the low cost power on the older Winnipeg River System which has no high cost lengthy HVDC transmission lines. It would then be enhanced by an additional rate inversion based on the relative load factors of different size residential customers, which consumes higher cost more modern Northern generation with associated lengthy transmission facilities.

Mr. Lazar, appearing on behalf of TREE/RCM, proposed the adoption of an inverted rate structure. The structure provides each customer a limited amount of power at one lower price per kilowatt hour and additional usage provided at a higher price per kilowatt hour. This contrasts with the current rate structure utilized by Hydro; a declining block structure, where larger customers pay a lower rate per kilowatt hour than smaller customers. Mr. Lazar noted that an inverted rate structure would be appropriate in Manitoba because it communicates the fact that the utility has only a limited supply of low-cost power and distributes the benefit of low-cost hydro resources uniformly among customers while the current declining block rate structure gives the largest users the largest share of the benefit.

Mr. Lazar further stated the inverted rate structure was most appropriate for Hydro, because it has two very different sources of power supply, including the older system on the Winnipeg River that provided a limited supply of low-cost power that could be recovered by the lower block rate and newer more expensive facilities in the north which provide a larger supply of power at higher debt service costs on dams and transmission, that could be recovered at a higher block rate.

Mr. Lazar recommended the following changes be made to implement an inverted rate structure:

- Flatten the customer demand charge to $6.25/month regardless of the connected average.
- Provide each customer an initial block of 250 kW.h/month at a rate of $0.02/kW.h lower than the rate for additional usage. Any further revision could await cost studies on the amount of low cost power and how to distribute export profit.
- Hydro undertake a stratified load research study of its customers and their respective end use electricity to determine if large use customers have a diversified load factor that is different from small customers to develop de-averaged distribution rates.

Mr. Lazar stated the impact on residential customers would result in those using less than 250 kW.h/month realizing a rate decrease of 32%. Large use residential customers (3,000 kW.h/month) would receive an increase of 8% noting further that very few customers would see large changes to their bills. However, as a result, all consumers would have a greater incentive to conserve electricity. Mr. Lazar stated the benefit of such a structure would be approximately a 4-5% less usage per customer than the current residential rate design.

Citing the principles of the Sustainable Development Act which TREE/RCM argued was applicable to Board decisions, TREE/RCM made nine recommendations as follows:

1. An explicit goal be added to the Power Smart program to increase the eco-efficiency of the energy supplied by Hydro.
2. Adopt methods for measuring absolute and relative efficiency performance for different customers and end use classes.
3. Consider for adoption comparative efficiency performance measures.
4. Adopt a more aggressive conservation program for the residential sector.
5. Create a rate regime in which each customer faces tail-block rates that are much closer to the marginal costs of electrical demand and energy.

6. Hydro be directed to file an inverted rate for residential customers holding the customer charge to $6.25, providing the first 250 kW.h block of power at a rate of $0.038/kW.h and additional power at the level needed to make Hydro revenue neutral, estimated to be approximately $0.059/kW.h. Alternatively, the Board could direct Hydro to file an inverted rate structure to give a larger low-cost block to all electric residential customers. A third alternative would be to have a minimum bill to replace the basic charge.

7. Hydro be directed to prepare load research on the relative load shape and load factor of large versus small use residential customers on the generation, transmission and distribution system.

8. Hydro be directed to study options for general service rate design changes to improve the efficiency of pricing information to customers.

9. Hydro be directed to implement an energy efficiency grant program funded from initially up to one quarter of the net export revenues.

TREE/RCM believes that adoption of their recommendations will strengthen the economy of Manitoba and reduce the adverse environmental impacts of energy production and consumption in the region and globally.

19.5 MKO

19.5.1 Rate Design

MKO stated that with the exception of the hydroelectric operations on the Winnipeg River, all of the existing and planned hydroelectric stations of Hydro are within the MKO region and directly affect the rights, interests, communities and traditional territories of the 12 MKO First Nations. MKO generally supports the basic principle of uniform rates established by legislation effective November 1, 2001. MKO further stated that, in respect of the rate rebalancing proposed by some interveners, as long as rates are less than those approved to be effective November 1, 2001, it appears doubtful the Board can alter the rates that went into effect after November 1, 2001 until Hydro applies by way of a GRA to change rates.

With respect to diesel rates, MKO argued that the First Nations communities do not have the financial resources to pay their electricity bills that are being assessed, which creates a circumstance that must be addressed. Although all residential customers in the diesel communities do pay the equivalent zone 1 rate, all consumption over 3,000 kW.h for non-government customers and First Nations facilities are assessed a surcharge, which in the view of MKO, is not consistent with the legislation. Therefore, the intent of uniform rates should be extended to all remaining customers in the diesel communities and all ratepayers, regardless of geography to pay the same rates. MKO further argued that Hydro has not exercised its duty to diesel community customers to promote economy and efficiency in the use of electricity. On that basis, customers have been exposed to substantial costs, and Hydro should assume the costs to the remaining customers in the diesel communities, and provide benefits to those customers that are being shared by other Manitobans.

MKO also suggested that Hydro should aggressively promote demand side management initiatives in the diesel communities, as well as seek alternative sources of supply to serve the communities in a more cost effective way.

MKO issued a subpoena to Mr. Fred Mills of Indian and Northern Affairs Canada to discuss the nature of the funding provided by Indian and Northern Affairs Canada to First Nations in respect of electricity costs. Mr. Mills testified that a formula pays for what is, in essence, a nominal amount of the electricity bills incurred by all First Nations government accounts, which could include schools, police stations, band offices, social services offices, etc. Mr. Mills also testified that Hydro and Indian and Northern Affairs Canada are really not involved in trying to resolve issues arising out of diesel rates.

19.6 PCW

19.6.1 Rate Design

PCW did not speak to the specifics of the status update, but expressed particular interest in the future regulation and public accountability of Hydro. PCW expressed concern for the increasing instances where the Government of Manitoba has denied Manitobans the opportunity for public scrutiny, and referred specifically to the implementation of Uniform Rates, the increases in government charges to Hydro, and the acquisition of Winnipeg Hydro, all done outside of the scrutiny and review of the Board. PCW argued that by far the most effective oversight of Hydro is by public process directed by the Board, and expressed concern that it took over six years for Hydro to apply to the Board for this Status Update hearing. PCW also expressed concern as to what future legislation the government might introduce to further diminish the Board's oversight role.

PCW endorsed the Board's role as a proxy for competition, and stated that Manitobans need regular review of Hydro by an informed watchdog, looking out for the public interest. PCW requested the Board to consider the timing of future reviews of Hydro.

20.0 Presenters' Positions

20.1 HBMS

HBMS is a base metal mining, smelting, and refining business in northern Manitoba. Together with the Mining Association of Manitoba, in 1999 HBMS proposed a variable rate structure that would strengthen its operation in low price periods and share the benefit of high price periods with Hydro. Applying this approach to multiple industries would diversify the utility's risk while ensuring continued strength of the Province's major economic drivers and Hydro customers.

HBMS argued that large power users in this Province have paid a disproportionate portion of the rates charged to Hydro customers over the last decade Hydro's industrial rates should more closely reflect the costs of producing and delivering electricity. A 10% reduction of GSL (over 100 kV) rates, to reflect more closely Hydro's actual cost of service, would have significant beneficial effect on any decision for future energy-intensive capital projects and improve the allocation of rates in the Province and enhance the long-term strength of significant customers and economic drivers of the Manitoba economy.

20.2 Inco

Inco, is a nickel mining company in Thompson. Inco stated increased debt guarantee charges, water use rates, and other cash extractions have resulted in a net transfer to the Manitoba Government. Inco stated that short-term export profits or long-term direct employment in Manitoba is a government policy choice. The 1,400 direct jobs, the support services jobs, and the revenues that they create for Hydro, as well as the taxes this employment generates affects Inco's competitive position. Inco believes that leveraging electricity rates to create and maintain jobs is paramount to protect the ratepayers from volatile energy markets.

Inco pays a demand charge winter ratchet for unused electricity in their scheduled summer shutdown. However, this electricity is sold again on the spot market. Inco suggested that Hydro stop charging twice for the same products.

20.3 Simplot

Simplot is an integrated fertilizer plant which manufactures nitrogen and sulphur based fertilizers as well as a limited range of industrial nitrogen products. Simplot submitted that Hydro costs and rates must remain subject to rigorous examination by the Board. Simplot is concerned that, while Hydro is not requesting a rate increase with this submission, it appears to be positioning itself for a series of rate increases over the immediate future. Simplot was disturbed that the provincial government continues to increase its revenues through special levies on Hydro.

The apparent shift in Hydro's priorities, away from its domestic customers to its export sales is of concern to Simplot. This shift has resulted in Hydro's stated position, in this filing, that domestic electricity rates are "as low as they need to be", and the further assertion that failure to recognize the real value of electricity (i.e., export value) could result in the diversion of energy from profitable export sales to energy intensive domestic industries.

Simplot, together with other members of MIPUG, have maintained that Hydro's rate structures impose an unfair burden on the GSL (over 100 kV) rate class. Hydro's response to the Board's Order, as evidenced by its Prospective Cost of Service Study, has been to develop a new method of service calculation to bring all rate classes with the zone of reasonableness, rather than to adjust the rate structure itself. Reducing firm power costs by 11% would significantly improve the competitive position of all large industrial power users in Manitoba.

Simplot optimistic that Hydro will be able to agree on a proposal that would provide Simplot and other large industrial customers some relief from the demand charge winter ratchet during scheduled plant maintenance shutdowns.

20.4 Nexen

Nexen uses an electrolytic process to produce sodium chlorate, which is used to bleach wood pulp. Nexen requested that the Board consider the presentations made by MIPUG in light of the competitive challenges faced by Nexen, and other energy intensive industries in Manitoba, and help them retain their competitive positions Nexen is currently a curtailable rate program customer. In 1998-2000, Nexen participated in the Industrial Surplus Energy program. However, as export power prices continued to rise, Nexen could not justify participating in the program. The introduction of Curtailable and Industrial Surplus Energy programs in the latter years has also been a positive factor in convincing Nexen's Board of Directors that expansions should occur in Manitoba. Dedication to providing reliable firm power at fair and reasonable rates that reflect cost of service and commitment to innovative rate options that benefit both industry and Hydro are important for the future growth of large industry in Manitoba.

Competitive power rates encourage new growth in the industrial sector. In 1994, the Board's direction to move firm industrial rates as close to cost as possible, and the subsequent 1994 reductions in provincial taxes on manufacturing energy purchases have both had significant positive impacts on Nexen's production in Manitoba, and in Nexen's commitments to capital expansion in this province.

20.5 Presentation of C. Nicolaou

Dr. Nicolaou, a Professor of Economics at the University of Manitoba, stated that the GSS class needs serious attention by the Board. Rates for the GSS class require modification to relieve the sector from a long-term burden.

Growth prospects of the Province rest squarely upon the small business sector. The typical small business is often, by its nature, ill-prepared to deal with adverse conditions. Without pressure from the unrepresented small business sector, and without representations to the Board, the small business sector has the highest revenue cost coverage above the Board's zone of reasonableness. Small business over pays $15-17 million annually.

The simplest, most direct and immediate redress of this long-term disadvantage imposed on small business is for Hydro to be ordered to lower rates for GSS, to bring the RCC to unity. The current and long-standing overpayment by the small business sector must end immediately. However, even this measure would not return past overpayments. Relief should be given to the class which is not only crucial for Manitoba's economic development but is also in need for even the smallest amount of assistance.

21.0 Board Findings

21.1 Operating Results and Financial Forecasts

The Board notes that for the fiscal years 1996 to 2001, Hydro has experienced actual financial results that are dramatically better than the results forecasted in IFF 95-2. The improvement in Hydro's financial results is due primarily to favourable water levels and market conditions, and the successful implementation of a strategy to develop extra-provincial sales opportunities. The Board commends Hydro for its proactive approach and effective execution of a strategy to capitalize on and adapt to the changes in the export market, brought on in part by the introduction of competition in the wholesale export market. Through membership and participation in MAPP, MISO and other key committees and organizations, and proactive marketing efforts, Hydro has been able to represent its interests and more than double the revenues related to extra-provincial sales since 1996. This has resulted in record profits, improved financial strength and stable rate levels for Manitoba consumers. The Board encourages Hydro to continue its active participation in MAPP and MISO and marketing efforts, which have resulted in benefits to Manitoba ratepayers.

Extra-provincial revenues now have a greater prominence within Hydro than in 1996, representing an increasingly significant portion of Hydro's total revenues. Risks related to losing those revenues have also increased substantially since 1996.

The Board notes that IFF MH 01-1 is based upon many assumptions which are beyond the control of Hydro. In the Board's view, IFF MH 01-1 represents a conservative forecast using reasonable assumptions. The IFF assumes a decline in export revenues through 2010 with a subsequent increase in 2011 and 2012. The Board believes Hydro has been conservative in its planning and its projection of future export revenues given historical increases in extra-provincial revenues, the current export market and Hydro's competitive hydraulic power advantage. The Board however recognizes the level of export revenues depends on a number of factors including available water flow, market prices, and a proper balance between demand and supply. Conservative assumptions are, in the Board's view, an appropriate and prudent strategy given the nature and magnitude of the risks involved.

The Board accepts IFF MH 01-1 is a general indication of Hydro's long-term financial direction for decision-making purposes. The Board notes that the IFF does not reflect any future major generation projects within the planning period, nor the impact of the acquisition of Winnipeg Hydro, both of which may significantly impact the financial forecast and plans of Hydro. The Board will direct Hydro to file an updated IFF reflecting new generation in-service dates within the planning period, and the financial consequences of the integration of Winnipeg Hydro's operations by no later than December 31, 2003.

21.2 Financial Targets

The Board has previously stated a debt equity ratio of 85:15 is a reasonable short to medium term financial target and agrees with Hydro that a long-term target ratio of 75:25 is appropriate. The Board notes that the achievement of the 75:25 debt equity target should include a strategy for the reduction of the level of its debt.

The Board remains concerned with the current high level of debt and the additional risk posed to Hydro of incurring higher finance charges due to increases in interest rates and fluctuations in the US exchange rate on its US denominated debt. The Board is particularly concerned with the dramatic increase in long-term debt from $5.17 billion in 1997 to $6.43 billion in 2002, especially during a period of limited major capital expansions in generation or transmission. The Board encourages Hydro to consider appropriate debt minimization strategies. The Board notes the Corporate Strategic Plan includes a reference to reducing debt and improving equity to meet this target. Accordingly, the Board will direct Hydro to file a detailed debt management strategy with the Board by no later than December 31, 2003. This strategy should include the implications of major new generation contemplated within the planning period, and the related financing implications.

The Board is of the view that a gross interest coverage target ratio of 1.20 and the capital coverage target of funding the capital program (with the exception of new generation) from internally generated funds are appropriate financial targets which assist Hydro in achieving its long-term target of 75:25 debt equity ratio. However, the Board is also of the view that once the debt equity target has been reached, the current interest coverage target may, at that time, no longer be required or appropriate, and a lower target should then be considered.

21.3 Risks

In the Board's view a five-year drought represents the greatest threat to Hydro's financial position. It has been estimated that retained earnings reserves of approximately $1.3 billion may be required to withstand the financial impact of such an event. Although the actual amount might be mitigated somewhat by certain strategies, Hydro's net revenues are nevertheless subject to the vagaries of weather and water flows. Establishing an adequate reserve level is an appropriate strategy to mitigate the financial impact of a drought.

If Hydro experiences a drought, most opportunity sales will be foregone, thereby reducing export revenues. The Board generally supports Hydro's conservative approach to forecasting export revenues. The Board notes that although high export revenues have brought positive financial impacts, it has also increased the risk to Hydro. Continued high export revenues may permit Hydro to offset the need for rate increases in the future.

While there may be some risk of an export market collapse due to US legislation, regulatory changes or energy subsidies, amongst other things, there is also a probability of increased market prices, and therefore, increased export revenues. Export revenues on average over the last seven years have been 15% higher than forecast under the mean flow scenario. If this trend continues over the next few years, Hydro will achieve its targeted debt equity ratio earlier than forecasted and a retained earnings level in excess of $1.5 billion. According to Hydro this level of retained earnings should be sufficient to deal with identified risks. As another risk, the Board would agree that higher interest rates could have a modest negative impact on Hydro's financial position, as could higher inflation rate than forecast. Similarly, major system outages could negatively impact Hydro's finances.

21.4 Risk Analysis and Reserve Levels

The Board understands the difficulty of preparing a comprehensive quantitative analysis of all risks facing Hydro, as recommended by Mr. Todd. The Board believes, however, there is merit in quantifying specific reserve provisions required to cover the major contingencies Hydro faces. The specific amounts should be based on a process that identifies and quantifies at least the major risks at a high level. To do otherwise would be tantamount to establishing a reserve provision at an arbitrary amount. Defining specific reserve amounts for contingencies may also help prevent reserve provisions from being depleted for other purposes.

Although each risk has its own financial quantification, one cannot simply consider all risks together as additive, since many of the risks are inter-related. In reviewing risks, Hydro is urged to further examine their inter-relationships.

The Board believes that Hydro should develop a policy to identify a reserve provision amount and, in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in *The Manitoba Hydro Act*. The Board expects that Hydro has most, if not all, of the required data in one form or another as part of its ongoing planning and risk management. The Board will therefore direct Hydro to prepare a document to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro, and file that document with the Board by no later than December 31, 2003. A more disciplined approach to risk quantification can only be beneficial to the financial planning of

Hydro and assist the Board in its rate setting obligations, particularly with regard to the objective of determining an appropriate rate reserve level.

21.5 Capital Expenditures

Order 51/96 recommended that Hydro "stringently limit its capital expenditures where safety and reliability constraints allow and apply itself to reducing long-term debt with urgency." The Board remains concerned with the progressive growth in capital expenditures, and notes the dramatic increase in capital expenditures from $250 million in 1996 to $425 million in 2002. The Board reiterates its concerns expressed in Order 51/96.

The Board is particularly concerned with planned future capital expenditures that are justified primarily by export revenue opportunities. While very few projects are now justified exclusively for export, many projects nevertheless have a substantial export component. Hydro has indicated that certain future major capital projects will initially be for export purposes. The Board directs Hydro to appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts. This information is required to ensure that export revenues are appropriately matched against the full costs of production and to ensure that Hydro's domestic ratepayers do not subsidize export market costs in the future.

Planning studies attracted substantial review in this hearing. Not only was the total amount spent of some $130 million of concern to the Board, but also the amount spent on particular projects (i.e., $34.1 million on Gull, $22.3 million on Wuskwatim). Hydro has agreed to pay for certain costs of the First Nations' participation in planning for new generation stations. Of concern to the Board is the very real likelihood of Hydro paying for what are, in essence, duplicate studies, by undertaking their own studies on aspects of new generating facilities and then paying for the First Nation partner to conduct a similar study. Given that such payments in 2002 are in the range of $1 million per month for the Wuskwatim generating station, and nearly $2 million per month for Gull, the Board urges Hydro to be diligent in how the ratepayers' monies are being spent and minimize such duplication.

21.6 Payments to the Province of Manitoba

Payments to the Province of Manitoba have increased dramatically, which impacts Hydro's revenue requirements. As many of the increases are legislatively enacted, Hydro has no choice but to make such payments. Nevertheless, such dramatic increases in payments have a negative effect on the ability of Hydro to achieve its financial targets, and may ultimately affect the level of rates paid for electricity. That having been said, the Board recognizes that dividend payments similar to the special export profit payments are not uncommon in publicly owned utilities.

Hydro does not intend to increase its sales rates as a result of the special export profit payment, or the increases in water rental rates or the debt guarantee fee. Hydro will be financing its payments to the Province of Manitoba. The costs of borrowing the $288 million for the special export profit payment over the next ten years is $276 million. Therefore, the total impact of that payment alone is $564 million over the next 10 years. Ultimately, future ratepayers will pay the financing costs. The Board encourages Hydro to pursue short-term financing options to pay down this debt expeditiously and reduce the impact of such charges to future domestic ratepayers.

21.7 Finance Expenses

The Board notes that a significant dollar value of transactions are conducted in US dollars including US extra-provincial sales, US sinking fund investment income and finance expenses. In addition, over $2.9 billion or 45% of the Corporation's debt is denominated in US currency, which exposes Hydro to risks related to the change in US exchange rate. The Board further notes that the exposure management program is in place to act as a hedge in protecting Hydro from the significant foreign currency risk related to the change in the US currency. As a result of the program, prior to the change in accounting policy, Hydro had reflected the balance of the US debt, and sinking fund at a designated US exchange rate, which has been significantly below the rates currently experienced. As a result of this policy, the debt of Hydro at March 31, 2001 was valued at approximately $1 billion less in the financial statements than it would have been if the year-end exchange rate had been used to translate the US denominated debt into Canadian dollar equivalent.

The Board notes that as a result of the accounting policy change, US denominated transactions and balances will better reflect the true economic costs and benefits and more clearly reflect the risks faced by Hydro to US denominated transactions and balances, which in the Board's view, are significant.

21.8 Operating Expenses

Although Hydro's operating and administration expenses appear reasonable, the Board encourages Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies.

Corporate performance measures such as the operating and administration costs per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities. Hydro should actively pursue all possible synergy savings in operating and administration expenses as a result of Hydro's recent acquisition of Winnipeg Hydro.

21.9 Transmission Tariffs

The jurisdiction of the Board over transmission tariffs is an area of concern to the Board and parties were requested to address this issue in their closing argument.

The MISO tariff does not apply to the Hydro transmission grid, but only outside the Province. Therefore, there is no provincial authority over the MISO tariff, and accordingly, no role for the Board.

The Board receives its jurisdiction and obligations for Hydro rates mainly from *The Crown Corporations Public Review and Accountability Act*. Rates for services provided by Hydro shall be approved by the Board, which rates for service means the provision of electrical power. Even though Hydro can issue its own tariff under s. 15 of *The Manitoba Hydro Act*, Hydro is still obligated to have such a tariff as a rate for service for the provision of electrical power approved by the Board. Whether the provision of power is bundled or unbundled between generation, transmission and distribution, the Board retains the jurisdiction to approve rates for service if offered in this province.

Accordingly, the Board will direct Hydro to make a separate application to the Board for approval of the Hydro Open Access Transmission Tariff. Hydro is ordered to file such an application by no later than June 30, 2003. Such an application should contain tariff and rate schedules, and a comprehensive explanation of the pricing and costs included in designing the rates.

21.10 Power Resources

Hydro stated that any periodic failure to meet base domestic plus firm export load is unacceptable. Base domestic load growth and firm export load growth are the primary drivers for new and additional power resources. Therefore a strategy to avoid brown-outs under all normal circumstances will result in substantial energy surpluses in most years. This surplus can then be sold as an opportunity sale on the export market.

If Hydro were to employ a median water flow scenario, instead of mean flow, in its energy forecasts, the amount currently available for export could be increased. By employing relatively conservative forecasting processes for supply and demand, Hydro will continue to enjoy more favourable financial results than forecast, except when droughts actually happen. From 1997 to 2001 there was an additional 10,000 GW.h of export energy due to hydraulic generation being above-median water supply, resulting in incremental annual revenues of approximately $200 million. Nevertheless, the Board considers it appropriate for Hydro to continue employing the conservative mean water flow scenario.

The Board notes the concerns expressed by Intervenors that Hydro may be paying less attention to creating competitive opportunities and developing energy conservation initiatives in the domestic market. While the Board encourages Hydro to pursue export markets and the corresponding revenue opportunities, Hydro's primary purpose continues to be the supply power adequate for the domestic needs of the Province.

The Board urges Hydro to explore ways to diversify and supplement its hydraulic generation capabilities by applying an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange, and hydrogen cells. Hydro should give particular consideration to exploring alternatives such as wind turbines for the four remaining diesel generation communities. Here, the back-up diesel power generator is already in place and an alternative energy supply may be justified on either an environmental or cost basis.

Hydro no longer supplies copies of its Power Resource Plan, citing confidentiality due to the increased competitive nature of electricity trading in the US. Should the Board be seized with a needs and justification hearing for major new generating stations, arrangements may need to be made to examine the Power Resource Plan.

21.11 Cost of Service Study

21.11.1 General

A cost of service study is one of the fundamental tools used by utilities in the overall rate design process. Much judgment is applied in completing a cost of service study. The results of a cost of service study are used in designing rates that are fair and equitable to customer classes. Generally, fairness is attained when revenues from each customer class approximates the net allocated costs of serving that class.

Hydro has made numerous changes to its proposed Cost of Service Study since it was last reviewed by the Board in Order 51/96. The Board will direct Hydro to file two cost of service studies; an actual cost of service study for the fiscal year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by no later than September 30, 2003. The following sections contain the Board's comments and directives with respect to changes proposed by Hydro, and requirements for the Cost of Service Studies to be filed with the Board in the future.

21.11.2 Winnipeg Hydro

Hydro has acknowledged that adjustments will be required to the proposed Cost of Service Study to accommodate the recent purchase of Winnipeg Hydro assets by Hydro. Hydro has stated it will have a better understanding of Winnipeg Hydro costs by late 2002. Achieving a precise understanding of detailed customer load and revenue cost information may take longer. Hydro did not rule out that methodological changes to the Cost of Service Study may be required. The

Board expects that the acquisition of Winnipeg Hydro may have a dramatic impact on the RCC's of the various customer classes. The Board also does not accept the methodology applied to Winnipeg Hydro matters in the March 2002 Cost of Service Study. The Board will therefore direct Hydro to treat Winnipeg Hydro customers in the same fashion as current Hydro customers in the March 2003 Actual Cost of Service Study and the March 31, 2004 prospective Cost of Service Study. It is important to know the impact of Winnipeg Hydro on the Cost of Service Study as soon as possible.

21.11.3 Allocation of Export Revenues

A major change to the Cost of Service Study methodology proposed by Hydro is to allocate net export revenues to customer classes on the basis of total allocated costs, being each class's share of generation, transmission and distribution costs.

The Cost of Service methodology approved in Order 51/96 allocates net export revenues to rate classes in proportion to class responsibility for generation and transmission costs. Distribution costs, of which a large percentage is allocated to residential customers, were not part of the allocation formula. It has long been argued by Hydro that it is primarily the generation and transmission assets that create the opportunity for export sales. Therefore, based on accepted cost causation principles, the benefits from export sales in the past were shared by the rate classes in proportion to each rate class' responsibility for generation and transmission costs.

In the public hearing related to Hydro's 1994 GRA, CAC/MSOS submitted that allocation of net export revenues on the basis of total cost responsibility (i.e., generation, transmission and distribution costs) would be more beneficial to the residential class. In 1994 Hydro opposed the CAC/MSOS cost of service methodology that Hydro now proposes in 2002. Hydro's position in 1994 was that export revenues are derived from generation and transmission capacity built to provide firm service to domestic loads, and since the costs of these facilities are allocated totally to domestic rate classes, it is proper to share the export revenues derived from this capacity in proportion to cost responsibility of such classes.

In Order 64/94, the Board stated at page 33, "…Hydro's method of allocating net export revenues is appropriate for Hydro's system, because it proceeds from the principle of cost responsibility rather than mere judgment." The Board further stated "… that it would be inappropriate to allocate any portion of export revenues as an offset to distribution costs within the central system or to costs in the Diesel Zone."

The Board has heard no new evidence at the current hearing to support or justify a departure from the principles of cost causation previously adopted for allocating net export revenues. Because export revenues arise from generation and transmission capacity, the Board believes that it continues to be appropriate to allocate the net export revenues derived from that capacity in proportion to class responsibility for generation and transmission costs.

In the Board's view, many direct and indirect costs related to export power sales are currently not included in Hydro's calculation of net export revenues. The Board notes that this matter was the subject of a recommendation in its March 31, 1988 Report to the Minister, at page 51 and 52, where the Board stated:

> "The Board recommends that revenues and costs related to export sales should be segregated in Hydro's accounting records. Costs include direct costs as well as indirect or allocated costs. The purpose of this segregation is to ensure that the Manitoba ratepayer is not subsidizing export sales.
>
> A possible method would be to treat export sales as a separate customer class in the Cost of Service Study. The result would not be used in designing rates for export sales because of the fact that such sales are open market negotiated sales. The only relevance to the resulting export class revenue/cost ratio would be to ensure that Manitoba customers are not allocated costs related to export."

This Board believes these comments remain appropriate today, and accordingly will direct Hydro to file an actual cost of service study for 2003 and a prospective cost of service study for 2004, that reflects:

(a) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(b) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

These Cost of Service Studies should include the impact of allocating net export revenues determined in accordance with the above directives on the basis of transmission and generation costs. Once these submissions have been filed, the allocation methodologies may require further consideration by the Board.

21.11.4 Functional Changes to the Cost of Service Study

Previously, all transmission lines and stations, including HVDC facilities, were included in the transmission function. In the March 2002 Cost of Service Study, all HVDC assets, with the exception of the Dorsey Converter station, were assigned to the generation function. The Board accepts this methodology and Hydro's reasoning that the primary function of the HVDC facilities is to move energy from the remote generation sites into the backbone transmission system and therefore serve as an extension of the generating facilities.

The Board, however, has some concerns about the exclusion of the Dorsey Converter Station from the HVDC assets assigned to the generation function. While the assignment of the Dorsey Station to the transmission function has relatively minor impacts to revenue cost coverage ratios under current operating circumstances, the Board has concerns this may change as additional generation and transmission facilities are constructed in the future. The Board will expect Hydro to re-evaluate the continued appropriateness of this treatment in the future.

Hydro has also assigned the AC transmission lines that provide power to the northern converter stations as generation. The Board accepts this methodology since these lines are required to bring generated power to the HVDC converter stations in the north.

The Board also accepts Hydro's proposed assignment of only those transmission facilities, which would be recognized for inclusion in Hydro's Transmission Tariff, to the transmission function. Radial transmission facilities, including those with voltages greater than 100 kV, are included in the sub-transmission function.

The Board accepts Hydro's creation of a new ancillary services function necessary to support the transmission of capacity and energy to the load.

21.11.5 Classification Changes to the Cost of Service Study

Hydro's November 2001 Prospective Cost of Service Study used marginal costing to classify generation costs to energy and demand. For reasons of commercial sensitivity, Hydro was unable to provide information supporting its determination of relative marginal costs. Hydro therefore proposed to revert back to the previous methodology. The Board accepts this approach given the commercial sensitivity of marginal cost information.

In the March 2002 revised Cost of Service Study, Hydro returned to the pre 2001 approach and classified total generation and transmission costs (including ancillary services) on the basis of the system load factor. However, in the March 2002 approach, transmission and ancillary services are classified as 100% demand related. The balance of demand related costs are then assigned to generation. This results in a demand to energy classification division of transmission and generation costs of approximately 36% to 64% respectively. If, however, transmission costs are classified as 100% demand and the system load factor is applied to generation costs only, this approach would result in a demand to energy classification division of generation and transmission costs of approximately 48% to 52%.

The Board accepts the classification of transmission assets at 100% demand related, however, the methodology used to classify generation costs is of concern to the Board. Hydro has stated it is prepared to undertake a further review with respect to the appropriate classification of generation costs. The Board will therefore direct Hydro to complete this review of generation cost classification methodologies by December 31, 2003. This review should critically examine the impacts of the various methods of classifying generation costs, and describe how such classification methods would impact the overall rate design process in terms of setting demand and energy charges.

The Board accepts Hydro's proposed methodology with respect to classifying ancillary services as 100% demand.

21.11.6 Allocation Changes to the Cost of Service Study

The process of allocation takes functionalized and classified costs and assigns the costs to the various customer rate classes and subclasses. Hydro has proposed a number of changes in cost allocation methodologies.

In the November 2001 allocation methodology, energy related generation costs were allocated to each customer class according to the class contribution of the highest integrated 50 hour load during the winter and summer seasons. This treatment was changed in the March 2002 where energy related costs of generation were allocated to customer classes on the basis of their share of overall annual energy requirements, the same methodology used in the Cost of Service Study approved in Order 51/96.

The March 2002 Cost of Service Study proposed to allocate generation demand costs on the basis of each class of customer's share of the average of the top 50 coincident load hours during the months of June, July and August and the top 50 coincident load hours during the months of December, January and February (2 CP Methodology). Hydro stated this treatment recognized the value of energy and capacity during the summer and winter seasons. Although the domestic peak continues to occur in winter, loads can be as high as other times of the year, particularly the summer months. With a strong export market during the summer months, transmission and generation assets can be fully utilized at the time of summer peaks. Based on this reasoning, the Board accepts Hydro's methodology to allocate demand related costs of generation on the basis of the 2 CP method.

Hydro has proposed to allocate transmission and ancillary services related costs to customer classes on the basis of the 12 CP method with each month being given equal weight. Hydro argued that this approach is consistent with the treatment in the Transmission Tariff in which transmission pricing in the open access market is based on the 12 CP method. The Board is of the view that allocation of costs on a 2 CP basis would be a stronger correlation to cost causation. Participation in MISO does not oblige Hydro to adopt similar pricing structures for the domestic market. The Board therefore rejects the allocation of transmission and ancillary service costs on the basis of the 12 CP and directs Hydro to allocate these costs on a 2 CP basis similar to that used for the generation demand costs.

The Board also supports the continued practice to allocating DSM costs to the customer classes that receive the benefit.

21.11.7 Future Cost of Service Studies

Given the above comments, the Board has fundamental concerns with both the November and March Cost of Service Study submissions. Therefore, the Board will direct Hydro to file an actual cost of service study for year ending March 31, 2003 by September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by September 30, 2003 reflecting the following:

(a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) Transmission costs, including Dorsey, are classified as 100% demand.

(d) Transmission and ancillary services costs are allocated on the basis of the 2 CP.

(e) Generation demand costs are allocated on the basis of the 2 CP.

(f) Energy related costs of generation are allocated on the basis of class annual energy (Non-Coincident Peak).

(g) HVDC costs (other than Dorsey) are functionalized as generation.

(h) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

(i) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(j) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

21.12 Rate Design

21.12.1 General

Although Hydro did not apply for any changes in rate design, the Board and the Intervenors considered the issues of rate design to be of considerable importance in this status update filing. As part of the Board's review as to whether the rates charged remain just and reasonable, the Board not only examined the overall revenue requirement, but also the cost of service methodology, and the rate structure itself.

The Board is disappointed with the inaction of Hydro to comply with the spirit of Order 51/96 with regard to undertaking a study and reporting to the Board by no later than the next GRA to develop a comprehensive rate design policy. More than six years have elapsed since that directive was issued, and Hydro stated at this hearing that it has no intention of preparing such a study in the near future. Such inaction is a disservice to the many Hydro customers, particularly those who might benefit from such a comprehensive rate design policy.

Having reviewed rate design issues as part of this status update, the Board believes that certain rates require adjustment.

21.12.2 Rates

After examining the overall revenue requirement of Hydro, the Board finds that there is no need for an overall rate adjustment for all customer classes. However, the Board is of the view that rates for certain customer classes should be adjusted.

Much time was spent at the hearing reviewing the Cost of Service Study. A revenue to cost ratio of 1.0 indicates that costs allocated to a customer class equal the revenues earned from that customer class. While unity may be the desired goal, Order 51/96 sets a zone of reasonableness target at 0.95 to 1.05 for revenue to cost coverage ratios. The Board is of the view that this zone of reasonableness of 0.95 to 1.05 continues to be an appropriate target for rate setting purposes.

As demonstrated in the table in Section 17.8.5, certain customer classes and subclasses have consistently remained outside of this zone of reasonableness for long periods of time, in some cases more than 10 years. Therefore, the Board is convinced that directional rate adjustments are appropriate now to address these inequities. Accordingly, the Board will order a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in subclasses greater than 30 kV. Such rate decreases are to be effective April 1, 2003. The Board will direct Hydro to file new rate schedules for Board approval reflecting these rate adjustments.

The Board will also eliminate the winter ratchet over the next two years, which will reduce revenues to Hydro by approximately $3 to 4 million. The Board understands that this change will likely bring the GSM class and GSL subclass less than 30 kV closer to unity. Therefore, no further rate adjustment will be ordered for the GSM or GSL less than 30 kV subclass at this time.

The Board is confident that these rate adjustments will not impact the overall financial strength of Hydro, or its ability to achieve its financial targets.

21.12.3 Inverted Rates and Rate Structure

The declining block structure is largely the result of the historical circumstances of electrification throughout the Province and the construction of major generating plants on the Northern rivers. While the Board is not prepared at this time to support an inverted rate structure, the Board accepts that certain concepts of an inverted rate structure for residential customers may have merit for consideration in the future. The Board compliments both Mr. Lazar and Hydro for preparing thoughtful evidence on this matter and raising interesting new approaches. The Board believes that more study is required before an inverted rate structure can be considered for any customer class. The Board will direct Hydro to prepare a study on the merits of an inverted rate structure across all rate classes including transition and implementation issues. As part of this study, Hydro should evaluate the impact of an inverted rate structure on electric heat customers and residential customers with higher than average loads. This study should be filed with the Board by no later than December 31, 2003.

While the issue of inverted rates was largely confined to residential rates, the Board investigated demand and energy charges levied on larger General Service customers as part of the overall rate design. In the Board's opinion, some of Hydro's demand charges are in the mid to high range as compared to other jurisdictions in Canada, while the energy charges are amongst the lowest in Canada.

The Board is of the belief a lower demand charge and higher energy charge may serve as an impetus to further conservation of electricity since the users may become more aware of their consumption and hence, may attempt to minimize usage. Accordingly, the Board will direct Hydro to prepare a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge and include recommendations and a timetable for possible implementation. The study should be filed with the Board by no later than December 31, 2003.

21.12.4 Winter Ratchet and Limited Use Billing Demand

In the 1996 GRA, Hydro sought to eliminate the winter ratchet with the implementation of seasonal rates. However, with little actual evidence and no customer consultation, the Board did not support the implementation of seasonal rates, and directed further study by Hydro. Since then, the LUBD program was introduced to alleviate some irritants posed by the winter ratchet. The Board is of the view that winter ratchet continues to pose problems for customers unable to benefit from the LUBD program.

The traditional rationale for the winter ratchet is that additional winter capacity to meet peak demand requires significant and costly capital expansions. The winter ratchet is designed to recover capacity costs incurred to meet this peak demand. The current system load runs nearly at capacity throughout the year as any additional capacity beyond domestic use is sold on the export market. Therefore, the Board finds that the use of the winter ratchet is not valid in the current circumstances. Accordingly, the Board will order Hydro to phase out the winter ratchet in two steps. On April 1, 2003, the winter ratchet is to be decreased to 70% of the maximum previous winter demand measured in December 2002, and January and February 2003. On April 1, 2004, the winter ratchet is to be eliminated. The Board will order Hydro to file the resulting rate schedules, for Board approval, prior to the above dates.

The Board will order the LUBD be eliminated on April 1, 2004. All LUBD customers will then revert to the billing rate of their appropriate class. Until April 1, 2004 the LUBD rate option will be considered a temporary rate offering. The Board also expects Hydro to inform all LUBD customers of this decision and its implication. The Board will grant final approval of Order 118/02 which extended the LUBD rate option on an interim ex parte basis.

21.12.5 Time of Use Rates

In Order 51/96 the Board directed Hydro to prepare a comprehensive rate policy including time of use rates which remains outstanding. The Board heard testimony that Hydro continues to install specialized metering equipment for certain general service customers with time of use capability. Accordingly, the Board considers it important to proceed with the development of time of use rates and directs Hydro to prepare a study, including a timetable and a plan for implementation, for a time of use rate program. Such study should also consider time of use rates for general service classes based on a seasonal, weekly, daily and hourly basis, including an evaluation of each alternative. The study should be filed with the Board by no later than December 31, 2003.

21.12.6 Diesel Rates

Any determination of whether rates are just and reasonable must include an examination of rates charged to those customers serviced by Hydro's diesel generation. The Board cannot make a determination on which customer should be included in a specific rate class of government versus non-government or whether a customer has sufficient resources to pay the bill, or funding formulas are appropriate.

During the hearing, Hydro stated it would be filing a separate application for diesel rates in December 2002. Such an application has now been filed and the Board will consider diesel rate issues at a future public hearing to review this filing.

21.12.7 Curtailable Rates

Hydro applied for a new CRP which included only minor variations from the existing curtailable service program. The rationale for curtailments has changed and, as stated by Hydro witnesses, the number of curtailments will likely decrease sharply. However, the Board is reasonably satisfied with the rationale used in the calculation of the Reference Discount.

Hydro has applied for the CRP to be a temporary program with an expiry date of November 30, 2003, given the unknown impact of MISO's requirement and the value of reserves. In the interest of rate stability, the Board will approve the CRP on a permanent basis.

21.12.8 Surplus Energy Program and Interim Ex Parte Orders

The Board will approve, on a final basis, all interim ex parte Orders relating to the DFH, ISE, SEP and CSP programs as attached in Appendix E.

21.12.9 Demand Side Management - Energy Conservation

The Board acknowledges that Hydro's initiatives on DSM since 1989 have achieved approximately 50% of targets set for 2012 of 356 MW and 1,272 GW.h. However, it is the Board's view the new DSM programs may not be effective for achieving DSM targets for 2012.

In this period of potential generation expansion the Board is concerned that Hydro may reduce efforts for DSM. It would appear that other utilities are more proactive in pursuing energy conservation measures. A program target for energy use reduction of 3% does not seem to be sufficiently aggressive.

The Board is of the view that, at present, Hydro provides few incentives for either residential or general service customer energy conservation. Financial incentives such as a movement toward lower demand and higher energy charges could encourage more efficient energy usage. Greater energy conservation within Manitoba opens the door for increased power exports with good financial returns. The Board views this as a positive process, particularly if the exported energy displaces coal or other greenhouse gas producing generation within other jurisdictions.

Therefore, the Board directs Hydro to re-examine the current level of DSM programs and pricing strategies to encourage conservation and develop a program with more aggressive targets to be filed with the Board by December 31, 2003.

Wind power offers potential fuel consumption reductions where the primary source of power is coal, natural gas, propane, or diesel. It can be a lower cost supplier of electricity where a primary fuel-based generator already exists and is available as a full back-up when the wind velocities are too low. The Board directs Hydro to consider the use of wind power in remote diesel electric communities where energy costs are high and file a report with the Board by December 31, 2003.

21.12.10 Future Regulation

The Board recognizes the many parties who expressed frustration with Hydro's absence from public review for over six years. The Board reiterates the statement made in Order 208/02 that Hydro establish a more regular schedule, not exceeding three years, for periodic rate reviews. This regular schedule should improve the efficiency, effectiveness and timeliness of the regulatory process, even if no rate changes are requested. Subject to other specific directives contained herein, the Board will approve Hydro's existing rate schedules to be in effect until March 31, 2006 or until otherwise amended by a further Order of the Board. The Board will direct Hydro to file a GRA for rates to be effective April 1, 2006 whether or not rate adjustments are sought. This directive does not preclude Hydro from filing applications for rate adjustments prior to this date.

22.0 It Is Therefore Recommended That:

1. Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and apply itself to reducing its long-term debt.

2. Hydro be diligent in ensuring it does not pay for duplicate planning studies for new generation projects.

3. Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba, and thereby reduce the impact of such financing charges to future domestic ratepayers.

4. In respect of operating and administration expenses:

   (a) Hydro pursue with vigour meeting the operating and administration cost per customer target of $600 by increasing productivity.

   (b) Hydro continue to participate in benchmarking initiatives.

   (c) Hydro actively pursue all possible synergy savings in operating and administrative expenses as a result of its recent acquisition of Winnipeg Hydro.

5. Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange and hydrogen cells.

23.0 It Is Therefore Ordered That:

1. The interim ex parte Orders listed in Appendix E of this Order BE AND ARE HEREBY CONFIRMED AS FINAL.

2. The Curtailable Rates Program as applied for by Hydro BE AND IS HEREBY APPROVED.

3. Hydro file for Board approval a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect:
   (a) A 1% rate decrease for General Service Small customers;
   (b) A 2% rate decrease for General Service Large customers in subclasses greater than 30 kV; and
   (c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

4. Hydro eliminate the Limited Use Billing Demand Rate option on April 1, 2004 and inform all affected customers of the changes to the winter ratchet and the Limited Use Billing Demand Rate option.

5. Hydro file an application with the Board by no later than June 30, 2003, for approval of Hydro's Open Access Transmission Tariff.

6. Hydro file the following information with the Board by no later than December 31, 2003:
   (a) An updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
   (b) A detailed debt management strategy;
   (c) A study to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro;
   (d) A study on the merits of implementing an inverted rate structure for all customer classes;
   (e) A study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;

(f) A study which considers time of use rates for GS classes based on a seasonable, weekly, daily, and hourly basis;

(g) A review of generation cost classification methodology options;

(h) Re-examine the current level of DSM programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board; and

(i) Consider the use of wind power in remote diesel electric communities and file a report with the Board.

7. Hydro's proposed Cost of Service Study dated March 2002, which includes a number of methodology changes including allocating net export revenues to customer classes on the basis of total allocated costs BE AND IS HEREBY DENIED.

8. Hydro file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects the following:

(a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as is proposed for general service customers; and

(d) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

(e) Transmission costs, including Dorsey are classified as 100% demand.

(f) Transmission and ancillary services costs are allocated on the basis of the 2 CP method.

(g) Generation demand costs are allocated on the basis of the 2 CP method.

(h) Energy related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak).

(i) HVDC costs (other than Dorsey) are functionalized as generation.

(j) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

9. Hydro appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts to ensure that export revenues are appropriately matched against the full costs of production.

10. Hydro establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings.

11. Subject to other specific rate directives contained herein, Hydro's existing rate schedules BE AND ARE HEREBY CONFIRMED, to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

12. Hydro file a General Rate Application for rates to be effective no later than April 1, 2006.

The Public Utilities Board

Chairman

Secretary

THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"G. O. Barron"
Secretary

Certified a true copy of
Board Order 7/03 issued by
The Public Utilities Board

Secretary

Appendix A

Integrated Financial Forecast IFF MH 01-1

Appendix A

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED OPERATING STATEMENT
(x 1,000,000)

For year ending March 31:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
REVENUES:											
General Consumers Revenue											
at approved rates	743	749	762	770	780	789	798	807	818	829	840
additional*	-	-	15	31	48	65	83	102	103	105	106
Winnipeg Hydro	48	48	50	51	52	53	55	56	57	58	58
Extraprovincial	628	553	528	467	454	448	430	425	404	425	427
Other	5	5	5	5	5	5	5	6	6	5	5
	1,424	1,355	1,360	1,324	1,339	1,360	1,371	1,396	1,388	1,422	1,436
EXPENSES:											
Finance Expense	496	504	507	493	497	490	484	478	475	492	491
Depreciation	237	256	269	280	286	296	303	312	317	322	332
Cost of Operations	254	262	266	268	273	278	284	290	295	301	307
Water Rentals	112	101	97	97	97	97	98	98	98	98	98
Tax Expense	40	41	41	42	42	42	42	42	42	42	42
Fuel & Power Purchased	65	81	89	86	75	80	84	90	94	96	102
	1,204	1,245	1,269	1,266	1,270	1,283	1,295	1,310	1,321	1,351	1,372
Net Income	220	110	91	58	69	77	76	86	67	71	64
Special Payment	150	75	63								
Contribution to Retained Earnings	70	35	28	58	69	77	76	86	67	71	64
*Additional General Consumers Revenue			15	31	48	65	83	102	103	105	106
Percentage Increase			2.0%	2.0%	2.0%	2.0%	2.0%	2.0%			
Cumulative percentage Increase			2.0%	4.0%	6.1%	8.2%	10.4%	12.6%	12.6%	12.6%	12.6%
Financial Ratios											
Debt:Equity	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29
Interest Coverage	1.43	1.21	1.18	1.12	1.13	1.15	1.15	1.17	1.13	1.14	1.13
Capital Coverage	1.10	1.05	0.99	1.05	1.06	1.17	0.99	1.20	1.07	1.24	1.61

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED BALANCE SHEET
(x 1,000,000)

For year ending March 31:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ASSETS:											
Plant in Service	8,720	9,267	9,592	9,912	10,206	10,473	10,776	11,110	11,336	11,948	12,221
Accumulated Depreciation	(2,800)	(3,038)	(3,287)	(3,545)	(3,808)	(4,082)	(4,361)	(4,649)	(4,945)	(5,243)	(5,550)
Net Plant in Service	5,920	6,229	6,305	6,367	6,398	6,391	6,415	6,461	6,391	6,705	6,671
Construction in Progress	352	179	218	224	248	294	368	355	472	149	84
Current & Other Assets	2,502	2,456	2,372	2,300	2,272	2,263	2,256	2,267	2,279	2,309	2,363
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
LIABILITIES:											
Long Term Debt (Net)	4,777	5,486	5,898	5,881	6,179	6,085	5,756	5,224	6,009	5,976	5,731
Current & Other Liabilities	2,577	1,927	1,521	1,479	1,143	1,193	1,542	2,035	1,245	1,231	1,366
Contributions in Aid of Construction	269	265	262	259	255	251	247	244	241	238	240
Retained Earnings	1,151	1,186	1,214	1,272	1,341	1,419	1,494	1,580	1,647	1,718	1,781
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
Debt:Equity Ratio	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29

UNDERTAKING #39
Transcript Page #1679-1680

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED FINANCING REQUIREMENTS STATEMENT
(x 1,000,000)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
FUNDS FROM OPERATIONS											
Net Income	220	110	91	58	69	77	76	86	67	71	64
Provision for Depreciation	237	256	269	280	286	296	303	312	317	322	332
Other	9	19	13	16	(6)	(2)	(4)	(7)	(5)	(5)	(11)
	466	385	373	354	349	371	375	391	379	388	385
APPLICATION OF FUNDS											
Capital Expenditures	425	367	376	338	330	318	380	325	355	312	239
Refinancing of LTD	627	757	-	211	-	90	107	3	501	-	-
Sinking Fund Deposit	116	123	87	121	139	137	128	128	206	192	205
Other	80	39	36	19	18	20	20	21	20	21	22
	-	225	63	-	-	-	-	-	-	-	-
	1,248	1,511	562	689	487	565	635	477	1,082	525	466
FINANCING REQUIREMENTS	782	1,126	189	335	138	194	260	86	703	137	81

Appendix B

Capital Expenditure Forecast CEF 01-01

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1) **Appendix B**

(IN MILLIONS OF DOLLARS)

FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
POWER SUPPLY													
NEW GENERATION													
BRANDON COMBUSTION TURBINE	183	92	16										108
HVDC FACILITIES													
HVDC BIPOLE RELIABILITY ENHANCEMENTS	56	3		-	-	-	-	-	-	-	-	-	3
BIPOLE 1 MERCURY ARC VALVES STAGE 3	74	0	2	45	27	-	-	-	-	-	-	-	74
HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5	1	-	-	-	-	-	-	-	-	-	-	1
CONVERTER TRANSFORMER BUSHING REPLACEMENT	7	1	1	2	-	-	-	-	-	-	-	-	3
DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7	1	2	-	-	-	-	-	-	-	-	-	4
BIPOLE 1&2 DC FILTER CAPACITOR REPLACEMENT	5	2	1	-	-	-	-	-	-	-	-	-	3
BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9	1	(0)	-	-	-	-	-	-	-	-	-	0
BIPOLE I & 2 ELECTRODE LINE MONITORING	1	-	1										1
HVDC SYSTEM SWITCHGEAR UPGRADE	3	1	1	1	-								3
HVDC AUXILLIARY POWER SUPPLY	2	1	0	1									2
DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	8		1	-	1	1	1	1	1				8
	-												-
HYDRAULIC REHABILITATION	-												-
GREAT FALLS G.S. REHABILITATION	23	4	9	6	3	0	-	-	-	-	-	-	22
PINE FALLS G.S. REHABILITATION	20	2	2	6	5	1	-	-	-	-	-	-	16
LAURIE RIVER PLANT 1 AND 2 REHABILITATION	17	-	3	1	1	1	-	-	-	-	1	1	6
GRAND RAPIDS G.S. REHABILITATION	96	8		-		-	-	-	-	-	-	-	8
JENPEG G.S. UNIT OVERHAULS (UNITS 1 - 6)	29	0	4	4	0	4	4	4	-	-	-	-	21
POWER SUPPLY DAM SAFETY UPGRADES	15	1	2	2	2	2	-	-	-	-	-	-	10
WINNIPEG RIVER CONTROL SYSTEM	17	2	3	3	-	-	-	-	-	-	-	-	7
LIMESTONE OUTSTANDING WORK	17	0	1	4	-	-	-	-	-	-	-	-	4
WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	7	1	1	1	1	1	1	-	-	-	-	-	4
KETTLE GS - IMPROVEMENTS & UPGRADES	69	1	1	1	0	-	-	-	-	-	-	0	2
KELSEY G.S. IMPROVEMENTS & UPGRADES	15	-	3	10	1	-	1	-	1	-	-	-	15
KETTLE ANNUNCIATION SYSTEM RENEWAL	2	1											1
NELSON RIVER CONTROL	6		2	2	2								6
													-
THERMAL REHABILITATION	-												-
BRANDON G.S. UNIT 5 LIFE EXTENSION	23			2	1	6	1	2	1	3	1	1	17
SELKIRK GS FUEL SWITCHING PROJECT	32	19	13										32
SELKIRK GS LIFE EXTENSION	29		2	15	12	0							29
													-
OTHER	-												-
200MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	9	0	1	1	2	-	-	-	-	-	-	-	5
SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	13	2	1	1	1	1	1	1	1	1	0	1	10
OIL CONTAINMENT	16	0	1	2	1	1	1	1	1	-	-	-	7
FIRE PROTECTION PROJECTS	8	1	3	-	-	-	-	-	-	-	-	-	4
GENERATION TOWNSITE INFRASTRUCTURE		2	3	-	-	-	-	-	-	-	-	-	4
PLANNING STUDY COSTS		41	12	6	5	4	3	5	7	16	26	10	135
													-
DOMESTIC ITEMS - POWER SUPPLY		11	11	11	11	12	12	12	12	13	13	13	131
													-
PROPOSED POWER SUPPLY		**197**	**100**	**124**	**76**	**33**	**24**	**26**	**25**	**32**	**42**	**26**	**705**

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)

Appendix B

(IN MILLIONS OF DOLLARS)

FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
TRANSMISSION AND DISTRIBUTION													
WUSKWATIM TRANSMISSION													
HVDC CONVERSION BIPOLE 3/CONAWAPA TRANSMISSION													
TRANSMISSION FOR GENERATION													
RADISSON - RIEL ± 500kV HVDC LINE	352		3	5	13	14	12	101	76	84	44	-	352
RIEL 230/500kV STATION	98		2	5	6	8	25	31	22				98
													-
INTERCONNECTIONS													-
200MW ONTARIO HYDRO SALE - T/L UPGRADE	5	0	-	-	-	-	-	-	-	-	-	-	0
GLENBORO - RUGBY 230KV LINE	25	13	9	1	1								24
													-
TRANSMISSION													-
NORTHERN AC TRANSMISSION SYSTEM REQUIREMENTS	31	0	2	7	11	9							30
THOMPSON>HERBLET LAKE 230kV TRANSMISSION	53	-	1	1	2	9	22	18	-	-	-	-	53
NORTH CENTRAL MANITOBA PROJECT	18	0		-	-	-	-	-	-	-	-	-	0
FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	6	0	(1)	-	-	-	-	-	-	-	-	-	(1)
HERBLET LAKE > THE PAS 230kV TRANSMISSION	46	-		0	0	1	1	2	7	20	16	-	46
DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	50	0	(0)	-	-	-	-	-	-	-	-	-	(0)
WINNIPEG > BRANDON TRANSMISSION IMPROVEMENTS	37	-	1	3	5	6	10	8	4	-	-	-	37
FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	5			0	3	2	-	-	-	-	-	-	5
RIDGEWAY TRANSFORMER ADDITION	9	-	-	0	1	1	4	3	-	-	-	-	9
ST. VITAL TRANSFORMER ADDITION	9	7	1		-	-	-	-	-	-	-	-	8
DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	2	0	0	-	-	-	-	-	-	-	-	-	0
DORSEY > ST. VITAL 230kV AC TRANSMISSION	8	6	1		-	-	-	-	-	-	-	-	7
DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	26	-	-	-	-	-	-	-	-	-	-	-	-
ROSSER > SILVER 230kV TRANSMISSION	30	0	0	3	7	14	-	-	-	-	-	-	24
NEEPAWA 230 -66kV STN	18	-	-	0	1	8	9	-	-	-	-	-	18
ASSINIBOINE - WILKES AVE 115-24 KV BANK 1 ADDITION	15	1	(2)	-	-	-	-	-	-	-	-	-	(1)
ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	3	-	0	1	2	-	-	-	-	-	-	-	3
RICHER SOUTH 230-66kV TRANSFORMER ADDITION	5	-	0	0	2	2	-	-	-	-	-	-	5
PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29						0	0	1	2	7	16	26
ST. VITAL > STEINBACH 230kV TRANSMISSION	23	-	-	-	0	0	1	3	4	14	-	-	23
RIDGEWAY > SELKIRK 230kV TRANSMISSION	26	-	1	2	4	5	7	6	-	-	-	-	26
SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	33	-	-	-	-	-	1	1	1	2	12	16	33
WINNIPEG AREA TRANSMISSION REFURBISHMENT	8	2	2	1	-	-	-	-	-	-	-	-	4
DORSEY STATION 230kV BREAKER REPLACEMENT	19	0	0	-	-	-	-	-	-	-	-	-	0
DORSEY > US BORDER D602F 500KV AC T/L INSULATOR REPLACEMENT	8	1	1	-	-	-	-	-	-	-	-	-	2
BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	15	4	5	-	-	-	-	-	-	-	-	-	9
DORSEY 230kV BUS ENHANCEMENTS	16	3	4	4	4	2	-	-	-	-	-	-	16
FLIN FLON AREA TRANSMISSION IMPROVEMENTS	22	1	-	3	5	3							12
PINE FALLS-GREAT FALLS 115-66kV SUPPLY	10	2	4	4	0								10
													-
SUBTRANSMISSION	-												-
JENPEG > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12	5	6			-	-	-	-	-	-	-	11
RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	16	0	0	0	2	4	-	-	-	-	-	-	7
PIKWITONEI & THICKET PORTAGE SITE REMEDIATION	6	2	1	-	-	-	-	-	-	-	-	-	2
BIRTLE SOUTH > ROSSBURN 66kV LINE	6	-	0	0	4	2	-	-	-	-	-	-	6
ST. BONIFACE PLESSIS Rd 115-25KV STATION	16	0	(2)	-	-	-	-	-	-	-	-	-	(1)
ROSSER - OAK POINT 115-24KV STATION	21	-	-	-	-	-	0	2	2	13	4	-	21

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)

Appendix B

(IN MILLIONS OF DOLLARS)

FOR THE YEARS 2001/02 TO 2011/12

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
ROSSER - OAK POINT BANK 2 ADDITION	10	-	-	-	-	-	-	-	1	6	3	-	10
ST. BONIFACE PLESSIS Rd BANK 2 ADDITION	3	0	2	0	-	-	-	-	-	-	-	-	2
NEEPAWA 66KV SYSTEM	4	-	-	0	4	-	-	-	-	-	-	-	4
RESTON/GLENBORO CAPACITY INCREASE	6	3	1	-	-	-	-	-	-	-	-	-	4
ST. LEON 230-66KV TRANSFORMER ADD'N AND IPL EXPANSION	6	4	0	0	-								5
BRANDON CROCUS PLAINS 115-24kV BANK ADDITION	8	1	-	-	-	4	2	0	-	-	-	-	8
BRERETON LAKE STATION AREA	7	1	1	2	0	0	1						7
	-												-
DISTRIBUTION	-												-
VIRDEN AREA DISTRIBUTION CHANGES	15	2	1	1	1	-	-	-	-	-	-	-	6
DEFECTIVE RINJ CABLE REPLACEMENT	8	1	2	2	2	1	-	-	-	-	-	-	7
PAINT LAKE FEEDER	2	2	-										2
													-
COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY	-												-
MICROWAVE RADIO REPLACEMENTS	141	13	41	23	8	28	7	-	-	-	-	-	120
MAPINFO IMPLEMENTATION	33	4	3	-	-	-	-	-	-	-	-	-	6
	-												-
OTHER	-												-
SITE REMEDIATION	10	2	2	1	0	-	-	-	-	-	-	-	5
OIL CONTAINMENT	4	1	1	1	0	-	-	-	-	-	-	-	4
													-
DOMESTIC ITEMS - TRANSMISSION AND DISTRIBUTION		61	68	70	72	73	75	77	79	81	83	84	822
PROPOSED TRANSMISSION AND DISTRIBUTION		**142**	**161**	**142**	**159**	**195**	**177**	**253**	**197**	**221**	**169**	**116**	**1,930**
CUSTOMER SERVICE & MARKETING													
DEMAND SIDE MANAGEMENT CAPITAL COSTS		11	14	22	22	19	16	13	12	12	12	8	162
	-												-
AUTOMATIC METER READING IMPLEMENTATION	31	2	3	3	3	3	3	3	6	2	0	-	31
	-												-
DOMESTIC ITEMS - CUSTOMER SERVICE		44	45	48	49	50	51	52	54	55	56	57	560
													-
													-
PROPOSED CUSTOMER SERVICE & MARKETING		**57**	**62**	**73**	**74**	**72**	**71**	**68**	**72**	**69**	**69**	**64**	**752**
FINANCE & ADMINISTRATION													
	-												-
CORPORATE BUILDING PROGRAM		7	8	8	8	8	22	10	8	8	8	8	100
	-												-
CUSTOMER INFORMATION SYSTEM	11	-	4	7	0	-	-	-	-	-	-	-	10
													-
HUMAN RESOURCE MANAGEMENT SYSTEM	13		12	1									13
													-
DOMESTIC ITEMS - FINANCE & ADMINISTRATION		22	21	21	22	22	23	24	24	25	25	25	253
													-
PROPOSED FINANCE & ADMINISTRATION		**29**	**45**	**37**	**29**	**30**	**45**	**33**	**32**	**32**	**33**	**33**	**377**
PROPOSED CAPITAL EXPENDITURES (ELECTRIC)		**425**	**367**	**376**	**338**	**330**	**318**	**380**	**325**	**355**	**312**	**239**	**3,764**

Appendix C

Revenue Cost Coverage Analysis – Schedule A-1

Manitoba Hydro
Retail Prospective Cost Of Service Study
March 31, 2002
Revenue Cost Coverage Analysis

S U M M A R Y

Class	Total Cost ($000)	Class Revenue ($000)	Contribution To Reserves ($000)	Revenue Cost Coverage %	Net Export Revenue ($000)	Total Revenue ($000)	Contribution To Reserves ($000)	RCC % Current Rates
Residential	533,184.3	306,544.7	(226,639.5)	57.5%	207,789.6	514,334.4	(18,849.9)	96.5%
General Service - Small	207,096.3	141,827.1	(65,269.2)	68.5%	79,973.3	221,800.4	14,704.1	107.1%
General Service - Medium	117,575.1	77,393.3	(40,181.9)	65.8%	45,402.3	122,795.6	5,220.5	104.4%
General Service - Large	317,203.9	193,745.6	(123,458.2)	61.1%	123,352.9	317,098.5	(105.4)	100.0%
Interruptible	4,237.1	4,115.2	(121.9)	97.1%	-	4,115.2	(121.9)	97.1%
Area & Roadway Lighting	15,589.7	13,769.2	(1,820.5)	88.3%	2,113.4	15,882.6	292.9	101.9%
Total General Consumers	1,194,886.4	737,395.2	(457,491.2)	61.7%	458,631.5	1,196,026.6	1,140.2	100.1%
Winnipeg Hydro	-	-	-	0.0%	-	-	-	0.0%
Net Export Revenue	-	461,413.9	461,413.9	0.0%	(461,413.9)	-	-	0.0%
Total Central System	1,194,886.4	1,198,809.1	3,922.7	100.3%	(2,782.4)	1,196,026.6	1,140.2	100.1%
Diesel	7,118.8	3,196.1	(3,922.7)	44.9%	2,782.4	5,978.6	(1,140.3)	84.0%
Total System	1,202,005.2	1,202,005.2	-	100.0%	-	1,202,005.2	-	100.0%

Appendix D

Revenue Cost Variance Analysis – Table D-1

Prospective Cost of Service Study for 2002
Detailed Variance Analysis
2002 PCOSS vs Final 2002 Alternate Scenario

	Residential	**GSS**	**GSM**	**GSL**	**S/L**	**Wpg Hydro**
2002 Prospective Cost of Service (Previous Methodology)	***88.4%***	***105.8%***	***107.3%***	***110.8%***	***97.6%***	***117.3%***
Impact of Changes on RCCs due to the following variables*:						
(1) HVDC (excl Dorsey) as Generation & Ancillary Services	-0.1%	0.0%	0.1%	0.2%	0.1%	0.1%
(2) Transmission 100% Demand	-1.6%	-0.5%	1.0%	4.2%	1.4%	-2.4%
(3) Transmission - Avg 12 monthly Peaks	1.7%	0.0%	-1.4%	-3.3%	1.6%	-1.1%
(4) Gen reclassification & allocation on seasonal demand	-0.1%	1.2%	2.1%	0.8%	-1.5%	-9.6%
(5) Removal of Winnipeg Hydro as a customer class	0.8%	-0.2%	-0.1%	-0.5%	0.3%	-104.3%
(6) Allocation of export revenue	7.4%	0.8%	-4.6%	-12.2%	2.4%	0.0%
Total Impact on RCCs	8.1%	1.3%	-2.9%	-10.8%	4.3%	-117.3%
2002 Prospective Cost of Service Study - REVISED	*96.5%*	*107.1%*	*104.4%*	*100.0%*	*101.9%*	*0.0%*

Appendix E

Interim Ex Parte Orders

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
09/09/98	120/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	Until confirmed or otherwise by a further Order of the Board following a public hearing.
16/09/98	122/98	“ “ “ “	“ “ “ “ “ “	“ “
23/09/98	124/98	“ “ “ “	“ “ “ “ “ “	“ “
30/09/98	129/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
07/10/98	131/98	“ “ “ “	“ “ “ “ “ “	“ “
14/10/98	133/98	“ “ “ “	“ “ “ “ “ “	“ “
21/10/98	134/98	“ “ “ “	“ “ “ “ “ “	“ “
28/10/98	135/98	“ “ “ “	“ “ “ “ “ “	“ “
04/11/98	142/98	“ “ “ “	“ “ “ “ “ “	“ “
10/11/98	146/98	“ “ “ “	“ “ “ “ “ “	“ “
18/11/98	150/98	“ “ “ “	“ “ “ “ “ “	“ “
25/11/98	151/98	“ “ “ “	“ “ “ “ “ “	“ “
02/12/98	156/98	“ “ “ “	“ “ “ “ “ “	“ “
09/12/98	157/98	“ “ “ “	“ “ “ “ “ “	“ “
16/12/98	159/98	“ “ “ “	“ “ “ “ “ “	“ “
23/12/98	164/98	“ “ “ “	“ “ “ “ “ “	“ “
24/12/98	167/98	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1998	“ “
30/12/98	168/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
06/01/99	2/99	“ “ “ “	“ “ “ “ “ “	“ “
08/01/99	3/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 1999	“ “
13/01/99	5/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
20/01/99	10/99	“ “ “ “	“ “ “ “ “ “	“ “
27/01/99	17/99	“ “ “ “	“ “ “ “ “ “	“ “
03/02/99	19/99	“ “ “ “	“ “ “ “ “ ”	“ “
08/02/99	21/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 1999	“ “
10/02/99	23/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
17/02/99	25/99	“ “ “ “	“ “ “ “ “ “	“ “
24/02/99	26/99	“ “ “ “	“ “ “ “ “ “	“ “
03/03/99	27/99	“ “ “ “	“ “ “ “ “ “	“ “
10/03/99	28/99	“ “ “ “	“ “ “ “ “ “	“ “
10/03/99	29/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	“ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
			Curtailable Service Program Reference Discount for March 1999	
17/03/99	41/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
24/03/99	54/99	“ “ “ “	“ “ “ “ “ “	“ “
31/03/99	56/99	“ “ “ “	“ “ “ “ “ “	“ “
07/04/99	57/99	“ “ “ “	“ “ “ “ “ “	“ “
12/04/99	60/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 1999	“ “
14/04/99	63/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
21/04/99	71/99	“ “ “ “	“ “ “ “ “ “	“ “
28/04/99	72/99	“ “ “ “	“ “ “ “ “ “	“ “
28/04/99	73/99	Hydro – Curtailable Rates Program	Interim Curtailable Service Program Order	???????????
05/05/99	83/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
10/05/99	85/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 1999	“ “
12/05/99	86/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
19/05/99	88/99	“ “ “ “	“ “ “ “ “ “	“ “
26/05/99	89/99	“ “ “ “	“ “ “ “ “ “	“ “
02/06/99	98/99	“ “ “ “	“ “ “ “ “ “	“ “
09/06/99	101/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 1999	“ “
09/06/99	102/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
16/06/99	111/99	“ “ “ “	“ “ “ “ “ “	“ “
23/06/99	114/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
30/06/99	119/99	“ “ “ “	“ “ “ “ “ “	“ “
07/07/99	122/99	“ “ “ “	“ “ “ “ “ “	“ “
14/07/99	139/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 1999	“ “
14/07/99	140/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
21/07/99	142/99	“ “ “ “	“ “ “ “ “ “	“ “
28/07/99	145/99	“ “ “ “	“ “ “ “ “ “	“ “
04/08/99	147/99	“ “ “ “	“ “ “ “ “ “	“ “
11/08/99	153/99	“ “ “ “	“ “ “ “ “ “	“ “
11/08/99	154/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	“ “

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DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
			Curtailable Service Program Reference Discount for August 1999	
18/08/99	155/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
25/08/99	156/99	" " " "	" " " " " "	" "
01/09/99	157/99	" " " "	" " " " " "	" "
07/09/99	160/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 1999	" "
08/09/99	161/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/09/99	162/99	" " " "	" " " " " "	" "
22/09/99	164/99	" " " "	" " " " " "	" "
29/09/99	165/99	" " " "	" " " " " "	" "
06/10/99	166/99	" " " "	" " " " " "	" "
12/10/99	169/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 1999	" "
13/10/99	170/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
20/10/99	171/99	" " " "	" " " " " "	" "
27/10/99	172/99	" " " "	" " " " " "	" "
03/11/99	178/99	" " " "	" " " " " "	" "
08/11/99	184/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 1999	" "
10/11/99	185/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/11/99	196/99	" " " "	" " " " " "	" "
23/11/99	198/99	" " " "	" " " " " "	" "
01/12/99	201/99	" " " "	" " " " " "	" "
07/12/99	203/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1999	" "
08/12/99	205/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/12/99	209/99	" " " "	" " " " " "	" "
22/12/99	216/99	" " " "	" " " " " "	" "
29/12/99	217/99	" " " "	" " " " " "	" "
5/1/00	1/00	" " " "	" " " " " "	" "
7/1/00	2/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2000	" "
12/1/00	3/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement	" "

DATE	**BOARD ORDER NO.**	**FILE NAME**	**SUBJECT MATTER**	**TO BE BROUGHT FORWARD**
			Energy Rate, Schedule B-2	
19/1/00	4/00	“ “ “ “ “	“ “ “ “ “ “	“ “
26/1/00	12/00	“ “ “ “ “	“ “ “ “ “ “	“ “
2/2/00	15/00		“ “ “ “ “ “	“ “
8/2/00	17/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2000	“ “
9/2/00	18/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
16/2/00	20/00	“ “ “ “ “	“ “ “ “ “ “	“ “
23/2/00	23/00	“ “ “ “ “	“ “ “ “ “ “	“ “
1/3/00	35/00	“ “ “ “ “	“ “ “ “ “ “	“ “
6/3/00	37/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2000	“ “
8/3/00	38/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
15/3/00	40/00	“ “ “ “ “	“ “ “ “ “ “	“ “
22/3/00	42/00	“ “ “ “ “	“ “ “ “ “ “	“ “
29/3/00	50/00	“ “ “ “ “	“ “ “ “ “ “	“ “
05/04/00	52/00	“ “ “ “ “	“ “ “ “ “ “	“ “
10/04/00	53/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2000	“ “
12/04/00	54/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
19/04/00	60/00	“ “ “ “ “	“ “ “ “ “ “	“ “
26/04/00	61/00	“ “ “ “ “	“ “ “ “ “ “	“ “
03/05/00	63/00	“ “ “ “ “	“ “ “ “ “ “	“ “
08/05/00	64/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2000	“ “
10/05/00	68/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
17/5/00	70/00	“ “ “ “ “	“ “ “ “ “ “	“ “
24/5/00	75/00	“ “ “ “ “	“ “ “ “ “ “	“ “
31/5/00	76/00	“ “ “ “ “	“ “ “ “ “ “	“ “
2/6/00	77/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2000	“ “
7/6/00	78/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
14/6/00	79/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
21/6/00	88/00	“ “ “ “ “	“ “ “ “ “ “	“ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
28/6/00	89/00	“ “ “ “ “	“ “ “ “ “ “	“ “
5/7/00	96/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
11/7/00	104/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2000	“ “
12/7/00	106/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
19/7/00	111/00	“ “ “ “ “	“ “ “ “ “ “	“ “
26/7/00	113/00	“ “ “ “ “	“ “ “ “ “ “	“ “
2/8/00	116/00	“ “ “ “ “	“ “ “ “ “ “	“ “
8/8/00	117/00	Hydro – Monthly Reference Discount	An application by Manitoba Hydro for Interim Ex parte Approval of Curtailable Service Program Reference Discount for August 2000	“ “
9/8/00	118/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
16/8/00	119/00	“ “ “ “ “	“ “ “ “ “ “	“ “
23/8/00	121/00	“ “ “ “ “	“ “ “ “ “ “	“ “
30/8/00	122/00	“ “ “ “ “	“ “ “ “ “ “	“ “
5/9/00	124/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2000	
6/9/00	125/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
13/9/00	126/00	“ “ “ “	“ “ “ “ “ “	“ “
20/9/00	129/00	“ “ “ “	“ “ “ “ “ “	“ “
27/9/00	131/00	“ “ “ “	“ “ “ “ “ “	“ “
4/10/00	133/00	“ “ “ “	“ “ “ “ “ “	“ “
10/10/00	134/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2000	“ “
11/10/00	135/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
18/10/00	136/00	“ “ “ “	“ “ “ “ “ “	“ “
25/10/00	139/00	“ “ “ “	“ “ “ “ “ “	“ “
1/11/00	144/00	“ “ “ “	“ “ “ “ “ “	“ “
7/11/00	145/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2000	“ “

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DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
8/11/00	147/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
15/11/00	148/00	“ “ “ “	“ “ “ “ “ “	“ “
22/11/00	149/00	“ “ “ “	“ “ “ “ “ “	“ “
29/11/00	150/00	“ “ “ “	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule SEP-1	“ “
6/12/00	155/00	“ “ “ “	“ “ “ “ “ “	“ “
6/12/00	156/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2000	
13/12/00	159/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
20/12/00	163/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
27/12/00	164/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
3/1/01	1/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
9/1/01	3/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2001	“ “
10/1/01	5/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
17/1/01	9/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	“ “
24/1/01	12/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
31/1/01	16/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
6/02/01	19/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2001	“ “
7/02/01	23/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
14/02/01	29/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
21/02/01	30/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
28/02/01	31/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
06/03/01	34/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2001	“ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
07/03/01	35/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
14/03/01	47/01	“ “ “ “	“ “ “ “ “ “	“ “
21/03/01	58/01	“ “ “ “	“ “ “ “ “ “	“ “
28/03/01	60/01	“ “ “ “	“ “ “ “ “ “	“ “
4/4/01	62/01	“ “ “ “	“ “ “ “ “ “	“ “
11/04/01	72/01	“ “ “ “	“ “ “ “ “ “	“ “
12/04/01	73/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2001	“ “
18/04/01	74/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “
25/04/01	76/01	“ “ “ “	“ “ “ “ “ “	“ “
2/5/01	79/01	“ “ “ “	“ “ “ “ “ “	“ “
7/5/01	85/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2001	“ “ “
9/5/01	86/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
16/5/01	88/01	“ “ “ “	“ “ “ “ “ “	“ “ “
23/5/01	89/01	“ “ “ “	“ “ “ “ “ “	“ “ “
30/5/01	90/01	“ “ “ “	“ “ “ “ “ “	“ “ “
04/06/01	92/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2001	“ “ “
06/06/01	93/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
13/06/01	96/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
20/06/01	102/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
27/06/01	103/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
4/7/01	105/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/7/01	110/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2001	“ “ “
11/7/01	111/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
18/7/01	112/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
25/7/01	115/01	“ “ “ “	“ “ “ “ “ “	“ “ “
1/8/01	120/01	“ “ “ “	“ “ “ “ “ “	“ “ “
8/8/01	121/01	“ “ “ “	“ “ “ “ “ “	“ “ “
8/8/01	122/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for August 2001	“ “ “
15/8/01	123/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
22/8/01	128/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
29/8/01	131/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ ” “
5/9/01	133/01	“ “ “ “	“ “ “ “ “ “	“ “ “
10/9/01	140/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2001	“ “ “
12/9/01	142/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
19/9/01	144/01	“ “ “ “	“ “ “ “ “ “	“ “ “
26/9/01	146/01	“ “ “ “	“ “ “ “ “ “	“ “ “
03/10/01	148/01	“ “ “ “	“ “ “ “ “ “	“ “ “
10/10/01	151/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2001	“ “ “
10/10/01	152/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
17/10/01	162/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
24/10/01	165/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
31/10/01	169/01	“ “ “ “	“ “ “ “ “ “	“ “ “
5/11/01	171/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2001	“ “ “
7/11/01	175/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
14/11/01	176/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
21/11/01	181/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
28/11/01	183/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
05/12/01	186/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/12/01	188/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2001	“ “ “
12/12/01	190/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
19/12/01	191/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
27/12/01	193/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
02/01/02	4/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
07/01/02	5/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2002	“ “ “
09/01/02	6/02	Hydro – ISE, Spot Market Replacement Energy Rate,	Application by Manitoba Hydro for an Interim Ex Parte Order	“ “ “

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DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
		Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Approving Surplus Energy Program Rates, Schedule Sep-1	
16/01/02	8/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/01/02	11/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
30/1/02	13/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
1/02/02	17/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2002	" " "
06/02/02	19/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
13/02/02	29/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/02/02	30/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/02/02	31/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
4/3/02	32/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2002	" " "
6/3/02	35/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
13/3/02	42/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/3/02	51/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/3/02	54/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
02/4/02	55/02	Hydro – '02 GRA – Vol. IV & Curtailable Rate Program	Application by Manitoba Hydro for an Interim Ex Parte order Approving the Curtailable Rate Program	" " "
03/4/02	56/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
09/4/02	57/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2002	" " "
10/4/02	58/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
17/4/02	71/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
24/4/02	73/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
1/5/02	74/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
6/5/02	80/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2002	" " "
8/5/02	81/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
15/5/02	83/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "

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DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
22/5/02	85/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
29/5/02	88/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
5/6/02	89/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
11/6/02	116/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2002	“ “ “
12/6/02	117/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
12/6/02	118/02	An Application by Manitoba Hydro for Interim Ex Parte Approval of the Limited Use of Billing Demand Rate Option	Hydro -- Application for Interim Ex Parte Approval for Continuation of the Limited Use of Billing Demand Rate	“ “ “
19/6/02	119/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
26/6/02	121/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
3/7/02	124/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/7/02	127/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
10/7/02	128/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2002	“ “ “
17/7/02	130/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
24/7/02	132/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
31/7/02	137/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
2/8/02	138/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for August 2002	“ “ “
7/8/02	140/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
14/8/02	153/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
21/8/02	155/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
28/8/02	156/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
4/9/02	157/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “
6/9/02	162/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2002	“ “ “
11/9/02	165/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	“ “ “

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DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
18/9/02	167/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
25/9/02	169/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
2/10/02	171/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
7/10/02	177/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2002	" " "
9/10/02	178/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
16/10/02	184/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/10/02	186/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
30/10/02	187/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
6/11/02	190/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
12/11/02	193/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2002	" " "
13/11/02	194/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
20/11/02	197/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
27/11/02	198/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
4/12/02	204/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
10/12/02	213/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2002	" " "
11/12/02	214/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
18/12/02	220/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
23/12/02	221/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
31/12/02	222/02	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
8/1/03	1/03	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. V of V	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	" " "
8/1/03	2/03	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2003	" " "

Tab 32

PUB MFR 154
Bipole III

Provide a table of Bipole III cost estimates corresponding to each CEF beginning with CEF06 through to CEF16, broken down by Transmission Line, Converter Stations, Collector Lines, and Community Development Initiative.

Figure 1 below contains the Bipole III cost estimates corresponding to each CEF from CEF06 to CEF16.

Figure 1. Bipole III Capital Expenditure Forecast

Bipole III Capital Expenditure Forecast
CEF06-CEF16
(in millions of dollars)

	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10*	CEF-11	CEF-12	CEF-13	CEF-14	CEF-15	CEF-16
Bipole III - Transmission Line	709	1,082	1,082	1,082	1,082	1,260	1,260	1,260	1,655	1,655	1,958
Bipole III - Converter Stations	1,171	1,166	1,166	1,166	1,166	1,829	1,829	1,829	2,675	2,675	2,781
Bipole III - Collector Lines	-	-	-	-	-	191	191	191	260	260	247
Bipole III - Community Development Initiative **	-	-	-	-	-	-	-	-	62	62	57
Bipole III Reliability	**1,880**	**2,248**	**2,248**	**2,248**	**2,248**	**3,280**	**3,280**	**3,280**	**4,653**	**4,653**	**5,042**

*An update to the cost estimate for CEF10 was approved in March 2011 which is reflected in CEF11.

** CDI was included in CEF13, but not within the Bipole III Total Project Cost ($3,280). The amalgamation of CDI into the Bipole III project occurred in CEF14.

Tab 33

MANITOBA	Board Order 116/08
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 29, 2008
Edited for format and typographical errors only August 25, 2008 Further amended September 4, 2008	

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS

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Executive Summary

Manitoba Hydro's (MH, the Corporation or the Utility) 2008/09 General Rate Application (GRA) was heard by the Public Utilities Board (Board) in the spring of 2008, with Board Order 90/08 released on June 30, 2008 to take effect July 1.

The Board further advised that Order 90/08 would be followed by another Order, one that would provide further direction on a number of other significant matters, and, as well, provide necessary background information and detailed rationale for the rate changes provided by Order 90/08.

Order 90/08 provided certain rate and other directions to the Corporation, as indicated elsewhere in this Order. Order 90/08 is available through the Board's office or by viewing its website, www.pub.gov.mb.ca.

With respect to "further direction", this Order contains various directives to provide new and revised information to the Board in respect of MH's:

- Integrated Financial Forecasts;
- Capital Expenditure Forecasts;
- Load Forecast and Power Resource Plan;
- Export Program;
- International Financial Reporting Standards Implementation;
- Benchmarking Study of Key Performance Metrics;
- Asset Condition Assessment Study;
- Terms of Reference for a Review of MH's Capital Program;
- Quantified Risk Analysis;
- Demand Side Management ("Power Smart" program enhancements);
- Green House Gas Reduction Strategy;
- Low-Income Programs, including a Bill Assistance Program;
- Cost of Service Study (COSS) Revisions;
- Rate Design Revisions;
- MH Diesel Rate Zone; and
- Energy Intensive Industry Rate Proposal.

Executive Summary

Detailed directives and recommendations are found in the last sections of this Order.

For all the reasons referred to in this Order and Order 90/08, the Board approved a 5% across-the-board rate increase as of July 1, 2008 that was larger than the Corporation sought, and, as well, indicated that a further 4% increase may be granted as of April 1, 2009 following the Board's review of additional information requested in this Order. As well, the Board accepted MH's forecast that its net income for the fiscal year 2007/08 will exceed $300 million, and that water conditions into fiscal 2008/09 were excellent, suggesting that another reasonably good net income result may be expected for fiscal 2008/09.

Order 90/08 also advised of the Board's concern with the scale of capital expenditures and new debt now planned over the next 15 years. There is a risk that the Corporation may not be able to meet domestic and export requirements and commitments without having to resort to high-priced imported power or other higher-cost generation in years of lower than median water conditions. The risk of lower than median water conditions, (including a drought), creates a financial risk. The other financial risks include the potential for future interest rate increases, currency fluctuations, capital cost escalations, new accounting standards (IFRS) and other operational factors, some or all of which may well challenge the Corporation's future financial strength.

The Board will direct MH to propose to the Board by January 15, 2009 terms of reference for a regulatory review of the impact that MH's planned Capital program may have on consumer rates. The Board will also direct MH to quantify its risks in an effort to determine the appropriateness of the current financial stability targets.

Executive Summary

The Board also expresses concern with the Corporation's withholding of information related to its export transactions and projections, for stated confidentiality reasons, as that withholding made it difficult if not impossible for the Board to arrive at findings with respect to such matters as to what constitutes the Corporation's marginal cost rate, a final determination of the rules to govern the allocation of costs and revenues to customer classes, the weight to be given to marginal and environmental factors in future differentiation of customer class rates, and, perhaps most importantly, the likelihood of profitability with respect to its export commitments and the risk that these commitments will lead to years of either additional imports of power or thermal generation to avoid supply shortfalls. Accordingly, the Board has requested additional information related to MH's export forecasts.

In this Order, the Board notes that there are approximately 100,000 low-income households that are customers of MH (many, also being customers of Centra Gas), and the particular affordability pressures on these households arising from energy price increases (gasoline, diesel, natural gas and, though much more modest, electricity).

The Board has recently approved issuance of a single bill for consumers of electricity and natural gas and provided MH an ability to maintain natural gas and electricity services, when financial delinquency conditions exist. These efforts avoid disconnections through the availability of an electricity load-limiter and will assist with the health and safety of consumers through the coming winter. However, the Board seeks further actions by the Corporation to address the varied problems of low-income households, problems exacerbated by rising energy costs.

Accordingly, by this Order the Board directs MH to increase its efforts to conserve domestic energy through far more aggressive DSM measures, including those particularly targeted at low-income households lacking the means to invest in energy efficiency measures without assistance from the Corporation.

The reduced consumption benefits expected to arise out of more successful DSM programs will assist low-income households in meeting their utility bills. It will also provide the Corporation with a higher level of supply security to meet future demand requirements.

There is a risk that if natural gas customers move in any significant way to electricity as the sole or supplementary space-heating source for their residences, (a growing risk given recent natural gas commodity price increases and volatility), MH will have less energy to export and may have to import power in some years to meet its commitments. MH's low rates for all of its customers, excluding "government accounts" in the diesel zone, are maintainable in part due to export profits.

Finally, herein, the Board suggests to government that it consider establishing a separate entity to manage the Corporation's DSM and low-income initiatives. The Board concludes that MH's full energies and focus should be placed on the effective implementation of its long-term expansion plans, towards meeting the demand for electricity and natural gas. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to target, together with providing funding to meet those targets. MH will benefit by being able to export the energy that is conserved.

1.0 Overview

1.1 History

Manitoba Hydro's last General Rate Application (GRA) was held in the spring of 2004, following a drought that contributed to a record loss of $428 million for the Corporation's electric operations. That 2004 GRA led to Board Orders 101/04 and 143/04, and those Orders approved a 5% average rate increase, effective August 1, 2004, and two additional average rate increases of 2.25% each, to be effective April 1, 2005 and October 1, 2005 – the latter two increases conditional on MH filing additional information and justification.

Subsequently, by Order 34/05 the Board confirmed the first of the two conditional 2.25% average rate increases, the first one taking effect April 1, 2005. However, due to a reported "dramatic" rebound in water conditions following the drought that contributed to rate increases in Order 101/04, and a favourable financial forecast for MH's fiscal year 2005/06, the Board was advised by MH (on July 5, 2005) that the Corporation would not seek the second conditionally approved rate increase, tentatively scheduled for October 1, 2005.

Water conditions ebb and flow, and subsequently, due to a return to poor water conditions during most of MH's fiscal 2006/07 (not anticipated by MH when it decided to forego the last of the two conditional rate increases), MH applied to the Board to reinstate that foregone average rate increase of 2.25%. After a thorough review of information submitted by MH, and by way of Order 21/07, the Board granted MH's application, effective March 1, 2007, on an interim basis. Final approval of that rate increase was later sought by MH as part of its 2008 GRA, and provided by the Board by way of recent Order 90/08.

1.2 2008 General Rate Application

In the summer of 2007, and pursuant to *The Public Utilities Board Act* and *The Crown Corporation Public Review* and *Accountability Act*, MH applied to the Board for the following:

a) Approval of rate schedules incorporating an across the board 2.9% increase in General Consumers' rates effective April 1, 2008 (with the exception of Area & Roadway Lighting which would receive a 1% increase);

b) Final approval of General Consumers' interim rates approved in Order 21/07 effective March 1, 2007;

c) Surplus Energy Program: immediate interim approval to extend the program (currently set to expire October 31, 2007) to October 31, 2008 together with final approval to extend the program to March 31, 2013;

d) Final approval of all Surplus Energy Program (SEP) interim rate orders as set out in Appendix 10.6 of the GRA;

e) Approval of modifications to the Curtailable Rate Program (CRP) as discussed in Tab 10, Section 10.2 of the Application, and final approval of all interim Curtailable Rate Program orders as set out in Appendix 10.6;

f) Final approval of changes to the Limited Use of Billing Demand Rate (LUBD) as set out in Appendix 10.6;

g) Contingent on final execution of the settlement agreement between Indian and Northern Affairs Canada (INAC), Manitoba Keewatinook Ininew Okimowin (MKO) and Manitoba Hydro, approval of interim *ex parte* Orders related to electricity service in the Diesel Rate Zone as set out in Appendix 10.6; and

h) Approval of a new General Service Large rate for new or expanding loads as set out in Tab 10, Section 10.3 of the GRA.

By Order 90/08 and following a public hearing of MH's GRA, the Board established an across-the-board rate increase of 5% effective July 1, 2008 for all MH customers, except for Area and Roadway Lighting customers, whose rates are not to change.

In addition, the Board approved:

a) A further conditional across-the-board general rate increase of 4%, with the exception of Area and Roadway Lighting customers (for whom rates are again not to increase), provisionally to take effect April 1, 2009 (subject to the Board's further review, that, depending on developments, could result in the Board increasing or decreasing the 4% increase conditionally approved);

b) An increase in the Basic Monthly Charge (BMC) for all customers of 5%, as of both July 1, 2008 and April 1, 2009;

c) As indicated above, finalization of Order 21/07 which established an interim rate increase of 2.25% on March 1, 2007;

d) A modest introduction of inverted rates for the "residential" class (SGS), establishing a precedent and indicating an intention to widen the differential in the future;

e) As requested by MH, extension of the Surplus Energy Program (SEP), although only to October 31, 2008 ahead of conclusions yet to be reached and a possible further extension to follow this Order;

f) Modifications to the Curtailable Rate Program, as proposed by MH;

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g) Changes to the Limited Use of Billing Demand Rate, as proposed by MH; and

h) Final approval for various interim SEP Orders through to the date of the close of the hearing that led to Order 90/08.

Order 90/08 was issued on June 30, 2008, and also indicated that final approval of several Interim *Ex-Parte* Orders related to electricity service in the Diesel Rate Zone would be deferred until final execution of a Settlement Agreement between INAC, MKO and MH had occurred.

The Order also advised MH to re-file, "with any adjustments it may deem appropriate, a revised proposal for a new industrial rate for new and expanding industrial load".

Although the Corporation had sought a 2.9% across-the-board increase, excepting for a proposed 1% increase for Area and Roadway Lighting customers, and had indicated a need for further 2.9% across-the-board increases for each year through to 2017/18, the Board concluded that higher increases were required, at least for 2008 and 2009.

In Order 90/08, the Board noted:

> "With MH's new export and construction commitments and plans, and with the increased risk that MH's Manitoba load forecasts may prove low given the large increase in the price of natural gas over the past year (yet to be fully reflected in natural gas bills), and providing the risk of energy switching, the Board is also concerned with the risk associated with advancing major new generation and transmission projects with industrial rates well below marginal cost."

And,

> "While the Board is now providing a 5% increase for 2008 and the prospect for a further 4% April 1, 2009, the latter subject to reconsideration following receipt and review of additional information, the electricity rate increases now set and contemplated pale in comparison to the increases being implemented or planned by other Canadian electricity utilities, and the cost increases now being experienced by consumers, businesses, institutions and governments with respect to other energy sources. "

And,

> "Notwithstanding the Board's appreciation of the negative implications of rate increases for MH's customers, and the Board's particular and on-going concern for low-income households, particularly, in this case, those relying on electricity for space heating, the Board will provide MH with a greater increase than the Corporation sought. This, because of a combination of concerns briefly cited below (to be) elaborate(d) on in more detail in a subsequent Order:

a) In its application, MH advised that its proposed series of 2.9% increases were required to maintain progress towards the eventual attainment of the Corporation's financial targets, primarily the achievement of the long-sought but not achieved target debt to equity ratio of 75:25. MH projected that notwithstanding its forecasts of annual rate increases and the assumption of continuing success with export markets, and taking into account forecast net income for 2007/09 to achieve or exceed $300 million, it still did not expect to achieve the debt:equity financial target of 75:25 by 2017/18 (let alone the current or previous earlier target dates);

b) MH's plans for capital expenditures may involve the expenditure of $18 billion or more over the next 15 years, expenditures predicated in part on what may or may not be overly optimistic export prices – this level of capital expenditure will result in significantly increased debt levels, export commitments and general business risks;

c) MH's reports and evidence of hyper-inflation with respect to construction and commodity costs, which are driving up the Utility's projected costs for new generation and transmission projects and have lowered its estimates of the return to be expected for the first of its new generation projects (Wuskwatim), a project that will likely be followed by further major construction (Pointe du Bois, Bipole III, and the Keeyask and Conawapa generation stations);

1.0 Overview

d) While the Board shares some Intervener concerns as to an apparent acceleration of MH's OM&A costs (Operating, Maintenance and Administration), which MH attributes to labour shortages as well as increased needs for system maintenance, (both factors cited to be beyond the direct control of the Utility), the Board does not have enough information on whether current and forecast OM&A expenditures are fully supported, since no formal and in-depth benchmarking has yet been undertaken;

e) The approaching adoption of International Financial Reporting Standards (IFRS), which will form the new Canadian Generally Accepted Accounting Principles (GAAP), with potentially materially significant and negative impacts for the Corporation's current forecasts of annual net income results through 2017/18;

f) There has been a significant increase in the value of the Canadian dollar relative to American currency, and it has had the effect of reducing the value of electricity exports as expressed in Canadian dollars. The Canadian dollar has climbed from just above 60 cents U.S. dollar (USD) to near parity with the U.S. currency. With MISO imports (MH's exports) priced in USD, this has affected MH's export revenues. While MH forecasts the Canadian dollar falling back about 15 cents from its current level, the Board is not confident with that forecast, and if near parity remains MH's export price forecasts are in jeopardy;

g) There appears to be a growing disconnect between electricity prices obtained from American markets and natural gas prices (in the past, when natural gas prices rose, the assumption and general experience was that MH's export prices rose as well); and

h) Continuing business risks related to interest rates (now at recent historic lows), the risk of further currency fluctuations, drought, inflation, market access problems, and other concerns: "

"Interest rates are at very low levels in both an absolute and relative to inflation sense – the current prime rate of the Bank of Canada is approximately only one percentage point higher than the current national rate of inflation – and with hyper-inflation present with respect to commodities (including energy) and processed products such as chemicals, steel and concrete, the Board is concerned that interest rates will increase at some point during MH's expansion phase, placing increased pressure on the cost of the Corporation's operations."

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And,

> "MH has benefited from 12 of the last 16 years being of above or near median water flows; statistically, poorer water conditions can be expected to occur at some point in the future and a drought, which has been experienced regularly through the Corporation's history, could have a devastating impact on MH's financial situation, as it recently did in fiscal 2003/04."

And,

> "MH's export market is primarily American utilities within the MISO market, and transmission lines on both sides of the border are required to transport the power to MH's export customers and carry power back to Manitoba when imports are required, and there are risks involved with reliance on a significantly predominant market. While a national east-west grid remains a worthy objective, there is no present indication that MH's Canadian provincial customer list, particularly from a volume perspective, can be assured to strongly develop."

The Board concluded its overview of the Corporation's risks by stating in Order 90/08 that it "is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks".

> "The rate changes and comments of present and future risks associated with this Order should not be perceived as a challenge to the perspective that MH remains a tremendous asset for Manitoba, and that the Corporation continues to have and represent large growth opportunities. Even with the rate increases announced and forecast herein, Manitobans should continue to benefit from some of the lowest electricity rates in North America.
>
> The Board also finds it important to recognize a present and growing disconnect between relatively stable and low electricity rates (set by a regulatory body with particular attention to historic costs) and other competing energy prices, the latter set by largely unregulated market forces little affected by the actual cost of production and distribution.
>
> With respect to MH, while the costs of generation, transmission and distribution assets acquired decades ago have allowed for residential rates of 6 cents per kilowatt hour (kW.h) and 3.2 cents for major industry, the new generating stations and transmission facilities will demand much higher rates simply to break even, let alone produce the net income required to allow MH to move forward supported by a reasonable capital structure.

> As a comparison to electricity rates … Combining actual and projected natural gas bill increases for 2008, it would not be surprising if natural gas customers end up paying 30% more for their natural gas this winter as opposed to the last. With respect to fuel oil, propane, gasoline and diesel, increases experienced are even more severe.
>
> In 1999, when MH purchased Centra Gas, space heating by natural gas … could be expected to come at half or less than half the cost of an electrically-heated home; this is no longer the case. (Now) … space heating by electricity (is) cheaper than by natural gas for all residences other than those that heat by way of a high-efficiency gas furnace. If the trend continues more and more new and existing residences may select or convert to electric heating, driving up domestic electricity load and limiting export sales and profits."

The Board noted that Order 90/08 would be followed by a more detailed Order that would provide further direction, necessary background information and detailed rationale for the rate changes of Order 90/08. The Board also noted that the subsequent Order, which is this Order:

> "… will also summarize and encapsulate the positions of Interveners and MH, the comments of presenters, and the evidence of witnesses all appearing before the Board at the public hearing of MH's GRA, a hearing held over 19 days in the Board's offices in the months of March, April and May 2008."

1.3 Previous Board Directives

In addition to MH's specific requests for Board approval in the Utility's GRA, MH reported on the status of various responses to previous Board Directives that were issued in Orders:

117/06 - A review of Manitoba Hydro's Cost of Service Study Methodology and other matters.

Order 117/06 followed a comprehensive public hearing which reviewed in depth MH's Cost of Service Study Methodology, and provided various directives to modify and refine the methodologies to be used in subsequent Cost of Services Studies. In the recent GRA, the Board and Interveners had the opportunity to consider those modifications and refinements in MH's Prospective Cost of Service Study - 08 (PCOSS -08).

173/06 – Application by Manitoba Hydro for the extension of the approval of the Surplus Energy Program (SEP).

By 173/06, the Board approved the extension of SEP to the earlier of October 31, 2007 or a further application by MH, with the expectation that the SEP would be included for review in MH's 2008 GRA.

176/06 - An Interim ex parte Application by Manitoba Hydro for an Order approving new electricity rates in four communities served by diesel generation, to be effective January 1, 2007.

This was the fourth Order, in a series of Orders (17/04; 45/04; 159/04; and 176/06) that adjusted rates, each provided on an interim basis, in the four communities that Manitoba Hydro services by diesel generated electricity. The communities are:

Barrenlands First Nation (also known as Brochet)

Northlands Dene First Nation (also know as Lac Brochet)

Syisi Dene First Nation (also known as Tadoule Lake)

Shamattawa First Nation (also known as Shamattawa)

The interim rates approved in Order 176/06 (as well as the other interim orders) were predicated on MH filing an Application to finalize all outstanding Diesel Zone Interim Orders, as soon as the Settlement Agreement among MH, MKO, and INAC has been fully executed.

20/07 - Manitoba Hydro - Interim Rate Increase effective March 1, 2007.

1.0 Overview

This Order approved, on an interim basis, the 2.25% average rate increase that MH, in the most recent GRA sought to confirm, and which the Board has confirmed by way of Order 90/08.

By this Order, the Board also comments on MH's responses to previous directives and provides additional directives for the attention of the Utility.

1.4 Board Findings

As was the case with Order 90/08, this Order addresses many complex issues and provides detailed analysis, discussion and decisions (in other sections of this Order) in support of not only the directed rate approvals provided by Order 90/08 but also with respect to other matters deferred to this Order.

For all of the reasons set out both above and in the Board's Findings sections included herein, the fiscal health of MH, along with the affordability of energy for low-income households, remain the Board's greatest concerns. While the Board's concern over MH's financial situation lies largely with the $18 billion of capital expenditures likely to lie ahead, and the debt expected to be incurred to fund those expenditures, the Board's concern for low-income households is with their ability to pay seemingly "ever-increasing" energy bills (not just electricity, but also natural gas, gasoline, diesel, fuel oil and propane).

The Board also notes elsewhere in this Order, findings related to MH's OM&A expenses and the Corporation's efforts at expense control, and observes that the unprecedented planned increase in such capital expenditures are beyond the Board's statutory jurisdiction to approve or deny. Nonetheless, the impact on finance and depreciation expense arising from capital expenditures, along with the risks ever-present with a Corporation dependent in large part on weather and other matters not within its control – general inflation, interest rates, currency fluctuations, represent the largest component of the upward pressure on consumer rates.

In considering its directions and comments, the Board is mindful of past directions from the Manitoba Court of Appeal:

1.0 Overview

> "The Board's function is not only to protect consumers from unreasonable charges, but also to ensure the fiscal health of the corporation and fairness between different classes of consumer." [1]

1. Coalition of Manitoba Motorcycle Groups Inc. v. Manitoba (Public Utilities Board) [1995] M.J. No. 301 (C.A.).

Attention to the fiscal health of MH (as one factor in the Board's determination of the public interest), has been supported by the Manitoba Court of Appeal.

The intent of the legislation is for the Board to approve fair rates, taking into account such considerations as cost and policy, or other factors as the Board may deem appropriate. Rate approval involves balancing the interests of multiple consumer groups (residential, commercial, institutional and industrial) with those of the utility. In the end, the long-term interests of consumers and the utility should coincide.

The Board's decision in Order 90/08 to build retained earnings more rapidly than MH proposed, in order to better protect the utility and consumers from the potentially devastating financial impact of future drought and other identified risks, clearly meets the intent of the legislation and is within the jurisdiction afforded to the Board in s. 26 of *The Crown Corporations Public Review and Accountability Act*.

It should be clear for the reasons cited herein that the Board understood its role in this regard.

> "The (Board) has two primary concerns when dealing with a rate application; the interests of the utility's ratepayers and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest." [2]

2 Consumers' Association of Canada (Man.) Inc. et al v. Manitoba Hydro Electric Board, 2005 MBCA 55

In arriving at its decision to grant MH rate increases as of July 1, 2008 and April 1, 2009 (the latter conditional), the Board took into account recent financial results and forecasts which, particularly if the forecasts are met, will contribute in a meaningful way to improving MH's financial strength in the near term.

Financial results for fiscal 2007 were $13 million better than projected and the current projection of $300 million (or more) of net income for fiscal 2007/08 represents a gain of at least $96 million over what had been anticipated given median water flows. The Board also understands that energy in storage (water in the reservoirs) was at record or near record levels going into 2008/09 and that water flow conditions remain favourable, both factors suggesting that the current forecasted net income of $156 million for 2008/09, (which was again based on median water flows), may be exceeded.

If these projections prove out, MH will have enjoyed 14 of the last 18 years of above or near median water flows. While such a result would be very good news indeed, history has a habit of repeating itself, particularly when it comes to weather, and years of water flow better than median may very likely be followed by years of below median water flows.

Then, there are the significant concerns expressed over the forecasted increase in capital spending, concerns expressed not only by the Board, but also MIPUG, the Coalition and MKO. The concern is of particular importance as the capital program increases now forecast are, at least initially, driven by export sales commitments.

Interveners suggest a capital justification hearing or, at least, a public dialogue on the appropriateness of the capital program, which brings risks as well as opportunities. The Board shares this view.

And, MH's intended capital program, unprecedented in the Corporation's history, and supported in large part by the expectation of large export sales, also has risks, the larger the commitments the larger the risks.

1.0 Overview

The Board would be remiss if it did not acknowledge that a primary driver of the Board's decision to increase 2008 rates by 5%, 2.1% more than MH sought, was the Board's perspective that attention should be paid to not only reaching but also maintaining the 75:25 debt to equity financial target.

It is not as if MH is already at its 75:25 debt:equity target, or that MH has projected to the Board that it expects to reach and maintain that target. In fact, due to the planned acceleration in capital spending, driven primarily by export considerations, the Corporation is not expected to meet its 75:25 debt to equity ratio target during the current forecast period, which extends to 2017/18, and those forecasts already assume annual average rate increases of about 3% each year.

In addition, major new contracts are being contemplated for export sales that will require new generation and transmission facilities costing over $6 billion, costs which have not yet been incorporated in the forecasts of the Corporation.

That said, the Board was reluctant to raise MH's rates by more than the Corporation sought. The Board is well aware that Manitoba's consumers are facing extraordinary increases in the cost of living caused largely by increases in petroleum prices. High petroleum costs are also translating into higher costs for staples: food, tires, gasoline and diesel prices, and heating oil, propane and natural gas heating costs.

For the Board, in meeting its mandate to serve the public interest, that interest includes the financial health of the Utility. A major capital program, combined with water, interest rate, accounting and currency risks, warrants larger rate increases than those sought by the Corporation, in order to improve the Utility's financial resilience.

1.0 Overview

The Board is encouraged by improved financial projections for fiscal 2008, noting that MH has indicated its financial results is likely to exceed $300 million, an improvement from the $264 million reflected in its previous forecast. The Board further notes that MH has indicated near record level energy in storage and favourable water flows at the outset of fiscal 2009, which bodes well for MH meeting if not exceeding its fiscal 2009 forecasted net income of $156 million. Such improved financial results would also assist in enhancing the financial strength of MH.

The Board notes that the improvement is very much linked to higher volumes of hydraulic generation and is not reflective of increasing export prices or demonstrated cost reductions from previous forecasts.

While MH's fiscal health has significantly improved from the financial impact of the 2003/04 drought, where the loss incurred was the largest in the Utility's history, a future drought, one that could extend over several years, would result in larger generation reductions than the 2003/04 drought brought about, and would result in greater financial loss.

The Board is of the view that further improving the financial strength of MH, regardless of current improved results, is important to the future of the Utility, and that Manitobans, already enjoying electricity rates well below the average found on the continent, and cognizant of the rapid and hyper-inflationary increases for commodities generally (and energy in particular), will accept that an increase of 5% is now necessary.

MH financial strength has a significant influence on the finances of the Province, and MH's financial strength is a major consideration in the evaluation of the credit rating of the Province. In fact, the interest rates MH now enjoys are far below what would be required if not for the guarantee of the Province. The Board further notes that MH has also indicated that the Corporations' debt to equity ratio would have to be similar to that of privately-owned utilities (i.e. 60:40) in order to borrow at rates comparable to the cost of funds received through the Province, without the Province's guarantee.

Any downward adjustment in the credit rating of the Province would likely result in higher borrowing costs for MH as well as the Province, and serve as a double blow against the interests of consumers and industry.

MH rates should gradually begin to recognize the rates required to support new generation and transmission. Given the economic benefits that flow to the current generation of Manitobans as a result of an extensive capital expenditure program and the maintenance of an efficient and effective electrical grid, it seems reasonable that (to some limited extent) the current generation should shoulder some of the rate burden possibly destined for future generations

Leaving aside the weather, maintenance and economic risks that the Corporation faces, there is also the matter of the adoption of IFRS and the consequences for the Corporation once IFRS becomes GAAP. The Board shares the concern expressed by MH's Vice President of Finance and Chief Financial Officer when he testified that IFRS accounting could reduce the Corporation's annual average forecast of net income through to 2017/18 by as much as $120 million a year.

In fact, the Board needs to have MH's risks fully quantified to provide guidance on future rate requirements. And, while revenue alone will not be sufficient to support projected capital spending, MH needs sustained and repeated annual rate increases to support its financial position. Furthermore, the Board is concerned that the recently-announced new export contracts have not yet been reflected in the Corporation's Capital and Resource Requirements analysis, and the Board needs to see an updated Integrated Financial Forecast (IFF), Capital

Expenditure Forecast (CEF), Load Forecast & Power Resource Plan going out to 2028, this beyond the regular forecast period of 2018 to better gauge fully what lies ahead for ratepayers.

For the reasons cited above, and given the overall situation and prospects for additional rate increases as well as borrowings in the future, the Board confirmed as final, by way of Order 90/08, the interim rate increase of 2.25% granted March 1, 2007 on an interim basis. The Board believes that the initial interim increase, which took effect in fiscal 2007/08, was an integral part of the improved financial results for the year just completed.

In light of all the pressures on MH, it is acutely important that the financial strength of MH be improved. In the past MH has been striving to achieve a debt to equity target of 75:25. Although the target was deferred to 2011/12, it now appears that it will not be achieved and held to until well beyond 2017/18.

MH is evaluated by credit rating agencies that are interested in seeing MH making progress toward its financial targets. It is vital that progress continues to be made to ensure no negative implications for the credit rating of the Province. A strong credit rating results in access to capital at reasonable costs. Any deterioration in the credit rating of the Province attributable to MH would likely lead to higher borrowing costs for both the Province and MH.

All this said, the Board does not believe ratepayers alone should shoulder the obligation to maintain the utility's financial health. The Board expects the Corporation to demonstrate and provide evidence of tangible results in the management of OM&A costs and the Capital program, as well as addressing other issues and meeting directives discussed in detail in other sections of this Order.

1.0 Overview

Approval of the conditional 4% increase now slated for April 1, 2009 is dependent on MH addressing (to the Board's satisfaction) certain directives set out in this Order and filing additional financial information to allow the Board to assess whether the conditional increase is justified. The Board will direct MH to file (before January 15, 2009), supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information to be filed with the Board by that date, MH is to include:

a) first, second and third quarter 2008/09 unaudited financial results and statements; and

b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

2.0 Operating Results and Financial Projections

2.1 MH's Forecasting Process

MH utilizes four main forecasting tools:

a) The integrated financial forecast (IFF) projects MH's financial results over an 11 year period and includes an income statement, balance sheet and statement of cash flow.

b) The System Load Forecast projects energy and capacity requirements for electricity in Manitoba over the next 20 years.

c) The Power Resource Plan forecasts MH's supply capabilities under dependable flow conditions.

c) The Capital Expenditure Forecast (CEF) includes the planned capital expenditures for a 10 year period including safety requirements, supply side enhancements major generation and transmission projects and investments in administrative assets.

2.2 Comparison of Actual Operating Results with Prior Forecast

The IFF reviewed at the last GRA was IFF03-1, presented at the Board's 2004 hearing of MH's GRA. At that time, MH had just endured a severe drought and was forecasting a loss of $355 million for fiscal 2004. At the 2004 hearing MH provided an update to the Board indicating that the forecasted drought loss would be greater than that reflected in IFF03-1, projecting a loss falling between $400 million and $430 million, which ultimately settled at $428 million.

As directed in Order 101/04, MH filed IFF MH04-1 to justify implementation of the first 2.25% conditional increase, which was granted by the Board effective April 1, 2005.

As a result of the increases granted by the Board, more favourable water levels in fiscal 2005, and higher export sales in fiscal 2006, MH's financial position improved in the order of $130 million over the forecasts of IFF03-1 and IFF04-1.

The favourable water conditions of 2005 and 2006 reversed in fiscal 2007. In January 2007, MH sought from the Board a 2.25% rate increase. In support of its application, MH filed IFF MH06-2, which forecast a $108 million net income for fiscal 2006/07. The Board granted that increase on an interim basis by Order 21/07, and it took effect March 1, 2007.

2.3 Integrated Financial Forecast (MH07-1)

At the most recent GRA, MH filed its most current IFF (IFF MH 07-1) for its electricity operations, as well as its most current capital expenditure forecast (CEF 07-1), both for the eleven-year period 2008 to 2018. The IFF provides an indication of MH's view of its long-term financial direction in both absolute terms and as to achieving its financial targets, and is for use in future planning. MH's operating results since its 2004 GRA are compared to actual and prior forecasts as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings ($ Millions)	**Actual**				**IFF07-1**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Revenue						
Domestic	936	954	1001	1,040	1,079	1,108
Requested Rate Increase	-	-	-	-	-	31
Export	351	554	827	592	582	468
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,607
Expenses						
Finance	455	473	473	472	404	426
Depreciation	276	291	303	314	332	347
Operations & administrative	293	308	322	332	351	360
Water Rentals	71	111	131	112	121	112
Tax expense	51	52	54	55	57	64
Fuel & power purchases	569	135	125	226	132	143
Total Expenses	1,715	1,370	1,408	1,511	1,397	1,452
Net income [IFF 07 - 1]	(428)	138	420	121	264	155
Compared to Prior Forecasts						
Net income (loss) [IFF03-1]	(355)					
[IFF04-1]	-	147	208			
[IFF06-2]	-	-	-	108	174	127
Net income difference	(73)	(9)	212	13	90	28
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,805
Retained earnings from above IFF	759	854	1,061	1,398	1,572	1,699
Cumulative difference	(52)	(9)	204 -	12	78	106

Domestic electricity revenues are forecast to increase with load growth (usage) and approved rate increases. Export revenue forecasts are based on volumes and market prices, the former limited by water conditions and transmission capacity, the latter on demand and supply conditions in the MISO market (the marginal cost of the next unit of production).

MH's projected net income for the three-year period 2006/07 to 2008/09 is projected to be $131 million higher in IFF 07-1 than the aggregate result for that period forecast in the earlier IFF 06-2 forecast. Incorporating the changes from prior IFF's, as discussed above, MH's net income for the five year period 2003/04 to 2008/09 is now forecast to be over $261 million higher than was the case with the previous forecast.

IFF MH07-1 reflects both the interim increase of 2.25% granted March 1, 2007, finalized by Order 90/08, and MH's requested 2.9% increase as of April 1, 2008, varied to 5% from July 1, 2008 by Order 90/08. The forecast also assumes annual increases of 2.9% for the years 2009/10 through 2017/18. While the Board has already indicated consideration of a 4% increase for 2009/10, later rate forecasts will be the subject of future applications and processes.

MH's decision to file the most current GRA was based on IFF MH06-4, a forecast which projected net income for fiscal 2007/08 to be $249 million, with a further $163 million for fiscal 2008/09. During the GRA, MH provided an oral update to IFF07-1, suggesting that net income for fiscal 2007/08 will be higher by at least a further $36 million. Relative to IFF MH06-4, net income for 2007/08 was then expected to be at least $51 million higher than that forecast. The most recent anticipated improved operating results for fiscal 2007/08 are not reflected in IFF MH07-1, and despite the oral update, MH did not revise its request for a 2.9% increase as of April 1, 2008.

MH advised that its actual financial results for fiscal 2007/08 would not be made available to the Board until mid-June 2008, and, then, only in confidence pursuant to normal legislative reporting requirements.

MH's operating results and forecasts compared to the forecast of the 2004 GRA were as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings ($ Millions)	Actual				IFF07-1		
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**Total 2004-2009**
Revenue							
Domestic	936	933	929	965	985	1,014	
Estimated PUB Approved Increases	-	21	72	75	94	94	356
Export	351	554	827	592	582	468	
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,576	
Expenses	1,715	1,370	1,408	1,511	1,397	1,452	
Net income (loss) [IFF 07 - 1]	(428)	138	420	121	264	124	
Compared to 2004 GRA Forecast							
Net income (loss) [IFF03-1]	(355)	40	31	30	17	29	
Net income difference	(73)	98	389	91	247	95	847
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,774	
Retained earnings IFF03-1	759	799	830	860	877	906	
Cumulative Retained Earnings difference 2004 GRA vs. 2008 GRA	(52)	46	435	526	773	868	

Overall, since the 2004 GRA, MH's net income has been $847 million higher than that forecast at that time. The increase in net income is due in part to improved water conditions, conditions better than the median results expected, which led to higher than forecast exports. As well, rate increases approved by the Board since the 2004 GRA have contributed approximately $350 million in additional revenue for the fiscal years 2004/05 through 2008/09.

2.4 Board Findings

There has been an improvement in MH's financial results from that forecast in IFF03-1 at the 2004 GRA, notwithstanding the severe drought experienced in 2003/04. The Board further notes that, aided by much better water conditions than expected, record export sales (provided not only by the water conditions but also by the prices obtained following hurricanes Katrina and Rita in the summer of 2005), along with rate increases, brought in approximately $350 million in revenue, and further contributed to the improved results.

The Board would have expected such additional revenue to have significantly improved the financial strength of the utility, as displayed in its meeting its financial targets, compared with the original forecast. Yet it didn't, and the Board is concerned that MH is still not forecasting to achieve its debt:equity target within its forecast period, not by 2011/12 or throughout the entire 11 year forecast ending in 2017/18.

While the forecasts through to 2018 assume annual rate increases of 2.9%, and annual profits that appear to be very large, particularly to a province accustomed to narrow government budget surpluses and relatively modest returns from government enterprises, the Board not only notes the magnitude of the growing asset base on which these earnings are forecast to occur (restrained as it is by asset costs incurred decades ago at very much lower prices than replacement costs), the Board continues to question the "solidity" of the results and forecasts.

While MH advised that its fiscal 2008 net income would exceed $300 million, due to higher than initially forecast water flows, risks abound with respect to MH's longer–term forecasts, particularly:

a) A decline in export contract sales, trending down to 145 GW.h by 2017/18 in the absence of new contracts [the recently announced sales to Minnesota and Wisconsin, if consummated, will reduce this risk];

b) The limitations of the Corporation's ability to export until Conawapa, Keeyask and other Generating resources, including wind, come on line, in conjunction with the expected restrictions on the Brandon thermal plant commencing in 2009;

c) MH's future domestic load growth forecast may prove low, with the risk of consumers switching to electricity from space heating by natural gas, which is now more expensive than electricity except in the case of high efficiency furnaces;

d) MH's Canadian dollar exchange rate forecast assumptions;

e) MH's future export price forecasts are predicated on imposition of a carbon tax, yet there is no current certainty of such a tax being implemented and having a materially beneficial effect within the immediate horizon of IFF07-1;

f) Escalation in construction cost inflation over the past five years. Increases in commodity costs (iron, steel, concrete, copper and nickel for example) have been sharp and sustained;

i) Based on recent experience, current capital expenditure forecasts related to future construction may prove to be low, and actual costs may exceed the forecasts;

j) Recent or good water flow levels suggest an increased risk of a severe drought during a time when MH's capital expansion plans are significant; and

k) The required adoption of IFRS as of MH's 2012 fiscal year (with MH's 2011 fiscal year financial statements required to be IFRS based for comparison purposes).

A further discussion of each of these risk factors is provided later in this Order.

3.0 Forecast Revenues

3.1 Domestic Revenues

In IFF 07-1, MH forecast that at pre-Order 90/08 rates domestic revenues would increase from $1.057 billion (for fiscal 2008) to $1.258 billion by fiscal 2018, a projected increase of $201 million. Additional revenue forecast to arise from assumed 2.9% annual rate increases for each year from fiscal 2008/09 on to 2017/18 was projected to contribute a further $395 million to MH's forecast revenue growth, with total revenue forecast for fiscal 2017/18 to be $1.653 billion.

The forecast of $200 million in additional domestic revenue at pre-Order 90/08 rates reflects projected net load growth of about 3,500 GW.h over the ten-year period. Of this, 2,200 GW.h, almost entirely expected to occur in the first three years of the forecast, relates to projected new industrial load. To the Board, it appears that MH has assumed that a new Energy Intensive Industry Rate, as initially proposed by MH to take effect in 2008/09, will be applied to almost all of the industrial load growth forecast in IFF 07-1.

3.2 Extra-Provincial Revenues

3.2.1 Energy Available for Export

MH's hydraulic generating resources, supplemented by thermal and wind generation as well as imports (the latter source when required) allow for projected annual exports of energy ranging from about 4,000 GW.h to 15,000 GW.h per year, actual volumes to be affected by water flows and domestic load.

Typically, MH has forecast exports (total supply minus domestic load) in each current year on the basis of known water supply conditions. For the second year of a multi-year forecast, MH utilizes known end of Year 1 conditions plus an assumption of median water flow for the second year. The third year forecast, and each year thereafter, uses the long-term mean flow conditions (basically the average experience of the past).

In IFF 07-1 export sales are forecast at:

MH Forecasted Export Sales

Fiscal Year	GW.h	$ million
2008	11,152*	$582 *
2009	7,549	$468
2010	6,608	$416

*Note**

MH has indicated that exports for fiscal 2007/08 will be significantly higher than its forecast due to higher than forecast water flow.

Also, exports assume that in addition to hydraulic generation, MH will have other resources, as follows:

MH Forecasted Power Resources (GW.h)

Fiscal Year	Thermal Generation GW.h	Imports GW.h	Wind Purchase GW.h	Total GW.h
2008	351	880	320	1,551
2009	203	1,194	320	1,717
2010	928	1,948	320	3,194

The export forecast for fiscal 2008/09 of 7,549 GW.h compares to total exports and average export prices in 2005, 2006, and 2007, as shown below:

MH Average Export Prices (2005 to 2007)

Year	2005	2006	2007
Export Revenue ($ millions)	$554	$827	$592
Export Power (GW.h)	10,780	16,034	11,717
Average Price (¢ per kW.h)	5.13 ¢	5.16 ¢	5.05 ¢

When river flows are above average, MH's hydraulic generation resources supply the export of energy surplus to domestic needs. MH provides "clean" energy at competitive prices into American, Ontario and Saskatchewan energy markets.

The following table illustrates the historical average annual export prices achieved by MH, in comparison to natural gas supply prices:

Average Annual Export Prices/Natural Gas Supply Prices

Fiscal Year	U.S. and Canadian Exports (Canadian ¢/kW.h)	Natural Gas Supply (USD/MMBtu)
1993	1.58	1.91
1994	2.54	2.25
1995	2.69	1.75
1996	2.54	1.95
1997	2.33	2.61
1998	2.16	2.41
1999	2.82	2.00
2000	3.43	2.46
2001	3.91	5.03
2002	4.90	3.08
2003	4.89	4.29
2004	4.99	5.16
2005	5.53	6.28
2006	5.19	9.29
2007	5.08	6.67
2008	5.00 (est.)	8.00 (est.)

Until 2004/05, the Corporation's average electricity export prices tended to track and move in tandem with changes in natural gas prices. However, from 2006 average export prices appear to have plateaued at just above 5.0¢/kW.h. This has occurred despite currently-high natural gas prices.

In 2007/08, a dramatic shift in the Canadian/U.S. exchange rate contributed to average export prices moving below 4¢/kW.h for opportunity energy sales, and below 5.5¢/kW.h for firm (dependable) energy contract sales. As illustrated in the following table, the recent price drop appears to be largely related to changes in the exchange rate. However, and as well, the Board notes no indication that prices for dependable energy in USD terms have escalated with inflation.

NEB Average Export Price Data* (converted to U.S. ¢/kW.h)

Date	Exchange Rate (CDN $)	Opportunity Export		Dependable Export		Imports	
		¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)
2006							
November	1.14	6.3	5.55	6.1	5.35	5.6	4.95
December	1.16	6.5	5.6	6.4	5.5	5.9	5.1
2007							
January	1.18	6.0	5.1	6.0	5.1	5.6	4.8
February	1.18	8.7	7.4	6.2	5.3	6.0	5.1
March	1.18	6.6	5.6	6.1	5.2	4.0	3.4
April	1.14	6.8	6.0	6.0	5.3	4.0	3.5
May	1.10	5.0	4.55	6.0	5.45	2.0	1.8
June	1.06	4.5	4.25	5.5	5.2	6.0	5.65
July	1.05	4.0	3.8	5.2	4.95	9.5	9.0
August	1.05	4.0	3.8	4.8	4.55	7.8	7.4
September	1.05	3.8	3.7	5.0	4.9	8.2	7.8
October	0.98	3.6	3.7	4.8	4.9	9.8	9.6
November	0.97	4.0	3.9	5.8	6.0	10.0	9.7
December	1.00	6.2	6.2	5.4	5.4	2.5	2.5
2008							
January	1.05	5.2	5.2	5.3	5.3	6.1	6.1
February	1.00						
March	0.98						

Firm dependable export contracts reflect the ’5 x 16 peak period’ (five days/week and 16 hours/day), with most of MH’s exported energy being sold being on-peak and displacing natural gas electricity generation. As previously indicated, export prices in USD terms have, at least until recently, tended to reflect natural gas supply costs.

Current long term export contracts assure MH of export sales of about 2,500 GW.h/year at prices above 5¢/kW.h (5.5¢/kW.h on average for fiscal 2007/08). Other active contracts are shorter-term market based arrangements, and, for them, prices are now running below 4¢/kW.h for sales volumes of 1,500 GW.h/year.

Overall, the above contracts engaged about 50% of tie-line capacity during the ‘5 x 16 peak period’ in 2007/08.

Interruptible opportunity export sales are broad-time spectrum sales that attempt to capture the remainder of on-peak tie-line availability, and relying on shoulder and off-peak periods to maximize total electrical energy sales. These off-peak sales in fiscal 2007/08 accounted for an additional 8,000 GW.h in 2007/08, and brought an average price somewhat below 5.0¢/kW.h.

Contract and other energy sales are as follows:

Export Revenue in CDN ($000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07	0	0	0	1,468	1,109	2,303	9,376	1,152	24,811
May/07	0	0	3,857	1,461	1,177	2,451	9.867	0	31,331
June/07	0	1,246	4,101	1,263	1,097	0	9,195	0	33,861
July/07	2,439	1,829	4,930	1,400	1,136	0	9,576	0	33,768
August/07	2,648	1,986	4,836	1,445	1,155	0	9,745	0	34,890
September/07	549	412	2,807	1,206	994	0	8,435	0	22, 852
CDN $MWh									
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07				87.65	55.03	68.64	56.07	68.57	73.20
May/07			60.86	79.81	53.29	67.31	54.10		48.55
June/07		36.22	53.19	80.34	54.43		55.73		43.35
July/07	36.30	36.30	54.38	79.84	53.78		54.65		39.45
August/07	35.98	35.98	50.08	78.81	52.74		53.41		38.31
September/07	33.93	33.93	37.44	75.39	51.80		52.87		32.94

The above table illustrates MH’s current firm export sales contracts (the first eight columns) and MH’s current opportunity sales (EPE-269). As the Canadian dollar strengthened, export prices in Canadian currency declined: 35% of the export prices realized by MH were in the 3.5 to 5.0¢/kW.h range; 60% of export sales were at prices between 5.0 and 5.5¢/kW.h; and export prices above 7.0¢/kW.h were realized in only approximately 5% of the sales.

The above low pricing situation may not prevail as new export agreements come into play, with potentially-higher environmental premiums. Opportunity sales outside the agreements currently being negotiated are averaging about 5¢/kW.h, as opposed to the 6-7¢/kW.h that MH had previously anticipated.

MH's forecasts of average export prices employed for the second year of each IFF compare favourably with actual prices in fiscal 2004 and fiscal 2005, though at that time, natural gas prices had soared following hurricanes Katrina and Rita and the connection between natural gas prices and MH's export sales were stronger. However, in the last three years MH has over estimated the average CDN $ export price.

Fiscal Year	IFF-2nd Year Price Forecast	Actual Results
2006	6.2¢/kW.h	5.2¢/kW.h
2007	7.5¢/kW.h	5.1¢/kW.h
2008	7.1¢/kW.h[1]	5.0¢/kW.h (est.)

[1] From PCOSS 07/08

MH contends that the current situation of a high Canadian dollar and flatter U.S. electricity prices is temporary. Accordingly, the Corporation's forecasts of future energy prices reflect the assumption of higher prices aided by a substantial environmental premium.

MH's IFF 07-1 appears to reflect export market conditions as experienced in fiscal 2007/08 to the end of September 2007, but also assumes that the

Canadian dollar will return to $1.16 USD/CDN exchange rate by the end of the forecast period (fiscal 2017/18).

The following table illustrates export values employed in IFF 07-1, and shows the difference in export market prices that could be expected should the Canadian dollar remain at or close to unity:

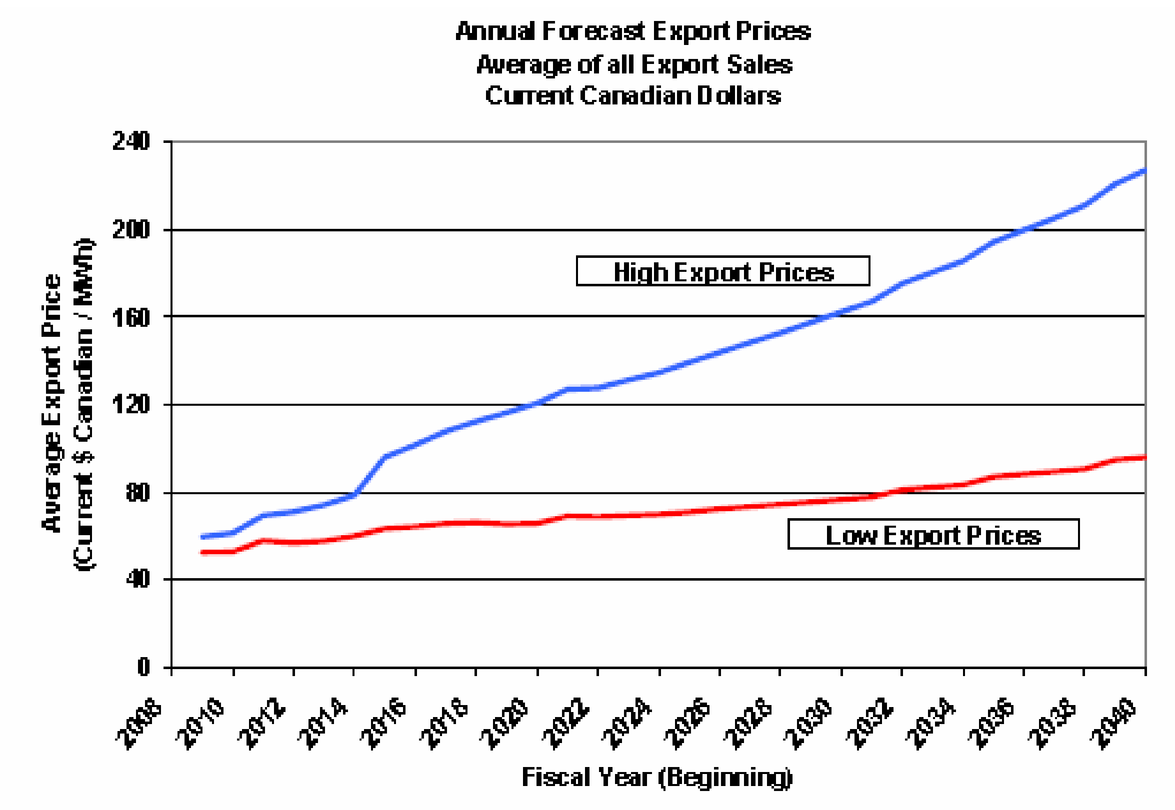
Year	IFF 07-1 (CDN $) ¢ Per kW.h	[1] USD/CDN$ EXCHANGE RATE	[2] IFF 07-1 (Unity) ¢ Per kW.h	[3] Forecast Range PUB/MH II-38 ¢ Per kW.h
2007/08	5.2¢	1.07	4.9¢	5.3-6.2¢
2008/09	6.2¢	1.08	5.7¢	5.3-6.3¢
2009/10	6.3¢	1.11	5.7¢	5.3-6.4¢
2010/11	6.4¢	1.11	5.8¢	5.5-6.4¢
2011/12	6.7¢	1.11	6.0¢	5.9-7.0¢
2012/13	7.1¢	1.13	6.3¢	5.9-7.2¢
2013/14	7.4¢	1.14	6.5¢	6.0-7.5¢
2014/15	7.8¢	1.16	6.7¢	6.3-8.5¢
2015/16	8.9¢	1.16	7.7¢	6.5-10.0¢
2016/17	9.3¢	1.16	8.0¢	6.6-10.5¢
2017/18	10.0±¢	1.16	8.6¢	6.7-11.0¢

Notes:

1 MH's forecast of CDN $ values reflect the average forecast of four independent consultants (all employing a starting exchange rate upward of 1.05).

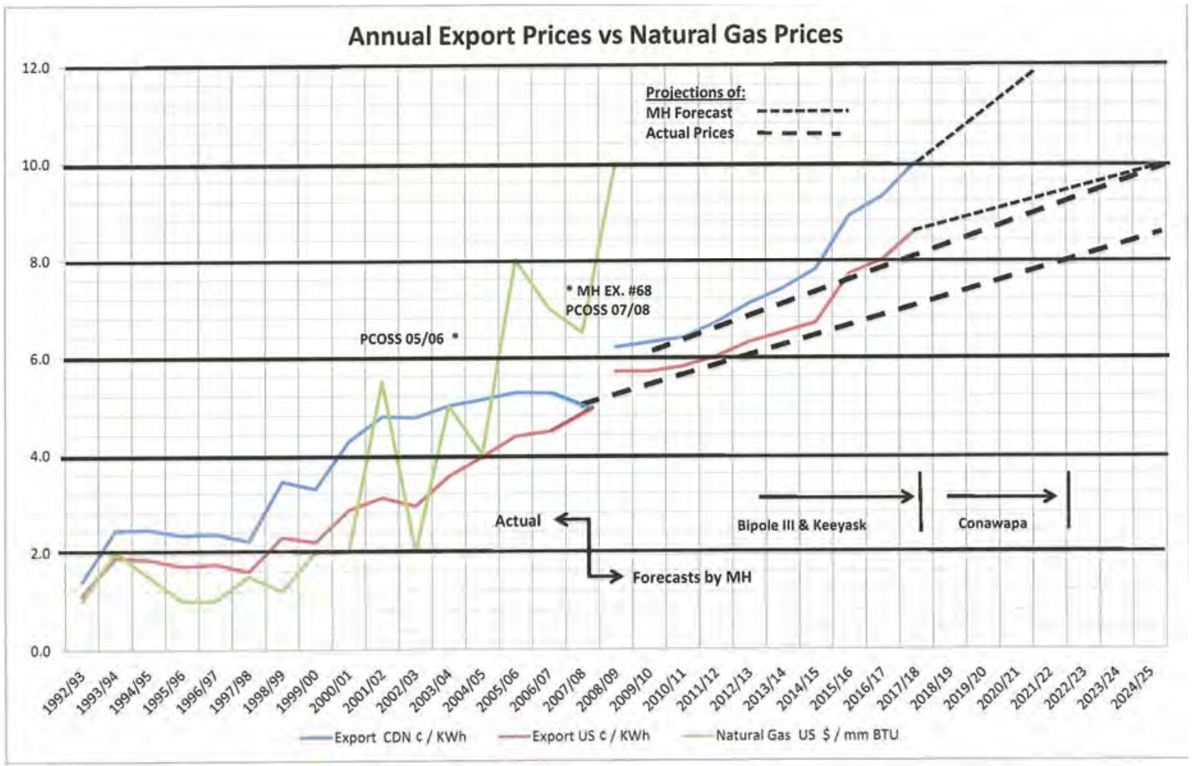
2 IFF-01 export prices recalculated on a unity exchange rate basis for the entire forecast period.

3 In an exhibit provided at the hearing (PUB/MH II-38, below), MH's export energy price market forecast was updated from that of the 2003 Clean Environment Commission application, and suggests a significant upward movement in Midwest Independent System Operator (MISO) region prices will occur in about seven years, assuming past historical exchange rates return.



Comparing IFF 07-1 to the forecast range depicted in PUB/MH II-38 shows that MH anticipates prices in the medium to high range. This would require the exchange rate to return to 1.16 USD/CDN and significant progress on the CO_2 emissions front (recognition of environmental costs reflected in pricing). The 1.5 to 2.0¢/kW.h increase in the high export price curve forecast circa 2015 appears to coincide with MH's anticipation of legislated action on the CO_2 front.

The following chart illustrates that from the early 1990s to about 2004/05, U.S. Export electricity prices achieved by MH (USD) moved in tandem with annual average natural Gas Supply prices. Subsequently, natural gas prices have risen dramatically while electricity export prices (USD) have grown only modestly. In terms of Canadian dollars, the prices have in fact plateaued at about 5¢ per kW.h.



The export energy prices employed by MH in PCOSS–06 and PCOSS-08 were 6.2¢ and 7.2¢ CDN/ per kW.h respectively. In IFF07-1, MH has forecast export prices (USD) to continue a gradual upward movement until 2014/15 when they are expected to step upward in response to carbon tax legislation and continue to rise more steeply to about 8.5¢ per kW.h in 2018. If a steep rise continued to 2022, export prices would be about 10¢ per kW.h.

MH has suggested that USD/CDN exchange rates will return to about 1.16 by 2015; this would yield forecast average export prices of 10¢ per CDN per kW.h in 2018, and 12¢ CDN per kW.h in 2022, and might be sufficient to support new generation and transmission development [Bipole III, Keeyask and Conawapa] if interest rates do not increase. However, if the movement to carbon taxation does not happen, lower prices may well prevail. It can be speculated the prices of 7¢ U.S. per kW.h in 2018 and 8¢ U.S. per kW.h in 2022 would result from projections of recent [2005 to 2008] actual average export prices. If the exchange rate moves to 1.16 USD/CDN as anticipated by MH, the export price forecast would be 8¢ CDN per kW.h in 2018 and about 9.5¢ CDN per kW.h in 2022.

It can be realistically speculated if the costs of Bipole III, Keeyask G.S., and Conawapa G.S. were fully allocated against export revenues, average export sales prices would have to be 11¢ CDN per kW.h to break even.

In the 1990s, natural gas prices were relatively constant $1.50 to $2.00 (USD) per BTU. Natural gas-fired electricity generation (with its low Capital Investment requirements) became very attractive as an alternative to building new coal plants. There were predictions as recently as 2001 that all new generation would be natural gas–fired, and numerous new natural gas generation plants did come into service in Western Canada and the U.S. Midwest.

In 2001/02 natural gas prices almost tripled but fell back the following year, only to renew the upward climb in 2003/04. This led to reduced natural gas generation, and consequently greater exports by MH at then favourable average prices of 3¢ to 5¢ U.S. per kW.h

The advent of Hurricane Katrina in 2005/06 led to a further doubling of natural gas prices. However, MISO average market prices for electricity only increased by about 25% and now appear to be almost static at about 5¢ U.S. per kW.h, even though natural gas prices have been above $11.00 U.S. per MBTU in June 2008 (falling back since). It appears obvious that current MISO market prices for electricity are not being driven by natural gas prices.

The Mid-Continent Area Power Pool (MAPP) merger into MISO after 2000 reduced the relative significance of natural gas generation in determining MH's export pricing. Access to more coal generation could be responsible for the low off-peak prices. Other possible explanations for this disconnect between market electricity pricing and natural gas prices are that:

- Mandated wind generation, when available, could also be used in conjunction with MH's exports during the off-peak period and create base load energy at prices only marginally above coal generated energy.
- Natural gas generated electricity provides a very limited fraction of the total energy consumed within the MISO region; in the 2005 summer, natural gas generation might have been in play about 25% of the time but only supplied about 5% of the total market energy.

Coal-fired Electricity Generation greatly influences MH export markets in the MISO region and, to a somewhat lesser extent, in Ontario and Saskatchewan. Coal based generation is inherently base load in nature (MISO utilities rely on coal and natural gas, hydro is a minor source) and the replacement of coal-fired generation by MH's hydroelectric power currently brings an average market export price significantly below 5¢/kW.h.

Consequently, at the prices MH seeks for its power (prices well above 5 cents), the Utility is not competitive for base load and can achieve export market access at better prices primarily at the time of MISO system peak loads. For MH to compete for base load, a substantial environmental premium would have to exist for clean energy; that is coal generation would have to be "penalized".

In MH's 2003 Clean Environment Commission (CEC) Application to construct the Wuskwatim G.S., the Corporation's energy price forecasts reflected environmental price premiums for its export sales. At the recent GRA, MH suggested that these scenarios are still valid and will come into play within the forecast period. Within its 2003 CEC submission, MH categorized three levels of environmental premiums in 2000 U.S. dollar terms:

- Low (long-term CO_2 valued at $10 U.S./ton)
- Medium (long-term CO_2 valued at $20 U.S./ton)
- High (long-term CO_2 valued at $25 U.S./ton).

For MH's future exports of hydraulic generation to realize prices of 7 cents or more per kW.h, it appears that coal generation by MISO market utilities would have to be assessed substantial CO_2 emission premiums.

Natural Gas Electricity Generation at current natural gas prices can readily be displaced economically by MH exports in the MISO region, even during peak load periods. During off-peak hours, there is little (if any) natural gas generation to displace, resulting in low export prices for the Corporation.

MH's own natural gas generation of electricity is not economical at today's natural gas supply prices. Incrementally, these generation costs range from 5¢/kW.h with natural gas at $3.00 CDN/GJ, to 15¢/kW.h with natural gas at $9.00 CDN/GJ.

MH has suggested that pending U.S. legislation on Green House Gas emissions will make new natural gas generation plants more economically attractive to U.S. utilities, as coal should bring much higher environmental cost premiums than natural gas. Such a development would favour MH and its price forecasts over the longer term.

Wind Generation has essentially been mandated in some U.S. states which now specify minimum levels of required renewable energy (not including large hydro) that must be incorporated within the supply system. As MISO market wind may be displacing MH exports (on an energy supply basis), about one third of the time, MH exports may also be called upon to serve to back up this generating source for the Americans.

3.2.2 Foreign Exchange

As suggested above, MH's export revenue is significantly influenced by the foreign exchange rate.

MH's present forecast of the exchange rate was updated in July 2007, and the exchange rate utilized in IFF MH-07-1 ranges from 1.07 USD/CDN to 1.16 USD/CDN. The exchange rate used for fiscal 2007/08 was 1.07 USD/CDN, and 1.08 USD/CDN was used for fiscal 2008/09, yet the CDN dollar remains close to parity with the U.S. dollar.

MH's exchange rate forecast fails to fully recognize the significant appreciation of the CDN dollar versus the U.S. dollar, and the underlying reasons for the appreciation that suggest the change may persist. This has had the effect of MH overstating both the value of U.S. export sales and finance expense.

MH indicated that if the CDN dollar was to remain at par with the U.S. dollar throughout the IFF forecast period, this would result in a decrease of $170 million in its forecast retained earnings. MH indicated that due to its Exposure Management Program, the exchange impact will be limited to the portion of dollar flows that are not perfectly hedged.

MH remained of the view that over the long term the CDN dollar will weaken against the U.S. dollar, consistent with its long-term 1.16 USD/CDN foreign exchange forecast.

3.2.3 Long-Term Export Contracts

MH has typically entered into long-term export contracts for the sale of dependable energy surplus to forecast domestic customer base loads. By and large, these contracts are for peak (5 x 16) energy sales and reflect a commitment by MH to provide a defined amount of capacity (MW) and energy (GW.h) during the 5 x 16 period throughout a year at an agreed price. MH has also entered into diversity agreements that involve the seasonal exchange of firm energy between the Corporation and a MISO counter-party, at prevailing market rates.

MH currently has executed agreements and/or term sheets for about 3,500 GW.h (900 MW) per year of firm energy for both 2008/09 and 2009/10. These volumes essentially utilize all of MH's dependable energy resources available for export.

The 500 MW commitment to Wisconsin Public Service (WPS), to commence in 2019, will increase MH's firm export requirements to 3,600 GW.h, and this is substantially above forecast dependable energy resources in place at that time. MH will require the Keeyask Generating Station to be in place or, alternatively, will have to employ natural gas turbines to provide the energy. MH will need to proceed with its new generation and transmission plans in a very timely fashion to avoid the high costs that would accompany being obliged to generate power through natural gas, import the power or buy the commitments out.

When the 250 MW contract with Minnesota Power takes effect in 2020, MH will then be committed to supplying 5,000 GW.h of firm energy into the U.S. If Conawapa is not in-service by then, natural gas turbine generation and more wind generation (or imports) will be required to offset a shortfall that could approximate 2,000 GW.h in 2020.

3.2.4 Inter-Tie Limitations

Extra-provincial sales or purchases of electricity are achieved at Manitoba's borders through a number of two-way transmission connections to the U.S., Ontario, and Saskatchewan. Theoretically, MH should be able to export a maximum of about a) 25,500 GW.h/year into the U.S., b) 2,600 GW.h/year to Ontario, and c) 3,900 GW.h/year to Saskatchewan.

To date, MH's maximum annual exports have been 16,000 GW.h, and those primarily went into the U.S. market. This means that about 7,000 GW.h/year can be exported during the 5 x 16 peak period and a further 9,000 GW.h/year during the off-peak periods. Consequently, during median flow years, MH can provide 3,500 GW.h to its existing firm export contracts and another 3,500 GW.h into the U.S. or other markets at peak period pricing. Other available energy can only be exported during off-peak periods, and at significantly lower prices.

During high flow years, MH can be faced with selling about as much as 9,000 GW.h at off-peak prices. This depresses the average export price achieved, but increases overall revenue.

3.2.5 Potential Hydraulic Generation

Reservoirs within the Nelson-Churchill drainage basins allow MH to store water for later generation of electricity. This 'energy-in-storage', held at virtually no economic cost to MH, permits the Corporation to shift energy generation into other seasons of the year to meet variable domestic demand for electricity and to optimize export sales.

At the time of the hearing, MH's energy-in-storage was near the historic high level achieved in 1977 when Lake Winnipeg Regulation and Churchill River Diversion came into service. Lake Winnipeg water levels were at the high end of its operating range; flows on the Winnipeg River and the Churchill River were above normal; Saskatchewan River flows were near normal; and only Red River flows were below normal. This situation augurs well for fiscal 2008/09.

In IFF 07-1, MH predicted hydraulic generation of 31,000 GW.h for 2008/09 (representative of about 1,000 GW.h above the median flow scenario), reflecting the-then (at the time of the forecast being prepared) high level of energy-in-storage and median river flows. Current indications suggest hydraulic generation will remain above median for 2008/09.

3.2.6 Fuel and Purchase Power

In defining "dependable energy" available for export contracts, MH counts on about 4,300 GW.h of thermal energy, available to utilize in a worst-case situation. In reality, MH has typically employed about 800 GW.h of coal-fired thermal generation, but, due to the high cost associated with natural gas, rarely has MH fired up its natural gas-fired thermal generation for delivery of energy to the market.

In IFF 07-1, MH expects to employ thermal generation of 350 GW.h and 200 GW.h respectively in fiscal 2008 and 2009. In subsequent mean (average) flow years, coal generation would be fully utilized to support export sales.

IFF 07-1 anticipated that imports of 1,200 GW.h at a cost of about 5¢/kW.h would be required for purchase in fiscal 2009, with a further 100 MW of wind energy purchases. In mean flow years (that is, average flow conditions), about 2,000

GW.h of imports are expected to be required, in addition to increased wind energy purchases to meet domestic and export commitments.

Power purchase unit costs beyond 2008/09 are forecast to be about 0.5¢/kW.h below average export prices. Presumably, this expectation reflects anticipation of a degree of off-peak purchases for on-peak sales.

MH is also involved in short-term 'energy trading' in the MISO market. MISO transmission rights allow for energy to be purchased from MISO utilities for resale, either to another MISO utility or to Ontario, all within very narrow windows of time. No internal MH generation of energy is employed in short-term energy trading. Usually these trades produce a profit; and both the purchases and sales are recorded in MH's records as revenue and expense.

3.2.7 Costs of Export

As reflected in MIPUG's evidence presented at the hearing, PCOSS-08 results indicate generation and transmission 'bulk power' unit costs for metered energy, as follows:

- Residential 3.72¢/kW.h
- GSS-ND 4.12¢/kW.h
- GSM 3.84¢/kW.h
- GSL>100 3.29¢/kW.h
- Exports 4.83¢/kW.h

These costs neither include existing DSM nor the uniform rate adjustment, nor reflect net export revenue allocations. The class variations in generation and transmission pricing are largely attributable to the impact of distribution system losses and class variable load factors.

If the above values were recalculated at generation, each domestic class would be reported as incurring 3.0 to 3.2¢/kW.h of generation and transmission costs, and exports would be indicated to incur about 4.4¢/kW.h of generation and transmission costs. The latter indicated export cost compares to MH's forecast export price of 7.0¢/kW.h (and the actual export price of 5.0¢/kW.h for 2007/08).

In the absence of exports, MH's total costs would be lower by:

Share of generation and transmission costs	$167 M (including water rentals)
Imports	$134 M
Thermal fuel cost	$ 23 M
MISO, etc./trading distribution costs	$ 20 M
	$344 M

Even without an export operation, MH's costs would still reflect:

Uniform rate adjustment	$ 17 M
DSM	$ 25 M
	$ 42 M

Without an export operation (also without a corresponding import capability), MH's costs would be expected to be higher because of a requirement for the additional usage of natural gas turbine generators, the costs of which are estimated to be between $50 million and $100 million/year.

3.3 Interveners' Position

None of the interveners actively questioned the reasonableness of MH's domestic and export revenue and price forecasts. While RCM/TREE expressed concern about the growth of domestic load and the potential for that to result in reduced exports, the pricing of such exports was not subject to Intervener comment.

3.4 Board Findings

Overall, in the three-year period 2005 to 2008 MH has exceeded forecasted export revenues despite significantly lower than forecast export prices. Substantially above-average water flows and hydraulic generation has allowed for the higher export volumes, which have more than offset the lower prices.

Export prices in the last three years have averaged about 5.0 CDN¢/kW.h for dependable (firm) and interruptible energy sales. These pricing levels, when adjusted for the exchange rate, suggest a 4.6 U.S.¢/kW.h average MISO market rate. This is substantially below MH's IFF projections for the last three years.

MH's dependable sales into the MISO region in 2007/08 earned about 5.3 U.S.¢/kW.h for 5 x 16 energy. This price was similar to that experienced in 2005/06 and 2006/07, for the period of time that followed by a major escalation of natural gas prices after the damages of hurricanes Katrina and Rita were largely repaired and demand fell with weather deviations. It does not appear that export contracts that came into force about 2005 have provided any market price escalation beyond the consumer price inflation.

MH's opportunity sales into the MISO region in 2007/08 earned about 4.6 U.S.¢/kW.h. This price was also very similar to prices in 2005/06 and 2006/07. It also continued to track below the firm energy price - contrary to MH's forecasts of 2005.

MH's export market prospects in Ontario and the MISO region have not improved since the CEC market analysis. Rather, it appears that competition from other energy sources - coal, wind, nuclear and purchased co-generation - are reducing the potential.

Accordingly, MH's projected export prices in IFF 07-1 may be overly optimistic, in that they require additional demand for MH exports and significant environmental premiums in future contracts. American electricity prices are also contingent on achieving decisive U.S. actions with respect to GHG emission controls in the near future.

Overall, there are logical bases for the Board questioning MH's forecast of export pricing in IFF 07-1. Lower export revenues will result if:

- Exchange rates remain closer to unity;
- CO_2 pricing does not progress to a $30 CDN/tonne level in MH's market area within the forecast period;
- New coal generation plant in MISO region does not include substantial CO_2 emission reductions; and/or
- Inter-tie transmission capabilities into MISO are not significantly increased.

Export Sales

For reasons of confidentiality (commercial sensitivity), MH did not provide specific contract energy prices to the Board; the Board was not willing to accept the information in confidence. However, from public information it can be inferred that MH currently has contracts providing 5.5¢/kW.h and may be considering future contract prices that would result in average export revenues of about 7¢/kW.h or less (for firm and opportunity sales) in the absence of legislated carbon pricing in the U.S.

As such, the Board is unable to assert that MH will not be hard pressed to achieve the forecast export energy prices implied in IFF 07-1. Off-peak pricing is usually several cents/kW.h lower than on-peak prices and tends to lower the average export revenue price. It is possible, perhaps probable, that pending contract negotiations will achieve some indexing relative to natural gas prices and inflation. Indexing to coal generation prices (if employed) would rely heavily on possible future carbon pricing, which, as yet, does not have a definitive timeline.

MH export contracts are priced at 5.3¢/kWh, well below forecast average prices of 6-7¢/kWh. Consequently, opportunity sales prices would have to be upwards of 7¢/kWh, levels not evidenced by the information that is available. MH opportunity export sales are expected to return 4.6¢/kW.h in 2007/08 under a high water flow scenario, and these prices did not exceed firm contract prices. In short, MH's export market pricing has not lived up to the potential anticipated in the 2003 CEC market analysis.

MH's IFF 07-1 forecast export prices are based on a low CDN dollar and the presence of environmental premiums (GHG emissions) for both dependable and interruptible export sales. Existing contract and recently-announced term sheet prices do not appear to provide significant market price escalations beyond general consumer price inflation. In fact, MH's IFF 07-1 forecast export prices appear to require substantial carbon emission premiums, likely to be well in excess of recently suggested cap and trade CO_2 prices.

MH's IFF 07-1 forecast prices may only be achieved by a combination of:

- Exchange rate returning to 1.16 USD/CDN;
- New coal plants in MISO being required to show substantial CO_2 reduction; and

- Additional inter-tie transmission capability being added in very near future.

MH's most recent commitment to continue supplying peak energy into the MISO region for the 2010 to 2020 period is expected to backstop substantial new wind energy projects in the region. By taking hydraulic energy from MH when wind is not blowing, the receiving utility will be able to blend the costs and achieve possible GHG savings of wind energy with peak energy contract prices from MH and off–peak energy purchases at typically low spot market prices. The resulting average cost of electricity for the U.S. utility could be below MH's forecast export prices.

This suggests that MH's practice of selling all of its available energy capable of being transmitted during off–peak hours supports MISO's energy blending process. It ensures that, in general, substantial surplus energy is available at low prices during the off–peak.

In the Board's view, it might be in MH's best interest to withhold this energy from the market. At minimum, the Board suggests that MH consider this option and the Board will require that MH file a report on this option, providing the option's pros and cons.

Inter-tie Capabilities

Even in the absence of major new generation, additional inter-tie capability would enhance the value of MH's exports in above median flow years. As yet, MH has not gained formal commitments from cross-border counter-parties to expand inter-tie capacity.

Existing transmission inter-tie capacities are a serious impediment to higher prices; current limits are restricting peak energy sales and resulting in frequent off–peak sales at very low prices.

Recent term sheets signed by MH with Minnesota Power and Wisconsin Public Service offer hope for additional transmission capacity from the Manitoba border into and from the MISO market. This, coupled with new transmission from Riel Station to the U.S. border, could add appreciably to MH's export market potential.

While the concept of an East–West transmission grid has received some political support, there currently seems to be only limited prospects for enhanced export capabilities for MH into Ontario and Saskatchewan. As such, MH does not have an alternative market at the MISO scale.

Hydraulic Generation

MH has enjoyed favourable water supplies in 12 of the last 16 years. On a long-term basis, a reversal of this situation is a virtual certainty. Below median flow years and droughts are in the Corporation's history and can be expected on a regular basis; MH has had a beneficial "run" of better-than-normal water flow conditions now for the better part of two decades, a period of time that has seen MH's highest and lowest net income years (the lowest being the drought year of 2003/04).

Because energy-in-storage normally cannot be substantially carried from year to year, lower hydraulic generation during the forecast period through 2017/18 is an issue of realistic possibility. Export sales are likely to be reduced significantly in below-average flow years, and increased imports at higher cost per unit than the unit value of sales can also be expected in such years.

In the absence of higher export sale prices, MH should expect lower export revenues as hydraulic generation reverts to median, near-normal and below-median levels in the upcoming years. The favourable water supplies experienced in 12 of the last 16 years cannot be expected to continue without interruption.

While MH does not provide specific contract information for reasons of commercial sensitivity, access to this information is essential in order to confirm existing and projected contract prices of between 5.5¢/kW.h and 7.0¢/kW.h, and to ascertain what environmental escalation assumptions are being “banked” on. Given the crucial nature of these contracts and assumptions and potential impact on domestic rates, the prior review of upcoming export contracts by this Board would seem wise and appropriate.

Fuel and Purchased Power

A number of questions require responses in assessing MH’s forecasts, these include:

- Does IFF 07-1 adequately represent MH’s prospects for domestic and export revenues?
- Has MH adequately defined potential energy for export sales, export sale prices, and energy purchase costs (thermal fuel, wind, and imports)?
- MH’s coal generation, on a fully costed basis (approximately 6.5¢/kW.h), probably can compete in the MISO market during the peak load periods as it would displace gas generation. On an incremental fuel and variable Operating and Maintenance cost basis (approximately 3.5¢/kW.h) MH’s coal generation is an attractive export product.
- If the Brandon Coal Plant is either ’moth-balled’ or limited to emergency operations after 2011/12, in accordance with the announced intention of government, MH will have to expect to import, in a median flow year, an additional 800 GW.h at a cost of between $10 - 20 million/year.

- The allocation of MH's system costs in PCOSS-08 suggests that exports incur up to about 5.0¢/kW.h in costs for generation and transmission. Recent average export prices have been only slightly above this cost level.
- With the large investments required to meet domestic load and committed and/or contemplated export levels, there may be a need for export revenue prices even higher than the average 9¢/kW.h projected for 2017/18 under IFF 07-1. An updated IFF that extends out to at least fiscal 2027/28 should be provided to the Board by MH, this to project export revenue requirements and domestic rate levels required to support the current assumptions as to the economics supporting export commitments and capital expenditure plans.

In light of the many complex issues and questions related to MH's export program, the Board will direct MH to file a report by January 15, 2009 addressing the following:

a) An Overview of strategy, options, and historical costs and revenues;

b) Historical prices (monthly for the last five years) for exports including both on peak and off-peak;

c) Existing and pending contract commitments with forecast revenues, both aggregated and also disaggregated (in confidence if necessary);

d) Forecast export revenues – until 2028 identifying opportunity sales distinct from firm contract sales- broken down by on/off-peak;

e) Detailed assumptions used in market price forecasts (filed in confidence if necessary);

f) A testing of MH's assumptions through detailed sensitivity analysis for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and

g) Given the crucial nature of these export contracts and assumptions and the potential impact on domestic rates, MH file for Board review all upcoming export contracts.

4.0 Finance Expense

4.1 Changes in Finance Expense

The Corporation's finance expenses were $454 million in 2003/04, then-representing over 26% of total operating expenses. Finance expenses increased to $472 million in fiscal 2006/07, yet for the fiscal years 2003/04 through 2006/07 actual finance expenses were $172 million lower than forecast in IFF 03-1 (2004 GRA), as a result of declining long-term interest rates and the strengthening of the Canadian dollar.

MH forecast finance expenses of $404 million for fiscal 2007/08, and to increase by $22 million to $426 million in fiscal 2008/09 (the latter then to represent 29% of forecast annual operating expenses). The increase is attributable to higher debt levels and to a lesser degree, an increase in the debt guarantee fee paid to the Province, in aggregate offset by foreign exchange gains on the sinking fund related to changes in accounting standards for financial instruments (discussed below).

MH capitalizes interest on all capital projects during the construction phase, and does not amortize these costs and reflect them in rates until the project is in service. MH's finance expense for its electric operation before capitalized interest was forecast at $515 million for fiscal 2008/09 and $426 million on a net basis, after deducting capitalized interest of $89 million.

MH's gross finance expense is forecasted to grow to $906 million by 2017/18, and to $616 million on a net basis (again, after adjusting for capitalized interest of $290 million).

4.0 Finance Expense

Finance expense and capitalized interest for the years 2009 through 2018 are as follows:

Finance Expense ($ millions) For the years ended March 28/29	**IFF MH07-1** 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Gross Finance Expense	$ 515	$ 572	$ 609	$ 640	$ 657	$ 695	$ 756	$ 803	$ 864	$ 906
(Less) Capitalized Interest	(89)	(126)	(158)	(141)	(104)	(152)	(209)	(247)	(285)	(290)
Total Finance Expense	$ 426	$ 446	$ 451	$ 499	$ 553	$ 543	$ 547	$ 556	$ 579	$ 616
% Capitalized	17%	22%	26%	22%	16%	22%	28%	31%	33%	32%

MH forecast that its debt would grow from $8.0 billion in 2008/09 to $13.6 billion in 2017/18, a projected increase of $5.6 billion. The major increase in finance expense (before and after the deduction for capitalized interest) relates to the planned new major generation and transmission projects.

Over the planning period to 2017/18, capitalized interest is expected to aggregate to $1.8 billion. And, once the projects are in-service, the interest costs that have been previously capitalized will begin to be amortized/expensed, to be recovered in MH customers' rates.

In addition to the major capital expenditures included in the capital expenditure forecast provided at the hearing, MH also indicated that due to potential new export contracts, it may incur at least $6 billion more in capital costs and debt for additional required major generation and transmission facilities.

If these plans are implemented, MH's long-term debt may approach $20 billion by 2022, a large number, particularly in comparison with current provincial debt of approximately $11 billion.

4.2 Exposure Management Program and Foreign Exchange

MH has an Exposure Management Program (EMP) to manage the Utility's exposure to USD-foreign exchange fluctuations. The EMP operates by establishing a natural hedge between USD cash inflows from export revenues and USD cash outflows (long term debt coupon and principal payments, thermal fuel purchases).

The Overall Exposure Strategy concerns itself with a horizon of up to 30 years, and attempts to limit overall US foreign exchange fluctuations to within a range of + or – 20% of total debt. Only the portion of the USD inflows and outflows that are not matched under MH's EMP may affect annual net income. Fluctuations outside the 20% parameter are valued at the market exchange rate, and affect the annual financial result. The exchange rate at year-end is used for the balance sheet presentation of USD-denominated debt and investment instruments.

Commencing with 2007/08, the new standard of the Canadian Institute of Chartered Accountants (CICA) for the recognition and measurement of financial instruments and for hedges will apply to MH, and the forecast result was included in the IFF MH07-1.

The new standard requires significant changes in MH's accounting for financial instruments and hedging relationships, as well with respect to the recognition and presentation of foreign exchange gains and losses in annual financial statements. The change is expected to result in positive impacts to net income in the first two years of the new standard, benefiting 2007/08 by a forecast $37 million and 2008/09 by $9 million.

As a result of the implementation of the accounting change, the Board notes that MH has forecast amending opening retained earnings for 2007/08 by a one-time increase of $65 million.

4.3 Debt Management

4.3.1 Long Term Debt

MH's debt was $7.3 billion as at March 31, 2007, and forecast to increase to $8 billion by March 31, 2009. MH must rely on debt as its primary source of capital to finance new major generation and transmission projects, as government does not inject capital into the organization but relies on retained earnings from operations to provide capital.

To hold borrowing to a minimum required level, MH funds all routine capital construction from internally generated funds (i.e. from net income). Non-routine and major capital expenditures under way or planned include major new (other than the Pointe du Bois revitalization) generation and transmission projects and the new downtown Head Office building.

MH is in an expansion mode with planned capital spending of $11.3 billion over the eleven year period between fiscal 2007/08 and March 31, 2018. Over that period MH plans on spending $3.8 billion on its regular capital program and $7.5 billion on New Generation and Major Transmission and the Head Office project, as previously reported. As the result of recent export undertakings, yet to be formally confirmed, MH also expects to expend and borrow a further $6 billion by 2022, in addition to the $11.3 billion noted above.

Generally, and on average, debt financing is expected to fund approximately 62% of capital expenditures, with the remaining 38% to come from increased retained earnings, the latter from domestic rates and net export profits – the percentages reported excluding the additional $6 billion of debt related to above.

All in, including the additional $6 billion, MH forecasts an increase in its debt, from 2008's $7.3 billion to almost $20.0 billion by 2022.

4.3.2 Fixed vs. Floating Rate Debt

Pursuant to *The Manitoba Hydro Act*, MH's short-term debt limit has been set at $500 million; MH uses short-term debt to fund seasonal working capital requirements and bridge the timing before new long-term debt issues.

Historically, and in a typically upward sloping yield curve environment, the borrowing costs of fixed rate long-term debt tends to be higher than for short-term debt, though long-term debt fixes the interest rate for the full and longer period of the term, therefore reducing the risk of having to refinance at higher rates. In contrast, the borrowing costs of short-term or floating rate debt tend to be lower on average than for long-term debt, but are fixed for shorter periods, increasing the risk of having to refinance the debt at higher interest rates.

MH's reported policy is to limit the level of its floating rate debt to no more than 30% of total debt outstanding, and to manage the level of floating rate debt within a target range of 15% to 25% of total debt.

MH utilizes these target guidelines in an effort to provide rate payers with the economic benefits associated with the typically lower interest rates of short-term debt while protecting their customers against the risk of higher refinancing charges by reliance on the majority of borrowing being through long-term bonds.

MH's percentage of floating rate debt at each quarter end over the past three fiscal years has been:

Period Ended	Floating Rate Portion
Mar-2004	21.85%
Jun-2004	19.33%
Sep-2004	18.58%
Dec-2004	19.34%
Mar-2005	18.76%
Jun-2005	17.88%
Sep-2005	18.18%
Dec-2005	18.00%
Mar-2006	16.61%
Jun-2006	17.52%
Sep-2006	17.71%
Dec-2006	18.20%
Mar-2007	18.98%

Over the past four years, long-term interest rates have been at recent historic lows, and MH's general preference during this period has been to fix the majority of its new financing at the relatively attractive and low long-term interest rates. The strategy of favouring long-term fixed rate financing during periods when long-term interest rates are low relative to historic norms, and when the premium associated with long-term fixed rate debt is low and the yield curve is relatively flat, may produce costs over the long-term similar to that of a strategy of adding more floating rate debt, but with the added benefit of reducing the volatility of interest expense.

4.3.3 Sinking Fund Management

MH's bonds obligate the Corporation to establish and maintain a sinking fund, that are segregated investments held towards ensuring repayment of the debt. This obligation is currently legislated.

The legislated minimum contribution requirement is 1% of the long-term debt outstanding at the end of the previous year, plus 4% of the balance of the sinking fund at that date. Contributions for fiscal 2007/08 and 2008/09 will be equal to the legislated minimum, and total approximately $100.6 million and $109 million, respectively. MH has $246.5 million of USD denominated debt maturing during fiscal 2008/09, which is forecast to be fully retired through the sale of the related sinking fund investments.

MH reported that changes to CICA accounting standards with respect to Financial Instruments have made sinking funds less valuable, and, as matters were currently understood, the Corporation did not foresee any negative impacts from either borrowing at current interest rate levels, or to access capital from an elimination of the sinking fund requirement from its Act.

MH alluded to a possible transitional phase that could be considered that would, over a few years, substantially reduce or eliminate the Sinking Fund. MH has further suggested that such an elimination might be associated with a forecast cost saving of $93 million over the 11 forecast years of IFF07-1.

4.4 Interveners' Positions

The Coalition

The Coalition observed that MH has kept floating rate debt at about 20% of the Corporation's overall debt portfolio, which now exceeds $7 billion. The Coalition noted that MH's longstanding policy is to have no more than 30% of its debt in the short-term floating category, and that it has held to a target guideline of between 15% and 25% of total debt for the category. The Coalition noted that the policy is over 20 years old and cited studies indicating that employing a higher proportion of short-term floating debt than has been and is the current practice may lower interest costs and reduce finance cost volatility.

The Coalition submitted that while floating debt appears to offer economic benefits, high levels of such debt doesn't necessarily lead to the lowest level of risk. Coalition stated that with MH's overall debt in excess of $7 billion and with the current level of short-term debt in the range of 15 to 25% of that total, there appears to be a potential to move approximately $700 million of currently long-term debt to short-term, and that if by so doing MH was able to reduce its interest cost by a mere five basis points, annual savings of $3.5 million would result.

The Coalition expressed concern that MH has been managing its floating debt policy at the bottom end of the 15 to 25% range, and noted that in the 13 quarters between March 2004 and March 2007, MH's proportion of floating debt was below 20% for 12 of the quarters. While not suggesting mismanagement of the debt portfolio, the Coalition suggested the potential for savings and the level of risk related to decisions to be made warranted a re-examination of the current policy.

The Coalition recommended that the Board request MH to engage an independent review of its floating vs. fixed target range maximum, with consideration of options to be in terms of economic benefit and stability.

MIPUG

MIPUG requested that the Board direct MH to seek relief from the province with respect to all sinking fund requirements as soon as possible, and that the sinking fund requirement for MH's debt should be eliminated. MIPUG noted the projections of savings to come with such elimination, that being $93 million over the IFF07-1 forecast period. MIPUG noted that MH had indicated that the Corporation does not expect that the elimination of the sinking fund requirements would have any adverse affect on its borrowing rates, its ability to access capital markets, its available range of borrowing instruments, or the debt rating for the Province of Manitoba.

MIPUG suggested this was an urgent matter, given the scale of borrowings anticipated over the next 15 years, and in light of the forecasted reduced cost of longer-term borrowing.

4.5 Board Findings

Finance Expense

The Board is concerned that the projected growth of finance expense through to 2017/18 and beyond is being obscured by the increasing amount and percentage of interest being capitalized i.e. $89 million or 17% of gross finance expense in 2008/09, to increase to $290 million or 32% in 2017/18. Given MH's expansion plans are consummated, MH's debt is expected to increase to about $20 billion by 2022, and gross finance expense is expected to almost double from 2008/09 levels to over $900 million in 2017/18, while the annual amount of capitalization of interest is expected to more than triple, masking the cash cost of financing major new generation and transmission projects, costs that will ultimately have to be recovered in rates.

The Board notes that MH's policy and practice of capitalizing interest raises a question of the risk of inter-generational inequity, and requires close examination. That said, the Board realizes that if less capitalization occurred, then more of MH's current years' interest costs would be expensed and reflected in rates. In short, without capitalization, the ratepayers of today through to those of the era when the new generation and transmission assets would be in-service would face increased rates to finance capital projects, projects intended (other than through the economic benefits associated with construction) to benefit future ratepayers.

Thus, the Board accepts there is an argument for MH's current approach. To expense costs in the current period and reflect them in current rates when the costs related to the projects are not expected to provide "rate related" benefits until the future would mean charging the current generation of MH's customers for costs that, arguably, should be met by future generations.

The major question relates to risk and conservatism with respect to financial planning. Probably the best approach is a balanced one, an approach that would have current ratepayers pay for some of the costs of proceeding with new projects – which will generate current economic benefits for the Province – while holding future generations responsible for the majority of these costs, as it is those future generations that are intended to reap "rate-related" benefits from the new construction.

The potential for the approach to change lies in part with the upcoming adoption of IFRS. The new standards may not allow MH to capitalize costs for future amortization to the same degree as is now occurring. And, as indicated above, expensing costs that are now being capitalized in the period incurred will result in future ratepayers' rates being reflective not only of "current" costs, including currently amortized costs, but also cost burdens that would otherwise have been reflected in future rates for future ratepayers.

For the welfare of succeeding generations, this generation will likely have to shoulder more responsibility for the costs and risks being assumed by the capital expenditure plans of MH. This was the experience with the prior development of generating stations in the lower Nelson River – i.e. there is precedent for less capitalization of current debt costs.

Fixed versus Floating Debt

As to what represents the optimal mix of fixed vs. floating debt, the Board agrees that increasing the exposure to short-term floating rates would likely benefit current ratepayers in lower finance costs in the near term, but it might also expose future ratepayers to greater volatility and risk over the long-term (as and if interest rates increase).

Given that the debt, by its very nature, has been incurred to fund capital assets with expected lengthy service lives, MH's approach of funding the majority of its debt requirements with fixed term debt appears reasonable.

However, with the anticipated unprecedented growth in debt levels, the Board sees merit in the concerns raised by the Coalition and agrees that MH's longstanding policy related to floating debt would benefit from an independent review. Such a review may suggest a different mix between fixed and floating debt, which may reduce finance expense.

Because of the potential for MH's overall debt level reaching $20 billion, possibly over twice the debt taken on by the province on its own account (with all debt guaranteed by the province) the Board will direct MH to engage an external assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009.

Sinking Fund

The Board notes that elimination of the sinking fund requirement has been forecast to result in savings of $93 million over an eleven year forecast period. While the potential savings are alluring and demand a consideration of the positions of interveners and the views of the Utility, the Board believes that MH has been served well in the past by the obligation to have sinking funds. Yet, the Board accepts that its future benefit may be diminished due to changes in accounting standards and improvements in the capital markets.

The Board understands MH's perspective that elimination of the sinking fund requirement will have no impact on the credit rating of MH or the Province, nor would it limit MH's access to the capital that it clearly needs to proceed with its expansion plans.

Out of an abundance of caution, and in light of the major capital expansion and related anticipated growth in debt levels now planned, the Board will recommend that MH seek independent advice, as well as advice from government and its credit rating agencies, as to the merits of a possible elimination of the sinking fund requirements.

5.0 Operating, Maintenance, and Administrative Expenses (OM&A)

5.1 General

Over 74% of OM&A costs relate to labour costs, which include employee benefits extending to pension obligations. Actual and forecast OM&A expenses for fiscal years 2004 to 2009 are:

Operating and Administrative Costs ($000's)	Actual				IFF07-1	
Fiscal Year	2004	2005	2006	2007	2008	2009
Labour						
Wages, Salaries & Overtime	343424	354,661	370,289	383,597	411,091	425,514
Employee Benefits	59,154	68,442	70,184	73,636	78,335	79,902
	402,578	423,103	440,473	457,233	489,426	505,416
Other Expenditures						
Employee Safety & Training	-	5,275	3,686	3,487	5,267	5,367
Travel	23,062	23,534	26,212	27,729	29,679	30,399
Motor Vehicle	16,687	17,726	19,380	19,735	20,017	21,036
Materials & Tools	23,325	23,891	26,040	25,420	24,663	25,249
Consulting & Professional Fees	8,024	7,269	7,229	8,498	10,071	10,137
Construction & Maintenance Services	11,373	13,345	13,700	13,711	15,481	15,669
Building & Property Services	21,799	21,031	22,973	24,697	24,522	24,700
Equipment Maintenance	9,571	9,546	10,720	11,606	12,235	12,475
Consumer Services	5,081	4,203	4,301	4,316	4,881	4,980
Computer Services	4,547	3,959	4,293	2,622	1,077	1,102
Collections	5,035	5,161	6,790	7,218	5,359	5,466
Customer & Public Relations	4,956	5,223	5,585	6,493	4,581	4,698
Sponsored Memberships	1,163	1,149	1,012	1,187	1,172	1,197
Office & Administration	14,996	15,448	15,904	14,939	15,532	15,882
Communication Systems	2,027	1,844	1,447	1,866	1,834	1,870
Research & Development Costs	3,742	3,685	3,542	3,251	3,414	3,483
Miscellaneous Expense	1,957	2,461	2,143	2,423	2,757	2,812
Contingency Planning	-	-	-	-	4,941	7,254
Operating Expense Recovery	(17,263)	(18,104)	(19,199)	(20,579)	(19,806)	(20,192)
Total Costs	542,660	569,749	596,231	615,852	657,103	679,000
Less: O&A Charged to Centra	(52,786)	(55,232)	(53,085)	(53,505)	(56,600)	(58,000)
	489,874	514,517	543,146	562,347	600,503	621,000
Capital Order Activities	(147,693)	(157,730)	(170,459)	(176,994)	(196,853)	(207,500)
Capitalized Overhead	(58,824)	(58,174)	(62,028)	(61,887)	(63,450)	(64,500)
O&A Costs Attributable to Electric Operations	283,357	298,613	310,659	323,466	340,200	349,000
Number of Customers	501,650	505,660	509,791	516,861	520,259	524,220
OM&A Cost Per Customer ($)	565	591	609	626	653	665

Total OM&A expenses attributed to electric operations and after allocations to Centra Gas and the deferral and capitalization of such expenses to be amortized in future periods have increased from $283.4 million in 2003/04 to $349 million in 2008/09, a compounded annual growth rate of over 4%.

MH indicated that over the last few years, the Corporation has experienced cost and operating program pressures relating to: increased maintenance requirements (due to aging infrastructure); wage and benefit settlements that exceed inflation; additional overtime and increased staffing levels (to meet extra-provincial requirements); the expansion of programs (to meet higher customer numbers) and needs; and the meeting of environmental and other stakeholder expectations. These pressures were reported to be continuing and being compounded by a looming shortage of skilled labour, manifesting itself in higher training and labour costs.

MH stated that the annual compound growth in labour and benefit cost per Equivalent Full Time (EFT) position has averaged 3.8% over the period 2002 to 2007. The increases are due to a combination of general wage increases, merit and/or pay schedule increments, and other adjustments. MH reported that wage and benefit settlements that have been above the general inflation rate reflect higher compensation requirements for attracting and retaining skilled trades and professional staff and, as well, higher compensation requirements for northern staff.

Unfortunately, MH was unable to provide a segregation of OM&A expense associated with maintaining/sustaining existing assets versus expenses associated with changed processes and plans and actions related to construction of new plant.

5.2 Staffing Levels

MH indicated that between 2005 through 2009, its staffing levels were projected to increase further, by 455 EFT employees (from 5,866 to 6,321), with related labour costs to increase by $102.8 million. These increases were reported to be largely due to increased work requirements, with the largest additions expected for staffing levels in Power Supply (234 EFT) and Transmission & Distribution (142 EFT). MH attributed the growth of 180 EFT's between fiscal 2004/05 and 2008/09 as being related to meeting the Corporation's operating and maintenance needs, particularly given the plans for major expansion.

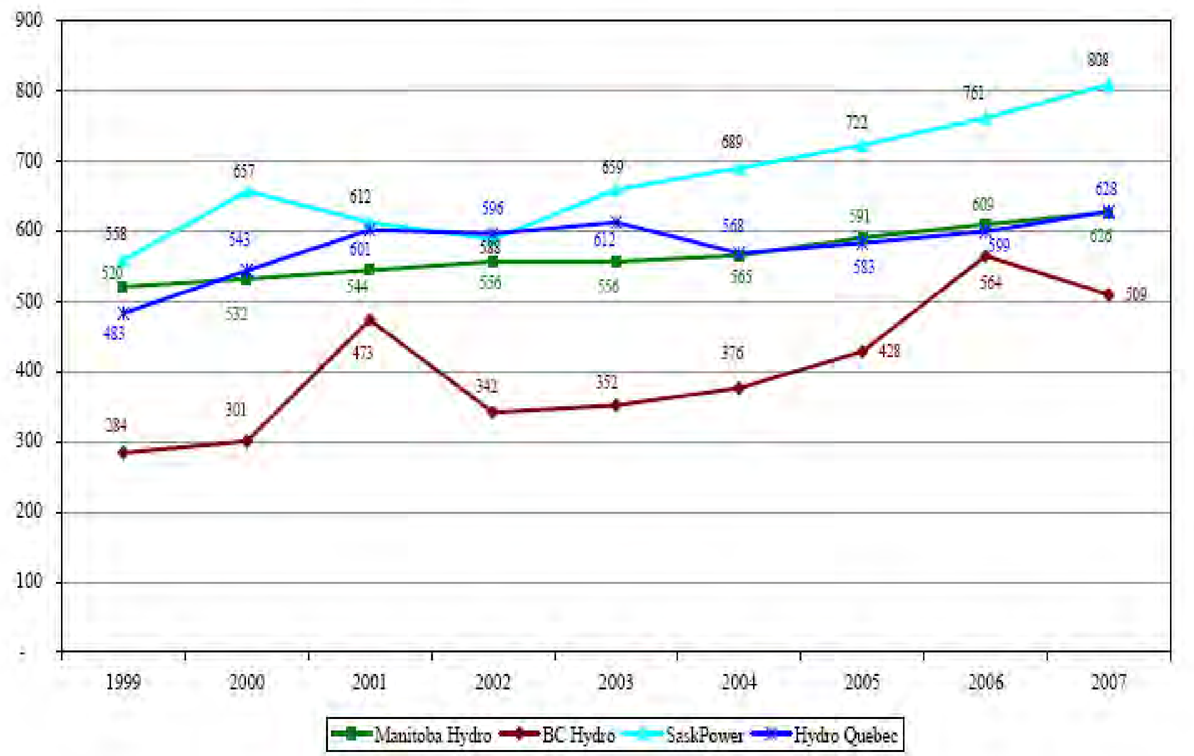
MH indicated that currently there were 200 unfilled EFT positions from the staff level forecast for fiscal 2007/08, and that between 125 and 150 of the EFT vacancies were due to difficulties in recruiting. The remaining unfilled positions were reported to be the result of awaiting the completion of the new head office and expected staff synergies to arise as a result of the consolidation of staff in one location. MH further noted that the hiring difficulty associated with the skill shortage had resulted in forecasted fiscal 2007/08 OM&A costs being $16 million less than forecast for the ten months ended January 31, 2008.

5.3 OM&A Costs per Customer

MH OM&A costs per customer have increased from $565 in 2004 to $626 in 2007. While MH indicated that it was not appropriate to directly compare its OM&A cost per employee to the ratios of other utilities, it noted that based on annual report information, Hydro Quebec's OM&A cost per customer was $628, BC Hydro's cost per customer was $509 and SaskPower's was $808, in 2007, as noted in the following graph.

MH compared its OM&A cost per customer with the other utilities for the years 1999 to 2007:

Manitoba Hydro
Operating & Administrative Expense per Customer
Comparison to BC Hydro, SaskPower and Hydro Quebec



MH reported that its OM&A expense per customer experience, relative to its established targets in the Corporate Strategic Plan, is as follows:

Fiscal year	CSP Target	Actual
2004	$600	$565
2005	$584	$591
2006	$600	$609
2007	$612	$626
2008	$640	$653 (est)
2009	N/A	$665 (est)

The Board notes that MH's OM&A costs and OM&A expense per customer levels were and are materially reduced by the capitalization of significant amounts of OM&A, making the comparisons with the other utilities of questionable value.

5.4 Capitalization of Operating and Administrative Expenditures

5.4.1 Current Capitalization Practices

MH segregates costs between operating activities, which are charged against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of the capital project. MH capitalizes certain of its OM&A expenditures.

Many of the expenditures are capitalized as deferred charges, and are amortized over a period of years; others allocated to construction in progress and amortized once the asset is in service over its expected service life.

MH indicated that employee's timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, MH also capitalizes 'overhead' by applying predetermined overhead rates to all capital projects.

OM&A expenses were $615.8 million in 2006/07, that is <u>before</u> capitalized activities and overheads. MH indicated that approximately 29%, or $177 million of the $615.8 million, was charged to capital order activities with an additional 10% ($61.9 million) charged as capitalized overhead. Overall approximately 39% of OM&A was capitalized.

MH forecast OM&A expenses of $679 million for fiscal 2008/09, of which $207.5 million (30%) is to be charged to capital order activities and $64.5 million (9%) as capitalized overhead.

MH capitalizes annually in excess of $60 million of overhead costs to its capital projects, to be amortized when the capital asset goes into service. In addition to the capitalized overhead, MH also includes some overhead costs to determine its activity rates, which are used for allocating direct costs of labour to operations or to capital projects.

MH also capitalizes Demand Side Management (DSM) expenditures arising from its Power Smart program. DSM program costs are deferred and amortized on a straight-line basis over 15 years, regardless of the expected present value of the benefits to be realized.

The carrying value of deferred DSM was $123 million at March 31 2007, and forecast to reach $180.9 million as at March 31, 2009.

Planning Studies involve costs related to uncommitted major generation or transmission facilities. These costs are recorded as deferred charges and are amortized to operations (expensed) on a straight-line basis over 15 years. If there is reasonable assurance that a project will proceed to construction, any unamortized balance related to that project is then transferred from deferred charges to construction in progress. The carrying value of the Unamortized Planning Studies balance was $28 million as at March 31, 2007 and forecast to be $22.5 million as at March 31, 2009.

Construction in Progress consists of contracted services, direct labour, material and expense, a proportionate share of overhead costs and interest applied at the weighted average cost of capital related to projects in development. Once the projects become operational, the costs are recovered in rates through depreciation and finance expense.

Establishment of the Affordable Energy Fund (AEF) by the provincial legislature, was funded by an allocation of electricity export revenues, and is to be used to fund low-income energy efficiency initiatives throughout the Province.

The AEF resulted in the creation of a $35 million deferred charge (asset) and a corresponding $35 million deferred credit (liability) in MH's financial accounts (balance sheet). Annual program expenditures from the fund are to be expensed against income in the year incurred, with the corresponding asset and liability reduced by the equivalent amount.

The balance of the AEF at March 31, 2007 was $34 million, after deductions for low-income related DSM project expenses, including overhead allocations, and the balance of the AEF as of March 31, 2009 was forecast to be $28 million. No interest accrues on the balance.

Goodwill of $62 million related to the 1999 acquisition of Centra Gas Manitoba Inc. and $46 million of additional goodwill associated with the acquisition of Winnipeg Hydro (WH) remains on MH's balance sheet. Goodwill represents the difference between the purchase prices paid for these enterprises and the values assigned to specific assets obtained. Goodwill is not amortized unless judged to be impaired, and impairment tests are performed annually in accordance with GAAP requirements – to-date, these tests have not indicated any impairment of the recorded goodwill.

MH also capitalizes experience gains and losses on its Employee Pension Plan, and amortizes the net result over the expected "life" of the employee group. The unamortized balance was reported to currently be in the $30 million range.

As of March 31, 2007, MH had $457 million of deferred charges recorded as an asset, including rate-regulated assets which, if MH were not subject to rate regulation would be charged to operations in the period that they were incurred.

The balance of the rate-regulated assets at March 31, 2007 were as follows:

Regulated Assets ($ millions)	March 31, 2007
Deferred taxes (Centra Gas)	$ 40
Site restoration costs	$ 38
Acquisition costs	$ 26
Power smart programs – gas	$ 11
Total	$115

Income Taxes paid by Centra Gas (July 1999) as a result of its change to non-taxable status upon its acquisition by MH were deferred and are being amortized on a straight-line basis over 30 years. Acquisition costs related to MH's purchase of both Centra and Winnipeg Hydro are also being amortized on a straight-line basis over 30 years.

Site restoration costs are deferred and amortized on a straight-line basis over 15 years.

5.4.2 Mitigation Costs

MH is party to a December 16, 1977 agreement also involving Canada, the Province of Manitoba and the Northern Flood Committee Inc., the latter representing the five First Nations in the communities of Cross Lake, Nelson House, Norway House, Split Lake and York Landing.

This agreement provides, in part, for compensation and remedial measures to ameliorate the impacts of the Churchill River Diversion (CRD) and Lake Winnipeg Regulation (LWR projects). Comprehensive settlements have been reached with all communities except Cross Lake. Expenditures incurred to mitigate the impacts of the CRD and LWR projects were $17.3 million during fiscal 2006/07 and, to March 31, 2007, $616 million had been spent in the effort. MH forecast to spend an additional $30.5 million in fiscal 2007/08 and a further $29.9 million in fiscal 2008/09.

In recognition of the anticipated future additional mitigation payments, the Corporation recorded a liability of $132 million as at March 31, 2007. Mitigation related expenditures are amortized over the remaining life of the Generation and Transmission assets to which they pertain.

MH has also entered into agreements with the Province of Manitoba whereby MH has assumed certain obligations of the province with respect to certain northern development projects.

To-date, MH has assumed obligations totalling $143 million and in return, Water Power Rental charges were fixed until March 31, 2001. The remaining liability outstanding as at March 31, 2007 was $13 million.

5.5 Future Changes in Accounting Standards

5.5.1 Adoption of International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) has established that 'publicly accountable enterprises' (MH, including its subsidiaries, is such a body) are to prepare their audited accounts in accordance with International Financial

Reporting Standards (IFRS). In short, IFRS is to replace current Canadian Generally Accepted Accounting Principles (GAAP) and it is to be implemented effective January 1, 2011. As annual accounts are provided with comparative information for the previous year, MH will be required to also develop IFRS-based accounts as of fiscal 2010 – 2011, to be disclosed as comparative information when it files its 2011/12 accounts.

In advance of the adoption of IFRS, Canadian GAAP standards have changed for rate-regulated operations. Specifically, section 1100 General Accounting of the CICA Handbook will apply to the “recognition and measurement of assets and liabilities subject to rate-regulation” for fiscal years beginning on or after January 1, 2009.

MH stated that the interim changes to GAAP are not expected to have an impact on its fiscal 2008/09 or 2009/10 financial results and statements. MH has taken the position that it will continue to be allowed its current accounting practices for rate regulated assets through its adoption of a secondary source of GAAP found in US accounting standards, also related to accounting for regulated operations. The assets and liabilities subject to rate regulation pursuant to US accounting standards amounted to $115 million at March 31, 2007.

Yet, early adoption of IFRS is provided for by GAAP and, depending on the actions of the Board, may result in a change in accounting for rate-regulated assets ahead of the required adoption date for IFRS.

5.5.2 Future Financial Implications of Adoption of IFRS

MH indicated that the major implications expected from the adoption of IFRS are reduced annual and forecast net income and retained earnings as of the date of adoption. These impacts are due to “stricter” standards than now exist with Canadian GAAP as to what must be capitalized as opposed to what should be charged to operations in a given year.

Although the implications for MH are not fully known, there is a likelihood that IFRS will require MH to recognize a higher level of expense each year, and a corresponding lower level of costs will be deferred and capitalized.

The current version of the International Accounting Standard (IAS) 38 - Intangible Assets, on which IFRS is based, is much more comprehensive than current Canadian GAAP. In order for an intangible asset to qualify, it must be separable from the entity, such that it can be sold, transferred, licensed or otherwise disposed of to another entity. Also, in order to record an intangible asset, it must be probable that future economic benefits are attributable to the asset and will flow to the entity.

If regulatory assets and deferred pension costs are not allowed under IFRS, the deferred balances at the date of implementation will no longer be allowed to be presented on the balance sheet and will be deducted from Retained Earnings, restating retained earnings to a lower balance.

MH stated that the full impact that IFRS will have on MH financial statements is not known at this time, as IFRS accounting standards are still in the discussion stage, with some of the discussion centred specifically on the capitalization policies of rate-regulated enterprises.

A major matter of considerable potential importance to the issue of rates to be resolved is whether IFRS will allow capitalization and deferral of certain costs for recovery through rates over future periods, providing that the utility’s regulator assures that future rates will reflect the deferred or capitalized costs.

MH indicated that it would be engaging a consultant to guide the Corporation through the transition to IFRS, and expects to have a better idea by the fall of 2008 on what impacts IFRS will have.

As of yet, there had been no preparation of pro forma IFF modeling the potential impact of the new accounting standards. MH further indicated that while the Corporation has no present plan to make an earlier adoption of IFRS, this decision may be revised once the impact that IFRS will have on its financial reporting is known.

In particular, MH testified that certain of its current capitalization policies may be affected by IFRS, and that several types of currently-deferred charges may have to be expensed for accounting purposes in the year they are incurred, unless it can be demonstrated that the charges have a future benefit to MH, thereby satisfying the requirements of IFRS. Included in deferred charges are $115 million of charges related to rate-regulated assets, which may or may not have a basis for capitalization and deferral under IFRS standards. MH further indicated that deferred charges related to Planning Studies (current balance, $28 million) and the Affordable Energy Fund (current balance, $34 million) may also not meet the IFRS capitalization criteria.

Another specifically cited major impact of IFRS adoption will be on MH’s practices related to capitalized overheads, which are now in excess of $60 million annually. MH’s understanding is that overheads will have to be a direct charge to specific projects, and to continue MH’s current approach may involve undue administrative complexity. Potentially, the full $60 million of annual capitalized overhead could be charged against operations in the year incurred, under IFRS.

MH further indicated that the allocation of direct labour to capital projects also includes an element of overhead, which also could be in contravention of IFRS and require revision. MH indicated that such a change in this matter could result in an additional $20 million to $30 million of annual costs to be expensed rather than capitalized. (MH testified that its understanding is that overhead capitalized in the years prior to IFRS will not have to be written off, and that IFRS would be prospective rather than retrospective in this regard.)

MH also stated that its current accounting policy that amortizes experience gains and losses on the Employee Pension Plan may also be affected by IFRS, and will likely result in a one-time write-off of the then-current unamortized balance, now being approximately $30 million. The future impact on operating results and retained earnings with respect to this particular matter will depend on the experience of the pension fund to fiscal 2010 – 2011, and thereafter.

MH also stated that its capitalization of mitigation costs may also be affected by IFRS, in that although costs may still meet the standards for capitalization, the tests used to treat them as an asset may require a more direct correlation to a specific capital project than is currently used.

MH opined that its current deferral of Power Smart Programs ($123 million) can be demonstrated to have a future benefit (that being the intended and expected creation of increased export revenue) and thus, continued deferral may be allowed under IFRS. Natural Gas Power Smart Programs (Centra) were specifically identified as possibly not meeting IFRS capitalization criteria, and thus may require expensing in the year incurred.

Overall, MH advised that the changes expected to be brought on by IFRS may result in annual increases in operating expenses in the order of $100 million (now, the equivalent of a 10% rate increase for domestic customers). In addition, MH has reported a potential $100 million write-off of disallowed assets against retained earnings on implementation of IFRS (and this may prove a low estimate).

MH understands that the application of IFRS will generally be prospective but noted that there are certain electives for first time adopters of IFRS that allow a deemed approach to be used to value items such as property, plant and equipment. This, too, could involve adjustments to MH's accounts, including retained earnings.

MH advised it expected to have its consultant's advice by the fall of 2008, at which time a more definitive assessment of the impact of IFRS will be available.

5.6 OM&A Cost Control Process

MH utilizes a comprehensive budgeting process to establish and monitor its OM&A expenses. An IFF target is established through a top-down process whereby submissions are made to MH's Executive Committee for review and assessment of the amount of operating costs required to operate the utility.

The Executive Committee reviews requests and makes submission to MH's Board of Directors for approval of a final budget. Once approved, target levels are allocated to the business units, and business units prepare detailed operating plans. Business units are expected to review opportunities for both cost increases and decreases in their detailed budgeting process, and are required to submit that information to the Executive Committee to assist with the next year's target-setting process. Variance analyses are performed monthly to evaluate the performances of the business units.

MH advised that its forecast for annual OM&A incorporates a 1% productivity factor to its otherwise expected labour costs in each of the years. Labour costs represent approximately 75% of MH's OM&A costs.

In Order 07/03, the Board stated:

> "Corporate performance measures, such as the operating and administration costs per customer or per kW.h targets, are of great assistance in assessing the performance of MH's cost control initiatives compared to other utilities. The Board recommends MH aggressively pursue meeting its operating and administration costs-per-customer target while finding ways to increase productivity. The Board also encourages MH to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities."

In its last three Corporate Strategic Plans (CSP), MH has outlined various strategies for improving productivity, including process benchmarking and the development of corporate and business unit performance targets. In the 2005/06 CSP, MH outlined two strategies for improving corporate financial strength: "leverage technology to reduce costs and the benchmarking of key corporate processes."

In the 2006/07 CSP, MH again outlined strategies for improving corporate financial strength, citing intentions to "leverage technology to reduce costs" and "benchmark against recognized service leaders". Yet, MH indicated at this GRA that it had not recently participated in any benchmarking exercises comparing its costs with those of comparable utilities.

In updating the Board on the status of these initiatives, MH stated that terms of reference and/or work plans have yet to be developed. MH conceded that work needed to be done in the area but stated that staffing resource limitations affect projects to be prioritized, and that benchmarking of processes was not of the highest priority level.

5.7 Intervener's Positions

The Coalition

The Coalition questioned whether MH had done what it said it would do to improve corporate financial strength. Mr. William Harper, a Coalition witness, expressed concern as to whether MH is undertaking everything it can do to identify and pursue productivity and efficiency improvements. Mr. Harper noted MH is forecasting an average annual increase in OM&A expense of 3.9% for the two year period fiscal 2007- 2009. Mr. Harper observed that the OM&A forecast of growth for this period was higher than reported in previous financial forecasts for the same period.

Mr. Harper further noted that the historical growth in OM&A over the last four years was 4% per annum. Looking forward, he noted that MH is forecasting annual customer growth of 0.6% per year, down from 0.9% historically, while wage and salary increases per FTE are also forecast to move down from 3.8% to 2.6%. Mr. Harper stated these two factors alone would suggest that OM&A spending over the two year period should be increasing significantly less than the 4% experienced historically, and less than the 3.9% increase proposed in the application.

Mr. Harper indicated that the potential annual savings related to a change in the expense growth factors would be $7 million in fiscal 2007/08 (the year finished before the hearing concluded) and $14 million in fiscal 2008/09, representing approximately a potential 1% reduction in rates.

Harper opined that overall projected OM&A cost for the periods through fiscal 2008/09 are too high and that a growth rate of 3% per annum (as opposed to the 3.9% forecast) would be more in line with the underlying cost drivers. Mr. Harper recommended the Board direct a reduction from the proposed rate increase of 2.9% (to 1.9%) to reflect this factor.

During the 2003-2007 period, MH's annual productivity improvement was reported to have been in the order of 1% per annum. However, during this period actual OM&A costs (when normalized on a per-customer basis) were generally higher than earlier forecasts and also higher than the annual CSP targets. Mr. Harper suggested that the evidence called for more discipline in the management of costs. Mr. Harper further stated that MH has consistently missed its CSP performance targets related to electric operations OM&A cost-per-customer. The OM&A cost-per-customer target for fiscal 2007/08 was $640 per customer; he suggested setting rates to match this target would reinforce the message that OM&A must be managed within expectations.

Mr. Harper suggested that productivity improvements cannot occur without action, and that what was required is an environment where opportunities for such improvements can be identified and staff encouraged to aggressively pursue them.

Mr. Harper noted that while appropriate strategies have been articulated in the CSP (such as leveraging technology to reduce costs and benchmarking key corporate processes against recognized service leaders), these steps have not been undertaken, and with respect to benchmarking, Mr. Harper noted that MH has indicated not having participated in any formal benchmarking exercises comparing its costs to those of comparable utilities. And similarly, that there has been no formal benchmarking process undertaken, even though the strategy has been articulated in prior corporate strategic plans over the last few years.

In the area of corporate and business unit performance measures, the Corporation has yet to develop a term of reference of work planned for this initiative, and Mr. Harper stated that MH should be encouraged to follow through on the strategies with a view of ensuring that the 1% per annum productivity improvement is actually achieved, if not exceeded.

The Coalition stated that given the large number of pending major new projects, it would be difficult for MH to balance priorities. The Coalition stated it was important for MH to get the "fundamentals" right, and that benchmarking has not been seen as a high enough priority for the Corporation.

The Coalition also cited the concerns raised by Mr. Bowman, a witness for MIPUG, about the divergence between forecast and actual OM&A results, a divergence that undermines the achievement of financial targets. The Coalition noted Mr. Bowman's' observation that systematic increases in OM&A spending have been a consistent and compounding reason underlying MH's failure to achieve the debt:equity target of 75:25.

The Coalition noted an example from its review of IFF05-1, where the forecast cost per customer in fiscal 2009 was $338 and that by IFF-07-1 the forecast costs per customer for the same year had increased to $360. The Coalition seconded Mr. Bowman's observation that this negative trend threatens to undermine the achievement of MH's financial targets.

With respect to the upcoming adoption of IFRS, the Coalition supported MH's position that it was premature to reach any conclusions on the impact at this time.

In supporting Mr. Harper's recommendation for the Board to reduce MH's requested revenue increase by 1%, the Coalition observed that while, at least in the short term, granting less than the requested rate increase might appear to be counter-productive to the goal of achieving financial targets, for the Coalition the short-term “pain” would likely prove beneficial in the longer term.

Reducing the requested rate increase would still leave the option for MH to put forward an application in 2009 or 2010 demonstrating improvements in cost control, and seeking increases in the revenue requirement once new capital expenses are projected and the Corporation has more certainty about the financial impact of the adoption of IFRS.

Mr. Harper suggested OM&A expenditures be evaluated on four criteria.

1. A review of cost elements, focusing on those that have changed significantly from one year to the next, to test the reasonableness of the underlying changes.
2. Evaluation of key cost drivers; with variations to be explained on the basis of unique or one-off requirements.
3. Benchmarking of the specific activity costs of the Utility against other utilities of similar characteristics.
4. Review of utility spending plans and priorities, incorporating an evaluation of an Asset Condition Assessment, to support any proposed increased spending. An Asset Condition Assessment (ACA) would, according to Mr. Harper, provide a “snapshot of the utility’s assets, noting the degree of degradation and need for rehabilitation and replacement”. For Mr. Harper and the Coalition, MH should be required to demonstrate that the condition of the assets has changed such that additional spending is required.

MIPUG

MIPUG also noted that MH's OM&A forecasts have progressively increased since the 2002 Status Update review, and that the Corporation's actual spending also routinely exceeds forecasts.

MIPUG noted that the growth in the level of OM&A spending has occurred despite prior Board directives for MH to consider cost control initiatives, citing that recently the Board noted in its decision with respect to MH's interim 2007 rate increase that it "…relies on MH's Board of Directors and senior management to continuously strive to operate the utility efficiently and incur no material costs that are not warranted from the perspective of sound business practices".

MIPUG submitted that MH's evidence in the proceeding did not support the conclusion that MH's OM&A spending is at levels consistent with an efficient operation. For MIPUG, this is particularly true when viewed in the context of forecasts prepared in recent years, as noted in some detail in the evidence of the Coalition's witness Mr. Harper which indicates increasing levels of spending.

MIPUG's witnesses Mr. Bowman and Mr. McLaren demonstrated that MH's OM&A forecasts generally trend higher, and have been doing so in each successive forecast since IFFO2-1, with IFFO7-01 being the latest of the series. Mr. Bowman and Mr. McLaren further observed that actual OM&A expenses have consistently been above the rising forecasts. In comparing the forecast period fiscal 2003 through 2013 with the forecasts in IFF 02-1 and IFF 07-1, Bowman and McLaren indicated a cumulative increase in OM&A of 10% as a consequence. MIPUG submitted that the Board should develop instructions and measures to better ensure MH applies effective cost control in the future.

MIPUG further suggested that the Board direct MH to provide full benchmarking information comparing its operations with other utilities, for review in a future GRA. MIPUG also suggested the Board direct MH to provide OM&A actual and forecast expenses by major function (Generation and Transmission, distinct from Distribution, Customer Service, and Administration). This request focused on the rationale that Generation and Transmission costs are not driven by the number of customers and, as such, a "cost/customer" ratio is of "no meaning".

For MIPUG, OM&A cost-per-customer ratios should be restricted to the distribution, customer service and administration functions.

In discussing the implications of the approaching adoption of IFRS, MIPUG stated there was insufficient information to make meaningful determinations on potential impacts on MH at this time. MIPUG urged the Board to direct MH to include with its next GRA filing an IFRS transition plan, including copies of reports produced for MH's consultants, and a summary of potential financial impacts.

With respect to adopting regulatory accounting to counter any negative implications of IFRS (in short, the construction of a set of financial statements prepared on a different basis than IFRS GAAP), MIPUG stated it was premature to consider whether such a step should be undertaken. MIPUG noted that regulatory accounting is an acceptable process currently being utilized by the Ontario Energy Board (OEB). MIPUG opined that there are an increasing number of issues that may lead to such an approach becoming justified in future, and in that event, the Board should not be averse to adopting the approach if needed.

As to MH making charitable donations, MIPUG opined that charitable donations, sponsorships and general economic development expenditures should not be reflected in rates, if material. However, MIPUG stated that there is no reason to exclude such costs in determining rates when such costs are not of material consequence to MH's financial results and forecasts. MIPUG opined that the current level of donations, as disclosed by MH in the GRA, should not be disallowed for reflection in rates, because the amounts involved are not material.

MKO

MKO agreed with the other interveners that MH should do more to restrain OM&A expenses, and also opined that MH's capital cost forecasts do not appear to be reasonable in light of the experience of actual costs. MKO also noted that MH's OM&A forecasts have generally trended higher in each successive forecast since IFF 02-1, with IFF 07-01 being the highest to date. MKO also demonstrated that MH's OM&A expenses have, in most cases, exceeded targets, and questioned MH's achievement of productivity gains.

MKO supported MH benchmarking costs against other utilities, and requested MH report to the Board why MH's costs deviate from the statistical average of benchmarked utilities.

MKO supported the suggestion of other Interveners that the implications of IFRS be considered in a future proceeding, at which time additional evidence would be required of MH and be tested by the Board and interested parties.

MKO recommended that MH revenues should ordinarily not be used for charitable purposes without specific direction from government. MKO suggested that MH had paid the Province $198 million in fees and capital taxes in 2007, and suggested that with provincial earmarking of such contributions for charitable purposes, the donations should be made directly by government, as that would be, in MKO's view, more appropriate.

MKO also recommended that MH and the Board clearly distinguish MH's necessary and appropriate costs (expenditures and investments related to operations, mitigation and agreement obligations) from "charitable donations". MKO suggested that endowments funded by MH's net export revenues (intended to benefit "MH Affected Communities", such as for regional economic development, community infrastructure and the enhancement of fish and wildlife) should not be "charitable donations".

5.8 Board Findings

The Board remains concerned with the growth of OM&A expenses, particularly the level and growth of these expenditures prior to deferrals, capitalization and allocations to subsidiaries.

As stated in Order 101/04:

> "The Board will expect MH to maintain vigilance over its costs, so that the additional revenues [from PUB approved rate increases] contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast."

Expectations from past recommendations related to OM&A expenses have not been met. The Board expects MH to control OM&A expense levels to assist in meeting its financial targets. Further control of OM&A costs is vital given the planned major capital expansion, and in light of the fact that MH will not meet its debt to equity target over the current forecast period.

And, in this Order, the Board continues to be concerned with MH's "aggressive" capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current generation of ratepayers leave the results for the generations that will follow to meet.

The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated:

> "The Board is concerned with the range and level of costs being capitalized by MH. While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers. If the Board questions whether aggressive capitalization policies are prudent...... The Board does not dispute that MH's accounting is based on GAAP, only that GAAP also provides for a more conservative capitalization approach."

In Order 117/06 the Board further stated:

> "The Board is concerned with MH's present capitalization and notes MH's comment that net export revenue represents a form of "windfall" which cannot be guaranteed to continue at recent levels. Even though net export revenues have been significant over the past decade, progress towards the debt:equity target of 75:25 is slow."

The Board notes MH defends its level of OM&A expenditures on the basis of 'need' and has argued that it has successfully 'controlled OM&A cost per customer account'. The Board is of the view that this premise will remain not fully substantiated, given the enormous amount and percentage of total OM&A costs that have been and are forecast to be capitalized, at least until adequate peer benchmarking has been performed and the results reviewed.

As expressed in past Orders, for two decades MH's annual net income result has been assisted/increased by its deferral and capitalization process. If non – direct construction costs (an allocation of the salary of staff in contracts not involved in actual construction but more in planning in supporting roles) had been expensed in the period incurred, rather than capitalized or deferred, annual net income would have been considerably lower, and possibly negative in many years; OM&A cost per customer account would have been much higher; rate pressure would have been considerably greater than has been demonstrated to date; and retained earnings would be much lower.

As indicated, while there is an argument for MH's current approach (to expense costs in the current period and reflect them in current rates, when the costs relate to projects not expected to provide benefits until the future, would mean charging the current generation of MH's customers for costs that could arguably be met by future generations), MH's rate structure and rates, even including the increases directed and indicated in Order 90/08, is premised on past and future OM&A cost deferrals and capitalization. If the approach was to change (a distinct possibility with the upcoming adoption of IFRS), costs now capitalized in the current period would be expensed. This would, again as previously noted, result in current and future ratepayers being billed for costs reflective not only of current costs but also cost burdens avoided by past ratepayers as a result of the current process of deferral and capitalization.

The Board does not believe OM&A should be adjusted based on the corporate strategic plan target of $640 per customer as suggested by the Coalition. The Board is not convinced the benchmark is completely relevant, given the level of expense deferrals and capitalization impacting the current result. Once more stringent capitalization requirements are put in place with IFRS such a metric may have more value and use in the establishment of rate requirements.

To arbitrarily direct, as some interveners have suggested, that a significant amount of expense not be reflected in rates, as a way of sending a message to

MH that it is spending too much on OM&A, would be irresponsible given what the Board and the recent process has revealed.

This Board must rely on the public GRA process to provide opportunities to assess OM&A, and while the Board continues to express concern, there is nothing on the record sufficiently concrete to justify not accepting the costs in rates.

IFRS

The Board notes the coming adoption of IFRS is likely to have a material impact on MH's financial reporting and results. The Board further notes that AcSB has, in advance of IFRS, established a new reporting standard with respect to accounting for intangible assets [including goodwill, deferred charges and capitalized expenditures].

These new requirements are effective for fiscal years beginning on or after October 1, 2008 and could have an impact on MH's fiscal 2009 - 2010 accounts. However, the Board is aware that MH is looking to U.S. Federal Accounting Standards Board (FASB) accounting standards in support of its continuing its present accounting practices in the short term.

The Board's primary concern is not accounting for the short-term, but the long term, particularly with MH's massive capital expenditure plans.

The Board notes in The FASB Handbook section 71.34 (in part), Accounting for the Effects of Certain Types of Regulation, reads as follows:

> "The regulator's action provides reasonable assurance of the existence of an asset (paragraph 9). Accordingly, the regulated enterprise would capitalize the cost and amortize it over the period during which it will be allowed for rate-making purposes."

The Board notes that interpretation of the above standard, which suggests continuing the current accounting practices of MH until IFRS is in place, will require the continued support of this Board.

Given MH’s reliance on a U.S. accounting standard, the question is - if the Board were to develop its own regulated retained earnings, net income and debt:equity ratio approach (ahead of mandatory IFRS adoption), one that is more “conservative” and has the effect reflecting in expenses and rates, more current period expenses, would regulatory accounting, in effect “two sets of books”, be in the public interest?

At the hearing, MH’s witness Mr. Derksen dismissed changes to rate regulated accounting at this time, noting that the CICA had deferred the matter awaiting a future conversion of Canadian GAAP to IFRS. Under US GAAP, exemptions from normal GAAP for rate regulated utilities depend upon the regulator directing the accounting treatment and are premised on the regulator effectively guaranteeing the utility future cost recovery of expenses then to be deferred through higher rates later on.

If the Board took the position that current capitalization and deferrals should not occur, perhaps reflecting its assessment of IFRS guidelines, MH would lose the ability to defer such items in its accounts, and this would affect total current expenditures, net income and, likely, rates.

The Board remains concerned with the Corporation’s ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider early adoption of IFRS standards. The Board further recommends that the Board’s prior concerns as well as its current views as expressed in this Order be brought to the attention of both MH’s external auditors and also, its independent consultant to assist the Corporation with its IFRS transition strategy.

In any case, with the reflection of IFRS in its accounts, intangible assets now on MH's books may have to be expensed. .

The Board further notes that MH has not adjusted its current forecast (IFF 07-1, which, as previously reported extends to fiscal 2017/18) to reflect the implications and impact of the new accounting standards. The Board accepts that such an adjustment, at least in a formal final sense, may be premature as the true impact and implications have not yet been resolved. Nonetheless, the Board is concerned with the impact on MH's financial statement of the transition to IFRS. The Board needs to be made aware of the implications to arise from the adoption of IFRS so as to be in a position to consider its regulatory options relative to the Board's jurisdiction.

Accordingly, the Board will direct MH to provide it a report by February 1, 2009, to be prepared by an independent professional accounting firm.

The Board will require MH to file, by January 15, 2009:

a) A report explaining and quantifying the proposed transition to IFRS.

b) A copy of MH's consultant's report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts.

c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS

d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS; MH's and its consultant's views of the Board's regulatory options, including a review of the pros and cons of special purpose financial reporting for utilities for rate-setting purposes.

e) Updated IFF and CEF forecasts, covering the years 2008 to 2028, reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH.

MIPUG recommended that regulatory accounting be considered as an acceptable deviation from GAAP for rate-setting purposes, following IFRS being implemented and assuming the implementation will have major implications for annual expenses, net income, retained earnings and, quite possibly, future rates.

MIPUG noted that regulatory accounting is prevalent in Ontario, and is a practice followed by OEB. However, the Board further notes that the OEB regulates natural gas utilities and 80 electric distribution companies, with varied ownership structures. In the Board's view, the use of regulated accounting by the OEB may be due more to the fact of the number of electric utilities it regulates and a perceived need to account for results on a consistent basis, rather than a desire by the OEB to depart from GAAP for rate-setting purposes. There is only one electric utility in Manitoba, MH, and it is regulated by this Board.

The Board notes the importance that MH and its financial position, plans and results has in the considerations of debt-rating agencies regularly assessing the financial strength and debt rating of the Province. The financial statements of MH are currently prepared in accordance with GAAP. IFRS will be the new GAAP required by all utilities, including MH. Any deviation from GAAP for rate-setting purposes may not be viewed in a positive light by debt-rating agencies, and a negative view could have negative implications on the credit rating of the Province, potentially limiting the source of capital and increasing the cost of borrowing for both MH and the Province.

Accordingly, the Board currently does not believe that separate regulatory accounting should be considered at this time, an approach that would involve deviating from GAAP and, in a sense, establishing a second set of books for MH rate-setting purposes. The Board further believes that a change to regulatory accounting, even if a case for it is established and found valid by the Board, is premature at this time.

The potential for adopting separate regulatory accounting standards that deviate from GAAP (after the adoption of IFRS) will be considered by the Board only once the Board has more information on the potential impact of the accounting changes on MH arising from IFRS, the implications of adopting regulatory accounting, and the potential implications of staying with GAAP or moving to regulatory accounting for rate-setting for the Utility's customers.

Staffing Levels

MH's personnel complement (measured in EFTs - equivalent full-time positions - and based on hours worked as recorded by MH) has soared since 1999, the first large increase accounted for by the additional staff added to the complement following the purchase of Centra Gas, followed up in 2002 by another major influx of personnel upon the purchase of Winnipeg Hydro (WH).

Even taking into account the additional personnel associated with those purchases, and after acknowledging MH's claims of synergistic savings resulting from one employer of all staff, it remains evident that considerable additional personnel growth also occurred, and this is ahead of the actual start up of construction (other than site preparation and roads at Wuskwatim) of Wuskwatim, Pointe du Bois, etc. (an increase of a few hundred additional personnel relates to new trainee positions associated with the Wuskwatim project).

Staffing levels are projected to further increase as the capital expenditure plan develops and is implemented. That said, and some growth explained, the Board remains of the view that MH should develop enhanced analytical tools to allow for a better understanding of the reasons for staff increases over the years. It is important to understand that staff costs represent the vast majority of OM&A expenses. Such staffing analytical tools should be developed and incorporated in the benchmarking analysis which the Board will direct be undertaken in this Order.

Cost Control Measures

The Board notes that staffing levels (EFT) is an important metric, though only one among others that should be further developed. The Board further notes that while the development of performance benchmarks and metrics has long been established as a performance goal of the Corporation, due to prioritization it, regrettably, is yet to be acted on.

The Board agrees with the Coalition that MH should develop performance benchmarks just as the Corporation has indicated it has planned to do for several years in a succession of corporate strategic plans. Given OM&A expense growth in prior years and forecast for the future, MH should assist GRA proceedings by providing the Board better tools to assess the appropriate level of OM&A for rate-setting.

Accordingly, the Board will direct MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:

a) Primary key drivers of OM&A in each operational division [Board preference is to allow for a comparison with a greater number of other utilities].

b) Comparable other Canadian Utility data for each of the drivers.

c) Key comparison indicators including staffing levels.

d) A comparison with and discussion of industry best practices.

e) Potential improvement areas.

The Board expects to be apprised of the scope of the study in advance of it being undertaken, and will anticipate being provided the opportunity to provide direction.

The Board is convinced that both the Province and ratepayers will benefit from the developments of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance and particularly because of, the proposed major capital expansion program.

MH's justification for the level and growth of OM&A expenditures includes an indicated need for increased maintenance and/or replacement of aging capital assets to maintain the safety and integrity of its electrical system. Recently this assertion is difficult for the Board to evaluate, as the Board lacks jurisdiction over MH's capital expenditures, yet capital expenditures are the major driver of rates.

One item that is lacking is sufficient support for the level of maintenance and upgrades to the existing capital assets of the Corporation. The Board notes Mr. Harper's suggestion that as a best practice, MH should undertake an Asset Condition Assessment, and his view that such a study will provide information on the degree of degradation of existing assets and the need for rehabilitation and/or replacement of capital assets.

Despite prior cautions from the Board, MH intends to spend, on average, $385 million a year on capital construction through to and including 2017/18, capital expenditures that are not related to major generation and transmission projects, which are accounted for separately. In an effort to better justify and demonstrate the necessity of such normal capital expenditures, the Board agrees with interveners on the need for a periodic Asset Condition Assessment Study.

The Board agrees that a study of this nature, done at reasonable intervals, will assist in evaluating MH's progress in maintaining the electrical system, and should also provide additional support for the level of OM&A being incurred and forecast. The Board believes it's appropriate that MH undertake such a study, and will so direct MH to undertake and file with the Board an Asset Condition Assessment by June 30, 2009, that defines:

a) major assets and categories of assets;

b) the estimated remaining economic life of each major asset and category of asset;

c) an indication of the implications for OM&A costs related to maintaining required and scheduled maintenance;

d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

e) forecast expenditures for planned renovations and/or replacements with respect to now-available energy supply and transmission; and

f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH is to file with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

New Head Office

With respect to MH's head office project, which is currently expected to involve capital expenditures in the range of $280 million (approximately 1/5th of the Corporation's retained earnings), the Board remains concerned that MH's savings from operating synergies and abandoned current leases may not develop sufficient overall savings to avoid a rate impact arising from the project.

MH suggested that there would be no increase in rates to pay for the new corporate head office, and that the Corporation expects the financial benefits of productivity improvements, and lapsed lease payment requirements, to offset the approximate $20 million of annual additional costs associated with its new building.

The Board has heard MH suggest it will target headcount (EFT) reductions and lease lapses to help offset the increased costs expected to arise with the new head office (depreciation, property and capital taxes, interest, operating costs, etc.), but also heard doubts expressed as to whether such savings would fully materialize.

The Board will direct MH to file a report with the Board by June 30, 2009, detailing the final all-inclusive capital cost of the corporate head office project including such things as construction cost, furniture and equipment, telecommunications, equipment leases and the contemplated or planned operating actions to recover incremental costs related to the new head office. The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.

The Board reminds MH that the Corporation has already been directed by the Board, through an Order arising out of a Centra GRA proceeding, that no additional costs are to accrue or be allocated to Centra as a result of the new head office. The head office came about as a condition of MH's purchase of WH; it had nothing to do with Centra.

6.0 Depreciation & Amortization

6.1 General

Depreciation and amortization expense was $276 million in fiscal 2003/04, rose to $314 million in fiscal 2006/07, and is forecast to further increase to $332 million for fiscal 2007/08 and $347 million for fiscal 2008/09.

MH attributed $6.5 million of the $18 million increase expected in fiscal 2007/08 (from fiscal 2006/07) to new depreciation rates, while the balance was attributed to normal amortization on increased capital assets.

MH instituted new depreciation/amortization tables as of April 1, 2007, flowing from a study that resulted in a forecast annual overall 2.2% increase in depreciation/amortization expense. The new study replaces the previous study that was undertaken in 2002; MH updates its depreciation/amortization studies every five years.

At the GRA, MH advised that it had revised the annual depreciation rate for the Pointe du Bois Generating Station from 1.94% to 11.65% to allow for the full amortization of the unamortized capital cost of the existing and old generating station over its estimated remaining life of nine years (a new generating station is planned to be constructed on the site, one with a higher capacity). As a result, the annual depreciation expense related to the existing facility increased by $1.9 million annually. MH plans on decommissioning the existing generating station effective March 31, 2015.

Depreciation and amortization is forecast to grow to $453 million by 2017/18, due to planned major increases in capital assets.

6.2 Board Findings

The Board agrees with the new depreciation rates, including the acceleration of the depreciation of Pointe du Bois to recognize that the existing asset is to be decommissioned and replaced. However, the Pointe du Bois upgrade and forecast work on the Slave Falls G.S., coming relatively shortly after the purchase of WH, raises a question as to the adequacy of present depreciation and amortization rates in use for the other generating, transmission and distribution assets acquired when WH was purchased, notwithstanding the five year review of such rates.

The Board further notes the provincial plan for curtailing Brandon Coal Plant generation [MH has estimated reducing the use of the plant to emergencies only will reduce its annual net income forecasts by $10 to $20 million dollars]. When the IFF is updated to reflect IFRS and other changes and issues raised in this Order, the decision to reduce the output of the Brandon Coal Plant should be reflected. And, if there is a decision to close the plant, this asset should be subject to an accelerated depreciation similar to that now in place for Pointe du Bois.

Accordingly, the Board will require MH to file a report by January 15, 2009 with the Board, indicating whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro, including Slave Falls, and the Brandon Coal Plant remain appropriate and the related proposed capital replacement, expansion and decommissioning costs.

The accelerated write-off of the existing Pointe du Bois facility also brings into question the price paid for Winnipeg Hydro, a price that also included a requirement to build the new head office, the cost of which is now roughly four times the original “placemarker” for the project reported by MH at the 2004 GRA.

The Board has concerns with the planned growth in capital expenditures and the related forecast increases in depreciation and finance expense, and comments further on this topic in other sections of this Order.

7.0 Payments to the Province

As a Crown Corporation, MH is not subject to corporate income tax, and it is neutral as to the federal Goods and Services Tax (GST), since GST paid for its purchases are refunded. While these exceptions are of considerable value to the Corporation, and, by extension, to its customers, MH does pay the Provincial Retail Sales Tax on its purchases, and, as well the Corporation Capital Tax, a tax that is to be deleted for private companies. The Province of Manitoba also levies a number of other fees on MH.

At the 2004 GRA, reported annual payments made to the Province from MH for fiscal 2003/04 were $175 million. The aggregate payment increased to $219 million in fiscal 2006/07 and was forecast to increase further to $230 million in 2007/08 and $223 million in 2008/09.

Total payments to the Province either made or forecast to be made from 2002/03 through 2008/09 are summarized as follows:

Payments to the Province ($millions)

	Actual					IFF 07-1	
Fiscal Year	2003	2004	2005	2006	2007	2008	2009
Corporation Capital Tax	33	35	35	36	37	38	40
Payroll Tax	6	6	7	7	8	8	8
Water Rentals	95	62	104	124	106	114	103
Debt Guarantee Fee	70	67	68	66	68	70	71
Sinking Fund Admin Fee	1	1	1	1	-	-	1
Special Payment	200	4	-	-	-	-	-
Total Payments	**405**	**175**	**215**	**234**	**219**	**230**	**223**
Retained Earnings	1135	707	845	1,265	1,386	1,650	1,774
Retained Earnings including Payments to the Province [1]	1,540	882	1,060	1,499	1,605	1,880	1,997
Total Payments as a % of Retained Earnings - Return to Shareholder[2]	28.8%	14.5%	22.1%	18.3%	14.1%	12.2%	11.2%
Total Payments as a Percentage of Gross Revenue	30.3%	13.6%	14.3%	12.8%	13.4%	13.8%	13.9%

Note 1. Approximates what retained earnings would have been at the end of the year if no payments to the Province were made.

Note 2. The Return to Shareholder is based on the payments to the Province over average Retained Earnings in each year (including the 2003 and 2004 special payments to the Province)

Overall, MH's payments to the Province have represented, excepting for 2003, a return on overall electricity sales to the shareholder in the range of 14%. While the concept of summary budgets results in the net income of MH also being recognized as income for the Province, that income is not available to the Province for its departmental spending unless paid in the form of a fee or dividend. Previously, this Board has recommended that no dividends be paid by MH to the Province until such time as MH has achieved and is expected to hold to its 75:25 debt:equity ratio target.

While MH pays Corporation Capital Tax to the Province based on its invested capital, which is a function of the level of capital employed, both debt and equity, Corporation Capital Tax is being phased out for all private corporations at the end of 2010. MH will remain subject to Capital Tax beyond 2010.

Water rentals relate to the use of provincial water resources, and the fees are paid to the Province on a monthly basis based on hydraulic generation. When, about a decade ago, MH was transferred certain northern liabilities of the Province, water rental rates were frozen to 2001.

The Provincial Debt Guarantee Fee is 1.0 % of the sum of MH bonds, provincial advances to MH and provincial short-term debt outstanding related to MH at MH's year-end. The fee was increased from 0.95% to 1.0% effective for fiscal 2006/07, and the level remains unchanged in MH's forecast for the full forecast period of IFF07-1. The Sinking Fund Service Charge is 0.075% of the amount of the sinking fund balance, and is paid to the Province for its managing of MH's sinking fund investments. MH's sinking fund is a covenant related to its bond issues.

A now expired legislative amendment to the MH Act provided for a special payment to the Province (dividend), which was made through a first instalment of

$200 million in 2002/03, followed by a remaining instalment of $4 million in 2003/04. For the purpose of comparison, dividends are regularly paid, and on an annual basis, by Hydro Quebec and B.C. Hydro to their respective provincial government owners.

The Province recently announced an intention to introduce new carbon legislation towards reducing Green House Gas emissions (GHG) in the province. MH stated that if it continued to operate the Brandon coal generating station at current production levels, the cost of the expected emissions tax on coal would be in the order of $5 to $6.5 million per year, commencing in 2011. However, it is expected that the generating station will, in the near future, be operated under very restricted conditions (for emergencies), which would reduce the emissions tax considerably. Nonetheless, the loss of the current level of average annual coal generation is forecast by MH to be $10 to $20 million annually – the operation of the plant has been profitable for the Corporation.

In addition to the payments to the Province, MH makes Grants in Lieu of Taxes (GILT) to municipalities with respect to MH buildings and structures that are located throughout the Province. In 2006/07, MH made $10 million in GILT payments, and the payments were forecast to increase to $15 million in 2008/09, the increase primarily the result of the new Corporate Head Office being added to Winnipeg's tax rolls. MH is currently negotiating with the City of Winnipeg and has estimated the annual property and business tax bill for its new head office will be in the range of $5 to $7 million dollars, the full effect to occur from 2009/10.

7.0 Payments to the Province

7.1 Interveners' Position

The Coalition noted that the special payment to the province of $204 million then-increased the debt to equity ratio by 3% and the debt component to 85% vs. 82%. By MIPUG's calculation, for 2008/09, the impact of the earlier payment remains at three percentage points.

The Coalition noted that payments to the province represent a significant benefit to the province.

7.2 Board Findings

The Board accepts that the projected payments to the Province represent a return to the Province of approximately 14% per annum of MH's overall electricity revenues. The Board understands that the Province employs these receipts to support health, education, social and other programs, for the benefit of all Manitobans.

MH is a prominent contributor to the overall economic well being of the Province, assisting in a variety of ways:

- Annual payments in excess of $200 million for water rentals debt guarantee fees, payroll taxes, capital taxes and other miscellaneous fees;
- Sales taxes, personal and corporate tax revenues with respect to staff and contractor complements and activities;
- MH's Annual net income, (projected to average $161 million per annum through 2017-18), which is included in the overall accounts of the Province;

- Mitigation payments to First Nations and Northern Communities related to the northern flood agreement and related pacts, amounting to in excess of $600 million on a cumulative basis, which has greatly assisted northern First Nations communities;
- Partnership agreement with NCN with respect to the Wuskwatim G.S. development, and potential pending relationships with other First Nations with respect to Conawapa and Keeyask;
- Targeted training and employment of northern and first nations residents;
- Grants in lieu of taxes payments to Manitoba's municipalities ;
- DSM expenditures towards the environmental objectives of the Province;
- Investment in wind generation, furthering provincial environmental objectives and rural community development;
- DSM low-income programs, to assist in sustaining low-income households;
- Planning for Bipole III to be constructed on the west side of the Province rather on the east side of Lake Winnipeg, to support the Province: object of protecting the boreal forest;
- Uniform rate design, (all communities and customers on the provincial electricity grid are subject to the same rate schedule, assisting with the economic and social development of rural and northern communities); and
- Export/import arrangements with American utilities within the MISO market and the provincial utilities of Ontario and Saskatchewan, which assist in increasing electrical reliability and the overall reduction of GHG emissions.

A further benefit to the City of Winnipeg has been the building of a new Corporate Head Office in downtown Winnipeg, a component of MH's agreement to purchase Winnipeg Hydro. The new head office will result in approximately 2,000 MH employees relocating to the new head office and contributing economically to local businesses and the further revitalization of the Winnipeg downtown.

The acquisition of Winnipeg Hydro has also provided the City of Winnipeg with an ongoing stream of revenue as a component of the sale agreement and saved the City and its ratepayers from the otherwise required massive expenditures to upgrade and maintain aging WH assets, such as Pointe du Bois G.S. Finally, with respect to the benefits provided to the City of Winnipeg, MH has expended over $13 million to upgrade the energy efficiency of the City's operations, the result to have an ongoing and substantial benefit to the City.

8.0 Financial Targets

8.1 Background

In September 1995, MH adopted the following financial targets, which were subsequently reviewed by this Board at the 2002 Status Update Hearing and, most recently, at the 2004 General Rate Application.

MH's current financial targets are as follows:

1. To achieve and maintain a minimum debt to equity ratio target of 75:25;
2. To achieve and maintain an annual gross interest coverage ratio of 1.20 annually; and
3. To fund all new capital construction requirements, except major new generation and/or major new transmission facilities (which include the new head office), from internal sources.

MH's financial targets have varied over the years, due to changing circumstances and priorities. Financial targets have been as follows:

Year	**Financial Target**
1995	75:25 debt equity ratio by 2005/06, interest coverage ratio of 1.20 to 1.35 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities and new head office building and DSM, from internally-generated funds

In 1995, MH moved to more aggressive financial targets to achieve a balance between fiscal responsibility, competitive positioning and customer bill affordability. MH expected that attaining the updated targets would result in lower debt, thereby reducing interest costs and ultimately assisting in rate restraint and competitiveness.

As at March 31, 2002, MH had a debt:equity ratio of 77:23, and appeared well on its way to meeting the 75:25 target. While the dividend to the Province represented an addition of 3 points to the debt element, the target was largely missed as a result of the 2003/04 drought.

The drought resulted in an approximate $600 million reduction to net export revenues relative to a normal flow period, and this, coupled with the $204 million special payment to the Province (planned and implemented before the drought), increased the debt ratio 10 percentage points in two years, severely impeding MH's progress toward its financial target.

Subsequently, the target year to reach a 75:25 debt equity ratio was changed from 2005/06 to 2011/12 to allow for a more gradual rate impact on customers. Since then, with major new capital construction in process and planned, requiring extensive new borrowings, there is no current expectation for the target to be met.

8.2 Debt to Equity

The debt to equity ratio measures the relationship of long and short-term debt (less short-term investments and sinking fund investments) to equity. The ratio is used by bond rating agencies and the Board, among others, to assess the financial risk MH represents.

Subsequent to reviewing the level of debt issued by the Corporation in relation to the amount of equity held in the form of retained earnings, there is no expectation that the Province will make equity injections into the Corporation; it is to manage its affairs such as to avoid such a requirement. MH established a debt to equity ratio target of 75:25.

MH's actual and forecast debt to equity ratios for fiscal 2003/4 to 2008/09, as compared to the forecasts of IFF03-1 presented at the last GRA, were and are as follows:

Debt to Equity Ratio Comparison Actual/IFF07-1 to IFF03-1

	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	87:13	85:15	81:19	80:20	77:23	77:23
IFF03-1	85:15	85:15	86:14	86:14	87:13	87:13

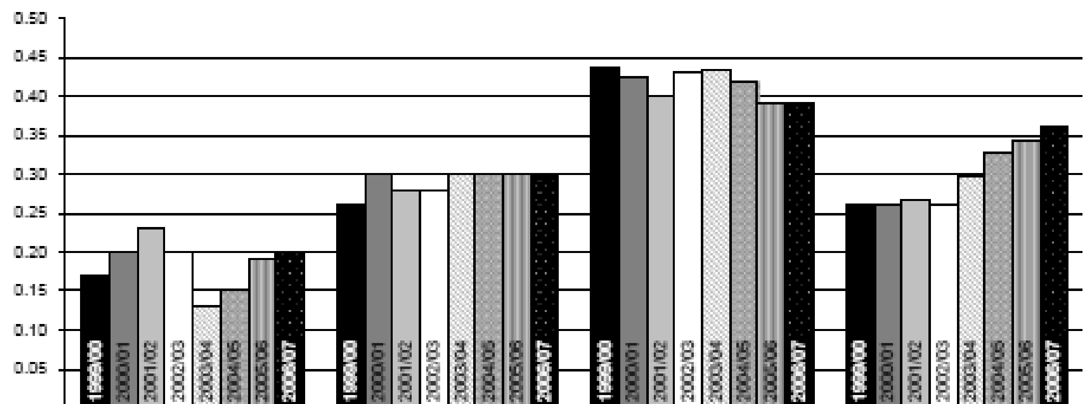
MH has made a marked improvement in its movement towards the 75:25 debt to equity ratio target since the 2003/04 drought. The Corporation's improved financial position relates to higher than expected extra-provincial revenue in fiscal 2005/06 and 2007/08, and rate increases granted by the Board in 2004 (5%), 2005 (2.25%), 2.25% (granted on an interim basis April 1, 2007 and finalized by Order 90/08), and 5% as of July 1, 2008 (Order 90/08). The 5% increase granted July 1, 2008 (Order 90/08) should assist.

8.0 Financial Targets

At the recent hearing, MH stated that its proposed 2.9% rate increase would assist MH in pursuing its debt:equity target, while being sensitive to the impact that electricity rate increases have on customers. The Corporation advised that it did not expect to reach the target debt to equity ratio within its latest long-term forecast period, that is, through 2017/18.

Compared to other Canadian utilities, MH has a higher debt to equity ratio:

Equity Ratios Comparison to Other Utilities



	Manitoba Hydro (Mar 31)	BC Hydro (Mar 31)	SaskPower (Dec 31)	Hydro-Quebec (Dec 31)
■ 1999/00	0.17	0.26	0.44	0.26
■ 2000/01	0.20	0.30	0.43	0.26
□ 2001/02	0.23	0.28	0.40	0.27
□ 2002/03	0.20	0.28	0.43	0.26
□ 2003/04	0.13	0.30	0.44	0.30
■ 2004/05	0.15	0.30	0.42	0.33
■ 2005/06	0.19	0.30	0.39	0.34
■ 2006/07	0.20	0.30	0.39	0.36

MH's current forecast IFF07-1 does not foresee MH meeting its 75:25 debt to equity target, neither by 2011/12 nor over the remainder of the IFF07-1 forecast period to March 31, 2018. MH forecasts a debt to equity ratio of 77:23 in fiscal 2017/18, the same as forecasted for fiscal 2007/08, even with cumulative rate increases of 33% assumed over the forecast period.

MH indicated in addition to the 2.9% rate increase it was seeking at the recent GRA, that (hypothetically) consecutive increases of 6.60% in fiscal years 2010, 2011 and 2012 would be required to reach the debt to equity ratio target of 75:25 by fiscal 2011/12.

Achievement of the 75:25 debt to equity target without larger rate increases appears to be virtually impossible due to the planned major increases for capital spending initiatives on New Generation, Major Transmission and the new office building, because of the corresponding increased debt levels to fund such construction.

As well, there is an increasing statistical probability that a new drought will set the Corporation back, and the losses from a serious drought could more than eliminate the current retained earnings balance. Other risks, including currency, interest rates, accounting standards changes, increased domestic loads and higher than now-projected capital expenditures also increase MH's risk status.

As suggested, changes in GAAP to come with the move to IFRS in fiscal 2011 can be expected to further hinder MH's progress to its debt to equity target, if not place even more pressure on rates going forward. A discussion of the IFRS changes is provided in other sections of this Order. As in previous Orders, the Board questions MH's cost deferral and capitalization practices which now have the effect of increasing annual net income and retained earnings and assisting in progress towards the stated debt:equity ratio.

8.3 Interest Coverage Ratio

The Interest Coverage Ratio is calculated to measure the degree to which net income before interest exceeds finance expense. MH's interest coverage ratios, actual or projected, for 2003/04 to 2008/09 are as follows:

Interest Coverage Ratio Comparison Actual/IFF07-1 to IFF03-1

	Actual				**Forecast**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	0.12	1.27	1.83	1.24	1.56	1.30
IFF03-1	0.29	1.08	1.05	1.05	1.03	1.04

The improved interest coverage ratio, relative to IFF03-1's actual and forecast, is due to higher than forecast net income and lower interest costs than forecast in IFF03-1. The actual ratio for fiscal 2003/04 was due to the drought and the loss incurred in that year. In the current IFF07-1, the interest coverage ratio target is achieved in all years of the forecast except for minor shortfalls from fiscal 2010 to 2014.

Again, achievement of the target in recent years has been assisted by MH's cost deferral and capitalization practices, which will change with IFRS. And, of course, there are the myriad of other risks that could lower annual net income and put the achievement of this target at risk.

8.4 Capital Coverage

The Capital Coverage, as formally stated, measures MH's ability to make "normal" non-major capital purchases without taking on additional borrowings. MH's actual or projected capital coverage ratios for 2003/04 to 2008/09 are:

	Actual				**Forecast**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
IFF03-1	(0.21)	0.54	0.50	0.41	0.48	0.56

Again, the actual results for fiscal 2003/04 were due to the drought, and the improved results since to improved water flow conditions and resultant higher exports, and with the continued exception of capital spending on major projects from inclusion in calculating the ratio.

MH's current practice is to exclude major capital expenditures when determining the capital coverage ratio. When major capital expenditures are included, the resultant capital coverage ratio indicates that MH must finance its major capital expenditures with debt, as opposed to the intended internally-generated cash flows.

Comparison of MH Capital Coverage Including Major Capital:

	Actual				Forecast	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
Including Major Capital and Head Office	(0.35)	0.86	1.64	0.70	0.58	0.34

Comparison of MH Capital Coverage Including Major Capital IFF07-1:

Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Actual/1FF07-1	1.74	1.07	0.69	0.76	0.84	1.13	1.03	1.1	1.22	1.21	1.40
Including Major Capital and Head Office	0.58	0.34	0.3	0.34	0.41	0.46	0.29	0.31	0.31	0.28	0.36

As previously indicated, the deterioration in the capital coverage ratio in 2003/04 was due to the drought; it led to MH's largest and a very major loss. The improvement since 2003/04, relative to the forecast in IFF03-1, is related to higher than forecast income due to excellent water conditions, providing for higher than expected export revenue, and a succession of Board-approved rate increases.

MH's capital coverage is forecast to decline in 2008/09 from that forecast for 2007/08 due to increases in capital spending. In the current IFF07-1, the target is met in all years except fiscal 2010 to 2012, those missed target years being due to increases in capital spending on new generation and major transmission projects.

Again, IFRS and the myriad of other risks faced operationally and financially by MH could reduce the net income now forecast for future years and further worsen the capital coverage ratios.

8.5 Reserves

The concept of MH establishing specifically defined reserves to meet risks associated with a drought or another calamity was suggested by MIPUG's witnesses.

The suggestion was that a reserve fund would be established out of retained earnings and future net income and, when deemed adequate, would be utilized to avoid what otherwise might be judged "excessive" rate increases, which, in the absence of adequate reserves, could be required.

With an adequate reserve in place, annual rate changes would be decided based on a judgment as to the sufficiency of the reserve funds in place to meet the risks of the Corporation, utilizing net income to build the fund during normal years and providing for a gradual recovery of a depleted reserve following a calamity that had resulted in the use of the reserve to prevent an "excessive" rate increase.

If MIPUG witnesses' advice and the intervener's recommendation was taken and such a reserve or reserves established, this approach would supplant the current reliance on retained earnings and the now-required or goal of meeting the 75:25 debt to equity target (as the means to avoid "excessive" rate increases driven by a calamity).

MH did not agree that a specific rate-protection reserve or reserves should be established, and considered the idea of segmented or restricted reserves to represent an outdated concept, and one abandoned by MH in 1992. Specific purpose reserves would, for Hydro, be inconsistent with contemporary principles of Enterprise Risk Management, in which the interdependence of risks is to be managed in a coordinated way across the Corporation.

In short, MH prefers to keep the 75:25 debt to equity ratio as its target "buffer" against <u>all</u> financial risks, and to forego the development of specific reserves to meet specific risks.

8.6 Interveners' Positions

Coalition

Mr. Harper opined that MH established a target debt to equity ratio for two primary reasons: first, to demonstrate to the financial community that MH is a financially sound Corporation (important because the perception of MH's financial integrity in the financial community affects the borrowing rate not only for MH but also for the Province of Manitoba, which guarantees the Corporation's debt), and the second, that maintaining a satisfactory level of equity provides a means of stabilizing rates under particularly adverse events such as a drought.

In meeting the financial impact of a drought (which brings losses and increased debt to equity ratios) what is important for Mr. Harper is the overall level of retained earnings and how it compares with the level of losses that might occur under various types of adverse events.

Establishing an appropriate level of reserves within this context involves more than estimating the cost of a five-year drought. Mr. Harper stated that more work needs to be done to assess MH's risks if the Board wants to establish an appropriate target reserve, even if the reserve is to continue to be expressed as retained earnings.

Mr. Harper stated that a proper determination of an appropriate level of reserves for MH would entail:

- Identification and quantification of the risks faced by MH;
- Identification of ways to manage these risks and, in particular, identification of those risks that would be managed through maintaining financial reserves as opposed to other approaches such as insurance, financial hedges and rate increases;
- A determination of the likelihood of occurrence of the various risks that are to be managed through reserves, and the extent to which individual risks are either independent or interdependent;
- A determination of the degree of a risk MH is willing to accept; and
- A quantification of the resulting reserves required.

Mr. Harper noted that the development of an appropriate reserve target should be an iterative process, as the degree of risk MH is willing to accept is dependent upon the level of reserves required and the cost of achieving such reserves, the cost being measured in the magnitude of possible rate increases.

Mr. Harper stated that forecast capital spending in 2007/08 and 2008/09 is considerably higher than historic averages, mainly due to expected higher spending on New Generation and Transmission, and noted that this spending is putting noticeable pressure on MH's debt to equity ratio. As of March 31, 2007, spending on major new generation and transmission projects was estimated to have increased the debt ratio by 2%, and by March 31, 2009, 5%.

MIPUG

MH's total capital – debt plus equity - is the denominator in the debt: equity ratio, and is expected to increase massively as the planned major new projects proceed. With domestic load expected to continue to increase, average export sales volumes can be expected to decline until new generation comes on stream. And, when new generation does come on stream, MIPUG noted that the experience has been that each new plant experiences a few years of marginal or loss years, placing pressure on annual net income levels and the debt to equity ratio during those years.

Thus, and for MIPUG, in the absence of annual and material domestic rate increases the current debt to equity target of 75:25 should not be expected to be reached in the foreseeable future, that is for more than a decade. Hence the problem, assuming the debt:equity target ratio of 75:25 is important and required to be met. If the target ratio is to be met, for MIPUG, ratepayers should expect annual rate increases, the only question being the magnitude of the increases.

To a large degree, the magnitude of the needed increases is, as MIPUG stated, necessarily related to major new capital projects and the new debt taken on to allow those plans to be realized. MIPUG thus linked future rate increases with projects to be advanced earlier than needed for domestic purposes, i.e. for export reasons, and claims that such rate increases would be contrary to "clear policy objectives" for these projects.

As such, for MIPUG, the debt:equity target (even if accepted as a valid target for assuring the Corporation's Board of Directors) is much too coarse to use as an analytical tool for the purposes of setting rate levels.

With the potential for further billions of dollars for additional capital projects in the years following the current IFF horizon, bringing debt up to, say, $20 billion by 2022, for MIPUG it is apparent that a 75:25 debt to equity ratio could only be achieved with unprecedented additions to net income by way of rate increases on top of the forecasts contained in IFF 07-1.

As to how much additional net income would be required to allow retained earnings to increase sufficiently to attain and hold to a 75:25 debt:equity ratio, MIPUG asserted up to an additional $2.5 billion in additional net income would be required, depending on the level of capital expenditures, above and beyond the net income forecast to come from annual 2.9% rate increases and net export revenues as currently forecast.

Reserves are required for the goal of protecting ratepayers from the risk of large rate increases driven by the actuality of a major risk. MIPUG's witnesses opined that MH's projected levels of retained earnings will be ineffective for this purpose, as the level of retained earnings is not directly overseen by this Board and does not provide the Board with a sufficient level of control.

MIPUG recommended that the Board should establish a reserve to cushion ratepayers from rate increases due to the risks faced by the Corporation, and discard further reliance on the debt:equity target ratio. And, per MIPUG, ahead of establishing the reserve to be required, the Board should direct that a major review of alternatives to the establishing of appropriate reserves be undertaken, as may be permitted within the appropriate legislation.

MIPUG urged the Board to consider the need for a focused debate on issues and options regarding establishing secure reserves. In such a review, consideration should, for MIPUG, extend to the determination of the appropriate levels of these reserves, alternatives for maintaining the reserves fully under the Board's jurisdiction and oversight, and, as well, measures for calculating, in any given year, the necessary level of appropriation to or withdrawal from, the reserve accounts – to affect the rate increase to follow.

8.7 Board Findings

Notwithstanding MIPUG's concerns and the hypothetical value the intervener claims for leaving the current method of determining the adequacy of MH's reserves, i.e. reliance on a debt to equity target, for specific reserves, the Board remains concerned that MH is not making sufficient progress in meeting and assuring holding to maintaining its current debt to equity target once met.

The Board is further concerned that during particular fiscal periods of the current forecast to and including fiscal 2017/18, MH does not expect to maintain either or both of its other financial stability targets, that being its interest and capital coverage ratio targets. The three measures of financial health and stability (debt to equity, interest coverage and capital coverage) are taken seriously by debt rating agencies and others, and while the ratios may not be expected to be maintained throughout the whole forecast period due to the effects of the expanded capital program, they still remain important.

Financial targets are set to be met, and to secure the future financial integrity of the Corporation MH also must, logically, take into account the upcoming adoption of IFRS, the possible future effects of continuing if not increased Canadian dollar appreciation and rising interest rates, and the rising cost of constructing new assets. The Board suggests MH consult with bond-rating agencies and government over what would represent an acceptable deviation from the existing financial stability targets during periods of considerable capital expansion, all to be financed by debt and rates.

The Board further notes that, cumulatively to March 31, 2009, and including the 5% established by Order 90/08 from July 1, 2008, approximately $400 million of additional revenue will have been generated from recent (since 2004) rate increases, following a decade of no domestic rate increases. However, despite these revenues and the on-going effect of these rate increases, with its current capital program plan and with ongoing increases in OM&A expenses, MH still does not expect to meet its debt to equity target within the current forecast period ending March 31, 2018.

The Board understands an argument can be made that current rate increases are due to capital expenses advanced for export purposes ahead of domestic load need, and that this may be considered to involve a degree of inter-generational inequity. However, the Board finds it unreasonable to expect current ratepayers to avoid any rate implications of plans now being made and implemented that contain not only opportunity but also increased risk for future generations.

The Board observes that this current generation of ratepayers may reasonably expect to gain from the economic activity associated with the Corporation's current capital plans, even ahead of those plans yielding any new export or domestic generation sales, and seeks a balance of interests.

That said, MH needs to provide the Board more assurance, through more detailed analyses and external assessments, that the risks now being taken on are reasonable and that the intended new projects will benefit not only current generations but future ones as well.

The Board notes that MH has a growing and significant level of non-revenue producing assets (intangible assets, such as deferred charges, goodwill and capitalized OM&A expenditures, the new head office building; and construction in progress, which includes large accumulations of capitalized OM&A). MH's current and forecast Retained Earnings through to 2017/18 is fully accounted for by these non-revenue producing assets, bringing into question the adequacy of a 75:25 debt:equity target with the current accounting approach - and this does not include reflection of IFRS.

The Board notes recent major export contracts being entered into since the filing of the GRA, though briefly reported on during the proceeding, are expected to require additional generation and transmission not yet included in the Corporation's capital expenditure forecast, projects that will push MH's debt closer to $20 billion by 2022 (assuming the forecast of the cost of these projects does not further increase materially).

It is the Board's view that, given the ambitious capital program and related increasing growth in debt, it is unrealistic to anticipate that MH will meet its debt to equity ratio of 75:25 even by the end of the current forecast period, 2017/18. Such a target has become seemingly impossible to attain given that the major capital expenditures contemplated are to be financed by debt, without truly significant rate increases.

The Board notes the Coalition's inference that Hydro's debt:equity ratio could be 80:20, and that such a change would be without risk as such a ratio is comparable to B.C. Hydro's new government-set target. However, BC Hydro does not have the same approach for deferral of expenditures as MH, and may not have the same OM&A capitalization policy as well. Furthermore, while BC Hydro's total long-term debt may be similar to MH's, BC Hydro has an annual revenue stream that is almost three times that of MH, providing a greater ability to service debt.

Furthermore, the degree to which B.C. government's debt ratings are dependent on B.C. Hydro is considerably less than the case with MH and Manitoba. It is the Board's understanding that rating agencies look prominently at MH's financial strength in assessing the credit rating of the Province. A weakening of the financial strength of MH would not be viewed favourably by those credit rating agencies and may have implications impacting the credit rating of the Province, making provincial borrowing more expensive. Such a development would not be in the pubic interest.

It is the Board's understanding that private utilities would have difficulty raising debt with a debt:equity ratio greater than 60:40, and that new projects would proceed only with the assumption of injections of additional capital. In MH's case, the assumption is that retained earnings represent the Utility's capital and that capital increases only by means of net income, derived from domestic rates and export profits.

If the Board were to implement, at least for rate regulation purposes, the Rate Stabilization Reserve model (RSR) proposed by MIPUG, it would be expected to deem certain earnings to contribute to the RSR while "unapproved" costs would "fall back" to MH and its sole shareholder, the Province. Under MIPUG's suggested approach, if the Province did not reimburse MH directly for such "unapproved costs", the Utility would be further at risk of missing vital financial targets.

As to MH's opposition to the RSR proposed by MIPUG, it is only partially valid. Put in the proper context, the RSR could be restricted only in the sense that it could only be used for identified operating "disaster" conditions. Under such an approach, deemed excess spending would not be reflected in rates by the Board, and would fall to the shareholder through the unrestricted retained earnings balance. However, if the Board were to adopt such an approach, a process would need to be developed to determine an appropriate level of the RSR.

What would represent an adequate RSR? Previously, the Board has requested that MH file a quantified analysis of its major risks and analysis that would put numbers to the major risks that have been identified. Not only would the risks associated with a five-year drought be quantified (MH has suggested that such a drought could result in losses of over $3 billion), but also the risks associated with the failure of major infrastructure, interest rate increases, further currency changes and, for any reason, the loss, even if temporary and for whatever reason, of the export market. In the absence of much more rigorous analysis, the Board is uncertain whether such an analysis would arrive at a RSR lower or higher than the current level of retained earnings required under a 75: 25 debt to equity target. The Board is concerned that there may be a case for establishing a higher reserve requirement, one that would further push rates.

On balance, the Board is of the view that a regulated RSR, i.e. the adoption of MIPUG's specific reserve proposal, is currently premature, at least ahead of MH identifying and properly quantifying its risks, as has been requested in past orders. Such quantification is vitally important given the increased risks that will accompany a debt level that may reach $20 billion by 2022.

Given the increase in capital spending, and recognizing MH no longer forecasts achievement (by 2012 or even 2018 for that matter); a 75:25 debt:equity ratio, it is time for MH to re-evaluate the equity target and set a new date for achievement.

Accordingly, the Board will require of MH a detailed, comprehensive and quantified Risk Review. The Board will withhold its final judgment on the development of reserves designed to meet the risks faced by MH until such a review has been placed before it and reviewed at a subsequent GRA. At least until then, the current financial targets stand.

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9.0 Capital Expenditures

9.1 General

MH's CEF 07-1 is a projection of MH's capital expenditures for new and replacement facilities to meet the electricity requirements in Manitoba, as well as expenditures to meet firm sales commitments outside the Province.

CEF 07-1 summarizes an eleven-year program of capital expenditures totalling $11.3 Billion to fiscal 2018, ranging from $831 Million in fiscal 2008 and increasing to $1.1 billion in fiscal 2018. Spending for New Generation, Transmission (and the New Head Office) total $7.5 billion, with the balance of $3.8 billion representing an ongoing capital program of, on average, $345 million per year. This represents a ten-year increase of $930 million in anticipated new capital costs, from that previously forecast in CEF 06-1.

New Generation and Major Transmission forecast in CEF07-1 was:

New Generation & Major Transmission Capital Expenditures CEF07-1 ($ millions)

Fiscal year	Project Cost	2008	2009	2010	Culmulative to 2018
Wuskwatim Generating Station	1,274.6	147.1	287.4	293.9	1,080.4
Wuskwatim Tansmission	319.8	79.2	107.9	47.1	280.0
Keeyask Generating Station Licencii	325.3	50.5	63.4	-	113.9
Conawapa Generating Station	4,978.4	32.6	57.8	54.7	2,162.1
Kelsey Improvements/Upgrades	183.9	36.1	30.6	28.4	123.0
Point du Bois Rebuild	900.5	13.5	23.3	35.0	896.0
Bipole III Western Route	2,447.8	1.9	2.9	9.3	2,237.0
Other	305.0	7.3	13.6	46.2	253.5
Demand Side Management		40.4	43.1	34.2	338.4
Total		408.6	630.0	548.8	7,484.3

9.2 Comparison of CEF03-1 to CEF07-1

At the 2004 GRA, MH filed CEF 03-1, which reflected capital spending of $5.8 billion over the eleven-year period from 2003/04 to 2013/14. Over the same eleven-year period, MH's actual capital expenditures for 2003/04 to 2006/07 and projected expenditures for 2007/08 through 2013/14 is now forecast at $8.5 billion, $2.7 billion greater than that forecast in CEF 03-1, as illustrated in the following table:

Capital Expenditures ($millions)

	Actual				Forecast				11-Year
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011-14**	**Total**
Actual/CEF07-1	455	485	504	634	801	1,016	958	3,648	8,502
CEF03-1	481	583	622	748	748	641	598	1,405	5,826
Difference	(26)	(98)	(118)	(115)	53	375	360	2,244	2,676

The major increase since 2004 is attributable to additional new Major Generation and Transmission, the new head office and cost escalations above the rate of general inflation on capital projects, expanded DSM programs, and increased maintenance on existing infrastructure.

9.3 New Generation and Major Transmission

There has been a significant increase in the costs of new generation and Major Transmission projects since 2004. MH cited the increase is due to inflationary pressures on labour, contract services and materials, the latter representing a condition of hyper-inflation, as well as other considerations. A comparison of significant projects cost changes between CEF 04-1 and CEF07-1 follows:

New generation and Major Transmission CEF04-1 to CEF07-1

($ millions)	CEF 04	CEF 05	CEF 06	CEF 07	$Increase 04-07
Wuskwatim G.S.	846	935	1094	1,275	429
Wuskwatim Transmission	199	200	257	320	121
Wuskwatim Total Project	1,045	1,135	1,351	1,595	550
Herblet Lake Transmission	55	54	54	95	40
Bipole III(1)	388	1,879	1,879	2,248	1,860
Pointe du Bois	288	692	834	900	612
Conawapa G.S. & licensing	4,050	4,516	4,978	4,978	928

Note 1: CEF-05 assumed Bipole III would be build east of Lake Winnipeg, the current intention is a western route.

MH indicated a significant escalation in capital costs for its projects that relate to many market factors beyond its control. Utility industry construction costs have risen and are expected to remain elevated for some time, reflecting underlying trends for cost increases for steel, copper and concrete due to high global demand and, as well, increased production and transportation costs due to much higher fuel costs. Another factor is a shortage of skilled workers that has driven costs higher for utility construction services.

9.4 Wuskwatim Generating Station (Wuskwatim)

9.4.1 General

The Wuskwatim Generating Station represents Manitoba's first new hydroelectric development since the late 1980s, and the first in Manitoba structured as a partnership (MH and the First Nations Nisichawayasihk Cree Nation (NCN). In approving the project the CEC recommended that:

> "The Government of Manitoba grant The Public Utilities Board jurisdiction to review, on an ongoing basis, as part of Manitoba Hydro's future General Rate Applications, the actual revenues and costs of the projects relative to forecast, along with the impact of the Projects on Manitoba Hydro's financial stability and its domestic rates."

This application represents the Board's first review of the Wuskwatim project as it now stands.

At the CEC hearing, MH justified Wuskwatim on the basis that the new generating station would be built to serve export markets, and stated that the power from the station would not be required for domestic consumption until 2019. Now, given current firm export contracts and an increase in forecast domestic load, MH indicates the power generated from Wuskwatim will be required by 2012 to meet domestic needs and firm export contracts.

9.4.2 Capital Cost of Project

At the outset, the capital cost of the Wuskwatim project, as presented to the CEC, was estimated at $900 million. The updated cost estimate now indicates a project cost of approximately $1.6 billion, an increase of $700 million since the CEC hearing in 2004, and an increase of $550 million since CEF04-1.

MH attributed the increase to inflationary pressures on labour, contract services and materials. The estimate also increased to account for both the deferral of the in-service date, from 2010 to 2012 and to account for increases in licensing costs.

MH also reported that the Wuskwatim Project Development Agreement allocates MH's overhead costs at a rate of 21% as opposed to the "normal" 29%, this reduction allowing for the exclusion of a share of costs related to Winnipeg facilities and computer systems not expected to be utilized by the project.

9.4.3 Wuskwatim Power Limited Partnership (WPLP)

The project is to be developed by the Wuskwatim Power Limited Partnership (WPLP), an equity partnership between NCN and MH. The project is unique, and represents the first time MH has entered into an equity partnership on a generating station project. MH suggested that the experience gained through the WPLP may be used in structuring agreements for future northern Generation projects, including the now-expected development of Keeyask and Conawapa.

The two Limited Partners are to invest equity in the project by subscribing for ownership units to represent 25% of the total capital cost of the project. The WPLP agreement allows for NCN, through its wholly owned Taskinigahp Power Corporation (TPC), to subscribe for up to a 33% stake in the Equity Partnership Units. MH, through a holding company (General Partner), would have a 0.01% interest, with MH, as a Limited Partner, holding the balance of 65.99%.

The assets of the Partnership are to consist of the Wuskwatim G.S. and required working capital. MH is to lend WPLP the funds required to build the generating station. Based on the Corporation's current estimated cost of constructing

Wuskwatim, excluding the transmission component, MH projects lending the partnership $927 million to build the generating station, representing approximately 75% of the cost of the project (the remaining funding to be through the Equity Partnership Units).

MH assumes TPC will subscribe for 33% of the ownership interest, i.e. 33% of the 25% equity component. Based on the current construction cost estimate for the generating station, TPC's cost for the partnership units would be $102 million. According to the agreements, TPC will invest up to $34 million of its own capital and borrow up to $68 million from MH to fund the balance.

Revenues generated from the project are to be allocated to the partnership from MH's overall revenues, based on an agreed-to (between NCN and Hydro) formula utilizing average export prices for peak and off-peak sales. Revenues are to be adjusted as changes in export prices are experienced and realized, and are to be based on the actual output of Wuskwatim G.S., reduced by the average system line loss rate for the MH system (currently 10%). WPLP is to pay MH 3% of the partnership's gross revenues, to contribute towards the marketing and transmission costs and risks borne by the Corporation.

MH will be fully responsible for the operations of the generating station and related transmission facilities, and will charge WPLP for its incremental operating costs. MH will make no cost allocation to WPLP for system generation and transmission. Control Center costs will not be directly charged to the project but be included in the overhead charge to the project. Finance costs incurred by the Corporation, related to the loans it will take on to allow it make loans to the partnership to build the generating stations, are to be recovered, at cost, from WPLP. The financing cost related to loans to WPLP has been estimated at 7%

interest, based on MH's expected long term-cost of borrowing of 6% plus a 1% Provincial debt guarantee fee.

The proposed Development Agreement requires that WPLP maintain a 75:25 debt to equity ratio, except for the first 10 years of operations where an 85:15 debt to equity ratio will be allowed (to account for anticipated initial losses in the operation of the facilities, losses are expected for the six-year period from fiscal 2011/12 to 2016/17).

If the partnership's debt to equity ratio falls below the above parameters, there is a requirement for further cash contributions from WPLP partners based on their ownership interest in the partnership.

The agreement between Hydro and NCN also allows for advances on dividends to NCN, even during loss years and/or when the equity threshold test has not been met. MH indicated that dividend advances are to be limited to 5% of the actual cash invested by NCN, and are to be repaid by NCN out of forecast future distributions.

9.4.4 Wuskwatim Transmission

In addition to the generating station, Wuskwatim requires incremental transmission facilities. MH is to build the required transmission facilities at an estimated cost of $320 million. The cost of incremental Wuskwatim transmission is to be recovered from WPLP by way of repayment over 50 years, the payments to include principal and interest.

Repayment of the loan is to commence upon Wuskwatim's in-service date, and MH stated that the blended principal and interest payment required will be the equivalent to having the transmission asset and offsetting debt on the books of the partnership and expensing depreciation and interest. In addition, the operating costs of the transmission facilities will be charged to WPLP.

9.4.5 Project Economics

In justifying the Wuskwatim project to the CEC, MH advanced many assumptions. Based on the then-projected construction costs of the project the levelized cost of the energy was to be 6.6¢ per kW.h (costs forecasted before the CEC). Given the escalated cost of the project, the Corporation's revised estimated cost of energy has increased to 7.2¢ per kW.h.

Before the CEC, and in forecasting export prices to be realized by Wuskwatim, MH utilized a USD/CDN exchange rate of 1.35. Based on its most current forecast in 2007, the exchange rate utilized in the Corporation's forecasts as for when Wuskwatim comes in-service in 2012 was 1.14, and this appreciation of the Canadian dollar from the original projection was forecast to result in a 5% reduction in forecast export revenues.

However, if the Canadian dollar remains near par with the U.S. dollar, MH projects export prices will be 17% lower than now forecast, a result that would further negatively impact the economics of Wuskwatim.

At the CEC Hearing, and in the Corporation's justification of the project, MH calculated that the Internal Rate of Return (IRR) would be 10.3%, based on generation being sold as exports. As a result of the escalation in the cost of the project and employing the same type of financial analysis as was presented to the CEC, the IRR has reduced to 7.8 %, excluding sunk costs, and to 6.5% including sunk costs. And, even this revised IRR would be further materially reduced if the Canadian dollar remains at par.

MH cautioned that recalculating the IRR on a similar basis to that presented at the CEC hearing, as reported on above, neither reflects the decision now required nor is consistent with engineering economics. MH's rationale for this view is based on Wuskwatim being built for domestic load purposes, and a comparison of the projected cost of energy to arise from Wuskwatim with the cost expected if that amount of generation arose from with operation of a MH combined cycle natural gas turbine. On that basis, for MH, Wuskwatim is expected to result in $14 million in annual savings over the next 30 years (providing $153 million of net present value).

9.5 Bipole III

Bipole III is to be a 2,000 MW, high voltage direct current (HVDC) transmission line from Gilliam, Manitoba to The Pas, and then down the west side of the Province to Winnipeg, Manitoba. In CEF 07-1 MH budgeted for a West Side Bipole III to be in-service in 2017 with a total cost, including escalation and interest during construction, of $2.247 billion.

The new HVDC line and associated converters (at Henday and Riel) is being advanced for domestic and export transmission capacity and reliability reasons. The recently-announced power sales to Minnesota Power and Wisconsin Public Service, (again not reflected in MH's forecasts as filed at the proceeding) if finalized, will also advance the need for Keeyask and Conawapa generation. On this basis, the new Bipole III line, with its converters, will be required to meet firm export load, as well as strengthen the domestic transmission system.

Due to provincial environmental and societal considerations, MH is proceeding with a West Side of Province routing for Bipole III, rather than the originally planned shorter routing on the East Side of Lake Winnipeg. MH provided a cost-benefit comparison of a West Side Bipole III as opposed to an East Side Bipole III, and identified a $400 million capital cost differential and a line loss differential of up to a further $181 million (in favour of an East Side Bipole III).

MH identified the potential for further significant price increases for construction as a whole, and power generation and transmission in particular. And, if this concern is realized, a further significant increase in forecast Bipole III costs could result.

Evidence presented at the recent hearing suggested that a repeat of the September 1996 failure of Bipole I and II, once Bipole III is in operation, built on the west side of the Province, would have more serious consequences if the interruption occurred during peak load. While an East Side Bipole III could function in parallel with existing Bipoles I and II, and in the event of the outage of both, make use of Bipoles I and II converters as well as the new Bipole III converters to provide 3,000 MW to the south, a West Side Bipole III would be limited to using only its own converters and thus could only provide the South with 2,000 MW in such a situation. MH advised that an outage of Bipoles I and II during the summer season could result in an additional cost to the Corporation of $160 million over the cost that would be incurred if Bipole III were built down the east side, the extra costs due to a requirement for additional imports to make up for the 1,000 MW differential.

In short, during a major outage of both Bipole I and II, an East Side Bipole III could serve both domestic and firm exports, while a West Side Bipole III would require significant additional needs and presumed expensive imports to meet domestic needs and firm exports.

9.6 Other Generation

Pointe du Bois Generating Station

MH is moving forward with its approval process for construction of a new generating station to replace an aged Pointe du Bois G.S. This $900 million replacement project is viewed to be an economically superior option to upgrading the existing plant.

In the 2005/06 Power Resource Plan, MH compared the capital costs of various scenarios as follows:

Capital cost scenarios ($ millions)

Capital Expenditure	Cost Estimate	Timeframe
Decommissioning	$125	By 2014
Rehabilitation	$358	By 2021
Repowering	$562	By 2017
Redevelopment	$615	By 2013

On the basis of subsequent economic, technical, environmental and socio-economic evaluations, MH concluded that the redevelopment of the Pointe du Bois G.S. was the more attractive alternative, with an in-service date of 2015/16. The capital cost estimates based on further analysis were refined and updated to reflect current conditions.

It is not clear whether this new capital requirement was taken into account during negotiations for the acquisition of WH.

Kelsey Generating Station

MH is upgrading the Kelsey G.S., at a forecasted cost of $123 million, by re-runnering the turbines. The intent is to increase plant capacity and gain additional energy output under average flow conditions. MH advises there was no expected gain in dependable flow generation from the enhancement.

Keeyask & Conawapa Generating Stations

In January 2008 after the GRA had been filed with the Board, MH announced it had signed a term sheet for a 250 MW power sale to Minnesota Power. And, at the hearing, MH stated that it had just signed a term sheet (an intent to sell) with Wisconsin Public Service (WPS) for 500 MW, the sale to start in the year 2018 for a 15-year term, with an expected value of approximately $2 billion over the term.

Occurring after MH had filed its GRA, the WPS sale was not considered in MH's filed Power Resource Plan. The sales, Minnesota and Wisconsin, are contingent on MH developing new hydro generation. New transmission inter-tie capabilities will be required by both MH and the counter-parties to the agreements, again to meet a condition of sale.

MH will require new transmission from Riel Station, on the East Side of Winnipeg, to the U.S. border, and estimated the cost of the Manitoba portion of the new transmission inter-tie to be approximately $30 million. Costs related to the new transmission line were not included in CEF07-1, and MH also suggested that additional Alternating Current (AC) transmission could also be required to optimize the new generation projects.

MH indicated it could have to develop Keeyask (620 MW) and Conawapa (1,420 MW) generating stations in close succession, (2018 and 2021, respectively) to meet the new export sales requirements. MH forecast that the cost of Keeyask, at approximately $4 billion, also not included in CEF07-1, and Conawapa, estimated to cost approximately $5 billion, of which $2.8 billion in capital cost are forecasted to be incurred after the current CEF07-1 forecast period of 2018, were not fully included in the latest IFF or CEF. (Recently, public statements have suggested that the cost of the Conawapa capital project could reach $6 billion.)

MH further stated that it may be required to build a combined cycle natural gas fired plant, at a cost of approximately $600 million, to meet projected energy deficits that could arise as early as 2017, ahead of Keeyask and Conawapa coming on stream. The cost of a new combined cycle natural gas fired plant was not incorporated in the current capital forecast, or in the latest IFF.

In short, the impacts expected to arise from the two new power sales are not fully incorporated in MH's forecasts; and IFF07-1 and CEF07-1 are to be revised by MH, with a copy to be filed with the Board.

9.7 New Head Office

As a condition of the purchase agreement entered into when WH was acquired, MH agreed to build a new Corporate head office in downtown Winnipeg. The building was originally forecast in CEF 03-1 at a cost estimate of $75 million, the amount then cited as a 'place marker' subject to design changes and cost revisions.

The new building is to accommodate approximately 2,100 employees and to be ready for occupation by 2009, and come at a projected revised cost of $278 million. Issues related to MH's new head office were also reviewed by the Board in Order 99/07, wherein the Board noted:

> "Centra estimated that overall cost impacts of the new head office would be $21 million per annum, to be offset by lease payment savings of $5 million and annual productivity savings projected to be in the range of $20 million annually. Centra assured ratepayers there would be no increase in rates".

The Board directed in Order 99/07, that:

> "Centra confirm to the Board that no incremental costs are to accrue to Centra's customers for MH's new head office;"

MH, on behalf of Centra, provided that confirmation in this GRA.

The incremental annual cost related to the new building was estimated at $22.8 million in the first year of occupancy, with an annual cost of $18.75 million thereafter. MH expects that productivity savings will be realized by bringing staff together at one location, allowing staff to work in closer proximity and in a more efficient environment, and that this will be sufficient to result in synergy savings of between 10% and 20% of otherwise head office payroll, to offset in part the incremental costs of the new building.

MH further stated that $20 million in productivity savings, to also include lapsed leases for currently-rented facilities, will be realized and offset the increased costs from the new building.

That said, MH indicated it would be difficult to focus on the details of savings associated with the new head office at future hearings. MH recommended the Board focus on the review of costs and savings from an overall basis to ensure that costs are fair and reasonable, rather than focusing on the head office.

While the new head office is being constructed as an obligation made upon the acquisition of WH, moving to common facilities may benefit both MH and Centra in terms of more efficient operations and better customer service, to be achieved through enhanced collaboration opportunities. Given that the costs allocated to MH's electricity and Centra Gas natural gas operations are based upon the costs incurred, any productivity savings that are attributable to providing service to gas customers would flow to Centra through the normal cost allocation process.

MH opined that substantial benefits were flowing to Centra as a result of the acquisition of WH and the related move to common facilities, and recommended that continuing to allocate the actual costs of the work performed on behalf of each utility to each utility would be the best course of action. As such, for MH there should be no special allocation process implemented to ensure that the costs of the new head office flow only to electric customers.

9.8 Interveners' Positions

The Coalition

The Coalition commented that the interaction of MH and the Province has led to tremendous benefits for Manitobans, citing benefits that included rural interconnection, connection of remote communities in the north, the northwest transmission developments, and cooperation between MH and the province that has realized significant economic development and provided contributions to provincial finances. The Coalition also stated it was important to also recognize costs to the Province in terms of these developments, including mitigation expenditures related to the Churchill River diversion.

The Coalition also observed ongoing impacts on MH's revenue requirements and financial indicators that are a product of the interaction between MH and the Province. The Coalition mentioned the new head office and the west side vs. east side debate concerning Bipole III as issues with important cost consequences.

In terms of Wuskwatim, the Coalition noted that the development is placing pressure on MH's debt to equity ratio and on its revenue requirement. In addition, the Coalition noted that the intended closure of the Brandon Coal plant (that is except, for emergency use) is another important impact arising from provincial involvement in MH decision-making. The Coalition stated that MH is experiencing significant pressures on its financial results from a variety of government policy and other initiatives, though many of them have, in the past, been beneficial to Manitobans.

Mr. Harper noted that MH's capital spending for the two closest forecast years, 2007/08 and 2008/09, is to be considerably higher than historic levels, mainly due to higher spending on new generation and transmission. Mr. Harper stated the spending is in part to protect in-service dates and is being done to meet export commitments and goals, and that this spending is putting noticeable pressure on MH's debt to equity ratio.

As of fiscal 2006/07, Mr. Harper opined the impact of spending on major new generation and transmission projects has increased the debt ratio by 2 percentage points. And, by fiscal 2008/09, increased capital spending will drive up the debt ratio by 5 percentage points.

Mr. Harper submitted that in the near term, Wuskwatim will have the most impact on the change in outlook for capital spending, due both to cost increases and as a result of the advancement of the in-service date. The Coalition observed that MH's capital spending plans influence decisions about the level of net income and the level of rate increases.

As previously mentioned, Mr. Harper argued for a direction to Hydro to develop an ACA and described an ACA as a snapshot of the condition of a utility's assets, noting that it would include degree of degradation and need for rehabilitation and replacement. He suggested that ACA are usually undertaken at intervals of two to three years.

Mr. Harper claimed that an ACA helps a utility pull together, on a systematic and organized basis, an overall comprehensive assessment (for planning purposes) of work to be prioritized across its entire asset base. And, through a process of prioritizing assets by way of an ACA, MH can further prioritize work in areas of the company where there is a deficiency of a critical nature. Mr Harper stated an ACA provides a logical foundation to support OM&A and capital spending

Mr. Harper further recommended that MH undertake regular ACAs every 2 to 3 years, and that the preparation of such assessments over time will allow MH to determine whether its assets are improving or deteriorating, helping to substantiate where there is a need for increased spending.

Mr. Harper noted that MH's capital spending requirements for both base capital and new generation and transmission projects are growing, when compared with past spending levels. He indicated that while increased export revenues should benefit future customers, the capital expenditures to prepare for those exports are putting pressure on current rates and are one of the drivers for MH's requested rate increases (that now exceed inflation). For Mr. Harper, MH needs to be mindful of these pressures when developing its overall capital expenditure plans.

Mr. Harper opined that the advancement of Wuskwatim was a contributing factor to current rate pressures. In reaching this conclusion, Mr. Harper noted that a significant portion of the increases in capital spending to be experienced in the next few years relate to the development of Wuskwatim.

The Coalition stated that there were lessons to be learned from the Wuskwatim development, lessons best learned before entering the anticipated decade or more of major capital expansion. The Coalition cited submissions made by MH to the Wuskwatim CEC proceeding, that:

> "Temporary increases in MH's debt to equity ratio and decreases to the level of interest coverage which may occur in the early years of the project are judged to be manageable without impacting the Corporation's financial stability or requiring off-setting increases to domestic rates."

The Coalition further cited the CEC report which stated:

> "The Commission's support for the project is contingent on Manitoba Hydro being able to maintain its commitment that domestic ratepayers will not experience rate increases as a result of the project."

The Coalition noted that the project is now forecast to cost $ 1.6 billion, including transmission. Taking into account both inflation and the effects of the delay in-service date, the Coalition noted an increase of $418 million (in 2002 dollars) in the expected cost of construction, and that as a result, the IRR, based on the methodology employed in the submission to the CEC, has been reduced to 7.8% when sunk costs are excluded, and to 6.5% when sunk costs are included.

The Coalition submitted that the revised IRR of 6.5% is roughly equivalent to the Corporation's cost of debt, and suggested that the lesson to be learned from the deterioration of expected return is that the CEC hearing did not examine closely enough the capital expenditure forecasts of MH.

As to the new head office, the Coalition questioned whether synergies forecast by MH will be realized to offset the approximate $20 million increase in annual costs.

As MH enters into a decade of expansion, the Coalition recommended that MH employ an independent review of both its capital expenditure procedures for major projects and also for its OM&A expenditures, considering both in terms of forecasting and management best practices.

The Coalition also recommended that the Province provide the Board the legal jurisdiction to review MH's major capital expenditures.

MIPUG

MIPUG also expressed concern with the growth in MH's capital spending. Mr. Bowman and Mr. McLaren suggested that the increase in capital spending has contributed to a deterioration in MH's financial position and is one reason that MH's debt: equity targets have not been achieved. Mr. Bowman and Mr. McLaren mostly attributed the failure to meet the accepted targets to major new generation and transmission plans, including Wuskwatim.

Given that these new projects were to be pursued on MIPUG's understanding that they would not drive rates higher for domestic customers but would, over the long term, benefit domestic customers, the witnesses opined that the use of these capital projects as an implicit justification for rate increases should be of concern to the Board.

MIPUG stated that although MH had not indicated it was seeking rate increases to address the costs of bringing Wuskwatim into service, the net effect of retaining the 75:25 debt to equity ratio target requires rate increases from domestic ratepayers.

In assessing the level of MH's capital spending and its impact on the province, MIPUG suggested the Board should set rates that both reflect the cost of operating the Utility plus provide provisions or reserves for the maintenance, operation and eventual replacement of existing assets.

For MIPUG, there is no basis or regulatory convention allowing the Board to focus on the credit condition of the shareholder (the Province) in determining rate levels. For MIPUG, the Board's role is to focus on the financial condition of the Utility, solely for the benefit of its customers.

MIPUG also opined there was no basis to argue that rates should be increased for "balance sheet" reasons, i.e. to "pre-fund" the equity required for the coming phase of capital expansion (Conawapa, Bipole III, Keeyask, new cross-border transmission, Wuskwatim and Pointe du Bois).

MIPUG strongly opposed the Board taking into account concern for the Province's credit rating, and suggested that to do so would be roughly equivalent to raising rates in the 1950s to advance Grand Rapids, which came into service in the 1960s. MIPUG contended that such an approach would not have been necessary, as the Grand Rapids project, as a long-lived MH asset, has been able to cover its interest costs, repay all debt borrowed for the purposes of its construction, and provide cost-effective power for generations of ratepayers..

MIPUG cited prior Board Orders which expressed concern as to the implications of increased capital spending by the Corporation, noting from Order 143/04:

> "The Board continues to be concerned with the progress of substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Keeyask, Conawapa, and may be justified individually when considering the each project purpose and forecast results over the long term. However, collectively these projects negatively impact MH's debt to equity ratio of and

> net income in the initial years, placing increase strain on the financial stability of the MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the company."

MIPUG noted that MH's normal capital program has not been reduced, despite the Board's "strong" directives of Orders 7/03 and 143/04. MIPUG argued for greater regulatory scrutiny of capital spending, and urged the Board to continue to seek the necessary legislative amendments, as sought in past Orders to provide for Board oversight of MH's capital expenditures, an oversight that, for MIPUG, would be consistent with the objectives of *the Public Utilities Board Act*.

Mr. Bowman and Mr. McLaren cited CEF 07-1 as indicating that MH will be spending approximately $4.1 billion on normal capital programs to 2017/18, an average of $375 million per year. When compared to CEFO2-1, where normal capital spending was forecast to be $3.1 billion, an average of $285 million per year, the witnesses expressed concern over an increase of 30%, or 6% per year.

Mr. Bowman and Mr. McLaren noted that this level of growth, only half being consistent with expected general inflation over the period, was excessive. They opined that with capital project cost escalation occurring, it is possible that while a 6% sustained annual growth may be justifiable as reflective of premium "construction project" inflation over the period, MH has not reflected any notable cost control measures consistent with the Board's past directives.

MIPUG again recommended the Board should pursue oversight of MH's major capital projects, perhaps via a recommendation to the government for a legislative provision similar to the Certificate of Public Convenience and Necessity process that occurs in other jurisdictions.

MIPUG further stated that in the event additional Board oversight is not provided by government, nonetheless the Board clearly retained the ability to set the Utility’s rates, and could employ that ability to ensure MH is not provided upward rate adjustments to compensate the Corporation for investments the Board may not view as prudent. MIPUG stated that the Board is not bound to “adequately fund” all operating and capital decisions made by the Utility, and that the Board should reach a conclusion on the prudence of the expenditures to be reflected in rates.

MIPUG further suggested that the Board request renewal of the mandate provided the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH’s Major Capital Projects (covering the period 1990 to 2009). Among the other benefits MIPUG suggested would arise from such a review, MIPUG suggested that the Board’s resulting report to the Lieutenant Governor-in-Council, which would arise from the review, could include a discussion of compelling policy considerations for the Government of Manitoba to address. Given the current expansion plans of MH, MIPUG held such a review would be timely.

MKO

MKO noted that MH has an aggressive capital plan that may be the most extensive in the Corporation's history, with the possible exception of the previous nearly back-to-back projects at Grand Rapids and Kettle.

MKO agreed with the position put forward by MIPUG, and suggested the Board should take on the responsibility to review major capital expenditures expected to have an impact on rates.

MKO further recommended that the Board acknowledge that MH-affected First Nations are, in essence, the original capital investors in the MH system. MKO asserted that Article 18.4 of the 1977 Northern Flood Agreement acknowledges its assertion.

Accordingly, MKO recommended the Board acknowledge that MH-affected First Nations are, at minimum, co-investors in MH's hydroelectric generating facilities, and are, in effect, "perpetual holders of Class "A" shares (in MH)", for which a return on investment should be identified and "paid" to First Nations.

RCM/TREE

RCM/TREE also noted that MH is facing significant capital costs with the major construction projects now expected and suggested that the capital costs to be incurred will take place at a time when MH has a high debt:equity ratio.

RCM/TREE suggested that even with the new construction programs, MH is forecasting energy shortages in the years 2009 to 2011, shortages to arise from accelerated domestic load growth. RCM/TREE indicated that load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment

RCM/TREE suggested that the consequence of 'suppressed electricity rates' is increases in domestic load growth that go beyond previous predictions, and that the increasing load growth threatens the export surplus, hastens the requirement to construct more costly new plants for domestic use, escalates the level of greenhouse gas emissions in North America, and has the potential for an adverse impact on Centra Gas' results and situation "if the flight from gas to electricity for water and space heating continues".

9.9 Board Findings

The Board recognizes its statutory jurisdiction does not extend to the approval of capital expenditures. Yet, it is clear MH's anticipated capital spending and associated increased debt levels is and will place upward pressure on rates. The Board has, as interveners have noted, expressed concern with MH's debt growth in previous orders. In Order 143/04, the Board noted:

> "The Board continues to be concerned with the progressive substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Gull, Conawapa, and may be justified individually when considering each project's purposes and forecast results over the long term.
>
> However, collectively these projects negatively impact MH's debt to equity ratio and net income in the initial years, placing increased strain on the financial stability of MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the Company."

The Board reiterates the prior concerns, and notes that with planned major capital expansion, such concerns are now graver.

In this GRA, interveners requested that the Board revisit its prior recommendations and recommend to government that the Board be provided with the statutory authority typically vested in the public utility regulators – that is, the authority to review MH's capital expenditures before such investments are committed.

In prior Orders, the Board has recommended to Government, that *The Public Utilities Board Act* be amended to make the regulation of MH equivalent to the regulation of Centra Gas by removing the exemption now provided under Section 2(5) of the Act.

In Order 143/04 the Board noted:

> ”Given the risks related to the very significant additional plant investments and associated borrowings contemplated, the Board is of the view that the Province of Manitoba should re-evaluate the existing legislation.”

The Board reiterates its past recommendation.

The Board’s concern with MH’s capital spending has previously been described, (Orders 07/03 and 143/04). With this new GRA, and with the update provided during the hearing, MH has set out planned capital expenditures that are unprecedented in the Utility’s history. The Capital Expenditure Forecast projects that from 2008/09 to 2017/18, the Corporation plans to spend $11.3 billion (of which $7.5 billion is for new major generation and transmission assets and $3.8 billion for other power supply requirements) – with further capital expenditures likely to also occur given recent export sales (i.e. Keeyask and Conawapa).

In its application, MH projected that its in-service undepreciated plant will increase by $8.6 billion to reach over $20 billion by the end of 2018, and that its debt would correspondingly increase from $7.2 billion to almost $12.7 billion by the same end date. In addition, due to recently-reported potential new long-term export contracts to Wisconsin and Minnesota, capital expenditures are expected to further increase. Assuming they are finalized, the new export contracts will require additional generation and transmission expenditures of a currently estimated cost of another $7 billion (for the planned construction of Keeyask by 2018, and Conawapa by 2022).

The additional capital expenditures are not reflected in the current capital forecast, and accordingly, the Board will, require MH to update and extend its forecasts to include the new projects. The overall level of capital spending now anticipated will result in a large increase in debt that will result in higher finance (interest), depreciation and OM&A expenses. The Corporation's debt:equity ratio, already not at the target range, will also be negatively affected.

And, based on historical experience, and consistent with MH's forecast with respect to Wuskwatim, new generating stations can be expected to operate at a loss during a large part of their first decade of operation, and this too will add pressure on the financial targets, debt levels and rates.

Limestone G.S., which came on line in 1992 at a favourable capital cost, did not achieve any positive cash flows from export sales during the first eight years of operations. However, the project recovered the initial shortfalls and now continues to contribute substantially to the Corporation's bottom line. In the absence of Limestone G.S., MH could not anticipate any significant export revenues in the IFF 07-1 forecast period.

With unexpectedly high capital costs and a somewhat flat export market, Wuskwatim G.S. may not achieve a positive cash flow for a period exceeding the projected loss estimates of the Corporation. By the time Wuskwatim can be expected to "break into the black" its output will serve domestic load only and the advancement of the project for export purposes, as originally planned, will not have proven out.

It could be reasonably expected that the advancement of Bipole III, Keeyask and Conawapa projects will face at least a decade of negative cash flow, even if transmission inter-tie capabilities are doubled. Thereafter these projects are projected to contribute to the bottom line as long as there is substantive action in the MISO region toward achieving CO_2 emission reductions.

To allow the Board to gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 an updated Capital Expenditure Forecast, and an Integrated Financial Forecast and Power Resource Plan and Load Forecast, all to extend from 2008 to 2028.

The updated Power Resource Plan should provide alternative scenarios with and without implementation of the pending new export contracts and related capital spending. It should also provide an indication of what hydro generation opportunities remain, such to be feasible opportunities, after Wuskwatim, Keeyask and Conawapa, and where the additional projects would occur and what possible quantity of energy would be expected, along with the assumed development timeline. The Load Forecast should also reconcile projected and actual DSM savings.

While MH anticipates that interest rates and inflation will continue to be low, history suggests that both factors fluctuate. Increases in either interest rates or inflation would be problematic to the costs of the proposed capital expansion program. Construction cost inflation over the past five years has been dramatic, in some years 10 times or more the rate of general inflation for some construction cost elements, particularly commodities. As to currency fluctuations, this factor is also subject to widely different possible scenarios, again outside the control of the Corporation (excepting, and to a limited degree, for longer-term “natural” hedges, and, for the short-term, financial instrument hedges).

While the Board agrees interest rates, currency fluctuations and commodity costs are affected by events outside MH’s control, the Corporation should still consider the risks of undue developments in these factors as it plans.

In the Board's view, the capital expenditure forecasts for future construction may prove to be low, thus it would be prudent to model worst case scenarios as well as those considered more likely and reasonable by the Corporation.

MH's export commitments appear to be the recent driver of the need for new major generating stations and transmission facilities. With the exception of Wuskwatim, which was reviewed by an expanded CEC hearing on the basis of export (not domestic) need, the new major capital project and export commitments have not been subject to regulatory review.

Such major capital projects and export agreements can either help or negatively affect MH's financial position, and one of the possible negative outcomes is the potential for rate increases. This was the case in 2004, when MH experienced a drought and the honouring of its export commitments came at a great cost and had a role to play in the rate decisions then made.

The consumers of MH electricity, as represented at the GRA by MIPUG, Coalition, MKO and RCM/TREE, advocate that the Board pursue oversight of MH major capital projects. MIPUG suggested a further recommendation to the Government of Manitoba, to establish legislation similar to the 'Certificate of Public Convenience and Necessity' employed by other regulators. Alternatively, Interveners want a review of MH's major capital projects through a renewal of the mandate provided to the Board in 1990 (via Order-In-Council 1990-177), when the Board was requested and did review MH's major capital plan, then covering 1990 to 2009 (a plan much modified since).

And, given the emphasis placed on exports (the source of rate subsidies for domestic customers and capital for early construction), and the risks for domestic customers if export commitments and water conditions collide, it could lead to significant financial losses.

The Board agrees with Interveners that regulatory review of the impact on consumer rates that MH's planned capital program may have is warranted, and that such a review should consider the risks faced by the Corporation and its ratepayers.

In light of the unprecedented capital expansion now under consideration, the Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its possible implications for consumer rates. The Board will also direct MH to prepare a study, for filing with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending, taking into account revenue growth, variable interest rates, inflation experience and risk, and potential further currency fluctuation.

To provide the maximum benefit of such a risk analysis, MH will be directed to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation. And, as a follow-up to the risk analysis study, MH will be directed to file, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, and risks quantified.

As for Wuskwatim, it is now clear that the economic justification presented to the CEC in 2004 has changed. At the CEC hearing, MH calculated the projects IRR (Internal Rate of Return) would be 10.3%. Before this Board and incorporating changed assumptions in that original forecast, a recalculation of the IRR yielded 6.5%, a yield that approximates MH's current annual cost of debt.

With higher than expected domestic load growth, Wuskwatim is now required to meet both domestic load and firm export commitments. However, the project is now of debateable economic value, given the ongoing escalation of construction costs and the potential for under-achievement of forecast export prices.

Wuskwatim's original cost estimates, as provided to the CEC, have risen by a factor approaching 2 – with the overall cost now expected to be not $900 million but $1.6 billion. The cost increase is troubling enough, but there is also no assurance that export sale prices have increased correspondingly (if at all). The dramatic rise of the Canadian dollar has lowered revenue expectations, and there is no certainty that either a cap or trade on carbon tax is on the immediate horizon, to benefit MH's planned newest generating station.

MH does not forecast that WPLP will be profitable for the first 6 years of operations, and these forecasts may be optimistic. While MH's cost allocation approach favours the Wuskwatim project, with the Wuskwatim partnership not being allocated all costs, particularly indirect overheads, yet being assigned full export prices for all of its energy output, it is possible the project in a full economic sense may not achieve a positive cash flow.

On an overall economic basis, with construction cost estimates up 60% more and the forecast price per kW.h basically unchanged, Wuskwatim's net present value may not meet the original floor threshold assumed at the CEC hearing. MH now bases its requirement for Wuskwatim on domestic rather than export requirements. Accordingly, MH states it no longer requires Wuskwatim to meet or exceed its threshold economic return, as MH now classifies the construction as being necessary to meet future Manitoba load requirements.

That said, the Board does not agree that Wuskwatim is required for domestic purposes, particularly with its current expected in-service date. Yet, this view is of little consequence, as the Board is not required to give approval to MH's capital plans and projects. As well, Wuskwatim's plans are well past the "point of no return". Yet, it is neither the fault of MH or the government that high inflation and a much higher Canadian dollar has developed massive construction cost over-runs and problems with export receipts in Canadian dollars.

As to the arrangement with NCN, the First Nation is to receive up to 33% of ownership of the limited partnership that will construct the generating station. Yet, and until the project is finished, NCN is required to invest only $1 million, with MH borrowing what is required to complete the project. Following completion, NCN will have to make its decision whether to come in as a partner or not. Overall, and assuming NCN does take up the full ownership position it has the option to take, NCN is only required to put up $34 million of its own capital, the balance to be borrowed from MH.

The First Nation carries no direct risk with respect to the $1.6 billion project. It has an option to take up to a 33% ownership position, but it need not do so; it can evaluate the situation upon the project's completion. And, an NCN holding company will hold NCN's partnership interest in the project. With the holding company inserted between it and the partnership, and with almost all of its investment funded through a loan from MH, without any mark-up, its risks are negligible. As well, NCN will be able to receive payments from the partnership once the new generating station is in-service, even during partnership loss years. Such advance dividends will also be funded by loans from MH, as advances on future dividends.

With respect to the capital structure of the partnership, the standard formula for determining MH's debt to equity ratio has been amended, and for the Wuskwatim partnership the debt to equity ratio will exclude the expected $320 million in debt related to the necessary transmission line loan. This arrangement, having the transmission asset held “off-balance sheet”, and by MH directly, will allow for profit-sharing to occur much earlier than would be the case if the standard 75:25 ratio test was applied employing the standard debt and equity components.

MH concurred with the hypothesis that the Wuskwatim/NCN arrangement was driven by factors other than "strict economics", and that the driving factor for the arrangement is MH's operative assumption that without an agreement with NCN Wuskwatim could not proceed. The Board notes that as the generating station and related transmission lines will be located in NCN's traditional trading area, it is not surprising that the First Nation would insist on compensation for its support of the project, and that a lack of support from NCN would have made proceeding unlikely.

From the Board’s review of the WPLP Agreements, it has arrived at significant concerns with the financing arrangements, cost sharing and revenue allocation, and while there may be reasons that go beyond strict “economics” that lie behind the terms of the arrangement, the Board’s concern with the overall structure of the arrangement is such that the Board cannot, at least without being in receipt of further rationale, recommend that the agreements serve as a template for any future joint ownership opportunity.

While the WPLP is not recommended for use as an “automatic” template for further First Nations participation in Generation and Transmission projects, the experience of Wuskwatim, todate, should be used to model possible outcomes of possible future arrangements with respect to Keeyask and Conawapa.

For any future projects where joint ownership is contemplated because of the potential impact on consumer rates, the Board recommends MH seek the Board’s prior review and approval.

With respect to Bipole III, MH reported that its construction cost estimates had increased dramatically, from IFF-03's forecast of under $400 million (that estimate excluded the cost of converter stations) to $2.2 billion (which now includes the advancement by several years of the construction of converter stations, required for future generating facilities now contemplated).

The increase in forecasted spending is primarily driven by a government policy decision, supported by MH’s Board of Directors, to place the line on the west side of the Province and materially increased construction costs.

The Board notes that the new $2.2 billion forecast neither includes the present value of line losses associated with the longer distances required to go down the west side of the Province, nor any value that could be associated with the additional risks pertaining to the possible future loss of Bipole I and II transmission, which, if it occurred, would require northern transmission from the north to the south to come only from Bipole III, at a potential capacity loss of 1,000 MW.

Including the present value of the additional line losses associated with increased distance, the revised routing of Bipole III has added over a half a billion dollars of additional costs. The Board notes that export prices are set in the marketplace and are not based on MH’s generation and transmission cost. Thus, it is not the Board’s assumption or expectation that the additional costs for a ‘west side’ routing of Bipole III can be passed on to MH’s export customers. It appears that the increased cost of Bipole III, brought about by a west side route will be a cost to MH that will reduce otherwise expected future export profits.

Again, it is critical to understand that this Board is not empowered to approve MH’s capital expenditures. To similar effect, the Board is required to honour explicit government policy. Given these conditions, the Board's options are limited when it comes to the rate regulation of MH.

To "starve" MH by suppressing rates in an effort to stymie a project would be to counter government policy, a measure that the Board cannot undertake, first lacking the legislative authority and secondly, the public mandate – unlike government, this Board is not elected. In short, government and the Board of MH has, as they should, taken responsibility for the major capital expenditures and policy actions of MH. The Board has no mandate to contradict such policies. Therefore, while the Board does not find all of MH's actions justifiable on a strictly MH-centric economic rationale, it considers itself obliged to ensure MH has sufficient revenue to allow it to achieve objectives transparently established or approved by government.

Before moving to a general discussion of MH's other capital expenditure plans, the Board has some further comments to make with respect to the projected routing of Bipole III.

Currently, Manitoba Hydro's primary electricity production, from the north, is transmitted through two transmission lines from Gillam to Winnipeg through the Interlake. For a considerable period of time, it has been assumed that a third line was required, for reliability purposes, and with the continuing growth of domestic load and committed or intended export contracts, the third line has become a necessity. Upon its completion, now scheduled for 2017, Bipole III will provide backup to the existing two lines and transmit increased volumes of electricity from the planned new generating stations to southern Manitoba and further south, the primary export market.

Bipole III, to be MH's third high-voltage, direct-current transmission line, is to be constructed down the west side of Lake Manitoba, rather than taking a much shorter route through boreal forest on the east side of Lake Winnipeg. The east side of Lake Winnipeg is marked by pristine boreal forest, which the government has indicated it wants to preserve by building Bipole III down the province's west side, rather than the east.

The government, in partnership with some “east-side” First Nations, seeks what is considered to be the second-largest intact boreal forest in the world to be designated by the United Nations Educational, Scientific and Cultural Organization (UNESCO – through UNESCO’s Word Heritage Committee) as a World Heritage Site.

World Heritage sites are important, having significant positive impacts for decades to come, draw considerable world attention, and can attract significant eco-tourism. The government has indicated that an attempt to construct a major transmission line through a potential World Heritage Site would be strongly resisted by First Nations and be so opposed by environmentalists that it could result in MH’s export potential being severely damaged. In short, the Board understands that the government’s claim is not based on “economics”, particularly “relatively” short-term economics, but broader concerns extending beyond the environmental to include the cultural and the political.

There is little doubt that the proposed route down the western side of the province is both longer and will cost hundreds of millions more than if the new transmission line were to be built on the east side of Lake Winnipeg. As the precise route for the line cannot be determined until a process of environmental, design and public consultation has taken place, the certainty of the government’s final direction cannot be assured.

While opponents and/or critics of a “west-side” Bipole III include interveners at this most recent GRA proceeding, with their criticism based largely on "economics" (the undisputed understanding is that a west-side line will cost more than an east-side approach, result in increased line losses due to the longer distances involved, and, as discovered through this recent proceeding, pose an increased reliability risk in the low-probability occasion of Bipoles I and II being out of service), neither the interveners nor MH set out in detail the argument for the west-side siting of Bipole III directed by government.

The Board's mandate is to determine what is in the public interest, and has previously defined this Board's definition of what represents the public interest with respect to a public monopoly utility incorporated and operated to provide required services to Manitoba. So, while this Board does not have the statutory authority to approve or reject MH's capital expenditure plans, it certainly does have a considerable interest in what those plans are and as to what the basis for those plans are. Capital expenditures represent a major driver of rates, and this Board does have oversight and responsibility for rates.

Accordingly, the Board, in this Order, sets out herein its conclusions to date on the rationale and implications associated with building Bipole III. In setting out its perspective on the matter as it now stands, the Board concludes that it is also in the public interest to set out, as it has above, the Board's understanding of the government's, and MH's, rationale for the decision to take Bipole III down the west-side.

The gist of MH and the government's position on the matter is that taking Bipole III down the west side of the Province will better ensure the Utility's reputation and relationship with its major American export customers, and provide an opportunity to achieve, develop and enjoy a potential World Heritage Site.

In short, it is the Board's understanding that MH and the government have concluded that constructing Bipole III on the West side of Lake Manitoba is, on balance, and despite it being considerably more costly and carrying additional risks, the only truly available option at this time (assuming domestic load growth and export commitments are to be met and reliability better assured).

Finally, the Board notes a third potential option, one involving underwater cables that would carry the power through at least a portion of the distance required. The Board senses that discussion and review is likely to continue, and, until that is concluded, is content with setting out its understanding of the costs and implications of the concepts and plans provided to-date.

10.0 Load Forecasts and Power Resources

10.1 Load Forecast

MH's 2005/06 metered domestic load was 20,800 GW.h., comprised by:

Residential	6,578 GW.h	32%
GSS-ND	1,329 GW.h	6%
GOSS-D	2,038 GW.h	10%
GSM	2,949 GW.h	14%
GSL<30	1,612 GW.h	8%
GSL 30/100	988 GW.h	5%
GSL >100	5,202 GW.h	25%
ARL	96 GW.h	<1%

The segmented metered load corresponds to a load at generation of 22,899 GW.h, after taking into account distribution and transmission losses as well as weather adjustments.

MH forecasts base domestic loads at generation of:

23,318 GW.h in 2006-07	actual	
23,769 GW.h in 2007-08	451 GW.h increase	2%
24,577 GW.h in 2008-09	808 GW.h increase	3%
25,509 GW.h in 2009-10	932 GW.h increase	4%
26,069 GW.h in 2010-11	560 GW.h increase	2%
26,503 GW.h in 2011-12	434 GW.h increase	1.5%

The forecast indicates a 3,200 GW.h increase (14%) in domestic load over the five-year period, which compares to a forecast 2,350 GW.h increase forecast for the same period in the 2005/06 load forecast. (Peak load grew by 10% during that period of 750 GW.h increased usage.)

MH's 2006 Electric Load Forecast indicated that residential and commercial load growth of 1% is expected from 2006/07, and onward that industrial load growth (GSL customers) of about 2.3% annual growth should be expected from 2006/07 to 2011/12, and a further 1% per annum or less thereafter.

The chemical and petroleum transport sectors of MH's industrial customer class are expected to provide about 75% (1,300 GW.h/year) of the 1,700 GW.h total anticipated industrial load growth between 2006/07 and 2011/12. These industry sectors are energy intensive and are usually associated with relatively low levels of employment per GW.h of energy consumption. Projected load growth in the sector has not been expected to produce high levels of additional Manitoba employment. As such, the sector represents the primary target for MH's interest in a new industrial rate class that would be assessed marginal rates.

The projection of load growth does not provide for the potential arrival of new industries in Manitoba with similarly low levels of employment per GW.h. Such firms, which may be attracted by low energy rates, would reduce MH's export sales and affect general consumer rates, and, as well, possibly affect the now planned in-service dates for new generation and transmission.

This situation has led to a concern that MH may have to increasingly forego export sales (at prices from 5¢ to 7¢/kW.h) in order to service domestic industrial loads assessed at 3.5¢/kW.h or less.

Again, to counter the impact of reduced exports caused by low-employment energy intensive industry, MH sought approval for a new energy intensive rate, one more reflective of export market pricing. However, the rate proposal has been deferred to a subsequent hearing, now expected to occur later this year or early in 2009.

MH's domestic load forecast contemplates:

- Only nominal increased demand from electric space heating;
- Significant increase in demand from electric water heaters;
- Significant increase in demand from computer and internet usage;
- No increased demand relative to climate change (global warming);
- Little change in seasonal load variation due to climate change;
- A significant increase in electric load due to customer movement from natural gas to geothermal heating but no identified decease for customer movement from electric to geothermal heating;
- No customer movement from natural gas to electric heating; and
- No change in loads due to self-generation.

Given the lengthy planning process required for new generation and transmission, the accuracy of domestic load forecasts, including the categories of customers associated with specific forecasts, are critical to assessing MH's domestic load and opportunities for exports. A major risk to the present load forecast lies with the nexus of natural gas and electricity, with natural gas potentially to be a more expensive heating source than electricity.

Over half of MH's space-heating customers rely on natural gas, while the rest primarily depend on electricity. Until the May 1, 2008 Centra rate changes, electricity was the higher cost option where natural gas service was available for space heat. However, natural gas commodity prices are linked to oil prices, and oil prices have increased from the range of $15 U.S./barrel in 1999 to over $140 U.S. in recent months; while some observers suggest oil prices could reach $200 U.S./barrel within five years prices have recently moved to below $130, still basically twice last year's level.

As to natural gas, it is becoming a world-traded commodity, priced by the markets on a supply and demand basis, as is oil. The advent of LNG, liquid natural gas, and the coincident ability to transport natural gas between continents, has further increased the risk that natural gas will follow the oil price curve and out-price itself relative to electricity in Manitoba. In jurisdictions where market prices prevail, the prices for electricity produced by natural gas, coal and nuclear are rising. This increases the demand (and price of) for natural gas as a direct heating source. Consequently natural gas heating in Manitoba becomes less attractive relative to electric heating.

Assuming that full conversion of heating from natural gas to electricity may be expected to cost in the order of $3,500 (assuming the customer has 200 amp service), the payback period for conversion to electric heat would be fairly lengthy at current price differentials. However, once the change is made a customer is unlikely to reverse that decision; fuel switches are essentially permanent.

A larger risk rests with the initial selection of a space-heating source with new construction. And, as to existing customers, they need not switch entirely from natural gas to electricity to affect the domestic electricity load. At a lesser level, customers may increasingly supplement their natural gas heating by electrical sources (electric base board heating and small electric space heating units) as natural gas prices outpace electricity prices.

Recently a surge and continued volatility in and with natural gas prices has brought about suggestions of subsidies or monetary transfers from MH to Centra in order to limit the rate impact on residential natural gas heating costs. The support for such action is based on:

- Limiting the degree of fuel switching from natural gas to electricity for heating and thus avoiding the loss of favourably priced export sales which may also provide a net reduction in GHG emissions;
- Cushioning the majority of Manitoban from the full impact of soaring natural gas prices on their winter heating bills; and
- Limiting the extent of fuel switching in older residential areas that lack of adequate distribution networks to service broad scale electric heating loads.

The counterargument on cross-subsidizing natural gas vs. electric heating is as follows:

- Paying subsidies to natural gas heating in order to limit electric heating does not necessarily result in economic gains for MH from exports. Residential electricity rates are typically higher than average export prices. The net GHG reductions for displacing natural gas generation in the U.S. are only nominal; displacement of coal generation is not assured;
- Having domestic customers pay more for electricity in order to maintain current levels of natural gas consumption by Centra may keep MH whole, but implies that the electricity customer should subsidize Centra’s natural gas imports as well as MH’s electricity exports;

- Moving costs from natural gas customers to electricity customers distorts the market economics. In the absence of cost causation, the issue becomes how to limit the subsidy if natural gas prices rise to $15 U.S. /GJ or $20 U.S. /GJ the need for a subsidy becomes greater and at some point the subsidy from power becomes unmanageable.

10.2 Energy Supply

10.2.1 Hydraulic Generation

MH's hydraulic generation resources consist of:

- Lower Nelson hydraulic stations - 3,670 MW (HVDC transmission) with dependable output of 13,780 GW.h and a high flow output of 26,690 GW.h.
- Upper Nelson hydraulic station - 350 MW (AC transmission) with dependable output of 2,260 GW.h and a high flow output of 3,000 GW.h.
- Saskatchewan River hydraulic station -479 MW (AC transmission) with dependable output of 1,320 GW.h and a high flow output of 2,520 GW.h.
- Winnipeg River hydraulic station - 582 MW (AC transmission) with dependable output of 2,300 GW.h and a high flow output of 4,410 GW.h.

Overall, MH's hydraulic generation output is 19,750 GW.h under dependable flow conditions, and 36,690 GW.h under high flow conditions. Although these generation forecasts assume normal water flows are not augmented by drawing water from reservoir storage, MH does use energy-in-storage to arrive at a dependable flow output of about 21,000 GW.h (representative of 85% of base domestic load).

In median flow years (i.e., approximately 50% of the time), MH's hydraulic output is expected to be 29,500 GW.h, while in mean flow years (i.e., on the average based on 94 years of experience), hydraulic output is 29,100 GW.h. These outputs cover about 115% of base domestic load, providing the opportunity for entering into firm export commitments.

10.2.2 Augmented Flow Programs

MH employs augmented flow programs to optimize hydraulic generation output at the various plants. These programs typically involve compensation through direct payments and/or energy offsets with other jurisdictions (Saskatchewan and Ontario), or to First Nations and other to Manitoba communities.

Examples of an augmented flow program include:

- The augmented flow program on the Churchill River Diversion system allow increased additional flows by up to 5,000 cfs, annually by the approval of the Provincial Minister responsible. Deviations from the original license were offset by mitigation projects and compensation payments with respect to the communities of South Indian Lake, Nelson House, City of Thompson and town of Churchill.
- The Lake St. Joseph project, in conjunction with the Lac Seul project in northwestern Ontario, utilizes flow storage and releases that augment Winnipeg River flows by up to 9%. Under the agreement with the Lake of the Woods Control Board, MH compensates Ontario Hydro for the additional energy values.

In response to MKO interrogations, MH has provided information on a proposed water regime modification, not yet implemented, where Saskatchewan Power would be compensated for seasonally adjusted outflows from Reindeer Lake and Churchill River, controlled by the Island Falls G.S. to the benefit of MH. According to MH, Saskatchewan manages Reindeer Lake's water level to meet Saskatchewan Power's needs at its Island Falls G.S., and that potentially extra flow in the summer could be made available to MH.

MH's review to-date has not determined whether there would be any economic benefits to arise from such a flow modification. Nor has MH explored the level of compensation or mitigation that would be required from upstream or downstream affected parties.

10.2.3 Thermal Generation

To support and back-up MH's hydraulic generation, and to meet domestic load and firm exports commitments, MH relies on thermal generation:

a) Brandon Unit #5 (coal-fired), 105 MW with a maximum output of 837 GW.h.;

b) Selkirk Units #1 and #2 (natural gas), 126 MW with a maximum output of 1,060 GW.h.; and

c) Brandon SCCT, two units (natural gas), 298 MW with a maximum output of 2,400 GW.h.

The plants can provide about 4,300 GW.h/year, if fully utilized. When the Brandon coal generation is removed from full service and related to "emergency use", pursuant to a government directive related to mitigating climate change, maximum thermal output will decline to about 3,500 GW.h/year. At the present time, combining thermal and hydraulic generation provides for 100% of base domestic load.

MH rarely uses its natural gas generation plants, as such generation is uneconomic when natural gas prices are above $5 CDN/GJ. With natural gas prices currently in the range of $8-11/GJ, imports of power from the MISO market may be used instead. It is assumed that these imports come from natural gas rather than coal generation.

MH currently relies on its coal generation to provide support to hydraulic and wind generation in meeting export sale commitments. On an incremental fuel cost basis, coal generation is economically viable and contributes $10-20 million a year to MH's annual net income, in a median flow year.

The availability of the Brandon coal generation during the 2002 – 2003 drought saved MH approximately $50 million; the government has indicated that he Brandon coal plant will still be available for use in emergency conditions in the future.

The energy deficit in the MISO market caused by the Brandon coal plant closure may well be filled by additional coal generation; Sask Power or Ontario Hydro in summer and MISO region coal plants in winter. These sources if available are likely to be lower priced than natural gas generation.

10.3 Wind Generation

MH currently purchases 100 MW of wind energy from a private energy firm. The power is generated at St. Leon, Manitoba and has had a capacity factor of approximately 39%, as expected wind speed and direction are neither constant nor consistent. With forecast annual output of 320 GW.h, to be drawn on in conjunction with hydraulic generation, wind is deemed to be dependable energy.

The St. Leon wind farm has now been operational for almost three years; providing a reasonable but still limited track record for defining on-line availability of dependable energy. Though MH has cited commercial confidentiality reasons for not disclosing the operation's specific operational profile, apparently there have been some wind downtimes due to cold temperature conditions that have fallen outside the design operating range.

Another 300 MW (900 GW.h) of wind generation is to be added by 2013/14, assuming reported ongoing contract negotiations with non-utility generators lead to acceptable terms, including pricing. And, a further 600 MW is to be considered at some time in the future, although MH has expressed concern about a declining energy value of wind as related to the energy integration process of moving wind generation into the Manitoba grid.

The recent movement of MH toward new major export commitments raises the possibility that more wind generation could have positive market values. In the long-term, MH may achieve greater transmission inter-tie capabilities allowing the export of more wind and hydraulic blended energy.

As MH's anticipated 2,000 MW of new generation projects come online to meet domestic load growth and export opportunities, the limited level of then-remaining untapped hydraulic generation may have to be supplemented. More wind may well be the choice.

As the pending restriction of the Brandon coal generation plant operation by 2012 will remove 800 GW.h from MH's power resources, wind energy may now be worthy for consideration as a cost effective replacement.

10.4 New Generation and Transmission

MH is proceeding with the Wuskwatim Generating Station with a targeted in-service date of 2012/13. An Agreement has been reached with WPLP for purchase of all output, estimated to be 1,515 GW.h on average. This arrangement is expected to provide a 1,220 GW.h increase in MH's dependable power (4%).

The replacement of the Pointe du Bois G.S. on the Winnipeg River with a new plant is expect to achieve a 150 GW.h/yr increase in the dependable flow output upon the expected 2016/17in-service date for the new plant, and would add 300 GW.h/yr to average flow plant generation. The planned Kelsey rerunnering will not increase dependable flow output but will increase the average energy output of the plant by 350 GW.h/yr.

Bipole III is slated to be in-service in 2017/18, and is expected to add 442 GW.h/yr to MH's dependable generation, this by reducing transmission losses on the HVDC system. The loss reduction could be 1,000 GW.h under average flow conditions, based on the existing Upper Nelson generation plant.

MH's 2007/08 Power Resource Plan indicates that by 2017/18 total generation plant output under a dependable flow scenario will be 28,845 GW.h, equal to base domestic load. At that point, and until Conawapa and Keeyask G.S. are constructed, exports would have be supplied from domestic load reductions, through DSM and by imports or MH natural gas generation.

The Power Resource Plan calls for Conawapa G.S. to come on-stream in 2021/22, but Keeyask G.S. had then not been scheduled. And, a number of new pending export contracts were not included in the Power Resource Plan, those being:

a) 375/500 MW sale to NSP (estimated 1,600/2,000 GW.h);

b) 250 MW sale to Minnesota Power (estimated 1,000 GW.h); and

c) 500 MW sale to Wisconsin Public Service (estimated 2,000 GW.h).

Essentially, these additional export sales, if consummated, commit MH to export 5,000 GW.h/yr firm on-peak (5 x 16) power and require the development of both Keeyask and Conawapa, in close succession, and to be in place by about 2020. In the absence of Keeyask, MH's dependable domestically generated energy of, then forecast to be, about 30,000 GW.h would just cover forecast 2022/23 base domestic load. In such a case meeting the new export commitments would require further domestic load reductions through DSM savings and additional imports or MH natural gas generation.

If either space heating conversions from natural gas to electricity occurred or new large industry or large industry expansion drew power, the situation would be more problematic.

The addition of Keeyask Generating Station and Conawapa would have the following impact on the generation available from the Lower Nelson and the loads to be:

Forecast Future Lower Nelson Power Supply in 2020 GW.h				
Flow Condition	**MW**	**Dependable**	**Average**	**High**
Conawapa (2020)	1,300	4,550	7,050	9,000
Keeyask (2018	600	2,880	4,400	5,000
Total New Plants	1,900	7,430	11,450	14,000
Total Existing Plant	3,560	13,770	21,350	26,130
Total Low Nelson	5,460	21,200	32,800	40,130

MH has identified a transmission loss reduction of 442 GWH for a west-side Bipole III at current dependable energy levels. On a relative basis, the loss reduction at current average flows would be about 1,000 GWH. This level of reduction would, if moved to the export market, contribute significantly towards the annual carrying charges of the $2.2 billion investment in Bipole III and with Keeyask G.S. online the revenue contribution would be considerably larger.

Hypothetically on a relative basis for an East Bipole III that average flow scenario loss reductions would have been an additional 300 GWH. In 2022 after Keeyask and Conawapa G.S. come into service, the loss differential would be about double that amount.

With Bipole III in place and both Keeyask and Conawapa on line, MH has suggested that additional transmission may be required presumably to lower transmission losses. This could further affect capital spending plans.

10.5 Alternative Fuels and Energy Supply

Notwithstanding the recent pursuit of DSM (to reduce domestic load growth) and additional wind resources, MH has not been aggressive in pursuing other energy sources. This, in large part, relates to the relatively high cost associated with alternative sources of generation in comparison to MH’s current costs and rates.

In justifying alternative energy sources, MH has to look beyond the current demand-supply economics to additional considerations, including environmental and social issues, when considering:

- Residential and general service DSM initiatives, with the average domestic rate higher than the average export price and with residential rates higher than general service rates;
- Wind costs (prices now similar to peak export prices, (i.e. in the range of 9 cents per kW.h);
- Bio-mass costs (above peak export price);
- Solar costs (currently estimated to be well above peak export prices);
- Geothermal (lost revenues and embedded costs may exceed export revenues, particularly during off-peak);
- Non-utility Generators (lost revenues and embedded costs may exceed export revenues);
- Brandon coal generation restrictions (higher prices for replacement energy) could approach $20 million a year; and
- Bipole III - West Side (no offsetting revenue for higher capital cost, reduced savings on transmission losses) and higher risk in the expected rare case of an outage of Bipole I and II.

10.6 Greenhouse Gas Emissions

MH's GHG 2005 emissions from electricity operation were reported to be about 650 kilotonnes of CO_2 equivalent. The Brandon Coal Thermal Generation station, on average, accounted for 550 kilotonnes of the total, while generating about 500-600 GW.h/year of electricity. Closure of the plant would result in net reductions of about 300 kilotonnes of $C0_2$ if the replacement energy source is natural gas based.

Converting from coal to natural gas generation would reduce CO_2 emissions by about 60%, but the costs involved would equate to about $120/tonne of CO_2. Theoretically that leads to a strictly economic conclusion that continues to favour operation of the coal plant, though buying carbon credits could reduce its economic profitability.

Electricity exports into the MISO market in 2005/06 were 9,800 GW.h and required 2,000 GW.h of imports, to arrive at a net export of 7,800 GW.h. If this level of net exports displaced American natural gas generation, the indirect GHG savings would have been about 2,500 kilotonnes; if the exports displaced some coal generation as well as natural gas, the CO_2 reduction would have been up to 50% higher.

In 2005/06, MH reported indirect GHG reductions of 738 kilotonnes arising out of deemed DSM energy savings of 1,030 GW.h/yr. MH's estimate is consistent with an assumed 50% natural gas/50% coal generation displacement.

Because 2005/06 involved record hydraulic generation of 36,200 GW.h from exceptionally high water flows, GHG reductions in that year actually resulted from surplus hydraulic generation and not from the DSM initiatives, as there was no additional energy export from DSM possible as tie-line and other transmission constraints limited both exports and total hydraulic generation in 2005/06.

10.7 Interveners' Positions

None of the interveners challenged MH's load growth assumptions, its portrayal of the existing supply situation, or MH's identification of the consequences of increasing domestic load.

RCM/TREE is concerned about the negative consequences of continued low electricity prices, which, it holds, encourage greater domestic consumption and leads to lower exports, and hence lower GHG reductions in the U.S.

MIPUG would promote DSM activities encouraging the use of natural gas rather than electric heating, questioned the pending restrictions on the Brandon coal plant and questioned the rationale for MH’s proposed new generation and transmission facilities, being built primarily to serve exports.

MKO suggested a need for what it would consider a more accurate reflection of the risk of fuel switching in MH’s load forecast.

MKO recommended that, as one test to be applied to determine whether or not MH's costs are just and reasonable, the Board should require MH to ensure that wherever it is able to identify value from a change in its operation, for example the Augmented Flow Program, that MH be required to associate any adverse effects with justified mitigation and ensure that the projected adverse effects are fully identified, reported, accounted for and addressed. MKO suggested MH be required to provide full disclosure of augmented flow programs, and any related extra-provincial arrangements on water supply.

The basic issue of there being a financial risk associated with energy intensive industry expansion, as identified by MH, was not been challenged by the interveners. And, both the Coalition and RCM/TREE indicated strong support for MH’s intentions to implement marginal cost pricing for new industrial loads not associated with strong Manitoba economic benefits.

MIPUG didn’t dispute the premise of charging higher rates for some industrial loads, but disagreed with MH’s proposed approach and placed a higher value on large industry’s contribution to the Manitoba economy.

10.8 Board Findings

Load Forecast

Based on past experience and recent price increases and volatility related to natural gas, MH's future domestic load forecasts may prove to be low, with space heating by natural gas potentially now more expensive (leaving aside the cost of conversion) than by electricity.

With natural gas prices continuing to rise faster than electricity prices (2008-09 natural gas space heating costs may be considerably higher than was the case in 2007-08), and far more costly than was the case in 1999 when MH purchased Centra Gas Manitoba Inc., more new customers may opt for electric heat and existing natural gas customers may either convert to electric heat in greater numbers or supplement gas heating with electric baseboard or small electrical heaters.

The result would be greater domestic load and reduced opportunity for the export of electricity unless and until new generation is available.

While MH has acknowledged that there is a growing potential for customers switching from natural gas to electric space and water heating, it has not reflected the risk in its current load forecasts. MH should include an analysis of the issue and the risks with its next Load Forecast.

MH has not been attempting to influence customer fuel choice, taking the view that it is the customer's responsibility to assess the relative merits of the options. The approach taken represents an attempt by MH to remain neutral on the relative merits of electric and natural gas space heating.

However, given the financial and environmental issues at stake, MH should carry out a study to define the implications of fuel choice and take a more active role in assisting consumers in making choices, given seemingly ever-increasing energy costs, both in an absolute and as a percentage of disposable household income sense.

As MH enters into more export contracts with fewer remaining hydraulic sites apparently available, it is more likely that wind generation could have a greater prominence, and potentially-an increased market value. In light of the current wind generation project(s) developed and contemplated for development in the future, the Board requires additional information on the implication of MH's wind strategy on future consumer rates.

Accordingly the Board will direct MH to submit a report to the Board on January 15, 2009 on the 300 MW additional wind energy project(s) and a discussion of the business case, wind strategy, prospects and timelines for this project, as well as the further 600 MW moving toward the government's target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s).

MH's recent announcements of new power sales into the U.S. have possibly precluded further firm energy contracts, as the Utility's dependable hydraulic energy has been largely committed. This suggests that, at least in the relatively immediate future material energy sales to Ontario, Saskatchewan and even Alberta may have to be non-firm and primarily off-peak. What this says with respect to the merits and prospects for an east-west national electricity grid is a subject for conjecture.

If GHG emission reductions are seriously targeted for achievement in Canada and the U.S., MH's available energy should gain value. It is important for MH to negotiate prices providing for escalation in certain circumstances, such as further increases in oil, natural gas and coal prices, and increased attention to emission reductions (by way of cap and trade or carbon taxes).

The decision to place Bipole III on the west side of the province involves major additional costs, when construction costs, transmission losses, and reliability considerations are included. A west side of the province location for Bipole III is favoured by government, giving consideration to a hoped-for and possibly pending designation of a large sector of boreal forest East of Lake Winnipeg as a World Heritage Site. The avoidance of major development in what is deemed one of the last undeveloped large areas of boreal forest in the world has, at minimum, intrinsic value, and is consistent with recognition of the overall climate change issue and the responsibility of governments to mitigate known and expected effects.

The westerly route, while traversing similar terrain over a greater distance than the rejected eastern route, is not expected to face the same constraints that an eastern route would encounter in seeking environmental and community approval. The west side of the Province is already developed to a significant degree, and may face less opposition to the construction of a new transmission line.

As sole shareholder of MH, the Province has the right to direct the west side routing. Yet, it should be acknowledged that the additional costs will be borne by Manitoba ratepayers, either in the form of higher rates in the longer-term or a reduced export "subsidy" reflected in rates. Export contracts are price competitive and, in the absence of CO_2 taxes, coal generation costs will largely dictate future energy prices negotiated in the MISO market.

As such, the added costs for Bipole III is unlikely to be reflected in the energy sales price, although, and this is an important consideration, ”clean hydro” power may eventually command a premium price and MH’s future sales may be made “easier” by its environmentally-friendly route choice.

For MH, the development of alternative energy in its export markets may tend to reduce energy demand from MH. As well, alternative energy sources that may come into use in the future in Manitoba may well affect domestic consumption and revenues, without a corresponding reduction in the need for infrastructure and services. While MH is a significant revenue generator, its margins are low (particularly if the cost of new construction is considered), and rates are likely to be under continued upward pressure going forward.

Given that MH is incurring costs for environmental and social purposes (i.e., West Side Bipole III; Brandon Coal Plant, etc.), such costs should be separately defined and tracked to allow for subsidies and for the cost of choices made for environmental objectives to be transparent.

As noted in the findings for MH’s capital expenditures, new export agreements are driving MH’s construction of new hydraulic generating stations. The underlying economics have not been publicly disclosed or tested. Because of the potentially negative impact on domestic consumer rates, at least in the initial years, the economic justification of expansion presented on export agreements should be reviewed and approved before such export agreements are finalized.

The Board is of the view that it would be in the public interest that MH’s export contracts be filed with the Board for review, and possible approval.

There does not appear to be any clearly-defined process that MH follows in achieving augmented flow projects. Parties potentially affected by such a program might be better served if a publicly-known approval process were in place. The Board will direct MH to provide a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. They should include the specifics of the program and mitigation and compensation related thereto.

11.0 Demand Side Management

11.1 General

MH's Demand Side Management (DSM) initiative, "Power Smart" consists of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. The most current plan is the 2006 Power Smart Plan.

For the electric business, the initiative is one element of the resource options available for meeting the Province's electrical needs and the initiative plays an important role in the Corporation's overall integrated resource plan. DSM initiatives are to assist customers in meeting their energy needs through energy efficient measures. For the electric business, such initiatives enable MH to serve more domestic customers with less energy. Reduced domestic load requirements allow for reduced capital expenditures and increased energy available for export. Electric DSM initiatives are evaluated utilizing the same underlying criteria and economic evaluation approach as used with alternative resource options.

11.2 Program Evaluation

To evaluate new programs a high level assessment Marginal Resource Cost Screen compares the expected benefits to the incremental capital costs. If programs pass the initial screening, a more detailed assessment is undertaken involving developing program concepts and designs and projecting costs and benefits.

MH determines the cost effectiveness of DSM programs using the Total Resource Cost and Rate Impact Measure Tests. The primary economic indicator for evaluating the effectiveness of both electricity and natural gas incentive-based programs is the Total Resource Cost (TRC) test. TRC measures the cost effectiveness of a product or program, and a TRC benefit/cost ratio greater than one (>1.0) indicates that a program is cost effective.

The secondary economic indicator for evaluating the effectiveness of programs is the Rate Impact Measure (RIM) test. RIM indicates the cost effectiveness of a program from the utility's perspective. All DSM related savings and costs incurred by the utility, including revenue loss and incentive payments, affect the RIM benefit/cost ratio. The results provide an indication of a program's expected long term impact on rates.

As a guideline, MH attempts to design electricity based DSM programs that have a RIM of 1.0 or greater. However a program with a RIM of less than 1.0 may trigger a program redesign, and may still proceed if the program design is judged to provide overall benefits.

Once Power Smart programs are in place, they are evaluated to determine the net program load savings and costs as well as the cost-effectiveness of the savings. Net savings take into consideration factors such as free riders (benefits derived that carry no specific cost), heating and cooling interactive effects, and system peak coincidence and persistence effects. Customer data and market information are used to assess the impacts of these factors on the overall savings attributable to incentive-based Power Smart programs.

In evaluating DSM programs, MH attributes no value to delayed generation in its TRC test, nor does it consider the full benefit of displacing carbon in export markets.

11.3 Program Costs and Amortization

MH plans to spend $401 million over the next 11 years on DSM expenditures. Of that amount, MH budgeted to spend $38.3 million in fiscal 2008-09, a figure later revised at the hearing to $43.1 million.

MH plants to spend a cumulative amount of $571 million on DSM expenditures through to the end of the 2017/18 fiscal year. While one purpose for spending on DSM is to delay new generation, new generation has, to date not been delayed due to DSM.

MH has defined "levelized" costs for various DSM initiatives. The following table provides insight as to the cost effectiveness of various activities and programs.

Exhibit 4.3.2.5
Electric Levelized Utility Costs
¢/KWh Saved by Incentive-Based Power Smart Program

Program		Results 2005/06
Efficiency Programs:		
1.	**Residential**	
	New Homes	7.2¢
	Home Insulation	2.8¢
	Compact Fluorescent Lighting	0.8¢
	LED Lighting	6.6¢
2.	**Commercial**	
	Commercial Construction and Renovation	1.1¢
	Internal Retrofit	1.8¢
	Commercial Lighting	1.7¢
	Agricultural Heat Pads	0.4¢
	City of Winnipeg Agreement*	7.7¢
3.	**Industrial**	
	Performance Optimization	0.3¢
4.	**Discontinued/Completed Program Costs**	N/A
	Efficiency Programs Costs Subtotal	1.0¢
	Rate/Load Management Programs:	
	Curtailable Rates**	N/A
	Overall: Program Costs	1.0¢
	Overall: Program + Support Costs***	1.1¢

* The levelized cost of the electricity savings estimate is being associated with the City of Winnipeg's Power Smart Agreement is 7.7¢/kW.h.

** Levelized cost analysis is not provided for rate/load management programs.

*** Support costs only include incremental support costs, no customer service initiatives or standard costs are included.

MH identified that its calculation of cents per kilowatt hour saved was based upon current program kilowatt hour savings, and assumed generation over a thirty (30) year planning period.

MH amortizes its DSM costs over an average 15 year period, which is longer than other comparable utilities. BC- Hydro and Quebec Hydro amortize DSM cost over a maximum 10 year period. While MH states that their policy is fully supportable. The Board has expressed reservations in past Orders and has suggested that MH could express such costs over a shorter time frame.

The unamortized balance of DSM expenditures was $17 million as of March 31, 1994, and is forecast to grow to $180 million by the end of the 2008/09 fiscal year. The amortization of DSM expenditures was $978,000 in fiscal 1993/94, to increase to $13.7 million in the fiscal year ending March 31, 2009.

MH has not yet determined the effect IFRS will have on its accounting treatment of DSM expenditures.

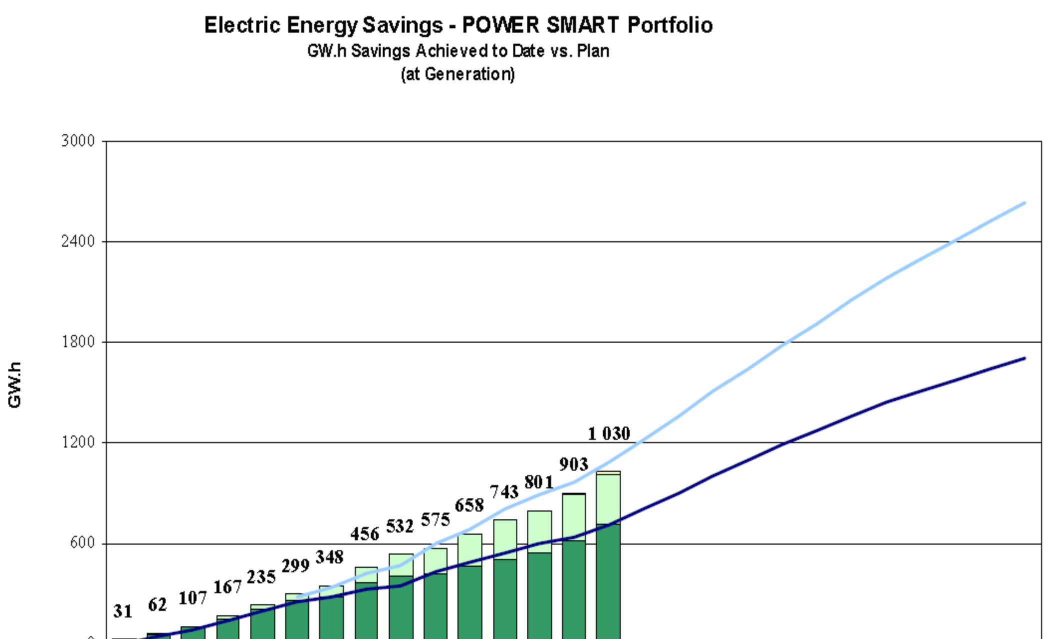
11.4 DSM Program Savings

By the end of 2005/06, MH opined that its Power Smart Programs would achieve an annual load reduction of 1,030 GW.h in energy, and 434 MW in winter peak demand (at generation), and that this level of “saved power” translated to a cumulative reduction of over $214 million in customer bills, and indirect greenhouse gas emission reductions of approximately 738,000 tonnes of carbon dioxide equivalent emission (the latter in 2005/06 alone).

Domestic energy reductions contribute to surplus generation capacity, which contributes to energy sales in the export market. The cumulative energy and demand reduction achieved (including savings to date) through the Corporation's DSM efforts is on target to achieve 2,695 GW.h/year of energy savings and 848 MW by 2017/18. MH also has a plan to achieve natural gas savings of 101 million cubic meters.

In total, the programs are expected to result in greenhouse gas emission reductions of 2 million tonnes by 2017/18.

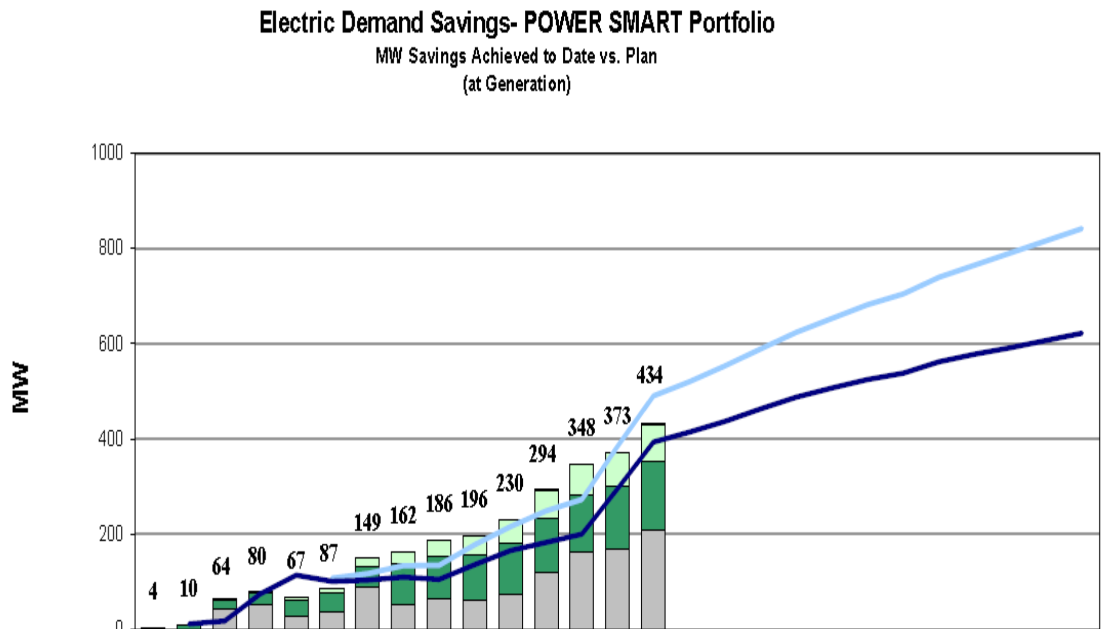
The following table depicts energy and demand savings realized to fiscal 2006, and that forecast through fiscal 2018:



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Customer Service Initiatives											2	4	7	10
Codes and Standards	0	2	8	16	25	40	63	93	125	156	189	228	248	274
Incentive-based-Efficiency	31	59	99	151	209	259	285	363	407	419	467	511	546	619
Total Achieved	31	62	107	167	235	299	348	456	532	575	658	743	801	903
Plan	0	50	86	138	195	252	279	327	350	435	491	544	603	634
Plan incl. Planned Codes & Standards						281	336	422	466	602	686	810	891	970

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives	18												
Codes and Standards	298												
Incentive-based-Efficiency	714												
Total Achieved	1030												
Plan	713	803	901	1000	1095	1186	1271	1360	1446	1514	1579	1642	1706
Plan incl. Planned Codes & Standards	1088	1220	1361	1506	1644	1783	1915	2051	2183	2296	2410	2523	2637

11.0 Demand Side Management



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives											1	1	2	3	3												
Codes and Standards	0	1	2	4	6	10	15	23	32	40	49	59	64	70	76												
Incentive-based - Efficiency	4	10	17	26	34	41	46	86	91	93	105	113	119	131	146												
Incentive-based - Rate/Load	0	0	45	51	27	36	88	53	64	63	75	121	163	169	208												
Total Achieved	4	10	64	80	67	87	149	162	186	196	230	294	348	373	434												
Plan		12	18	75	114	101	104	110	105	136	166	183	200	296	394	414	437	463	488	507	525	538	562	578	592	607	622
Plan incl. Planned Codes & Standards						108	118	134	135	178	216	249	273	385	491	520	553	589	624	653	682	705	740	765	791	816	842

The tables suggest that MH's DSM initiatives are running at about 90% of target. Incentive-based programs, which are individually tracked, run above 95% of target, but Codes and Standards programs, which have not been specifically defined, are running at about 80% of target.

DSM has managed to offset about 20% of otherwise domestic load growth and freed-up additional energy for export. However, it does not appear to have delayed the Wuskwatim G.S. in-service date.

MH claims to have reduced GHG indirectly by 730 kilotonnes on a cumulative basis, due to reduced emissions resulting from their export of electricity.

MH acknowledged that the estimated GHG benefits have no tangible financial benefit for MH.

11.5 City of Winnipeg DSM Program

As a condition of MH's acquisition of WH, MH and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002. The objective was to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. MH guaranteed the City an annual savings of $800,000 from the measures or the equivalent in the form of deemed savings plus a monetary payment by MH. MH's commitment over the ten year term this condition applied had a total value of $8 million.

A variety of energy efficient measures have been implemented for new construction and renovations in a large number of City owned or operated facilities towards meeting the objective of the program.. The energy savings forecasted to be achieved is 12.3 GW.h, a goal to be limited to a 20 year time horizon.

The estimated annual saving achieved by the City of Winnipeg related to the agreement is as follows:

Contract Year, ending August 31	**Savings ($)**
2003	607
2004	65,175
2005	144,426
2006	654,239
2007	771,905
2008 (forecast)	850,000
2009 (forecast)	900,000

To the end of 2007/08, MH has paid $2.4 million to the City, this because it could not deliver the $800,000 of annual DSM savings each year as prescribed in the agreement with the City.

So far, including the $2.4 million paid, MH has spent over $10.3 million under the agreement, exceeding the ten-year commitment of $8 million of savings and/or payments. MH states that the levelized cost of the program has been the equivalent of 7.7¢ per kW.h.

MH stated that due to the energy savings realized from the initiatives undertaken, MH is economically better off, as the energy saved has been and may be exported to the United States.

11.6 Carbon Trading

In 2002, MH became a founding member of the Chicago Climate Exchange (CCX). CCX requires participants to reduce emissions relative to historic baselines. Each participant is provided an annual allowance (of CCX units), an allowance that decreases each year from the historic baseline. If a participant's emissions exceed their allowance, the participant is required to buy additional units through the exchange. Conversely, if their emissions are below their allowance, they are able to sell the surplus units.

Through participation in this CCX, MH gains experience with the measurement, reporting and trading of admissions. Export sales, for which MH negotiates ownership of the associated emission reductions, make up a significant component of the offsets earned. While having these reductions delivers real value in complying with the voluntary commitment, surplus reductions may not yield additional value.

MH reported its intention to continue to monitor emerging market rules for opportunities to extract value from its emission reductions achieved in either Manitoba or in the Corporation's export market.

11.7 Low Income DSM Program

In its 2006 Power Smart Plan, MH included a new residential program, the "hard to reach" (HTR) program. The HTR program targets low-income residential households on an integrated basis (i.e. for both natural gas and electric consumption). The program has since been modified and now integrates funding made available by the federal government's ecoEnergy program. The current design of the low-income program was implemented December 14, 2007.

MH's Lower Income Energy Efficiency Program is designed to bring Power Smart and energy efficient measures to an estimated 4,600 lower income households over the next three and a half years ending 2010/11. The program targets lower income Manitoban homeowners and tenants.

In the case of lower income tenants, an agreement must be reached between MH and the landlord/building owner in order that a substantial portion of the benefits associated with retrofit measures funded by MH's program will be passed on to tenants. Private landlords and non-profit social housing organizations, including Manitoba Housing Authority (MHA) public housing and other non-profit subsidized housing organizations, are eligible to participate in the program.

Eligibility for households pursuant to the program was established by the Corporation at 125% of the Low Income Cut-off (LICO) established by Statistics Canada. Targeted measures to be addressed by the program include:

- low or no-cost basic energy efficiency measures, such as compact fluorescent lights;
- faucet aerators, low-flow showerhead, pipe wrap, hot water tank set back, and caulking/air-sealing;
- insulation for basement, attic and crawlspace installation; and
- High-efficiency natural gas furnaces.

Energy Efficiency Measures	Assumptions		
	Ave. electric Savings Per Home* (kw.h.)	Net to Gross Adjustments (Persistence Factor)	Participation
Insulation: including attic, basement and crawlspace	2,797	100%	Attic: 84% Basement: 58% Crawlspace: 8%
Compact Flourescent Lighting (6 CFLs per home)	138	90%	100%
Drainger	162	100%	18%
Water Measures: including tank set back, 1-Low-Flow Showerhead and 2-Faucet Aerators, pipewrap	404	Tank set back: 50% Showerheads: 90% Aerator: 90% Pipewrap: 95%	50% 100% 100% 100%
Weatherization: including air sealing and gasket covers	640	100%	100%

*- includes single detached homes, town houses, multiplexes and mobile homes

The anticipated duration of MH's Lower Income Program is tied to the Federal government's ecoEnergy program, which is currently approved to operate until March 31 2011. Contemplation of changes to the existing program will be undertaken closer to the date of the end of the Federal funding commitment.

MH intends to deliver the program through both Community Based Organizations (CBO) and individual household participation. Both approaches require pre- and post-audits, to identify energy efficiency opportunities and verify work completion.

The cumulative budget through fiscal 2017/18 for MH's Lower Income Program is $12.6 million, including rate-based, federal and Affordable Energy Fund (AEF) funding; the program's budget for 2008 was reported to be:

Program	**Budget (millions in 2008$)**
AEF Low Income - Electric Component	$3.5
AEF Low Income – Natural Gas Component	$6.1
AEF Total	**$9.6**
Power Smart Low Income – Electric	$1.1
Power Smart Low Income – Natural Gas	$1.9
Total Low Income DSM	**$12.6**

In assessing the economic benefits associated with the Lower Income Program, MH determined that the TRC for the program is 0.9, the RIM, 0.7, and the levelized cost of the program, 11.2¢ per kW.h. The results of testing indicate that the program results in some degree of cross-subsidization (of lower income customers by other residential customers).

11.8 The Affordable Energy Fund (AEF)

Following a spike in oil and natural gas prices in the summer and fall of 2005 on the heels of hurricanes Katrina and Rita, which damaged energy availability from south-east American production and distribution sites, and the Board's subsequent action as of November 1, 2005 when it deferred costs and restrained natural gas rates for Centra Gas' residential customers to recognize what the Board then-deemed to be a price bubble, the Provincial Government introduced

The Winter Heating Cost Control Act (which was subsequently passed, proclaimed and implemented in 2006).

Among other provisions, the Act established the Affordable Energy Fund [AEF], requiring MH to contribute 5.5 % of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of $35 million to be utilized for various energy efficiency initiatives, including if not primarily, assisting low-income electricity and natural gas customers.

MH indicated that $19 million of the AEF's $35 million was earmarked for province-wide low-income initiatives, with $8 million for community energy development, $0.25 million to expand the eligibility of Power Smart programs in Manitoba to include residential homes heated with energy other than natural gas or electricity, $0.75 million for rural and northern support and outreach, and $1 million for special projects then-yet to be defined.

MH indicated its intention that the $19 million reserved for low-income programs would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from MH/Centra's rate-based DSM programs, including the Corporation's HTR Program.

In commenting on the establishment of the AEF at the most recent Centra GRA, in Order 99/07 the Board stated:

> "The Board notes Centra has indicated that the AEF is not slated to be credited interest on unused balances. Centra should impute interest income on AEF funds transferred to it, the proceeds to be utilized to underwrite additional or expanded low-income programs. Such an approach would also allow the funds available within the AEF to represent some measure of an endowment (the problem with the AEF is that it has been funded with a "one-time" transfer, while the work of upgrading heating efficiency and retention is likely to require more than a decade and cost more than the initial allotment of

> $19 million – which must address both electricity and natural gas low-income households)."

In Order 99/07 the Board directed:

> "Centra segregate funds transferred to it from the Affordable Energy Fund (AEF) and funds accumulated for the new Furnace Replacement Program, with such funds to earn interest at Centra's short-term borrowing rate."

MH has yet to act on the direction, responding that the AEF should not attract interest as it would result in an accumulation, before deductions for expenditures made, of more funds than were contemplated in the Act. MH stated having the fund attract no interest to be consistent with the legislation.

Recently, MH, in partnership with the Spence Neighbourhood Association initiated a pilot project. The next steps for the Corporation's province wide low-income program were reported to include continuing with the execution of private and community programs, and marketing and promoting in communities, rural areas, and other relevant venues.

11.9 Interveners' Positions

The Coalition

DSM Program Evaluation

The Coalition suggested that MH should think of DSM in a different way. Mr. Dunsky, who appeared on behalf of the Coalition, opined that the RIM Test should not be utilized to screen for justification of DSM programs, and that while the TRC should remain the primary test for DSM programs, under MH's current approach there will be proposed measures that will fail the TRC test that should still be pursued if they pass the "utility cost" test. The Utility cost test compares money invested in a program with the value of expected energy savings for the utility. For Mr. Dunsky, if MH can generate cost effective kW.hr savings, the program initiative should proceed.

Mr. Dunsky further stated that in evaluating low income programs it was extremely important to account for non-energy benefits (NEBs), noting that a growing body of evidence points to very significant NEBs arising from low-income programs. Mr. Dunsky suggested that NEBs include fewer shut-offs, reduced emissions and health and safety benefits. Mr. Dunsky recommended that the Corporation take into account NEBs in its future cost-benefit analyses of low-income programs.

The Coalition recommended NEBs be included in the screening of potential DSM programs. The Coalition further recommended that either an independent or an internal review of MH's current DSM portfolio be undertaken, and that the review consider the screening tests, portfolio of programs and NEBs.

Low-Income Programs

Mr. Dunsky observed that consumers face an array of market barriers to the adoption of cost effective energy efficiency products and practices, and suggested that the barriers are most acute for low-income customers. Mr. Dunsky cited that barriers such as information and search costs and below average language and computational skills (literacy, poor math skills, English as a second language) represent significant hurdles to both participation in DSM programs and adoption of efficiency measures.

Mr. Dunsky also cited performance uncertainty and higher than average housing mobility for low-income consumers (multiple moves within a short period of time) adds to the uncertainty regarding the economic value of long-term energy savings measures for low-income households. He also cited transaction costs: and greater difficulty experienced by low-income households in dealing with complex transactions can also lead to lower measure uptake and higher dropout rates. And, of equal importance as operating barriers to the participation of low-income households in energy efficiency measures, Mr. Dunsky noted:

a) financing difficulties – a general lack of access (or access at unreasonable cost) to capital;

b) an aversion to debt due to the payments associated with debt;

c) a diminished ability to meet upfront costs;

d) the organizational practices of many contractors, unwilling to work for low-income customers or charging a premium for the perceived risk of non-payment; and

e) the daunting issue of split incentives in rental markets, whereby landlords are unwilling to pass on savings to tenants or invest in measures that would assist in lowering utility bills but not benefit the landlord financially.

Mr. Dunsky reiterated a concern previously expressed by the Board that generally low-income customers will lack access to the capital required to make improvements to the energy efficiency of their homes. He further noted that low-income individuals are often caught in a "vicious cycle of debt", such that even if they could have access to capital, they will have an aversion for incurring debt requiring increased demands for their disposable income, and, therefore are unlikely to invest in their home (even if the investment would be in their long-term interests).

Mr. Dunsky suggested four key principles for success in administering a low-income program:

1. Keep it simple. Participation drops precipitously as complexity increases. Program implementers need to take "A-Z" ownership of the complexity involved in conducting audits, hiring contractors and overseeing work. Complexity should occur on the implementer's side, not the participant's. Similarly, proof of income and other eligibility requirements need to be flexible.

2. Keep it free. While it may be tempting and intuitive to request even symbolic participant contributions, Mr. Dunsky suggested that attempts to do so in other jurisdictions have generally met with failure.

3. Incent "sales" (outreach). For Mr. Dunsky, the difference between a good theoretical design and good performance is sales. Ideally, the utility, the contractor and other low-income stakeholders (supporters) will contribute to an active outreach effort, with only the utility and the supporting community having the capacity, tools and incentives to find potential customers and "close the sale".

4. Be comprehensive. As with any sale, the hard part is getting in the door. Mr. Dunsky suggested that once a participant is in the program, it is critical to capture all possible opportunities, recognizing that any measures not installed will likely be lost for years and/or their savings will cost significantly more to achieve at a later date. Comprehensive programs typically include education, a suite of "light" measures (CFLs, caulking/weather-stripping, low-flow aerators and showerheads, etc.), envelope measures (insulation and weatherization) and appliance and equipment replacements (especially old fridges and furnaces).

Mr. Dunsky opined there were a number of major weaknesses in MH's low-income energy efficiency program, beginning with the fact that the current program design is too complex, consisting of a number of hurdles that the low-income customer must overcome to participate. Mr. Dunsky noted that MH has not taken ownership of the delivery of its programs, passing the responsibility to low-income customers, an approach that he opined represents a serious barrier for low-income customers.

To assist in reducing low-income household resistance to implementing energy efficiency measures, Mr. Dunsky proposed that MH take full ownership of its DSM programs, including taking on all the necessary administration. He noted that in other jurisdictions where programs have been successfully implemented, full utility ownership of all approaches taken had been followed, with the benefits including the elimination of needless hurdles, the ability to negotiate better prices with contractors than can be achieved by individual low-income homeowners, and assurance of quality control.

Mr. Dunsky criticized MH's reliance on others, suggesting that relying on CBO's to identify and involve low-income customers is unlikely to secure success. Mr. Dunsky opined that another weakness in MH's program relates to the involvement of CBO's in program delivery. He recommended that MH be selective and choose only organizations with the institutional ability, reputation and capacity to deliver low-income programs effectively. He also suggested that MH invest significantly in helping CBO's develop the necessary capacities and abilities to deliver programs effectively.

Mr. Dunsky recommended that when such organizations are involved they be closely monitored and regularly assessed, particularly as to their ability to meet targets. For Mr. Dunsky, MH should measure and evaluate the time from "first contact to work completion", and both undertake quality control spot checks and utilize client satisfaction surveys.

To avoid the problems he expected to arise with involving CBOs in MH program delivery, Mr. Dunsky recommended that MH lead the projects and underwrite the costs of the measures required, dealing with the Federal government directly to recover any federal incentives that may be available.

The Coalition suggested that approximately 30% of MH's residential accounts pertain to rented homes, excluding duplex apartments, and that there are almost 98,000 apartment units. The Coalition noted renters' average household income is significantly lower than the Manitoba average, and that apartment units, where renters predominate, are currently excluded as a target group for the low-income energy efficiency program.

Mr. Dunsky stated that a major barrier faced by low-income customers is the lack of access to capital and a concurrent aversion to new debt. Mr. Dunsky also noted that the majority of low-income households are renters, and that a renter would not be willing to invest in improving the energy efficiency of a building if they were not to receive the benefit. Conversely, a renter responsible for the utility bill may find the owner of the building not willing to invest in improving the energy efficiency of the building envelope, because the landlord will not retain the benefits.

Mr. Dunsky stated that programs requiring landlord support should be made attractive for both the low-income tenant and the landlord, and that otherwise a low-income tenant will not benefit because of a lack of landlord participation. Mr. Dunsky proposed that MH offer a turnkey approaches, whereby MH would pay for all the measures undertaken and collect any external incentives. Mr. Dunsky indicated such an approach would best facilitate landlord participation.

With specific respect to natural gas furnace replacement, Mr. Dunsky indicated that MH's current program is inadequate. Mr. Dunsky suggested MH offer a zero-interest loan or, preferably, a lease. The loan/lease would involve owner payments over a maximum of 10 years.

He suggested that a leasing approach would allow repayment to remain tied to the furnace, the newer more efficient furnace to provide the energy savings benefits allowing the lease payment to be made. Mr. Dunsky also suggested that a more aggressive financing offer may overcome low-income customers' reluctance to participate, and provide an opportunity to replace inefficient furnaces (which result in high levels of emissions and bills).

Mr. Dunsky also suggested MH expand its current DSM program to include a fridge replacement program, which would target the early retirement of inefficient refrigerators. Mr. Dunsky estimated that replacing inefficient refrigerators could be expected to result in an average saving of over 900 kW.h annually for each fridge replaced.

Based primarily on its witness' testimony, the Coalition recommended, for Low-Income and Tenancy DSM:

1. MH provide turnkey service;
2. CBO capacities be evaluated prior to involvement;
3. A fridge replacement program be implemented;
4. A more aggressive approach to furnace replacement be undertaken; and
5. Expedite the rollout and implementation of low-income DSM programming, addressing costs, benefits, and sources of funding.

The Coalition did not endorse RCM/TREE's recommendation for a bill assistance program, stating that while the intervener was open to a further study of the issues involved, it had concerns with problems found in US jurisdictions, those reported to be related to low participation levels, and suggesting the potential to divide low-income customers from other customers and, as well, a concern with the income means testing that would be required.

MIPUG

DSM Programs

MIPUG suggested MH pursue all DSM opportunities where the projected costs to secure energy savings are at or below the marginal cost of new generation.

MIPUG advised MH not to screen out DSM opportunities on the basis of customer economics, but instead focus on ensuring customers have sufficient information to conduct their own evaluation of the costs and benefits of the DSM opportunity. MIPUG suggested MH's current approach may be screening out beneficial DSM measures.

DSM Program Evaluation

MIPUG expressed concern that MH's present approach is screening out economically justifiable opportunities, and opined that the TRC test excessively focuses on participant economics, and that it is possible that DSM activities that would be economically beneficial to MH and its customers are being screened out under the TRC test because the economics were not sufficiently advantageous to the participant.

Low-income programs

MIPUG opined that affordability programs to benefit low-income customers represent social policy considerations that more properly lie within the mandate of the provincial government. To base rates on a customer's ability to pay is, for MIPUG, discriminatory. Similarly, operation of a DSM program targeted solely at low-income customers is considered by MIPUG to be discriminatory, with MIPUG focused on MH's obligation to provide power to all its customers.

MIPUG opined that precedent suggests that decisions undertaken that exceed or define the bounds of discrimination should be made by explicit direction by the legislature and should not be undertaken in the absence of such direction. MIPUG's cited past legislation related to uniform rates and the establishment of the AEF, both created through government initiated legislative changes.

MIPUG further stated that if any approaches are to be undertaken to benefit low-income customers, they should be revenue neutral to non- low income customers

MKO

DSM Program Evaluation

MKO submitted that DSM programs should not be required to be revenue neutral for any particular customer class, or group of customers.

For MKO, to the extent that a provincial government elects to use MH rates as a social policy implementation tool, and provides clear direction to MH to do so, then the variance from standard rate design principles is justified.

MKO further stated for DSM programs targeted to benefit certain customers, that in the absence of a clear provincial government direction on “who should pay”, MKO submits that all MH customers should bear the costs.

Diesel Community DSM Programming

MKO submitted that energy efficiency measures are very important, especially for high-cost diesel served communities. In measuring energy savings in the diesel zone, 1 kW.h saved also reduces the cost of diesel fuel to generate the kW.h. However, since a kW.h saved in the diesel zone does not provide an extra kW.h for export sale, the more traditional approach of valuing a kW.h saved with respect to delaying new generation capacity or adding to export sales should not be used with respect to the diesel zone.

MKO noted that MH has suggested that through population growth the electricity required to serve the diesel communities may double over the next 20 years. MKO noted its understanding that INAC will pay for new generation capacity only for the diesel communities, whereas all MH customers pay for new generation capacity for the rest of the province. MKO is concerned that since MH does not have to pay for new generation capacity in the diesel communities (with the costs largely being met by INAC and rates), the Corporation has not pursued energy efficiency programs in the remote communities to the extent that it should.

MKO indicated concern with MH’s statement that its home audit program would not apply to homes in MKO communities, where, for MKO, MH perceives the benefits flow to INAC. Accordingly, MKO recommended that the Board immediately direct MH implement DSM programs for all customers in all MKO First Nation communities, whether or not MH perceives that benefits may accrue to INAC. MKO further recommended that MH personnel working with MKO First Nations customers be directed to meet with MKO First Nations to resolve misconceptions regarding the beneficiaries of DSM programs in the MKO First Nations communities.

MKO submitted that MH has been operating in violation of the spirit of Board Order 17/04, where MH was directed to implement DSM and energy efficiency programs in the diesel communities as part of the effort to reduce the financial burden on MKO customers. MKO further submitted that MH should re-evaluate its energy efficiency programs and incorporate Mr. Dunsky's recommendations to revise qualification criteria and set more realistic targets for the amounts MH will invest in energy efficiency measures in the diesel communities.

RCM/TREE

DSM Programs

RCM/TREE stated the principles of sustainability and justice should guide the Board in its determination of the public interest.

RCM/TREE noted that despite MH's internal assessment of success in its DSM program efforts, MH's standard electric residential customers continue to increase their energy consumption while Saskatchewan Power customers reduce their consumption.

While RCM/TREE supported MH in its bid to be both financially secure and socially responsible, the intervener suggested MH should further develop DSM and bill affordability programs for low-income customers.

Mr. Paul Chernick, a witness engaged by RCM/TREE, suggested that MH should double or triple its energy-efficiency spending, and energy savings, from current levels. Mr. Chernick stated that increased energy savings over the next few years would help to offset the expected and/or risk of energy shortages that may lie ahead, and that while MH asserts that “the only option available for 2009 is imported power” (to meet a possible energy shortage), accelerated DSM is clearly a lower-cost option.

For Mr. Chernick, increased energy savings over the next decade would increase MH’s flexibility, allowing it to avoid the anticipated 2020/21 energy deficit (before both Conawapa and Keeyask are expected to be on stream), without having to extend the operation of the thermal plants, while allowing the Utility to commit to larger and longer-term firm export sales.

Mr. Chernick advised that if the Board were to increase MH’s funding for DSM, low-income programs, economic development, or to strengthen MH’s balance sheet, the additional charges should come in the form of higher energy rates rather than increased demand charges, and by way of inverted higher tail-block energy charges.

DSM Program Evaluation

Mr. Chernick recommended the RIM test be discarded as a guide to the selection of DSM programs, and suggested that there are better ways to evaluate DSM programs. As to the evaluation of DSM programs, Mr. Chernick suggested the Board embed a value for carbon even though a carbon tax is currently not being received through current export prices.

Mr. Chernick recommended the Board direct MH to incorporate in its planning environmental costs for which it is not now being paid by export customers, and report back to the Board on the feasibility of including the additional benefits to Manitoba and the global environment from the reduction of carbon emissions, and how these benefits might best be incorporated in rate design and DSM evaluation.

Low-Income Programs

RCM/TREE submitted that MH should institute an affordability program, as recommended by Mr. Steven Weiss, a witness engaged by the intervener. For RCM/TREE, in addition to the social benefits that would come from a bill affordability program for the least well-off in society, such programs are also beneficial to non-participating customers because of reductions in utility collection and administration costs and reduced bad debts of low-income customers.

Mr. Weiss stated to make energy affordable, it is important for the Corporation to focus on customer energy burdens and target for benefits the most vulnerable, the benefits to be DSM and direct bill assistance. He defined energy burden as the percentage of income that non-transportation energy costs represent of household income. Mr. Weiss described a high-energy burden to represent 11% or more of household income, with a severe energy burden defined as being 15% or more of a household's income paid for energy.

Mr. Weiss recommended MH measure energy affordability, gather information on the energy burden of Manitobans, and track the effectiveness of its programs in reducing the number of customers with high and severe energy burdens. Mr. Weiss recommended MH should aim to reduce low-income residential consumers' energy burden to, at minimum, levels below the severe burden level of 15% of household income. He also suggested that over time MH should amend its goal, and seek to reduce the maximum energy burden to 11% of household income.

Mr. Weiss stated specific plans should be set to target the Low income households with the highest usage, and these residences should be provided conservation measures and bill assistance. Mr. Weiss also suggested MH should set goals and outreach targets for seniors, minorities, the disabled and families with young children.

Mr. Weiss noted that the bill assistance programs of other jurisdictions take many forms, including one-time crisis assistance payments (in the $200 - 300/year range), arranging forgiveness, rate discounts, monthly credits and assistance based on maximum percentage of household income..

Mr. Weiss indicated that programs considering the percentage of income required to be devoted to energy bills work best, when assistance levels can be set according to income level. He provided an example, whereby a customer would be charged no more than 9-10% of his/her income, being deemed a level that is "affordable." In Mr. Weiss' example, any bill amount over that level would be met through the bill assistance program.

Mr. Weiss stated that the customers of utilities offering such programs are often required to make timely payments in order to remain with the program; the goal being to provide an incentive for customers to stay current within a budget they can afford. Mr. Weiss further stated that these programs have proven to be extremely successful in reducing disconnection, arrearages and write-offs. He also recommended that such measures work best with equal payment plans.

Mr. Weiss' final recommendation was that a bill affordability program could begin as an experiment, and involve the use of a control group of low-income customers not enrolled in the program. He suggested that frequent evaluations of bill assistance programs and pilots are very useful, and that an advisory group consisting of social service agencies, low-income customers, conservation and social justice advocates, as well as utility personnel involved with the program would prove useful.

In addition, RCM/TREE expressed support for the proposals put forward by Mr. Dunsky, the witness for the Coalition who proposed recommendations to remove barriers to low- income program access.

In addressing the question of whether the Board has the jurisdiction to implement low-income programs, RCM/TREE referred to a recent decision of the Ontario Supreme Court of Justice Divisional Court (dated May 16, 2008) involving the *Advocacy Centre for Tenants* and others versus the *Ontario Energy Board* (OEB). In the Court's decision, Justices Kiteley and Cumming dealt with the issue of whether low-income programs could be viewed as being within the OEB Board's jurisdiction.

In that decision, the Court held:

> "However, in our view, the Board need not stop there. Rather, the Board, in the consideration of its statutory objectives, might consider it appropriate to use a specific method or technique in the implementation of its basic cost of service calculation to arrive at a final fixing of rates that are considered just and reasonable rates."

RCM/TREE interpreted the finding to mean the Board's jurisdiction could extend, to include the objective of energy conservation, and, as well, to the use of incentive rates or differential pricing, to further the objective of protecting the interests of consumers. RCM/TREE further interpreted the decision to suggest the Board may take into account income levels in setting utility rates, to achieve the delivery of affordable energy to low-income consumers (on the basis that this would meet the objective of protecting the interests of consumers with respect to prices).

RCM/TREE submitted the Board is engaged in rate setting within the context of the interpretation of its statute (*The Public Utilities Board Act*) in a fair, large, and liberal manner and that is not engaged in setting broad social policy; accordingly RCM/TREE urged the Board consider the approaches it recommended.

11.10 Board Findings

DSM Programs

The Board recognizes that MH has been making an increasingly significant investment in DSM programs, and has gone beyond the efforts made by the vast majority of other utilities, with spending increasing in recent years from $11.9 million in 2003/04 to a forecast in the order of $43.1 million for fiscal 2008/09.

MH's program now has a low-income component and it is a segment of MH's integrated resource plan, as energy savings allow for additional energy to either be sold on the export market or allow for the deferral of expensive new generation. Both outcomes can have the effect of improving MH's financial position and dampening the need for sizeable future rate increases.

The Board encourages MH to continue to pursue environmental objectives on an integrated natural gas-electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions.

For the Board, the Utility's DSM focus should be four-fold:

a) environmental – the reduction of wasted energy through reduced GHG emissions (here and in MH's export markets – climate change is a global challenge, the wind blows north as well as east, south and west);

b) economic – energy not consumed by Manitobans should be available for sale on the export markets, and as much of that as possible during on-peak hours at peak prices – exports are taken into account in determining domestic rates without exports current rates would be, on average, 15% higher;

c) economic – energy not consumed by Manitobans and not sold on the export market, either due to transmission capacity or price issues, can assist in the deferral of new generation and transmission, saving capital dollars and attendant interest and depreciation (construction and commodity costs have recently soared, driven in part by extraordinary expansions – of oil sands production in Alberta and the energy demand of China and India; sometimes delays can allow for projects to take place in times of more stable prices); and

d) social – increasing the energy efficiency of low-income households will allow more families to remain in their homes and to have more disposable income available for necessities other than energy (the total cost of energy – gasoline, natural gas, electricity, propane, etc., has soared for all households, but the cost increases have been particularly devastating for households in the bottom four deciles of household income levels).

With respect to the approach the Utility now takes to accounting for DSM costs, as it has in past orders the Board continues to question the appropriateness of deferring DSM costs, an approach that is now challenged not only by the Board's concern but also by the upcoming IFRS. The Board has had and remains of the view that DSM costs should either be expensed in the period incurred or amortized consistent with the much shorter periods of amortization followed by other jurisdictions.

MH defers DSM expenditures for subsequent amortization over 15 years, whereas Hydro Quebec and BC Hydro, (sister crown utilities) defer less DSM and amortize deferred DSM expenditures over a much shorter time frame. In the case of BC Hydro, DSM costs are amortized over the short term of the useful life of the program or a maximum of 10 years. Hydro Quebec also amortizes DSM expenditures over a 10-year period. With the coming introduction of IFRS, the current amortization policy will be reviewed and a more conservative approach may be an option for early adoption.

Amortization of DSM spending is forecast to grow from $9 million in fiscal 2007 to over $13.7 million in fiscal 2009, while actual spending on DSM initiatives is forecast in 2007 at $36.1 million, and to grow to over $43 million in fiscal 2009. Thus, MH now plans for deferred DSM to grow to over $180.9 million by March 31, 2009, a balance expected to continue to grow significantly through to 2018, due to increasing annual DSM spending which will eventually have to be recovered in rates – now to be achieved over a period too long for the Board.

The Board recommends MH consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years.

DSM Program Evaluation

The Board notes that MH projects that by fiscal 2017/18 (and speaking now as to electricity operations) it will have achieved 2,637 GW.h of DSM savings (1,706 GW.h through incentive-based programs and 931 GW.h of savings through changes to Codes and Standards, etc.). If achieved, this would represent a 240% increase in DSM savings over 12 years, a growth rate of almost 20% per year. (Demand savings are expected to reach 842 MW, an increase by 170% over 12 years, or almost 15% per year.).

While the projections are impressive, the Board suspects the opportunity for further reductions is great. As well, the projections are also highly subjective. MH relies on forecasts which can only be partially verified.

Despite major increases in DSM expenditures over the last four years, DSM has not had a marked effect on the deferral of planned generation and transmission projects. Since inception, DSM has, at best, offset 20% of domestic load growth. The Board notes that MH is forecasting the risk of energy shortfalls (demand, domestic and committed exports, as compared to local hydro-electric supply) through to the in-service dates of future generating stations Keeyask and Conawapa. If shortfalls do occur, and past experience and probabilities suggest a high risk of drought or below median water conditions occurring within the next five to ten years, then, as matters now stand, MH will have to rely on imported power from the MISO market. MH's MISO-market partner utilities generally use natural gas for peak demands, so the cost of imports can be a multiple of the average price of MH's exports.

In such a condition, and if a drought were to be sustained for five years (which has occurred in the past), MH has advised the Board that it could "run" a loss of over $3 billion, an amount that dwarfs the Corporation's current retained earnings balance and which would have implications for rates and the general view of the Corporation's fiscal stability going into a period of expected significant expansion.

For the Board, the risks inherent to a Corporation depending in the end on the weather suggest that there should be an even more increased focus on conservation and DSM, so as to further reduce demand to provide an increased buffer between Manitoba hydro-electric supply and likely demand in the future. Such increased DSM initiatives may also address the currently-forecast future expected shortfalls.

Energy conservation has never been of such importance to MH as it is now, as it contemplates a massive capital expenditure program, to produce power that now is expected to be required to meet rising domestic load and continuing committed export markets.

Now, as previously indicated, MH does not expect the conversion of current natural gas space heating load to electricity, nor does it expect an abandonment of natural gas as the space heating choice for new residential construction. Given the Board's understanding of current and forecast natural gas prices, and its expectation for even higher domestic load growth due to such new phenomena as "electric" and "hybrid" cars, relying on electricity rather than gasoline, the Board urges MH to focus on conservation and upgrade and develop new DSM programs, to free up hydro-electric generation to meet the risk of much higher domestic load growth than the Corporation now forecasts.

This will likely require an expansion of existing as well as additional DSM programs, along with taking more into consideration societal impacts in the evaluation of DSM programming. In short, the Board recommends that MH "step-up" its DSM plans and targets.

Indirect GHG Reductions

Interveners have suggested that increased export sales achieved by diverting price restrained domestic load growth to MISO will achieve global GHG reductions comparable to displacing coal-fired generation.

MH's evidence was that the GHG reductions are, to a greater degree, reflective of natural gas generation displacement, since the carbon footprint for natural gas generation is less than 50% of that for coal generation.

The Board sees a need for more clearly defining the relative environmental benefits of exports, and will direct MH to provide a detailed analysis and report to the Board before June 30, 2009 as to whether there are greater global environmental (GHG) and economic benefits by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of exports. The assumptions should also be included in the report. Currently, Manitoba consumers and businesses transfer $1 billion to the gas producing provinces and states that supply Manitoba's natural gas, and these costs and transfers of funds to outside the province may soar even higher in the future.

Low-Income Energy Efficiency Programs

With respect to low-income programs, the Board commends MH for recently beginning to address the energy conservation needs of low-income households.

The Board is also encouraged that MH plans to enhance its low-income programs and target rental premises as well as owner-occupied residences, with MH's commitment to extend the low-income program to tenants of apartments. The Board further understands that there may be resistance for landlords to take part in the program due to split incentives and low-cost business models that some landlords may choose to operate under.

The Board also urges MH to make efforts to incent landlords to participate in the program to improve the energy efficiency of their properties, to the benefit of their tenants and the environment. The Board will expect MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development and implementation of this program.

Although MH is beginning to address the issue of energy poverty, more is required. The Board is very concerned with the slow pace of the overall effort. The Board notes that MH's current program is anticipated to address only 4,600 lower-income households over the next three and a half years, while the current low-income population is likely at least in the order of 100,000 households – and that is before taking into account recent major inflationary increases in general energy costs and risks of a slowing economy and higher unemployment.

Based on the current pace of MH's low-income DSM programs, the Corporation's spending over the next three years on low-income programs will not put a dent in the problem, and, at best, address only a very small fraction of low-income households. At the proposed pace of the program, it would take decades to obtain a significant level of participation of low-income households in MH's energy efficiency programs.

Low participation acts as a barrier to the lowering of excess energy bills and GHG emissions, and the putting in place of meaningful inverted rate program designs for residential customers. The Board agrees with the views expressed by the Coalition and RCM/TREE that more should be done in this area, to accelerate its efforts with respect to reducing the energy burden of low-income households.

The Board will direct MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural gas and electricity) energy efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade.

The Board notes the evidence of Mr. Dunsky who critiqued MH's design of its low-income programs. Mr. Dunsky's suggested changes to MH's program were designed to overcome the barriers of program participation, barriers that clearly remain a significant concern of the Board. The suggested changes put forward by Mr. Dunsky have merit and should be considered by MH in its design of current and new low-income programs. The Board notes a willingness by MH to consider many of Mr. Dunsky's recommendations, and urges MH to not only consider the recommendations, but to internalize many of them, and take full ownership as to the delivery of the programs.

The Board was intrigued by the refrigerator replacement program proposed by Mr. Dunsky, and will direct MH to report back to the Board on a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009. And, with respect to MH's new natural gas furnace replacement program (launched following Board direction that arose out of a Centra GRA), the Board appreciates the evaluation provided by Mr. Dunsky, and takes note of Mr. Dunsky's suggested changes to the program, including his suggestion for a lease program, with the lease payment linked to the energy benefit.

The Board notes Mr. Dunsky's critique that, as designed, the furnace replacement program will not prove an adequate incentive for the early replacement of inefficient natural gas furnaces and, at best, will likely only marginally assist the natural replacement market. The Board urges MH to seriously consider program changes to increase participation in early replacement of inefficient furnaces. Changes to the program that will better provide this opportunity are well worth the effort, and should provide energy savings for low-income customers and significant non-energy benefits to society, the Utility and the participants in the program.

The Board is aware that MH only recently launched its furnace replacement program, and suggests that design changes may be fairly easy to introduce at this time. MH has an opportunity to put this program on the “right footing” in advance of the upcoming heating season – when natural gas bills for all customers, not only low-income, may be considerably higher than they were in the previous winter.

The Board is interested in the take up of the program, and understands that it has been very low to-date, and will require MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunsky, on or before September 30, 2008.

While not as aggressive, perhaps, as the Board’s recommendation that low-income customers be allowed subsidized Power Smart Loans and payment schedules involving an option requiring payment only upon the sale of the residence, Mr. Dunsky’s lease concept has merit as an option. Whether MH proceeds to adopt the Board’s recommendation for a subsidized loan program secured by the residence, or follows up and introduces a furnace lease program as suggested by Mr. Dunsky, either approach appears to be more likely of achieving success than the current approach being followed by the Corporation.

Installing high-efficiency furnaces in residences now relying on furnaces that may have efficiency ratings as low as 40% or below should assist in restraining the conversion from space heating by natural gas to electricity, that would, if it occurred, only intensify MH's supply/demand situation in the years to come.

With respect to the AEF, MH has taken the position that interest should not accrue on AEF balance, this contrary to that directed by the Board in Order 99/07. If interest was accrued on outstanding AEF balances, the AEF would have additional revenues available to fund further low-income programs. The Board recognizes that capacity issues may exist in program delivery; however, the Board believes that if more funds were made available, such programs could be expanded to meet more of the needs. If interest is not allowed to accrue to the AEF, its purchasing power will decline by at least the rate of CPI inflation; accruing interest will remove any disincentive to move quickly to put the AEF to work.

The Board does not agree with MH's perspective of the intent of the legislation that gave rise to the AEF. The Board will require MH to accrue interest on the AEF balance to ensure additional funds are available to fund expanded low-income energy efficiency programs.

The Board is also particularly concerned with the delivery of low-income programs on First Nations diesel communities. The Board notes MKO's concern that energy audits and low-income programs may not be available to diesel community households, with the perception that the benefits will be realized by INAC. The Board expects MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008.

The Board is very concerned with the burden low-income households face with higher energy costs, even more so given the rapid increases in both oil costs and natural gas pricing. The Board believes that MH has a duty to ensure a safe and reliable service to its customers. The question is whether that duty should extend to ensuring electricity is made available on an affordable basis.

Bill Assistance

The Board notes that the low-income high energy burden problem is extensive in Manitoba and that MH now relies on a voluntary program, Neighbours Helping Neighbours (Salvation Army), which allows MH customers to donate to a fund, a fund the Board finds sorely inadequate. Families and seniors who are unable to pay their natural gas or electricity bill due to personal hardship or crisis can receive support from the program, but only if sufficient funds are available.

While a voluntary program is beneficial, it cannot meet the need in the Province as it is now established. A low-income bill assistance program would assist in reducing the energy burden faced by low-income households. Significant non-energy benefits would arise, including increased comfort, reduced health costs, lower bad debt write-offs etc. .

Manitoba is a cold environment from the fall through to the spring; in this Province, adequate heat is a necessity of life. In light of this reality, the Board recommends government seek from the Federal government an exemption from GST for residential customers, as heat in Manitoba is a necessity like food; and to fund low-income and DSM programs, the Province should set aside all or a portion of provincially and or municipally sanctioned sales taxes charged to residential customers on energy used for heating purposes.

The Board notes that MH's commercial customers may recover GST paid on input costs and that health and educational institutions also receive favourable treatment with respect to the GST.

In a 2007 proceeding before the Ontario Energy Board (OEB) the Low-income Energy Network (LIEN) sought approval of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of LIEN's position was that low-income consumers [estimated at approximately 18% of Ontario households] should pay less for gas distribution service than other customers. The issue LIEN sought to advance were:

- Should the utility's rates include a rate affordability assistance program for low income consumers?
- If so, how should such a program be funded?
- How should eligibility criteria be determined?
- How should levels of assistance be determined?

In a split decision, the majority of the OEB panel concluded it did not have jurisdiction, pursuant to its existing legislation, to order the implementation of a low-income affordability program. The majority of the OEB concluded LIEN'S proposal amounted to an income redistribution scheme requiring one consumer rate class based on income characteristics as well as implicitly require subsidization of this new class by other rate classes.

LIEN appealed the OEB decision to the courts. Also by a split decision, the Ontario Superior Court of Justice, Divisional Court recently allowed the LIEN appeal and declared that the OEB has the jurisdiction to establish a rate affordability program for low-income consumers of the utility.

Because both the Manitoba and Ontario rate setting jurisdictions are similarly broad, this Board has previously indicated its concurrence with a dissenting position of the OEB on its ability to establish a rate affordability program for low-income utility customers, a position since upheld by the Court.

Energy affordability for low-income families is very much an issue that requires more or less immediate attention in Manitoba. The Board suspects that low-income individuals, families and seniors, unable to pay their natural gas or electricity bills due to personal hardship or crisis, could receive support from a rate reduction program without causing a major rate increase for MH's other customers.

The Board believes that in light of the recent Ontario court ruling, it (the Board) would be acting within its mandate and in the public interest if it were to direct MH to implement a bill assistance program. Accordingly, the Board sees merit in the proposition put forward by Mr. Weiss. And, therefore, the Board will direct MH to propose for Board consideration (as soon as possible for the coming heating season, but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction to and compliment an expanded low-income DSM program.

MH should address the issues of: how such a rate affordability assistance program should be funded, how eligibility criteria should be determined and how levels of assistance should be determined. Consultation with the Coalition and RCM/TREE may be of assistance to MH.

The Board understands the issues and problems raised by the Coalition relative to similar programs available in the US, where access to funds is "real", thanks to U.S. federal government funding. The Board further believes a bill assistance program (as proposed by Mr. Wiess) should be extended along with a program to improve the heat retention and the efficiency of low-income homes, and the sooner the better.

12.0 Risk Analysis

The Board has, in past Orders, requested that MH to file a quantified Risk Analysis. To date, MH has submitted limited scope and/or generic discussions of issues that would better be incorporated in a fully integrated and quantified risk analysis that provides a detailed quantification of all substantial risks and a probability analysis to assist in the testing of the appropriate level of debt:equity ratio.

Over the years and at various GRA proceedings, MH has flagged numerous business risks to its financial well being, and stressed the need for adequate retained earnings in order to make progress towards its debt/equity target of 75:25. And, consistent with these views and in response to past Board Orders, MH submitted the following reports at this year's GRA:

a) Risk Advisory Report (January 18, 2005) (2004-04 Drought Risk Management Review);

b) MH's report on Risk Strategy and Quantification (January 31, 2005); and

c) MH's analysis of Financial Loss Due to Extended Periods (July 26, 2007).

The first of these reports was narrowly focussed on MH's response to the 2003/04 drought, particularly as related to hedging and energy buy-backs. The report did not deal with MH's operational strategies going into the drought, an issue the Board has a considerable interest in (now, as an indication of possible future risks). MH's second report addressed generic issues of risk management and how the Corporation defines overall business risks. Again, it neither provided detailed assessments nor quantifications of those risks.

In the third document filed, MH quantified the financial implications associated with a repeat of the three extreme drought events in recorded history. The events were presented as individual risks and not integrated in an overall quantified business risk assessment. Also, MH, in response to interrogation, provided forecast financial impacts for a variety of business risks. However, it remained MH's position that these risks should not be aggregated and that appropriate methodology does not exist to allow the incorporation of risk probabilities to produce an overall risk quantification.

The Board observes that Manitoba Public Insurance also faces a diverse list of risks for which an aggregation would not provide a fair impression of even likely worst case scenarios yet, its actuarial advisor has assigned probability, allocated provisions for adverse deviations, and produced an overall assessment.

12.1 Drought

The following tables identify the reduction in retained earnings as of March 31, 2018 that MH projects as being associated with various unfavourable events (as identified during the hearing).

Drought Risks ($ millions)

Event in Forecast Period	Frequency	Retained Earnings Reduction	Retained Earnings, March 31, 2018
IFF 07-1	0	0	$3,349
One Year Drought (50% of 2003/04 Loss)	1 in 10	$ 490	$2,859
2003/04 Drought	1 in 15	$ 891	$2,458
Five-Year Drought (as per 1987-91)	1 in 50	$2,800	$ 549
Seven-Year Drought (as per 1936-42)	1 in 100	$3,500	($ 151)

A review of 94 years of river flow history revealed that MH has faced drought situations in 23 of the 94 years (1 year of each 4). Consecutive years of drought occurred in the periods 1929 to 1932, 1936 to 1942, 1976 to 1977, 1980 to 1981, and 1987 to 1991. MH has recognized the compounding effect on retained earnings of a multi-year drought and defined the financial consequence of a five-year drought modelled on the 1987 to 1991 experience, and, as well, the consequence of a seven-year drought modelled on the experience of 1936 to 1942.

These forecasts are presented as if these events had happened during the forecast period, to 2017/18. (The 2003-04 drought may well have been the most severe single-year drought in MH's flow history.)

The modeled multi-year droughts were projected to have retained earnings impacts of $2.8 billion for a five-year drought, and $3.5 billion for a seven-year drought. MH has never identified a "dollar based" retained earnings target, but relies on a 75:25 debt:equity target.

For a seven-year drought projected as above, and given an initial retained earning of $1.7 billion, MH forecast that an additional 4.0% annual rate increase, on top of the currently projected annual increase of 2.9%, applied over a 10-year period would not only restore the $1.7 billion projected to be lost as a result of the drought but would provide for a doubling of retained earnings to $3.5 billion by March 31, 2018.

This may suggest that $1.7 billion could be considered an adequate reserve for a seven-year drought, and that a 2% to 2.5% additional and annual rate increase for the ten years following such a drought would restore the initial reserve. However, assuming MH's current capital expenditure forecast is realized, restoring the $1.7 billion of retained earnings through annual 4.9-5.4% rate increases would not achieve a 75:25 debt:equity ratio; in fact, the retained earnings deficiency in such a situation would be quite significant.

The 2003-04 drought demonstrated that MH's generally "aggressive" approach to export energy marketing, while conducive to higher profits in median or above flow scenarios, carries the risk of increased losses during drought or low flow years. MH has acknowledged this risk, but believes its present strategy (that is, depending on median water flows) provides greater longer-term financial returns. The Board is not so certain and would prefer an independent assessment be conducted and filed.

Some of MH's exports involve three to four month advance sales of firm energy, without the certainty that the firm energy sold will be available (i.e., precipitation may not replenish water resources). Such practices lead to reasonable results in the absence of poor water conditions, but significant cost consequences when water flows fall and imports have to be purchased to fulfill contract obligations. This situation occurred in the summer of 2006/07 and, in the Board's view, contributed to MH's request for a 2.25% interim rate increase (granted initially as an interim increase and finalized by Order 90/08).

The drought scenarios represent events that could all occur over a 100-year period. However, the Board considers it reasonable that there is a very low probability that more than one multi-year drought would occur in a 50-year time period, let alone more than one during a 10-year forecast period. As such, the forecasts of multiple drought situations are not reasonably additive.

MH cannot prevent droughts from occurring, but, arguably, could do more than was done in 2003/04 to mitigate the consequences of a multi-year drought. In 2003/04, energy from water held in reserves was sold at low prices (off-peak pricing) to boost that year's annual income, only for the energy to be required to be "bought back" from the MISO market to meet MH's export commitments, and then at much higher prices than what the energy was sold for.

12.2 Other Risks

The "other risks" displayed in the following table are also circumstances that MH cannot control. However, as with droughts, the cost consequences of each can be mitigated to some degree by MH actions:

Impact of other Risks ($ millions)

Event in Forecast Period	**Frequency**	**Forecast Retained Earnings Reduction**	**Forecast Retained Earnings, March 31, 2018**
Lower Average Hydraulic Generation for 10 Years (1,000 GW.h Less)	(1)	$500	$2,849
Lower Export Revenue Prices (6¢/kW.h for 10 Years)	(1)	$800	$2,549
Exchange Rate Remains @ Unity for 10 Years	(1)	$170	$3,179
7.5% Capital Cost Price Escalation Per Year	(1)	$872	$2,477
Loss of Bipole I & II (for 4 months in 2011/12)	(1)	$200(2)	$3,149
Higher Interest Rate (up 2% on Average)	(1)	$234	$3,115

(1) Each of the above “other risks” have potentially high probabilities, ranging from 1 year in 5, to 1 year in 50

(2) Does not include costs for infrastructure repair or replacement.

The risks shown in the above table are “all inclusive”, and reflect scenarios that were raised in Board proceedings. As such, each is indicative of levels of risks that MH may be subject to at various times in the near future. From the Board’s perspective, given the importance of MH to the Province and the capital expenditure plans that are now “on the table”, a more exhaustive listing is still required, again with probabilities quantified.

The financial implications of these “other” risks may be considerably increased when MH’s recent export sales commitment announcements are confirmed in contract form. The nature of these sales and the additional capital costs associated with Conawapa and Keeyask generation and such additional transmission as may be required to meet the new commitments could substantially increase the magnitude of forecast reductions in retained earnings upon the occasion of an adverse event.

Not included in the above table are variations in domestic energy demand, medium-high domestic load scenarios as a result of extremely cold winters that can lead to energy shortages which would have to be offset by high priced imports, or conversions of energy sources to electricity from natural gas and propane. On the other hand, low-medium domestic load scenarios that arise with very mild winters can lead to energy surpluses, which in high flow years may have very limited market value.

Domestic residential and small commercial load growth comes with average revenue rates that have been above those achieved by average export rates. Domestic load growth in the large industry sector obtains the lowest rates offered by MH, other than those obtained from export sales during off-peak hours.

Overall, adverse events have variable probabilities. Two or three of these additional risks could occur in the same time period and, as such, their impacts on retained earnings could be additive. However, it appears that the total impact of the “other risks” might be of a lesser magnitude than what would be occasioned under severe drought situations.

12.3 Interveners' Positions

MIPUG, Coalition, and RCM/TREE all questioned the need for a retained earnings level based on a ratio of debt to equity, but, excepting for MIPUG's concept of specific reserves, have not made specific recommendations. A specific Board initiated review and quantification of risks has been recommended and the Coalition continues to support improved equity levels and suggests that further testing of retained earnings and reserves targets are required.

MIPUG proposes that the Board convene a special hearing to deal with risk and reserve issues, and that the Board should provide MH with prescriptive requirements and scope to define what would represent an acceptable comprehensive risk analysis and adopt an appropriate reserve mechanism for testing at future proceedings.

MKO also supports a broader role for the Board in defining business risks, including those associated with major capital programs.

12.4 Board Findings

Drought

Over the past decade or so, extra-provincial revenues have represented a significant portion of MH's actual and forecast revenues. And, as demonstrated by the $428 million loss in 2004, MH honours its obligation to meet firm export commitments by purchasing high price power in the event of a drought. The drought made clear the significant dependence that MH has on water flows; reasonable water conditions are clearly a requirement for MH to obtain favourable net export revenues and sustain domestic rates at below-cost levels.

As such, MH's energy supply resources and export commitments require constant monitoring, particularly as its assets and debts are to increase with planned massive capital expenditures.

MH has suggested that the drought of 2003/04 can be expected to re-occur once every 15 years, on average. Yet, longer droughts of greater consequence have occurred at least three times in MH's relatively short history. While MH has defined the potential impacts of various drought events, it has not provided a frequency-based in-depth analysis that is required to demonstrate the full range of economic consequence of the risk. MH will be directed to provide such an analysis.

In low water years, when MH experiences an energy shortfall, the available sources of "make-up" energy in the MISO market tend to be less efficient and very high cost natural gas generation (like the Brandon SCCT units, which recently had output costs of about 15¢/kW.h – compared to 6 cent rates for residential customers and 3.2 cents for large industry). Consequently, when MH operates gas generation to meet its export commitments, it is fulfilling export contract commitments at a substantial loss.

Unfortunately, in high flow years, MH's surplus (can be up to 7,000 GW.h greater than average) may only attract off-peak prices (and these have been under 2¢/kW.h during the summer months), as peak and shoulder-hours generation sales are limited due to transmission capacity and MISO needs. The difference between the price of a sale during peak hours and one during off-peak hours can be very significant, the former sometimes 10 times the latter, and with the latter usually being so low as to give rise to the question as to whether the sale was of strategic value.

This indicates a fairly large market risk related to MH's marketing strategies. To monitor these, the Board will be requiring MH to provide the Board with specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data). Alternatively, the Board could rely on annual reports, but they would enable only a form of post-mortem analyses and provide no opportunity for the Board to offer comment on more current strategies and their possible implications for consumer rates.

Infrastructure

Given the risks that abound with massive operations of high importance to not only utility customers but the Province overall, the Board will direct MH to provide regular due-diligence reports on its infrastructure, focusing on the risk aspects of the operation (e.g., Dam Safety Reports, Maintenance, and Rehabilitation Schedules, etc.), as part of expected regular updates to an Asset Evaluation Study.

Load Growth

The Board acknowledges MH's concerns about domestic load growth, particularly in the industrial sector. MH should provide a more detailed tracking of industrial load growth, along with a range of reasonable projections for the future when it re-files its application for a new industrial rate category in the fall..

The Board understands that MH's increasing DSM program is expected to offset a significant portion of domestic load growth. As such, it is essential that MH reconcile forecast DSM savings with its load forecasts and actual domestic loads. This type of analysis should be incorporated in Future Load Forecasts.

MH has yet to take a position on what might be likely climate change impacts on hydraulic generation, yet it assumes the global warming scenario in defining its export price forecasts and DSM benefits. The Board wants to explore the risks and opportunities that may lie with climate change at the next GRA, and trusts that MH is involved presently with such studies and is considering various possible scenarios, given recent new export commitments and plans for additional investments in generation and transmission facilities.

Capital Cost Escalation

The ambitious major capital program which has been undertaken to meet future export commitments and domestic load growth is expected to result in the spending of approximately $18 billion on major projects, including Bipole III, Keeyask and Conawapa. The Board notes that hyper-inflation and labour shortages was cited by MH as major reasons for the escalation in the costs to construct Wuskwatim, which is currently under development. In its evidence, MH did not indicate that the price increases experienced to date represented a short-term trend.

The Board is concerned that this higher-cost trend may continue. The Board questions and is concerned whether current forecasts of major capital programs are fully reflected in the forecast before the Board, and is concerned with the risk that an updated capital forecast more reflective of recent inflationary experience related to capital projects may show substantially-higher capital requirements, putting upward pressure on future rates.

The Board needs to examine a variety of cost and price scenarios to better assure it that the planned new capital projects will not require significant domestic rate increases over the longer term. The Board has directed MH to file an updated Power Resource Plan and provide an analysis of the rate impacts of the new planned capital projects.

Export Commitments

While the Board has not been provided with MH's specific export contract prices and terms, it is concerned because of recent average export price history. MH's forecasts assume an USD/CDN exchange rate of 1.16 and CO_2 legislation to achieve average export prices of 10¢/kW.h by 2018. If that expected price in Canadian currency does not materialize, MH could be faced with an extended period of time where average export prices will not cover incremental costs associated with Bipole III, Keeyask G.S., and Conawapa G.S, just as happened after the Limestone G.S. in-service of 1992, and as expected for several years following Wuskwatim coming into service.

With construction costs in a higher inflation mode and with interest rates at recent historic lows, it is impossible to be certain prices that have been secured on the export market will prove adequate. A relatively modest worst-case scenario could involve a 1-2¢/kW.h shortfall on export sales extending well beyond 2025. And, with Bipole III routed on the West Side of the Province, costs to be allocated under the COSS model may be 0.5¢/kW.h more than if Bipole III was to be on the East Side of the Province. A shortfall from required export pricing could have the effect of reducing future annual net income significantly after 2018, placing further pressure on domestic rates.

Other Risks

With inflation increasing and transportation costs soaring, it is difficult to imagine interest rates being sustained at current historically low levels. And, with oil at $140 a barrel and some industry observers predicting the price reaching $200, it would appear less than conservative to assume that the Canadian dollar is going to depreciate significantly from its current "near parity" level. Both an increase in interest rates and, perhaps, even a further appreciation of the Canadian dollar would have significant implications on the operations and results of MH, implications not yet quantified.

In light of the many risks discussed, the Board has directed MH to prepare a Risk Analysis to fully quantify the financial impact of the risks faced by MH.

13.0 Cost of Service

13.1 Background

Currently, MH's Cost of Service Study is a prospective study of average (embedded) historically-based costs classified, functionalized, and allocated to each customer class and sub-class on the basis of system usage. The costs reflect invested funds in Generation, Transmission, and Distribution, updated to use in forecasting costs for the next upcoming fiscal year.

Costs related to finance (interest, etc.), depreciation, and OM&A are shared by domestic customer classes and one export class on the basis of energy consumption, peak load demand, and customer numbers. Currently, surplus export revenues (above assigned and allocated costs, i.e. notional profit) are credited to the various domestic classes proportional to their share of total allocated costs.

COSS is a tool to assess the extent to which each customer class' revenues recover/compare to allocated and historic costs. The revenue to cost coverages derived from PCOSS-08 illustrate a degree of disparity in embedded cost sharing by the various classes. Yet, the results should not be viewed as being representative of a degree of unfairness, but rather as an indication of possible rate increase differentiations, if only historic costs are to be taken into account and the current method of allocating costs and revenue (including net export results) is maintained.

MH employs a Zone of Reasonableness (ZOR) from 95% to 105% to assess the need for differentiated rate increases. In this GRA, MH chose to seek an across-the-Board rate increase for all classes other than Area and Roadway Lighting (a class composed of municipal and other governments providing area roadway lighting to their communities).

MH opined that an across-the-board increase was justified, as no rate class is “paying” its full cost of service as long as MH has a retained earnings deficiency.

13.2 Amended PCOSS-06

In response to Order 117/06, which followed a comprehensive review of MH’s cost of service methodology, MH submitted a 16-page document that reflected most of the changes directed to be made by the Board in PCOSS-06 by Board Order 117/06.

Notably, the amended COS employed the following energy inputs:

Domestic Load at Generation	22,830 GW.h
Export Load at Generation	9,786 GW.h
Total Load at Generation	32,616 GW.h

For hydraulic generation cost sharing purposes, export load at generation was reduced by 9,786 GW.h, comprised of:

2,010 GW.h	(derived by imports)
587 GW.h	(derived by thermal)
1,117 GW.h	(DSM savings)
6,072 GW.h	(exports served hydraulic generation pool)

Revenues reported in the COS were:

Domestic:	$1,018.2 M (19,900 GW.h @ 5.12¢/kW.h at meter)
Export:	$547.4 M (8,800 GW.h @ 6.22¢/kW.h point of sale) - actual average export prices in 2005/06 were 5.2¢/kW.h.

MH carried out a 12-period weighting process of all hydraulic generation using the average Surplus Energy Program (SEP) pricing over an eight-year period. This approach was applied to actual domestic energy consumption and 2003/04 net export sales at generation. The use of a drought year for defining the 12-period export sales would have overstated the share of generation costs allocated to the export class (and accordingly, was not employed).

13.3 Export Costs

The COS directly assigned $123.8 million of costs and allocated a further $248.7 million of costs to the export class. These costs reflected:

	($ Millions)
Uniform Rate Adjustment	$16.7
DSM	$17.8
Trading Desk Costs	$9.1
MAPP/MISO/NEB costs; Purchased Power; and Thermal Costs	$80.2
Allocated Generation and Transmission (including Water Rentals)	$248.7

Revenue to Costs Coverage Ratios (RCC)

The revenue cost coverages for the amended COS were reported at:

Residential	94.1
GSS-ND	107.6
GSS-D	107.0
GSM	101.4
GSL<30	91.4
GSL 30/100	91.4
GSL>100	104.8
ARL	106.1

The Board did not formally respond to MH's filing of the Amended PCOSS-06, and requested the Corporation to employ the COS approach directed by Order 117/06 for the next GRA, the subject of this Order.

13.4 Embedded Cost Revenue Cost Coverages (RCCs)

In PCOSS-08, MH calculated the RCCs for the various customer classes as follows:

	After Net Export Credit	**Prior to Net Export Credit**	**MIPUG/MH I-25(b)**
Residential	96.4%	83.0%	95.9%
GSS-ND	104.3%	90.8%	103.9%
GSS-D	107.2%	93.8%	107.5%
GSM	101.1%	87.7%	101.3%
GSL <30	90.4%	76.9%	90.3%
GSL 30-100	103.7%	90.1%	104.6%
GSL >100	108.7%	94.8%	110.4%
AWR	105.8%	96.7%	105.6%

The foregoing PCOSS-08 RCC's (pre-2008 rate increase, 5% as per Order 90/08) continue to suggest a need for differentiated rate increases in the future. The results are relatively consistent with historical embedded cost RCC's, as shown in the following table:

Table: Historical RCC

	RCC PCOSS-08	RCC PCOSS-06[1]	RCC PCOSS-04	RCC PCOSS-03	RCC PCOSS-02	RCC PCOSS-01	RCC PCOSS-99	RCC PCOSS-97
Residential	96%	97%	91%	92%	97%	91%	92%	91%
GSS-ND	104%	107%	105%	107%	109%	104%	107%	107%
GSS-D	107%	105%	110%	108%	105%	105%	108%	105%
GSM	101%	101%	105%	103%	104%	109%	106%	102%
GSL 0-30 KV	90%	90%	100%	93%	97%	103%	101%	101%
GSL 30-100 KV	104%	102%	110%	109%	109%	119%	110%	108%
GSL >100 KV	109%	103%	114%	114%	100%	116%	109%	111%
A&R Lighting	106%	107%	109%	110%	102%	92%	93%	109%

1. MH's Recommended Version

The methodology used for the Cost of Service Study was changed for each of the following studies (suggesting, as was stated by the Board in Order 117/06, that COS is 'in a state of flux'):

- PCOSS-99
- PCOSS-01
- PCOSS-02
- PCOSS-04
- PCOSS-06
- PCOSS-08

13.4.1 Compliance with Board Order 117/06

Board Order 117/06 directed MH to re-file COS as presented in "PCOSS 06 - Recommended Method" on the basis of directives provided by the Board. The following identifies the Board's directives and the extent of MH's compliance.

One Export Class

MH defined a single export class encompassing both firm (dependable) energy exports and interruptible (opportunity) energy exports. Costs were either to be assigned directly or allocated on the basis of total export energy sales.

However, MH has not specifically defined the export operation as a class for regulation purposes.

Uniform Rate Adjustment

As per Order 117/06, MH credited the residential, general service small, and the area and roadway lighting classes with appropriately calculated energy-based shares of foregone revenue incurred as a result of the Uniform Rate Adjustment (URA). URA, established by provincial legislation, provides for all grid-served customers to receive the same rate, pursuant to the Board's class rate schedule.

The URA provides significant savings to rural and grid-served northern communities, compared to the previous approach which established grid rates by customer zone, with rural and northern zones being allocated higher proportional costs to serve that urban areas. Grid-rates have also been provided to residential customers served by diesel-generated power in the four northern communities still not on the grid.

The full amount of the adjustment has been deducted from the total export revenues, the assumption being that the URA has been “paid for” by export profits.

Imports and Power Purchases

As per Order 117/06, MH directly assigned all energy import and wind energy purchase costs as costs to be allocated against export revenues. Import energy costs include energy actually transmitted into the MH system and energy purchased for immediate resale (arbitrage) in the external export market. These latter energy amounts have been deducted from exports in determining the export class’ share of overall costs.

Thermal Generation

MH’s interpretation of Order 117/06 resulted in the Utility directly assigning only thermal fuel (coal and natural gas) costs at $19.3 million/year to the export class. Other generation costs, totalling $69.3 million/year for finance, depreciation, and OM&A, were not directly assigned, but placed in the generation pool for overall system cost-sharing customer classes.

However, MH elected to deduct the full amount of thermal generation (587 GW.h) from exports in determining the percentage of generation costs to be shared by exports. This interpretation by MH results in no embedded costs being allocated to the export class for the 587 GW.h thermally-generated electricity. The net effect was to reduce costs otherwise allocated to the export class by approximately $10 million.

Overall, MH’s approach reduced the unit cost assigned to exports by nearly 1¢/kW.h. MH rationalized the deviation from the Board’s instruction of Order 117/06 on the basis that while fuel costs fluctuate with export levels, the other costs do not. And, these other costs relate to fixed plant, and that the thermal plants were constructed to provide added security of reliability to domestic load demand requirements.

DSM Energy Deduction

In keeping with Order 117/06, MH charged all DSM costs directly to the export class. However, MH also deducted the DSM energy savings from exports in defining the export class share of hydraulic generation costs.

If DSM costs were allocated to exports (as per the Uniform Rate Adjustment), but energy savings were not, about $28 million of generation costs would be shifted from domestic classes to export class.

The longer-term result of MH's approach to the DSM energy savings, if accepted by the Board, would have very little (if any) generation costs being allocated to the export class; this, because DSM-derived energy savings could outstrip actual exports by 2017/18.

Energy Weighting (12 periods)

As per Order 117/06, in the cost allocation process for Generation energy supply, MH employed a 12-period price weighting rather than the four periods at initially proposed in PCOSS-06. The weighting was based on energy values during both the four seasons and the peak/shoulder/off-peak periods. The weightings in the following table reflect the average from January 1999 to December 2006, relative to a summer off-peak base value of 1.000.

The relative value of energy supply resulting were:

	Peak	Shoulder (¢ per kW.h)	Off-peak
Spring (2 months)	2.513	2.144	1.246
Summer (4 months)	3.258	2.388	1.000
Fall (2 months)	2.624	2.155	1.396
Winter (4 months)	3.406	2.262	1.796

The energy consumption values employed in the generation cost allocation process by MH reflected the domestic and export energy consumption profiles for 2003/04 in PCOSS 06 (a drought year) and for 2005/06 in PCOSS 08 (a high flow year). Consequently, the generation cost allocation to exports are quite different in the two PCOSS'.

13.5 PCOSS-08

13.5.1 Treatment of Exports Class Cost Allocations

In Board Order 117/06, MH was directed to establish a single export class, to be fully allocated costs for generation and transmission. MH opposed this direction opining that opportunity sales should only attract variable costs and not fixed costs. This view was reflected in MH's treatment of thermal costs, where MH assigned only fuel costs to the export class in contravention of the Board's directive.

13.5.2 Review of PCOSS-08

PCOSS-08 employed the following energy inputs:

Domestic Load at Generation	23,740 GW.h
Export Load at Generation	8,460 GW.h
Total Load at Generation	32,200 GW.h

Forecast Revenues in PCOSS-08

Forecast Domestic	- \$1,066 M (20,800 GW.h @ 5.13¢/kW.h at meter) (actual average export prices in 07/08 were 5.0¢/kW.h)
Forecast Export	- \$551.5 M (7,700 GW.h @ 7.16¢/kW.h at point of sale)
	(While the above were forecast, the actual average export prices in 07/08 appear to be 5.0¢/kW.h)

For hydraulic generation cost sharing purposes, export load would be reduced as follows:

	GW.h
Export Load at Generation	8,462
Less	
Served from imports and power purchase	(2,028)
Served by thermal generation	(560)
DSM savings	(1,350)
Net exports served from hydraulic generation pool	4,524

13.5.3 Treatment of Exports Class Cost Allocations

Out of a total generation and transmission cost of $1,165 million , PCOSS-08 defined export costs as follows:

Directly Assigned Costs

Uniform Rate Adjustment		$17 M
DSM Costs		$25 M
Trading Disk Costs		$13 M
MAPP/MISO/NEB Costs		$7 M
Imports and other purchased power		$134 M
Thermal Fuel Costs		$23 M
	Sub-total	**$219 M**

Allocated Costs

Generation (including water rentals)		$116 M
Transmission		$51 M
	Sub-total	**$167 M**
Total export costs		**$386 M**

Export sales accounted for 27% of system energy sales, about 20% of winter CP demand and 33% of summer CP demand.

The $386 million of defined export costs equates to approximately 5¢/kW.h at the point of sale – and were derived by MH without assigning “fixed” thermal costs to the export class as directed by the Board. While MH’s forecast export sales prices in PCOSS-08 were 7.2¢/kW.h, it now appears that the actual average export price will be closer to 5¢/kW.h

MH Position

MH contends that its current COSS model, as depicted in PCOSS-08, does not provide the most suitable basis for evaluating either class revenue requirements or establishing a rate design. MH’s fundamental issue with PCOSS-O8 relates to the magnitude of assignment (allocation) of costs to Exports.

The ultimate impact of the Board’s directives with respect to these matters was depicted in the pre-filed evidence of Patrick Bowman and Andrew McLaren, witnesses for MIPUG. In their Table 4-1, Bulk Power costs are depicted for each of the major classes, as follows:

13.0 Cost of Service

Table 4.1
Levelized RCC Ratios per kW.h PCOSS08 with DSM Correction

	Residential		GSS-ND		GSM		GSL>100kV		Exports	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	$248.8	3.78	$54.8	4.12	$113.2	3.84	$171.1	3.29	$372.2	4.83
2 DSM adjustments	($4.2)	(0.06)	($3.2)	(0.24)	($4.2)	(0.14)	($6.6)	(0.13)	$24.6	0.32
3 Net Bulk Power Costs	$244.6	3.72	$51.6	3.88	$109.0	3.70	$164.5	3.16	$396.8	5.15
4 plus: Subtransmission-related	$38.5	0.59	$6.8	0.51	$11.7	0.40	$0.0	0.00	$0.0	0.00
5 plus: Distrib. and Cust. Serv.	$229.7	3.49	$42.1	3.16	$39.7	1.35	$2.0	0.04	$0.0	0.00
6 **Total Costs**	**$512.9**	**7.80**	**$100.4**	**7.56**	**$160.5**	**5.44**	**$166.4**	**3.20**	**$396.8**	**5.15**
Rates										
7 Total Sales Revenue	$417.8	6.35	$91.7	6.90	$144.2	4.89	$164.0	3.15	$490.3	6.36
8 Uniform Rate Credit	$15.4	0.23	$1.2	0.09	$0.0	0.00	$0.0	0.00	($17.2)	
9 System Merchant Sales									$61.2	
10 **Total PCOSS Revenue** (7 + 8 + 9)	**$433.1**	**6.59**	**$92.9**	**6.99**	**$144.2**	**4.89**	**$164.0**	**3.15**	**$534.3**	**6.93**
Surplus/Shortfall before Net Export Credits										
11 **Rates compared to costs** (10 - 6)	**($79.8)**	**(1.21)**	**($7.5)**	**(0.57)**	**($16.3)**	**(0.55)**	**($2.4)**	**(0.05)**	**$137.5**	**1.78**
Net Export Credits										
12 Net Export Revenues Allocation	$58.6	0.89	$11.5	0.86	$18.3	0.62	$19.7	0.38	($137.5)	(1.78)
13 **Surplus/(Shortfall) after net export revenue credits** (11 + 12)	**($21.1)**	**(0.32)**	**$3.9**	**0.30**	**$2.0**	**0.07**	**$17.3**	**0.33**		
Total Class Metered Energy (GW.h)	6,578		1,329		2,949		5,202		7,707	

The table illustrates that for transmission voltage domestic customers (General Service Large > 100kV), MH's embedded historic cost per kW.h is 3.29¢ compared to 4.83¢ for the Export Class. In fact, bulk power costs for Generation and Transmission (G&T) for all domestic classes are lower than the costs allocated to exports. MH opined that the view was counterintuitive, and that the embedded bulk power (G&T) cost of export sales should not be higher, on a unit basis, than the embedded cost to Transmission voltage domestic customers, and probably should be lower than the embedded cost of similar voltage domestic sales.

Board Order 117/06 also directed that certain other costs be specifically assigned to the Export Class, including the revenue impacts of Uniform Rates and the costs of DSM for domestic customers.

MH contends that the directed methodology of Order 117/06 assigns a much larger portion of Generation and Transmission costs against exports, and thus reduces the amount of residual export revenue available for allocation to domestic customer classes. This approach would appear to have the same effect on class RCC ratios as previous methodologies, in which the allocation of export revenues to the domestic rate classes was limited to only the Generation and Transmission functions.

With respect to DSM costs, MH interpreted Order 117/06 to mean that all DSM energy savings should be assumed to serve the export market. Accordingly, the $24.6 million in forecast DSM costs and the associated 1,350 GW.h of annual energy savings associated with all DSM carried out to-date were applied to the Export Class.

If the Board continues to direct DSM and thermal costs be assigned to exports, MH recommends that the Board confirm the treatment proposed by the Corporation for PCOSS08. However, MH reiterated that the Corporation has serious overall concern about what it perceives as an over-allocation of costs to Exports, with resulting deleterious impact on the outputs of the embedded cost study.

13.6 Marginal Cost Considerations

In Board Order 117/06, MH was directed to provide a strategy to allow for the consideration of marginal costs and environmental costs, in addition to the current embedded costs, within the COS. In the current Application, MH provided a single page marginal cost analysis without explanation or suggestion as to how the analysis would best be applied in the context of rate design.

Briefly, MH's marginal cost calculations assumed that for:

- **Generation**: All domestic customer classes should be allocated costs on the basis of annual consumption applied to forecast peak (5 x 16) export prices. (No costs were to be assigned to the export class.)
- **Transmission**: All domestic customer classes should be allocated costs on the basis of two coincidental peak (2 CP) peak load cost sharing of future additions to in-service assets, plus OM&A costs. (No costs were to be assigned to the export class.)
- **Distribution**: All domestic customer classes should be allocated costs on the basis of (NCP) peak load cost sharing of future additions to the assets in-service plus OM&A costs.

The proposed methodology was subsequently amended during the hearing; the revisions dealt with numbers employed but did not address how the RCCs calculated should be applied to rate design.

In the absence of disclosure of key assumptions (deemed commercially sensitive by MH), it is unclear to the Board as to how MH determined key inputs to the marginal cost calculations. For example, it appears that no generation or transmission investments were allocated to exports. And that no costs for water rental, imports, fuel, transmission losses, etc. were deducted from forecast export prices, employed in assigning marginal costs for generation to domestic customers. High levels of distribution investments in the distribution plant over the last ten years were not reflected in marginal cost going forward.

MH's filing on marginal cost was subsequently amended by MH, and presented marginal cost values for:

- Generation - $1.315 billion (equivalent to 20,800 GW.h @ 6.32¢/kW.h) allocated to various classes on SEP weighting basis and is essentially based on export market values;
- Transmission - $280 million (equivalent to 20,800 GW.h @ 1.35¢/kW.h) is allocated to various classes on a 2 CP basis and reflects the cost of all new transmission plant; and
- Distribution - $294 million ($133 million for distribution plant and $161 million for OM&A costs) allocated to various classes, as applicable, on a NCP basis.

There is no readily apparent definition of marginal cost, although MH's approach could be taken to represent the cost of providing each additional increment of energy, demand, or service (as these requirements grow). It could also be taken to mean the value of the last increment already supplied.

MH's approach suggests that marginal cost could be a stand-alone COSS, rather than being incremental to the existing embedded cost of service study.

Marginal cost of service methodology is complex and, to the Board's understanding, has only been employed for rate setting by a limited number of electric utilities. It could be argued that it is not readily applicable to MH's circumstances that being a vertically integrated utility with surplus energy going into a competitive export market.

13.7 Interveners' Positions

The Coalition

The Coalition cited a changing face of consumption among the various customer classes, noting that annual consumption from General Service top customers are projected to exceed residential customers by 2009/10 and are projected to be significantly higher than residential sales by 2017/18.

The Coalition further noted that average gross export rate prices for fiscal 2007/08 and fiscal 2008/09 were forecast at 5.4¢ per kW.h and 5.6¢ per kW.h respectively. This compares with an average residential rate above 6¢ per kW.h, while the average GSL greater than 100 KV rate is less than 3.5¢ per kW.h. The Coalition observed that residential rates are closer to marginal rates than those of large industrial customers. Current residential rates are 6¢ per kW.h while the long run marginal cost is 7.6¢ per kW.h, as compared to GSL greater than 30 KV with a current rate of 3.2¢ per kW.h while the long run marginal cost is approximately 6.8¢ per kW.h.

The Coalition suggested that the Board's objective is to look at the results of a marginal cost based cost allocation and use it to help inform decisions with respect to revenue allocation to customer classes. The Coalition prefers MH's approach, while considering MIPUG's approach to be better suited to a situation where one wants to incorporate marginal cost principles in an embedded COSS (as opposed to doing a marginal cost based COSS).

The Coalition noted the allocation of generation costs using the SEP prices is an example of where MH is utilizing an approach very similar to MIPUG's (i.e., determine the marginal cost for a function and use them to allocate the cost of that function). The Coalition further noted if the Board wanted to review the implications of using a marginal cost based COSS it should not look at the end results proposed by MIPUG, as MIPUG's approach distorts the results by forcing a reconciliation to the embedded cost approach on an individual function basis.

With respect to whether the differential rate increases should be based on the new cost of service study, Mr. Harper noted that the Board has directed that the zone of reasonableness (ZOR), a range of between 95% to 105%, be considered, and that some minor rebalancing might be appropriate given that three out of the eight classes are outside the range, though some only marginally.

However, Mr. Harper further stated this represents the first time that the revised cost of service study has been reviewed and that there remain some methodology issues that require resolution. Therefore, given that the RCCs are relatively close to the ZOR boundary, for Mr. Harper it would be appropriate to resolve the outstanding issues before entering into rate rebalancing.

In addition to cost of service study results, the Board has indicated that it may consider a number of other factors in assessing the revenue allocation between the classes, including the pre-export allocation as well as an allocation based on marginal environmental costs.

Mr. Harper noted that given various exhibits filed by MH and others these varying perspectives yield significantly different results, and depending upon how much weight one puts on one perspective as opposed to another can result in totally different view as to what differentiated rate increases would result to the customer classes. In addition, Mr. Harper noted that MH is seeking an increase that is higher than inflation and that differentiated rate increases would compound a negative impact for some customer classes.

The Coalition concluded that, except for Area and Roadway Lighting, there should be no differential rate increases at this time.

MIPUG

MIPUG stated the current COSS fairly reflects the embedded cost of service with the exception of the treatment of DSM. For MIPUG, MH has correctly assigned the DSM costs to the export class as directed by Board Order 117/06, however MH has also deducted 1,350 GW.h in DSM savings from the export energy used to allocate common generation pool costs.

MIPUG stated that as these same DSM Energy savings are accounted for in the domestic sales forecast, MH's treatment has erroneously double-counted the DSM Energy savings, and created an energy imbalance in PCOSS-08.

MIPUG stated MH's approach also effectively "claws back" from the common generation pool a priority allocation of generation to exports. The result being that for all intents and purposes the benefits secured from the domestic classes' participation in DSM is lost. MIPUG suggested that the Board's directive in Order 117/06 did not specify a specific treatment of DSM energy. As MH's treatment results in an energy imbalance in the PC0SS-08, MIPUG recommended the issue must be addressed.

MIPUG recommended that the Board direct MH to address the error by removing the 1,350 GW.h DSM Energy credit from the export class. MIPUG submitted the DSM costs should continue to be directly assigned to the export class but that the energy savings should remain with the domestic customer classes that undertook the measures leading to the savings.

MIPUG further stated that PCOSS-08 also failed to strictly reflect the Board's directive from Order 117/06 as to the assignment of all thermal plant costs to exports. (MH assigned only fuel to the export class, with the remainder of thermal plant costs allocated to the overall generation pool.) Yet, although the approach did not strictly conform to the Board's directive, Mr. Bowman stated MH's treatment does not appear unreasonable as thermal assets are a necessary complement to the hydraulic assets and, as a result, merit treatment as common pool generation assets. MIPUG recommended the Board approve MH's treatment of thermal costs in the COSS.

MKO

MKO concurs with the MIPUG recommendations on the 2008/09 COSS. MKO did not provide recommendations on whether embedded versus marginal costing should be utilized or whether rate increases, if granted, should be set on a differential basis.

MKO noted that it was reasonable to identify how additional environmental costs were included in PCOSS-08. In general, MKO supports greater consideration of environmental costs being given and advised it would continue to argue for a fair share of environmental benefits to accrue to MKO communities. MKO recommended that future PCOSS should quantify both environmental benefits and costs.

RCM/TREE

RCM/TREE observed that this GRA was the first to employ the new cost of service methodology, which treats export customers as a separate class and defines a revenue surplus arising from that class.

RCM/TREE noted that all domestic customer classes have a revenue shortfall relative to allocated costs, and are subsidized by export surpluses. RCM/TREE stated that this reality raises a policy question, that being how best to distribute export surplus (to the elements, activities, and classes of the utility).

RCM/TREE stated that general service large customers should be charged the embedded energy rate for usage up to a baseline, and assessed marginal cost, including environmental costs, for consumption above that level. RCM/TREE also recommended that new general service large customers should be charged the marginal energy rate. For the intervener, additional revenue raised through the implementation of the recommendations would best be used to fund economic development grants, increase DSM efforts, and to decrease demand charges.

RCM/TREE recommended that the Board direct MH to participate in a public review of marginal costs, and that those costs include environmental costs. RCM/TREE further submitted that if MH's forecast data is to be considered commercially sensitive, then publicly available information should be used to satisfy the Board's directives of Order117/06. RCM/TREE stated that MH had not satisfied the Board's directive, by including only environmental costs internalized in the market, and that those costs are only part of the full costs of full cost accounting, which should inform decision-making as prescribed by guideline one of *The Sustainable Development Act.*

Mr. Chernick stated that reducing domestic consumption would either lead to increased exports, reduced imports, or reduced MH's thermal generation, and that all of these possible outcomes would result in reduced GHG emissions. According to Mr. Chernick, currently the "costs" of greenhouse gases are not internalized in the prices charged by U.S. utilities.

Mr. Chernick submitted that the total social cost of domestic consumption of electricity is thus higher than the direct costs as calculated by MH. Mr. Chernick recommended that such additional environmental costs should be incorporated in marginal costs and reflected in the COSS, although the benefits flow to the U.S. and reduce environmental costs incurred in the U.S.

Mr. Chernick recommended that MH's rate design should be based on marginal costs, not embedded cost. and that the current COSS is based on a faulty model of cost causality, as it ignores the effects of energy use on transmission and distribution (T&D) costs.

Mr. Chernick stated that the transmission and distribution system is impacted by energy in at least three respects:

First, a large portion of MH's transmission is required to move power from remote hydro stations in the north to the load centers located in the south, and for export. Second, MH's transmission system is more expensive because it is designed to allow for large transfers of energy between neighbouring utilities. Third, MH's transmission system is designed to minimize energy losses over extended hours of high loads. Mr. Chernick submitted that were the system designed only to meet peak demand, a less costly system would suffice and, in some cases, lines or circuits now in place would not be required, voltage levels could be lower, and fewer or smaller transformers would be needed.

Mr. Chernick stated that MH's distribution costs are impacted by energy requirements, and that the sizing of transformers and underground lines are driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads. Mr. Chernick also stated that similar high load energy usage affects the service life of transformers as well as impacts the cost of other components of the transmission and distribution system.

For Mr. Chernick, high-load factors impact the sizing of underground transmission, primary, and secondary lines, and he stated that since heat builds up around hydro lines, the length of peak loads and the amount of load relief in the off-peak period affect the sizing of the underground lines.

Mr. Chernick further stated that since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

Mr. Chernick concluded that there is a cost causation relationship between energy, transmission and distribution costs. Reflecting these effects by incorporating transmission and distribution costs in energy charges rather than demand charges, would, for Mr. Chernick, encourage energy efficiency. Accordingly, he recommended that a portion of the cost of transmission and distribution facilities should be allocated to customer classes based on energy.

RCM/TREE suggested that MH's reluctance to release marginal cost information goes beyond the restrictions placed by most other utilities in North America. And, while **MIPUG** supported MH's need for non-disclosure of commercially sensitive price data, RCM/TREE cautioned against excessive restrictions on the release of information, as without the information, rigorous testing cannot be achieved.

In short, **Coalition and MKO** alluded to the need for transparency and did not support the Board accepting information in confidence from the utility.

13.8 Board Findings

Embedded Cost of Service

(i) The Board will require future COSS regulatory filings to incorporate the export and diesel zone classes in the same fashion as other customer classes (i.e., separately disclosed, and including all exports in all COSS calculations and charts).

ii) The Board considers MH's interpretation of the Board's direction as to what thermal costs to assign to exports to essentially constitute a "Motion to Review and Vary Order 117/06". While MIPUG agreed with MH's interpretation, the Board reiterates its requirement that MH is to assign fixed costs as stated in Order 117/06 and allocate them to the export class, (including the $69.3 million/year for finance, depreciation and OM&A of thermal plants).

The Board understands that this will result in more costs being allocated to the export class, and that as a result unit export costs will rise above 5¢/kW.h.

The Board also accepts the risk that the stricter interpretation of the directions of Order 117/06 may result in zero or negative net export revenues in some future years. For example, in 2006 MH assigned $386 million of costs to the export class, representing a unit cost basis of approximately 5¢/ kW.h. By assigning $69.3 million of additional costs to the export class, the total cost will increase to $455 million, or approximately 6¢/kW.h.

When Brandon Coal Generation is restricted to emergency use only (in accordance with the government's direction), the allocation of costs to the export class will decrease, assuming MH doesn't replace coal with natural gas generation (e.g., combined cycle combustion turbine).

In reaching this conclusion, the Board also discards the option of directing MH not to deduct the 587 GW.h of energy from the total export energy costs and only assign fuel costs to exports. To take this route would have increased total allocated costs to the export class for generation by $10 million ($396 million as compared to $386 million). And, restriction of the Brandon plant would essentially eliminate the fuel cost and energy deductions for average year scenarios (and, the estimated $10 – 20 million of annual net income attributed to current coal-fired generation.

The Board understands that the rationale to support MH's rejected option (i.e. not charging thermal finance and depreciation charges against the export class) is that the thermal plants provide dispatchable energy, increase dependable energy for export, and enhance the reliability of domestic energy and, as such, all non-variable costs should be shared by both domestic and export classes.

However, for the Board to allow the approach favoured by MH and MIPUG would mean the Board would reject the principles of cost causation and would be avoiding a proper allocation of costs (of the thermally generated component of exports).

The Board observes that with the pending restriction on the Brandon plant, the Board's direction will have less of an effect on the average cost of export class generation; that is, unless MH moves to increased natural gas generation. At this time the Board will amend its Order 117/06 directive and assign all fuel costs and 50% of the fixed costs to the Export class. Upon the coal plant going into emergency service status, the allocation will be further reviewed.

(iii) Re: DSM: MH's approach to charging DSM costs to exports and deducting DSM energy saving from the export class results in an arithmetic imbalance in the energy generation calculation, and could ultimately result in zero generation cost allocations being made to the export class.

Because DSM-originated energy savings reduce domestic consumption, prior to determining available energy for export, DSM energy savings should be added back to the domestic loss component, to determine the percentages for generation cost-sharing.

(iv) The energy consumption values employed in the generation cost allocation process by MH reflected two distinct consumption profiles for both domestic and export energy - one for 2003/04, which was a period of drought, and the other, 2005/06, a year of high water flows.

Consequently, the generation cost allocations to the export class were quite different in the two studies. Compared to the 8-year price period, the drought year costs would be overstated, and in the high flow years, those costs would be understated. Accordingly, it would be preferable to utilize the same 8-year time period for weighting both prices and consumption.

(v) In making its closing submission, MH remained critical of Order 117/06's "considerable" cost allocations to the export class, particularly with respect to:

a) Imports (no reduction for domestic load support);

b) Thermal generation costs (fuel costs not shared by domestic load);

c) Degree of embedded costs going to both firm and opportunity exports (with MH contending that no fixed costs should be directed at opportunity sales in the export class). That argument by MH was heard and rejected by the Board at the earlier Cost of Service Review proceeding;

d) DSM (costs should only be directed to export class if energy savings are credited to export);

e) Uniform Rates Adjustment (a legislated provision); and;

f) Trading Desk/MAPP/MISO costs (no reduction for domestic load support).

The Board previously found that MH is designing and building greater generation and transmission plant capacity to achieve additional opportunity sales. Therefore, those extra costs incurred in that effort should be allocated to the export class; with the emphasis being placed on total exports, exports can no longer be viewed as “by-products” of MH’s system.

In reality, exports tend to employ the last units of generation and could arguably, and fairly, be costed (if not priced) on a marginal cost basis.

The Board decision in 117/06 appears consistent with MH’s Power Resource Plan, in which hydraulic generation capacity in excess of dependable flow is not used to supply either domestic load or firm export contracts. Typically, dependable flow from MH’s hydraulic stations represents less than 60% of installed capacity. Therefore, the balance of plant capacity can be utilized in most years to produce energy for additional opportunity export sales.

MH's position that export cost allocation should be no greater than GSL > 100 cost allocations has only limited merit. Intuitively, one could argue that generation and transmission (G & T) costs relate to common energy sources, which should be shared on an equal access basis. This suggests export load has equal status to domestic load.

Alternatively, the counter argument is that domestic load has covered the past investments in G & T, and is entitled to "Heritage rates". Hence, exports should use and carry the cost of newer assets on an incremental cost basis. Examples are:

- Imports (not usually required for domestic load);
- Thermal (not usually required for domestic load);
- Transmission (losses increase exponentially with added export loads); and
- New Generation (built to serve export contracts)

The current COSS falls between these two positions, and assigns imports and thermal fuel costs directly to exports while allowing exports to share in the overall blended costs of generation and transmission (without regard for vintage pricing). The approach does not make exports solely responsible for incremental embedded costs or marginal costs for energy.

Government and Board directives have assigned the costs of the uniform rate adjustment and the evolving DSM programs to exports. These must be considered as societal benefits, the charges for which do not vary with MH's actual energy sales on either the export or domestic fronts.

Use of Marginal Costs in COSS

MH argued that there is sufficient data on the public record to support the marginal cost values it advanced. While there may be sufficient data, the key assumptions are lacking, and are required to confirm MH's marginal cost forecasts.

MH's marginal cost for generation appears to assume an unlimited market for MH's entire energy output at 5 x 16 peak prices. Because of inter-tie transmission capacity constraints, MH can only achieve that pricing for about 7,700 GW.h of energy. In addition, firm export commitments and deliveries now fully utilize the entire tie-line capability during median flow scenarios. Consequently, new energy coming from load reduction or new plant can only earn off-peak prices.

Accordingly, the value of export energy for marginal cost purposes should be estimated to be substantially lower than the $1.315 billion suggested by MH. And the reduced amount should be further reduced by deducting appropriate costs; the Board is of the view that current export prices and market conditions do not support marginal costs of 6.3¢/kW.h for generation.

Greater inter-tie capability during the 5 x 16 period could become available when the newest export contracts go on-line, but these would likely be fully utilized by Conawapa and Keeyask. Output reductions in domestic load through DSM activities would still not be able to earn on-peak prices if that energy were exported, given transmission capacity and MISO demand limitations.

MH's marginal cost for transmission appears to reflect significant new plant requirements during the next two decades ($240 million/year of financing and depreciation costs would equate to about $3 billion of plant upgrades or expansions). The most obvious new facility, Bipole III, is being built for domestic reliability and new export loads and not for domestic load growth. The expected cost of the project was also largely allocated to the generation function in PCOSS-08. As such, most of its costs should not accrue to the domestic transmission marginal cost.

MH's marginal cost for distribution appears to be derived from a forecast of plant investment level that is considerably lower than actual capital expenditures on distribution plant over the past decade. The resulting substantially-lower marginal cost of distribution (compared to embedded costs in PCOSS-08) raises a question as to how the embedded (sunk) costs for distribution should be recovered.

The projected overall marginal cost for generation and transmission provides a perspective of what additional revenues could be extracted from domestic customers if they were to be treated as an export customer by an externally-owned utility providing only generation and transmission services. With respect to MH's current mandate, the generation and transmission marginal cost values are seriously flawed and, in the current form, should not be considered as a basis for rate adjustments.

MH has not presented any compelling arguments to support its marginal cost calculation, and reference to multi-year analysis in the SPLASH model, using undisclosed (confidential) inputs and assumptions, does not allow for any critical review or instil confidence in what would best be a transparent process.

Furthermore, MH has implied marginal cost is a separate (free standing) cost coverage process that can be compared to embedded costs. In reality, marginal cost should be treated as being only incremental to embedded costs. Historical costs still need to be recovered.

MH has suggested that available public information on actual export sales and prices is sufficient for the Board and Interveners to test the validity of the Corporation's projected marginal cost value(s). Reference was made to MH's SEP and NEB's cross-border trading data, and MISO clearing prices, etc., as useful and valid sources of information for defining marginal cost.

MH's position is only partially correct. The marginal cost identification process involves critical key assumptions (i.e., quantity of energy that has marginal cost value, transmission assets being acquired for export versus domestic load expansion, and the distribution assets which are due to load expansion). For better transparency, the Board will direct MH to file all appropriate data (e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.) required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process with the Board (on a confidential basis if necessary) on or before December 1, 2008.

Forecast Export Price Input

In MH Exhibit #68, it appears that a forecast export energy price of 7.48¢/kW.h (6.32¢/kW.h for generation and 1.16¢/kW.h for transmission) at the meter has been employed in the marginal cost calculation. This rate is difficult to rationalize given that average export prices have been about 5.0¢/kW.h for generation and transmission over the last three or four years. The Board may be compelled to direct the release and use of actual prices rather than forecast unless more transparency is displayed.

MH has suggested that historical price data has been corrected upward to reflect market conditions for electrical energy under median flow scenarios. And, this would seem reasonable given that recent years have seen above average to high flow situations which result in a greater proportion of off-peak sales, effectively driving the average export price down. However, that scenario is flawed because, in the Board's considered opinion, MH has not and cannot support its forecast of achieving an energy price of 7.5¢/kW.h based on known existing export circumstances:

Median flow scenario reflects 7,700 GW.h of export energy in 07/08, which theoretically could all be 5 x 16 peak energy, but about half would be covered by contract prices at about 5.5¢/kW.h. While the remaining peak energy might achieve 7.0¢/kW.h, it would appear that the overall average cannot reach 7.5¢/kW.h.

Dependable flow scenario reflects 4,000 GW.h of export energy, all of which could be 5 x 16 peak energy and covered by existing contracts at 5.5¢/kW.h, this well below the 7.5¢/kW.h forecast; and the high flow scenario reflects 11,700 GW.h of export energy, of which about 7,700 GW.h could be 5 x 16 peak energy including existing contracts at 5.5¢/kW.h, and 4,000 GW.h would be off-peak energy in a surplus market pricing at below 3¢/kW.h, which brings down the overall average to about 5¢/kW.h.

MH suggests export pricing will escalate in tandem with rising natural gas prices. However, this assumption is contrary to the experience over the past 4 or 5 years.

In the determination of generation marginal cost, MH applied a marginal cost, derived primarily from forecast export prices, to the entire domestic energy consumption (20,800 GW.h as metered), and arrived at a marginal cost of domestic generation of $1,315 million (or 6.3¢/kW.h at sales).

Unfortunately, MH's scenario appears unrealistic and unattainable, because:

a) the calculation suggests MH expects to export 20,800 GW.h over and above the existing export level of 7,700 GW.h, when maximum tie-line capabilities are only about 16,000 GW.h;

b) the forecast suggests it is possible to achieve peak (5 x 16) export prices above 6¢/kW.h for an additional 20,800 GW.h, although the peak period tie-line capabilities are limited to about 7,500 GW.h and are already fully committed;

c) with existing export sales contracts of 4,000 GW.h for 5 x 16 energy at current average prices of 5.5¢/kW.h, and assuming the sale of the entire remaining 3,500 GW.h of peak energy and 8,500 GW.h of off-peak at average prices of 9¢/kW.h, when MH's average price for exports has been about 5¢/kW.h for both generation and transmission, this suggests the projection is not realistic;

d) to transmit 16,000 GW.h/year of energy into the MISO market and not see average prices decline below 5¢/kW.h seems unlikely; and.

e) shifting domestic load of 8,300 GW.h (16,000 GW.h minus 7,700 GW.h median flow exports) to export would appear to yield additional revenue of about $415 million at today's average export prices. Given this could not be at 5 X 16 peak pricing, this appears to suggest a marginal cost of about 2¢/kW.h when applied to the entire 20,800 GW.h of domestic load. (This compares to the $615 million (or 3¢/kW.h) of embedded costs allocated to domestic load for generation in PCOSS-08.)

The foregoing review suggests that the marginal cost scenario for generation presented by MH is flawed and in need of revision. It also suggests that the RCCs that arise are being driven by an overstatement of generation marginal costs.

Only MIPUG, of the Intervener groups, provided comment on MH's marginal cost calculations for generation. They submitted an alternative that assigns embedded costs on an energy price (SEP-based) weighting basis.

In MH Exhibit #68, MH applied unit marginal cost for distribution to the entire load served from the distribution system. In a previous MH filing (Marginal Cost of Transmission and Generation Study of 2004), the authors suggested that the values derived were only applicable to load growth or reductions of 85 MW and should not be extrapolated further.

Accordingly, MH will be directed to revisit and re-file a better-formulated marginal cost/value, one reflecting the realities of covering embedded costs as well as future costs, and as to potential export revenues. The re-filing should include an in-depth discussion of assumptions and inputs to MH's marginal cost COS. The re-filing should also cover the marginal costs of the export class.

As for use of marginal costs and the use of RCCs in rate setting, the Board will require the additional information from MH before assessing the weighting for embedded cost RCCs and marginal cost RCCs. Presumably, the marginal cost recalculation will be equally applicable to the Energy Intensive Industry rate design.

Marginal Cost Confidentiality

MH declined to publicly present its key assumptions and specific input data that it employed with its SPLASH model in the determination of generation marginal cost. Similarly, the "avoided cost" calculations, employed in defining transmission marginal cost and distribution marginal cost, were also not made available to the proceeding.

The Board will direct MH to make all this information available (however, on a confidential basis to the Board) and will assess whether the information should be further shared with interveners. The Board will not share the information with interveners without first engaging MH in discussion ahead of a meeting to involve all parties.

During the hearing process, MH invoked a confidentiality constraint on the specifics of:

a) How forecast export prices were determined;

b) SPLASH model inputs and assumptions;

c) Transmission marginal cost assumptions and avoided cost calculations; and

d) Distribution marginal cost assumptions and avoided cost calculations.

The result is that none of the interveners were in a position to challenge the marginal cost determined by MH for generation, transmission, and distribution. While MIPUG provided an alternative to MH's calculation process, the intervener did not attempt and probably could not have challenged the unit marginal costs and/or forecast export prices.

This left the Board in the position of either accepting MH's forecast marginal cost, despite the absence of any serious testing, or directing MH to provide more detailed justification for the marginal cost calculations. The Board opts for the latter.

Forecast and Calculation of Marginal Cost

The Board suggests that MH's forecast of export prices is overstated and does not adequately recognize:

a) Current U.S. export market prices;

b) Current USD/CDN exchange rates; and

c) Current transmission inter-tie capacity to U.S. constraints.

Further, the Board has concerns about MH calculations of marginal cost for generation, specifically the total marginal cost value assigned to domestic generation. Also, as previously outlined, the Board has concerns about the lack of information (assumptions and inputs) on the transmission and distribution marginal cost provided to the proceeding.

Weighting of MC-COSS

Given this, the Board cannot establish, other than directionally, the value of the marginal cost (MC) as a COSS consideration. Much more marginal cost information and justification will be required from MH in advance of the next GRA, to allow the Board to place a weighting on the two sources of RCCs, and begin to differentially allocate future rate increases.

Therefore, the Board will not be assigning a specific weighting to the MC-RCC developed by MH, or for the amended approach proposed by MIPUG. However, after a review of the information put before it, the Board remains of the view that, in a proper form, marginal cost consideration should be given comparable weighting to that of the embedded COSS.

While previously the PCOSS was viewed to be a stand-alone tool for rate setting, it does not appear that a marginal cost determination could be other than a modifying procedure. In any event, appropriate generation and transmission costs should be allocated to the export class.

The Board therefore directs MH to provide a revamped MC-COSS analysis, one reflecting needed refinements to generation/transmission/distribution marginal costs. One scenario to be explored, among others, should involve the addition of marginal cost to embedded costs in COSS for domestic classes and the export class, prior to comparison to class revenues.

Environmental Consideration in COSS

Despite MH's contention that export pricing automatically builds in environmental considerations, it is apparent that MH, at least to date, has been unable to gain significant revenue increases of any kind related to environmental factors. Environmental or green energy considerations do not, at least at present and by no means for lack of effort on the part of MH or the Province, appear to have affected base-load coal generation prices in the MISO market region.

MH's export price forecasts assume that GHG legislation will come into play as early as 2012, and boost export prices. The Board is concerned with this degree of optimism, with $18 billion of capital expenditures lying in the future; 'best case" scenarios, while interesting and useful as goals, need to be balanced by other less positive views. The Board will direct MH to revisit its export pricing forecasts to reflect recent realities on market prices and exchange rates.

On a similar vein, MH has indicated that embedded costs incorporate substantial levels of mitigation efforts and costs. By capitalizing these costs, MH is deferring the impacts on the COSS, and on rates. The Board is mindful of the possible effects to arise out of the adoption of IFRS, and that one of those effects may well be less capitalization and more direct allocation and expensing of period costs; if this occurs, it means either less annual net income or it will require higher rate increases.

The foregoing suggests explicit consideration of environmental factors is either not necessary, or that to do so would be a form of double-counting. This issue needs further definition and development.

14.0 Rate Design

14.1 Inverted Rates

In Order 117/06, the Board reiterated its directive to MH to move towards the elimination of declining block rates. MH has, with some notable exceptions, moved toward this objective.

MH introduced, on a very limited scale, an inverted rate structure for the residential class, where the tale block rate is to be greater than the first block by a modest 1% differential. MH has suggested a continued future GRA movement in the direction of marginal cost, through future gradual increases in the to the tale block closer to the marginal cost of energy (now 7.01¢/kW.h.).

MH proposed that the first block of energy consumption be set at 900 kW.h per month, regardless of the season or the energy source for residential space heating. MH did not propose any changes to the basic monthly charge block rate.

MH acknowledged that the future evolution of the inverted residential rate should take into consideration the needs and constraints of customers who currently use electricity as a primary heating fuel, while continuing to encourage natural gas as the appropriate fuel choice in areas of the province served by natural gas. MH indicated that to address heating loads, there are essentially three approaches that could be taken to provide for meeting these needs within a lower cost first block.

The more complex mechanism would be to design a separate residential rate for electric heating loads. MH stated that this is the method preferred by Mr. Chernick, the witness for RCM/TREE, and would provide existing electricity heating customers an allowance of an additional 6,400 GW.h/ year in the initial price block during the heating season. This would result in an increase in the percentage of heating energy served at the initial rate block of roughly 54% that non-electric heating customers receive.

MH cautioned that such a specific rate targeted at electric heat customers may create an incentive for customers to report electric heat capability though staying with natural gas, and may create increased administrative burden and cost to manage/police.

MH offered two alternatives that may be simpler to administer, and which may not specifically target all electric heat customers or exclude customers using other sources of heating. MH noted the simplest method would be to differentiate the size of the first block by season, with a larger first block in winter, as is done in Ontario. The other is to provide a larger first block in winter only in areas not served by natural gas (although this may be complicated by the uniform rates legislation). MH concluded that further review of the alternatives were required.

Given the significance of residential electric heat in Manitoba (natural gas distribution is limited), as well as higher degree-days compared to Ontario, the Board would consider it appropriate to set a winter “first block size” higher than that now set in Ontario.

14.2 General Service Small and Medium Classes (GSS and GSM)

MH is moving to consolidate the GSS and GSM rate structures, supported by previous Board direction. Both classes are served from MH-owned transformation and utilize similar voltages.

The following rate table illustrates the proposed changes as initially proposed by MH (1) and the revised rates (2) as per Order 90/08 as follows:

14.0 Rate Design

	Small			**Medium**		
	March 2007	**April 2008**		**March 2007**	**April 2008**	
		1	**2**		**1**	**2**
Basic Charge Single Phase	$15.60	$16.50	N/C			
Basic Charge Three Phase	$21.75	$23.55	$22.99	$27.60	$27.60	N/C
Energy Charge:						
1st 11,000 kW.h	6.18¢	6.31¢	6.48¢	all kW.h	5.90¢	6.13¢
Next 8,500 kW.h	4.00¢	4.30¢	N/C	@	4.07¢	4.30¢
Balance kW.h	2.55¢	2.65¢	2.73¢	2.55	2.65¢	2.73¢
					no charge	
Demand Charge:						
1st 50 Kva	no charge	No charge		all KVA @		
Balance of KVa	$8.34	$8.34	N/C	$8.34	$8.34	N/C

The proposed changes are the first step of two or three transitional moves to a single rate table for GSS and GSM.

A major rate component that currently differentiates the small and medium rate classes is the application of demand ratchets, which impact the determination of monthly billing demand. The general service small class is not subject to any ratchet provisions and the class' customers are only billed on their recorded demand above 50KVa. General service medium customers are, on the other hand, currently subject to paying the higher of their recorded demand or the ratchet.

Once the classes are fully consolidated, the ratchet would not impact current general service small customers as long as they remain below 200 KVa. In MH's Application, it did not propose that the 70% winter ratchet provision be modified, but that it would continue to be applied against loads in excess of 200 KVa.

14.3 Area and Roadway Lighting (ARL)

MH has proposed a 1% increase in the ARL rate.

City of Winnipeg raised its continuing claim of the overpayment by municipal lighting customers relative to costs being allocated to the class in the embedded cost COSS. As this class has almost always been charged more than 105% of its allocated costs, MH did not dispute the City of Winnipeg's suggestion that the accumulated sum of "overpayments", relative to an RCC of unity, totals in the multi-million dollars. The City of Winnipeg did not request a refund, but rather suggested that ARL rates remain unchanged until a RCC of 1.00 is achieved.

14.4 Time of Use (TOU) Rates

Over the last eight years, the concept of Time of Use energy charges has been a subject of debate. MH has commissioned several studies to address the applicability and consequences of charging customers different seasonal and/or diurnal energy rates.

The major stumbling block has been, and continues to be, the need for more sophisticated and expensive metering and billing systems (an investment of $90 million was suggested as being required). At present, most GSL >30 customers have appropriate metering in place, however, that is not the case for GSL <30, GSM, GSM, and Residential classes.

MH has and is currently running pilot studies in Selkirk and Steinbach, to test customer response to greater awareness of actual consumption levels; the results to-date have been somewhat confusing, and have failed to give support to a massive move to TOU for residential customers.

MH acknowledged that, on balance, a TOU rate for General Service customers would likely provide increased revenues for the Corporation. MH indicated that such a TOU program could take about 12 - 18 months for start-up studies and to obtain program approval for classes with TOU meters. And that implementation could take at least four more years for the classes currently without TOU meters.

For the residential class in particular, a TOU program would involve changes to meter reading frequency. While new technologies are possible, it would appear costs could be prohibitive.

14.5 Rebalancing of Demand and Energy Charges

MH's rate structure has for many years been over-collecting on demand charges and under-collecting on energy charges relative to COSS allocations. In response to Board direction, MH has, since 2003, been assigning rate increases entirely to the energy portion of rates.

The result has been a gradual shift of the source of customer revenues, with the change viewed as being conducive to be objectives of conservation.

The following table illustrates the March 2007 imbalance situation, when comparing PCOSS-08 allocated costs to revenue at March 2007 rates.

	Demand ($/KVA)			Energy (¢/kW.h)		
	March 7/07 Rate Revenue	**117/06 Allocated Cost**	**Revenue/ Cost %**	**March 7/07 Rate Revenue**	**117/06 Allocated Cost**	**Revenue/ Cost %**
GSS	8.34	6.92	120	2.55	2.65	96%
GSM	8.34	7.09	118	2.55	2.68	96%
GSL <30	7.08	7.94	89	2.38	2.61	91%
GSL 30-100	6.06	4.26	142	2.29	2.44	94%
GSL >100	5.40	2.21	244	2.26	2.41	94%

The table suggests that MH still has a considerable way to go before revenues and costs for GSL demand and energy are in balance. Of particular note is that GSL <30 KV class revenues and rates are under-collecting for both energy and demand.

MH's March 2007 Report suggests that over a four-year period, the movement toward "full balance" has eliminated 50% of the initial discrepancy. This infers it could require another four years of rate increases applied through energy changes alone to achieve balance.

For GSS and GSM customers, the demand charge partially offset the under-funded basic monthly charge for customer service and distribution plant.

14.6 The Basic Monthly Charge

All MH customers other than GSL pay a basic monthly charge, which is intended to cover (but does not) allocated customer service and local distribution costs.

	Billing Rate	**Allocated Unit Cost (Net of Export Credit)**
Residential:		
- (<200 amp)	$6.24/month	$18.70/month
- (>200 amp)	$12.48/month	
GSS-ND	$16.50/month	$31.25/month
GSS-D	$23.55/month	$51.22/month
GSM	$27.60/month	$227.78/month

The argument for not increasing the basic monthly charge is based on the premise that the under-charge is justified by the "incentive provided" in high energy charges to reduce consumption.

14.7 Diesel Rates

At one time, in excess of thirty northern Manitoba communities were provided electricity service by means of diesel-fired generation. Over time, the number of communities served by diesel generation fell, at first to thirteen and, eventually, to the now current four.

The remote Northern Manitoba Communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, with a total population of approximately 2,000 people having 800 separate accounts with the Corporation, are not connected to MH's transmission and distribution grid. While diesel fuel is very expensive, there are other problems with diesel generation such as winter road supply uncertainties, customer service levels and environmental issues.

Diesel generation does not provide the quality of service represented by grid service, as the four diesel class communities are limited to 60 amp service and the 800 accounts are not supposed to use electricity service for space heating.

In Manitoba, the first 2,000 kW.h of electricity consumed monthly by residential and General Service customers in the diesel zone is billed at grid comparable rates. The subsidy from full cost rates is borne by "Government Accounts" by way of surcharges or premiums. In some other Northern Canadian jurisdictions, less than 900 kW.h of diesel generated electricity is provided at grid comparable rates.

Excepting for the first 2,000 kW.h of electricity, diesel class rates are very much more expensive than grid rates. Most diesel class customers are residential, but there are also General Service, Federal and Provincial Government and First Nations accounts.

In Order 159/04, dated December 22, 2004, the Board approved interim sales rates for the diesel communities based on MH's then-Application, which reflected a tentative settlement arising out of MH's negotiations with MKO, acting on behalf of the diesel communities, and Indian and Northern Affairs Canada (INAC).

The terms of the tentative settlement were summarized in Order 159/04 to include:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit which was approximately $16.9 M as of March 31, 2004. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

2. INAC would pay $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;
3. INAC, on behalf of the Federal Government, would pay MH 69% of the $28.8 million of MH's diesel-related capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and by no later than January 7, 2006;
4. MH would request that other Federal and Provincial Government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's $28.8 million of undepreciated capital costs;
5. MH would assume the remaining 21% of undepreciated capital costs on behalf of residential and General Service customers that are neither First Nations members nor Government accounts; and
6. for major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nations communities, and secure funding prior to making further capital expenditures.

At the time of issuing Order 159/04 the Board was advised that the signing of the Settlement Agreement was expected on or before July 7, 2005 – now three years ago. Because of various factors, the signing date has been delayed.

If the Settlement Agreement is not concluded, MH has indicated a desire to reconsider its recommendation that the class receive an allocation of net export revenue in the COSS. The delay in the finalization of the Settlement Agreement relates to the Federal Government and is beyond the control of the Board, MH, the four communities served by diesel-fired generation and the Province.

14.8 Surplus Energy Program (SEP)

MH was earlier provided with interim approval to extend the Surplus Energy Program to October 31, 2008. As part of the GRA process, MH requested that SEP be approved for five years to March 31, 2013, without any changes to the terms and conditions.

The SEP makes surplus energy available on an interruptible basis to MH's general service customers. Customers may be eligible for:

Option #1 Industrial load >1,000 KVA monthly demand (<25% of total load); or

Option #2 Space and/or water heating >200 KW per month (separately metered with full back-up); or

Option #3 Self generation displacement 200 KW to 50,000 KW with Load Factor of 25% (separately metered with full on-site back-up).

The program primarily displaces export sales, but the energy supplied to SEP customers may be supplemented from import supplies, though at much higher costs than domestically supplied energy. Energy prices (Spot Market) are forecast weekly and submitted for Board approval, for peak, shoulder, and off-peak prices.

Since December 2000, SEP has involved about 25 GSM and six GSL customers, with average (over seven years) sales of about 22 GW.h/year, average revenues of $9 million (4¢/kW.h) and average net revenues of $45,000/year (varying from a loss of $35,000 to a surplus of $210,000/year).

The customer usage of the SEP has been seasonally variable, with winter weekly high consumption being ten times summer weekly low consumption. Over the whole year, the daily usage pattern has been 24% peak, 40% shoulder, and 36%

off-peak. Demands during the summer off-peak when prices are low have been well below average.

14.9 Curtailable Rate Program (CRP)

The Curtailable Rates Program provides incentives to MH's large industrial customers; these customers curtail electrical load when called upon by MH. Incentives are provided by way of a credit to the customer's monthly energy bill.

Under the CRP, MH looks to:

- Quickly re-establish contingency reserves that are required by MAPP-GRSP;
- Maintain planning reserve obligations;
- Protect firm Manitoba load from curtailment;
- Maintain spinning and non-spinning contingency reserves; and
- Meet firm energy requirements when MH has supply shortfall.

Different CRP options provide MH with the ability to curtail demand and energy for specified time periods. Customers are provided with power price discounts on the basis of the amount of load available for curtailment. The Board approves the reference discount on an annual basis.

Savings to MH resulting from the Curtailable Rates Program are available as long as the service offering continues, whether or not actual curtailments are made at the time of system peak or at any other time. The expected availability of this load, and not the timing of its dispatch, determines the future benefits of CRP.

MH requested a change to the terms and conditions of CRP, to increase the notice period from 24 to 48 hours of anticipated plant operations shut down. This would affect the capacity reduction that could be achieved by MH.

14.10 Limited Use Billing Demand (LUBD)

The LUBD rate option was implemented July 1, 2000 and continues to be a relatively simple way for MH to address the concerns of low load factor customers and reduce demand charges they would otherwise face. Initially, the program was intended to mitigate the impact of the winter ratchet on seasonal, commercial, and light industrial winter operations. However, the program has attracted a considerable number of GS customers who are not affected by the winter ratchet. Only 5 of 123 GS customers were subject to the winter ratchet in 2004.

Currently, the customer list on LUBD is:

GSS-D -	68 (winter ratchet not applicable)
GSM -	22
GSL <30	17
GSL >100 -	1
	123

LUBD allows eligible customers to opt for higher energy rates and lower demand charges. For customers with a load factor of 18% or less, the revised rates are economically beneficial. The rate has turned out to be attractive to certain agricultural, recreational, municipal services, and wood product customers, which now account for 40% of the customers utilizing the program.

From MH's point of view, LUBD customers with their low load factor generally have lower coincident system peaks. As such, they place a lesser demand on system transmission and distribution.

MH did not propose to alter the LUBD rate structure as it applies to GSS-D and GSM, but sought to revise the eligibility requirement from 36 months to 12 months.

14.11 Winter Ratchet

The winter ratchet refers to MH's demand billing practice of charging customers the greater of:

- Actual billing demand (KVA) in each month (measured on 15 minute interval); or
- 70% of highest demand in any previous months of December, January, and February; or
- 25% of the customer's contract demand; or
- 25% of the highest measured demand in any of the previous 12 months.

The rate is applicable to GSS-Demand/GSM, and GSL classes and particularly affects seasonal customers that have high winter demand and minimal summer demand. These customers have contended that MH was charging them a demand charge related to energy that they were not using and was thus available for export by MH.

MH contends that the energy freed up is unreliable and not always of value, and recent history suggests that the energy probably has similar value to DSM freed-up energy.

The winter ratchet impacted about 700 customers in 2004, primarily in the GSM class, generating about $2 M in billing revenue. Notably, schools, hospitals, senior's residences, and similar facilities are included in this class.

The Board found that with MH's system running at near capacity throughout the year, the winter ratchet was of questionable merit and, in Board Order 07/03, directed MH to eliminate the winter ratchet effective April 1, 2004. MH sought and was granted (Board Order 15/03) a deferral to allow further study. An August 2004 report by MH argued for the retention of the winter ratchet pending further review. MH suggested that time-of-use rates may be an alternative to the winter ratchet.

Since 2004, the situation has remained essentially unchanged. MH is still considering the preparation of a time-of-use study and has not advanced a detailed analysis supporting the retention of the winter ratchet.

14.12 Interveners' Positions

The City of Winnipeg

The City of Winnipeg indicated that the rates charged the city for area and roadway lighting have been consistently above the zone of reasonableness (over the last 30 years, with the exception of one year). The City indicated that over the years MH has overcharged it approximately $49 million.

The City noted that MH proposes to address the "$620,000 excess" the City is now paying each year, or the $1 million "over collected" province wide (other municipal accounts approximate 40% of the annual bills to the class).

The City urged Board action to correct the situation.

The Coalition

Inverted Rates

The Coalition stated they are supportive of the concept of inverted rates but that for the intervener significant equity concerns exist; concerns for the impact of all-electrical customer with no competitive options; concerns for low-income persons who lack the resources to pursue DSM; and concerns for renters who may lack the ability to pursue DSM or for whom energy efficiency is uneconomic due to split incentives.

The Coalition stated that most new homes in rural areas are installing electric water and space heat, and that many of the new all-electric homes are being built in First Nation communities (many of which being low-income households). The Coalition noted that many customers with all- electric homes don't have access to competitive alternatives such as natural gas, and would not be able to adjust consumption with changes in prices and would be negatively impacted by an inverted rate scheme.

The Coalition opined that residential consumers have an inelastic demand for electricity, which means a change in consumer demand should be expected to be less responsive to a change in price. The Coalition cited a study by the Rand Corporation that dealt with electricity consumption in the US, which stated:

> "Locations where particular energy uses are very valuable, such as air conditioning in southern states or winter heating in northern states, could have price elasticity smaller in absolute magnitude because air conditioning and heating are so valuable during periods of extreme climate. The consumers are unwilling to change their use when prices change."

The Coalition underscored the importance of price signals, indicating that, in particular, commercial and industrial customers were more responsive to changes in price in adjusting their consumption.

The Coalition further suggested that there is a low-income context that needs to be addressed related to inverted rates. The Coalition suggested that MH currently has over 18,000 customers earning less than $30,000 a year that are consuming more than 18,000 kW.h per year, of which over 16,000 of those customers are all-electric customers.

The Coalition noted that this group would be negatively impacted by an inverted rates scheme, that is unless the current barriers to participation in energy efficiency DSM programs are addressed. The Coalition stated there are substantial barriers faced by low-income individuals that discourage their participation in energy savings initiatives.

Mr. Harper noted that the inverted rated proposal put forward by MH has a modest differential between the first and the second blocks, but that the modest differential does at least begin to send the correct message, i.e., that increased use is more expensive. Mr. Harper further stated the issue of bill impacts is important and should be addressed before MH makes further changes in implementing inverted rates.

Mr. Harper proposed a gradual implementation of inverted rates, and proposed that before any further changes are made MH should first ensure that its DSM programs are focused in fully supporting those low-income customers who will be most notably impacted by inverted rates, and customers who typically use more than 1,500 kilowatt hours a month (over 18,000 kW.h annually).

The Coalition stated that it would be unfair to implement inverted rates before giving vulnerable groups the tools to achieve energy efficiency. The Coalition recommended delaying inverted rates until adequate DSM programs are in place for low-income households with high consumption levels, tenants, and all-electric space heat customers that have no competitive space-heating options.

To address the inequity faced by all-electric customers, the Coalition suggested the focus should be on the differentiation between the all-electric block and the standard-use block, providing the all-electric block a larger first block during the heating season. From its perspective, the key issue is addressing the vulnerability of those customers who rely upon electric heat for their home heating.

Time of Use Rates

The Coalition expressed interest in advanced metering technology, which would be required to implement time of use rates. The Coalition urged the Board to direct MH to report on developments in terms of such metering, including the potential for the Utility controlling thermostats for peak shaving purposes.

Energy Demand Rebalancing /Basic Monthly Charge

Coalition opined there should be no increase in the BMC and suggested that the cost allocation process be changed for residential customers.

As well, the Coalition recommended the BMC recover only a percentage of customer costs, excluding customer related distribution costs, and recover only in part customer service and metering costs, with the balance of costs to be recovered through energy charges

MIPUG

Inverted Rates

MIPUG suggested that MH's inverted rate proposal for the Residential Class was inadequate, and that the small differential would not send a meaningful price signal to customers.

MIPUG suggested that MH implement inverted rate proposals for other customer classes, including the General Service large class and sub-classes. MIPUG recommended the Board direct MH to develop an inverted rate proposal for the General Service large class, in consultation with customers, and file it with the Board for consideration.

Time of Use Rates

MIPUG recommended MH be directed to develop seasonal time-of-use rates. Mr. Bowman and Mr. McLaren stated that for customers with some ability to shift their loads, a rate design that includes time-of-use components could reduce MH's costs and that these cost savings could flow, at least in part, to the load-shifting customer. For MIPUG, properly designed time-of-use rates would provide incentives to optimize the use of the generation and transmission system, resulting in cost savings and/or increased export revenues to the mutual benefit of MH and its customers.

MIPUG stated that TOU rates meet a valid regulatory objective of promoting efficiency and conservation and would provide customers the right price signal for every kilowatt hour of consumption. MIPUG stated that such an approach would be an improvement over the winter ratchet, which, for MIPUG, sends too strong a price signal for some, and none to others.

Energy Demand Rebalancing /Basic Monthly Charge

MIPUG noted that MH sought applying the Industrial rate change entirely to the energy component (and not the demand component). Given the substantial outstanding issues arising from the lack of contemporary pricing mechanisms, MH's efforts at improving the price signal were, for MIPUG, effectively irrelevant and should be rejected.

MIPUG recommended the Board reject the proposed allocation and direct MH to propose a logical process for implementing, in consultation with customers, rates that address contemporary elements of industrial rate design. In the meantime, any rate increases for industrial customers should be implemented as an equal percentage increase to the demand and energy components of the existing rate structure.

MIPUG did not take a position on whether any changes should be made to the BMC.

Winter Ratchet

MIPUG recommended the elimination of the Winter Ratchet, with it to be replaced by time of use seasonal rates.

MKO

Inverted Rates

MKO stated general support for the concept of inverted rate structures, to encourage demand and improved energy management. However, MKO shared the concerns expressed by the Coalition that inverted rates for residential customers may disadvantage consumers with electric water and space heating - customers that include MKO consumers, most of which were reported to be of low income.

MKO also noted the inelastic demand response residential customers have to electricity price changes, as noted in studies referenced by the Coalition. MKO supported the Coalition's comments on addressing the barriers to entry to DSM measures noted by Mr. Dunsky, and supported making DSM and energy efficiently programs universally available to all MH residential customers, including those in the diesel communities. MKO suggested that DSM in the diesel zone would likely have a greater impact on reducing domestic demand growth and providing for increased net export revenues than inverted rates for residential customers.

MKO proposed a more gradual inverted rate be applied to the diesel communities, and suggested such an approach may accomplish the objectives of MH without the controversy that would be inherent in trying to set and administer baselines.

MKO cautioned the Board that the inverted rate design proposed by RCM/TREE requires further testing and review to ensure that low-income and remote community MKO customers are not unduly disadvantaged.

MKO suggested the Board direct MH to propose inverted rates structures in the next GRA across all customer classes.

Basic Monthly Charge

MKO did not provide a position on changes to the BMC.

RCM/TREE

Inverted Rates

RCM/TREE recommended changes to the inverted rates program as proposed by MH, and suggested that the BMC be reduced to approximately $4.70 per month and the first block of energy be reduced from the 900 kW.h per month allowance to 600 kW.h.

RCM/TREE suggested that the rate for the initial energy block should be set at 6¢ per kW.h for 600 kilowatt hours per month for non-heating customers, and for all customers in non-winter months. In addition, to counter the impact of the inverted rates on all-electric customers, RCM/TREE proposed a 6,400 kilowatt hour annual allowance be distributed over the heating season, and be priced at the initial block rate.

RCM/TREE proposed that the rate for additional energy should be set at approximately 6.28¢ per kilowatt hour.

RCM/TREE discounted MH’s concerns about the accuracy of the Corporation’s customer database for identifying customers with electric heat capability, and suggested that exceptional cases and administrative gaps should not obstruct sound policies. RCM/TREE stated it advocates an integrated approach to affordability and efficiency.

Paul Chernick, a witness for RCM/TREE, stated inverted rates are a good and sound economic policy, and observed that while there are low-income customers that would be affected by the implementation of inverted rates that should not act as a “veto” for the program’s implementation.

Mr. Chernick stated proper steps to protect lower income individuals should be put in place. Mr. Chernick proposed the implementation of targeted low-income conservation programs and bill assistance, the latter through vouchers, as mitigation measures, enabling the Corporation to move more quickly to implement conservation measures. "There is no time for the extreme gradualism advocated by Mr. Harper", according to Mr. Chernick.

RCM/TREE stated that if MH requires time to prepare education materials and mitigation measures with respect to the introduction of inverted rates, it might be possible to begin introduction by residential rate increases under a flat rate structure, and then implement a revenue neutral inverted rate structure in the fall.

RCM/TREE did not agree with the Coalition that gradualism in the implementation of inverted rates is a good idea.

Energy Demand Rebalancing/ Basic Monthly Charge

RCM/TREE proposed the elimination of the BMC over time, and the recovering of those costs through volumetric energy charges to be applied on the tail block of inverted rates.

RCM/TREE countered concerns raised by MH that lowering the BMC for electric customers might encourage customers with small gas usage to switch to all electric appliances to avoid the recently increased gas BMC. However, RCM/TREE noted, since gas customers are also electric customers, such an incentive to switch is already built into the BMC for small users of gas. Lowering the BMC for electric customers and increasing the tail block rate provides a counter incentive for that move, according to RCM/TREE.

RCM/TREE also countered concerns raised by MH that suggested that because customer-related costs are real costs, larger consumers of energy will subsidize costs of smaller energy consumers. RCM/TREE noted that all customers are subsidized from export profits, and that credits applied to the BMC rather than energy would be a more equitable approach, and also provide a stronger price signal to conserve.

Time of Use Rates (TOU) & Demand Ratchets

RCM/TREE recommended MH should implement TOU rates, starting with the largest customers, and move revenue collection from demand charges to time-of-use energy charges. RCM/TREE acknowledged that time of use rates will require appropriate metering, but held that they should be implemented as soon as feasible. The intervener also recommended that MH eliminate demand ratchets.

Mr. Chernick noted that in jurisdictions where TOU rates have been implemented a parallel billing system was utilized, where a customer would, along with the existing bill, receive a bill as if they were on time of use rates. This allowed the customer to gauge the impact the TOU system had on their consumption and billing, and allow them time to make changes in energy use behaviour.

14.13 Board Findings

Inverted Rates

The Board encourages MH to develop plans to employ an inverted rate structure for all customer classes, initially to be designed on a revenue neutral (to MH) basis and to send a "price signal" for every kilowatt hour of energy used, to promote conservation.

MH suggested that too large an inversion would be prejudicial to all-electric customers. However, the nominal inversion of the Residential Rate approved by Order 90/08 can be expected to cost an all-electric customer approximately $45/year.

In comparison, a natural gas space-heated home, with a conventional furnace, can expect to pay hundreds of dollars more for space heating this upcoming winter as compared to a similarly adequately-insulated, electrically-heated home.

The Board agrees with the principle of inverted rates but notes, based on demand studies presented, that residential customers, in particular, do not significantly change their consumption patterns upon a price increase.

The Board shares the concerns expressed by all parties on the impact that sharply inverted rates would have on both low-income customers and all all-electric heat-load customers, who are unlikely to diminish consumption with increases in electricity prices. So, if the inversion were to be sharper, to promote conservation, this could be expected to result in a relatively high proportion of consumption being exposed to the higher second-block rate.

The Board notes that (with respect to the identified problem which electric heat customers could incur with sharply-inverted rates) there are methods to address what could be considered the inequity that could result from such sharply-inverted rates. The Board is aware of the complexities that MH will face in addressing this concern, but it warrants a fulsome analysis.

In particular, the Board is interested in MH providing additional information on seasonal variations in the size of the first electric block for electric heat-load customers. The Board agrees with MH that the size of the first rate block for Manitoba, as compared to the one utilized in Ontario, will likely have to be higher to take into consideration the greater heating load factor due to Manitoba's colder winters. The Board will direct MH to file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue.

The Board is quite concerned with the impact that sharply-inverted rates will have on low-income customers. The Board shares the concerns raised by the Coalition that barriers exist that preclude low-income customers from taking actions to reduce electricity consumption. Given that the proposal currently under consideration only reflects a nominal differential between the first and second block, the implementation of inverted rates should not be delayed, and the Board will address the problems of higher energy costs for low-income households in a broader way.

Nonetheless, the Board will expect MH to put forward more comprehensive plans to shield low-income customers from the impacts that will result from higher electricity rates in a sharply-inverted rate scheme.

With respect to the level of the basic monthly charge, the Board will direct MH to increase the Basic Monthly Charge by 5% on July 1, 2008 and a further 5% on April 1, 2009, by way of Order 90/08. The increases will result in BMCs that will still be well below a representation of MH's actual customer-based costs.

MH is to continue with the process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion.

Time of Use (TOU) Rates should be fast-tracked for customer classes where the required meter technology is currently installed. TOU rates assist in defining marginal cost, and therefore, should be included in any new proposed energy-intensive industry rate for consideration by the Board.

The Board will direct MH to provide a planned implementation strategy outline by September 30, 2008 for TOU rates, as appropriate to the classes with required metering technology already in place. Alternate rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing.

Energy and demand balancing is a policy issue that speaks to the fairness of rates to individual customers within a class. The argument for reducing demand charges, and increasing energy charges, is that it does send an improved price signal and thus promotes conservation. As the change occurs, Demand and Energy Cost recoveries will be brought more into line with cost causation principles. The Board will therefore direct MH to plan to re-balance demand and energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earlier of December 31, 2009 or the next GRA.

Diesel Zone: MH has indicated it will apply to the Board for finalization of the 4 interim Orders related to Diesel Rates. In such an application, the Board will also direct that MH provide reports on:

a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);

b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required);

c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the Grid which will serve as a comparison; and

d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs.

Area and Roadway Lighting (ARL)

The Board agreed with the position advanced by the City of Winnipeg and, by Order 90/08, did not approve any rate increase for the Area and Roadway Lighting class for either July 1, 2008 or April 1, 2009.

SEP

The Board is concerned with MH's marketing practices that yield extremely low prices for off-peak exports, and suggests that retaining energy in storage may prove more beneficial in the longer term than selling power for extremely low prices. The Board acknowledges that MH may be operating the system at near optimal levels to avoid "spilling" water, but there may be a benefit to spilling when prices get too low.

MH will be directed to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program; the report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefits and costs of the actual operation of the hydraulic generating system pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods.

The report may show whether selling at any cost increased the financial losses in 2003/04; and may also have resulted in foregone opportunity exports in 2004/05 because of low energy in storage.

In the interim, and by Order 90/08, the Board approved the extension of the SEP until October 31, 2008, on the condition that annual reports will continue to be provided.

The Board also approved all weekly interim SEP Orders, from August 1, 2007 (Order 100/07) through and including May 21, 2008 (Order 61/08), by way of Order 90/08.

CRP

Having heard no opposition to the request, the Board approved the requested change in the Terms and Conditions for the CRP by way of Order 90/08, with annual reports to be provided as previously.

LUBD

By Order 90/08, the Board also granted final approval of the revisions to the Terms and Conditions of LUBD, reducing the eligibility requirement from 36 months to 12 months. This revision will provide customers with increased flexibility to opt out and into the LUBD option, with minimal financial impact on MH or other participating ratepayers. The Board will, however, require annual reports on this program to illustrate the economic impact on MH and customers.

Winter Ratchet

The winter ratchet should be eliminated, such that customers are billed actual demand. With MH's summer and winter demands being nearly equal, there is not a strong case for retention of the ratchet. The ratchet does not send a strong price signal and is a source of considerable customer complaint. The ratchet can be removed with only a negative $2 million a year financial impact. Unless MH provides an acceptable TOU implementation process, the ratchet is to be removed ahead of the winter of 2009/10, and the change will be confirmed in an Order to follow in due course with respect to the conditional rate increase for April 1, 2009.

As previously mentioned, MH should file an implementation program for TOU rates for GSL customers with a fast-tracking of the subclasses that have the necessary metering technology in place.

It is currently the Board's intention to direct the elimination of the winter ratchet by September 30, 2009; the matter will be addressed in the Order related to the conditional April 30, 2009 rate increases.

15.0 Class Rate Impacts

15.1 Rate Changes/Rate Impacts

MH increases as of July 1, 2008 approved in Order 90/08 were::

	2008/09	**Range of Bill Impacts**	
Class		Low	High
Residential	5.06%	3.8%	5.52%
General Service Small Non-Demand	5.08%	4.88%	5.08%
General Service Small Demand	4.83%	3.98%	6.10%
General Service Medium	5.01%	3.22%	5.53%
General Service Large <30 kW	5.16%	3.35%	6.27%
General Service Large 30-100 kV	5.04%	3.21%	5.77%
General Service Large >100 kV	5.07%	3.07%	5.33%
Area and Roadway Lighting	0.0%	-	-
Overall General Service	4.95%		

Based on the approved July 1, 2008 rates, residential customers will experience increases ranging from 3.8% to 5.5%, depending on monthly consumption. Customers using more energy will experience higher than average increases.

For example, a typical residential customer without electric space heat consumes approximately 1,000 kW.h per month on average and will note an increase in their monthly bill of $3.03 or 4.7%. A residential customer with electric space heat, using on average 2,000 kW.h per month, will note an increase of $6.36 or 5.2% per month.

General Service Small commercial customers will experience increases ranging from 3.98% to 6.10% depending on monthly consumption and/or load factor; the overall class average increase is 4.94%.

General Service medium: commercial/industrial customers will experience rate increases ranging from 3.22% to 5.53%, depending on monthly consumption and/or load factor; the overall class average increase is 5.01%.

Increases to General Service large customers vary depending on the voltage level served and the load factor of each customer. MH proposed that the demand charge applied to the General Service large classes remain the same with only the baseline energy charge to increase. This charge results in higher load factor customers receiving a higher percentage increase.

For rates effective July 1, 2008, customers served at 750 V – 30 kV will have increases in their monthly bills ranging from 3.35% to 6.27%, with the average increase being 5.16%. Customers served at 30 kV to 100 kV will experience increases ranging from 3.21% to 5.77% with the average being 5.04%. General Service large customers served at over 100 kV will note increases ranging from 3.07% to 5.33% per month, with the average being 5.07%.

15.2 Differential Rate Increases

MH did not propose any class differential rate changes in its application other than for ARL, as it was MH's position that the current COSS has not been sufficiently tested to justify relying solely on the RCC results indicated therein. Furthermore, MH noted that the Board had not given MH any indication as to how marginal cost and environmental considerations will be reflected in Rate Design.

15.3 Interveners' Positions

RCM/TREE suggested that only marginal costs be considered in Rate Design, while the Coalition took the position that while the COSS should be the primary basis for rate setting, marginal cost should also be considered.

MIPUG took the position that the COSS has been adequately vetted to allow it to be established as essentially the entire basis for rate setting. MIPUG strongly supports the concept of moving RCCs to unity over five years, and suggested that a five year migration based on a 2.9% annual rates increase would bring about annual rate increases of:

- Residential 3.78%
- GSS-ND 1.92%
- GSS-D 1.26%
- GSM 2.65%
- GSL <30 5.36%
- GSL 30/100 2.04%
- GSL >30 0.93%
- ARL 1.31%

15.4 Board Findings

The Board has accepted MH's proposal for across-the-Board increases for 2008/09 and 2009/10, in order to allow further consideration of marginal cost factors for subsequent GRA's, and, by Order 90/08, directed a 5% across-the-board increase for all customer classes except for Area and Roadway Lighting, which is to receive no increase.

Also, by Order 90/08, the Board has indicated, on a conditional basis, subject to a number of reports to be required of MH, a further 4% across-the-board increase as of April 1, 2009, except for Area and Roadway Lighting which is to receive no increase.

16.0 Energy Intensive Industry Rate (EIIR)

16.1 Background

In the public hearing that resulted in Board Order 117/06, MH raised a concern related to energy consumption by energy-intensive firms, using energy as a manufacturing input. MH foresees its revenue position and the rates of other customer classes as being threatened by new or expanding industrial loads.

MH outlined its concern by considering its energy sales to energy intensive industrial customers, typically earning the Utility approximately 3.2 cents per kW.h while energy to secure such new or expanding load may be diverted from profitable export markets, which MH forecasts to return approximately 5.39 cents per kW.h. MH's example was a new or expanded load of, say, 100 MW causing a reduction of up to $18,000,000.00 per year in MH's net income, which would, according to MH, likely necessitate a rate increase of approximately 1.8% to all domestic customers served by the Utility (to recover such a revenue deficiency).

The issue compounds in the longer term, when MH assumes the risks of advancing construction of a major new generating station to meet new industrial load at prices below marginal costs. The decision that lies ahead following MH's refiling of its application potentially has large economic consequences.

While identifying the problem is relatively straight forward, the solution(s) is/are more elusive.

Against that background, the Board notes that it provided direction in Order 117/06, including that:

- MH to consult broadly, and in particular with government and industry, prior to advancing a proposal;

- MH to develop its proposal taking into account that existing industry came, remained and expanded in Manitoba with certain assumptions as to energy prices and supply – and therefore a distinction between new and existing industry is reasonable; and
- MH to provide a report and recommendations with respect to establishing a new energy – intensive industry class, including criteria developed after broad consultations with industry and government, and rate design recommendation.

16.2 MH'S Proposal

In its GRA, and in response to Order 117/06, MH proposed a new General Service Large rate schedule that would limit the application of "heritage" energy rates (based on embedded costs) to industrial customers specific baseline energy quantities per year.

Beyond the specific baseline energy quantities, higher rates, based on the marginal value of the energy, would be applied unless the industrial customer qualifies for an exemption to raise its baseline.

In essence, MH's new energy intensive rate proposal has three interrelated components:

1. new rate based on marginal value of foregone export revenue and marginal cost of generation;
2. a baseline, which would be set as an annual quantity based on a customer's prior maximum usage; and
3. exemptions, based on economic factors which would result in an increase in that customer's baseline if the exemption criteria was satisfied.

MH initially included the proposed rates and method of calculation of the baseline within its GRA; the exemption criteria was filed subsequently.

Underpinning MH's new energy intensive industry rate proposal was the principle that the revenue from such new rates would equal the foregone revenues of the same energy if it had been sold on the export market.

In short, MH sought to make the new energy intensive rate "revenue neutral" to the Utility.

16.3 MIPUG Motion

After MH's GRA filing, and also after the filing of the exemption criteria, the MIPUG advanced a motion to the Board seeking to sever the portion of the industrial rate that deals with new and expanded loads, from the GRA proceedings.

Following oral submissions on MIPUG's motion, the Board issued Order 8/08, which severed in part consideration of the new industrial rate from the GRA proceeding. At the GRA hearing, the Board and Interveners were provided the opportunity to cross-examine MH on the Utility's full proposal.

The Board, in Order 8/08, agreed that, at a minimum, consideration of the exemption criteria would occur at a special hearing. Interveners were also advised that if they so wished, they could bring new evidence forward at a separate hearing. To that end, the Board was advised, during the GRA hearing, that at least MIPUG intends to bring new evidence forward on this issue.

16.4 MH's Revised Position

While the Board and Interveners had the opportunity to explore the strengths and weaknesses of MH's proposed rates for new or expanding industrial load, so too was MH afforded the opportunity to continue to consider the issue.

During the proceedings, MH advised the Board and all parties that MH would not seek, through the GRA hearing, approval of the proposed energy intensive industry rates. Rather, MH indicated that it wanted an opportunity to review the information provided through the GRA process and have further discussions with its large industrial customers.

And, following further consideration and discussions, MH advised that it "…… may well refile or refine [its] proposal once the new hearing date is set and the process is established".

MH further advised that its request of the Board related to this issue, flowing from the GRA, would be for the Board to endorse in principle, the end date of December 31, 2007 for the setting of any baseline that may relate to a new rate for energy intensive industry. By the Board endorsing the date of December 31, 2007, as the end date for establishing a baseline, MH wants to put customers on notice for their planning purposes.

16.5 Service Extension Policy

In June 2005, MH suspended a long standing service extension policy which provided that MH would invest up to three times the anticipated annual revenues on facilities required to strengthen or extend the common grid to service customers (not including dedicated facilities). MH did not seek Board approval of this policy suspension.

MIPUG has suggested that the suspension may not be valid, or at the least, requires Board approval. Furthermore, MIPUG requested consideration should be given to refunding the costs incurred by customers due to the suspension.

16.6 Interveners' Positions

The Coalition

New and Expanded Load

The Coalition attributed the pressure on MH's load growth to load growth related to electricity intensive industry, and noted that load growth for electricity intensive industry for the next five years was projected to amount to 57% of the total load growth.

The Coalition stated that large energy intensive industry has been attracted to Manitoba on a scale large enough to threaten the Corporation's revenue position. Coalition noted that in the short-term this would impact by loads being diverted from the export market. In the long-term, for the Coalition the impact would not only be load diverted from the export market but also the implications of advancing costs in terms of new Generation and Transmission.

Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, the Coalition raised concerns with the MH's proposed dispute resolution process, which would come into effect in the event that there was a dispute with the establishment of the baseline or the granting an exemption between the Corporation and an industrial customer.

The Coalition held that if exemptions are to be granted they should be brought before the Board or be testable in some public forum. The Coalition opined that transparency is important because, to the extent exemptions are granted, there will be an impact on customer bills. The Coalition suggested MH address this issue when it refilled its proposal.

MIPUG

New and Expanded Load

MIPUG rejected MH's premise that new and expanded load from industry negatively affects all other customer classes, and held that such a premise would compromise in a material way fundamental ratemaking principles.

MIPUG stated that, should MH propose this ratemaking premise in future hearings, more detailed and comprehensive analysis is required. MIPUG contended that the Board will only be in a position to rule on such an important issue if it is presented with detailed analyses of both the expected short-term and long-term implications of the measure.

MIPUG contends that in the short-term, and due to export tie-line constraints, MH's ability to export additional power at times of high export prices is limited, and, as such, industrial load expansion would result in only minor impacts on MH's revenues over the short-term. Over the long-term, and in an era of expansion, MIPUG contends that the benefits arising from developing assets sooner should be included in the analysis, to allow the Board to properly assess the impacts that increased domestic loads have on long-term rate levels.

With respect to the Service Extension Policy, MIPUG opined the Utility neither had the authority nor should have suspended the policy without Board approval. Furthermore, for MIPUG, consideration should now be given to refunding costs that were disallowed by MH's unilateral suspension of the policy.

None of the other Interveners pursued this issue.

Energy Intensive Industry Rate

MIPUG accepted that MH had withdrawn its new industrial rate proposal and planned to refile an application, and that there is, therefore, no need for the Board to comment on this issue at this time. MIPUG stated that the Board should not set a date for the Corporation to return with its application, to allow MH to "take the time it needs" to properly support its proposal.

With respect to MH's proposed date of December 31, 2007 to establish a baseline for energy intensive industry rates, MIPUG's view was that the only benefit of establishing the baseline at that date would be to prevent "gaming" (i.e. new load being "rushed into service" ahead of a new rate and class being established). MIPUG's view was that the baseline should not be based on that date as other measures can be used to prevent "gaming", if and when a new rate and rate class was ultimately adopted.

MIPUG stated that the level of consultation with affected stakeholders should be commensurate with a rate proposal of this magnitude, and that the Corporation should take the time it requires to consult with the businesses and communities that may be affected by its proposal.

MKO

New and Expanded Load

MKO submitted that charging higher rates to new energy intensive general service customers would increase MH revenues and potentially provide for lower rates for all customers and greater "dividends" to the Manitoba government.

Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, MKO limited its comments to its view of the rate design principles that should be considered by MH in setting an energy intensive industry rate.

Firstly, MKO submitted that the proposed energy intensive industry rate violates several fundamental rate design criteria in that having such a rate would result in the charging of different rates to similar customers, and that the implementation of such a rate should only be done after the Manitoba government has set and communicated clear policy direction that such a rate is in the best interests of Manitoba.

Secondly, MKO advised of its concern that the proposed rate design will have a fixed implementation date that could “create a price cliff and intergenerational inequities”.

Thirdly, for MKO, the proposed energy intensive industry rate will differentiate customers based on “who” should receive net export benefits and “who” should not. MKO expressed a concern that MH would be “moving away” from the fundamental principle that all MH customers, including diesel community customers, should share the net export benefits, and that such a move may be a dangerous precedent and a decision to proceed with MH proposal should not be taken lightly.

Fourthly, MKO advised of a concern that the proposed rate will only apply to the large general service customer class. MKO submits that limiting the rate to one customer class violates standard rate design principles. MKO suggested that if limiting the sale of electricity to new energy intensive industry customers is a policy objective of the Manitoba government, then a more appropriate mechanism should be used instead of altering MH’s rates.

RCM/TREE

New and Expanded Load

RCM/TREE submitted that Energy Intensive Industry load growth will have a significant impact on MH's other customers, and that MH's load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment.

RCM/TREE further opined that MH may face energy shortages in 2009 to 2011, due to accelerated load growth.

Energy Intensive Industry Rate

RCM/TREE observed MH has acted on the energy-intensive industry issue by proposing a new rate for the general service large category. RCM/TREE also noted that the complexities of the proposed rate calculation are subject to consideration by the Board in a subsequent hearing.

Mr. Chernick suggested that MH's industrial rate proposal and exemption criteria were flawed, in that:

a) the baseline consumption level proposed was too high; and
b) the proposal allowed the baseline to increase to cover large amounts of increased load, with a total growth allowance of up to 39 GW.h (to qualifying companies).

Mr. Chernick noted that under MH's proposal if the industrial customer exceeded its baseline, the baseline in future years would be increased, so that marginal cost based rates would apply only in the first year of the load growth.

With respect to the proposed exemptions and/or discounts for economic development (payroll and taxes), Mr. Chernick suggested these would be the "wrong mechanism, implemented by the wrong entity", and would not be properly designed to meet the targeted objective, in that the discounts would destroy the conservation incentives of marginal-cost pricing and the computation of the cost of additional load would fail to count the environmental costs of reducing exports, and the lost benefits of the export revenues while new loads would be eligible for exemptions, regardless of the efficiency of the equipment and process installed.

Mr. Chernick stated that the baseline proposed to be established was too high and that the base usage for which a customer would be charged embedded rates should be less than a fixed historical base usage, such as the maximum annual usage in 2005-07 as proposed by MH. For Mr. Chernick, the base usage might better be set as 95% of the historical value in 2008, falling by 2% or so each year thereafter and with no future growth allowance.

Mr. Chernick stated the growth allowance eliminates any efficiency incentive provided by MH's proposal, and that "the only qualification for the growth allowance appears to be that the customer's load is less than 78 GW.h". Mr. Chernick opined that this proposed provision appears to eliminate any efficiency incentive for any customer adding less than 39 GW.h.

Mr. Chernick did not agree that incentives for economic development (exemption from the new rate due to economic development considerations) should be included in MH's rate structure. For him, the allocation of incentives should be the responsibility of an agency of the Manitoba government, not MH.

Mr. Chernick further suggested that if the Board were to want to use some of MH's revenues to support economic development; it should designate an amount to be collected and then direct that sum to be paid to the designated economic development agency, which should then decide which development projects are desirable and economically efficient.

Mr. Chernick suggested that revenues for economic development can be collected from the higher blocks of inclining-block rate structures, and that this proposal for the collection and disbursement of economic-development incentives would retain marginal-cost pricing for industrial rates, for both new and expanded loads, while not burdening MH with an economic-development role for which it has no special expertise or mandate.

RCM/TREE stated that each GSL customer should be charged the embedded energy rate for usage up to a baseline, and that marginal cost, including environmental costs, should be charged for consumption above that level. For Mr. Chernick, new general service large customers should be charged entirely at the marginal energy rate.

RCM/TREE proposes that the Board direct MH to participate in a collaborative effort with interested parties to determine if there are areas of agreement for the design of a new industrial rate proposal, and agreed with MH's proposal to fix December 31, 2007 as the end date for determining baseline levels.

16.7 Board Findings

Energy Intensive Industry Rate

The issue of the fairness of embedded cost rates being considerably lower than marginal costs or marginal values of energy, and the potential financial impact on the Utility, is not unique to Manitoba. The Board understands that other jurisdictions have, and continue, to face this issue.

And while the issue, in its basic form, exists for each new or expanded load by any customer, the financial implications of expanded load are magnified in the case of industrial customers.

While how best to address the issue in Manitoba remains an open question, one that will be pursued at a subsequent proceeding following MH's expected refiling of an application for a new industrial rate, it is an important issue that the Board is deeply interested in.

MH proposed a calculated rate for energy consumed above a baseline level, with that rate comprised of a marginal value of generated energy based on a "normalized" forecast of export values (i.e. 5.58¢ per kW.h), together with a marginal cost of transmission based on avoided costs (i.e. 0.816¢ per kW.h).

There was neither a marginal cost nor a marginal value for distribution included in MH's proposed new energy-intensive rate, this, because general service large customers have only nominal use of MH's distribution assets. The energy rate to recover the marginal cost, as proposed by MH, was also adjusted by the current demand charge of 0.740¢ per kW.h, providing for a proposed rate for new or expanded load for GSL > 100kV customers of 5.656¢ per kW.h (5.58 + 0.816 - 0.740 = 5.656).

While the Board appreciates that MH is not asking for approval of the energy-intensive rates at this time, the Board is concerned about the use of forecast export prices (as opposed to actual export prices) in the determination of marginal costs, and encourages MH to explore and advance other options for consideration at the separate hearing into this rate matter.

To explore other options and to avoid some of the concerns with the current calculation of an energy intensive rate, MH should consider:

- Baseline and growth allowance, and whether new industry coming to Manitoba [and existing industry] should get any growth allowance at heritage rates;

- Using data that is transparent and available to all customers and is not protected by a claim of confidentiality. The Board does not accept the bid for confidentiality when the information is publicly available from other industry or regulatory sources;
- Including time-of-use alternatives and variations to reflect the different values of energy at different times;
- Keeping the overall implications for revenue requirement neutral. The Board does not consider MH's proposal revenue-neutral as presented in MH's filed Proof of Revenue and IFF; and
- Perhaps including a marginal cost component or signal in rates for all classes, not just GSL. MH has identified that over the past ten years, more than 50% of the growth in Manitoba industrial loads is attributable to expansions in the electrochemical processing industry, an industry in which 70% of the costs can be incurred for electric energy used for processing purposes. The other major energy-intensive industry load (forecast by MH to significantly increase) is the pipeline compressor load.

A question to be considered is whether these specific industries should be targeted, or whether the concern is best addressed across the entire class, or perhaps all classes, served by MH.

Therefore, for the special hearing, MH will be expected to provide options, including its preferred option. The Board notes that MH may change its preferred option from what was presented at the GRA.

Export Contracts

MH should be required to reconcile its proposed treatments of energy-intensive industries with existing and proposed export contracts. Export sales do not create any direct or indirect Manitoba employment in the sense that domestic industry does.

It can be argued that MH should be pricing energy for domestic industry at average export price minus appropriate credits for direct and indirect job creation. While this might be difficult to administer, it would reward job creation and economic values input to Manitoba.

Further to the above, it would appear that the proposed energy-intensive rate may well discourage the further growth of existing industries. For example, if an industry added work shifts it would attract substantially-higher energy prices, in addition to shift premium payroll costs, even though this growth might well be employing off-peak energy (that being of low value as an export product).

TOU rates would significantly reduce the cost to industry for such expansion, and MH could benefit by gaining more value for its off-peak energy.

Time of Use (TOU) Rates

MH has suggested TOU rates will be considered after the new intensive-energy rate is implemented. This approach avoids addressing the issue of uneconomic exports and the considerable differences in domestic customer energy usage patterns. The Board, while recognizing that the implementation process for TOU may be protracted, believes that TOU should be built into the initial concept for the new rate.

In addressing confidentiality issues, MH has suggested that there is sufficient publicly-available information for the Board and Interveners to make informed judgements on the validity of MH's marginal cost forecasts. This information (sources: SEP/NEB/etc.) should also allow MH to define time-of-use pricing on a conceptual basis for Board consideration in the new rate design.

MH has acknowledged that TOU billing could have favourable revenue results for the utility in most years. On the other hand, TOU rates should provide an opportunity to industry to optimize its energy usage and thus benefit from TOU rates.

Marginal Cost Values for Export

MH's case for increased rates to energy-intensive industry assumes that all energy used by industrial growth could alternatively be sold as peak market exports. Contract prices (generally below peak market values) apply during low flow years; only part of the exports achieve better than contract prices in average flow years, and surplus energy prices tend to fall below contract prices in high flow years. In light of the transmission tie-line constraints, the Board questions MH assumptions on the relative value of export sales and domestic load growth during the off-peak period.

Accordingly, the Board directs MH to provide an in-depth analysis of the value of peak versus off-peak energy sales into the MISO market.

MH also employs an element of avoided costs in determining the marginal cost of energy to be employed for intensive-energy usage rates. This would be appropriate if MH was actually contemplating deferral of new generation or transmission on the basis of reduced domestic load growth. In reality, MH is advancing new generation and transmission to meet new export contract sales now under negotiation.

he Board directs MH to report on the specific deferral values that could be achieved by constraining industrial load growth.

Consumption Baseline

In defining the new intensive-energy rate and by its application, MH focussed on industrial customers using more than 39 GW.h of energy per year. However, the proposed rate schedule provided marginal cost second block rates for all GSL customers.

In the Board's view, MH should have provided the impact analysis for all GSL customers, in order to justify the proposed 39 GW.h floor for new rate exemption. Accordingly, the Board directs MH to provide an analysis for all GSL customers, to justify the 39 GW.h floor for new rate exemption, and to report on the potential extension of the rate and or lowering of the threshold.

Fairness Principles

There was at least a sense of a degree of consensus from all parties that selling energy domestically at prices well below the average export market value is an issue that must be addressed. Beyond that, the Interveners were quite divided on what is a fair price level and who should pay the higher price if there is to be one.

Currently under the COSS, all domestic customer classes are allocated about 3.0 to 3.5¢/kW.h in costs for generation and transmission. Some customers pay more and others pay less than their allocated costs. No class pays the average export market value. The issue is further distorted because different classes are allocated varying amounts (zero and upward) for local distribution services. The Board will be looking to reconcile the current rate proposal with cost causation principles.

Service Extension Policy

It would appear that the policy (pre-2005) was intended to support industrial expansion in areas of the Province that did not have access to 30 kV or greater power. The scale of the investments incurred and revenues gained under this policy were not identified at this hearing. MH did not carry out a detailed feasibility test prior to suspending the policy; for the longer term, and in light of the proposed new energy-intensive rate, that policy may be reconsidered by MH.

The Board considers that the service extension policy logically falls under the Terms and Conditions that are generally believed to be integral with rate setting. Without reaching a conclusion on legal jurisdiction at this time, the Board will direct MH to file an economic feasibility test report with the Board on September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed and explain why that rationale apparently no longer exists, together with an accounting of instances since the policy was suspended where customers paid more to have a service connection than other previous customers.

17.0 Presenters' Positions

17.1 Mr. Ciekiewicz

Mr. Ciekiewicz's view is that the March 31, 2007 interim rate increase was not justified because it was prompted by the occurrence of only a short period of low water levels in 2005/06, rather than the "long established method" of using longer periods of time to set rates.

Mr. Ciekiewicz also indicated that MH's proposed residential rate increase, and the approach the Corporation used to develop its inverted rate structure proposal penalizes home owners who are dependent on electrical heating, and/or have converted to electrical heating. He was concerned that all-electric rate-payers will face an increase greater than the rate of inflation. He argues that those who do not have the option of other fuel sources for heating should get a rebate, rather than an increased rate. As well, he predicted that inverted rates will result in heating choices by rate-payers that are not friendly to the environment.

Mr. Ciekiewicz was also concerned that it is the nature and length of the firm export contracts that constitutes the main risk affecting the financial well-being of MH, and that in years of drought the costs associated with fulfilling firm export commitments could wipe out the retained earnings.

He opined that the Board has jurisdiction over MH's export contracts, by way of section 47 of *The Public Utilities Board Act*. He recommended that the firm export contracts negotiated by MH include clauses that the contracts can be cancelled in the event of drought conditions, or that certain incentives on export prices be included in the contracts as a concession to the export customers for this cancellation clause.

Mr. Ciekiewicz also challenged the meaning of firm contracts as interpreted by MH, he based his challenge on a definition from the North American Electric

Reliability Corporation that implies that the obligation to provide power ceases when the "system reliability is threatened, or during emergency conditions".

Mr. Ciekiewicz also questioned MH assertions that the incremental costs of new office building over the efficiency savings will be cost neutral, and never affect rates. He did not accept that the $278 million price tag for the new head office will not adversely affect retained earnings, and by extension, rates.

Mr. Ciekiewicz was unclear as to whether NCN will be liable for one-third of any losses that may materialize if a future drought prevents MH from meeting its export sale commitments, and sought to have the issue clarified.

Mr. Ciekiewicz made reference to what he termed contradictory responses from MH on some Information Requests with respect to the Brandon Coal Fired Thermal Generating Station Unit 5. One apparent contradiction cited appears that MH has stated that the closure of the Unit 5 would result in firm energy deficits in 2013 to 2025 and would reduce the surplus available for export, while MH stated elsewhere in its responses to interrogatories that the thermal plants were not constructed to support export sales. Another contradiction in MH responses noted by Mr. Ciekiewicz was that MH stated in one Information Request that Unit 5 produces an average $20 million to $30 million in net income per year, while the Corporation's response to another Information Request stated that MH does not calculate the annual revenues or net income for the unit.

17.2 Mr. Forrest

Mr. Robert Forrest provided an electronic submission; he indicated opposition to MH's proposed rate increase.

Mr. Forrest stated that rates were already too high and that the current increase was not justified because MH had reported in the news a large surplus and that an increase had already been granted.

17.3 Mr. Rader

A written presentation in the form of a letter from Mr. Robert Rader, Managing Director, Koch Fertilizer Canada, Ltd., to Mr. Bob Brennan, President and Chief Executive Officer, Manitoba Hydro and to Public Utilities Board, dated February 11, 2008 was read into the record of the proceeding.

Mr. Rader made reference to the document entitled General Service Large – New or Expansion Rate Baseline Energy Consumption Level and Exemption Application Discussion Paper. He did not agree with the proposed annual growth allowance of GW.h, and recommended the growth allowance be a percentage of the base versus a fixed number.

Mr. Rader also recommended that expenditures made to reduce energy consumption should be credited at 100% rather than the 50% contemplated in the document.

Mr. Rader also stated that while his company may expand its production volume without increasing its payroll, it would still be providing secondary benefits to truck and rail companies, and that such economic benefits should be taken into account in considering exemptions from any new industrial rate.

17.4 Mr. Svidal

Mr. Kaare Svidal is the manager of the Energy Management Group of Enbridge Pipelines, and he stated that MH had made presentations across the province on the proposed new industrial rate, and that in these presentations MH had indicated that pipeline companies provide very little economic benefit to the province. He disagreed with MH on that issue, and argued that Enbridge has provided considerable value to Manitoba in the last 58 years.

He stated that Enbridge pays annual salaries of $5 million to Manitobans, and $7 million of annual property taxes in the province. He also noted that Enbridge benefits industry in Manitoba in that it delivers all the refined products to Manitoba in a reliable and economical way.

He also noted that the growing Manitoba oil producing industry, which generated $400 million in capital expenditures in 2006, relies on Enbridge to deliver their product to US markets.

He pointed out that Enbridge is a long-term financially stable A-rated base load customer of MH whose continued presence in Manitoba is required to justify the MH infrastructure in place today. He reminded the Board that his firm had switched from diesel to electrical pumping stations in 1965 at the request of the government of Manitoba, and that Enbridge was a long-term and committed customer of MH.

17.5 Mr. Turner

Mr. Bill Turner is plant manager of Canexus Chemicals at Brandon and the Chairman of MIPUG. He indicated that low-cost electricity is necessary for industry to remain competitive in Manitoba because it offsets existing geographic, climatic and other disadvantages of locating in this province, disadvantages that also include higher taxes and a growing foreign exchange problem.

Mr. Turner stated that MIPUG members pay rates that are 8% greater than the cost to MH of providing the firms the electricity they consume; MIPUG member firms were reported to consume 5,000 GW.h. annually at a cost in excess of $150 million.

Mr. Turner further advised that MIPUG members employ 4,500 Manitobans, and that the association's membership have capital assets employed in Manitoba greater than $2 billion. Mr. Turner also stated that 90% of MIPUG members' sales were exports.

Mr. Turner indicated that the new industrial rate is a new policy direction from MH with major implications for the use of energy and the development of industry within the province. He expressed frustration that the discussion meetings between MIPUG and MH on this issue were ineffectual, and that the discussions were not open and transparent. He expressed concern that the Province of Manitoba has not participating directly in the new industrial rate discussions, and stated his view that the Province may be poorly informed on the issue.

He suggested there will be far reaching impacts if the new industrial rate is adopted, in particular to the employees of affected companies and their families, and to rural and northern communities in which the firms are located.

Mr. Turner explained that with respect to his company, Canexus, 60% of the firm's manufacturing costs are for electricity ($48 million annually). He stated that 100% of his firm's product is exported, with 95% going to the US. Mr. Turner noted that the recent strengthening of the Canadian dollar had resulted in major income losses for Canexus.

He stated that his company has 6 plants in other provinces and one in Brazil, and that when the firm is not required to operate at full capacity, the firm will operate the factories with the lowest electricity cost. He also pointed out that his company is one of MH's largest DSM participants.

Mr. Turner stressed that companies such as Canexus require stability and certainty in electrical rates in order to make sound business decisions as to where they locate. He indicated that his company relocated a plant from Louisiana to Manitoba in 2004, at a cost of $55 million, because of electrical rates. He stated that further expansion plans are now being reconsidered due to the uncertainty of rates in Manitoba over the last 3 years.

He further stated that through his association with various industry groups, that business in general is concerned with the new industrial rate issue. He declared his disappointment that MH has stated that sodium chlorate companies and pipelines provide very few economic benefits in this province, and he advised of benefits being provided to the people of Brandon and the related construction trades.

18.0 IT IS THEREFORE RECOMMENDED THAT

1. MH seek independent advice as well as advice from government and its credit rating agencies as to the merits of a possible elimination of the sinking fund requirements;

2. The Board remains concerned with the Corporation's ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider an early adoption of IFRS standards. The Board further recommends that both the Board's prior concerns and current views, as expressed in this Order, be brought to the attention of both MH's external auditors and its independent consultant assisting the Corporation with its IFRS transition strategy;

3. Because of the current and future impact on rates of the unprecedented capital program and related tentative export sales contracts, the Board repeats its recommendation to government that *The Public Utilities Board Act* be amended to make the Board's regulation of MH equivalent to the Board's regulation of Centra Gas, by removing the exemption now provided under Section 2(5) of the Act;

   Or alternatively, the Board recommends that government renews the mandate provided to the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH's Major Capital Projects in light of pending export commitments (then-covering the period 1990 to 2009). Such an updated mandate would allow for a similar review covering the period 2009 to 2028;

4. Because of the impact (and potential impact) on consumer rates, the Board recommends MH seek the Board's prior review and approval of

future agreements involving the joint ownership of Generation and Transmission assets;

5. With respect to DSM and Low-Income Energy Efficiency Programs:

   a) MH accelerate its DSM plans to achieve targets earlier than presently scheduled, and at the same time, consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years;

   b) MH to continue to pursue environmental objectives on an integrated natural gas electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions;

   c) MH undertake changes to its furnace replacement program so as to increase low-income household participation in the early replacement of inefficient natural gas furnaces. Changes to the program, as recommended by the Board by way of Order 99/07, would better provide this opportunity and should provide energy savings for low-income customers and significant non-energy benefits to society (reduced GHG emissions), the Utility (in the form of less risk of the conversion of natural gas space heating to space heating by electricity), as well as to all participants in the program;

   d) MH incent landlords to participate in the low-income DSM program, to improve the energy efficiency of their properties for the benefit of their tenants and the environment;

e) MH expand finance options for low-income customers, including subsidized Power Smart loans for the furnace replacement program, with an option either requiring repayment on the sale of the residence or, alternatively, a 10-year lease financing program as suggested by Mr. Dunsky;

6. The Board recommends government consider:

   a) Seeking from the Federal government an exemption from GST for residential customers for space heating, as heat in Manitoba in winter is a necessity like food; and

   b) Funding low-income and DSM programs, by setting aside all or a portion of provincially and or municipally-sanctioned sales taxes charged to residential customers on energy used for heating purposes.

7. The Board recommends government consider establishing a separate entity to manage the Corporation's DSM and low-income initiatives. The Board concludes that MH's full energies and focus should be placed on the effective implementation of its long-term expansion plans toward meeting the demand for electricity and natural gas to develop over the next few decades. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to meet or exceed, together with providing adequate funding to meet those goals (energy conserved is energy available for export).

19.0 IT IS THEREFORE ORDERED THAT:

1. MH file with the Board, MH's 2007/08 Annual Report, with audited financial statements, immediately after the Corporation meets its statutory filing requirement with respect to the Legislature;

2. With respect to MH's export program, MH to file a report with the Board by January 15, 2009 on the following:

   a) Overview of strategy, options, historical costs and revenues;

   b) Monthly historical export prices for the last five years, disaggregated for both peak and off-peak periods;

   c) Existing and pending export contract commitments, with annual forecast revenues both aggregated and also disaggregated (in confidence if necessary);

   d) Forecast export revenues until 2028, identifying opportunity sales distinct from firm contract sales and broken down by peak/off-peak;

   e) Detailed assumptions used in export market price forecasts (filed in confidence if necessary). MH to resubmit its export pricing forecasts to reflect recent realities of market prices and exchange rates;

   f) A testing of MH's assumptions through detailed sensitivity analyses for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and

   g) Given the crucial nature of the Corporation's export contracts and assumptions, with potential impacts on domestic rates, MH file for Board review all proposed export contracts;

3. MH to provide the Board with:

    a) Specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data); and

    b) Annual reports on the LUBD Program performance;

4. MH to provide the Board an independent assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009 ;
5. With respect to IFRS, the Board requires MH to file on or by January 15, 2009 :

    a) A report explaining and quantifying the proposed transition to IFRS;

    b) A copy of MH's consultant's report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts;

    c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS;

    d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS, together with MH's and its consultant's views of the Board's regulatory options, including a review of the pros and cons of special purpose financial reporting for utilities for rate setting purposes; and

e) An updated IFF and CEF (covering the years 2008 to 2028) reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH;

6. MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:
   a) Primary key drivers of OM&A in each operational division [Board preference is for a divisional break-down to allow for a comparison with other utilities, even if the comparison needs to be limited to specific divisions/activities],
   b) Comparable other Canadian Utility data for each of the drivers;
   c) Key comparison indicators, including staffing levels;
   d) A comparison with and discussion of industry best practices; and
   e) Potential improvement areas.

   The Board expects to be apprised of the scope of the benchmarking study in advance of it being undertaken, and will anticipate being provided a study outline on or before January 15, 2009, to allow the Board the opportunity to provide direction and/or comment.

7. MH to undertake and file with the Board an Asset Condition Assessment Report by June 30, 2009, that defines:

   a) major assets and categories of assets;

   b) the estimated remaining economic life of each major asset and category of asset;

   c) an indication of the implications for OM&A costs related to required and scheduled maintenance;

d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and

f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH to file with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

8. MH to file a report with the Board by June 30, 2009 detailing the final all-inclusive capital cost of the corporate head office project (including such things as construction cost, furniture and equipment, telecommunications, equipment leases, etc.), and the contemplated or planned operating actions to recover incremental costs related to the new head office. (The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.)

9. MH to file a report with the Board by January 15, 2009 indicating:

a) whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro [including Slave Falls] and the Brandon Coal Plant remain appropriate; and

b) the related proposed capital replacement, expansion and decommissioning costs;

10. To gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 :

    a) An updated Capital Expenditure Forecast, and Integrated Financial Forecast covering the fiscal years 2007/08 to 2027/28;

    b) An updated Power Resource Plan covering the years 2008 to 2028. The updated Power Resource Plan should provide alternative scenarios with/without implementation of the pending new export contracts and related capital spending. The report should also indicate the remaining feasible hydro generation opportunities, following Wuskwatim, Keeyask and Conawapa, where and what possible quantity of energy would be expected, and the assumed development timeline; and

    c) An updated Load Forecast covering the fiscal years 2007/08 to 2027/28; the Load Forecast should reconcile projected and actual DSM savings;

11. The Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its impact on consumer rates;

12. MH to prepare a study, and file it with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending and take into account revenue growth, variable interest rates, drought, inflation experience and risk, and potential currency fluctuation;

13. MH to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation set out in the previous directive (12);

14. MH to provide the Board, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, with risks quantified;

15. MH to provide the Board by June 30, 2009, a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. The summary should include the specifics of each program and mitigation and compensation related thereto;

16. MH to submit a report to the Board on January 15, 2009 on the 300 MW of additional wind energy project(s), with a discussion of the business case, general wind strategy, prospects and timelines for the project, as well as with respect to the prospect for a further 600 MW consistent with the government's identified longer-term target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s);

17. MH report to the Board before June 30, 2009, as to whether there are greater global environmental (GHG) and economic benefits to be achieved by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or

geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of these exports. The overall assumptions and impacts on the Load Forecast should also be included in the report;

18. With respect to low-income programs, MH to prepare and report on the following:

    a) MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development of and implementation of this program;

    b) MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunsky, on or before September 30, 2008;

    c) MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008;

    d) MH to propose for Board approval (as soon as possible but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction with and complimentary to an expanded low-income DSM program;

e) MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural gas and electricity) energy-efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade;

f) MH to report back to the Board on the potential for a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009; and

g) MH to accrue interest on the AEF balance, to ensure additional funds are available to fund expanded low-income energy efficiency programs and to avoid the loss of "purchasing power" of the AEF due to continuing inflation;

19. MH to refile the COSS by January 15, 2009 on the following basis:

a) As defined by Order 117/06;

b) Incorporating diesel and exports in the same fashion as other domestic customer classes;

c) The assigning of 50% fixed and 100% variable thermal plant costs to the Export class;

d) Assign DSM cost directly to export class and add DSM energy savings to domestic load for Generation cost-sharing purposes;

e) Use the most recent actual [not forecast] export prices to establish export revenue in the COSS; and

f) Use actual [eight year] energy [SEP] prices and energy use profiles in Generation energy weighting process;

20. MH to provide and file with the Board by January 15, 2009 a revamped Marginal Cost (MC)-COSS analysis, one reflecting needed refinements to generation, transmission and distribution marginal costs. This should include specific demonstrations of how alternative MC adjustments could be applied to an embedded COSS. Among the scenarios to be explored, MH should consider the addition or blending of marginal costs to embedded costs prior to comparison to class revenues;

21. MH to file all appropriate data [e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.] required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process, with the Board [on a confidential basis if necessary] on or before September 30, 2008;

22. MH to provide a planned implementation strategy outline by September 30, 2008 for TOU Rates as appropriate to the classes with required metering technology already in place. Alternative rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing;

23. MH file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue over the next five years;

24. MH to plan to re-balance demand and energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earliest of June 30, 2009, or the next GRA;

25. MH to continue with the consolidation of process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion;

26. MH to include in its future application to finalize the four interim Orders related to Diesel Rates, reports on:

    a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);

    b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required); and

    c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the grid which will serve as a comparison; and

    d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs;

27. MH to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program. The report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefit and costs of the actual operation of the hydraulic generating system

pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods;

28. MH to file an economic feasibility test report with the Board by September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed, and explain why that rationale apparently no longer exists, together with an accounting of instances (since the policy was suspended) where customers paid more to have a service connection than other previous customers;

29. With respect to an Energy Intensive Industry rate for new and expanded load, MH is to file an updated application with the Board on or before September 30, 2008. Such an application should include:

    a) An in-depth analysis of value of on-peak versus off-peak energy sales into the MISO market;

    b) A report on the specific deferral values that could be achieved by constraining industrial load growth; and

    c) An analysis for all GSL customers, to justify the proposed 39 GW.h floor for new rate exemption, and report on the potential extension of the rate and/or lowering of the threshold;

30. MH to file before January 15, 2009, supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information identified above to be filed by January 15, 2009, MH is to include:

    a) first ,second and third quarter 2008/09 unaudited financial results and statements; and

b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

THE PUBLIC UTILITIES BOARD

“GRAHAM LANE, CA”

Chairman

“H. M. SINGH”

Acting Secretary

Certified a true copy of
Board Order 116/08 issued by
The Public Utilities Board

Acting Secretary

Appendix A

Appearances

R. Peters	Counsel for The Manitoba Public Utilities Board (Board)
O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./ Winnipeg Harvest (COALITION)
T. McCaffrey J. Landry	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson	Representing Manitoba Keewatinook Ininew Okimowin. (MKO)
W. Gange D. Rempel P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Buhr	Counsel for the City of Winnipeg (CITY)
J. Scott (np) T. Trull (np)	TransCanada Keystone Pipeline GP Ltd.

(np)- not present at the hearing

Appendix B

Witnesses for Hydro

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Section Head, Generation System Studies, Resource Planning and Market Analysis,
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
W. J. Derksen	Manager, Corporate Accounting
C. S. Thomas	Manager, Electric Rates & Regulatory Department
L. J. Kuczek	Division Manager, Consumer Marketing and Sales
I. S. Page	Manager, Financial Planning Department
W. Hamlin	Senior Energy Policy Officer, Energy Policy & Emissions Trading, Power Supply

Appendix C

Interveners of Record

1. Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors/Winnipeg Harvest (Coalition)
2. Manitoba Industrial Power Users Group (MIPUG)
3. Manitoba Keewatinook Ininew Okimowin (MKO)
4. Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
5. City of Winnipeg (CITY)
6. TransCanada Keystone Pipeline GP Ltd. (KEYSTONE)

Appendix D

Intervener Witnesses

Coalition

W. Harper	Manager, Econalysis Consulting Services, Inc.
P. Dunsky	President, Dunsky Energy Consulting

MIPUG

A. McLaren	Consultants, InterGroup Consultants Ltd.
P. Bowman	

RCM/TREE

P. Chernick	President, Resource Insight Inc
S. Weiss (np)	Sr. Policy Analyst, NW Energy Coalition

Appendix E

Presenters

Mr. A. Ciekiewicz	Citizen
Mr. B. Turner	Chair, Manitoba Industrial Power Users Group
Mr. K. Svidal	Manager, Energy Management Group, Enbridge Pipelines
Mr. R. Rader (written only)	Managing Director, Koch Fertilizer Canada, Ltd.

Tab 34

Order No. 59/18

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2017/18 AND 2018/19 GENERAL RATE APPLICATION

May 1, 2018

BEFORE: Robert Gabor, Q.C., Chair
Marilyn Kapitany, B.Sc., (Hon), M.Sc., Vice Chair
Hugh Grant, Ph.D., Member
Shawn McCutcheon, Member
Sharon McKay, BGS, Member
Larry Ring, Q.C., Member

Table of Contents

1.0 Overview

Under Manitoba law, the Public Utilities Board ("Board") must set electricity rates for Manitoba Hydro's customers that are just and reasonable. In so doing, as confirmed by the Manitoba Court of Appeal, the Board balances two concerns: the interests of Manitoba Hydro's ratepayers and the financial health of Manitoba Hydro. Together and in the broadest interpretation these interests represent the general public interest.

1.1 The Manitoba Public Utilities Board

The Board is an administrative tribunal created by provincial legislation to act as an independent decision-maker in the regulation of public utilities in Manitoba. To carry out this mandate, the Board is empowered by legislation with many of the same powers, rights, and privileges as the Manitoba Court of Queen's Bench. As such, the Board is court-like and transparent in its processes. Those processes include the receipt of evidence under oath from utilities, interested or affected groups (also known as "Interveners"), and members of the public.

In order to make decisions on the applications before it, the Board deliberates on the evidence obtained in accordance with fair processes pursuant to principles of administrative law. For example, in the present Application before the Board, the Board received written and oral evidence from witnesses on behalf of Manitoba Hydro, expert witnesses retained by Interveners, Independent Expert Consultants, and members of the public. All of the documents filed in the proceeding, as well as transcripts of oral evidence and submissions, are available on the Board's website at www.pubmanitoba.ca.

The Board's Rate Review Mandate

The Board's mandate with respect to the regulation of Manitoba Hydro (or "the Utility") is derived from *The Public Utilities Board Act*, CCSM c P280 ("Board Act"), *The Crown Corporations Governance and Accountability Act*, CCSM c C336 ("Crown Act"), and *The Manitoba Hydro Act*, CCSM c H190 ("Hydro Act").

Pursuant to subsection 25(1) of the Crown Act, the prices charged by Manitoba Hydro with respect to the provision of power ("rates for services") are reviewed by the Board under the Board Act. No change in rates for services can be made and no new rates for services can be introduced without the approval of the Board. Manitoba Hydro is required to submit proposals regarding rates to the Board for approval.

The Board's jurisdiction over Manitoba Hydro is limited by subsection 2(5) of the Board Act, such that the Board's primary authority over Manitoba Hydro is the review and approval of rates as set out in the Crown Act. As a result, unlike all other rate-setting jurisdictions in Canada, the Board does not have statutory authority to approve Manitoba Hydro's capital project plans or expenditures; however, the Board Act provides that the Board may perform duties assigned to it by Order in Council of the Lieutenant Governor in Council.

1.2 Manitoba Hydro

Manitoba Hydro is a Crown Corporation established pursuant to provincial legislation in order to provide for the supply of power adequate for the needs of the province, and to engage in and promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power. Further to this mandate, Manitoba Hydro provides safe and reliable electricity service to Manitobans at rates that are among the lowest in North America.

When Manitoba Hydro applies to the Board for rate increases, Manitoba Hydro bears the statutory onus of demonstrating that the increases sought are just and reasonable. While the focus of Manitoba Hydro may be on the financial risks faced by the Utility, the Board's role is broader. As noted above, to set rates in the public interest, the Board considers not only the financial health of Manitoba Hydro. Rather, the Board must balance the financial health of Manitoba Hydro with the interests of ratepayers.

In addressing these two concerns, any application by Manitoba Hydro for a rate increase cannot be divorced from the context in which Manitoba Hydro operates. As a monopoly Crown utility that generates, transmits, and distributes electricity (also known as vertically integrated), Manitoba Hydro is different from many other electric utilities operating in Canada, and in particular, from privately owned for-profit corporations. Unlike private corporations, Manitoba Hydro does not have private shareholders in the traditional sense. While owned by the Province of Manitoba for the benefit of Manitobans, Manitoba Hydro is a non-share capital corporation. This means that Manitoba Hydro does not have investors or shareholders that contribute equity to the Utility and it is not required to make payments to any equity investors. Any equity acquired by Manitoba Hydro is obtained from domestic ratepayers or export power sale customers. Rather, as a Crown utility, Manitoba Hydro has a public policy purpose.

In addition, Manitoba Hydro is a pure cost recovery utility. Unlike many other government-created utilities in Canada, Manitoba Hydro is not required to pay dividends to the provincial government. As a cost recovery utility, Manitoba Hydro is within a subset of types of utilities; it is further within a subset of cost recovery utilities because Manitoba Hydro's debt is borrowed by the Province of Manitoba. The government raises debt capital from the capital markets, and provides the funds to Manitoba Hydro with the addition of a debt guarantee fee.

1.3 The General Rate Application

In 2017, Manitoba Hydro applied to the Board for changes to its consumer rates. Specifically, Manitoba Hydro is seeking in the present General Rate Application ("GRA"), approval of three rate increases: (1) finalization of the 3.36% interim rate increase that was effective August 1, 2016, (2) finalization of the 3.36% interim rate increase that was effective August 1, 2017, and (3) a 7.9% rate increase to all components of all consumer rates, effective April 1, 2018.

While only the three rate increases listed above are before the Board for approval, the 7.9% increase sought by Manitoba Hydro for the 2018/19 fiscal year is part of a new 10-year financial plan that replaces the Utility's previous 20-year plans that were predicated on projected 3.95% annual rate increases. Under Manitoba Hydro's new 10-year financial plan, following the August 1, 2017 3.36% interim rate increase, Manitoba Hydro projects a rate path of six years of 7.9% annual rate increases, followed by a one-year rate increase of 4.54% and then two years of rate increases at 2%.

The new 10-year financial plan includes six years of rate increases at a level twice the previously requested annual rate increases and four times the rate of inflation. The new plan is designed to have Manitoba Hydro reach a 25% equity level, from the current 15%, in 10 years by 2027, while generating additional cash flow and enabling repayment of a portion of Manitoba Hydro debt. This differs from the previously projected 20-year timeframe for achieving a 25% equity level.

The Utility sees the fundamental underlying problem with its financial health as being the major capital expansion and the amount of the debt required to pay for the simultaneous construction of the $8.7 billion Keeyask Generating Station project ("Keeyask") and the $5.0 billion Bipole III Transmission Line project ("Bipole III"). Manitoba Hydro seeks a prospective level of income and cash flow that, in the Utility's view, would restore its financial strength while also being capable of enduring drought or material negative deviations from export price and interest rate forecasts without requiring emergency relief from ratepayers. While the change in risk tolerance of the Manitoba Hydro-Electric Board is a significant factor underpinning the new financial plan, Manitoba Hydro also cites lower revenue growth and increased debt as contributing factors.

The 7.9% rate increase requested for the 2018/19 fiscal year is part of Manitoba Hydro's new financial plan. While the 10-year plan is part of the circumstances before the Board in this GRA, rate increases for years beyond 2018/19 are not before the Board for approval. The Board cannot bind itself to future rate increases that are not the subject of the immediate request before the Board. Similarly, and as indicated by Manitoba Hydro, the Utility may alter its plans based on circumstances as they arise. Currently, Manitoba Hydro's Retained Earnings are at record levels and already twice the level that would be required to deal with the negative financial impacts of a five-year drought; however, should unforeseen or negative risks occur, this Board will consider the evidence of the specific circumstances and the options, including rate increases, to address such circumstances as the Board has done when warranted in the past. For example, when a drought occurred in the early 2000s, this Board approved rate increases in excess of what Manitoba Hydro requested to address the financial health of the Utility.

In its Letter of Application filed on May 5, 2017, Manitoba Hydro sought the following specific approvals in the current GRA:

1. Final approval of Order 59/16 which approved, on an interim basis, an across-the-board rate increase of 3.36% effective August 1, 2016, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to the conclusion of this proceeding;

2. Approval, on an interim basis, of rate schedules incorporating an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective August 1, 2017.

   After the Board's Order approving a 3.36% interim rate increase effective August 1, 2017, Manitoba Hydro revised its request for the 2017/18 fiscal year and sought only finalization of the 3.36% interim rate increase;

3. Approval of an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective April 1, 2018;

4. Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14, and approval of new LED rates for the Area and Roadway Lighting class (Sentinel Lighting) as discussed in Tab 9 of Manitoba Hydro's Application;

5. Approval to remove the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from Manitoba Hydro's rate schedule, as discussed in Tab 9 of its Application;

6. Endorsement of modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") that were accepted on an interim basis in Order 43/13, as outlined in Tab 9 of its Application;

7. Final approval of all SEP interim *ex parte* rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of its Application and prior to the Board's Order in this matter;

8. Final approval of Curtailable Rate Program ("CRP") *ex parte* Order 54/16 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of its Application and prior to the Board's Order in this matter;

9. Final approval of Orders 116/12 and 117/12 that approved, on an interim basis, a 6.5% rate increase to the full cost portion of the General Service and Government rates in the four remote communities serviced by diesel generation ("diesel zone") effective September 1, 2012, and final approval of diesel zone Orders 17/04, 46/04, 176/06, 1/10, 134/10, 1/11, and 148/11, subject to confirmation that Manitoba Keewatinowi Okimakanak has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement.

   In this proceeding, Manitoba Hydro's request for final approval of the diesel zone interim rates was predicated on receipt of the executed Settlement Agreement documents. In the course of the hearing, Manitoba Hydro advised that it was no longer seeking final approval of diesel zone interim rates in this proceeding as the final executed Settlement Agreement documents had not yet been provided to the Utility;

10. Endorsement of the proposed deferral and subsequent amortization of costs incurred with respect to the Conawapa Generating Station project, as discussed in Tab 4 of its Application; and

11. Endorsement of the proposed amortization period for disposition of the regulatory deferral accounts established to capture the differences between Depreciation Expense and Operating & Administrative Expense calculated for financial reporting purposes based on International Financial Reporting Standards, and Depreciation Expense and Operating & Administrative Expense calculated for rate-setting purposes reflecting Board directives in Order 73/15, as discussed in Tab 4 of its Application.

1.4 The Board's Hearing into the General Rate Application

The process for the Board's consideration of this GRA formally commenced when Manitoba Hydro filed its Letter of Application. On May 12, 2017 and May 26, 2017, respectively, Manitoba Hydro filed copies of the Revenue Requirement information with its Integrated Financial Forecast MH16 ("MH16") and the Rate Design and Cost of Service Study information in support of its GRA. On July 11, 2017, Manitoba Hydro filed an update to MH16 ("MH16 Update"), which maintained the same increases as in the new 10-year financial plan contained in MH16.

Manitoba Hydro's Application garnered significant public attention, including over 2,300 public comments on the Board's website, increased numbers of public presenters, and a greater number of applications for Intervener status than filed in prior proceedings – 12 in total, including from groups that had not previously participated in electricity regulatory matters before the Board.

Following a Pre-Hearing Conference held on June 12, 2018, the Board issued its procedural Order 70/17, in which the Board approved the following Interveners:

- Assembly of Manitoba Chiefs
- Business Council of Manitoba
- Consumers Coalition (Consumers' Association of Canada (Manitoba) / Winnipeg Harvest)
- Representatives of the General Service Small and General Service Medium Customer Classes
- Green Action Centre
- Keystone Agricultural Producers
- Manitoba Industrial Power Users Group
- Manitoba Keewatinowi Okimakanak

The Board also subsequently approved the intervention of the City of Winnipeg, as well as a request by Representatives of the General Service Small and General Service Medium Customer Classes and Keystone Agricultural Producers to combine their intervention.

An oral public hearing into Manitoba Hydro's request for a 7.9% interim rate increase effective August 1, 2017 was held on July 18 and 19, 2017, at which the Board heard oral submissions from approved Interveners and Manitoba Hydro. In Order 80/17, dated July 31, 2017, a majority of the Board denied an interim rate increase for Manitoba Hydro's general operations, and approved an interim rate increase of 3.36% effective August 1, 2017, with all revenues flowing to the previously established Bipole III Deferral Account to be utilized to pay the additional costs once Bipole III enters service.

The Board member who dissented in Order 80/17, Sharon McKay, would not have granted any interim rate increase.

After release of the Board's interim rate decision, Manitoba Hydro filed a revised financial plan, Integrated Financial Forecast "MH16 Update with Interim". MH16 Update with Interim incorporated the 3.36% interim rate granted by the Board for 2017/18 and revised Manitoba Hydro's 10-year financial plan to now forecast six consecutive years of 7.9% rate increases, through fiscal year ending 2024, followed by one year of a 4.54% increase in fiscal year ending 2025, and then two years of 2.0% increases. The revision to the financial plan maintains Manitoba Hydro's target of achieving a 75:25 debt-to-equity ratio in 10 years, rather than 20 years as the Utility projected previously. The cumulative rate increase in the MH16 Update with Interim 10-year plan is 77%.

The process for the Board's consideration of Manitoba Hydro's GRA also included a review of Manitoba Hydro's capital expenditures. This duty was assigned to the Board for the GRA filed in 2017 in Order in Council 92/2017 as a factor in setting rates for services in a manner that balances the interests of ratepayers and the financial health of Manitoba Hydro. In addition to a review of the reasonableness of current budgets and schedules for ongoing major capital projects, Order in Council 92/2017 gave rise to the Board's assessment of the economics of the Manitoba-Saskatchewan Transmission Line in this GRA proceeding. While the Order in Council expanded the Board's scope of review compared to previous GRA proceedings, the paragraph assigning the Board the duty of considering Manitoba Hydro's capital expenditures as a factor in setting rates reflects the Board's existing jurisdiction under its governing legislation. Beyond this, the Order in Council gave the Board greater procedural powers with respect to Manitoba Hydro's provision of information and documents related to capital expenditures, project justifications, and revenues and income records. The text of Order in Council 92/2017 is contained at Appendix B to this Order.

Along with the filing by Manitoba Hydro of its written pre-filed evidence in its Application and written responses to Minimum Filing Requirements from the Board, the Consumers Coalition, and the Manitoba Industrial Power Users Group, the process for this GRA included:

- a post-filing workshop,
- a technical conference on Business Operations Capital expenditures,
- a workshop on bill affordability and rate design,
- written responses by Manitoba Hydro to two rounds of Information Requests from the Board and Interveners,
- the filing of written pre-filed evidence by Intervener-retained expert witnesses,
- written responses by Intervener-retained expert witnesses to Information Requests from the Board and all parties, and
- Manitoba Hydro's written rebuttal evidence.

In addition, to assist in the Board's consideration of issues in the GRA, especially in light of the Order-in-Council, the Board retained the following Independent Expert Consultants to test commercially sensitive and voluminous information provided by Manitoba Hydro to the Board:

- MGF Project Services ("MGF") – construction management experts retained as the project lead to conduct a review Manitoba Hydro's major capital expenditures;
- Amplitude Consultants Ply Ltd - to assist MGF with the review of Manitoba Hydro's high voltage direct current transmission assets;

- Klohn Crippen Berger – to assist MGF with the review of Manitoba Hydro's hydroelectric generation projects;

- Daymark Energy Advisors - to review and provide an expert opinion on Manitoba Hydro's export price and revenue forecasts, electricity load forecasts, and to conduct an economic analysis of the Manitoba-Saskatchewan Transmission Project; and

- Dr. Adonis Yatchew - to examine the impacts of proposed electricity rate increases on the Manitoba economy.

The Independent Expert Consultants were independent of all parties and the Board, and were represented by independent counsel. The written and oral evidence of the Independent Expert Consultants was tested by all parties and the Board. The Independent Exert Consultants filed written evidentiary reports. One round of Information Requests was directed to the Independent Expert Consultants and Manitoba Hydro provided written rebuttal evidence to the written reports of the Independent Expert Consultants. All parties and the Board had the opportunity to conduct oral cross-examination of the Independent Expert Consultants.

The Board also adjudicated a number of process matters, including the aforementioned Intervener applications and related budget submissions, a procedural Motion regarding the process for the receipt of confidential information, multiple Motions by Manitoba Hydro for confidential treatment of information filed in the proceeding, and requests for extensions of time.

The oral evidentiary hearing of the GRA commenced on December 4, 2017. The Board heard 31 days of oral evidence, including four Manitoba Hydro witness panels, nine Intervener-retained expert witness panels, five Independent Expert Consultant witness panels, a ratepayer panel sponsored by the Consumers Coalition, Manitoba Hydro's oral rebuttal evidence, and three oral public presentation sessions along with three written public presentations. A summary of the evidence given by presenters in the proceeding is contained in Appendix C to this Order.

Following the conclusion of the oral evidentiary portion of the hearing, the Board heard closing submissions from Manitoba Hydro and Interveners and Reply argument from Manitoba Hydro on February 5, 7, 8, and 14, 2018.

A Glossary of Terms for technical terminology used in this Order is included as Appendix A.

2.0 Summary of the Board's Findings

By this Order, the Board denies Manitoba Hydro's request for a rate increase of 7.9% effective April 1, 2018. The Board approves a 3.6% average revenue increase to be recovered in Manitoba Hydro consumers' rates effective June 1, 2018. The recovery of these additional revenues is to be through rate increases at a different level for each customer class to address past and current under- and over-payment of costs by the customer classes.

Manitoba Hydro is to calculate the required rates to achieve the approved revenue increase of 3.6%, based on gradually adjusting the rates of all customer classes such that the revenues from each class will approximately align with the allocated costs to serve each class within a 10-year period. The Board anticipates that General Service Small Non-Demand, General Service Large 30-100 kV, and General Service Large >100 kV will experience a rate increase slightly less than the approved revenue increase of 3.6%, while other classes, including the Residential class, will experience rate increases slightly greater than 3.6%. The exception to this is First Nations on-reserve residential customers. The Board directs the creation of a First Nations On-Reserve Residential class and approves a 0% rate increase for this class for 2018/19. The customers in this class will therefore not experience any change to their rates as a result of this Order.

The Board further finalizes the previously approved interim rate increases of 3.36% effective August 1, 2016 and 3.36% effective August 1, 2017. Because these increases were previously granted and are already being collected, there will be no additional impact on ratepayers.

The Board directs Manitoba Hydro to provide a compliance filing pursuant to the directives in this Order. The compliance filing shall be provided by May 15, 2018 in order for Manitoba Hydro to receive consumer rate increases effective June 1, 2018.

Further to Order in Council 92/2017, in reaching its decision regarding rates, the Board considered capital expenditures by the Manitoba Hydro as a factor to support setting rates for services in a manner that balances the interests of ratepayers and the financial health of Manitoba Hydro.

2.1 Rate Increases for 2016/17, 2017/18, and 2018/19

Approval of August 1, 2016 and August 1, 2017 Interim Rate Increases

In this Order the Board approves, as final, the 3.36% interim rate increase effective August 1, 2016 (granted as interim in Order 59/16) and the 3.36% interim rate increase effective August 1, 2017 (granted as interim in Order 80/17). The dissenting member in Order 80/17, Sharon McKay, is in agreement with the decision to finalize the interim rate that was effective August 1, 2017 based on the review of the full record in the GRA hearing. Because these interim rates are already incorporated into existing rates, the Board's final approval now does not result in any additional bill impacts to ratepayers. While no party opposed the interim rates being finalized, the lack of testing by Interveners and lack of focus by Manitoba Hydro underscores the problems associated with interim rate processes. Interim rates are set without the benefit of a full evidentiary record, involve an abbreviated process, and are adjudicated against a less onerous legal standard than are final rates.

Interim rate processes are not to be used for purposes of convenience or as substitutes for the proper planning of GRAs. Both the ratepayers and the Utility benefit from a robust process that results in final rates that are just and reasonable. Future GRAs by Manitoba Hydro are not expected to be of this magnitude or duration as process improvements have and will continue to be implemented to focus the scope and expedite proceedings. In the absence of unforeseen or emergency circumstances, the Board will not consider future interim rate applications.

The Board appreciates Manitoba Hydro's desire to establish a regulatory timetable that does not require the use of interim rates. The Board is prepared to work with Manitoba Hydro and other parties towards the development of that regulatory timetable.

Denial of 7.9% Rate Increase Requested for 2018/19

Having considered all of the evidence in this GRA, the interests of Manitoba Hydro's ratepayers, and the financial health of Manitoba Hydro, this Board has determined that for the fiscal year April 1, 2018 to March 31, 2019 (also referred to as the "Test Year"), an average rate increase of 3.6% effective June 1, 2018 is just and reasonable. The Board further directs that rate increases are to be differentiated by customer class. To accurately quantify the expected bill impacts, for all customer classes at various consumption levels, Manitoba Hydro is directed to provide by May 15, 2018 a compliance filing containing the new rates, the bill impacts by customer class, and a proof of revenue. The results of the compliance filing will be included in the Board's Order approving the specific rates for 2018/19.

Manitoba Hydro did not provide evidence as to the economic impacts on customers in various sectors - such as residential, commercial, and industrial - or macroeconomic impacts of its proposed rate plan. However, expert witnesses retained by Interveners and the Board provided evidence that Manitoba Hydro's projected rate path may lead to short-term job losses and negative impacts for some industries that are more economically vulnerable, based on the electricity intensity of their production and the competitive nature of the markets into which they sell their products. Industry representatives similarly gave evidence that the projected rate path will make Manitoba businesses less competitive, will lead to corporate decisions to not make investments in Manitoba locations, and may lead to plant closures.

Residential ratepayers also voiced concerns about their ability to pay projected Manitoba Hydro rate increases and regarding the impact such increases would have on their standard of living.

Manitoba Hydro's Financial Plan

In reaching its decision, the Board finds that a particular equity level or pace to achieve such a target should not determine the rate increases approved in this GRA, particularly when Manitoba Hydro is undergoing record expansion in the value of its capital assets. There was no expert evidence independent of Manitoba Hydro before the Board that Manitoba Hydro's debt is leading to higher interest rates for the debt borrowings of the province. With rate increases in line with prior approved levels, Manitoba Hydro's financial metrics related to cash flow will be improved from those forecast following the NFAT for the 2018/19 Test Year. The Board also does not accept that rate increases should be higher in order to allow Manitoba Hydro to retire debt according to their new proposed debt management plan, which envisions using cash flow from the 7.9% projected rate increases to retire $3.1 billion in debt by 2027. While there are benefits to a shorter-term debt retirement plan, such a plan imposes a short-term cost on ratepayers that is not justified.

Reduction in Expenditures

In addition, while the Board appreciates that Manitoba Hydro has, in good faith, brought forward its concerns respecting financial risks and unforeseen events, the circumstances of this GRA for a 2018/19 rate increase do not require a rate increase of the magnitude proposed by the Utility. Rather, by this Order, the Board sets out its expectation that Manitoba Hydro will continue to reduce its costs, including capital and Operating & Administrative costs, and will also continue to maximize its export revenues.

For the 2018/19 Test Year, in advance of the analytical data-driven approaches to managing capital assets being developed by Manitoba Hydro, the Utility identified $160 million of Business Operations Capital expenditures that can be safely deferred. Business Operations Capital includes expenditures to renew failing assets, increase capacity to address load growth, and to connect new customers but does not include Major New Generation & Transmission capital expenditures. The Board does not accept that all Test Year Business Operations Capital investments are condition-driven and reasonably required for the safe and reliable operation of the system. The Board recommends that Manitoba Hydro defer $160 million of this capital spending, thus improving the Utility's cash flow. Manitoba Hydro should continue to find reductions in Business Operations Capital spending during the current period of record spending on major capital projects such as Keeyask and Bipole III.

Manitoba Hydro forecasts its Voluntary Departure Program will provide annual cost savings of $92 million once the one-time $53 million of restructuring costs have been incurred. Manitoba Hydro's additional reduction of operational positions and Supply Chain Management initiatives are further steps taken by the Utility in its continuous cost reduction efforts. The Board expects that Manitoba Hydro will continue to find savings as it assesses its operations following the conclusion of the Voluntary Departure Program.

Accounting Issues

There were several accounting-related issues that affect consumer rates and were the subject of evidence and adjudication during Manitoba Hydro's GRA.

- The Board directs that depreciation expense is to continue to be recorded using the Average Service Life methodology for rate setting purposes, without reversion to Equal Life Group in the financial forecast. The Board orders Manitoba Hydro to not amortize the difference between Average Service Life and Equal Life Group for rate setting.

- The Board accepts Manitoba Hydro's proposed treatment of the $380 million of past costs incurred with respect to the Conawapa Generating Station that is not proceeding. Manitoba Hydro proposes that the costs pertaining to the construction of Conawapa be recorded in a regulatory deferral account effective March 2018, with amortization of the costs to income on a straight line basis over a period of 30 years beginning on April 1, 2018. This treatment is appropriate because the decision to discontinue Conawapa construction was part of the NFAT review of the Utility's long-term system planning for long-lived assets. Further, this approach smooths out the impact of this one-time cost on consumers.

- The Board directs that the $20 million in annual ineligible overhead should continue to be deferred, consistent with the Board's direction in Order 73/15. With respect to the amortization period, the deferral account balance should be amortized over 34 years to match the average service life of the assets. This recognizes that the balance relates to a deferral of capital costs that are linked to services that will be provided by capital assets in the future.

- The Board directs that the Bipole III Deferral Account should begin to be recognized in domestic revenues once Bipole III enters service (which is expected in 2018/19) and amortized over a five-year period. This amortization will contribute $80 million annually to further smooth the rate increases necessitated with Bipole III entering service. Additionally, once Bipole III enters service, the approximately $180 million of annual revenues currently being deferred should no longer be deferred and instead accrue to Manitoba Hydro's general revenue.

Demand Side Management Spending

In addition, the Board finds that Manitoba Hydro's revenue requirement should be reduced to reflect lower demand side management spending. These expenditures should be reduced for rate-setting purposes from the level of spending currently incorporated in the Utility's Integrated Financial Forecast. The Board's approved rate increase directionally takes into consideration a reduction in demand side management spending as well as an increase in domestic load that will result from fewer demand side management programs.

Demand side management is a common utility strategy for reducing consumer demand for energy in order to defer the need for new generation assets. Manitoba Hydro seeks to pursue all cost-effective demand side management opportunities which are assessed against the Utility's marginal value of electricity. For 2018/19, Manitoba Hydro forecasts demand side management spending of $101.1 million. This amount was determined using a now-outdated marginal value of electricity. In light of the new lower levelized marginal value of electricity introduced in this hearing, and as acknowledged by the Utility, some of Manitoba Hydro's demand side management programming will no longer be cost-effective. Consumer rates should not, at this time, recover the costs of demand side management programs that are no longer economic, unless justified by a lower-income target market.

The Board also recommends that Manitoba Hydro reduce its demand side management spending, based on an assessment by Manitoba Hydro of the cost effectiveness of each of its demand side management programs. However, given the evidence adduced in this proceeding about energy poverty and bill affordability, it is reasonable for Manitoba Hydro to continue spending on lower-income demand side management programs.

In addition to continued Utility investment in lower-income demand side management programs, the Board recommends that the provincial government amend Efficiency Manitoba's mandate to explicitly include considerations of lower-income consumers and energy poverty.

Export Revenues and Load Forecasting

The Board finds that Manitoba Hydro's export revenue forecast is conservative. An export revenue forecast with a probabilistic goal of P50 (that is a 50% chance of being higher and a 50% chance of being lower) would reduce Manitoba Hydro's level of requested and projected rate increases.

In addition, the Board's finding in this Order that Manitoba Hydro's demand side management spending should be reduced for rate-setting purposes and recommendation that the Utility reduce its demand side management expenditures, along with the price elasticity impacts of the decrease in the overall rate increase, all else being equal, will result in a higher load forecast and higher domestic revenue.

Differentiated Rates

Manitoba Hydro's Cost of Service Study methodology was extensively reviewed and refined in the public hearing process that led to Order 164/16. The Cost of Service Study and the resultant Revenue to Cost Coverage ratios are tools available to be used by the Board when setting rates as the costs to serve a particular customer class can be compared to the revenues that are paid by that customer class.

Many utilities do not set rates in order to achieve class Revenue to Cost Coverage ratios of exact unity (i.e. revenues received by each customer class exactly recover the allocated cost to serve each customer class). Instead of unity, a 'zone of reasonableness' is used to target the Revenue to Cost Coverage ratios of the customer classes. Revenues that are within this range are deemed to represent full cost recovery. Since 1996, Manitoba Hydro has used a zone of reasonableness of 95-105%.

The General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV customer classes have Revenue to Cost Coverage ratios in excess of 105% and thus are all overpaying their allocated costs to a significant degree. The two General Service Large customer classes have been overpaying in almost every year since 1996. The Residential customer class is currently below the zone of reasonableness, and therefore underpaying its allocated costs.

Manitoba Hydro is directed to begin to implement differentiated rates for its customer classes. The differentiated rates mean customers in the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV customer classes will experience a slightly lower rate increase than the average rate increase approved by the Board. Customers in the Residential, General Service Small Demand, General Service Medium, and Area & Roadway Lighting classes will experience a slightly higher rate increase in order for Manitoba Hydro to collect the approved revenue requirement based on the average rate increase approved by the Board. For the 2018/19 Test Year rates, Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness, using the alternative methodology to calculate the Revenue to Cost Coverage ratios by treating export revenues as a reduction to allocated costs. This approach to the implementation of differentiated rates is consistent with the principle of gradualism and limits the revenue recovery responsibility of the other customer classes, while maintaining overall revenue neutrality.

Manitoba Hydro is directed to include in its compliance filing for 2018/19 rates differentiated rates by customer class consistent with the Board's direction in this Order. The compliance filing is to be provided by May 15, 2018. The results of that compliance filing will be published in the Board's Order approving the specific customer class rates.

Bill Affordability

Although Manitoba Hydro's rates are among the lowest in North America, this does not mean that all Manitoba ratepayers can equally afford to pay their electricity bills. The Board has long been concerned with utility bill affordability issues. Evidence with respect to energy poverty in the province of Manitoba has been brought before the Board for at least a decade. The Board recognizes that Manitoba Hydro has, over time, developed programs to assist customers in managing their energy consumption, thereby reducing individual customer bills, and such programs include targeted support for lower-income customers. However, the Board has consistently expressed concern that measures focused on energy efficiency implemented by Manitoba Hydro to date, while commendable, have been insufficient to address the energy burden faced by lower-income customers. This is particularly the case in a time of major capital construction by the Utility, which has and is forecast to continue to put upward pressure on electricity rates at a level greater than the rate of inflation.

The Board finds that it has legal jurisdiction under its governing statutory framework to order a bill affordability program such as a lower-income rate, and to take into account affordability as a factor in setting just and reasonable rates.

The Board agrees with Manitoba Hydro's President and Chief Executive Officer that there is an important role for governments in this area. The Board recommends that the provincial government introduce a comprehensive bill affordability program run by a government department to address energy poverty issues faced by Manitobans throughout the province. The Board heard evidence that there is a long-standing need to address this issue and the provincial government is best situated to do so in a comprehensive fashion, given its social program infrastructure that is already in place.

The Board reiterates the recommendation in the NFAT Report that the provincial government should use some of the revenues it receives from Keeyask to fund a comprehensive bill affordability program.

First Nations on Reserve Residential Customer Class

A majority of the Board directs Manitoba Hydro to establish a First Nations On-Reserve Residential customer class for existing First Nations reserves and that this customer class will receive a 0% rate increase for the 2018/19 Test Year, such that the rate for this customer class will be maintained at the August 1, 2017 approved residential rate. The 0% rate increase for 2018/19 is also to apply to First Nations diesel zone residential customers. This decision by the Board to create a new customer class is not unanimous and there is a dissenting decision from Board member Larry Ring in this Order.

In this Order, the Board concurs with Manitoba Hydro's President and Chief Executive Officer that electricity rates and the resulting bills place a particularly heavy burden on First Nations communities due to inadequate housing infrastructure and the absolute levels of poverty. As noted by Manitoba Hydro's President and Chief Executive Officer, there may not be a single solution to this multifaceted bill affordability problem. While government has a role to play in addressing the issue of affordability, so too does Manitoba Hydro and rate design can assist the Utility in fulfilling its role.

The Board concludes that, under its mandate to set rates in the public interest, the Board can and should play a part in addressing bill affordability.

An appropriate starting point for bill affordability in Manitoba is a program targeted at on-reserve ratepayers, specifically through the creation of a First Nations On-Reserve Residential customer class with a differentiated rate to address energy poverty.

The creation of this new customer class is justified by the need to address energy poverty on-reserve, supported by evidence that 96% of First Nations people on-reserve live in poverty and that reserves in Manitoba have the highest rates of child poverty in Canada. In addition, the poor housing stock on reserves in Manitoba and the fact that the vast majority of on-reserve First Nations residential customers (61 out of 63 First Nations communities) have no access to the more economical option of natural gas for heating exacerbate the issue of energy poverty.

The new customer class and related affordability measure of a 0% rate increase are also consistent with the principle of reconciliation. As defined in *The Path to Reconciliation Act*, reconciliation is the ongoing process of establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples in order to build trust, affirm historical agreements, address healing, and create a more equitable and inclusive society.

Manitoba Hydro is kept whole because the cost of the 0% rate increase for this new customer class has been factored into the level of the average general rate increase granted for the Test Year to all other customer classes. The Board is fully aware that there will be some obvious anomalies created where one household on-reserve will receive a lower rate than a nearby off-reserve household living in similar circumstances. This new customer class is a limited measure designed to reach a targeted group experiencing a high degree of poverty. The anomalies that result from this measure are best addressed by a more wide-reaching government bill affordability program. The Board envisions that, with the introduction of a comprehensive government bill affordability program, the new First Nations On-Reserve Residential customer class and lower rate built into the 2018/19 Test Year may no longer be required.

2.2 Payments to Government

Manitoba Hydro makes payments to the Province of Manitoba for water and land rentals, debt guarantees, and capital and other taxes. Manitoba Hydro also pays grants in lieu of taxes to municipalities. For the fiscal year that ends March 31, 2019, Manitoba Hydro forecasts that it will pay $433 million to governments, with $406 million to be paid to the Province of Manitoba. The evidence in the public hearing demonstrated that, excluding payments made to municipal governments, approximately 17 to 18 cents of each dollar of gross revenue is directed by Manitoba Hydro to the Province of Manitoba.

Manitoba Hydro's major capital expansion places upward pressure on rates, including due to the Utility's increased obligations to the provincial government. With respect to Keeyask, after it is fully in-service Manitoba Hydro will pay an approximate $140 million per year to the Province of Manitoba on account of water rentals, debt guarantee fees, and capital and other taxes. As noted by the Board in its 2014 NFAT Report:

> *While ratepayers will shoulder a significant rate burden over the next 20 years, the Province of Manitoba will reap substantial incremental revenues through capital tax and water rental payments from Manitoba Hydro as a result of the Keeyask Project. The Province should give serious consideration to using some of these incremental revenues to fund energy affordability programs targeted to vulnerable consumers, particularly lower income consumers and customers residing in northern and First Nations communities. This could involve rate relief programs as well as targeted DSM programs.*

Previously, the provincial government indicated it would consider this recommendation from the NFAT Report. The Board continues to be of the view that the provincial government should use some of the revenues that would otherwise accrue as a result of Keeyask in order to fund a comprehensive a bill affordability program.

With respect to Bipole III, the project was initially scoped, designed, and engineered by Manitoba Hydro using the most cost effective route. While the majority of Manitobans are both taxpayers and ratepayers, there is an important distinction. Domestic ratepayers are ultimately responsible for the costs of operating Manitoba Hydro's system, including recovering the costs of Manitoba Hydro's major capital projects once the assets are in service. As a result of a policy decision by the provincial government, the routing of Bipole III was changed to a western route at an additional cost of approximately $900 million. This decision created a $900 million burden for ratepayers with no apparent technical benefit for the new route. The Board considers that this was a policy decision of government that should be a cost to taxpayers, not Manitoba Hydro's ratepayers.

The Board therefore recommends that the provincial government suspend payment of the annual Bipole III debt guarantee fee and capital taxes made by Manitoba Hydro to the provincial government starting with the 2019 fiscal year. Manitoba Hydro – and ultimately the ratepayer - should be reimbursed through suspension of such payments until the $900 million burden of a policy decision made by government is satisfied, estimated at this time to be in 13 years.

Finally, the inter-relationship between Manitoba Hydro and the provincial government will be enhanced with provincial carbon pricing. In the transition to a low-carbon economy, the Province of Manitoba does and will benefit from the strength of its clean hydroelectric resources. As the provincial government will receive revenue from the planned carbon tax, the Board further recommends that the provincial government transfer a portion of the carbon tax revenues to Manitoba Hydro to strengthen Manitoba Hydro's financial health, which may allow for lower consumer rate increases.

2.3 Capital Project Review per Order in Council 92/2017

On April 5, 2017, by Order in Council 92/2017, for the GRA anticipated to be filed by Manitoba Hydro in 2017, the Board was assigned the duty of considering capital expenditures made by the Manitoba Hydro-Electric Board as a factor in the Board reaching a decision regarding setting Manitoba Hydro's rates for services in a manner that balances the interests of ratepayers and the financial health of the Utility.

The Board's review of Manitoba Hydro's capital expenditures included the following projects:

- Keeyask, with a focus on the reasonableness of Manitoba Hydro's capital cost estimates filed in support of the Utility's financial forecasts. The timeframe for the review began with the cost estimates presented at the NFAT;
- Bipole III, also focused on the reasonableness of the capital cost estimates beginning with the initial western routing control budget for Bipole III;

- The Manitoba-Minnesota Transmission Project ("MMTP") and the Great Northern Transmission Line ("GNTL"), also focused on the reasonableness of the capital cost estimates; and.
- The Manitoba-Saskatchewan Transmission Project and related SaskPower export sale, focused on whether the project is economic.

The Board's goal in its review was to gain an understanding of the reasons for past cost increases in order to better understand the forecasts of future costs. The importance of obtaining an accurate forecast of capital costs for these large projects was highlighted by evidence from Manitoba Hydro that a $1 billion increase in capital costs over its current projections would require 0.43% annual consumer rate increases for 10 years, over and above any other rate increase required for the Utility's operations, to achieve the same retained earnings level.

Major Capital Projects and Rate Setting

For rate setting purposes in this GRA, the Board accepts, as incorporated by Manitoba Hydro into its Integrated Financial Forecast, the major capital project budget amounts and construction schedules for Keeyask, Bipole III, the Manitoba-Minnesota Transmission Project, the Great Northern Transmission Line, and the Manitoba-Saskatchewan Transmission Project.

In this Order, the Board reaches several conclusions related to Manitoba Hydro's major capital projects that may assist in future capital projects.

Manitoba Hydro has been approving projects too early in the process, without sufficient development of scope, design, and engineering. The Board recognizes that, with additional scope and engineering development prior to advancing the capital project for financial and economic analysis and subsequent executive approval, there will be additional front-end costs. In the Board's view, that would be money well spent as it will allow a more informed decision by Manitoba Hydro's Executive.

The Board finds there is merit in Manitoba Hydro considering the "stage gate" approach put forward by MGF, in order to improve its past performance on cost estimating and completing projects on budget. The 'stage gate' concept is that a project does not move from one stage to the next – that is, receive approval to go to the next stage – until a set of criteria is satisfied. The Board recommends that Manitoba Hydro engage an external consultant to assist in studying this matter.

Review of Major Capital Project Planning and Construction

Keeyask

The primary reasons for the Keeyask cost increase from $6.5 billion to $8.7 billion are due to: unachievable productivity levels in the general civil contractor's bid, slow start up in the 2016 construction season when the first permanent concrete was poured, and geotechnical issues with the river bed. The Board finds the root cause for the cost overrun relates to the nature of the cost reimbursable payment structure in the Keeyask general civil contract ("GCC"), which was not sufficient to drive the general civil contractor to achieve the productivity levels contained in its original bid for the Keeyask work. Manitoba Hydro expected that tying the contractor's profit to the target price in the general civil contract would provide sufficient motivation to the contractor to meet the productivity levels in its bid, but that did not occur. It further appears that Manitoba Hydro never contemplated that the contractor's profit could erode to zero so early in the project. Once the profit eroded to zero, with no chance of re-establishing profit, the contractor had little or zero motivation to progress the project expediently. In the Board's view, this was a principal failing of the original GCC. Underpinning the reason for the profit eroding to zero so early in the project was the fact that the general civil contractor bid unachievable productivity levels. Those unachievable productivity levels formed the basis for an unrealistic target price and an unrealistic original cost estimate.

Manitoba Hydro requires a 10% improvement in productivity by the general civil contractor to meet its $8.7 billion control budget. The Independent Expert Consultants retained in this hearing evaluated Manitoba Hydro's progress to date on Keeyask and in their opinion the final cost of Keeyask will be in the range of $9.5 billion to $10.5 billion. According to the Independent Expert Consultants, unless Manitoba Hydro takes control of the Keeyask project and works with the general civil contractor to improve productivity, the final cost of Keeyask will approach $10.5 billion due in part to the cost reimbursable pricing structure in the general civil contract. The Independent Expert Consultants also made useful recommendations that Manitoba Hydro should consider implementing, and indeed, in part already has implemented. Manitoba Hydro gave evidence that the 10% improvement required is attainable and that the $8.7 billion control budget remains reasonable.

Manitoba Hydro explained that it has taken steps to mitigate schedule and productivity issues, including through retaining external consultants. The Board's expectation is that Manitoba Hydro will closely monitor and take steps to improve productivity in order to achieve the 10% improvement in productivity required to meet the $8.7 billion control budget and construction schedule. There was evidence in the GRA that Manitoba Hydro has achieved milestones in the construction of Keeyask, including that the project is on track to divert the river through the spillway in July 2018 to permit work to begin on the south dam.

For future projects, if the cost reimbursable payment structure of a contract is used, effective oversight of the contractor must be exercised. The results for Keeyask indicate there was not effective oversight under the cost reimbursable contract arrangement.

Bipole III

With respect to Bipole III, Manitoba Hydro undertook unreasonable risk when it developed its $3.28 billion Bipole III cost estimate in 2011. It appears that Manitoba Hydro had rejected its 2009 internal cost estimate of $3.95 billion, based on what was referred to as the “classic” line commutated conversion technology for the HVDC converter stations, in order to try to take advantage of new, unproven voltage source conversion technology. Manitoba Hydro compounded this risk by significantly reducing the contingency amounts.

The provincial government excluded Bipole III from the scope of the NFAT review; however, all of the development plans considered at the NFAT included Bipole III at a projected cost of $3.28 billion. The Board finds that, had a more realistic cost of Bipole III been used in the financial analyses, Manitoba Hydro’s debt under all development plans would have been higher and would be closer to the current projections of debt, as discussed in other sections of this Order.

Manitoba-Minnesota Transmission Project and the Great Northern Transmission Line

The Board accepts the forecasts of costs and construction schedules by Manitoba Hydro and Minnesota Power are acceptable for the purpose setting the approved rates for the 2018/19 Test Year.

Manitoba-Saskatchewan Transmission Line

The Board finds that the Manitoba-Saskatchewan Transmission Line project remains economic at this point in time. This transmission line from Birtle, Manitoba to the Saskatchewan border facilitates a 100 MW power sale agreement with SaskPower. The Board supports Manitoba Hydro's decision to develop firm export sales to other Canadian jurisdictions including to the west.

The Board's review of the Manitoba-Saskatchewan Transmission Line project in this proceeding is a precedent for how independent reviews can be conducted of Manitoba Hydro's capital projects. The Board continues to be of the view that in addition to its rate setting approval it should have statutory authority to approve Manitoba Hydro's capital expenditures, which is jurisdiction the Board now lacks.

3.0 Background

3.1 Previous Rate Increases

In Order 43/13, the Board established a deferral account to assist in funding Bipole III in-service costs and to assist in smoothing the rate impacts of Bipole III. The Bipole III Deferral Account is a means by which to gradually increase rates and to partially fund the depreciation, interest, and operating costs of Bipole III to avoid rate shock at the time the asset enters service. In subsequent Orders, the Board directed additional rate increases to the Deferral Account. To date, the cumulative compounded total of the rate increases directed by the Board to the Bipole III Deferral Account is 11.6%. The amounts directed to the Deferral Account have increased and have now reached approximately $180 million on an annual basis. The Bipole III Deferral Account is projected to reach approximately $400 million by the time Bipole III enters service

Payment of the costs associated with the Utility's new major capital projects (excluding Bipole III) was considered at the Board's 2014 NFAT review of Manitoba Hydro's development plans, during the 2014/15 & 2015/16 GRA, as well in the August 1, 2016 and August 1, 2017 interim rate proceedings initiated by Manitoba Hydro.

In Order 73/15, the Board finalized the interim 2.75% rate increase effective May 1, 2014 and granted a final 3.95% rate increase effective August 1, 2015. The total 3.95% rate increase was separated into a 2.15% increase for Manitoba Hydro's general operations and a 1.8% increase, the revenues from which were to be placed into the Bipole III Deferral Account.

In November of 2015, Manitoba Hydro filed an interim rate Application, seeking an interim rate increase of 3.95% effective April 1, 2016. In Order 59/16, the Board granted a 3.36% interim rate increase effective August 1, 2016 for the purpose of collecting additional revenue in the Bipole III Deferral Account. The Board found that, since Order 73/15, Manitoba Hydro's long-term financial projections had significantly improved and the Utility did not require additional revenues from a rate increase to obtain a positive net income for 2016/17. The Board concluded that the public interest would be best served if the entirety of the interim rate increase were to flow into the Bipole III Deferral Account to reduce expected rate shock when Bipole III and Keeyask enter service. The Board further directed Manitoba Hydro to file a GRA for the 2016/17 and 2017/18 years by no later than December 1, 2016, in recognition of the importance of GRAs being heard on a regular basis. The Board stated that interim rate applications ought not be the norm for Manitoba Hydro as such applications do not offer the same level of public review as a GRA.

In Order 80/17, as part of the current GRA process, the Board denied Manitoba Hydro's Application for a 7.9% interim rate increase to be effective August 1, 2017. A majority of the Board approved a 3.36% interim rate increase, with all additional revenue generated from the interim rate increase to flow into the Bipole III Deferral Account. In dissent, Board member Sharon McKay rejected any rate increase.

3.2 Manitoba Hydro's Previous Financial Plans

Manitoba Hydro's 2014 Integrated Financial Forecast MH14, which underpinned the 2014/15 & 2015/16 GRA, consisted of a 20-year rate plan of annual rate increases of 3.95% through 2031 and 2% thereafter, achieving a 25% equity level at the end of the 20-year period. The MH14 forecast projected that Manitoba Hydro would incur losses of $980 million from 2019 to 2026, the time period when Bipole III and Keeyask were forecast to enter into service. As noted above, in Order 73/15, the Board ordered a 3.95% rate increase for 2015/16, including a 2.15% increase for Manitoba Hydro's general operations and an additional 1.8% increase that was not required for operations but which the Board determined would flow into the Bipole III Deferral Account.

Similarly, the 2015 Integrated Financial Forecast MH15 also projected equal annual rate increases of 3.95% through 2029, followed by 2% annual increases thereafter, and achievement of a 25% equity level in the year 2032. The MH15 forecast reflected an improved financial position with losses incurred in only three years, totalling $58 million. As noted above, in Order 59/16, the Board concluded that Manitoba Hydro's financial projections had significantly improved and directed that the entirety of the 3.36% rate increase would flow into the Bipole III Deferral Account as it was not required for the Utility's operations.

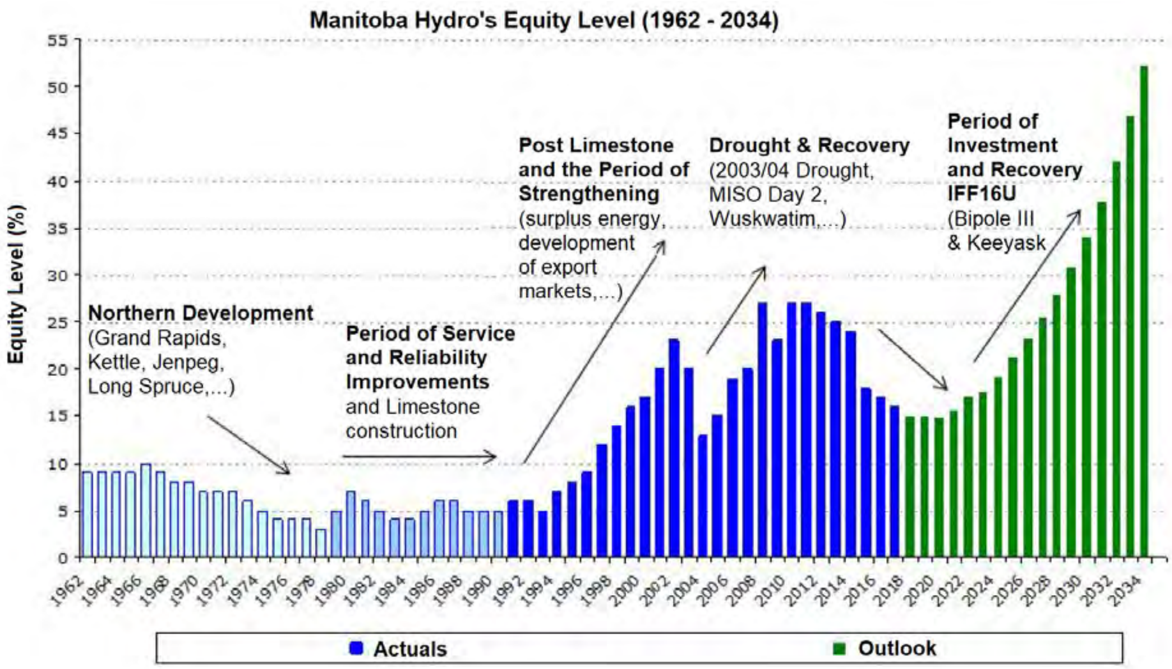
These previous plans followed rate projections used by Manitoba Hydro in the NFAT review of equal annual rate increases of approximately 4%.

Projected rate increases and the level of Retained Earnings since the NFAT have evolved over time. The chart below sets out the Retained Earnings achieved as a result of projected rate increases over 20 years from Integrated Financial Forecasts dating back to 2012, as well as in the forecast underpinning the current GRA. The previous Integrated Financial Forecasts projected rate increases predominately at the 3.95% level, while the projections in MH16 Update with Interim include six years of annual rate increases of 7.9%, one year of a 4.54% rate increase, and 2% rate increases thereafter. The table shows the earlier achievement of a 25% equity level and increased Retained Earnings as a result of Manitoba Hydro's new financial plan as compared to previous plans.

	Integrated Financial Forecast (“IFF”) MH12		IFF MH13		IFF MH14		IFF MH15		IFF MH16 Update with Interim (20 year)	
	Equity %	Retained Earnings ($Millions)	Equity %	Retained Earnings ($Millions)	Equity %	Retained Earnings ($Millions)	Equity %	Retained Earnings ($Millions)	Equity %	Retained Earnings ($Millions)
2013	25%	2,442								
2014	22%	2,502	24%	2,584						
2015	17%	2,295	22%	2,638	22%	2,717				
2016	15%	2,368	18%	2,592	18%	2,778	15%	2,612		
2017	14%	2,425	16%	2,611	16%	2,837	14%	2,641	16%	2,749
2018	13%	2,444	15%	2,599	15%	2,902	14%	2,703	15%	2,842
2019	12%	2,376	14%	2,533	14%	2,812	13%	2,663	14%	3,053
2020	11%	2,368	13%	2,502	13%	2,696	13%	2,684	14%	3,258
2021	10%	2,361	12%	2,427	12%	2,518	13%	2,671	15%	3,606
2022	10%	2,413	11%	2,366	11%	2,312	12%	2,677	17%	4,124
2023	10%	2,576	11%	2,372	10%	2,126	12%	2,673	17%	4,557
2024	10%	2,804	11%	2,440	10%	2,001	12%	2,729	19%	4,969
2025	11%	3,105	11%	2,572	10%	1,948	13%	2,858	21%	5,498
2026	12%	3,463	11%	2,741	10%	1,924	13%	2,987	23%	5,987
2027	13%	3,881	11%	3,022	10%	2,007	14%	3,219	25%	6,564
2028	14%	4,251	12%	3,299	11%	2,161	16%	3,538	27%	7,214
2029	16%	4,785	13%	3,558	12%	2,427	17%	3,977	30%	7,969
2030	18%	5,495	15%	3,967	14%	2,826	20%	4,497	33%	8,842
2031	20%	6,330	16%	4,499	16%	3,361	22%	5,089	37%	9,831
2032	24%	7,384	18%	5,241	19%	4,008	25%	5,784	41%	10,977
2033			22%	6,193	22%	4,732	28%	6,553	46%	12,257
2034					25%	5,557	31%	7,402	52%	13,680
2035							35%	8,348	57%	15,259
2036									64%	16,927

Manitoba Hydro explained in this GRA that the rate strategy contained in the filed financial projections “essentially compresses the previously projected 3.95% annual rate increases which were planned until 2028/29, into the next five-year period”. As can be seen in the graph that follows, Manitoba Hydro was last at a 25% equity level in the years before construction on the $8.7 billion Keeyask and $5 billion Bipole III projects began. This is similar to the situation experienced by Manitoba Hydro at other times of major capital construction, although the equity levels have not dipped to those experienced at the time the 1350 MW Limestone Generating Station entered service in the early 1990s.

The graph below includes both the actual equity levels achieved since 1962 (shown in blue) and the projected outlook arising from Manitoba Hydro's MH16 Update with Interim projected rates (shown in green).



Source: MIPUG/MH I-2(h-i); MIPUG-26 pg 10

Since Limestone entered service, Manitoba Hydro's retained earnings (also considered as 'equity') have grown to a record level, as shown in the table below. In addition, the Utility's DBRS credit rating has improved to and been maintained at "A(high)". At the same time, Manitoba Hydro's debt financing has increased to meet the construction costs of Keeyask and Bipole III, causing the equity level to decline.

Year	Equity %	Total MH Assets ($Million)	Total MH Net Debt ($Million)	MH Retained Earnings ($Million)	DBRS Bond Rating
1992	6	6,505	4,972	183	A
1993	5	6,025	4,533	159	A
1994	7	6,543	4,948	228	A
1995	8	6,449	4,507	284	A
1996	9	6,737	4,685	354	A
1997	12	7,133	4,493	455	A
1998	14	7,617	4,559	566	A
1999	16	7,866	4,772	666	A
2000	17	8,692	5,488	818	A
2001	20	9,966	6,114	1,088	A
2002	23	10,405	6,146	1,302	A
2003	20	10,234	6,320	1,170	A (high)
2004	13	9,903	6,675	734	A (high)
2005	15	9,952	6,642	870	A (high)
2006	19	10,482	6,614	1,285	A (high)
2007	20	10,922	6,597	1,407	A (high)
2008	27	11,766	6,853	1,822	A (high)
2009	23	11,547	7,521	2,076	A (high)
2010	27	12,437	8,155	2,239	A (high)
2011	27	12,882	8,365	2,389	A (high)
2012	26	13,791	9,010	2,450	A (high)
2013	25	14,542	9,633	2,542	A (high)
2014	24	15,639	10,757	2,716	A (high)
2015	18	17,567	12,566	2,779	A (high)
2016	17	19,780	14,527	2,828	A (high)
2017	16	22,338	16,438	2,899	A (high)

Source: MFR14 and Manitoba Hydro Annual Report

The Board learned in this proceeding that the Utility's rate requests in those previous hearings before this Board were capped at 3.95% by the Manitoba Hydro-Electric Board. In its rate increase request for the Test Year, Manitoba Hydro's new management now seeks rate increases of 7.9% for all customer classes.

4.0 Manitoba Hydro's New Financial Plan

The two concerns that must be balanced by the Board in setting just and reasonable rates are the interests of the Utility's ratepayers and the financial health of Manitoba Hydro. Regarding the latter, central to the Application and the rate requests by Manitoba Hydro in this GRA is the Utility's assertion that the "old financial plan has now failed" as it was not adequate and was far too risky. This assertion underpins the new financial plan presented by Manitoba Hydro in this GRA, which features:

- a 10-year trajectory to achieve a 25% equity level,
- achievement of $6.5 billion in retained earnings in a 10-year period to safeguard against the risks faced by Manitoba Hydro,
- improved cash flow from operations,
- higher net income, and
- a proposed debt management strategy aimed at removing approximately $4 billion of debt from the Utility's balance sheet.

The requested 7.9% rate increase for the 2018/19 Test Year is Manitoba Hydro's first step in its new financial plan.

In Manitoba Hydro's view, this new financial plan will allow for rate stability with the potential for lower rates for consumer bills in the long run (as opposed to up to 20 years of the previously projected approximately annual 4% increases). According to the Utility, its new financial plan will also avoid unfairly placing an unsustainable debt burden on future ratepayers, while managing the risk of rate shock to consumers in the event of adverse conditions such as drought and/or rising interest rates.

Manitoba Hydro acknowledged that its new financial plan and increased rates in the plan will result in a transfer of money from ratepayers to the Utility at a greater level than previous plans. Further, Morrison Park Advisors, an expert witness jointly retained by the Consumers Coalition and the Manitoba Industrial Power Users Group, gave evidence that, because Manitoba Hydro does not have shareholders to contribute equity, ratepayers are ultimately responsible for all the costs of building Manitoba Hydro's level of equity through rates. Morrison Park Advisors' view is that customer contributions – in the form of bills paid by customers - have a cost of capital for individual ratepayers, and for some customers, that cost of capital can be quite high. Morrison Park Advisors' evidence was that, from the perspective of the ratepayers who are the ultimate funders of all of the Utility's operations, equity is essentially "dead money": it earns no return, but nevertheless has been taken out of the hands of the ratepayers who could otherwise use it. Moreover, Morrison Park Advisors stated that, because Manitoba Hydro is a Crown Utility that does not have equity investors at risk for its performance, Manitoba Hydro could theoretically be 100% debt financed.

In response to Manitoba Hydro's presentation of its new financial plan in this GRA, residential ratepayers, organizations, and representatives of business and industry gave evidence that lower rate increases over a longer period of time are preferred to maintain the financial health of Manitoba Hydro while providing predictability and stability for ratepayers. As Ms. Emily Mayham testified in her oral presentation, "I would prefer the lower rate increases for a longer period of time because it's predictable. I'm able to adjust and adapt as needed." Similarly, Mr. Dan Mazier, President of Keystone Agricultural Producers, gave evidence that he does not hold much weight in the suggestion that there will be a reduction in electricity rates in 10 years, and therefore prefers a more stable approach to rate increases over a longer period of time. The Chair of the Manitoba Industrial Power Users Group testified that industrial companies "seek predictable energy rates that allow us to manage our business and plan for our future" and that Manitoba Hydro's projected 10-year rate plan will impact industrial companies' "decision-making regarding future investment in these operations and, for some, it threatens their very future."

Against this backdrop, evaluating Manitoba Hydro's assertion that a new financial plan is needed requires consideration by the Board of the issues identified by Manitoba Hydro of:

- the Utility's equity level as measured by the debt-to-equity ratio;
- the Utility's financial reserves;
- the Utility's cash flow as measured by Manitoba Hydro's new cash flow analysis as well as the traditional financial metrics of interest coverage and capital coverage;
- the Utility's debt management strategy; and
- the credit ratings of the Province of Manitoba and Manitoba Hydro.

4.1 Manitoba Hydro's Position

Manitoba Hydro's new 10-year financial plan seeks to reduce debt and increase equity through the revenues generated from six successive annual 7.9% consumer rate increases, followed by a 4.54% rate increase, followed by two years of inflationary rate increases of 2% each, in order to return Manitoba Hydro to a 25% equity level in 10 years. The Utility believes this to be the appropriate balance between addressing its financial risks and managing the impact of proposed rate increases on customers.

The new financial plan presented by Manitoba Hydro is a 10-year plan, with a 25% equity level being achieved in 2026/27. However, in response to Minimum Filing Requirements and Information Requests, Manitoba Hydro filed 20-year forecasts. The 20-year forecast included in the MH16 Update with Interim reflects an equity level exceeding 25% and achieving 64% by 2036, but Manitoba Hydro believes that limited value should be placed on forecasts that extend beyond a 10-year period. Manitoba Hydro states that it is focused on a 10-year financial plan and does not intend to achieve an equity level of that size over 20 years.

Manitoba Hydro’s position is that the rates that will be appropriate after the tenth year of its plan will be a function of events between today and 2027, but a rate reduction may be one option that could be considered among others. One forecast scenario filed by Manitoba Hydro at the request of the Board was designed to maintain 25% equity following achievement of that level in 2026/27 and includes a forecast rate decrease of 19.75% for 2027/28. An alternative scenario requested by the Board incorporated equal annual rate decreases of 5.76% in the three years from 2027/28 to 2029/30 in order to reduce forecast net income to the range of $200 million per year, while yet another scenario modeled 0% rate increases beginning in 2027/28 and every year after.

In its new financial plan, Manitoba Hydro seeks a prospective level of income and cash flow that, in the Utility’s view, would restore its financial strength while also being capable of enduring drought or material negative deviations from export price and interest forecasts without requiring emergency relief from ratepayers. Recognizing that the requested Test Year rate increases and projected future rate increases in its 10-year financial plan are materially greater than in previous GRAs, Manitoba Hydro included in its key reasons for the rate increases that:

- its current and projected financial situation, absent the proposed rate increases, represents an untenable risk to both the financial sustainability of the Utility and the overall economic health of the Province of Manitoba. The credit rating of the Province has been downgraded by both major international rating agencies and the Province has diminished capacity to absorb inclusion of Manitoba Hydro's debt in its consolidated credit profile without risking further erosion of the Province's credit standing;

- previous financial plans and requested rate increases did not adequately prepare Manitoba Hydro to absorb the significant increase in operating and borrowing costs that result from the completion of Keeyask and Bipole III. The cost overruns for Keeyask and Bipole III have increased by $2.2 billion and $400 million respectively, necessitating further increases in gross borrowing under the financial plan;

- inclusive of cash interest on reliability projects and Business Operations Capital expenditures, Manitoba Hydro has been and, without substantial rate increases, will continue to be cash flow negative on its core operations;

- since the last GRA, the financial outlook of Manitoba Hydro has deteriorated because of a reduced outlook for domestic load growth, lessening the opportunity for Manitoba Hydro to look to growth to cure its financial challenges; and

- since the last GRA, there has been continued delay in the recovery of opportunity export prices. Export price growth expectations have been tempered from past forecasts as the outlook for sustained low fossil fuel costs perpetuates.

Manitoba Hydro's financial plan involves its three self-imposed key financial targets that provide a measure of the Utility's overall financial strength. Those financial targets may also be useful to guide proposed rate increases, although consumer rates are not set to produce a target return on equity for the Crown-owned public utility. The financial ratio targets approved by the Manitoba Hydro-Electric Board are:

- A minimum debt-to-equity ratio of a 75% debt level to a 25% equity level. This ratio measures the portion of assets that are financed by internally generated funds (referred to as equity) rather than being financed by debt;

- The cash flow financial metric of an interest coverage ratio of earnings before interest, taxes, depreciation, and amortization ("EBITDA") greater than 1.80. This ratio measures the Utility's ability to meet interest payment obligations with cash flow as reported in Manitoba Hydro's cash based financial statements; and

- The cash flow financial metric of a capital coverage ratio of greater than 1.20. This ratio, which is unique to Manitoba Hydro, is a measure of the ability of cash flow from Manitoba Hydro's operations to fund Business Operations Capital expenditures, excluding consideration of spending and capitalized interest on major capital projects. Where the ratio falls below 1.0, Manitoba Hydro will have to borrow to fund Business Operations Capital spending. Manitoba Hydro notes that, as the Utility continues through a phase of unprecedented investment, the exclusion of the capitalized interest on major capital expenditures from the metric overstates the capital coverage ratio.

Debt-to-Equity Ratio

The debt-to-equity ratio is a measure of the portion of assets that are financed by Manitoba Hydro's internally generated funds, rather than debt. The measurement evaluates the relationship of debt (comprised of long-term debt, sinking fund investment, short-term debt, and short-term investments) to equity (comprised of Retained Earnings, customer contributions, Accumulated Other Comprehensive Income, and Non-Controlling Interest) through a comparison of Manitoba Hydro's net debt to total capital. The debt-to-equity ratio identifies the capital structure of the Utility.

Specifically, and as noted in the Board's 2014 NFAT Report:

> *The debt-to-equity ratio is a long-term target, which serves as a financial guideline only, not an annual requirement. In 2013 it stood at 75/25. Manitoba*

Hydro expects a significant deterioration in this ratio over the next 20 years to about 90/10 in the 2020s as debt levels increase because of Bipole III and the Preferred Development Plan.

In this GRA, Manitoba Hydro acknowledges that past applications and testimony indicated a willingness by the Utility to tolerate a relaxation to below a15% equity level during the current phase of debt-funded capital investment (primarily for Keeyask and Bipole III). In past applications, Manitoba Hydro also proposed a financial plan that would have seen an approximate 15-year to 20-year time frame for restoring a 25% equity level. According to Manitoba Hydro, conditions and outlook have changed significantly since the last GRA, including with respect to the Utility's governance with the appointments of a new President and Chief Executive Officer ("CEO") in December 2015, a new Board of Directors in early May 2016, and a new Chief Finance and Strategy Officer in September 2016.

Manitoba Hydro's evidence is that the applications previously filed by the Utility were "wrong" and that the Manitoba Hydro-Electric Board and the Utility's senior management were required to chart a new financial plan for the Utility. The Manitoba Hydro-Electric Board's tolerance for risk has changed. It is now Manitoba Hydro's view that a path back to a 25% equity level of longer than 10 years is too risky.

Financial Reserves

Manitoba Hydro's financial reserves, or Retained Earnings, are the sum of all profits received by Manitoba Hydro through customer revenues since the Utility's inception, primarily from domestic ratepayers but also from export sales. Manitoba Hydro's financial reserves are not cash and are not retained in a bank account, but rather have been reinvested back into the Utility, including through reducing the amount of new borrowing requirements. Put another way, equity and Retained Earnings are debt that is avoided. Manitoba Hydro's Retained Earnings are included in the Utility's measurement of its total equity level.

The requested and projected 7.9% annual rate increases included in Manitoba Hydro's 10-year financial plan are to provide the Utility with cash flow to ensure that it is capable of enduring drought or material negative deviations from forecast without requiring emergency rate increases from ratepayers. Under its cost of service regulatory regime, Manitoba Hydro considers its non-cash Retained Earnings as a temporary reserve to allow for cost recoveries and rates to be smoothed out over time.

In Integrated Financial Forecast MH16 Update with Interim, Manitoba Hydro's Retained Earnings are at a record-high level of $2.75 billion. By 2027, the end of Manitoba Hydro's 10-year financial plan, Retained Earnings are forecast to more than double to $6.56 billion. Under the 20-year MH16 Update with Interim forecast, following 2027 a decade of 2% rate increases results in a forecast of $16.93 billion of Retained Earnings and a 64% equity level in 2036.

Manitoba Hydro identifies that drought, rising interest rates, and export prices are the largest risk items that could negatively affect Manitoba Hydro's Retained Earnings. Manitoba Hydro estimates that the Retained Earnings impact of a five-year drought beginning in 2019/20 is approximately $1.4 billion. Due to the quantum of Manitoba Hydro's planned debt, the Utility sees rising interest rates as a greater risk than drought.

Cash Flow from Operations

Manitoba Hydro constructed a new analysis of the cash flow metric to demonstrate that, without the proposed rate increases in Manitoba Hydro's 10-year financial plan, the Utility will be unable to cover both its Business Operations Capital expenditures and its newly defined capital requirements.

According to Manitoba Hydro, capital spending to maintain normal operation and growth of the system (excluding major projects such as Keeyask and Bipole III) is in excess of what is presently being recovered annually in the depreciation expense portion of customer rates. This is because depreciation expense is based on historical costs which, given the age and long useful life of the underlying assets, is not indicative of the actual ongoing costs of maintaining and replacing the system. This situation is expected to reverse in approximately 2023 at which time depreciation expense will be greater than annual capital spending.

Manitoba Hydro argues for the first time that actual Business Operations Capital needs of the Utility have historically been understated in debt service and capital coverage financial metrics. This is because capital projects ascribed “Major New Generation & Transmission” status, due to their individual size based on dollar amounts, are excluded from the financial metrics. Manitoba Hydro now maintains that most of these Major New Generation & Transmission projects are essentially for system renewal or reliability and are not, once finished, contributing to any material increase in revenue. As such Manitoba Hydro now includes these capital expenditure requirements for the purposes of its new cash flow analysis. Major New Generation & Transmission projects continue to be excluded from Manitoba Hydro’s long-standing interest coverage and capital coverage metrics.

Additionally, Manitoba Hydro suggests that the capitalization of interest effectively delays the recognition of increased carrying costs associated with new plant as that capitalized interest is not recognized on the Income Statement for rate-setting purposes until the underlying capital asset enters service. As an example, capitalized interest on funds borrowed to finance reliability and sustainment projects like Bipole III is deferred and excluded from the determination of revenue requirement and net income until that capital asset enters service for ratepayers.

Manitoba Hydro uses a new cash flow analysis that it developed to illustrate the difference between net income under International Financial Reporting Standards (as reported in Manitoba Hydro's audited financial statements) and the Utility's new perspective on its actual cash flow requirements.

Debt Management and Borrowing Strategy

Unlike privately owned utilities, Manitoba Hydro does not have access to share capital as a source of funds and must rely on a combination of internally generated funds from operations (referred to as equity) and debt financing in order to fund its capital investment program. Manitoba Hydro is forecasting that, in the next four years, it will fund the vast majority of new major generation and transmission capital expenditures, including the sums remaining on the $8.7 billion Keeyask and $5.0 billion Bipole III projects, primarily through debt financing.

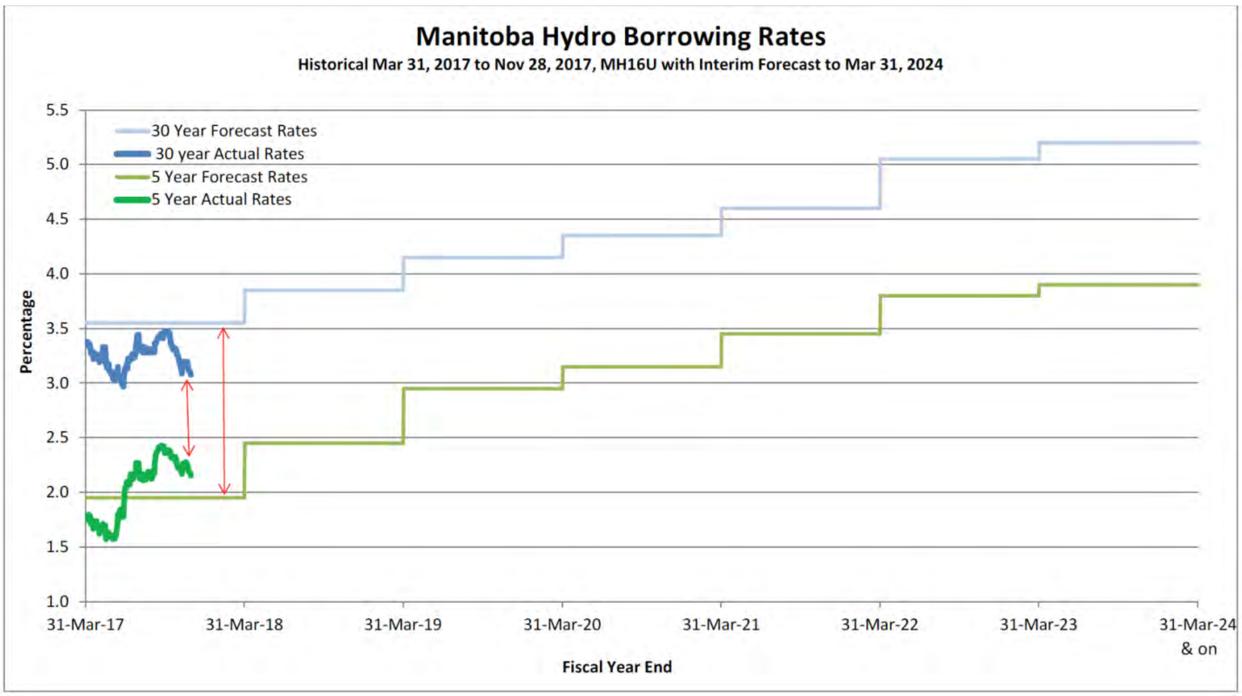
Manitoba Hydro maintains that its requested and projected rate increases in its 10-year financial plan will allow the Utility to reduce its borrowing requirements in the future, retire debt, and serve to mitigate future rate increases that may be required should interest rates rise. The risk identified by Manitoba Hydro is that interest rates will rise over and above the increases already embedded into Manitoba Hydro's Integrated Financial Forecast. Manitoba Hydro derives its long-term (10+ year) interest rate forecast from a consensus of external forecast views from the average of 10- and 30-year forecasts Canadian debt interest rate forecasts. The long-term interest rates are projected to increase over the forecast period: from 3.15% (excluding the one percent provincial debt guarantee fee) in 2017/18 to 3.90% in 2019/20 and to 4.95% in 2023/24 and thereafter.

Manitoba Hydro states that actual interest rates in the Canadian capital markets have been on a downward trajectory over the past two decades and are currently at the lowest levels in Canadian history. The implications from this record low interest rate environment are such that, should interest rates rise, and with the increasing level of debt financing required by Manitoba Hydro, the Utility is at risk of experiencing escalating debt servicing costs on its maturing and new debt issuances.

In order to reduce refinancing risk, Manitoba Hydro adopted a ‘leapfrogging’ strategy in 2008 that favoured longer-dated debt maturities that largely skipped over the future period of large borrowings for new cash requirements. This strategy enhanced debt stability by extending the debt portfolio’s weighted average term to maturity by over five years. Manitoba Hydro also took advantage of the low interest rate environment to decrease the debt portfolio’s weighted average interest rate by over 2%.

Manitoba Hydro indicates that, combined with its projected rate increase plan, the leapfrogging approach undertaken has provided the opportunity for Manitoba Hydro to now shorten the weighted average term to maturity of new debt issuance from approximately 20 to 12 years so as to retire debt permanently. The financial benefit associated with this opportunity has the potential to provide a reduction in debt servicing costs of $500 million, based on an assumed 1.6% difference between the five-year borrowing rate and 30-year borrowing rate in MH16 Update with Interim. However, Manitoba Hydro revised its estimate of the reduction of debt servicing costs during the GRA hearing down to under $250 million as a result of the recent flattening of the yield curve between shorter-term (five year) and longer-term (30 year) debt.

The forecast of 30-year and five-year interest rates and recent actual rates, including the 1% debt guarantee fee paid by Manitoba Hydro to the provincial government, is reflected in the following table and the narrowing of the differential is depicted with the arrows in the table:



Source: MH-68

Manitoba Hydro indicated that its last two debt issuances were 30-year issues and that the weighted average term to maturity of the debt portfolio is currently 18 years, not the 12-year weighted average term to maturity envisioned in Manitoba Hydro's new financial plan.

Manitoba Hydro states that, when spending on Keeyask and Bipole III is complete, and with the forecast improvement in operating cash flow stemming from the proposed rate increases and cost reductions, it sees an opportunity to use this future cash to permanently retire significant levels of debt. This debt retirement plan is a key factor in the forecast reduction in finance expense and is predicated on the successive annual 7.9% rate increases in Manitoba Hydro's 10-year financial plan. Manitoba Hydro submits that, should there be no reasonable prospect for the cash flow from its proposed rate plan, it would be unable to retire as much debt as forecast. Prudence would then dictate that the debt strategy shift to longer-dated maturities in order to protect ratepayers from interest rate refinancing risk.

Credit Ratings of Manitoba Hydro and the Province of Manitoba

Manitoba Hydro's long-term debt is provided by the Province of Manitoba. The Province raises debt capital from the capital markets, advances the funds to Manitoba Hydro, and charges Manitoba Hydro a debt guarantee fee. As a result, Manitoba Hydro's long- and short-term credit ratings are the same as the Province's credit ratings.

According to Manitoba Hydro, the Province's credit rating should be of concern to the Utility's customers as it affects the cost of borrowing that Manitoba Hydro must recover in its rates. Debt advances to Manitoba Hydro form a significant and growing portion of the total provincial debt and the Utility's financial performance is considered by credit rating agencies as a contributing factor toward the financial strength and assessment of the Province's credit rating. Manitoba Hydro maintains the proposed rate increases in its 10-year financial plan are necessary to demonstrate to the credit rating agencies that Manitoba Hydro is on a path to maintain its self-supporting financial status as it is able to support the cost of its borrowings.

Manitoba Hydro states that each credit rating agency independently evaluates Manitoba Hydro by considering the Utility's financial risk profile, including financial performance, ratios, and forecasts as well as the business risk profile in assessing whether or not

Manitoba Hydro is "self-supporting". The status of self-supporting means that Manitoba Hydro is able to adequately support its borrowing costs through its operations without seeking assistance from the province. Provided that the rating agency views Manitoba Hydro as self-supporting, the credit rating agencies do not include Manitoba Hydro's debt levels in the net tax-supported provincial debt. Should Manitoba Hydro lose its self-supporting status and the contingent liability represented by Manitoba Hydro's debt to the Province of Manitoba materializes, the implication to the Province is a heightened risk of further credit rating downgrades.

The different credit rating agencies use different methodologies and scales to measure ratings. Standard & Poor's now defines "self-supporting" as maintaining stand-alone investment grade credit metrics. Since Manitoba Hydro does not meet this standard nor intends to meet this standard, Manitoba Hydro's debt is now included by this rating agency in the tax-supported debt of the province. However, the credit rating and outlook from both the Moody's Investor Services and DBRS rating agencies have remained unchanged since 2015.

4.2 Intervener Positions

The Consumers Coalition submits the financial outlook consistent with Integrated Financial Forecasts IFF14 and IFF15 should be retained for rate setting purposes. In adopting the evidence of its expert witness, Morrison Park Advisors, the Consumers Coalition states that Manitoba Hydro's new cash flow analysis is not shared with credit rating agencies and should not be used for rate setting purposes. That the Utility has cash flows less than its annual spending on property, plant and equipment at least until 2023 is entirely consistent with Manitoba Hydro's major capital expenditure plan in the construction of the $8.7 billion Keeyask and $5 billion Bipole III projects.

The Consumers Coalition emphasizes that capital markets are not credit rating agencies and credit rating agencies are not capital markets. While both are important, they are not the same thing. This Intervener reminds the Board that, following the NFAT review, the markets did not react negatively when Keeyask was approved to be constructed with a plan of achieving a 25% equity level after approximately 20 years. Two rating agencies have long taken the position that, as long as Manitoba Hydro is paying its costs through ratepayer bills, there is no practical impact on the provincial credit rating or on the cost of the Utility's debt. In addition, the Consumers Coalition adopts the evidence of Morrison Park Advisors that Manitoba Hydro's focus on capital structure does not appear to be shared by capital markets observers, who instead are more focused on measures of cash flow sufficiency to meet debt obligations, in keeping with their primary interest of protecting their debt investments.

The Consumers Coalition maintains the 7.9% rate increase path by Manitoba Hydro is not warranted when rate increases at approximately half of that amount still allow the Utility to reach a 25% equity level by 2033/34. Rate increases at or below 3.95% are consistent with the rate path outlined in the 2014 NFAT hearing and subsequent Board rate increase decisions and ought to be the maximum rate increase allowed for 2018. In any event, as stated by Morrison Park Advisors, as Manitoba Hydro is a pure cost recovery, government-owned utility, it is not clear why "equity" should be a priority *per se*.

The Consumers Coalition submits that financial reserves should be used to manage drought risk, but not interest rate risk or export price risk, the latter two of which can be addressed through rate increase requests at future GRAs. The Consumers Coalition questions the need to have increased reserves to withstand a drought when, under Manitoba Hydro's 7.9% rate increase trajectory, Retained Earnings are growing during a drought due to excessively high consumer electricity rates. This Intervener supports the researching and developing of a probabilistic analysis to assist the Board in determining the appropriate levels of reserves for Manitoba Hydro, including through technical conferences.

The Manitoba Industrial Power Users Group advocates progressing towards a 725% equity level target over approximately twenty years (i.e. 2035/36) while maintaining rate stability and predictability. Consistent with the long life of the Keeyask and Bipole III major capital assets under construction, the recovery of the costs ought to be spread to the customers that will benefit from the assets. To proceed at the rate path projected by Manitoba Hydro would result in Retained Earnings exceeding $6.5 billion by 2026/27, while there have been no scenarios provided to suggest ratepayers face risks commensurate with this level of reserves. Additionally, it states that Manitoba Hydro has not provided a credible scenario for what happens after 10 years. Currently, the Manitoba Industrial Power Users Group sees Manitoba Hydro's approximate $3 billion of Retained Earnings as sufficient to manage a five- or seven-year drought, even without further rate increases.

Manitoba Hydro uses an uncertainty analysis to assess risk. The Manitoba Industrial Power Users Group indicates the recently developed uncertainty analysis capability of Manitoba Hydro is a significant enhancement but it is not ready to be used as a rule-based methodology in the rate-setting process. An improved uncertainty analysis will need to incorporate a rate response where rates would be expected to increase while the event (such as drought) is being experienced. An uncertainty analysis can be used as a signal to capital markets that rates are sufficient to address most future conditions without default. It can also help customers understand how rates are building reserves that yield rate stability.

In assessing the responses of capital markets and the credit rating agencies to annual 3.95% increases, the Manitoba Industrial Power Users Group indicates that there appears to be no prospect that the test used by KPMG, the Utility's external consultant, for self-supporting status (zero retained earnings combined with uncompetitive rates) would fail to be met over the near term or the long term as currently projected. Further, there is no sign that any updated information on the Utility's debt is leading to a higher cost of credit for the province. Considering that the debt guarantee is a kind of backstop or insurance, no evidence has been provided that the Province is being exposed to risks or costs that exceed the payments it has received over the period. As noted in the evidence, the Province's cost of borrowing, measured as a spread over both the federal government and the Ontario government, improved after the Standard & Poor's downgrade.

The Manitoba Industrial Power Users Group sees Manitoba Hydro's interest coverage ratio as reasonable, recognizing it will rise and fall depending on performance. For example, this target was not met under Integrated Financial Forecast MH14 for 10 years. However, there are some issues with the capital coverage ratio due to the arbitrariness of definitions of what is and is not included. According to this Intervener, the capital coverage target is met under the 3.95% rate increase trajectory in all years except 2019/20, 2025/25, and 2026/27 but the Utility's external consultant would consider the target met in each of these years as the results are within 10% of the target. This is an improvement from MH14.

The Manitoba Industrial Power Users Group maintains that, on a normal basis, rate setting for a regulated utility such as Manitoba Hydro should be performed with the primary focus being on the income statement and net income sufficiency, not capital coverage which is a cash flow test.

The 7.9% per year rate trajectory in Manitoba Hydro's new 10-year financial plan drives rates to high levels (81% above 2017's level by 2027/28), net income to record levels of $650 million per year and more, with Manitoba Hydro's financial targets (interest coverage and capital coverage) being far exceeded. The Manitoba Industrial Power Users Group maintains the analyses demonstrate that there is no overall financial deterioration compared to the NFAT or the previous GRA and there is therefore no need to deviate from the prior rate trajectory.

Representatives of General Service Small and General Service Medium Customer Classes and the Keystone Agricultural Producers adopt the Morrison Park Advisors' expert evidence, as well as the general positions as to rate increases of the Consumers Coalition and Manitoba Industrial Power Users Group.

The City of Winnipeg maintains that Manitoba Hydro's position as to financial metrics is without sufficient justification and is arbitrary. Most importantly, it states that Manitoba Hydro completely fails to take into consideration the interests of ratepayers. As such, the City of Winnipeg argues that the Utility has failed to demonstrate its proposal results in just and reasonable rates as it considered only half of the legal test the Board must apply – that test being the balancing of the interests of ratepayers and the financial health of the utility.

Simply put, the City of Winnipeg submits the Utility has not established that circumstances have so drastically changed that the conclusions of the NFAT Report are no longer are valid. On this point, this Intervener reminds the Board that Manitoba Hydro does not expect to meet all of its financial targets during periods of major capital expansion. Additionally, the uncertainty analysis from the NFAT modelling shows that rate increases of approximately 3.95% are sufficient to maintain the long-term viability of the Utility.

The Business Council of Manitoba recommends the Board deviate from the historical rate path in favour of a short-term rate path increase along the lines proposed by Manitoba Hydro. This Intervener calculates the difference between the 3.95% rate path and the MH16 Update with Interim rate path as being an incremental revenue increase of about $70 million in the next year. Interest rates going higher than forecast by 1.5% would result in $350 million in additional interest costs that would have to be borne by Manitoba Hydro in 2021 if the Utility's debt is $23.3 billion, as is currently forecasted.

The Business Council of Manitoba sees increases in interest rates and Manitoba Hydro being found to be a non-self-supporting entity as virtual certainties. This Intervener submits that, based on the current credit rating reports, the risk of a credit downgrade of Manitoba Hydro or the Province is extremely high. This Intervener concludes that the risk that any of these factors will negatively affect Manitoba Hydro and the Province in the short and long term is very high.

4.3 Board Findings

Having considered the interests of the Utility's ratepayers and the financial health of Manitoba Hydro, the Board finds that a particular equity level target and pace to achieve that target should not determine the rate increases approved in this GRA. Although the Board finds that the rate increase should not be driven by achievement of a particular equity level, the Board's assessment must include consideration of the circumstances of Manitoba Hydro's operations. Because of Manitoba Hydro's use of hydraulic resources to meet the electricity needs of the province, it has historically undertaken large investments such as generating stations and transmission lines that have initial large surpluses of capacity for the needs of Manitobans. These assets have large upfront construction costs but relatively low annual operating costs that extend through a very long expected useful life – which, in some cases, can be as much as one hundred years. With Manitoba Hydro's investments currently underway in Keeyask and Bipole III, the situation today is no different.

An important question from a rate-setting perspective is how these large investments should be funded. On the one hand, if they are to be paid for exclusively by revenues from new rates charged to domestic ratepayers, this would result in a "saw tooth" pattern of rates featuring sharp spikes when new facilities are under construction, and a return to lower rates once the desired equity portion of the project has been funded. On the other hand, if projects are funded through borrowing, rate increases may be "smoothed" over time but the cost of servicing the debt becomes an issue. The concern is to find the right balance between rate increases and the level of debt to fund large capital projects.

In making this determination, the Board is guided by two considerations. The first is: what "reserves" should Manitoba Hydro hold to manage risk and which risks should it take into account? As an example, as per the question posed in the evidence of Morrison Park Advisors, what is the level of retained earnings needed in the event of a five-year drought? The second is to place concerns about the amount of debt and retained earnings in a different perspective by also considering cash flow, using two long-standing financial metrics used by Manitoba Hydro: interest coverage ratio and the capital coverage ratio.

As detailed below, on assessment of these considerations, the Board finds that raising consumer rates by an amount equivalent to four times the rate of inflation is not required to support Manitoba Hydro's current operations. The Board recognizes the sincerity of Manitoba Hydro's concerns about potential future risks materializing. However, as the Board has demonstrated in past decisions – including in years of drought where the Board awarded rates in excess of those sought by the Utility – it will consider all of the facts and circumstances which confront Manitoba Hydro at that point in time in determining the appropriate rate relief. The Board is prepared to take regulatory action – whether through a rate rider, an interim rate increase, or a general rate increase – as required in times when emergent situations face Manitoba Hydro. At this time, however, the Board finds the circumstances confronting Manitoba Hydro, including those raised in the hearing about credit rating agencies and debt management, do not justify the 7.9% rate increase sought by Manitoba Hydro.

Any benefits of Manitoba Hydro's financial plan must be balanced against the interests of ratepayers. Funds taken out of the pockets of ratepayers through higher rate increases have a cost. In balancing this against the benefits of Manitoba Hydro's plan, the Board finds that the cost to ratepayers is not justified. The Board further notes that, while one financial scenario filed by Manitoba Hydro at the request of the Board showed rate reductions in its 20-year rate forecast, including a significant rate reduction in 2027/28, the Utility did not commit to those reductions. Instead, Manitoba Hydro acknowledged that requests for rate increases or reductions in future years will be dependent on the circumstances at the time.

Debt-to-Equity Ratio

The Board accepts Morrison Park Advisors' evidence that debt-to-equity is a questionable metric for a vertically integrated monopoly Crown utility with a debt guarantee from the provincial government. The equity level target does not have the prominence suggested by Manitoba Hydro given the context in which the Utility operates. The concern regarding the value of the equity level target is compounded when Manitoba Hydro is going through an unprecedented major investment period to more than double the value of its assets in the next four years. As noted by Manitoba Hydro's external consultant KPMG, there is a "practical recognition that this target will not be met during a period of large capital expenditures when newly constructed assets are placed in service. Accordingly, the 75/25 could remain the long-term objective." The Board supports this view. The Board agrees with the evidence that there is a cost associated with equity as equity is provided by ratepayers who could otherwise use those funds. As such, the Board is not prepared to look at the issue of pacing to achieve a particular equity level target at least until the current phase of major capital construction is completed, now projected by Manitoba Hydro to be in 2024.

The current 25% equity level target was established by the Manitoba Hydro-Electric Board in 1995 when the Utility had 8% equity and less than $300 million of Retained Earnings. Except for approximately five years during the last 20 years, immediately prior to the start of Keeyask construction, this target has not been achieved.

The 25% equity level target is "self-imposed" by Manitoba Hydro. While Manitoba Hydro may determine that the 25% target remains relevant, the Board does not accept that consumer rate increases should be granted at the level proposed by Manitoba Hydro so that the Utility can achieve its target within a 10-year time frame. As stated by the Board in the NFAT report:

> *The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased.*

Financial Reserves

The Board finds that Manitoba Hydro's forecast achievement of $6.56 billion of Retained Earnings by 2027 is too aggressive considering that the two major capital projects contributing most to the doubling of the Utility's assets are still under construction. This increase in Retained Earnings would be funded by ratepayers, with a resulting opportunity cost. In assessing this cost to ratepayers against the benefits to Manitoba Hydro, the Board finds that under the Utility's MH16 Update with Interim rate path, and as illustrated in Manitoba Hydro's sensitivity analysis and as confirmed by Manitoba Hydro in its testimony, Manitoba Hydro's Retained Earnings would continue to increase even during a five-year drought. Even though a five or seven-year drought would result in Manitoba Hydro not accumulating the same Retained Earnings as it otherwise would have, such a drought would also not result in a reduction in the Utility's Retained Earnings. The Board agrees with the evidence of Morrison Park Advisors, that this raises a question: if a primary purpose of having Retained Earnings is to withstand a drought, why does Manitoba Hydro need rates at a level that would allow it to build Retained Earnings during a drought? The Board concludes this supports the determination that a 7.9% rate increase for 2018/19 is not required.

In addition, the Board accepts the evidence of Morrison Park Advisors that Retained Earnings should be used to manage drought risk in combination with regulatory action by the Board. The Board further agrees that interest rate and export price risks over the long term should be addressed with rate increases as and when those risks materialize. Rates should not be set to increase Retained Earnings to manage those longer-term risks. As discussed elsewhere in this Order, the Board is prepared to consider regulatory action when required to address emerging risks facing Manitoba Hydro. In this context, and having considered Manitoba Hydro's new financial plan and the opportunity costs to ratepayers, the Board finds that the 7.9% requested and projected rate plan is not the appropriate balanced plan for meeting the risks and challenges that confront the Utility.

However, the Board concludes that there is merit to gaining better understanding of the financial reserves required for Manitoba Hydro under various circumstances. This would include consideration of risk tolerances, what risks should be protected by reserves, and the circumstances which would guide the need for more aggressive rate increases to continue full cost recovery for Manitoba Hydro. The Board is mindful that the financing and depreciation expenses related to these new major capital assets entering service already require additional revenues from rate increases. Consideration of the appropriate level of financial reserves, for example a minimum retained earnings test, is best done through a collaborative approach with stakeholders.

The Board directs Manitoba Hydro to participate in a technical conference hosted by Board Staff or an external consultant appointed by the Board for the consideration of the establishment of a minimum retained earnings or similar test to provide guidance in the setting of consumer rates for use in rule-based regulation. The test or rule is to be based on maintaining appropriate or minimum levels of retained earnings and meeting other financial metrics in the face of potential risks to the Utility. The Board will develop the terms of reference for the technical conference. Parties will be invited to contribute to the scope and terms of reference for this initiative.

Cash Flow from Operations

The Board finds that, in assessing whether Manitoba Hydro is meeting its ongoing financial obligations, the focus should be on the accrual accounting methodology used in the Utility's audited financial statements and the financial forecasts used for rate setting. This methodology was also previously used by Manitoba Hydro for rate setting purposes and continues to be used by Manitoba Hydro for its financial forecasting and reporting. Accrual accounting used by Manitoba Hydro includes capitalizing interest to capital projects until those new assets enter service for ratepayers. Once in service, the financing and depreciation costs are recorded on the Income Statement to be recovered in consumer rates.

Manitoba Hydro's new cash flow analysis does not appear, from the evidence, to be a typical part of financial analysis, and its value is somewhat obscure. The newly presented cash flow analysis is a "new view" created by Manitoba Hydro that the Board does not accept for rate-setting purposes. The new view treats Bipole III inconsistently, departs from the prior treatment of certain Major New Generation and Transmission projects, and deviates from accrual accounting principles. However, the Board accepts that Manitoba Hydro's payments to the City of Winnipeg and mitigation payments should be included in a cash flow analysis of the Utility's operations for rate-setting purposes. The Board notes that insufficient information was provided about the items included in Other Cash Payments in its Integrated Financial Forecast and directs Manitoba Hydro to provide that information in the next GRA filing.

With respect to the traditional financial metrics of interest coverage and capital coverage, the Board finds that the question of financial targets must be assessed in the context of a Crown Utility that is currently in the midst of a major capital expansion, doubling its asset base. With rate increases in line with prior levels, Manitoba Hydro's interest coverage and capital coverage ratios will be improved from those forecast at the time of the NFAT. These metrics therefore do not support rates at a level higher than prior rate increases. The forecast of financial measures, such as the interest coverage ratio and capital coverage ratio, even with the inclusion of City of Winnipeg and mitigation payments, do not support Manitoba Hydro's arguments that a 7.9% increase is justified solely by Bipole III entering service in 2018/19. As well, due to the Bipole III Deferral Account established by the Board and as directed by the Board in prior Orders, 11.6% is already embedded in current compounded consumer rates, despite not previously being required for the Utility’s operations, in order to smooth the rate effect of Bipole III entering service.

Debt Management and Borrowing Strategy

The Board does not accept that rate increases should be higher in order to allow Manitoba Hydro to retire debt according to their new debt management plan. The refinancing risk identified by Manitoba Hydro is linked to the Utility’s shorter-term debt retirement plan. Longer-term issuances at current low interest rates mitigate this risk as identified by Manitoba Hydro’s Treasury Department. Manitoba Hydro’s recently amended approach to the debt management plan, whereby it placed longer-term debt issues to take advantage of a flattening yield curve, demonstrates that Manitoba Hydro’s treasury function is well exercised.

While there are benefits to a shorter-term debt retirement plan, such a plan imposes a cost on ratepayers that is not justified by the evidence.

Credit Ratings of the Province of Manitoba and Manitoba Hydro

The Board finds that, while important, care must be taken to avoid placing too much weight on reports by credit rating agencies. The Board accepts that credit ratings and capital markets are related, but are not the same thing.

The Board does not accept that Manitoba Hydro’s debt is leading to a higher cost of credit for the province. Neither Manitoba Hydro nor the Business Council of Manitoba chose to call any witnesses from the credit rating agencies, financial markets, or the provincial government to testify as to the impact of Manitoba Hydro’s debt on provincial credit ratings. In so doing, the Utility and the Business Council of Manitoba appeared to take the position that it was self-evident that higher levels of debt would damage the provincial credit rating. There was no expert evidence independent of Manitoba Hydro presented to that effect. More specifically, as submitted by the Manitoba Industrial Power Users Group, there was no evidence that “even if Hydro acted prudently, yet adversely affected the province’s rating, that it would be a net short-term or long-term negative effect on the province compared to not having Hydro’s debt on the books”. The Board accepts the evidence of Morrison Park Advisors that the capital markets will be reassured by a long-term rate plan that acceptably manages Manitoba Hydro’s risks and by this Board’s regulatory action where required to address circumstances as they arise.

5.0 Major Capital Revenue Requirement

On April 5, 2017, by Order in Council 92/2017, for the GRA then-anticipated to be filed in 2017, the Board was assigned the duty of considering capital expenditures made by the Manitoba Hydro-Electric Board as a factor in reaching a decision regarding setting rates for services in a manner that balances the interests of ratepayers and the financial health of Manitoba Hydro. To facilitate the Board's review of Manitoba Hydro's capital expenditures, Order in Council 92/2017 directed the Utility to provide extensive capital expenditure, explanatory, and revenue information.

As such, this GRA proceeding included review of Manitoba Hydro's current major capital projects, specifically Keeyask, Bipole III, the United States interconnection project made up of the Manitoba-Minnesota Transmission Project ("MMTP") in Manitoba and the Great Northern Transmission Line ("GNTL") in Minnesota, and the Manitoba-Saskatchewan Transmission Project. This review included consideration of the budget estimates for these projects incorporated into the Utility's Integrated Financial Forecast, and therefore its revenue requirement.

The Board's review of Manitoba Hydro's capital expenditures included the following:

- A review of Keeyask, with a focus on the reasonableness of Manitoba Hydro's capital cost estimates filed in support of the Utility's financial forecasts. The timeframe for the review began with the cost estimates presented at the NFAT;
- A review of Bipole III, also focused on the reasonableness of the capital cost estimates beginning with the initial western routing cost estimate for Bipole III;
- A review of the MMTP and GNTL, also focused on the reasonableness of the capital cost estimates. The timeframe for the review began with the cost estimates presented at the NFAT; and

- An economic review of the Manitoba-Saskatchewan Transmission Project and related SaskPower export power sale, to determine whether the project was economic.

In order to exercise its authority and responsibility under the Order in Council in this GRA, the Board engaged the services of the following Independent Expert Consultants:

- MGF, construction management experts in the profession of Quantity Surveyors. Quantity Surveyors have construction, contract, and project management expertise. MGF was the lead Independent Expert Consultant for the review of the capital costs of Keeyask, Bipole III, MMTP, and GNTL;

- Klohn Crippen Berger ("KCB"), which has expertise in hydroelectric generating station design and engineering, including the civil, electrical, and mechanical engineering aspects. KCB assisted MGF with the review of Keeyask;

- Amplitude Consultants, which has expertise with high voltage direct current ("HVDC") transmission systems including HVDC converter stations. Amplitude Consultants assisted MGF with the review of the Bipole III converter stations;

- Stanley Consultants, which has expertise with transmission line design, engineering, and construction. Stanley Consultants assisted MGF with the review of the Bipole III, MMTP, and GNTL transmission line reviews; and

- Daymark Energy Advisors ("Daymark"), which has expertise in resource planning and utility economics. Daymark reviewed the economics of the 100 MW SaskPower power sale agreement and the Manitoba-Saskatchewan Transmission Project.

The Board developed scopes of work for each Independent Expert Consultant with input from Manitoba Hydro and Interveners in the GRA. In the case of Bipole III, the focus of the Independent Expert Consultants was on the pre-construction budget of $4.65 billion and whether the current forecast of $5.04 billion can be relied upon by the Board. The Independent Expert Consultants did not investigate the prior Bipole III cost estimates, nor did they investigate the change in routing of Bipole III from east of Lake Winnipeg to west of Lake Manitoba.

5.1 Keeyask

Keeyask is a 695 MW hydroelectric generating station located in northern Manitoba at Gull Rapids. The Keeyask project also includes infrastructure, such as the access road and accommodation camp, as well as the transmission lines to connect Keeyask to Manitoba Hydro's HVDC Bipole facilities in order that the power may be transmitted to southern Manitoba.

Keeyask is being developed through the Keeyask Hydropower Limited Partnership ("KHLP"), a partnership between Manitoba Hydro and four First Nations: Tataskweyak Cree Nation and War Lake First Nation (acting as the Cree Nation Partners), Fox Lake Cree Nation, and York Factory First Nation. The commercial terms of the arrangement are set out in the Joint Keeyask Development Agreement. The four First Nations together currently own 17.5% of the Partnership and have the right to increase their investment and own up to 25%. Manitoba Hydro will own at least 75%. The Partnership has delegated project management responsibility to Manitoba Hydro. Consequently, Manitoba Hydro is the sole entity responsible for planning, design, engineering, procurement, construction, and operation of Keeyask.

At the commencement of the NFAT review in 2014, the anticipated cost for Keeyask was $6.2 billion and the target in-service date for the first of seven generating units was November 2019.

Prior to the completion of the NFAT, the General Civil Contract ("GCC") for Keeyask was awarded to a consortium of Bechtel Canada Co., Barnard Construction of Canada Ltd., and EllisDon Civil Ltd ("BBE"). Following awarding of the GCC, the Keeyask cost estimate was updated to $6.5 billion. The GCC is the largest contract related to Keeyask and includes river management, earthworks to build the dykes, concrete structures such as the powerhouse and spillway, and electrical and mechanical work to complete Keeyask. Construction commenced in July 2014 with the building of the powerhouse cofferdam.

The pricing structure in the GCC is that of a "cost reimbursable nature with a target price" contract. The "cost reimbursable" aspect means the contractor is paid for its costs for materials and direct labour, plus profit and general administration and overheads. The "target price" aspect means that the contractor's profit erodes if the target price is exceeded and the contractor's profit increases if the actual cost is less than the target price. The target price and this so-called 'pain/gain' pricing mechanism are intended to incent the contractor to perform well.

In a cost reimbursable contract, the owner (Manitoba Hydro) is at risk for quantities, productivity, and inefficiency of the contractor. As an example, under a cost reimbursable payment structure, the contractor would be paid in full for 10 hours of work even if the contractor's successful bid was based on the contractor taking only six hours to perform the specific work task.

Other types of payment structures are 'fixed price' or 'unit price' structures. In a fixed price contract (also known as a lump sum contract), a contractor is paid a fixed price regardless of the costs it incurs or the duration of the project. In this type of payment structure, the contractor is at risk for quantities and productivity. In a unit price contract, the contractor is paid a pre-defined unit rate (or rate per quantity) multiplied by the quantity of work. For a hydroelectric project such as Keeyask, a common unit would be a cubic metre of earth excavation or a cubic metre of concrete placement. In this type of payment structure, the contractor is at risk for productivity but the owner (Manitoba Hydro) is at risk for variation in quantity from the initial estimates provided by the owner.

For Keeyask, Manitoba Hydro attempted to address and mitigate the issues and concerns that resulted in the Wuskwatim generating station exceeding its initial cost projections. At the NFAT, Manitoba Hydro identified the availability and productivity of craft labour as a major issue with Wuskwatim. To address this issue, Manitoba Hydro designed and built premier camp accommodations for Keeyask in order to attract and retain labour. Manitoba Hydro also implemented a retention bonus for craft labour which raised the remuneration under the Burntwood-Nelson Agreement to be more competitive with other remote northern construction projects. Manitoba Hydro also implemented an early contractor involvement process with the general civil contractor. Early contractor involvement is a process whereby the contractor is involved early in the project and afforded time to plan the work for its craft labour teams. One objective of early contractor involvement is to maximize productivity of the workforce.

Manitoba Hydro expected greater productivity – that is, fewer person-hours per unit of work – on Keeyask than it experienced with Wuskwatim. The productivity in the BBE bid was similar to the productivity that was achieved during construction of the Limestone generating station in the early 1990s. When evaluating the bids for the GCC, Manitoba Hydro described BBE's productivity bid as a "red flag" as it was higher than Manitoba Hydro had achieved on Wuskwatim. Manitoba Hydro further investigated BBE's bid and its productivity forecast, but Manitoba Hydro ultimately accepted the productivity rates in BBE's bid and used them to calculate the target price of the GCC and the overall Keeyask cost estimate. The optimistic productivity of the BBE bid was one reason Manitoba Hydro included a labour reserve in the Keeyask cost estimate. Manitoba Hydro characterized the amount in the labour reserve as significant, to address, in part, its concern over the productivity contained in BBE's bid. A labour reserve was not carried for Wuskwatim.

At the NFAT, the risk of cost overruns was known and the Board commented on this risk in its report:

> *The Keeyask general civil contract is a costs-reimbursable contract rather than a fixed price contract. This means that if volumes of materials increase, Manitoba Hydro is responsible for that increase. The Panel had the opportunity to consider the contract in camera as Commercially Sensitive Information, and has concluded that Manitoba Hydro bears a significant cost risk.*

And:

> *Manitoba Hydro submitted that the risk associated with the Keeyask construction is somewhat addressed given that 80% of the construction contracts have now been negotiated. However, this only partially mitigates cost risk. The Keeyask general civil contract is a cost-reimbursable contract, not a fixed price contract. This leaves the contract vulnerable to cost escalations as a result of: quantity risk, especially in areas where quantities may have been underestimated; escalation to the contractor's cost factors due to labour productivity or labour costs; escalation in the cost of supply and equipment; and challenges related to adverse weather conditions.*

The 2016 construction season was the first where significant amounts of permanent concrete were poured, beginning in May 2016. By June of 2016, BBE was falling behind on its targets for concrete placement. Manitoba Hydro requested a recovery plan from BBE in order to get the project back on schedule. The plan was implemented in June 2016, but did not achieve the desired results in terms of concrete placement or productivity. By the end of the 2016 construction season, only 65% of the earthworks target and 41% of the concrete target were met.

Manitoba Hydro investigated the root causes of the lower-than-expected concrete and earthworks productivity and completion rates. The primary root causes identified by Manitoba Hydro were: 1) unachievable productivity rates for earthworks and concrete as contained in BBE's original bid, 2) slow ramp-up by BBE to full production in the early part of 2016, and 3) geotechnical and geological challenges. These difficulties led to a potential two-year delay. Manitoba Hydro explained that the difference between the productivity bid by BBE and the actual productivity achieved is the largest driver of the cost increase from $6.5 billion to $8.7 billion. The actual number of person-hours per unit of work was much higher than the BBE bid.

Concurrently in the summer of 2016, Boston Consulting Group was retained by the Manitoba Hydro-Electric Board to investigate options related to stopping or rerouting Bipole III. Boston Consulting Group's review was expanded to include a review of Keeyask. Boston Consulting Group identified the potential cost and schedule overruns for Keeyask related to the performance under the GCC as an increase from $6.5 billion to $7.8 billion and a 32-month delay if no mitigation actions were taken. In Boston Consulting Group's opinion, mitigation measures could reduce the delay to 21 months and limit the cost overrun to $7.2 billion. Mitigation measures included extending the steel columns deeper in the powerhouse to allow concurrent construction of concrete below and steel structures above, use of auxiliary power to operate the spillway gates instead of waiting to complete the spillway ancillary building, and improving concrete and earthworks productivity.

In September 2016, Manitoba Hydro initiated development of its own recovery plan. Manitoba Hydro determined that, of the recovery options available, amending the scope of the GCC or terminating BBE were higher cost, higher risk options and that amending the existing contract with BBE was the lowest cost, lowest risk option. In January 2017, Manitoba Hydro negotiated a revision to the GCC with BBE, referred to as Amending Agreement 7.

Amending Agreement 7 also has a cost reimbursable-target price payment structure. Manitoba Hydro advises that, in order to renegotiate the contract with BBE, there were 'gives and takes' involved as well as limits to how much risk related to labour productivity, weather, geotechnical, northern logistics, and other risks that Manitoba Hydro could transfer to BBE. Amending Agreement 7 re-established the possibility for BBE to earn profit by setting a new target price based on revised productivity factors and a new schedule with the first generating unit expected to enter service in August 2021.

The schedule delay has a consequential impact on other contracts, triggering compensation related to delays on fixed price contracts as well as increased costs related to extended performance of other contracts, such as camp services. The schedule delay also increases the period over which interest charges accrue to the project. The cost increase for the GCC combined with increased interest charges due to the higher amounts borrowed and the delay result in the revised Keeyask control budget of $8.7 billion with a schedule delay of 21 months, which Manitoba Hydro made public in March 2017. A control budget is a formal project budget developed by the project team and approved by management. The revised control budget constitutes a 34% cost increase for Keeyask over the cost forecast by Manitoba Hydro in the 2014 NFAT.

The Keeyask cost estimate includes a contingency amount that is determined by probabilistic modeling of the probability and consequence of various risks. The $8.7 billion estimate with a 21-month delay incorporates a P50 contingency, such that the contingency is expected to address 50% of the risk outcomes. The Keeyask P90 cost estimate, which addresses 90% of the risk outcomes, escalates to $9.6 billion and factors in an additional eight-month delay for a total delay of 29 months from the in-service date forecasted at the NFAT.

	Pre-Construction	Revised Estimate	
	P50 Contingency	**P50 Contingency**	**P90 Contingency**
Total In-service Cost	$6.5 billion	$8.7 billion	$9.6 billion
Unit 1 In-service Date	November 2019	August 2021	April 2022
Unit 7 In-service Date	April 2020	August 2022	April 2023

Amending Agreement 7 was in place prior to the start of the main construction season in 2017. Despite revised target productivity factors (i.e. person-hours per cubic metre of concrete placed) and other changes in the GCC that were made to get the project back on budget and back on schedule, BBE still fell short of end-of-year targets for concrete placement and earthworks by 20% and 25%, respectively.

Manitoba Hydro stated that the productivity to date on Keeyask has been worse than for Wuskwatim. Manitoba Hydro explained that there are different craft labour attraction and retention issues with Keeyask than with Wuskwatim. However, the approaches put in place by Manitoba Hydro – a premier camp, retention bonuses in excess of Burntwood-Nelson Agreement wages, more favourable shift rotations – did not address the underlying labour productivity issues experienced at Wuskwatim, and the low labour productivity has been repeated at Keeyask. The actual productivity rates achieved on Wuskwatim and Keeyask to-date, as well as the productivity bid by BBE, are commercially sensitive and confidential and were heard by the Board *in camera*.

Independent Expert Consultant Evidence

MGF reviewed the Keeyask project and agreed with Manitoba Hydro that the GCC was the single largest driver of the cost increase from $6.5 billion to $8.7 billion. MGF developed its own cost estimate for Keeyask based on the productivity factors achieved by BBE in the October 2016 to October 2017 timeframe. MGF's cost estimate for Keeyask is $9.9 billion with an additional 410-day delay over the currently anticipated 21 month delay, although MGF also provided a range of likely Keeyask costs of $9.5 billion to $10.5 billion. In MGF's view, the root cause of the billions of dollars of cost overruns is that the cost reimbursable payment structure of the GCC fails to provide sufficient incentive for BBE to be responsible for productivity. According to MGF, BBE struggles to plan, manage, and execute the work. MGF further states that it has not seen Manitoba Hydro address the root causes of the poor productivity by BBE.

Similarly, KCB found that the principal reason for the cost increase in the GCC and overall Keeyask budget is the nature of the payment structure in the GCC. Specifically, BBE is being paid in full for its actual costs for labour and materials rather than for quantities of work performed against fixed or unit prices. Put another way, BBE is paid for any reasonable costs to pour a cubic metre of concrete, irrespective of the price it bid to do so. KCB also identified an unusual payment arrangement between Manitoba Hydro and BBE, whereby BBE is paid for planned work two months in advance of completing the work. KCB stated that it had never seen a contract that required such a payment condition; in KCB's experience, the way a contractor ensures its cash flow remains positive is through a mobilization payment, followed by performing the work and earning revenue based on quantities times unit prices.

KCB found that geotechnical issues were not a major driver of the GCC increase as the actual quantities of earthworks and concrete required closely aligned with the original estimates that Manitoba Hydro provided to BBE. KCB also found that the production of construction drawings by the engineering contractor has been timely, that overall design was substantially complete prior to the award of the GCC, and that design changes and extra work orders have been minimal. As such, these are not the major factors that have driven the increase in the Keeyask cost estimate.

A further serious problem MGF identified was that Manitoba Hydro, while competent at administering the payment of the construction project costs and project accounting, is not managing the GCC in a manner that is required to exert control over a contract with a cost reimbursable pricing mechanism. In MGF's view, Manitoba Hydro is managing the project and GCC as if it were a lump sum or unit rate contract.

According to MGF, Manitoba Hydro needs to take back control of the project by enforcing its rights under the GCC and holding BBE accountable for its performance, hiring experienced trades supervisors to work with and assist BBE with planning the work in a more efficient manner, understanding why planned progress is consistently not achieved, and recasting forecast at completion costs based on a realistic and achievable schedule. MGF further opines that, if Manitoba Hydro continues to stand back and watch the project unfold as if it were a lump sum contract, then the final cost will be closer to $10.5 billion, rather than $9.5 billion, which MGF views as the lowest final cost that Manitoba Hydro can achieve. Unless changes are made, MGF is of the view that BBE's poor performance will continue.

MGF also recommends that Manitoba Hydro initiate periodic contract compliance reviews. According to MGF, BBE is not complying with certain terms of the GCC. For example, BBE is consistently late in providing Manitoba Hydro with monthly progress reports. Another example is BBE's schedule has over one thousand activities with 'negative float' (i.e. activities that have not or will not meet a scheduled or specifically identified date) while the GCC requires the schedule to have no negative float.

Manitoba Hydro's Position

Manitoba Hydro states that due to the state of the competitive market across North America for major project construction work in the 2012 to 2013 timeframe, and after meeting with several contractors prior to release of the tender, it decided to tender the GCC as a cost reimbursable-target price contract instead of as a unit price or fixed price contract. There were dozens of major construction projects underway at the time across North America, including oil sands and liquefied natural gas projects. Manitoba Hydro's assessment of the marketplace was that major project general contractors would not be receptive to "hard money" contracts - that is, contracts that transferred significant risks to the contractor by requiring a firm price, either through a fixed price or unit prices. Manitoba Hydro points to its experience with the Wuskwatim generating station where it attempted to tender a unit price contract but received only one bid which was nearly double the price Manitoba Hydro expected. Manitoba Hydro further stated that the unit price bid for the Wuskwatim general civil contract was higher than the final actual costs under the cost reimbursable-target price contract.

Manitoba Hydro has a current control budget for Keeyask of $8.7 billion. Manitoba Hydro argues that it has a strong plan in place to meet this control budget, and is working cooperatively with BBE to do so.

Manitoba Hydro indicates that, to meet or be under its $8.7 billion control budget, it requires a 10% improvement in productivity in each aspect of the GCC starting in 2018, as well as for no major negative risks to materialize. Those major risks include unseasonable weather, unexpected geotechnical or geological conditions (including as the geotechnical conditions in the area of the south dam have not yet been ascertained), and work stoppages. If Manitoba Hydro does not achieve a 10% improvement in productivity starting in 2018, the final cost of Keeyask will exceed $9 billion and will approach $9.5 billion. In order to drive a 10% improvement in productivity, Manitoba Hydro states that it continues to work with BBE to develop work plans for the 2018 construction season. Manitoba Hydro has also retained former contractors to review and test the work plans developed by Manitoba Hydro and BBE, a process known as a “cold eyes” review.

Manitoba Hydro states that BBE has not performed to the original plan or the plan under Amending Agreement 7. Manitoba Hydro further states that, if it were to do the Keeyask GCC all over again with hindsight, it would take a hard look at the marketplace and decide whether a cost reimbursable-target price contract was the appropriate pricing structure for the GCC.

Amending Agreement 7 is also a cost reimbursable-target price contract, so there is the possibility that after another construction season Manitoba Hydro and BBE may be in the same position as after 2016 where there is no longer any profit for BBE. If that happens, there would be no incentive or motivation for BBE to perform under the contract, leaving Manitoba Hydro in the same position as after the 2016 construction season and contemplating whether to renegotiate the contract. Such an eventuality was contemplated by Manitoba Hydro during negotiation of Amending Agreement 7, so Manitoba Hydro attempted to narrow the possibility of this occurring. The details of how Manitoba Hydro attempted to do this are commercially sensitive and confidential and were disclosed to the Board in camera.

Intervener Positions

The control budget amounts for revenue requirement purposes were not contentious in the proceeding, although the Consumers Coalition and the Manitoba Industrial Power Users Group recommend further review of the Keeyask budget following the 2018 construction season. With respect to the Keeyask budget, the Manitoba Industrial Power Users Group argues that it is premature at this time to conclude that further cost overruns, compared to the estimates used in MH16 Update with Interim, are sufficiently likely for the purpose of inclusion in Integrated Financial Forecast projections.

Board Findings

The Board finds that the $8.7 billion control budget amount incorporated by Manitoba Hydro into MH16 Update with Interim for Keeyask is to be used for Integrated Financial Forecast modeling and rate setting in this GRA.

The control budget for Keeyask will be reviewed at the next and future GRAs in the Board's consideration of Manitoba Hydro's revenue requirement. There are four more years of construction for Keeyask and there are opportunities for unforeseen issues to arise. One potential issue is the geotechnical condition of the south channel of the Nelson River, which will not be ascertained until the river is diverted through the spillway and the south channel cofferdam is completed. To achieve the $8.7 billion control budget no major geotechnical issues can be encountered in the area of the south dam.

The Board acknowledges that Manitoba Hydro has taken steps to mitigate schedule issues and productivity, including through retaining Boston Consulting Group, KPMG, Revay, Validation Estimating, and Borden, Ladner, Gervais LLP for recommendations. There was evidence in the GRA that Manitoba Hydro has achieved milestones in the construction of Keeyask, including that the project is on track to meet the schedule for diverting the river through the spillway to permit work to be done on the south dam. The Board's expectation is that Manitoba Hydro will closely monitor and take steps to improve productivity in order to achieve the 10% improvement in productivity on all aspects of the GCC required to meet the $8.7 billion control budget. The Independent Expert Consultants, MGF and KCB, made useful recommendations that Manitoba Hydro should consider implementing, and indeed, in part already has implemented. This will help Manitoba Hydro use the four years left remaining on the Keeyask project to stay on track with the schedule and budget. Manitoba Hydro is directed to report to the Board, at the next GRA, the extent to which it has implemented these recommendations and the results.

The Board expects Manitoba Hydro to take the actions it identified in its evidence at the GRA Hearing, namely to work with BBE to plan the work in 2018 to drive productivity improvements and to bring in external expertise for a "cold eyes" review of the project to test the proposed work plans.

The Board concurs with MGF and KCB that the primary root cause of the cost overrun of the GCC, and the whole Keeyask project, relates to the nature of the cost reimbursable payment structure in the GCC. Manitoba Hydro appears to have assumed that tying the contractor's profit to the target price, with the possibility that the profit could erode to zero, would provide sufficient motivation to the contractor to meet the productivity levels in its GCC bid. It further appears that Manitoba Hydro never contemplated that the contractor's profit could erode to zero so early in the project. However, underpinning the reason for the profit eroding to zero so early in the project was the fact that BBE bid productivity levels that proved to be unachievable. While Manitoba Hydro performed an evaluation of the productivity levels bid by BBE, the Utility accepted the bid, which was ultimately unachievable and formed the basis for an unrealistic target price. Once the profit eroded to zero, with no chance of re-establishing profit, the contractor had little or zero motivation to advance the project expediently. This was a principal failing of the original GCC.

The evidence of Manitoba Hydro, MGF, and KCB was to the effect that in the planning for Keeyask and the preparation of the contract tendering documents, Manitoba Hydro was able to determine with remarkably high precision the quantities of concrete and earthworks (i.e. dams and dykes) that needed to be supplied and constructed. With hindsight, a unit price contract would have been more appropriate as it would have shifted the risk of labour productivity to the contractor while Manitoba Hydro retained the quantity risk. The Board recognizes that Manitoba Hydro had a negative experience when trying to tender the Wuskwatim GCC. Understandably, contractors are not willing to assume the risk for geological conditions and unknown quantities of excavation when bidding on construction projects.

The Board concludes that, had Manitoba Hydro exercised more effective oversight of BBE from the beginning, the current cost overruns may have been mitigated. As MGF observed, Manitoba Hydro is not a construction manager and it appears that it did not have the expertise or the awareness of how to manage a cost reimbursable contract.

5.2 Bipole III

The Bipole III Transmission Line is a reliability project that consists of:

- five 230 kV alternating current power lines, which are the outlets for the power from the northern generating stations,
- the Keewatinohk converter station, located approximately 80 km northeast of Gillam, Manitoba, which converts the alternating current into direct current,

- the Bipole III high voltage direct current ("HVDC") transmission line, a 500 kV line that is approximately 1,385 km in length,
- the Riel converter station, located east of Winnipeg, which converts the direct current power back to alternating current power for use in the domestic system or for further transmission south to be exported.

Manitoba Hydro had been considering the need for Bipole III since at least the 1980s. A wind event in September 1996 damaged 19 Bipole I and II towers and interrupted the delivery of power from its Lower Nelson River generating stations. Following that event, Manitoba Hydro began planning in earnest additional high voltage direct current transmission options to provide redundancy and increase the reliability of power supply. Initially, only a separate Bipole III transmission line was considered by Manitoba Hydro, routed down the east side of Lake Winnipeg in order to provide physical separation between the existing Bipoles I and II and the new Bipole III. As discussed elsewhere in this Order, the routing was changed to west of Lake Manitoba which necessitated the inclusion of converter stations at the northern and southern terminuses due to the longer length of the transmission line and the resulting inability of the existing HVDC converter stations to operate with the longer line. With the construction of Keeyask and any other future northern generation, additional HVDC converters are required to bring the full power of the new generation to southern Manitoba. Therefore, a transmission line-only option was no longer feasible.

Bipole III is nearing completion, with a scheduled in-service date of July 2018, at a final cost of $5.04 billion. The cost estimates for Bipole III have dramatically increased over the years since the western routing for the line was established. The following table shows the escalation of the western route Bipole III costs – including converter stations – through the years as specified in Manitoba Hydro's capital expenditures forecasts ("CEF").

Western Route Bipole III In-Service Cost Estimates - Capital Expenditure Forecast ("CEF") ($millions)					
CEF06	CEF07 to CEF10	CEF11 to CEF12	CEF13	CEF14 to CEF15	CEF16
1,880	2,248	3,280	3,341	4,653	5,042

The $1.88 billion estimate in 2006 was described in the capital project justification by Manitoba Hydro as a "placeholder". The revision to the capital project justification by Addendum 05 in CEF07 increased the cost by $368 million to $2.25 billion due to:

- an increase in the line length of 45 km in addition to the increase in line length arising from the western routing,
- increased transmission line material costs due to market price increases,
- increased transmission line construction costs as experienced by Manitoba Hydro on recent transmission line projects, such as the Wuskwatim-Birchtree line, and
- increases in interest and escalation charges.

Notably, capital expenditure forecasts CEF06 through CEF10 appear to use HVDC converter equipment estimates developed by an external consultant in 2001, meaning the largest component of the project did not have a current cost estimate. In the current control budget, the converter stations are approximately 55% of the total cost. These capital expenditure forecasts also did not include any amounts for contingency and assumed many of the converter station site development costs were included in other projects such as the Conawapa generating station and the Riel 500 kV sectionalization project.

In 2009, Manitoba Hydro prepared a revised Bipole III cost estimate of $3.95 billion, an increase of $1.71 billion. The increase was due to re-estimates of the transmission line and converter station costs, the inclusion of contingency at 15% of the base costs, the inclusion of costs previously assumed to be included in other projects, and changes in interest and escalation charges. This estimate assumed line-commutated converter ("LCC") technology, which in turn required four synchronous condensers at Riel station. This estimate, while approved by the Vice Presidents of Transmission and Power Supply, was not approved by the Manitoba Hydro Executive.

After Manitoba Hydro commissioned an estimate by an external consultant in 2010, Manitoba Hydro projected a Bipole III cost of $3.28 billion, which was reflected in CEF11 and approved by the Executive. The most significant changes were the inclusion of voltage source conversion technology instead of LCC technology and the elimination of synchronous condensers at Riel station, as well as substantial reductions in the contingency for the transmission line and converter stations. This estimate included a contingency of $205 million, representing 6% of transmission line base costs and 11% of converter station base costs, compared to the previous $525 million contingency.

The next revision to the Bipole III project cost estimate occurred in October 2014, with an increase to $4.65 billion due to:

- receipt of the HVDC converter station bids in March 2014 which provided firm, fixed pricing to refine Manitoba Hydro's internal estimates. Other contracts were finalized and incorporated into the revised estimate;
- HVDC converter station suppliers were only willing to provide LCC technology converters, necessitating the need for synchronous condensers. Manitoba Hydro had assumed that HVDC suppliers would bid the newer voltage source conversion technology which did not require synchronous condensers;
- finalization of the transmission line route according to Clean Environment Commission recommendations;

- an increase in the capacity of the HVDC converters to 2300 MW, in case additional generation is added in the future;
- a delay in the in-service date from October 2017 to July 2018;
- updated land acquisition costs;
- inclusion of the Community Development Initiative; and
- an increase to the transmission line contingency and the inclusion of a management reserve.

As explained by the Board in Order 73/15:

> *Manitoba Hydro was initially optimistic that it could utilize lower-cost voltage-source conversion (VSC) technology in the Bipole III converter stations. However, while vendors initially indicated that the use of this technology was feasible, they ultimately were not prepared to design and provide VSC technology, resulting in a requirement for line-commutated converter (LCC) technology and synchronous condensers to meet performance requirements.*
>
> *Manitoba Hydro advised that the three bids for High Voltage Direct Current (HVDC) conversion equipment closed on March 20, 2014. All bids were based on LCC technology. Manitoba Hydro completed its technical review of the proposals by June 20, 2014. The revised control budget was prepared in August of 2014 and approved by Manitoba Hydro's executive committee in August 2014. Manitoba Hydro indicated that it did not advise the Board of cost increases during the NFAT since it took several months to prepare the control budget.*

The $4.65 billion estimate was the final pre-construction estimate prepared by Manitoba Hydro. It is comprised of contracts with varying payment structures, including fixed price (HVDC converter equipment), unit price (transmission line tower foundations, towers, and conductor stringing), and cost reimbursable (camp operations) arrangements.

Of the cost increase from $4.65 billion to $5.04 billion, $106 million is due to increased HVDC converter station costs and $302 million is due to increased transmission line costs, partially offset by decreases in the Bipole III collector transmission lines and Community Development Initiative. The main reasons for these increases are as follows:

- Increased contingency to address a greater number or consequence of risks;
- Costs related to highway upgrades and the access road to the Keewatinohk converter station which were transferred from the canceled Conawapa project to Bipole III;
- Additional payments to a reserve as specified by a letter of agreement amendment to the Burntwood-Nelson Agreement;
- An increase to the HVDC converter station costs due to commodity (copper, steel, concrete) price escalation;
- Increased transmission line construction costs due to higher actual costs for anchors and foundations than anticipated, delay claims due to weather and material shortages, schedule compression using helicopters to assemble towers and string conductors, and increased costs related to biosecurity;
- Increased transmission line property acquisition costs; and
- Increased vehicle costs.

Independent Expert Consultant Evidence

Amplitude found the costs of the HVDC converter stations and the synchronous condensers to be reasonable. On a cost per megawatt basis, the Bipole III converter stations are within the range of the costs of other converter stations in Canada and internationally, although at the high end of the range. Amplitude explained that this is reasonable given the remote location of the Keewatinohk converter station, that there are two valve groups per pole compared to one for the comparison stations, and the extreme weather and environmental conditions experienced during construction. Amplitude similarly determined that the Riel synchronous condensers are within the range of other recent projects but at the high end of the range.

MGF found Manitoba Hydro's cost estimating methodologies (with respect to the $4.65 billion and $5.04 billion estimates) are consistent with industry standard and best practices. Manitoba Hydro prepared a Basis of Estimate which, in MGF's view, was extremely well done. MGF found Manitoba Hydro's approach to market, tendering of contracts, and contracting methodologies were appropriate.

MGF found the potential for a cost overrun on the HVDC converter stations to be low, due to the fact that most of the remaining work is being performed under fixed price contracts. MGF expects Manitoba Hydro will deliver the transmission line within the estimated cost.

MGF found that Manitoba Hydro has managed the project well. MGF's view is that the project is on schedule but some critical path activities are slipping, specifically work to complete tower erection and conductor stringing. Manitoba Hydro advises that it has addressed this schedule slippage by removing this scope of work from the under-performing contractor and contracting with another construction company to complete this work prior to the end of the 2017/18 winter construction season.

MGF recommends improvements for Manitoba Hydro's estimating processes on future projects, such as having the estimate team prepare the estimate with input from each department and providing supporting back-up and more detailed explanation outlining the structure and relationship between the physical scope of work and resources. MGF also suggested that a higher contingency, such as a P95 contingency, be used when evaluating the business cases of future projects.

Manitoba Hydro's Position

Manitoba Hydro submits that Bipole III is on schedule for a July 2018 in-service date and is on target to be completed within the $5.04 billion control budget.

Manitoba Hydro states that the remaining risks to Bipole III relate to schedule and not cost, as the remaining work is predominantly under fixed price or unit price contracts. As such, while the in-service date may slip from July 2018, the cost should not exceed $5.04 billion. The remaining risks include weather, transmission line contractor performance in erecting towers and stringing conductors, delays in delivery of the final synchronous condenser transformer, and commissioning of the system.

Intervener Positions

The Consumers Coalition states that Manitoba Hydro's proposed use of voltage source conversion technology for the HVDC converters, as was anticipated in the $3.28 billion cost estimate prepared in 2011, represented a high-risk decision based on new technology that had not been executed at that time. The Consumers Coalition notes that all three HVDC converter equipment vendors rejected voltage source conversion technology in their bids.

Bipole III Western Versus Eastern Routing

In 2005, Manitoba Hydro was instructed by the provincial government to consider a western routing of Bipole III. In the capital project justification prepared by Manitoba Hydro's Transmission business unit and approved by the Manitoba Hydro Executive, Manitoba Hydro identified several reasons why a western routing was inferior:

- Technically inferior solution to the eastern-routed Bipole III line with converters; less load served on average in situations for which the line is to be built.
- Less reliable solution since the west side scheme would still only provide an outlet of 2000 MW of northern generation in the event of another Bipole I & II corridor outage, while an east side Bipole III line would allow the paralleling of Bipole I & II converters on the Bipole III line providing the outlet of 3300 MW of northern generation. Also, the longer line length associated with a western route increases exposure to outages on Bipole III.
- A delayed ISD [in-service date] over an eastern routed line, placing Manitoba customers at greater risk for a longer period of time. A western line will likely take longer for conducting environmental assessment/public work consultation and will take more time to build. The earliest date for initiation of environmental work is after the October 2006 recommendation of an alternative to the east of Lake Winnipeg Bipole III line.
- Justification at a public hearing by Manitoba Hydro of the westerly routing concept vs. an easterly route concept will be problematic.
- Although 1265 km is used as a proxy minimum for the line length, it is likely the actually built line will be considerably longer with more cost and losses, due to efforts to maximize separation from the existing HVDC right of way.
- The siting of Bipole III in a western corridor would make the placement of the next north/south transmission line very problematic with the east of Lake

Winnipeg routing being blocked and the Interlake routing presenting significant risk of a common mode outage.

In 2007, the provincial government finalized its policy decision to build Bipole III with a western routing, rather than the previously planned eastern routing. In its September 20, 2007 letter to the Manitoba Hydro Electric Board, the Government explained as follows:

> *The Manitoba Government does not regard an east side Bipole III as being consistent with these commitments and initiatives. We recognize the importance of the Bipole III initiative to improving system reliability and accommodating future northern generation. We would encourage the corporation to move ahead with required consultations and planning for an alternative Bipole Ill route.*

With this letter, the provincial government eliminated the eastern route from consideration and mandated that Manitoba Hydro consider alternate routings. Manitoba Hydro had already eliminated the Interlake route because of its proximity to Bipoles I and II. Consequently, the western route was the only route considered by Manitoba Hydro to be feasible. The resulting change to the western routing gave rise to the consequent increase in capital cost associated with the longer western route, although the western routing is technically inferior and leaves Manitoba Hydro customers at greater risk of power outages.

In Order 116/08, the Board noted additional inferiorities with the western routing:

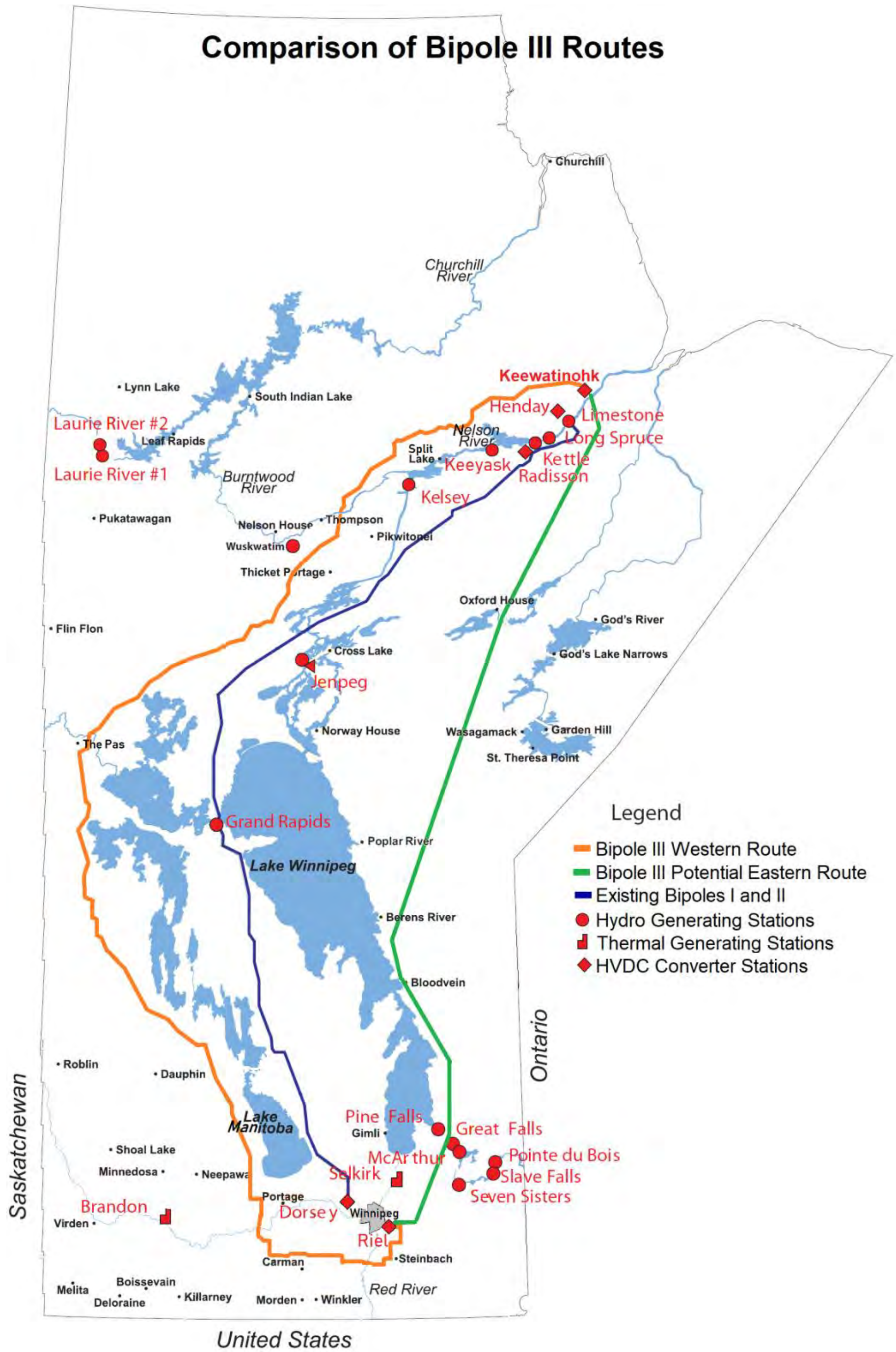
> *While an East Side Bipole III could function in parallel with existing Bipoles I and II, and in the event of the outage of both, make use of Bipoles I and II converters as well as the new Bipole III converters to provide 3,000 MW to the south, a West Side Bipole III would be limited to using only its own converters and thus could only provide the South with 2,000 MW in such a situation. MH advised that an outage of Bipoles I and II during the summer season could result in an additional cost to the Corporation of $160 million over the cost that would be incurred if*

Bipole III were built down the east side, the extra costs due to a requirement for additional imports to make up for the 1,000 MW differential.

In short, during a major outage of both Bipole I and II, an East Side Bipole III could serve both domestic and firm exports, while a West Side Bipole III would require significant additional needs and presumed expensive imports to meet domestic needs and firm exports.

Boston Consulting Group identified the increased costs of a western routing as $900 million.

Along with the existing routing of Bipoles I and II, the western and eastern routings of Bipole III are shown in the following map:


Comparison of Bipole III Routes
Churchill
Churchill River
Keewatinohk
Henday
Limestone
Long Spruce
Kettle
Radisson
Nelson River
Split Lake
Keeyask
Kelsey
Lynn Lake
South Indian Lake
Laurie River #2
Leaf Rapids
Laurie River #1
Burntwood River
Pukatawagan
Nelson House
Thompson
Wuskwatim
Pikwitonei
Thicket Portage
Oxford House
God's River
God's Lake Narrows
Flin Flon
Cross Lake
Jenpeg
Norway House
Wasagamack
Garden Hill
St. Theresa Point
The Pas
Grand Rapids
Poplar River
Lake Winnipeg
Berens River
Bloodvein
Ontario
Legend
Bipole III Western Route
Bipole III Potential Eastern Route
Existing Bipoles I and II
Hydro Generating Stations
Thermal Generating Stations
HVDC Converter Stations
Roblin
Dauphin
Saskatchewan
Lake Manitoba
Pine Falls
Gimli
Great Falls
Pointe du Bois
Slave Falls
Seven Sisters
McArthur
Shoal Lake
Minnedosa
Neepawa
Selkirk
Portage
Dorsey
Winnipeg
Brandon
Virden
Riel
Carman
Steinbach
Melita
Boissevain
Deloraine
Killarney
Morden
Winkler
Red River
United States

Board Findings

The Board finds that the $5.04 billion control budget amount incorporated by Manitoba Hydro into MH16 Update with Interim for Bipole III is to be used for Integrated Financial Forecast modeling and rate setting in this GRA.

The Board agrees with the Consumers Coalition that Manitoba Hydro undertook unreasonable risk when it developed its $3.28 billion Bipole III cost estimate in 2011. It appears that Manitoba Hydro had rejected its 2009 internal cost estimate of $3.95 billion, based on what was referred to as the “classic” LCC technology, in order to try to take advantage of new, unproven voltage source conversion technology. The Board finds that Manitoba Hydro compounded this risk by significantly reducing the contingency amounts. Exploring options to use new, improved technology should not be avoided. However, the Board concludes that when estimating costs for a project that includes new, unproven technology, the contingency amounts should be increased, not decreased as was done by Manitoba Hydro.

During the NFAT, Manitoba Hydro did not inform the Board that all the HVDC converter equipment vendors had bid LCC technology and had rejected the riskier voltage source conversion technology. However, as the Board concluded in Order 73/15, Manitoba Hydro at that time was in a position to know that its $3.28 billion cost estimate – which included a cost for converter stations of $1.83 billion – was not realistic and that a cost estimate approaching $4 billion was realistic.

The provincial government excluded Bipole III from the scope of the Board review at the NFAT; however, all of the development plans considered at the NFAT included Bipole III at a projected cost of $3.28 billion. The Board finds that, had a more realistic cost of Bipole III been used in the financial analyses, Manitoba Hydro’s debt under all development plans would have been higher and would be closer to the current projections of debt, as discussed in other sections of this Order.

The Board finds that the $5.04 billion estimate of the final cost of Bipole III is $900 million higher due to the western routing of the line compared to an eastern routing. The Board finds that this was a policy decision of government that should be a cost to taxpayers, not Manitoba Hydro's ratepayers. The Board's recommendation is that the payments Manitoba Hydro makes to the Government related to Bipole III be reduced until the $900 million burden is satisfied, as discussed in another section of this Order.

5.3 Manitoba-Minnesota Transmission Project and Great Northern Transmission Line

The Manitoba-Minnesota Transmission Project ("MMTP") is a single circuit, 883 MW, 500 kV alternating current transmission line starting at the existing Dorsey Converter Station northwest of Winnipeg and connecting at the Manitoba-Minnesota border to the Great Northern Transmission Line ("GNTL"), a new transmission line proposed by Minnesota Power terminating at a new station near Grand Rapids, Minnesota. Together, MMTP and GNTL form a new interconnection between Manitoba Hydro and the Midcontinent Independent System Operator market in the northern United States. MMTP and GNTL facilitate a 250 MW power sale to Minnesota Power beginning June 1, 2020 and ceasing May 31, 2035. MMTP and GNTL were reviewed at the NFAT proceeding. In its NFAT report, the Board recommended these projects proceed.

GNTL is being built in Minnesota by Minnesota Power. Manitoba Hydro, through its wholly-owned subsidiary 6690271 (Manitoba) Ltd., exercises oversight of the construction of GNTL through a Construction Management Agreement with Minnesota

Power. The Agreement grants 6690271 consultation and veto rights over construction decisions. GNTL has received all of its necessary permits for construction.

Manitoba Hydro is responsible for 100% of the construction, operating, and capital maintenance costs of the MMTP. Minnesota Power will fund 28% of the GNTL construction costs, based on the proportion of 883 MW total transmission capacity needed for the 250 MW Power Sale Agreement. Manitoba Hydro will fund the remaining 72% share. Manitoba Hydro is further responsible for 66.7% of the GNTL operating costs. Minnesota Power is responsible for 100% of the GNTL sustaining capital costs.

The new interconnection provides many benefits to Manitoba Hydro, including:

- additional import capacity of 700 MW; the additional winter import capacity allows deferral of new generation by one year,
- reduced import costs by allowing Manitoba Hydro to purchase power at the Minnesota trading hub, avoiding transmission line congestion that can push prices up at the MHEB trading node by 2% to 5% when Manitoba Hydro is importing power,
- improved energy security, emergency response, and reliability benefits in event of drought through increased access to imported power,
- additional export capacity of 883 MW, sufficient to sell the full exportable capacity of Keeyask to the Midcontinent Independent System Operator market under firm transmission,
- economic benefits in average and high flow years as Manitoba Hydro can export more power during more lucrative peak periods and spill less water when the existing interconnection would otherwise be at its maximum export limit, and

* increased prices for exported power through improved bilateral transmission access to the Wisconsin market as well as ability to sell power at the Minnesota trading hub, avoiding congestion and improving prices by 2% to 5%.

Since the NFAT in 2014, the capital cost estimates for MMTP and GNTL have increased. At the NFAT, MMTP was forecast to cost $350 million; Manitoba Hydro now estimates MMTP to cost $453 million. In 2014, GNTL was forecast to cost US$712 million in 2020 dollars. The current cost estimate is confidential and commercially sensitive and was reviewed by the Board *in camera*.

Manitoba Hydro completed the MMTP environmental permitting process before the Clean Environment Commission in 2017 and is awaiting a licence from the provincial government. In late 2017, the National Energy Board ("NEB") ruled that Manitoba Hydro must proceed with a certification process and not a permitting process, adding some additional cost. The in-service date for MMTP is June 1, 2020, coincident with the commencement of the Minnesota Power 250 MW power sale agreement. Manitoba Hydro indicated that it did not anticipate the NEB certification process would delay the in-service date, but that may be contingent upon obtaining a decision from the NEB prior to that regulator's March 2019 decision deadline.

MGF found the cost estimate for MMTP to be reasonable, although the estimated cost is low compared to a benchmark of similar transmission line projects.

MGF recommended that Manitoba Hydro prepare a Basis of Estimate to support the MMTP cost estimate. Preparation of a Basis of Estimate is an industry best practice that helps define the project scope, identifies risks and opportunities, provides a record of documents used in development of the estimate, provides a record of communications made during development of the estimate, and facilitates the review and validation of the estimate.

MGF found MMTP to be on schedule, although MGF identified some issues with the excessive complexity in some schedule areas, insufficient detail in other areas, and problems with the logic of the schedules. MGF recommended that Manitoba Hydro update the construction schedule for MMTP more frequently than every two months, which has been Manitoba Hydro's past practice, once construction commences.

MGF found the cost estimate for GNTL to be high compared to a benchmark of similar transmission line projects and high compared with MMTP. MGF recommended that an updated estimate be prepared.

MGF found that the Construction Management Agreement between Minnesota Power and Manitoba Hydro's subsidiary 6690271 Manitoba Ltd. adequately protects the interests of Manitoba Hydro.

Manitoba Hydro's Position

Manitoba Hydro advises that, although still in relatively early stages, both aspects of the United States interconnection project are on schedule and on budget, with a budget of $453 million for the Manitoba portion of the new interconnection.

Board Findings

The Board finds that the $453 million control budget amount for the Manitoba-Minnesota Transmission Project and Manitoba Hydro's currently forecast portion of the Great Northern Transmission Line project cost are to be used for Integrated Financial Forecast modeling and rate setting in this GRA. The Board expects that Manitoba Hydro will exercise effective management oversight, including with respect to schedule updates and schedule quality.

The Board recommends that, as suggested by MGF, Manitoba Hydro update the MMTP schedule more frequently than every two months once construction begins, especially considering the potential for a delay impact due to the National Energy Board licensing and certification process for MMTP. Manitoba Hydro is to consider implementing the recommendations made by MGF and report to the Board at the next GRA whether and the extent to which it has implemented these recommendations.

5.4 Manitoba-Saskatchewan Transmission Project

The Manitoba-Saskatchewan Transmission Project is a new 230 kV transmission line that runs from Birtle, Manitoba to Tantallon, Saskatchewan. The Manitoba portion of the line is approximately 44 km in length and together with associated upgrades to Manitoba Hydro's transmission system is expected to cost $57 million.

The line is being constructed to facilitate a 100 MW export power sale from Manitoba Hydro to SaskPower Corporation. The power sale agreement begins June 1, 2020 and ceases May 31, 2040. The pricing terms of the power sale agreement are confidential and commercially sensitive but were disclosed to the Board at an *in-camera* hearing. Manitoba Hydro indicates that the environmental attributes, such as carbon-free energy produced by Manitoba Hydro's hydroelectric generating stations, are transferred to SaskPower. The price paid by SaskPower includes these environmental attributes as there is no explicit pricing of environmental attributes.

In 2015 and 2016, prior to signing the contract with SaskPower, Manitoba Hydro evaluated the economics of the power sale agreement against the capital and operating costs of the new transmission line. The economic analysis showed that it was in Manitoba Hydro's interest to proceed with the power sale and construction of the transmission line. As this power sale agreement required the construction of new facilities, approval of the provincial government was sought and obtained through Order in Council.

The power sale agreement was signed in January 2016. The transmission line is currently in the design and licensing phase. Manitoba Hydro anticipates that the transmission line will require a Class 2 environmental assessment. A licence from the provincial government is expected in the second quarter of 2019. The transmission line is expected to be in service in the second quarter of 2021. This is one year after commencement of the power sale agreement. Manitoba Hydro and SaskPower have made alternative arrangements for the period prior to the transmission line entering service.

Daymark Energy Advisors found that, with updated information, the economic analysis indicates that it is still in Manitoba Hydro's interest to proceed with the project.

Board Findings

The Board finds that the $57 million control budget amount incorporated by Manitoba Hydro into MH16 Update with Interim for the Manitoba-Saskatchewan Transmission Project is to be used for Integrated Financial Forecast modeling and rate setting in this GRA.

The Board finds that the power sale agreement and transmission line project remain economic at this point in time. The Board supports Manitoba Hydro's decision to develop firm export sales to other Canadian jurisdictions including to the west.

6.0 Business Operations Capital

Manitoba Hydro prepares a projection of the capital expenditures needed annually for new and replacement equipment and facilities to meet the electricity requirements in Manitoba and firm export sale commitments outside the province. For Manitoba Hydro's fiscal years ending March 31, 2018 and March 31, 2019, total capital expenditures for its electric operations are forecast to be $3.0 billion and $2.6 billion, respectively.

Historically, and until its most current Capital Expenditure Forecast, Manitoba Hydro had three primary categories of capital projects:

1. "Major New Generation & Transmission Projects", such as Keeyask and Bipole III, which increase capacity and energy or provide increased reliability. In this context, increased reliability refers to reliability that was not previously inherent in the system. For example, replacement of an asset that restores the original or "new" reliability is not typically classified as Major New Generation & Transmission.

2. "Major Capital Projects", the category for larger expenditures, typically in excess of $50 million and with a construction period that usually extended beyond one year, which are not classified as Major New Generation & Transmission projects.

3. "Base Capital Expenditures", also previously referred to as Sustaining Capital, the category for numerous, unspecified projects below the $50 million threshold. These typically represent expenditures to renew existing assets and facilities (also referred to as "sustainment") replacements, to expand the electrical system to new customers, and to address load growth and requirements for additional capacity.

Under Manitoba Hydro's new management and the most current Capital Expenditure Forecast, capital expenditures are divided between Major New Generation & Transmission projects and Business Operations Capital projects, which combines the former categories known as Major and Base capital projects. Under the new approach, Major New Generation & Transmission projects are those that provide significant new generation and transmission capacity and include projects of a substantial cost. Business Operations Capital projects address requirements to sustain electricity service through renewal of aging or obsolete assets, to expand the electrical system to new customers, to address load growth and requirements for additional capacity, and to enhance system performance and functionality.

Of Manitoba Hydro's $3.0 billion of total annual capital expenditures in fiscal 2018, approximately $526 million is forecast to be spent on Business Operations Capital. In future years, the forecast of Business Operations Capital spending is between approximately $500 million and $650 million each year, totaling approximately $13 billion by the end of the 20-year Capital Expenditure Forecast in 2036. Under the Board Act and the Hydro Act, the Board does not have legal jurisdiction to approve Business Operations Capital projects and spending, but only to consider the revenue requirement of those projects for rate-setting purposes.

Manitoba Hydro is an asset-intensive organization that has been managing assets for generations and it has identified the need to mature its asset management practices to maximize value from scarce funding. Due to the magnitude of the past and future Business Operations Capital spending, the Board has long supported the need for Manitoba Hydro to review its spending plans and priorities by incorporating more formal, mature asset management processes.

Asset management involves the balancing of costs, opportunities, and risks against the desired performance of assets to achieve the organizational objectives. Manitoba Hydro defines asset management as the framework of processes and metrics used to make asset life cycle decisions, including operating context (duty cycle), maintenance schedules, and replacements or upgrades in accordance with corporate priorities and risk tolerances to maximize value. In its simplest terms, asset management means providing the required level of service in the most cost effective manner - the “right” work undertaken to achieve the desired performance outcomes in the most efficient and financially responsible manner. Mature and competent asset management enables the application of analytical data-driven approaches to managing assets over the different stages of their life cycle.

In prior Orders, including 116/08 and 73/15, the Board directed Manitoba Hydro to develop asset condition assessments, which are a necessary component of mature asset management processes. Asset condition assessments provide the data necessary with which to make informed asset management decisions. Manitoba Hydro has since developed asset condition assessments and health indices for many of its asset classes, however there are still many asset classes for which there are no condition assessments and the corresponding health indices are based solely on the assets’ ages.

In a comparison of Canadian Electricity Association members, Manitoba Hydro ranks in the top quartile for reliability when compared to rural Canadian utilities and in the second when compared to urban utilities. Manitoba Hydro surveys its customers four times a year for their level of satisfaction with the reliability of their electricity service as well as the price. Since 1999, customers have expressed high levels of satisfaction with reliability, while satisfaction with the price is lower. Manitoba Hydro has more limited survey data concerning customers' preferences for paying higher rates in order to reinvest in Manitoba Hydro's system and maintain the historical high levels of reliability. A 2014 survey indicated that two-thirds of the customers surveyed opposed annual rate increases of 4% to invest in modernizing Manitoba Hydro's system and add generating capacity.

6.1 Manitoba Hydro's Position

In this GRA, Manitoba Hydro identified the need to improve its asset management practices to maximize the value from limited funding. While the Utility is developing more advanced and mature asset management processes, it reports that it is at least three to five years away from being in a position to use these processes in developing its Capital Expenditure Forecast. The proposed spending in the 2016 Capital Expenditure Forecast, which is incorporated into the Integrated Financial Forecast, is based on Manitoba Hydro's long-standing capital planning processes and assumes that historical spending trends will continue into the future.

Manitoba Hydro is developing its new Asset Management Framework in three phases:

- Phase 1: assessment of current asset management practices, through a "gap assessment" performed by UMS Group Inc., an external consultant engaged by Manitoba Hydro in September of 2016;
- Phase 2: development of asset management policies and strategies. Implementation of Phase 2 has not commenced due to competing organizational priorities and the reduction of resources as a result of the Utility's Voluntary Departure Program. A timeline for initiating Phase 2 and has not been finalized although it is expected to be in 2018; and
- Phase 3: development of a detailed 'roadmap' for the implementation of a corporate asset management framework at Manitoba Hydro.

Manitoba Hydro implemented a software tool called Copperleaf C55 (“C55”) to assist with asset management, and engaged Copperleaf Technologies Inc. to help with the development of an initial Corporate Value Framework. The purpose of the Corporate Value Framework is to help Manitoba Hydro understand the value of investments and to identify the optimal set of investments across the different business units (Generation, Transmission, and Distribution) which deliver the greatest value.

According to Manitoba Hydro, all Test Year system renewal investments are condition-driven and reasonably required for the safe and reliable operation of the system. However, Manitoba Hydro also gave evidence that $160 million of capital spending proposed for the 2018/19 Test Year could be deferred. Manitoba Hydro states that a deferral of this magnitude cannot be repeated in future years.

6.2 Intervener Positions

The Consumers Coalition highlights the fact that Capital Expenditure Forecast CEF16 is based on Manitoba Hydro’s historical capital planning processes, not the asset management processes being developed. The Consumers Coalition states that the competence rating given to Manitoba Hydro in the UMS assessment applies to the asset management processes that the Utility is proposing to implement, not the processes that underpin CEF16 and the Test Year spending.

The expert witness retained by the Consumers Coalition, METSCO Energy Solutions (“METSCO”), was critical of Manitoba Hydro for implementing the C55 software prior to the development of the asset management roadmap and in advance of Manitoba Hydro understanding how the software will be used and what it will achieve.

The Consumers Coalition further submits that, while Manitoba Hydro engineers know their system and deliver good reliability results, the Utility has not demonstrated that it does so in a cost effective manner. Manitoba Hydro may not be doing the right project at the right time. The Consumers Coalition states that Manitoba Hydro does not have a consistent definition of risk that can be used across the three business units: Generation, Transmission, and Distribution. The Utility also does not have a means of planning and prioritizing capital spending across the different business units or across the different geographical areas it serves. For example, Manitoba Hydro may be spending on a Transmission project when the greater need and the greater reliability benefit may be realized with a Distribution project.

In addition, the Consumers Coalition argues that Manitoba Hydro has underspent on Business Operations Capital by 18% over the past three years compared to its planned spending, indicating that Manitoba Hydro's estimates for Test Year Business Operations Capital spending cannot be relied upon for rate setting purposes.

The Manitoba Industrial Power Users Group noted the assessment of the Boston Consulting Group that the equity ratio benefits from reduced spending on Business Operations Capital. In what was described by the Boston Consulting Group as a "Realistic 5-year Change", the deferral of low value capital projects totaling $100 million per year for five years shows a sustained benefit to the equity ratio through the year 2035 (i.e. the deferral was not depicted as a temporary change). In the view of the Manitoba Industrial Power Users Group, Manitoba Hydro has opportunities to reduce its Business Operations Capital spending, and has proven in the past that it is capable of reducing expenditures from forecast amounts.

6.3 Board Findings

The Board finds that, while in a period of major capital spending on Keeyask and Bipole III, Manitoba Hydro should find savings in Business Operations Capital.

The Board does not accept the Business Operations Capital spending forecast in Capital Expenditure Forecast CEF16. The Board does not accept that all Test Year investments are condition-driven and reasonably required for the safe and reliable operation of the system. The Board finds that Business Operations Capital spending can be safely decreased by $160 million, based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year. This is consistent with the Board's findings in Order 73/15 that Manitoba Hydro has not adequately evaluated the long-term pacing and prioritization requirements for Business Operations Capital spending. In that Order, the Board did not endorse Manitoba Hydro's long-term Business Operations Capital plan. The Board accepts the evidence that Manitoba Hydro can reduce the level of spending from its forecast and has shown that it has done so in the past, as with the Gillam Town Site Redevelopment project and with the lower spending in the past three years than was originally forecast.

Based on the suggestion of the Boston Consulting Group in its initial report that the spending reductions can be maintained over a longer period, this issue will be revisited at future GRAs. Reducing Business Operations Capital helps offset the expenditures on Keeyask, which are anticipated to mostly be complete by 2023. Reductions in Business Operations Capital result in a reduced need to borrow funds and will enhance Manitoba Hydro's cash flow. Furthermore, the additional reliability obtained from Bipole III and additional generating capacity from Keeyask mean Manitoba Hydro will have added system-level redundancy, reducing the need for non-critical generation investments.

In addition to the positive impact on Manitoba Hydro's cash flow, reducing Business Operations Capital also results in improvement to the debt-to-equity ratio. Manitoba Hydro's analysis also shows that a reduction of capital spending of $100 million annually increases its retained earnings by $414 million after 10 years.

The Board accepts METSCO's evidence that Manitoba Hydro cannot demonstrate the proposed spending is necessary or has been optimized to any extent. Manitoba Hydro acknowledges that it has not evaluated alternative Business Operations Capital spending scenarios or the performance and reliability impacts of different Business Operations Capital spending levels.

The Board recognizes that Order in Council 92/2017 does not give the Board authority to direct Manitoba Hydro to amend its planned Business Operations Capital spending. Rather, the Board has factored into its rate decision the reduction in Business Operations Capital of $160 million. Manitoba Hydro can decide whether to accept the Board's finding and reduce its Test Year Business Operations Capital spending, or to incur additional debt in order to maintain spending at the proposed levels in CEF16.

The reduction in spending on Business Operations Capital in no way diminishes Manitoba Hydro's responsibility and obligation to provide for an ongoing safe and reliable supply of energy to its customers in the most efficient and environmentally sensitive manner. The Board expects that Manitoba Hydro will appropriately assess, plan, and prioritize Business Operations Capital spending in order to meet its obligations in this regard.

The Board finds that Manitoba Hydro has taken initial steps towards developing asset management processes, and is to be commended for doing so in order to better ensure that the financial resources allocated to Business Operations Capital bring maximum value to the Utility's ratepayers. Further to the direction from Orders 116/08 and 73/15, Manitoba Hydro has developed asset condition assessments for some asset classes, but the health of certain asset classes is characterized solely by the age of the assets. Manitoba Hydro must continue to develop asset condition assessments for all of its major asset classes so that it has the necessary data to make prudent spending decisions within its asset management framework.

At present, Manitoba Hydro prioritizes its capital spending based on the views and experience of its subject-matter experts in Generation, Transmission, and Distribution. Manitoba Hydro has not yet developed processes and practices that would enable it to objectively compare the value of different projects across its business units, nor can Manitoba Hydro quantify in terms of increased reliability the impact of spending on a generation project compared to a transmission project compared to a distribution project. More mature asset management processes, including a more complete set of asset condition assessments, are required so that Manitoba Hydro is in a position to objectively prioritize and optimize its spending across business units based on a common definition of risk.

The Board understands that developing a modern asset management system takes time and wishes to monitor Manitoba Hydro's progress. Manitoba Hydro is directed to hire an independent consultant to assess the Utility's progress with the development of its asset management program and in addressing the recommendations made by its consultant, UMS. The consultant is to also assess progress with the development of the Corporate Value Framework. Manitoba Hydro is to file with the Board by June 29, 2018 the Terms of Reference for the consultant for the Board's review and comment. Manitoba Hydro is directed to report back to the Board on its progress and the result of the consultant's assessment at the next GRA.

The Board acknowledges the contributions from past and present Manitoba Hydro personnel in designing, constructing, and maintaining the electrical system. Clearly, with top quartile reliability, Manitoba Hydro has constructed, operated, and maintained an outstanding electrical system to the benefit of Manitobans. With this Order, the Board does not intend to diminish these contributions, but it does recognize the cost pressures that result from the capital program that includes Bipole III, Keeyask, and a new interconnection with the U.S. Those cost pressures mean that Manitoba Hydro can no longer continue to fund Business Operations Capital at its historic levels unless and until it can demonstrate through mature asset management processes that those investments are necessary.

7.0 Demand Side Management Spending

Demand side management is a common utility strategy for reducing consumer demand for energy in order to defer the need for new generation assets. Manitoba Hydro's Demand Side Management Plan, marketed under the Power Smart brand, involves various education and incentive programs aimed to reduce domestic consumption of both electricity and natural gas.

Manitoba Hydro combines the impacts of demand side management activities with the load forecast to represent the forecast net load, which is used to forecast domestic revenues in the Integrated Financial Forecast.

As noted above, *The Efficiency Manitoba Act* creates a new Crown Corporation, Efficiency Manitoba, which will have a mandate to provide demand side management programming. *The Efficiency Manitoba Act* requires annual net electricity energy savings of 1.5% of sales (compared to the previous year's weather-normal consumption) for the first 15 years of operation; however, this target can be changed by regulation. Until Efficiency Manitoba develops its long-term demand side management plan, Manitoba Hydro intends to carry forward its 2016/17 15-year Demand Side Management Plan, with one-year plans continuing to be developed.

Manitoba Hydro seeks to pursue all cost effective demand side management opportunities. The Utility assesses the cost effectiveness of demand side management programs against its marginal value of electricity. The assessment of the cost effectiveness considers the levelized resource cost of each program, taking into account, on a per kilowatt-hour basis, the combined incremental cost of the installed program plus any administrative costs associated with promoting the program. The marginal value is the value to the Utility's system of deferring an increment of load growth to Manitoba Hydro's integrated system.

Marginal value is determined based on each of the components of serving residential load: generation supply, bulk transmission capacity, and distribution capability. The transmission and distribution components are based on a one-year deferral of planned capital additions to meet ongoing capacity requirements. The generation marginal value is based on the value for each of generation capacity and generation energy. In 2017, Manitoba Hydro changed its methodology for calculating the value of generation capacity. Previously, generation capacity was valued using the potential for sales of capacity on the export market. Under the new methodology, Manitoba Hydro values generation capacity on the basis of the deferral of a new generation resource in Manitoba. Under the 2017 methodology, generation energy continues to be valued using the forecast price of energy sales on the export market.

In assessing each individual program, Manitoba Hydro considers the capacity and energy benefits over a period of time, including variations in marginal value by time of day, season, and year. As a result, a specific program may have a levelized cost that is higher or lower than the long-term average marginal value. However, in general terms, when the levelized cost of a program is below the marginal value, Manitoba Hydro considers the program cost effective. This means that, over the life of the program, there is an economic return to the Utility with respect to generation, transmission, and distribution benefits that arise from the energy savings achieved through the program.

The programs in the 2016/17 plan are measured against the 2015/16 levelized electric marginal value of 7.8 ¢/kWh. The planned levelized total resource cost of the individual electric demand side management opportunities, including both the customer's and Manitoba Hydro's investment, range from 1.1 to 13.6¢/kWh, with an average of

3.7¢/kWh for the portfolio of programs as a whole. The average levelized utility cost, or the cost of solely the Utility's investment levelized over a fixed time period, is 1.6¢/kWh for the entire electric demand side management portfolio.

During the course of the GRA proceeding, Manitoba Hydro filed updated marginal value information. The marginal value has decreased to 5.75¢/kWh for generation when serving residential customers. Although the marginal value has decreased by 28%, Manitoba Hydro does not plan to reassess the cost effectiveness of its demand side management programs under a total resource cost test because of the anticipated transfer of programming to Efficiency Manitoba.

Manitoba Hydro's 2016/17 15-year plan seeks to realize electricity savings of 1.2% of the annual average load over the next 10 years, with a Utility investment of $1.2 billion over the next 15 years. Manitoba Hydro's 2017/18 Demand Side Management one-year plan seeks to realize electricity savings of 238 MW and 310 GWh in 2017/18, with an electric utility investment of $58.7 million. Of that amount, $43.7 million was spent as of November 30, 2017. For the 2018/19 Test Year, Manitoba Hydro forecasts Power Smart electric capital and operating spending of $101.1 million for electric capital and operating spending.

The evidence is that demand side management spending exerts an upward pressure on consumer rates. Retained Earnings would be $4.2 billion greater by 2036 if no money was spent on demand side management and no energy savings achieved. While demand side management energy savings can be sold into the export market, there is currently a differential between domestic and export prices, which leads to lower overall revenues for Manitoba Hydro.

7.1 Manitoba Hydro's Position

Manitoba Hydro's position is that, while there continues to be uncertainty in how Efficiency Manitoba will pursue its mandate, it would be poor planning to arbitrarily reduce forecasted demand side management in the face of a legislative mandate that exceeds Manitoba Hydro's current plan. Manitoba Hydro argues that assuming savings on programming that is moving from Manitoba Hydro's control, but not its financial responsibility, is imprudent. Manitoba Hydro estimates that an additional $1 billion in Utility investment, over and above the currently planned $1.2 billion investment, is needed to meet *The Efficiency Manitoba Act* annual savings target of 1.5% of sales.

7.2 Intervener Positions

The Consumers Coalition raises significant concerns about the reliability of projected demand side management expenditures due to a demonstrable failure by Manitoba Hydro to undertake post-NFAT integrated resource planning. Specifically, the Consumers Coalition's position is that Manitoba Hydro has not demonstrated optimized demand side management spending, given excess load, reduced marginal cost thresholds, and the flexibility that exists under *The Efficiency Manitoba Act* to make recommendations regarding appropriate targets. With respect to the latter, the Coalition argues that the legislation supports an ongoing dialogue about the target itself and any efficiency plan that Efficiency Manitoba puts forward. This dialogue should include issues related to accessibility of demand side management programs for all ratepayers. In addition, declining marginal values may leave some demand side management uneconomic.

The Consumers Coalition submits that the Board should direct the formation of a working group on integrated resource planning, involving stakeholders, Efficiency Manitoba, and Manitoba Hydro. The Board should also recommend that funds paid by Manitoba Hydro to the Province be used to fund more extensive demand side management programs specifically targeted to lower-income and high consumption consumers.

The Green Action Centre submits that the Utility's revenue requirement should include sufficient additional funds in a dedicated account to cover rate discounts for the energy poor. As well, these funds should support more aggressive demand side management in order to meet the legislated targets and provide geothermal heating system subsidies as a rate mitigation measure for electric space heating customers.

The Manitoba Industrial Power Users Group argues that it is not apparent that Manitoba Hydro's "status quo" approach to demand side management is reasonable given that export prices and related marginal values have materially declined. The level of demand side management spending included in the financial forecast should be consistent with integrated resource planning, including a material reduction to reflect the decrease in marginal value by approximately one-third. Demand side management should be encouraged where it is proven cost-effective, including where it can benefit customers to manage electricity bills without negatively affecting other ratepayers.

7.3 Board Findings

The Board finds that Manitoba Hydro's revenue requirement should be reduced to reflect lower demand side management spending as a result of the new lower marginal value. The Board agrees with the Manitoba Industrial Power Users Group that the level of demand side management spending included in the financial forecast should be consistent with integrated resource planning, including a material reduction to reflect the decrease in marginal value by approximately one-third. As discussed below, the Board also recommends that Manitoba Hydro reduce its demand side management expenditures from the level incorporated in MH16 Update with Interim that targets 1.2% in energy savings on average in each year over the next 10 years.

The Board's approved rate increase takes into consideration a reduction in demand side management spending as well as an increase in domestic load that will result from fewer demand side management programs. This reduction in the revenue requirement is appropriate for rate-setting purposes while Manitoba Hydro remains responsible for demand side management spending and programming. Considerations other than the reasonableness of expenditures for rate-setting purposes will apply once Efficiency Manitoba has assumed demand side management programming and presents a demand side management plan to the Board for review.

While Manitoba Hydro has forecast demand side management spending to achieve energy savings over the next 10 years at a level of 0.3% below the energy savings target in *The Efficiency Manitoba Act*, the amount of spending is not justified for the Test Year. Efficiency Manitoba is not yet operational and once it is, there are legislated steps that must occur prior to the entity's implementation of an approved efficiency plan. The adverse rate impacts that arise from Manitoba Hydro's plan are not reasonable in the present context.

Reduced demand side management spending for rate-setting purposes is supported by the change in circumstances since the NFAT review in 2014. In 2014, new generation resources – such as Keeyask - were required as early as 2024 under the load forecast accepted in the NFAT Report, with additional generation resources needed by 2030. With reductions to the load forecast since 2014, including the loss of expected Top

Consumer Petro/Oil/Gas sector loads, the next new generation resource is not needed until approximately 2040, even with new export contract obligations since the NFAT. The 2017 marginal value is lower than the 2013 marginal value by approximately one-third, which affects the economics of demand side management programs. As well, as noted by Manitoba Hydro and expert witnesses in the proceeding, rate increases above inflation will themselves have a conservation impact.

The Board finds that, in light of the new, lower, levelized marginal value, some of Manitoba Hydro's demand side management programming may no longer be cost effective. This was acknowledged by Manitoba Hydro witnesses and is not contested. Consumer rates should not, at this time, recover the costs of demand side management programs that are no longer cost effective, unless justified by having a lower-income target market. Given the evidence adduced in this proceeding about energy poverty and bill affordability, it is reasonable for consumer rates to recover the costs of lower-income demand side management programs, even if not cost effective as assessed against the new lower marginal value.

In light of the above, the Board recommends that Manitoba Hydro reduce its demand side management spending. Manitoba Hydro should review its demand side management programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers. In addition to continued Utility investment in lower-income demand side management programs, the Board recommends that the provincial government amend Efficiency Manitoba's mandate to explicitly include consideration of bill affordability. This would include targeting of lower-income consumers with demand side management programs, as well as consideration of the impact of demand side management costs being paid by non-participants.

Amendment of Efficiency Manitoba's mandate to include bill affordability is appropriate in light of the interplay between demand side management, which seeks to mitigate the impact of rate increases, and bill affordability. The Board remains concerned about bill affordability, including in the context of projected annual rate increases over the forecast period. As such, lower-income demand side management programs that are uneconomic or do not meet a cost-effectiveness assessment should continue to be pursued once the transfer to Efficiency Manitoba is complete.

Finally, the interrelationship between demand side management, the need for new generation resources, and the cost of those resources reinforces the recommendation in the NFAT Report that integrated resource planning be implemented in Manitoba.

From one perspective, Manitoba Hydro is financially worse off over the forecast period for undertaking demand side management due to the difference between domestic rates and the price for which Manitoba Hydro can sell energy saved by domestic customers into the export market. However, this analysis neglects the benefits of deferring new generation resources that may be considerably more expensive than the aggregate demand side management investments. For example, in its NFAT report, the Board concluded that:

> *…treating the DSM savings from the Supplemental 2014 Power Smart Plan as a separate, independent energy resource, yields capacity savings that amount to more than 80% of the net system capacity addition from the proposed Conawapa Project. Similarly, the annual dependable energy savings from the Power Smart Plan exceed 85% of the dependable energy output from the proposed Conawapa Project. To achieve these electricity savings, Manitoba Hydro budgets to spend $822 million, which is less than 8% of the $10.7 billion cost of building Conawapa.*

In the current proceeding, by 2031, the 2016 Demand Side Management Plan is expected to deliver capacity and energy savings of 1,232 MW and 4,506 GWh at a cost of $1.2 billion. This compares to Keeyask, which provides 630 MW of winter peak capacity and 4,400 GWh of energy in an average year, at a cost projected by Manitoba Hydro to be $8.7 billion. This is illustrative of the importance of integrated resource planning.

8.0 Export Revenue Forecast

Manitoba Hydro cites a deterioration of its anticipated export revenues as a factor in the Utility seeking higher domestic rate increases than in previous rate applications. While export prices are still forecast to increase over time, that increase is less than previously expected by Manitoba Hydro. Manitoba Hydro now tempers its export price growth as the outlook for low costs of fossil fuel continues and also because American utilities have local options for carbon-free electricity.

A higher forecast of export prices, all else equal, will require lower revenues from domestic ratepayers on a forecast basis. However, if the export price forecast is projected at a level higher than actual revenues achieved, then Manitoba Hydro will not realize the expected export revenues and, as a result, domestic ratepayers will be asked to pay higher rates to make up the shortfall.

Manitoba Hydro’s export revenue forecast is comprised of three main components:

- The volumes of energy and generation capacity that are surplus to the needs of Manitobans.
- The forecast of export prices for the surplus energy and capacity. Manitoba Hydro predominantly has two types of export sales: firm, also known as dependable, and opportunity. Firm export energy sales are made from energy which is forecasted to be available if the worst drought conditions previously experienced are repeated. Firm capacity sales are made from energy that is surplus to domestic needs based on winter or summer peak demand. Opportunity sales are from energy that is surplus to domestic requirements and firm sales.
- The revenues from firm export contracts that Manitoba Hydro has negotiated with counterparties.

The exportable volumes are determined based on Manitoba Hydro's domestic load forecast and the generating capability of the Utility's resources. Export revenues are forecast for the first year in the Integrated Financial Forecast based on the actual water inflow conditions, the most current reservoir and lake level elevations, and the expected inflows through to the end of the fiscal year. For the second forecast year, export revenues are now determined for each of the entire range of flow conditions based on expected reservoir levels. Previously, Manitoba Hydro determined the export revenue projections for the second year by using a single median flow scenario and expected reservoir levels. For the third and subsequent years of the forecast, the methodology is unchanged from previous and export revenues are determined for each of the entire expected range of flow conditions and reservoir levels. For each of these 'flow cases' for the second and subsequent years, Manitoba Hydro calculates the expected export revenues by multiplying the exported volumes by the forecasted price. Manitoba Hydro then averages the expected export revenues to arrive at a forecast of export revenues for each year of the financial forecast.

8.1 Manitoba Hydro's Position

To forecast export prices, Manitoba Hydro continues to use a consensus forecast for a 'reference case' derived from the equal weighting of four independent price forecasting consultants; however, as in the past, the Utility has made its own adjustments to the export price forecast.

In this GRA, Manitoba Hydro has removed the premium that has historically been applied to uncontracted long-term dependable energy forecast prices because utilities in the Midcontinent Independent System Operator market have other, competitive options for long-term, fixed-price, and carbon-free energy supplies. The Utility also removed the value of capacity from the pricing of potential uncommitted export sales made from surplus capacity as there is surplus capacity in the Midcontinent Independent System Operator market. The financial effect of Manitoba Hydro's revisions to the export price forecast is to value all surplus energy at opportunity prices rather than ascribe a higher value for its dependable surplus product.

Lost opportunity export revenues from the delay in the Keeyask in-service further decrease export revenues.

Manitoba Hydro assumes no new firm long term contracts will be negotiated for the substantial surplus dependable energy and capacity in the 20-year forecast. Manitoba Hydro further assumes existing long-term firm contracts will expire without negotiating extensions.

The following is the current list of Manitoba Hydro's long term contracted export sales:

Power Sale Contract	Contract Start	Contract End
Minnesota Power 50 MW System Participation	May 2015	May 2020
Minnesota Power 250 MW System Participation	Jun 2020	May 2020
Minnesota Power 50 MW ZRC System Participation	Jun 2017	May 2020
Great River Energy 200 MW Seasonal Diversity	Nov 2014	Apr 2030
Northern States Power 125 MW System Power	May 2021	Apr 2025
Northern States Power 375/325 MW System Power	May 2015	Apr 2025
Northern States Power 350 MW Seasonal Diversity	May 2015	Apr 2025
Northern States Power 75 MW Seasonal Diversity	Jun 2016	May 2020
Wisconsin Public Service 100 MW Sale	Jun 2021	May 2027
Wisconsin Public Service 108 MW System Participation	Jun 2016	May 2021
SaskPower 100 MW System Participation	Jun 2020	May 2040
SaskPower 25 MW System Participation	Nov 2015	May 2022
American Electric Power 79 MW ZRC	Jun 2016	May 2018
American Electric Power 50 MW ZRC	Jun 2018	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2018	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2020	May 2021
NextEra 30 MW ZRC Sale	Jun 2015	May 2018
NextEra 100 MW ZRC Sale	Jun 2016	May 2018

Source: Appendix 3.1, pg 16

8.2 Independent Expert Consultant Evidence

Daymark Energy Advisors reviewed Manitoba Hydro's forecast of exportable volumes of energy and capacity and found those forecasts reasonable. Daymark assessed the revenues from Manitoba Hydro's firm export contracts and likewise found those revenues reasonable and were appropriately included in Manitoba Hydro's forecast of total export revenues.

In Daymark's view, Manitoba Hydro did not demonstrate that the independent price forecasts it purchased from the four external forecasting firms were "reference case" or "P50" forecasts, and therefore the resulting average of these forecasts may not be a true P50 forecast.

Daymark found that Manitoba Hydro did not use the consensus forecast for capacity prices. Daymark also found that not including a dependable energy premium or any revenue potential for capacity sales does not result in a P50 forecast, but rather a P100 forecast. Daymark found that not including the premium or capacity value may be reasonable in the short term but not in the long term, as there is evidence that the Midcontinent Independent System Operator market will be short capacity by 2022 and United States Federal and State policies may still favour Manitoba Hydro's carbon-free, firm electricity exports.

In summary, Daymark found that Manitoba Hydro's export revenue forecast is conservative or low relative to Manitoba Hydro's stated goal of having a P50 forecast of export revenues.

8.3 Intervener Positions

The Consumers Coalition argues that Manitoba Hydro's export revenue forecast is biased low as it is based on policy decisions, is not a true "P50" forecast (i.e. results being higher 50% of the time and lower 50% of the time), and does not reflect the benefits of Manitoba Hydro's new transmission interconnection with the Midcontinent Independent System Operator market in the United States. The United States Federal Energy Regulatory Commission and the United States Energy Information Administration reports support the view of Daymark that Manitoba Hydro's export forecast is conservatively low. The Consumers Coalition submits that this puts unnecessary upward pressure on the domestic rate increases.

The Manitoba Industrial Power Users Group maintains that Manitoba Hydro's Integrated Financial Forecast should include the best estimate for the prices at which the Utility can sell its surplus capacity and energy, including values for capacity, premiums, and continuing bilateral contracting arrangements. Manitoba Hydro is being pessimistic by assuming its major export contracts that expire in 2025 will not be renewed or replaced with anything that offers more than opportunity export energy value. Manitoba Hydro has assumed the worst-case scenario, and as such the Utility's approach is inconsistent with P50 forecasts in an integrated financial forecast. This Intervener argues that this should be considered by the Board in determining the appropriate rate increases to be awarded.

8.4 Board Findings

The Board finds Manitoba Hydro's forecast of export revenues to be conservative such that, on a probability basis, it will under-forecast the revenues expected to be realized from export sales. Under-forecasting export revenues results in Manitoba Hydro forecasting a need for higher domestic rates. Manitoba Hydro's failure to provide a "P50" probability export revenue forecast is a factor considered by the Board in reducing the rate increase requested by the Utility.

Accepting the evidence of Daymark Energy Advisors, the Board finds Manitoba Hydro's export revenue forecast to be conservative for the following reasons:

- Manitoba Hydro's export revenue forecast is not consistent with a financial forecast that that has a probabilistic goal of P50; and
- Manitoba Hydro's change of methodology - to remove capacity values and dependability premiums from the substantial surplus dependable energy - is reasonable in the near term, but is not reasonable in the long term as it biases the export forecast to be low and is not consistent with third party forecasters nor with the needs in the Midcontinent Independent System Operator and Minnesota markets.

Despite Manitoba Hydro purchasing capacity price forecasts from four independent price forecasters, Manitoba Hydro did not use these forecasts to develop a consensus capacity price forecast, and instead assumed zero capacity prices and revenues. With respect to the carbon price forecasts of the independent price forecasters, Manitoba Hydro argued that the goal to have an unbiased consensus forecast is achieved by accepting other experts' views of the future and not imposing its own biases by choosing forecasts to produce a predetermined result. Yet, it appears Manitoba Hydro did not do this when it ignored the consensus forecast of capacity prices and instead forecast zero capacity prices and revenues.

Additionally, the Board finds that Manitoba Hydro's export revenue forecast is low as it does not reflect the estimated 2% to 5% increase in export prices (and 2% to 5% reduction in import prices, which will increase the net export revenues) that will be achieved once the Manitoba-Minnesota Transmission Project and the Great Northern Transmission Line are in service.

9.0 Load Forecast

Manitoba Hydro's electric load forecast is used for several purposes. Short-term forecasts of sales are needed to forecast revenue for rate design and accounting purposes. Short-term forecasts of energy and peak demand are needed for system operations planning. Long-term forecasts of energy and peak demand are required for power planning to determine long-term supply requirements. Manitoba Hydro's 2017 Electric Load Forecast was created as the Utility's best estimate of Manitoba's future energy requirements on a P50 basis, meaning there is a 50% chance that the future load will exceed the forecast and a 50% chance that it will be less than the forecast.

9.1 Manitoba Hydro's Position

In this GRA, Manitoba Hydro cites a reduced forecast of domestic load growth as a contributing factor for the deterioration in the Utility's financial outlook. The reduced forecast of domestic load growth delays the Manitoba domestic need for energy from Keeyask until the mid-2030s and also, in the Utility's view, lessens the opportunity for Manitoba Hydro to look to load growth to address its financial challenges.

Manitoba Hydro expects no net load growth over the next 10 years when the impact of its current Demand Side Management Plan is included. Over the next 20 years, the net load growth is expected to average 0.7%. Manitoba Hydro identified several other factors that will further depress its load forecast that were not incorporated into the 2017 Electric Load Forecast. One factor is the cancellation of a project in the Top Consumers' Petroleum/Oil/Gas sub-sector that will reduce the load forecast by approximately 500 GWh in 2021. Another factor not included in the 2017 Electric Load Forecast is the six years of 7.9% rate increases that form part of Manitoba Hydro's current plan. The 2017 forecast is based on five years of 7.9% rate increases.

The primary driver of energy load growth in Manitoba is the population and the secondary driver is the economy. The population of Manitoba has grown from 1,185,000 people in 2006/07 to 1,323,000 people in 2016/17, averaging 1.1% growth per year. Manitoba's population is forecast to grow to 1,638,000 by 2036/37, averaging 1.1% per year. 'Real' (i.e. with inflation removed) Manitoba Gross Domestic Product ("GDP") is expected to grow 2.0% in 2017/18 and average 1.6% annually for the next 20 years.

The three main components of Manitoba's electricity use are:

- Residential Basic, with 480,365 customers, including mostly residential structures that include single-family dwellings, multi-family dwellings, and individually metered apartment suites. This residential component of the Load Forecast accounts for 32% of Manitoba Hydro's Total Consumer Sales and is projected to grow at an average rate of 1.3% per year over the next 20 years (excluding demand side management impacts). Customer growth, paralleling population growth, is growing 1.1% per year.

- General Service Mass Market, with 67,676 customers, are small to large commercial and industrial customers. The load growth for this group of customers accounts for 41% of Manitoba Hydro's Total Consumer Sales and is forecast to grow at an average of 1.5% per year (excluding demand side management impacts), which is higher than the historic growth of 1.1% per year over the past 10 years. The growth is primarily due to expected growth in residential customers and GDP.

- General Service Top Consumers, are 10 high-usage companies with 26 individually metered accounts that are forecast individually. This group of customers accounts for 26% of Manitoba Hydro's Total Consumer sales.

  The load growth for these Top Consumers customers is forecast at an average rate of 0.9% per year, which is higher than the 0.2% growth per year experienced during the past 10 years. However, it is less than the 3.2% growth per year during the period 10 to 20 years ago. The 20-year historical growth of the Top Consumers has been 1.7% per year.

9.2 Independent Expert Consultant Evidence

The Board engaged Daymark Energy Advisors as Independent Expert Consultants to assess Manitoba Hydro's load forecasting methodologies, evaluate historical performance, and assess changes between the Utility's 2014 and 2017 load forecasting methodologies. Daymark concluded that Manitoba Hydro's changes to the forecasting methodology for Potential Large Industrial Load for the Top Consumers category result in a more conservative methodology and significantly reduce the load forecast. Daymark also concluded that Manitoba Hydro has not fully considered fuel switching or the short-term impact of the proposed and projected rate increases on Top Consumers, which could reduce the load forecast and cause the forecasted loads to be lower than the actual future loads. This Independent Expert Consultant also gave evidence that Manitoba Hydro's estimated price elasticity for all sectors of customers may not be reliable. Price elasticity estimates the responsiveness of electricity demand to changes in the price of electricity.

Daymark recommended improvements to Manitoba Hydro's load forecasting methodology, as follows. According to Daymark, Manitoba Hydro should:

- incorporate scenario analysis into its load forecasts. Scenarios should be based on plausible alternative futures. Such scenarios may entail a combination of factors such as high or low growth of population, GDP, or electric vehicles, or high or low adoption of energy efficiency. Considering different scenarios allow utilities to more effectively plan and understand where and how future loads may differ from present forecasts,

- perform probabilistic assessments of the load forecast to determine the sensitivity to input variables such as population or GDP forecasts. This would help Manitoba Hydro and stakeholders understand the uncertainties in the load forecast,
- utilize more than two years of load history to determine the weather dependency of electricity consumption,
- utilize fewer than 25 years of weather data to generate the normal weather baseline, and
- test its econometric models for statistical concerns, such as multi-collinearity.

Dr. Yatchew, an Independent Expert Consultant retained by the Board to provide economic analysis, assessed the likely impacts on and responses of various customer groups to rate increases of the magnitude included in Manitoba Hydro's financial plan as well as the implications for the economy as a whole. Dr. Yatchew found offsetting forces such that electricity price increases will cause a reduction in consumer demand but, as the provincial Gross Domestic Product grows over time, the consumption of electricity to support that economic growth will increase. Factoring in Manitoba Hydro's requested and projected 7.9% rate increases in its 10-year financial plan as well as the expected provincial growth, the net result is that load in Manitoba is likely to be stagnant over the coming decade.

9.3 Intervener Positions

The Consumers Coalition accepts Manitoba Hydro's price elasticity values as being reasonable but questions the conservatism used by the Utility in forecasting long-term load as well as the significant uncertainty relating to the mobility of large industrial customers who may respond to large rate increases by relocating businesses. This Intervener recommends that Manitoba Hydro revise its methodology for estimating the load of the large industrial customers as well by providing alternative load forecast scenarios through stochastic modelling.

The Manitoba Industrial Power Users Group compared Manitoba Hydro's 2013 Electric Load Forecast, which underpinned development Plan 5 – which is akin to the plan recommended by the Board and which includes Keeyask and the new interconnection with the United States – at the NFAT proceeding, with the 2017 Electric Load Forecast. Compared to the 2013 forecast, in the year 2026/27, there is a 7.1% decrease in load. Of that decrease, approximately 5.3% arises due to customer responses to the assumed five years of 7.9% rate increases as compared to 3.95% rate increases assumed for the NFAT forecast. Absent the effect of successive 7.9% rate increases on load growth, the decline in the load forecast would only be approximately 1.8%, with some portion of this smaller decrease attributable to assumed demand side management activities. Put another way, this Intervener submits that, if approved rate increases are more in line with 3.95%, the load forecast will be higher, resulting in increased domestic rate revenue for the Utility and an improved financial situation for Manitoba Hydro.

9.4 Board Findings

The Board finds that, compared to the methodology used in 2014, the new methodology used by Manitoba Hydro in 2017 generates a lower long-term forecast of consumers' electricity consumption in Manitoba. The Board is prepared to accept the results of Manitoba Hydro's Electric Load Forecast for financial forecasting and rate setting purposes, but concludes that different considerations from those used by Manitoba Hydro support the forecast. The total load in the Test Year should be higher than that forecasted by Manitoba Hydro due to the decrease in the overall approved rate increase from 7.9% to 3.6% and the Board's recommendation in this Order that Manitoba Hydro reduce its demand side management, all else being equal. The change in the methodology to forecast the long-term Potential Large Industrial Load, while responsive to the Board's prior direction in Order 73/15, may now be an overly conservative methodology, as was found by Daymark Energy Advisors. The Board finds that the overly conservative nature of the Potential Large Industrial Load forecast is partially offset by the fact that the 2017 forecast does not factor in the cancellation of the project in the Top Consumer Petroleum/Oil/Gas sub-sector.

The Board agrees with Dr. Yatchew's assessment that the load growth will be essentially flat over the coming years. The Board finds that any long-term load forecast cannot be relied upon, due to the inherent limitations in forecasting the effects and impacts of disruptive technology, such as customers generating their own electricity with solar photovoltaic systems and storing that electricity in batteries.

The Board finds that Manitoba Hydro's price elasticity for all three of the customer sectors may not be reliable. The Board accepts the evidence in the literature cited by Dr. Yatchew, although the Board also notes that applying those elasticities results to Manitoba Hydro's load data yields results not dissimilar from Manitoba Hydro's load forecast. That literature suggests the price responsiveness of industrial customers can be greater than residential customers. In addition, as discussed in a subsequent section, the Board's recommendation that Manitoba Hydro reduce its demand side management spending will increase domestic load growth.

The Board encourages Manitoba Hydro to review and study the areas Daymark Energy Advisors and Dr. Yatchew identified for improvement and enhancement of the load forecasting methodology. Manitoba Hydro is directed to consider the areas recommended by the Independent Expert Consultants for improvement and enhancement of the load forecasting methodology and to provide details of the implementation of these recommendations, or reasons for not implementing them, at the next GRA.

10.0 Operating & Administrative Expenses

Operating and administrative expenses ("O&A") are one of Manitoba Hydro's highest expense categories in its revenue requirement. These expenses primarily consist of labour and benefits, materials, contracted services, and overhead costs associated with operating and maintaining Manitoba Hydro's facilities and providing services to customers. O&A expenses do not include capitalized salaries and benefits for employees who work on capital projects, or materials and services related to those projects. The salaries of approximately one out of three Manitoba Hydro employees are capitalized and are therefore not included in O&A expenses.

Dating back to at least Order 116/08, the Board has expressed concern regarding the level of growth in Manitoba Hydro's O&A costs.

In Order 5/12, the Board noted that, from 2005 to 2010, Manitoba Hydro's O&A expenses grew at a compound average growth rate of almost 5% annually, while inflation for the same period was under 2%. The Board concluded that a major reason for the increase of O&A expense was due to staffing levels having increased by 900 additional Equivalent Full-Time positions, or a 15% increase, in the period of 2004 to 2012. Of the additional 900 positions, 498 were in the Power Supply Business unit, which at that time managed the planned development of Keeyask and Conawapa.

In the 2014/15 & 2015/16 GRA, Manitoba Hydro expressed a commitment to reducing the growth of O&A expenses to one percent, excluding the impact of accounting changes. Since that time, Manitoba Hydro has pursued a cost containment strategy. First, over the period of 2014/15 to 2016/17, Manitoba Hydro reduced its operations by 429 positions through attrition and process efficiencies. As a result, Manitoba Hydro achieved cumulative savings of $43.2 million.

In February of 2017, Manitoba Hydro announced a plan to reduce its total workforce by 15%, or 900 positions. This plan commenced with a reduction of the executive leadership team by 30%, or three Vice-President positions, and a reduction of the senior management team by 25%. Manitoba Hydro also implemented a Voluntary Departure Program to achieve the remaining position reductions. By mid-2018, the Voluntary Departure Program will result in 817 employees leaving Manitoba Hydro (plus four employees related to Manitoba Hydro's subsidiaries), approximately 70% of which are assumed to be operational in nature. Including the position reductions resulting from the Voluntary Departure Program, the total reduction of senior management is approximately 40 positions.

10.1 Manitoba Hydro's Position

Manitoba Hydro estimates the salaries associated with the reduced positions to be $91.9 million. These savings do not include the approximately $2 million value of the salaries for those employees who did not leave the Utility through the Voluntary Departure Program but were severed.

The costs of the restructuring program include the severance and salaries paid pursuant to the terms of the Voluntary Departure Program (forecast to be $53 million). In addition, the Utility estimates reorganization costs (for retraining, information technology, and potential benefit impacts) to be $12 million in 2018/19.

Manitoba Hydro also introduced cost reductions through a Supply Chain Management initiative, intended to realize savings on goods and services purchased, reduce or avoid operating costs, reduce working capital, and reduce capital expenditures. Since these initiatives began in 2014/15, the accumulated realized savings to date total approximately $8 million. Manitoba Hydro estimates future annual cost savings between

$20 million and $50 million over the five-year period 2017/18 through 2021/22, with 30% related to operational savings and the remainder related to capital projects.

Due to the timing of the Voluntary Departure Program, Manitoba Hydro did not file detailed O&A budgets as part of the GRA and all detailed schedules embedded in the Application and filing materials for 2017/18 and 2018/19 are incomplete. In addition, Manitoba Hydro has not yet determined the impact of the Voluntary Departure Program on the Utility's pension liability. Manitoba Hydro does not expect to be in a position to forecast the pension liability until the 2018/19 fiscal year. The O&A target for 2017/18 was based on the year-end projection for 2016/17 actual results, adjusted for known wage settlements and the assumptions associated with senior management reductions and the Voluntary Departure Program. The forecast assumed savings for a partial year from a staffing reduction of 500 positions. The O&A target for 2018/19 was based on the preliminary 2017/18 forecast adjusted for known wage settlements and a partial year of operating costs for Bipole III. The forecast was then reduced by the full year impact of the assumed reduction of 500 positions. While 821 and not 500 employees left as a result of the Voluntary Departure Program, there were also differences in timing from the forecast and increased costs associated with the number of employees leaving, such that Manitoba Hydro maintained its forecast amount for 2017/18 and the Test Year.

Manitoba Hydro's position is that it has implemented effective cost reduction measures that have resulted in a growth in O&A costs at or below inflation since 2009/10. While the International Brotherhood of Electrical Workers presented evidence that O&A reductions have sacrificed the safety of Manitoba Hydro employees and customers, and have the potential to lead to decreased reliability of service, Manitoba Hydro maintains that it continues to operate safely and effectively. It submits, however, that further reductions would result in undue risk to service levels and reliability.

Manitoba Hydro cautions against making comparisons between utilities due to the myriad of factors that can influence the organizational structure, operations, and decisions of an individual utility.

10.2 Intervener Positions

The Consumers Coalition argues that, while Manitoba Hydro provides reliable service, it has failed to demonstrate that it offers economic or efficient service. This position is based on benchmarking undertaken by the Boston Consulting Group which identified that Manitoba Hydro is not generally a top quartile or second quartile performer. The Consumers Coalition indicates concern over Manitoba Hydro's suggestion that it has been able to reduce over 1,100 operational positions since 2014 while continuing to claim that it can provide reliable and quality service. The Consumers Coalition suggests that benchmarking is a useful tool for determining the appropriate level of a utility's costs, including in the context of maintaining services while reducing operational positions, and recommends that a benchmarking working group be convened for 2019/20 and 2020/21.

Representatives of the General Service Small and General Service Medium Customer Classes and Keystone Agricultural Producers submit that, prior to the next GRA, an independent Manitoba Hydro cost benchmarking and customer impact analysis should be performed. This Intervener argues that there is not presently enough detail or information to make a determination on whether Manitoba Hydro's cost control measures are sufficient. It recommends that the Board encourage Manitoba Hydro to follow through with full cost reduction measures and to file with the Board data that would allow the Board to assess the results and whether further measures are required.

The Manitoba Industrial Power Users Group argues that Manitoba Hydro should fully pursue O&A expense reductions, including reductions to staffing of 900 positions. The Manitoba Industrial Power Users Group is supportive of Manitoba Hydro responding to longstanding Board concerns over staffing levels, dating back to at least 2008.

10.3 Board Findings

The Board accepts the O&A forecast for the Test Year for financial forecasting and rate-setting purposes. The Board accepts that the level of detail needed for a full testing of the forecast is not available until the results of the Voluntary Departure Program are known. The Board directs Manitoba Hydro to file with the next GRA the details of its O&A expenditures with an explanation of the operational plan developed to continue running operations with a workforce that has been reduced by 15%, including any advice or recommendations received from external consultants retained by the Utility to assist with the restructuring and transition. This explanation should include confirmation that and details as to how Manitoba Hydro's operations are being run safely after the workforce reductions are complete. The Board further directs Manitoba Hydro to file with the next GRA details of its actual O&A expenditures dating back 10 years through to the date of the filing, along with forecast O&A expenditures by cost element and business unit, including the details of the Utility's pension liability related to the reduced staffing levels. The actual O& A expenditures are to include the compound annual growth both before and after accounting changes.

The Board acknowledges Manitoba Hydro's efforts to implement cost containment measures. While the level of cost containment has not met the 1% target on average over the five-year periods from 2009/10 through 2013/14 and from 2014/15 through 2018/19, based on the average of both actual and forecast costs, growth in O&A expenditures is at the level of inflation on average over these periods. Further, Manitoba Hydro forecasts a 3.3% reduction in O&A expense in each of 2017/18 and 2018/19, primarily due to staffing reductions. The Utility's review of its operations, at a time of restructuring and transition, presents an opportunity to find further areas to reduce O&A costs. The Board recommends that Manitoba Hydro continue these efforts, both in terms of staff reductions and Supply Chain Management, after the Voluntary Departure Program transition concludes.

The Board notes that, in Order 116/08, Manitoba Hydro was directed to undertake and file with the Board an independent benchmarking study of key performance metrics, using the most currently available data. Completion of this directive was deferred pending Manitoba Hydro's implementation of International Financial Reporting Standards ("IFRS"). While IFRS was adopted April 1, 2015, the benchmarking study directed in order 116/08 has not been filed. The Board views this as an outstanding directive and finds that independent benchmarking should be completed; however, the study should not be performed until after the transition period resulting from the Voluntary Departure Program concludes. The Board will expect an update on the status of the post-Voluntary Departure Program re-organization at the next GRA, including with respect to how the safety of employees and customers has been maintained.

11.0 Accounting Issues

The accounting treatment of Manitoba Hydro's spending has implications for the revenue requirement in the Test Year, as well as in the financial forecast. Five items were at issue in the GRA proceeding: depreciation expense, the regulatory treatment of Conawapa costs, ineligible overheads, the Bipole III Deferral Account, and the Demand Side Management Deferral Account.

11.1 Depreciation Expense

Depreciation expense is Manitoba Hydro's third highest expense category. In Integrated Financial Forecast MH16 Update with Interim, Manitoba Hydro forecasts $396 million in depreciation expense for 2017/18 and $471 million for 2018/19. Depreciation expense is projected to grow to $752 million by 2026/27 as a result of both new major generation and transmission assets and planned Business Operations Capital expenditures.

Two common methods of recording depreciation expense are Equal Life Group and Average Service Life. The Equal Life Group methodology groups assets according to their lifespan, not the type of asset. Average Service Life methodology groups assets by the type of asset and then depreciates the assets in the group according to their average service lives. The Equal Life Group methodology typically increases depreciation costs in the early years of the life of each group of assets, which increases the revenue requirement and therefore the rates that need to be recovered from consumers in those years. Most Canadian Crown-owned electric utilities use the Average Service Life methodology for rate-setting.

In the 2012/13 & 2013/14 GRA, Manitoba Hydro indicated to the Board that it planned to switch to the Equal Life Group methodology of recording depreciation for financial reporting purposes and asked the Board to consider the impact of the change for rate-setting purposes. Manitoba Hydro previously used the Average Service Life methodology.

In Directive 8 of Order 43/13, the Board ordered Manitoba Hydro to file updated depreciation rates and schedules based on an IFRS-compliant Average Service Life methodology with the next GRA. In Directive 9 of Order 43/13, Manitoba Hydro was to file, with the next GRA, a chart showing a comparison of the impact on its Integrated Financial Forecast of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

In Order 73/15, the Board ordered Manitoba Hydro, for purposes of rate-setting, to continue to determine depreciation expense based on the Average Service Life methodology. The Board directed that the Average Service Life methodology be maintained until Directives 8 and 9 from Order 43/13 have been complied with and the Board has been provided with an IFRS-compliant depreciation study based on Average Service Life.

As Manitoba Hydro uses the Equal Life Group methodology for financial reporting purposes, Manitoba Hydro defers the difference between depreciation expense calculated for financial reporting and depreciation expense calculated for rate-setting purposes in a regulatory deferral account. Manitoba Hydro also makes a corresponding adjustment through the net movement in regulatory balances account such that, for rate setting purposes, the revenue requirement reflects depreciation expense based on Average Service Life depreciation rates.

In Integrated Financial Forecasts MH16, MH16 Update, and MH16 Update with Interim, Manitoba Hydro proposed ceasing the deferral of the difference between the two depreciation methodologies in 2022/23, which in effect is a reversion to Equal Life Group. Manitoba Hydro also amortizes the cost of the deferral over 20 years and charges it through net income.

Manitoba Hydro's Position

Manitoba Hydro indicates that its preference is to have a single method of depreciation for both rate setting and financial reporting purposes, so as to avoid the growth expected in the deferral account and the administrative costs associated with maintaining two sets of records for calculating depreciation balances. With respect to an IFRS-compliant Average Service Life depreciation study and the amortization of the deferral account balance for rate setting, Manitoba Hydro asks that the Board hold an alternative process, such as a technical conference, where the issues can be explored in more detail outside of a GRA process and before 2019/20.

Although Manitoba Hydro's GRA filing requested the Board's endorsement of the proposed amortization for the disposition of the regulatory deferral associated with the differences in depreciation methodology, in its closing argument, Manitoba Hydro stated that it is not seeking approval of the amortization period at this time.

Intervener Positions

The Consumers Coalition argues that there should be no amortization of the deferral account pending Manitoba Hydro's IFRS-compliant Average Service Life depreciation study and resolution of the issue of depreciation methodology.

The Manitoba Industrial Power Users Group recommends that the Board direct the implementation of depreciation rates consistent with the Average Service Life methodology, with no reversion to Equal Life Group in the financial forecast. The Manitoba Industrial Power Users Group agrees with the Consumers Coalition that there should be no amortization of the difference in rates.

Board Findings

The Board finds that depreciation is to continue to be recorded using the Average Service Life methodology for rate setting purposes, without reversion to Equal Life Group in the financial forecast. The Board orders Manitoba Hydro to not amortize the difference between Average Service Life and Equal Life Group for rate setting.

The Board finds that Manitoba Hydro has not fully complied with the Board's prior directives on depreciation methodology. In Order 73/15, the Board ordered that the Average Service Life methodology be maintained until the directives from Order 43/13 are complied with and the Board is provided with an IFRS-compliant Average Service Life depreciation study. This study has not been performed. In the absence of full compliance with the Board's past directives, the Board will not make a final disposition with respect to the appropriate long-term depreciation methodology for rate setting purposes. As was the case at the time of Order 73/15, the Board does not currently have sufficient information upon which to make a decision, especially given that a change in methodology leads to significant long-term consumer rate consequences.

By extension, the Board is not in a position to endorse any amortization of the deferral account. As noted by the Consumers Coalition witness, William Harper, the appropriate time to assess the amortization of the regulatory account balance is once Manitoba Hydro has provided the study directed by the Board, when the implications of the change in depreciation methodology will be better understood. In addition, as indicated by the Manitoba Industrial Power Users Group witness, Patrick Bowman, the principle is that the two depreciation methods will match over time as under both methods, assets are fully amortized upon retirement. This means that any difference will naturally amortize and balance over time, therefore not requiring amortization of the deferral that is intended to recognize the difference.

While Manitoba Hydro proposes that the Board hold an alternative process, the Board has previously established the process to be followed for resolution of this issue. Once Manitoba Hydro has completed and provided to the Board its IFRS-compliant Average Service Life depreciation study, the Board will make a final disposition.

11.2 Conawapa Costs

Manitoba Hydro incurred approximately $380 million in costs related to the development of the Conawapa Generating Station. Following the Board's NFAT Report recommendation, the development of Conawapa was discontinued. Manitoba Hydro expects that its auditor will view this asset as a stranded asset and will require that the asset be written off.

The issue in this hearing is whether the write-off of Conawapa should be recognized as a regulatory asset, which should then be amortized and recovered from ratepayers over a set time period. Pursuant to IFRS, regulatory assets represent the timing differences between when an expenditure must be recognized for financial reporting purposes and when an expenditure is to be recognized for rate setting purposes, as directed by an entity's regulator.

Manitoba Hydro initially advised that expenditures related to Conawapa would be maintained in the Construction Work In Progress category through to the end of fiscal 2018/19. Consistent with this, MH16 included an assumption that, for financial reporting purposes, Manitoba Hydro would be required to write off 100% of the $380 million deferred Conawapa expenditures to net income in fiscal year 2020. However, in the course of the oral GRA hearing, Manitoba Hydro indicated that, as a decision was made to discontinue any further development of the station at this time, the Utility anticipated its auditor would require that the costs would be written off in 2017/18.

In 2015/16, Manitoba Hydro capitalized $19.6 million of interest on the borrowing costs of Conawapa. In 2016/17, the capitalized interest was $15.0 million. Effective December 31, 2016, with the completion of all wind-down activities on the project, Manitoba Hydro ceased capitalizing the Conawapa interest amounts. This was done in accordance with IFRS, which does not allow the capitalization of borrowing costs for projects which are not proceeding. As interest is no longer being capitalized, but still must be paid annually on the expenses, the non-capitalized interest costs are included in finance expense in the Utility's 2017/18 financial statements and in "interest paid" under Operating Activities on the Cash Flow statement.

Manitoba Hydro's Position

Manitoba Hydro proposes that the costs pertaining to the construction of Conawapa be recorded in a regulatory deferral account effective March 2018, with amortization of the costs to income on a straight-line basis over a period of 30 years beginning on April 1, 2018. Manitoba Hydro has not forecast the inclusion of the non-capitalized interest subsequent to December 31, 2016 on Conawapa in the regulatory asset, but rather in finance expense on the financial statement.

Manitoba Hydro submits that its proposal to recognize Conawapa costs as a regulatory asset and amortize those costs over time minimizes the impact on customers. Manitoba Hydro advises that, while the non-capitalized interest on the Conawapa borrowing costs is not currently included as part of a regulatory deferral account asset in the Test Year, the inclusion of that interest is in the discretion of the Board.

Intervener Positions

The only Intervener to take a position on Conawapa costs was the Consumers Coalition, which accepts Manitoba Hydro's proposed treatment.

Board Findings

The Board accepts Manitoba Hydro's proposed treatment of the Conawapa costs. This treatment is appropriate because the decision to discontinue Conawapa construction was part of the NFAT review of the Utility's long-term system planning for long-lived assets. Further, this approach smooths out the impact of this one-time cost on consumers.

The Board finds that the non-capitalized interest related to Conawapa from January 1, 2017 on should not be included with the regulatory deferral account asset, consistent with Manitoba Hydro's forecast treatment of the interest.

11.3 Ineligible Overheads

In its transition to IFRS, Manitoba Hydro reduced the extent of overhead costs capitalized in Property, Plant and Equipment as certain annual overhead costs were deemed ineligible for capitalization under IFRS. In the 2014/15 & 2015/16 GRA, Manitoba Hydro proposed that a higher level of O&A costs than in previous proceedings be expensed due to changes made by the Utility in compliance with IFRS. In Order 73/15, the Board did not accept for rate-setting purposes the higher level of O&A costs requested and directed that the remaining administrative costs continue to be capitalized.

For rate-setting purposes, Manitoba Hydro defers $20 million annually of O&A charges in a deferral account.

Manitoba Hydro's Position

In Integrated Financial Forecast MH16, the deferral of ineligible overheads discontinues in 2023/24, when the regulatory account balance is expected to be $160 million. Manitoba Hydro proposes that the balance be amortized over a 20-year period, commencing in 2017/18.

Manitoba Hydro argues that, in Order 73/15, the Board did not provide any direction for how long the capitalization of ineligible overhead costs should be continued. It submits that an indefinite deferral is not appropriate given that the deferral and amortization is a non-cash adjustment and there is no impact to net income by the end of the amortization period. This is true regardless of the amortization period used. Manitoba Hydro supports finding an alternate process where the issue of the indefinite deferral of ineligible overhead can be discussed in more detail.

Intervener Positions

The Consumers Coalition submits that the $20 million in ineligible overhead should be continued and the deferral account balance should be amortized over 30 years.

The Manitoba Industrial Power Users Group recommends that the deferred ineligible overhead account should be amortized over 30 years as this is approximately equal to the average age of Manitoba Hydro's overall asset base. The witness for the Manitoba Industrial Power Users Group, Patrick Bowman, recommended a 34-year amortization period to match the average service life of the assets. The Manitoba Industrial Power Users Group further states that the deferral should be continued in perpetuity to mimic the continued capitalization directed by the Board in Order 73/15.

Board Findings

The Board finds that the $20 million annually in ineligible overhead should continue to be deferred. This is consistent with the Board's direction in Order 73/15 that Manitoba Hydro is to continue this practice.

With respect to the amortization period, the Board finds that, if these costs were capitalized, the costs would be amortized over the in-service lives of the assets. As supported by the expert witness for the Manitoba Industrial Power Users Group, Patrick Bowman, the deferral account balance should be amortized over 34 years to match the average service life of the assets. This recognizes that the balance relates to a deferral of capital costs that are linked to service that will be provided by capital assets in the future.

11.4 Bipole III Deferral Account

The Bipole III transmission line is being constructed to improve domestic reliability and to permit exports into the United States. However, while the construction of Bipole III is tied to revenue-generating assets such as Keeyask, the transmission line itself will achieve only limited revenue (approximately $20 million in incremental revenue) through additional export revenue from reduced line losses. As such, there are in-service revenue requirement impacts, with yearly amounts having to be recovered in domestic customers' rates.

In Order 43/13, the Board established a deferral account to assist in funding Bipole III in-service costs and to defray a portion of the rate impacts of Bipole III. Due to the significant rate increases needed at the time Bipole III comes into service, the Deferral Account is a means by which to gradually increase rates and to partially fund the depreciation, interest, and operating costs in order to avoid rate shock at the time the asset enters service. In Order 43/13, the Board directed that the revenues from a 1.5% rate increase were to flow to the Bipole III Deferral Account. Additional rate increases were directed to the Bipole III Deferral Account in subsequent Orders, as follows:

- 0.75% in Order 49/14
- 2.15% in Order 73/15
- 3.36% in Order 59/16
- 3.36% in Order 80/17

In total, Manitoba Hydro has received 11.6% compounded in consumer rates above what the Board determined was necessary for the Utility's general operations in order to assist in mitigating the rate impacts of Bipole III coming into service. At the time Bipole

III is scheduled to enter service in July of 2018, Manitoba Hydro forecasts that there will be approximately $400 million in the Deferral Account.

Manitoba Hydro's Position

As Bipole III is scheduled to enter service in 2018/19, Manitoba Hydro proposes that the Deferral Account begin to be recognized in domestic revenues following the in-service date, effective August 2018. Specifically, Manitoba Hydro proposes that the Deferral Account be amortized over a five-year period through July 2023.

Manitoba Hydro proposes the amortization of the Bipole III Deferral Account over a five-year period as it will help mitigate the initial expected increases in annual in-service costs related to Bipole III. Manitoba Hydro reasons that, after 2023, additional export revenues from Keeyask will be available to help offset those charges, so further recognition of the deferral will not be required at that time.

Intervener Positions

The expert witness for the Manitoba Industrial Power Users Group, Patrick Bowman, testified that, while he opposed the Deferral Account when the Board first introduced it, in retrospect he believes that it was a "very wise decision". No Interveners took issue with Manitoba Hydro's proposed treatment of the Deferral Account.

Board Findings

The Board finds that the Bipole III Deferral Account should begin to be recognized in domestic revenues once Bipole III enters service and amortized over a five-year period.

The Board directs that, once Bipole III enters service, the revenues currently being deferred should no longer be deferred and instead accrue to general revenue. However, the deferral is to continue until the in-service date, including any period of delay. The Board notes that a delay of the in-service date of Bipole III will have an impact on net income in the Test Year, as the compounded cumulative 11.6% in rates will continue to flow to the Deferral Account. This will increase the amount in the Deferral Account, will decrease the amount that is recognized in general revenue in the Test Year, and will correspondingly reduce net income.

11.5 Demand Side Management Deferral Account

In each Integrated Financial Forecast prepared by Manitoba Hydro, the Utility forecasts the level of demand side management spending based on its Power Smart Plan, thereby incorporating these expenditures in the revenue requirement. In response to Directive 12 in Order 43/13, to the extent that Manitoba Hydro's actual spending on demand side management falls below the level included in the Utility's revenue requirement, the amount of the underspending is accumulated as a regulatory deferral debit balance. There is a corresponding regulatory deferral credit balance. This means that, while the Demand Side Management Deferral Account had a March 31, 2017 "balance" of $48.8 million, this amount is purely notional and has no impact on the Utility's net income. The only demand side management amount that is amortized into rates is the amount of actual demand side management expenses, over a 10-year period.

In March 2017, the provincial government introduced legislation to establish a new Crown Corporation, Efficiency Manitoba, to assume responsibility for energy efficiency initiatives in the province. *The Efficiency Manitoba Act* came into force during the GRA proceedings, on January 24, 2018.

Manitoba Hydro's Position

Manitoba Hydro's position is that, until Efficiency Manitoba is fully established and delivers its initial plan, it is uncertain what the impacts will be on future domestic load and what actions are necessary to clear the Demand Side Management Deferral Account balance. Manitoba Hydro states that it therefore continues to incorporate the costs and savings reflected in its current Power Smart Plan.

Intervener Positions

No Interveners offered specific recommendations with respect to the deferred demand side management costs.

Board Findings

The Board finds that there is no cash balance related to this regulatory asset as Manitoba Hydro has established an offsetting regulatory liability. To avoid the misconception that there is a specific reserve for demand side management spending, this accounting practice should be discontinued. The Board will review Manitoba Hydro's disposition of the regulatory asset and liability at the next GRA.

12.0 Macroeconomic Impacts of Rate Increases

The economy is a complex web of interactions and a change in one sector creates ripples through the rest of the economy as households and industries adjust. Households, firms, and governments will adjust their spending patterns – spending more on electricity bills means spending less on other goods and services or inputs.

Manitoba Hydro did not provide a study on the economic impacts on the Utility's ratepayers and the provincial economy arising from Manitoba Hydro's 10-year financial plan. The Board and Interveners further examined this issue through independent expert witness reports and testimony. Expert witnesses in the proceeding filed written evidence and were cross examined on the economic impacts of electricity rate increases. All witnesses agreed that there would be significant negative economic impacts from the proposed and projected rate increases. A number of presentations were also made to the Board highlighting the negative economic impacts of the projected rate increases.

Through computer modelling, including the use of the latest Statistics Canada Input-Output tables for Manitoba, the economic impact of the requested and projected electricity rate increases is measurable. There will be initial direct effects, secondary indirect effects, as well as induced effects.

Doctors Compton and Simpson gave evidence that the electricity rate increases over seven years of Manitoba Hydro's proposed financial plan would result in the decline of Manitoba's GDP of between 2.16% and 3.63%, which is approximately equivalent to a loss of one year of growth in the Manitoba economy. They further found that, relative to electricity rate increases equal to the rate of inflation, Manitoba Hydro's planned rate increases will result in permanent job losses of between 2,480 and 4,105 jobs. Based on the 467 average monthly jobs created in the Manitoba economy over the past 10 years, Manitoba Hydro's projected rate path is estimated to cost the economy approximately five to eight months of employment growth.

Dr. Yatchew gave evidence that, as the long-term price responses are roughly three times short-term price elasticities (i.e. how much less electricity might be used on an incremental basis due to customer price response to higher rate increases), the economic impacts of the requested rate increases will not be fully realized for some time to come. According to Dr. Yatchew, steady energy price increases that are spread over a number of years do not necessarily lead to disastrous adverse effects on aggregate economic activity. One of the reasons is consumers have some opportunity to adjust and take the price effects into account in their planning for the future. In contrast, large unexpected energy price changes can have a significant disruptive effect on the economy. Large rate increases will induce a price response. This is sub-optimal in a period of energy surpluses, particularly for Manitoba Hydro as its existing surplus of energy will increase when Keeyask enters service and will continue until its energy is needed for domestic load in the mid-2030s.

The City of Winnipeg's witness, Mr. Tyler Markowsky, calculated the direct and indirect costs of electricity rate increases as planned by Manitoba Hydro as well as the increased tax revenue that would result from the City's tax on electricity for non-heating purposes over a 20-year time span. Mr. Markowsky calculated the net increase in electricity costs for the City over this 20-year time period would exceed $100 million. This would result in increases in property and business taxes and user fees, as well as reductions in services.

Dr. Yatchew explained that, while Manitoba has a diversified economy, residential ratepayers, businesses, industries, and community organizations will be negatively affected – possibly severely – by the proposed rate increases. By way of example, some companies may choose to relocate or to scale back production; some will consider very carefully whether to make major new capital investments in Manitoba. The spectre of increasing electricity rates, in the near or more distant future, may have already discouraged investment. The risk of future electricity rate increases that cumulate to 50% or more would likely be part of the decision matrix for any electricity-intensive firm in Manitoba.

The Board heard from the Chair of Manitoba Industrial Power Users Group that its member companies are among the largest electricity users in the province. Collectively, the Manitoba Industrial Power Users Group companies provide $165 million of revenue to Manitoba Hydro each year, contribute $233 million annually in taxes, have invested over $6.4 billion of capital, and directly employ 6,000 Manitobans with an additional 1,300 jobs through contract labour.

The Chair of the Manitoba Industrial Power Users Group echoed the concerns by Dr. Yatchew that Manitoba Hydro's 10-year financial plan ignores the risks of plant closures and downstream effects if the rate increases lead to job losses, out migration, or reduced household budgets. He testified that low energy costs were one of the prevailing reasons that member companies initially invested in Manitoba.

These risks were also discussed by representatives of Manitoba Industrial Power Users Group member companies and other industry representatives who gave oral presentations in this proceeding. Member companies such as Gerdau Long Steel North America ("Gerdau"), Maple Leaf Foods, and Koch Fertilizer Canada have no ability to pass through incremental costs to customers, giving rise to competitiveness concerns in a global market. A representative from Chemtrade, a sodium chlorate plant located in Brandon, gave evidence that its decisions to further invest in and grow the Brandon facility are being re-evaluated in light of Manitoba Hydro's projected rate path, particularly as many other competing jurisdictions have announced either no or modest electric rate increases for 2018. Similarly, a representative from Gerdau stated that the impact of Manitoba Hydro's rate increases may cause the company to limit investments in its Selkirk facility and to shift production to facilities in other jurisdictions. In 2007, Gerdau shut down its New Jersey location, mainly as a result of high electricity cost forecasts. Testimony from a representative of Maple Leaf Foods reflected similar concerns. In the short-term, Maple Leaf Foods stated that it estimates that electricity rate increases will lead to reductions in discretionary spending, employee headcount, capital spending, and community donations, while in the long-term, Maple Leaf Foods may scale down the work done at its Brandon facility.

Roquette, a company that produces speciality foods in locations across the world, presented evidence that it recently decided to invest in a new $400 million pea processing facility in Portage La Prairie, which in the construction phase will generate approximately 300 jobs. Manitoba's low and stable electricity costs were a factor in Roquette's decision to locate in Portage La Prairie; however, at the time of its decision to build a facility in Manitoba, Roquette was not aware of Manitoba Hydro's plans to accelerate rate increases above the 3.95% level. Manitoba Hydro's projected 7.9% rate increase path would significantly affect the operation and profitability of Roquette's Portage la Prairie facility and would cause Roquette to be less likely to make further investments in Manitoba.

A representative from the Mining Association of Manitoba echoed the concern that higher electricity rate increases will erode Manitoba's competitiveness, will jeopardize ongoing investment decisions by mining operators, and will cost the province billions of dollars in total economic activity over the forecast period.

Beyond industry, representatives from municipalities and community recreation organizations presented evidence that, in combination with a provincial government freeze on municipal operating funds, Manitoba Hydro's planned rate increases will have a negative impact on public recreation facilities and municipal operating budgets. This will result in increased user fees and reduced services. The Board heard evidence that between 20 and 50 recreation facilities in the Interlake region could close as a result of five years of electricity rate increases of 7.9%.

Presenters on a ratepayer panel sponsored by the Consumers Coalition testified that, as opposed to higher rate increases in the near-term with the possibility of rate decreases after 10 years, stable and predictable rate increases are preferred. In particular, Mr. Dan Mazier, who farms 1,000 acres in Elton, Manitoba, and is the President of Keystone Agricultural Producers, expressed concern that Manitoba Hydro's indicated rate plan includes rates that increase too quickly when compared to the expected growth of agricultural businesses, leading to Manitoba's agricultural producers being uncompetitive.

Dr. Yatchew opined that the projected rate increases in Manitoba Hydro's new financial plan are likely to have a modest net effect on aggregate Manitoba output in the long-run, though there could very well be job losses and reduced output in the short-run. The immediate main effects will be distributional, in that portions of certain sectors will be disproportionately affected. Specifically, lower-income households and remote and First Nations communities will be more strongly affected as well as others who do not have access to alternative sources of energy, in particular natural gas. In addition, lower incomes will hamper substitution of capital goods, such as improved insulation and efficient windows and doors.

In a presentation on behalf of the Business Council of Manitoba, Mr. Murray Taylor testified that a 7.9% increase in the Test Year would not make Manitoba uncompetitive with any other jurisdiction. This witness questioned where businesses could relocate in order to receive electricity rates at a low enough level that the costs of relocation would be economic.

12.1 Intervener Positions

The Consumers Coalition maintains that, compared to inflationary rate increases, the Manitoba Hydro path of sustained 7.9% rate increases would slow the economic growth of the province, the growth in labour income, and the growth in jobs.

Representatives of the General Service Small and General Service Medium and Keystone Agricultural Producers agree with all the expert witnesses who concluded there would be significant negative impacts on the Manitoba economy should Manitoba Hydro's rate plan be followed. This Intervener is also critical of Manitoba Hydro for not factoring into its consideration of the proposed rates the additional carbon tax impact on the agricultural and small and medium business sectors.

The Manitoba Industrial Power Users Group submits that, concurrent with the economic stimulus from the construction of Keeyask ending, the successive 7.9% rate increases in Manitoba Hydro's financial plan will impose material adverse impacts on the overall provincial economy. The impacts are exacerbated as the revenues from the increased rates are planned to be used for debt repayments and not injected back into the Manitoba economy.

The Assembly of Manitoba Chiefs raises concerns that the level of rate increases projected by Manitoba Hydro will substantially increase energy poverty.

The City of Winnipeg is critical of Manitoba Hydro for not undertaking an economic assessment of the impact of its proposed 7.9% rate increases considering the Utility has multiple economists on staff. According to the City of Winnipeg, Manitoba Hydro ignored half of the test of what needs to be considered when setting rates: the impact on ratepayers. The City of Winnipeg's GDP will be reduced by the Utility's proposed rate increases. As with businesses, and for the additional costs that cannot be absorbed within its operating budget, the City will need to pass on the costs of Manitoba Hydro rate increases through increased fees, reduced services, and increased taxes. The impact on residential and business customers will be magnified as a result of the trickle-down effect.

12.2 Board Findings

Manitoba Hydro did not provide evidence as to the macroeconomic impacts of its proposed rate plan, including the Test Year increase. This is a factor in the Board's conclusion that Manitoba Hydro did not meet its onus to establish that the rate increase sought by the Utility is just and reasonable.

Evidence was, however, provided by expert witnesses retained by Interveners and the Board. The Board accepts the evidence that the projected rate path may lead to short-term job losses and negative impacts for some industries that are more economically vulnerable based on the electricity intensity of their production. While the Business Council of Manitoba witness asserted that a 7.9% increase would not make Manitoba businesses uncompetitive, this was not supported by the evidence, including that provided by representatives of Manitoba industries. The Board notes the compelling evidence from the industrial and large commercial presenters in this regard. While there was evidence regarding potential job losses that could occur, the Board did not hear enough about the long-run general equilibrium effects.

The Board accepts Dr. Yatchew's evidence that the immediate main effects of the projected rate path will be distributional. In the first instance, this involves a transfer of money from ratepayers to the Utility. The Board also accepts Morrison Park Advisors' evidence that rate increases above inflation take money out of the economy and that is a factor to be considered in setting electricity rates. Secondly, rate increases affect lower-income households and remote and First Nations communities more significantly than other electricity customers.

Based on evidence presented, the Board determines that principles of rate stability and predictability are important for residential ratepayers, industry, business, and community organizations. The Board further finds that the rate increase sought by Manitoba Hydro for the Test Year departs from these principles.

13.0 Consumer Rate Increases

As noted above, Manitoba Hydro's GRA sought the Board's approvals for three separate rate increases:

- the 3.36% rate increase to all customer rates, previously approved on an interim basis effective August 1, 2016 in Orders 59/16 and 68/16. Manitoba Hydro requests this interim rate be finalized in this GRA without adjustment.
- a 7.9% interim rate increase for all rates to all customer classes to be effective August 1, 2017. As a result of the interim hearing process, the Board issued Order 80/17 approving a 3.36% average rate increase on an interim basis, effective August 1, 2017. This interim rate was to be further reviewed and considered in this GRA hearing. Manitoba Hydro now requests this interim rate be approved on a final basis with no adjustment.
- an additional 7.9% rate increase for all rates to all customer classes proposed for April 1, 2018.

13.1 Manitoba Hydro Position

While Manitoba Hydro's three rate requests are the subject of adjudication in this proceeding, the Utility also presented a new 10-year financial plan including rate increases beginning with the 2017/18 fiscal year rate increase requested in this GRA. The Utility's new 10-year projected rate plan begins with the 3.36% increase in 2017 and indicates 7.9% rate increases annually for six years followed by a 4.54% rate increase and then returning to inflationary rate increases of 2% in each year thereafter.

Manitoba Hydro acknowledges that the 7.9% rate increase request for 2018/19 and proposed for five years thereafter is an exceptional rate increase not previously sought by the Utility in recent decades. Manitoba Hydro states that "the previous plan has failed". Manitoba Hydro presented extensive evidence as to how the additional revenues from the 7.9% rate increases would enhance cash flow to facilitate payments of operating expenses, interest expense, and capital expenses while reaching a 25% equity target in a decade so as to be better financially prepared to manage risks.

Manitoba Hydro considers that a 7.9% rate increase fairly shares the burden of rate increases between current and future ratepayers. The Utility's concerns include the prospect that, without 7.9% rate increases now, future rate increases will have to be even larger.

While Manitoba Hydro has implemented cost cutting measures including staff reductions, it determined that lower load growth and lower export revenues from previous forecasts means that higher rate increases than previously forecast are now required.

With respect to the two interim rates, Manitoba Hydro's view is that these rates do not present a challenge to the Board's decision making as the Utility is not seeking to retroactively vary the interim rate increases and no Intervener gave evidence that those rates should be adjusted. Manitoba Hydro advises that it is not seeking an increase in the level of the rates awarded because it chose to focus on the 2018/19 rate increase, recognizing the compounding effect that ratepayers would face if the interim rates were finalized at a higher level at the same time as a general rate increase was implemented for 2018/19.

Manitoba Hydro indicates that it welcomes assistance from the Board in bringing to an end a regulatory cycle that includes frequent interim rate requests.

13.2 Intervener Positions

The Consumers Coalition has long been opposed to the consideration of Manitoba Hydro rate increases through interim hearing processes. Accordingly, should Manitoba Hydro seek a further rate increase for its 2019/20 fiscal year, the Consumers Coalition recommends that the Utility be directed to file its next GRA by the fall of 2018, such that it avoids the need for any interim rate hearing.

This Intervener submits that both the August 1, 2016 and August 1, 2017 3.36% interim rate increases are already built into rates and therefore are 'immunized' through the passage of time. This Intervener directed its focus to the 7.9% rate increase sought for April 1, 2018, rather than deploy resources on the historic interim rate increases.

As for the requested 7.9% rate increase for April 1, 2018, the Consumers Coalition maintains that Manitoba Hydro has not satisfied its legal onus to demonstrate that the requested rate increase is just and reasonable in achieving the needed balance as between the interests of the ratepayers and the financial health of the Utility. According to the Consumers Coalition, the GRA evidentiary record demonstrates that a 7.9% rate increase is more likely to harm Manitoba ratepayers and the Manitoba economy compared to the impacts of a smoothed rate increase at or below the 3.95% NFAT range. Smoothing rate increases at or below the 3.95% NFAT range makes sense, according to the Consumers Coalition, given the long lived and 'lumpy' nature of the Keeyask and Bipole III assets and considerations of regulatory stability, intergenerational equity, risk, and affordable access to the capital markets.

The conclusion of the Consumers Coalition is that, even assuming unbiased forecasts by Manitoba Hydro, appropriate implementation of Board Orders on accounting matters, and prudent management, Manitoba Hydro has not demonstrated a material change in its financial circumstances to justify the Utility's requested radical departure from the 3.95% NFAT range of rate increases. This Intervener submits that the rate increase for the 2018/19 Test Year could be in the range of 2.95% to 3.5%, where the higher end of the range recognizes the risks related to Keeyask costs and the lower end of the range would send a message of accountability to the Utility for its forecasting inaccuracies. Ultimately, this Intervener recommends a 2.95% rate increase for Manitoba Hydro's next fiscal year.

The Manitoba Industrial Power Users Group concludes that the evidence in the full GRA proceeding sufficiently demonstrated a need for the two 3.36% interim rate increases and that both should be approved by the Board as final without adjustment.

According to the Manitoba Industrial Power Users Group, comparing the previous GRA to this GRA:

- on a net income basis, Manitoba Hydro is now better off;
- on a comparative risk basis, the Utility is now much better off;
- on a total costs over time basis, Manitoba Hydro is approximately equal to previous forecasts;
- on a maximum debt level basis, and with the cost overruns on Keeyask and Bipole III, the Utility is now 'a bit worse off'.

The Manitoba Industrial Power Users Group suggests that, considering this mix of 'ups and downs', it would be reasonable to consider Manitoba Hydro's overall financial position as comparable to previous years.

The Manitoba Industrial Power Users Group submits any rate increase for Manitoba Hydro's 2018/19 fiscal year should fall between 3.36% and 3.57%, based on the evidence on the public record. However, this Intervener advocates this range should be lowered by the Board because of confidential information related to the understated or pessimistic export revenue forecast and load forecast that were reviewed by the Board. This Intervener also recommends the Board take into account the improvements to Manitoba Hydro's financial forecast resulting from a higher load forecast that would result from a lower rate increase.

The City of Winnipeg argues that nothing has changed from what was presented to the Board when it issued interim Order 80/17 approving a 3.36% August 1, 2017 rate increase, and as such, that rate increase should not now be altered.

As for the 2018/19 requested rate increase, this Intervener adopts the submissions by the Consumers Coalition and maintains Manitoba Hydro has not demonstrated the need for a 7.9% increase or to depart from the NFAT 3.95% rate trajectory. The City of Winnipeg maintains Manitoba Hydro has not justified the change in its financial forecast modelling, which relies on speculation and hypothetical concerns of water flows, export prices, and interest rates to promote a 10-year timeline for reaching a 25% equity level. This Intervener submits the requested 7.9% rate increase is an "exceptional rate increase", is "larger than any previous increase sought from the Public Utilities Board" by Manitoba Hydro, and has not been borne out by the evidence. The City of Winnipeg concludes such a rate increase is neither just nor reasonable nor in the public interest.

The Green Action Centre takes no position on the rate increases. This Intervener accepts the conclusions and recommendations from expert witnesses that the 7.9% proposed and projected rate increases represent a long-term problem for energy poverty in Manitoba, such that only direct rate assistance and energy efficiency plans can mitigate the impacts.

The Business Council of Manitoba encourages the Board to deviate from the historic rate path and order a 2018/19 rate increase along the lines of that requested by Manitoba Hydro. This Intervener submits the accuracy or inaccuracy of previous forecasts is irrelevant to the issues that have been raised as the focus needs to be on the issues that will occur in the near term.

Representatives of General Service Small and General Service Medium Customer Classes and the Keystone Agricultural Producers indicate that the rate increase request by Manitoba Hydro for 2018/19 cannot be considered in isolation. This Intervener maintains that the Board should consider the totality of Manitoba Hydro's 10-year financial plan and all of the 7.9% requested and projected rate increases. If 7.9% rate increase is approved for 2018/19, based on a perceived need to reach a debt-to-equity target by a certain timeframe, this would signal that 7.9% is also needed for the following years in order to achieve the date for that target. Put differently by this Intervener, the only justification for 7.9% rate increases is if the Board concludes a 25% equity level must be achieved by 2027. This Intervener submits that meeting this debt-to-equity target is not required within 10 years and that a 2018/19 rate increase of 3.95%, consistent with the prior rate paths, is appropriate.

A further recommendation by this Intervener is that the Board should schedule annual, shorter reviews of the Utility's rates.

The Assembly of Manitoba Chiefs takes no position on the appropriate rate increase for 2018/19, but submits that the 7.9% rate trajectory in Manitoba Hydro's 10-year financial plan will increase energy poverty in the province and will magnify the problems of affordability for First Nations customers.

Manitoba Keewatinowi Okimakanak adopts the submissions and positions taken by the Consumers Coalition and concludes that there has not been a material change in Manitoba Hydro's financial circumstances since that forecast at the 2014 NFAT such that the maximum rate increase for 2018/19 should be 3.9%. Manitoba Keewatinowi Okimakanak urges the Board, after determining the average electricity rate increase for 2018/19, to reduce the rate charged to First Nations customers by an amount which would serve to remove the portion that accounts for mitigation costs paid to First Nations. Manitoba Keewatinowi Okimakanak's position is that First Nations should not be paying for these costs as they are the beneficiaries of such mitigation payments.

13.3 Board Findings

The approach taken by Manitoba Hydro in this GRA is different than in prior proceedings. In this GRA, the Utility focused on reaching a particular debt-to-equity target in a 10-year time period, rather than a 20-year period as it proposed previously. In addition, Manitoba Hydro constructed a new cash flow analysis that was presented in this GRA as a "new view" of the Utility's cash flow situation. This cash flow analysis was presented to the Board, although Manitoba Hydro advises that it is not used in their audited financial statements or financial forecasts, nor is it presented to credit rating agencies. The Utility placed emphasis on this new cash flow analysis due to its view that traditional financial metrics, including the capital coverage ratio and interest coverage ratio, are deficient in certain aspects.

2016 and 2017 Interim Rate Increases

Based on an assessment of the full GRA evidentiary record, the Board approves as final each of the 3.36% interim rate increases which were effective August 1, 2016 and August 1, 2017. The dissenting member in Order 80/17, Sharon McKay, is in agreement with the decision to finalize the interim rate that was effective August 1, 2017, based on the review of the full record in the GRA hearing.

No evidence was presented as to why the 3.36% rate increases were not appropriate. However, the lack of testing by Interveners and limited focus from Manitoba Hydro underscores the Board's previous concerns about interim rate applications. The Board reiterates its conclusion in Order 59/16 that "interim rate applications ought not be the 'norm' for Manitoba Hydro. Interim rate applications do not offer the same level of public review as General Rate Applications." Interim rate processes are not to be used for purposes of convenience or as substitutes for the proper planning of GRAs. Both ratepayers and Manitoba Hydro benefit from a robust process that results in final rates that are just and reasonable. Future GRAs by Manitoba Hydro are not expected to be of this magnitude or duration as process improvements have and will continue to be implemented to focus the scope and expedite proceedings. In addition, the Board agrees with the Consumers Coalition that interim rates may create a regulatory *status quo* that is difficult to overturn, despite a lack of full regulatory review. Therefore, in the absence of unforeseen or emergency circumstances, the Board will not consider future interim rate increases.

To avoid future interim rate applications, should Manitoba Hydro request a rate increase for April 1, 2019, it must file a GRA by no later than September 1, 2018. Filing of a GRA after September 1, 2018 but before December 1, 2018 is required for consideration of a request for a revised rate in fiscal year 2019/20. For the next GRA, the Board will not consider rate increases for more than two Test Years.

The Board appreciates Manitoba Hydro's desire to establish a regulatory timetable that does not require the use of interim rates. The Board is prepared to work with Manitoba Hydro and other parties towards the development of that regulatory timetable.

Rate Increase for 2018/19

Manitoba Hydro's request for an April 1, 2018 rate increase of 7.9% is denied. The Board finds that Manitoba Hydro has not met its onus of proving that a 7.9% rate increase is just and reasonable. A 7.9% rate increase is not required for Manitoba Hydro's operations in the Test Year. In addition, the Board does not accept that achieving a 25% equity level in 10 years is an adequate reason in itself to justify a rate increase of 7.9% in 2018/19.

The Board finds that Manitoba Hydro failed to present economic impacts of the 7.9% rate increase or the impact on customers in various sectors – such as residential, commercial, and industrial. In future rate applications, the Utility is to assess the broader impacts of rate increases beyond only the financial health of Manitoba Hydro. The Board is concerned about the impact of electricity rate increases that are four times the rate of inflation in light of impending carbon taxes, both of which will affect individuals and Manitoba businesses, groups, and organizations. Representatives from industry, as well as agricultural representatives and individual ratepayers that presented evidence, stressed the need for stable and predictable rate increases. A summary of the evidence provided by presenters in the GRA proceeding is contained at Appendix C to this Order.

Based on a balancing of the interests of the ratepayers with the financial health of Manitoba Hydro, the Board approves on a final basis an overall rate increase of 3.6% effective June 1, 2018. As discussed below, the Board also approves rate increases that vary by customer class.

The Board finds an overall rate increase of 3.6% to be just and reasonable and in the public interest as it affords Manitoba Hydro sufficient revenues for financial purposes including cash flow and payments of operating expenses, interest expense, and capital expenses. With this rate increase, the Board finds that Manitoba Hydro has sufficient revenue to operate its business, manage its risks, and pay its finance expenses. From the evidence, the Board finds that the overall rate increase awarded in this Order will provide the revenues required to maintain Manitoba Hydro's cash flow and to allow the Utility to manage its debt advantageously for ratepayers. The Board's recommendations on capital expenditures and demand side management will also assist the Utility in this regard.

The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: continued deferral of $20 million in ineligible overheads, amortized at a 30-year rate; Average Service Life depreciation methodology, without amortization of the difference with the Equal Life Group methodology; achievement of a 25% equity level over a longer period of time, specifically by 2035/36; and debt management based on a weighted average term to maturity of 12 years. In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order.

Beginning in the Test Year, the Manitoba Hydro Exhibit 93 Integrated Financial Forecast scenario results in equal annual rate increases of 3.57%. The Board finds that with minor adjustments, this scenario is directionally consistent with the Board's decisions in this Order.

The Board finds that the 3.6% overall rate increase is to be effective June 1, 2018 in order to begin to move Manitoba Hydro back to a regulatory cycle that is consistent with the start of its fiscal year. The Board accepts that there is a benefit to both Manitoba Hydro and ratepayers in moving back to a regular regulatory cycle. If Manitoba Hydro does not adjust its planning to allow for sufficient time for the Board's review of the next GRA, any rate increase granted will not be effective April 1, regardless of the Board's intention to return the Utility to a regular regulatory cycle.

14.0 Payments to Government

Manitoba Hydro makes payments to the Province of Manitoba for water and land rentals, debt guarantees, and capital and other taxes. Manitoba Hydro also pays grants in lieu of taxes to municipalities. In Integrated Financial Forecast MH16, Manitoba Hydro forecasts that it will pay $433 million to governments in 2018/19, with $406 million to be paid to the Province for water rentals, debt guarantee fees, payroll tax, and the capital tax.

Pursuant to *The Water Power Act*, water rentals are paid to the Province for Manitoba Hydro's use of water resources for its hydroelectric generation. Land rentals are annual payments for the use of Manitoba Crown lands used for water power purposes.

The debt guarantee fee is an annual fee payable to the Province in exchange for the Government's guarantee of the Utility's debt (with the exception of Manitoba Hydro-Electric Board Bonds). The fee is calculated using a rate of 1% multiplied by the applicable outstanding debt at March 31st of the previous fiscal year. The debt guarantee fee is capitalized to the capital project to which the payment of the fee relates, and forms part of the cost of project.

The Utility pays capital tax to the Province at a rate of 0.5% which is applied to the taxable paid-up capital of Manitoba Hydro. The only corporations that pay a capital tax to the Province are Crown Corporations and financial institutions.

Manitoba Hydro pays grants in lieu of taxes on its land and buildings. The amount of grants in lieu paid is determined based on property valuations and municipal and school division mill rates, similar to the manner in which property taxes are determined for other taxpayers in Manitoba.

Payroll tax is based on a tax rate of 2.15%, which is applied to the Utility's gross payroll.

Business taxes are paid with respect to commercial space occupied by Manitoba Hydro in both leased and owned properties. The Utility pays property taxes to the landlords of leased premises as part of the required lease payments.

Manitoba Hydro also makes other municipal payments with respect to the Town of Gillam and the Frontier School Division.

As noted in the NFAT Report, the Utility's payments to the Province totaled $262 million, representing 16% of Manitoba Hydro's revenues. Since then, the ongoing construction on the $8.7 billion Keeyask and the $5.0 billion Bipole III projects, as well as other capital projects, has increased the annual amounts paid and payable to the Province. Even though Bipole III is not yet in service, in fiscal year 2018, Manitoba Hydro will pay $43 million to the Province for the debt guarantee fee and an additional $22 million to the Province for capital tax. Each of those amounts will increase when Bipole III is fully in-service in fiscal 2019. Likewise, even though Keeyask's in-service date has been delayed 21 months, in fiscal year 2018, Manitoba Hydro will pay $44 million to the Province for the debt guarantee fee and an additional $22 million for capital tax. No water rental fees for Keeyask will be paid to the Province until that generating station enters service when those water rental fees will reach $18 million per year in 2025.

When those two major capital projects are completed and beginning in 2023, Manitoba Hydro estimates it will pay approximately $490 million to the Province each year. The amount paid to the Province will decrease once Manitoba Hydro is repaying debt, thereby reducing its debt guarantee fees.

A comparison of payments to government by Manitoba Hydro and other Canadian Crown-owned electric utilities was provided in evidence and is set out in the chart reproduced below. In addition, the chart separately shows dividend payments in the jurisdictions where dividends are paid. Manitoba Hydro reiterated that there is no policy or policy discussion in Manitoba for paying dividends to the Province and the Utility's rates are not set on the basis of generating a rate of return for the Province. As illustrated in the chart below, Manitoba Hydro's total payments to Government (excluding dividend payments) as a percentage of gross revenue are higher, by a minimum of 7%, than other Canadian Crown-owned electric utilities. When dividend payments are factored in, Manitoba Hydro's total payments to Government as a percentage of gross revenue are second only to Hydro Quebec, which paid $2.146 billion in dividends to the Province of Quebec in 2016 pursuant to a dividend formula.

Payments to Governments ($ Millions)						
($ Millions)	Manitoba Hydro (Forecast 2018/19)	British Columbia Hydro (Forecast 2018/19)	Hydro-Quebec (2016 Actual, forecast not available)	Newfoundland Labrador Hydro (Forecast 2018/19)	SaskPower (Forecast 2018/19)	New Brunswick Power (Forecast 2018/19)
Water Rentals	103	350.1	667	0	21	0
Debt Guarantee Fee	185	0	218	2.2	0	31.8
Capital & Other Taxes	145	238.7	284	0	50	45.1
Other	0	0	0	0	35	0
Payments to Gov't	**433**	**588.8**	**1,169**	**2.2**	**106**	**76.9**
Gross Operations Revenue	2,246	4,836.8	13,339	696.5	2,697.6	1,705.5
Payments to Gov't as Percentage of Gross Revenue	***19.3%***	***12.2%***	***8.8%***	***0.3%***	***3.9%***	***4.5%***
Dividends	0	70.8*	2,146**	0	21	0
Total Payments to Gov't (with dividend)	**433**	**659.6**	**3,315**	**2.2**	**127**	**76.9**
Total Payments to Gov't (with dividend) as Percentage of Gross Revenue	*19.3%*	*13.6%*	*24.9%*	*0.3%*	*4.7%*	*4.5%*

Source: MIPUG-30

* BC Hydro was historically mandated to pay a dividend equal to 85% of net income, subject to an 80:20 debt-to-equity cap; however, this formula was amended by Order in Council, such that beginning in fiscal year 2018, the dividends payable will be reduced by $100 million per year until zero is reached and will thereafter remain at zero until BC Hydro reaches a debt-to-equity ratio of 60:40.

** The amount of dividends paid by Hydro Quebec in 2016 was a result of the formula in that province that requires a dividend of 76% of net income be paid to the Quebec government, unless the Utility's equity ratio would fall below 26%. Hydro Quebec's high net income in 2016, which largely resulted from high run-off and favourable weather conditions, allowed the Utility to pay more than $2 billion in dividends to the Quebec government.

14.1 Intervener Positions

The Consumers Coalition requests that the Board recommend to Government that a portion of capital taxes, water rental fees and debt guarantee fees be redirected by the Province toward extensive demand side management programs for vulnerable customers, such as lower-income customers.

The Manitoba Industrial Power Users Group submits that the Board should recommend that Government implement a 10-year forgiveness of capital tax and debt guarantee fees on Keeyask and Bipole III, commencing with their respective in-service dates. The resulting financial benefits of any such relief could be split between the core objectives of permitting accelerated achievement of longer-term equity level targets and bringing average rate increases to within the range of inflation. This Intervener argues that applying these high capital tax and debt guarantee fees to major new capital projects is not appropriate so long as such charges aggravate concerns regarding equity or reserve levels and add pressures to increase domestic electricity rates above inflation. In addition, these payments have certain features that are consistent with hidden taxes. In the Manitoba Industrial Power Users Group's submission, if the Government is seeking to raise revenues, there are fairer ways than through electricity bills. This Intervener quantified the impact of its suggestion as being worth an approximate 10.6% impact on rates by 2022.

Manitoba Keewatinowi Okimakanak also submitted that the Government of Manitoba should forego some of the revenues it receives from Manitoba Hydro, as did British Columbia's government in respect of B.C. Hydro.

14.2 Board Findings

The Board finds that as a percentage of gross operations revenue, Manitoba Hydro's payments to the Province of Manitoba are high, both before and after considering the jurisdictions where dividends are paid by Crown-owned electric utilities. The evidence demonstrated that, excluding payments made to municipal governments, approximately 17 to 18 cents of each dollar of gross revenue is directed by Manitoba Hydro to the Province of Manitoba.

While the majority of Manitobans are both taxpayers and ratepayers, there is an important distinction. Consistent with the Board's responsibility for setting just and reasonable rates, ratepayers should be responsible for the economic costs associated with electrical services in Manitoba. Economic costs include both the direct costs of producing and supplying electrical power. Ratepayers are therefore billed based on their own consumption. In contrast, taxpayers should be responsible for the broader policy objectives as set by the elected members of Government. This means that the Government, on behalf of taxpayers, is custodian of the economy, owns Crown land and natural resources, and pursues social policies in the collective interest. As citizens of the province, taxpayers contribute revenues towards collective goals and collective good – such as the cost of a hospital that an individual taxpayer may never use. Nor are ratepayers and taxpayers economically identical: although most households are both, the proportion of income paid for electricity bills versus taxes varies considerably across households. As a result, any shift in the burden from taxpayers to ratepayers can have significant distributional impacts.

Consideration must be given to the appropriate allocation of revenues and costs as well as to risks and benefits as between taxpayers and ratepayers. In Manitoba, this issue is informed by the distribution of revenues and costs between the provincial government and the Crown-owned Utility. In general, the costs of Manitoba Hydro's capital projects are borne by ratepayers once the assets are in service.

The Bipole III project was initially scoped, designed, and engineered by Manitoba Hydro using the most cost effective route. However, as a result of a policy decision by the provincial government, the routing of Bipole III was changed to a western route at an additional cost of approximately $900 million. This decision created a $900 million burden for ratepayers with no apparent technical benefit for the new route. The Board finds that this was a policy decision of government that should be a cost to taxpayers, not Manitoba Hydro's ratepayers.

As such, the Board recommends that the Government suspend payment of the Bipole III debt guarantee fee and capital taxes made by Manitoba Hydro to the provincial government starting with the 2018/19 fiscal year. Manitoba Hydro – and ultimately the ratepayer – should be reimbursed through suspension of such payments for approximately 13 years until the $900 million burden of a policy decision made by government with respect to the Bipole III western route is satisfied.

With respect to Keeyask, after it is fully in-service, Manitoba Hydro will pay approximately $140 million per year to the Province of Manitoba for water rentals, debt guarantee fees, and capital and other taxes. As noted by the Board in its 2014 NFAT Report:

> *While ratepayers will shoulder a significant rate burden over the next 20 years, the Province of Manitoba will reap substantial incremental revenues through capital tax and water rental payments from Manitoba Hydro as a result of the Keeyask Project. The Province should give serious consideration to using some of these incremental revenues to fund energy affordability programs targeted to vulnerable consumers, particularly lower income consumers and customers*

residing in northern and First Nations communities. This could involve rate relief programs as well as targeted DSM programs.

In response to the Board's NFAT recommendations, the provincial government issued a letter on July 2, 2014 to both the Chair of the Manitoba Hydro-Electric Board and to the President and CEO of Manitoba Hydro stating:

> *The Manitoba Government will also consider the Panel's specific recommendation respecting Government revenues from new hydro development, as well as potential alternatives to support vulnerable consumers to reduce their bills.*

As revenues are already accruing to the Province as a result of Keeyask and in the context of projected annual electricity rate increases, the Board continues to be of the view that the Government should use some of the revenues it receives from Keeyask to fund a comprehensive bill affordability program, as discussed in detail below.

Finally, the inter-relationship between Manitoba Hydro and the provincial government will be enhanced with provincial carbon pricing. In the transition to a low-carbon economy, the Province of Manitoba does and will benefit from the strength of its clean hydroelectric resources. As the provincial government will receive revenue from the planned carbon tax, the Board further recommends that the provincial government transfer a portion of the carbon tax revenues to further strengthen Manitoba Hydro's financial health which may allow for lower consumer rate increases.

15.0 Cost of Service Study and Implementation of Order 164/16

Cost of Service is a method of allocating a utility's costs to the various customer classes it serves. Its purpose is to determine the allocation of the utility's approved costs, also referred to as the revenue requirement, among the customer classes. The Utility's Cost of Service Study determines each customer class's share of Manitoba Hydro's overall revenue requirement. A Cost of Service Study is normally filed with each GRA and, together with the proposed revenue requirement, rate design, and other pertinent information, forms the background supporting rate setting.

Through a process that began in December of 2015 and culminated in Order 164/16, the Board reviewed Manitoba Hydro's Cost of Service Study methodology. Order 164/16 provides an explanation of the concepts and terminology related to the Cost of Service Study.

In Order 164/16, the Board determined that the principle of cost causation – the idea that customers should pay for the costs they "cause" the Utility to incur - is paramount in determining the appropriate Cost of Service Study methodology. As such, ratemaking principles and goals should not be considered at the Cost of Service Study stage.

Following the Board's review, Manitoba Hydro implemented Board directives from Order 164/16 in the Prospective Cost of Service Study for Year Ending March 31, 2018 ("PCOSS18"). In scope for the current GRA hearing was the issue of whether the cost treatment of PCOSS18 follows the directions and principles of Order 164/16. Specifically, the matters raised for Board consideration are:

- the classification of wind resources, which was directed to be 100% energy in Order 164/16 on the basis that wind energy cannot be relied upon to meet peak demand and capacity needs. However, Manitoba Hydro now includes wind in its resource planning for capacity purposes, giving rise to the question of whether the classification of wind resources should be revised;

- the allocation of General Customer Services costs in the remaining general Customer Services sub-category to General Service Large 30-100kV and General Service Large >100kV customers. In PCOSS18, Customer Services activities have now been disaggregated and separated into three distinct categories: (1) Industrial and Commercial Solutions to General Service Large customers, the costs of which are allocated only to that customer class using the C23 allocator, (2) the costs of comparable services provided to smaller customers, which are allocated to all customer classes except General Service Large using the C13 allocator, and (3) the remaining general customer services, the costs of which are allocated to all customer classes on the basis of class revenues using the C10 allocator. The general customer services costs include outage calls, line locates, marketing research & development, safety watches & building moves, and rates & regulatory. These costs are allocated to all customer classes proportionately by revenue;

- the functionalization of Generation Outlet Transmission and specifically, whether there are other Generation Outlet Transmission facilities than those identified by the Board in Order 164/16 that meet the Board's criteria to be functionalized as Generation;

- whether radial transmission lines, also known as non-tariffable transmission, should be included in the allocation of export revenue as these assets are not integrated with the networked transmission system and therefore do not facilitate exports;

- the completion of the further study directed in Order 164/16 of the allocation of common costs, the service drops allocator, and the treatment of primary and secondary distribution lines; and

- how Bipole III revenues should be treated in the Cost of Service Study.

15.1 Manitoba Hydro's Position

Manitoba Hydro submits that PCOSS18 is essentially fully compliant with the methodology directed in Order 164/16. With respect to the remaining Customer Service activity costs allocated using the C10 allocator, Manitoba Hydro argues that the disaggregation of these activities into three distinct categories demonstrates that there is no overlap in the allocation of customer costs. Moreover, the activities in this sub-category are public safety-related and therefore allocable to all customers.

Manitoba Hydro acknowledges that there are two outstanding directives from Order 164/16 that remain to be addressed in the next Cost of Service Study, specifically: updating the allocator for service drops and studying the allocation of common costs. Manitoba Hydro will complete these directives in the next Cost of Service Study, but states that it does not expect that there will be a material impact on allocated costs. With respect to primary and secondary distribution lines and the Board's directive to continue with the existing methodology unless and until additional study and data are presented to justify any changes, Manitoba Hydro states that its records do not distinguish the costs of primary and secondary lines, so the data required are not available.

Manitoba Hydro submits that it annually reviews the facilities functionalized as Generation Outlet Transmission.

While Manitoba Hydro now attributes some capacity to wind generation in its resource planning, the Utility is not looking to vary the Order 164/16 Cost of Service treatment of wind costs.

With respect to the treatment of Bipole III Deferral Account revenues, Manitoba Hydro proposes returning the revenue to domestic classes on the same basis by which the revenues were accumulated in the fund (i.e. proportionally by class). Manitoba Hydro submits that this approach most fairly apportions the reserve account to each class.

15.2 Intervener Positions

The Manitoba Industrial Power Users Group submits that, while PCOSS18 largely follows Order 164/16, the evidence does not support the use of the C10 allocator to allocate the costs of contact centre – outages, marketing research and development, line locates, or building moves and safety watches to the industrial classes. Of these costs, $2.6 million are allocated to the General Service Large classes, but the costs are either driven by the distribution system, do not relate to the services received by the industrial classes, or relate to activities whose costs are already allocated to General Service Large 30-100kV and >100kV customers through the C23: Industrial & Customer Solutions sub-function allocator. The Manitoba Industrial Power Users Group recommends that C10 costs, other than education & safety and rates & regulatory not be allocated to the General Service Large 30-100kV and General Service Large >100kV classes.

15.3 Board Findings

The Board finds that, aside from the issues addressed below, Manitoba Hydro's PCOSS18 is consistent with the methodology arising from the Board's review in Order 164/16. The Board continues to find, as found in Order 164/16, the principle of cost causation is paramount in determining the appropriate Cost of Service Study methodology. As such, ratemaking principles and goals should not be considered at the Cost of Service Study stage.

Classification of Wind

The Board finds that no adjustment is needed to the classification of wind. As the Consumers Coalition expert witness testified, refinement in order to address the now-recognized capacity benefit of wind would add complexity to the Cost of Service Study methodology with minimal benefit. In addition, as a resource, wind is transacted on an energy basis through contracts with suppliers. Manitoba Hydro does not invest in wind assets in order to serve peak demand. This supports the continued classification of wind as 100% energy.

General Customer Service Costs (C10 Allocator)

The Board finds that the activities of education & safety and rates & regulatory should be allocated to all customer classes using the C10 allocator.

The Board finds that cost causality supports allocating the costs of the education & safety and rates & regulatory activities to all customer classes. Education and safety programs include safety around dams, waterways, substations, and overhead powerlines. Rates & regulatory activities relate to the work done by that department of Manitoba Hydro, including for General Rate Applications. It was not contentious in this proceeding that these costs are incurred for the benefit of all customers. As no party proposed an alternative allocator for the education & safety and rates & regulatory costs, Manitoba Hydro is to continue with the PCOSS18 methodology of allocating these costs on the basis of class total revenue.

Building moves and safety watches, contact centre – outages, line locates, and marketing research and development costs should not be allocated to the General Service Large 30-100kV and General Service Large >100kV customer classes.

Manitoba Hydro is directed to allocate the costs of these customer service activities to all classes other than General Service Large 30-100kV and General Service Large >100kV. The costs for these activities relate primarily to distribution-level assets or service to smaller customers or are already solely allocated to the General Service Large 30-100kV and General Service Large >100kV classes through the Industrial & Commercial Solutions sub-function. As detailed below, the evidence does not establish that General Service Large 30-100kV and General Service Large >100kV customers cause these costs to be incurred.

Building moves & safety watches relate primarily to distribution facilities. The safety watches activity primarily relates to on-site safety watching for residential homeowner and contractors during work in close proximity to distribution facilities, although Manitoba Hydro does not track these services by type of electric plant.

Similarly, with respect to contact centre – outages, Manitoba Hydro does not track outage reports by customer class. While Manitoba Hydro states that the contact centre is the initial point of contact for all customers, the Utility could not confirm if General Service Large customers have used the call centre. In addition, industrial customers can directly contact their key account representative, the costs of which are allocated within the C23 costs.

The costs of marketing to large customers are also specifically included in the C23 costs. Manitoba Hydro could not provide information to show that the costs in the C10 activity of marketing research & development are focused in some aspect on the General Service Large >100kV customers.

Line locates relate primarily to distribution facilities. General Service Large 30-100kV and General Service Large >100kV customers use transmission facilities, not distribution facilities. The Board understands that Manitoba Hydro does not have underground transmission lines in its system, therefore Manitoba Hydro does not incur line locating costs related to transmission lines.

Functionalization of Generation Outlet Transmission

The Board finds that Manitoba Hydro conducted a review of the functionalization of Generation Outlet Transmission and no further study is required at this time, other than reviews of the functionalization Generation Outlet Transmission that the Utility states it undertakes from time to time.

Non-Tariffable Transmission

The Board finds that non-tariffable transmission costs are not to be included in the allocation of export revenues. By definition, these lines are not used to facilitate export revenues. As such, it is consistent with the principle of cost causality to exclude the costs from the allocation of export revenues.

Matters for Further Study

Manitoba Hydro is directed to complete the study of the Service Drops Allocator and the Common Costs study that were ordered in Order 164/16 in time for its next Prospective Cost of Service Study. Manitoba Hydro has committed to completing these directives in this time frame.

The Board will not direct further study on primary and secondary lines. The necessary data are not available to conduct such a study. Moreover, Order 164/16 did not direct that this study be completed; rather, the Board directed Manitoba Hydro to continue with its existing methodology unless and until additional study and data are presented to the Board to justify any methodology changes. There is therefore no outstanding directive on the study of primary and secondary lines.

Treatment of Bipole III Revenues

The Board finds that the Bipole III Deferral Account revenues are to be returned in the Cost of Service Study to the domestic classes proportionally. No party opposed this treatment and it is consistent with the basis by which the revenues were accumulated in the fund as each class contributed to the Deferral Account proportionally. If the revenues were applied directly against the cost of the asset, classes that make relatively greater use of Generation facilities would disproportionally benefit, notwithstanding that each class has contributed 11.6% compounded in rates towards the Deferral Account. Inconsistent treatment as between the revenue collection and the recognition of the revenue for cost of service purposes is not justified.

16.0 Revenue to Cost Coverage Ratios and Differentiated Rates

As detailed by the Board in Order 164/16:

> *One of the outputs of a COSS is the calculation of total costs allocated to each customer class. The COSS output is a tool that can be used in the ratemaking process to assign target revenue for each rate class. This step includes comparisons showing scenarios of target class revenue to the cost of service-based costs allocated to the respective class. The ratio of target revenues by class to the allocated class costs results in a Revenue to Cost Coverage ratio ("RCC"). A RCC ratio less than unity (1.0) means that the revenue generated by a class is not sufficient to recover all the costs allocated and assigned to that class; conversely, a RCC ratio greater than unity (1.0) means that Manitoba Hydro is recovering more revenue from that class than its allocated and assigned costs.*

The Revenue to Cost Coverage ratios are calculated by dividing each customer class's revenue by the allocated costs for the class. In addition to revenue from domestic rates, Manitoba Hydro also receives revenues from its export business and those revenues are credited back to the domestic customer classes in the Cost of Service Study. Historically, when calculating class Revenue to Cost Coverage ratios, Manitoba Hydro added each class's share of export revenue to its domestic revenue, and then divided this total revenue number by allocated costs.

An alternative calculation methodology is to treat export revenue as a reduction to allocated class costs, such that domestic class revenue is divided by allocated costs less the class share of export revenue. If this methodology is used, classes move further from unity, particularly those that are outside of the zone of reasonableness, such that they are under- or over-contributing revenue to a greater degree.

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Many utilities do not set rates in order to achieve class Revenue to Cost Coverage ratios of exact unity. This is because, despite the appearance of arithmetic exactness, every Cost of Service Study contains a degree of imprecision due to the need to make decisions by applying judgment and limitations on the available data with respect to customer loads. Thus, instead of unity, a zone of reasonableness is used to target the Revenue to Cost Coverage ratios of the customer classes. Revenues that are within this range are deemed to represent full cost recovery. Since 1996, Manitoba Hydro has used a zone of reasonableness of 95-105%. In the current GRA, Manitoba Hydro proposes that the Board consider expanding the zone of reasonableness to a broader 90-110% range.

One use of a Cost of Service Study is to assess class Revenue to Cost Coverage ratios against the zone of reasonableness to indicate where adjustments could be made to customer class rates to address any under- or over-recovery of revenues. The means of making such adjustments is through differentiated rates. As opposed to an across-the-board rate increase, where all components of all class rates are increased by the same percentage, differentiated rates shift revenues between customer classes to bring classes outside of the zone of reasonableness within the zone. Such adjustments may be upwards – the collection of more revenue than the average rate increase – or downwards – the collection of less revenue than the average rate increase.

Revenue to Cost Coverage ratio movement may also occur naturally as new assets of significant magnitude enter service and increase the costs that are allocated to the domestic customer classes in the Cost of Service Study. Manitoba Hydro anticipates that when Bipole III enters service, there will be a degree of immediate impact to class Revenue to Cost Coverage ratios. This is because the increased annual costs associated with Bipole III will be functionalized as Generation. As a result, once Bipole

III enters service, classes with a greater proportion of allocated Generation costs relative to their total costs, such as General Service Large >100kV, will see their allocated costs increase to a greater extent than those classes that do not, such as Residential. As illustrated below, one impact is that the General Service Large 30-100kV, General Service Large >100kV, and Residential customer classes, which are currently outside of the 95-105% range, move closer to unity when Bipole III enters service.

The class Revenue to Cost Coverage ratios are as set out below, including for the Manitoba Hydro PCOSS18 calculation methodology, the alternative calculation methodology, and the estimated ratios in 2020 when Bipole III is in service:

Customer Class	PCOSS18 Revenue to Cost Coverage Ratio	Alternative Methodology Revenue to Cost Coverage Ratio	Estimated 2020 Revenue to Cost Coverage Ratio with Bipole III*
Residential	94.8%	93.5%	96.7%
General Service Small Non-Demand	112.5%	115.7%	115.3%
General Service Small Demand	101.0%	101.3%	101.3%
General Service Medium	98.3%	97.8%	97.4%
General Service Large 0-30kV	99.1%	98.7%	96.5%
General Service Large 30-100kV	109.3%	113.0%	103.5%
General Service Large >100kV	108.6%	112.3%	101.5%
Area & Roadway Lighting	100.3%	100.3%	118.2%

* Based on Manitoba Hydro's PCOSS18 methodology of calculating the Revenue to Cost Coverage ratios

16.1 Manitoba Hydro's Position

Manitoba Hydro submits that the Cost of Service Study and its resultant Revenue to Cost Coverage ratios are tools that may be used when setting rates, but the results of the study should not be used in a purely mechanistic manner. Rather, there should be a reasonable balance with the Utility's ratemaking objectives.

Manitoba Hydro argues that the Board should expand the zone of reasonableness to a broader 90% – 110% range in order to address fairness and equity matters that are no longer guiding principles of the Cost of Service Study. With this expansion of the zone of reasonableness, only the General Service Small Non-Demand class is outside of the zone.

The Utility argues further that revising the method of calculating the Revenue to Cost Coverage ratio would require an expansion to the zone of reasonableness because the alternative approach generates results with a much broader set of outcomes, suggesting a need for a more dramatic and immediate rate adjustment. As such, changing the calculation methodology should not be done in isolation, but rather in concert with acceptance of a broader zone of reasonableness. In addition, the alternative methodology would represent a significant departure from the traditional and long-standing calculation that has been used by Manitoba Hydro to report PCOSS outcomes, producing results that will not be directly comparable to those historically reported.

Manitoba Hydro submits that any evaluation of the current Revenue to Cost Coverage ratios must consider the directional changes that are expected in the next Cost of Service Study once Bipole III is in service and reflected in the revenue requirement. Manitoba Hydro states that the impacts by class of Bipole III entering service are predictable based on each class's relative usage of the bulk power system and the change in cost structure to the significant, lumpy increase in the amount of Generation-related revenue requirement included in the study. The expected change in costs is sufficient to move the Revenue to Cost Coverage ratios for the Residential and General Service Large classes into the zone of the reasonableness as soon as Bipole III enters service, without any additional rate differentiation.

Based on the foregoing, Manitoba Hydro is not proposing to shift revenues between customer classes to adjust Revenue to Cost Coverage ratios.

16.2 Intervener Positions

The Consumers Coalition notes that the most common zones of reasonableness employed by Canadian regulators are 90% to 110% and 95% to 105%, but submits that the 90% to 110% range is preferred. It argues that, even with the current zone of reasonableness of 95% to 105%, the result of Bipole III entering service will be to move the Residential class well within the zone. There is therefore no basis for a disproportionately higher rate for the Residential class. As well, Residential class rates tend to be significantly above marginal costs, so differential rates for the class are not justified from an economic efficiency perspective.

Representatives of the General Service Small and General Service Medium Customer Classes and Keystone Agricultural Producers argue that the Board should consider improvements to the Revenue to Cost Coverage ratios for certain classes, and in particular the General Service Small Non-Demand class, which is outside the zone of reasonableness at 112.5% (using the PCOSS18 calculation methodology) or 115.7% (using the alternative calculation methodology). Differential rates would therefore be consistent with the rate-making principle of fairness, which seeks to avoid a situation where any class pays an arbitrarily high rate through a contribution to costs that has the effect of subsidizing another class. There should be adjustment to the ratio for General Service Small Non-Demand in the range of a 1% lower rate increase.

The Manitoba Industrial Power Users Group submits that the calculation of Revenue to Cost Coverage ratios should be performed using the alternative methodology. It argues that the zone of reasonableness of 95% to 105% is appropriate for a large utility with a sophisticated Cost of Service Study like Manitoba Hydro. In evaluating the current Revenue to Cost Coverage ratios, the Board should set rates with positive movement towards the zone of reasonableness to reflect principles applied to utility regulation and to address longstanding overpayment of costs by the General Service Large classes. The degree of adjustment should be a rate increase 1% - 2% lower than average for the classes above 105% to reflect gradualism and to ensure that reversal will not be required in the near-term when Bipole III enters service.

16.3 Board Findings

The Board finds that the Revenue to Cost Coverage ratios are to be calculated using the alternative methodology of treating export revenues as a reduction to allocated class costs. Although this is a departure from the calculation methodology historically used by Manitoba Hydro, the goal of consistency has less weight at this time when the Cost of Service Study methodology itself has changed as a result of the Board's review in Order 164/16. Aside from the means of calculating the Revenue to Cost Coverage ratios, the results from previous Cost of Service Studies are already not directly comparable to post-Order 164/16 results given that significantly different methodologies are employed.

Further, the Board finds that the alternative methodology is consistent with cost causation. As stated by the Board in Order 164/16, "export revenues are not a 'dividend' that can be assigned or based on considerations other than cost causation". The domestic customer classes incur costs to facilitate Manitoba Hydro's export business. Treating export revenues as a reduction of allocated costs in the Revenue to Cost Coverage ratio aligns with the economic justification for major capital projects such as Keeyask, which is based on using the full quantum of export revenues to lower the cost of new generation and transmission.

As such, the Revenue to Cost Coverage ratios arising from PCOSS18 are:

Customer Class	**Revenue to Cost Coverage Ratio**
Residential	93.5%
General Service Small Non Demand	115.7%
General Service Small Demand	101.3%
General Service Medium	97.8%
General Service Large 0-30kV	98.7%
General Service Large 30-100kV	113.0%
General Service Large >100kV	112.3%
Area & Roadway Lighting	100.3%

In evaluating class Revenue to Cost Coverage ratios, the Board does not accept that the zone of reasonableness should be expanded to 90% to 110% and finds the zone of reasonableness should remain at 95% to 105%. While rate-making principles may justify accepting Revenue to Cost Coverage ratios that are outside of the zone, those principles do not support broadening the zone itself. A 95% to 105% range recognizes the sophistication of Manitoba Hydro's Cost of Service Study and departure from this range has not been justified.

The Board finds that the Revenue to Cost Coverage ratio output of the Cost of Service Study is to be used at this time to more closely align the revenues collected from each customer class with the costs of the electrical system that are caused by each class. As determined in Order 164/16, the Cost of Service Study is a tool that can be used in rate-making. With Manitoba Hydro's implementation of the methodology changes resulting from the Board's review of the Cost of Service Study in Order 164/16, the Utility now has a valid, regulator-approved cost of service result. While the cost of service should not necessarily be the overriding factor in designing rates, it is consistent with the rate-making principle of fairness to consider the output of the Cost of Service Study.

The Board directs Manitoba Hydro to begin to implement differentiated rates to collect the approved revenue requirement. General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV are all overpaying costs to a significant degree outside of the zone of reasonableness, at 115.7%, 113.0%, and 112.3% respectively. The two General Service Large classes have been overpaying in almost every year since 1996, even using the previous ratio calculation methodology which tended to narrow the range of class ratios.

Manitoba Hydro is to adjust class revenue targets in order to begin to move the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV customer classes Revenue to Cost Coverage ratios into the zone of reasonableness. This will result in these customer classes receiving a level of rate increase that is slightly lower than the average rate increase.

For the 2018/19 Test Year rates, Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness, based on the alternative calculation methodology as directed in this Order. The rate increase impact of doing so is to be shared across all customer classes that are either below or within the zone of reasonableness: Residential, General Service Small Demand, General Service Medium, General Service Large 0-30kV, and Area & Roadway Lighting. As a result, the Residential customer class, which is currently the only class below the Zone of Reasonableness, will begin to move into the zone of reasonableness.

This approach to the implementation of differentiated rates is consistent with the principle of gradualism and limits the revenue recovery responsibility of the other customer classes, while maintaining overall revenue neutrality. This approach will also assist in limiting the prospect of over-correction of the issue at the time Bipole III enters service.

Manitoba Hydro is directed to include in its compliance filing for 2018/19 differentiated rates consistent with the Board's direction in this Order.

The Board will examine the Revenue to Cost Coverage ratios arising from the Prospective Cost of Service Study filed with the next GRA and will consider adjustment to the differentiation of rates as necessary, including to consider the impact of Bipole III entering service.

17.0 Rate Design

Manitoba Hydro designs its rates to collect the required amount of revenue from each customer class. In selecting a rate design, Manitoba Hydro considers its general rate-making objectives, which it identifies as: recovery of revenue requirement, fairness and equity, rate stability and gradualism, economic efficiency, competitiveness of rates, and simplicity and understandability.

Manitoba Hydro's existing customer class rate designs use a combination of the following charges: (1) a basic charge, which is a fixed charge that includes the direct costs of metering, portions of the distribution system, as well as billing administration, (2) a demand charge, which is a variable charge based on the maximum use of electricity within a specified time period and recovers costs that vary with peak electricity usage, and (3) an energy charge, which is a variable charge based on the electric energy consumed that recovers costs that vary with the consumption of electricity.

A simplified illustration of the existing class rate structures, based on the rates in effect as of August 1, 2017, is contained in the table below:

August 1, 2017	Basic Charge	Energy Charge (¢/kWh)	Demand Charge (/kVA)
Residential	$8.08	8.196	N/A
GSS Non-Demand (1 phase)	$21.91	8.609 * 5.976 ** 3.944	N/A
GSS Demand (3 phase)	$30.89	8.609 * 5.976 ** 3.944	$10.10
GSM	$32.61	8.609 * 5.976 ** 3.944	$10.10
GSL 0-30kV	N/A	3.709	$8.57
GSL 30-100kV	N/A	3.448	$7.34
GSL >100kV	N/A	3.342	$6.53

* First 11,000 kWh
** Next 8,500 kWh

Source: PUB 42-5-1

If a customer class's rate structure is changed, the general result will be to redistribute the collection of revenues between the customers within that class. Some customers within the class will pay more in rates than they would have under the previous rate structure, while others will pay less.

In the current GRA, Manitoba Hydro is seeking to have the requested 7.9% rate increase apply to all components of customer rates, without any change to the existing rate structures. This would increase the basic charges, energy charges, and demand charges by the approved rate increase.

In this proceeding, there were a number of proposals from Interveners and expert witnesses related to changing the rate structure, as well as an illustrative residential electric heating rate design filed by Manitoba Hydro.

First, the expert witness retained by the Green Action Centre, Paul Chernick, recommended that Manitoba Hydro be required to: 1) reduce demand charges over time while increasing energy charges and 2) eliminate the use of demand ratchets (rate provisions that charge demand-metered customers based on their maximum demand in current and previous months). Mr. Chernick gave evidence that these changes would send appropriate price signals to customers.

Second, Mr. Chernick proposed the implementation of a residential conservation rate, also referred to as an inverted block rate. This form of rate design includes a first block of consumption, set at a specified level of consumption exceeds the first block threshold – also referred to as the tail block – is priced at a higher level, based on the marginal value of energy. Because customers under this rate design pay less for consumption in the first block, and more for all kilowatt hours consumed in the tail block, there is a price signal to conserve energy.

Mr. Chernick's inverted block rate design recovers all of the requested rate increase in the tail block, with no increase to the basic charge or the energy charge for the first block of consumption.

Manitoba Hydro last used an inverted block rate structure between 2008 and 2011; however, in Order 40/11, the Board eliminated this rate design because it did not consider home heating load such that electric space heating customers were negatively affected due to their higher winter electricity consumption.

Third, Mr. Chernick proposed a rate design for residential electric space heating customers. Manitoba Hydro also filed an illustrative rate design scenario for residential electric space heating customers. The rationale for a reduced rate for electric space heating customers is that almost 20% do not have the choice of switching to natural gas space heating which is a lower-cost heating fuel. Natural gas is not available in many areas of the province and, where it is available, converting to natural gas heating may not be economically viable. As a result, rate increases place a burden on consumers who do not have the option of switching to alternative fuel sources.

Mr. Chernick's electric space heating rate design is an inverted block rate with seasonal blocks, such that the level of consumption for the first block threshold varies based on seasonality. The discount for all consumption in the first block of energy is 4¢/kWh. His objective with this rate design was to offset the cost of electric space heating, without reducing incentives to conserve energy, by targeting the reductions to usage blocks that will not be the customer's marginal usage.

Manitoba Hydro's illustrative rate design scenario is aimed at shielding electric heating customers from a portion of the proposed rate increase. Non-electric heating residential customers bear the additional revenue responsibility. This rate design scenario was not approved by the Manitoba Hydro-Electric Board and is not proposed by Manitoba Hydro for regulatory approval.

Fourth, Mr. Chernick and the expert witness retained by the Manitoba Industrial Power Users Group, Patrick Bowman, each proposed time-of-use rates for the General Service Large customer classes. A time-of-use rate recovers the Utility's costs primarily through an energy charge, which is differentiated between on-peak and off-peak hours. This creates an incentive for customers to shift consumption to off-peak times, when the energy charge is lower. Manitoba Hydro previously applied for time-of-use rates in the 2014/15 & 2015/16 GRA, but the Board determined that the issue would be addressed in the Cost of Service Study review. The Cost of Service Study proceeding ultimately excluded the review of rate-related matters from scope and deferred these to the next GRA. In this GRA, Manitoba Hydro did not submit a time-of-use rate proposal as such a rate design would shift revenue responsibility to customers who cannot make use of off-peak periods to reduce costs, exacerbating the bill impacts from the requested rate increase.

In his evidence, Mr. Chernick recommended that time-of-use energy charges be introduced to encourage reduction of usage in high-load periods. He proposed a three-period (on-peak, shoulder, and off-peak), seasonally differentiated rate with a narrow “critical peak” period. His proposal to eliminate demand charges would be a step towards the introduction of time-of-use rates.

Mr. Bowman proposed an optional time-of-use rate for industrial customers that could make use of off-peak energy at reduced rates to reduce electricity costs. Mr. Bowman’s evidence was that this would help address the issue of industrial customers having a limited number of ways to control costs without burdening customers who could not make use of the program. Mr. Bowman acknowledged that an optional time-of-use rate could result in revenue loss to Manitoba Hydro as only customers that could reduce their bills would opt for it, but suggested that the effect is likely to be a very small percentage of what the General Service Large >100kV class has been paying above costs for many years.

17.1 Manitoba Hydro’s Position

Manitoba Hydro argues that there should be no change to the rate structure at this time, as the introduction of such changes in an environment where the average customer bill is proposed to increase by 7.9% would result in some customers facing bill increases in excess of 7.9%. As such, Manitoba Hydro proposes that the rate increase of 7.9% apply to all components of the customer class rate structure.

Manitoba Hydro submits that demand charges are appropriate to provide a meaningful price signal to general service customers, without which customers may place greater demand on the system than they would otherwise. Demand charges also provide the Utility with a greater degree of revenue stability. Minimum billing demand and contract demand provisions reinforce the price signal to customers of the cost of demand that they impose on the system.

Manitoba Hydro argues that inverted block rates should not be implemented at this time due to the need to assess this rate design against the future conditions that may be experienced with Keeyask entering service, as well as with the significant change in marginal value. The tail block rate proposed by Mr. Chernick is considerably in excess of the levelized marginal value of electricity and would send an inappropriate price signal to customers.

Manitoba Hydro does not endorse the illustrative residential rate design scenario for a residential electric heating rate. With respect to Mr. Chernick's electric heating rate design, Manitoba Hydro submits that no weight can be given to the proposal as no proof of revenue was provided, making it impossible to test the design to ensure that it produces the appropriate level of revenue.

Manitoba Hydro does not accept that there should be an optional time-of-use rate, as this would result in a revenue shortfall to the Utility of approximately $1.5 million. The suggestion from the witness for the Manitoba Industrial Power Users Group that non-participating customers would not make up the revenue shortfall means that Manitoba Hydro would not be compensated for this revenue loss. This would violate the rate-making objective of full recovery of the revenue requirement.

17.2 Intervener Positions

The Consumers Coalition does not support an alternative residential rate design. At a time when any rate increase is likely to be significantly above inflation, intra-class revenue adjustments would compound consumer challenges. There is also no basis for an inverted block rate due to the differential between estimated marginal costs and the actual residential rate, based on current rates and their projected trajectory. As well, the Consumers Coalition believes that Manitoba Hydro's illustrative rate scenario is not justified by cost causation or efficiency reasons. The Revenue to Cost Coverage ratio for non-electric heating customers is already higher than that for electric heating customers, and it is likely that the marginal cost for electric heating customers is also higher.

The Green Action Centre recommends that it be a strategic priority for Manitoba Hydro and Efficiency Manitoba to address affordability for electric space heating customers through initiatives that reduce and affordably finance the capital costs of geothermal systems. The Green Action Centre also submits that the Board should accept the marginal cost calculation performed by Mr. Chernick, which indicates that current rates are below marginal costs and further supports the implementation of an alternative rate design.

The Manitoba Industrial Power Users Group argues that the Board should direct Manitoba Hydro to bring forward for the Board's review at the next GRA an optional time-of-use rate for General Service Large customers. The rate should be prepared by Manitoba Hydro in consultation with affected customers.

17.3 Board Findings

The Board finds that there will be no change to the rate design, except as may be required to achieve the class revenue targets as directed in the previous section.

First, the Board does not accept that there should be a reduction in demand charges or elimination of the demand ratchet. This change in the existing rate structure would contribute to the magnitude of bill impacts that some customers will have to absorb, including the general rate increase as well as the shift in revenue responsibility as a result of differentiated rates. In addition, the Board heard evidence in this proceeding about the potential for increased use of disruptive technology for non-utility generation, such as customer solar photovoltaic installations. This could potentially require the review of demand charges in the near future in order to ensure that class revenues are fully recovered and that the value of grid reliability is properly assessed when used by customers as a back-up power resource.

Second, the Board finds that the implementation of a residential inverted block rate is not supported on the evidence. Due to the updated marginal value, which is less than the current residential energy rate, an inverted block rate would send an inappropriate price signal and would be contrary to the rate-making principle of efficiency. However, the Board notes that the General Service classes have declining block rate structures and an explanation for this rate design was not provided in this GRA, despite the updated marginal value information. Manitoba Hydro is directed to provide in its next GRA filing the rationale for the rate design for the General Service customer classes and an evaluation of the block thresholds and charges.

Third, the Board finds that neither of Manitoba Hydro's illustrative residential rate design nor the electric space heating residential rate design proposed by Mr. Chernick are to be implemented. These rate designs are not justified on a cost of service basis, given the higher cost to serve electric space heating customers. Due to their higher cost to serve, electric space heating customers are already subsidized by non-electric heat customers. The Board also notes the lack of proof of revenue provided for Mr. Chernick's rate design proposal. However, as discussed further below, the Board is concerned about bill affordability issues for lower-income electric space heating customers and recommends that bill assistance for these customers be provided through a comprehensive Government bill affordability program.

Finally, with respect to time-of-use rates, the Board continues to be of the view that time-of-use rates should be implemented for General Service Large customers; however, due to the updated marginal values filed in this proceeding, further study is required. The Board therefore accepts the recommendation of the Manitoba Industrial Power Users Group and directs Manitoba Hydro to bring forward for the Board's review at the next GRA a time-of-use rate design proposal. The proposal is to be based on further analysis in the context of the updated marginal values. Manitoba Hydro is directed to consult with General Service Large customers before filing its proposal with the Board and to include the results of that consultation with the information provided to the Board.

18.0 Bill Affordability

The Board has long been concerned with utility bill affordability issues. Evidence with respect to energy poverty in the province of Manitoba has been brought before the Board for at least a decade. The Board recognizes that Manitoba Hydro has, over time, developed programs to assist customers in managing their energy consumption, thereby reducing individual customer bills, and such programs include targeted support for lower-income customers. However, the Board has consistently expressed concern that measures focused on energy efficiency implemented by Manitoba Hydro to date, while commendable, have been insufficient to address the energy burden faced by lower-income customers. This is particularly the case in a time of major capital construction by the Utility, which has and is forecast to continue to put upward pressure on electricity rates at a level greater than the rate of inflation. This concern is heightened with Manitoba Hydro's projected rate path that, if implemented, would increase consumer rates by 77% cumulatively over 10 years. The history of the substantial discussions on this important matter bears repeating.

Ten years ago, in Order 116/08, the Board noted that the lower-income, high energy burden problem is pervasive in Manitoba and that "a low-income bill assistance program would assist in reducing the energy burden faced by low-income households. Significant non-energy benefits would arise, including increased comfort, reduced health costs, lower bad debt write-offs etc." The Board went on to hold that "Energy affordability for low-income families is very much an issue that requires more or less immediate attention in Manitoba." The Board directed Manitoba Hydro to propose for Board consideration a lower-income bill assistance program no later than September 30, 2008. Following a Review and Vary Application by Manitoba Hydro, the Board revised its directive to remove the deadline date and to require Manitoba Hydro to provide a new date for the earliest implementation of a Lower-Income Bill Assistance Program in its update to the Board required by November 30, 2009.

Manitoba Hydro filed a report on lower-income bill assistance on March 4, 2009. In the report, Manitoba Hydro discussed possible bill assistance program expansion and indicated that it would investigate the viability of potential program expansion, citing many variables that required investigation. In Order 32/09, the Board accepted that implementation of a program would require the addressing of issues that are complex and far-reaching. The Board directed Manitoba Hydro to provide a report with respect to Manitoba Hydro's plans for a program after the Utility's planned consultation with stakeholders and subsequent recommendation to the Manitoba Hydro-Electric Board. The Board reiterated the vital importance of protection for lower-income customers, noting Manitoba Hydro's plans for a capital program predicated on consistent future rate increases and the Board's expectations that Manitoba Hydro would put forward its preferred lower-income bill assistance program.

In Order 5/12, the Board expressed its concern with the slow pace of the overall energy poverty relief effort and stated that more should be done, particularly for First Nation communities and specifically First Nation diesel communities. However, the Board found that, before it would require Manitoba Hydro to develop a definitive bill assistance program, more information was required as to existing funding made available by Government and the programs available to directly or indirectly alleviate poverty.

In the NFAT Report, the Board again expressed concern about the impact of projected rate increases on lower-income consumers, including customers living in First Nation communities. The Board noted the significant rate burden on consumers over the next 20 years and the likely substantial incremental revenues that would accrue to the Province of Manitoba as a result of Keeyask. The Board recommended that the

Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of Keeyask be used to mitigate the impact of rate increases on lower-income consumers.

In Order 73/15, the Board recognized that higher electricity rates – then forecast to be at the level of annual increases of 3.95% for 17 years – would have an impact on lower-income ratepayers, and particularly electric space heating ratepayers. On the recommendation of the Green Action Centre's expert witness in the proceeding, the Board directed Manitoba Hydro to initiate a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting lower-income ratepayers. The Board stated that, upon completion of the collaborative process, the Board would evaluate the options presented and decide on their implementation.

In response to the Board's directive in Order 73/15, Manitoba Hydro established the Bill Affordability Working Group ("Working Group"), which was comprised of a variety of stakeholders who represent, work with, or provide services to lower-income Manitoba Hydro customers. The Working Group participants were:

- Consumers' Association of Canada (MB)
- Employment & Income Assistance (Manitoba Department of Families)
- Green Action Centre
- Manitoba Housing
- Manitoba Hydro
- Manitoba Industrial Power Users Group

- Manitoba Keewatinowi Okimakanak
- Manitoba Metis Federation
- Southern Chiefs Organization
- Social Planning Council of Winnipeg
- Winnipeg Harvest

The Working Group carried out the first collaborative in-depth examination of energy affordability in Manitoba. The collaborative process took place over sixteen months and, in January of 2017, culminated in The Manitoba Hydro Bill Affordability Collaborative Process Summary Report & Recommendations ("Working Group Report"). The Working Group's primary findings included:

- A definition of energy poverty in Manitoba.

  The Working Group established the following definition of energy poverty: "Energy poverty refers to circumstances in which a household is, or would be, required to make sacrifices or trade-offs that would be considered unacceptable by most Manitobans in order to procure sufficient energy from Manitoba Hydro." For the purposes of the Working Group Report, the Working Group considered a household to be energy poor if it spends more than 6% or 10% of pre-tax income on energy and also has a level of income lower than the current Low Income Cut-Off 125 ("LICO-125"), which is 25% above the Statistics Canada lower-income measurement;

- Greater understanding and insights into energy poverty in Manitoba, including an improved understanding of which Manitobans are affected or likely to be affected by energy poverty, and why.

  Based on research conducted as part of the Working Group process, the Working Group concluded that the relationship between unpaid bills or arrears and energy poverty is relatively weak;

- Assessment of existing affordability programs for lower-income customers, including evaluation of program delivery, uptake and success in meeting stated objectives.

  Manitoba Hydro's existing programs and approaches to bill affordability reviewed by the Working Group were the Power Smart Affordable Energy Program, Neighbours Helping Neighbours, the Equal Payment Plan, deferred payment plans, arrears management, and community outreach. The Working Group also considered other assistance and options available in the province, including Employment and Income Assistance, Manitoba Housing programs, and contributions by Indigenous & Northern Affairs Canada towards the cost of Manitoba Hydro bills for customers on First Nations reserves who receive social assistance;

- Research and evaluation of bill affordability programs in other jurisdictions, to better determine if successful initiatives from elsewhere in Canada and the United States could be implemented here.

  Based on a jurisdictional scan, the Working Group concluded that Ontario appears to be the only Canadian jurisdiction to have implemented a rate assistance program. The Ontario Electricity Support Program ("OESP") was introduced in 2016 and provides fixed monthly bill credits to eligible customers. The OESP was initially ratepayer funded, but as a result of provincial legislation, is now taxpayer funded with higher fixed credit amounts;

- Potential impacts of proposed Manitoba Hydro rate increases, determined by a rate-modelling exercise to evaluate how increases would likely affect lower-income customers.

  This showed that impacts of higher energy costs are anticipated to be most pronounced for households that already spend a significant proportion of their total income on energy; and

- Rate assistance mechanisms and options that could improve affordability for lower-income customers, as well as analysis of estimated revenue losses associated with each option.

> The Working Group identified and modelled three rate assistance options: (1) basic monthly charge waiver (2) straight rate discount (3) percentage of income payment plan.

Ultimately, the Working Group concluded that its findings illustrate:

> *the deeply complex, multi-faceted nature of energy poverty. Energy poverty spans issues of income, geography, cultural identity, family size, awareness of available support programs, and more. The Working Group's findings make it clear that no single initiative or program will solve the issue of energy poverty. Rather, the Working Group's recommendations reflect the consensus view that a suite or "toolkit" of improvements is required to improve energy affordability in the province.*

The Working Group's recommendations addressed lower-income energy efficiency initiatives, electric heating, emergency assistance, landlord and tenant initiatives, extreme weather impacts, equal payment plans, bill collection, arrears management and bill forgiveness, and funding. While improvements to Manitoba Hydro's existing lower-income offerings were recommended, the Working Group did not reach consensus on any specific rate options or rate assistance program.

18.1 Jurisdiction of the Board to Order Lower-Income Rate Assistance

In Order 116/08, the Board found that it would be acting within its legislative mandate if it were to direct Manitoba Hydro to implement a bill assistance program.

In Order 73/15, the Board again considered an argument from Manitoba Hydro that the Board does not have jurisdiction to order the Utility to implement a bill affordability program. On review of the Board's constating legislation, the Board rejected Manitoba Hydro's submission and reiterated its finding from Order 116/08 that ordering a bill affordability program is within the Board's legislative powers. The Board concluded that any future proposals for bill assistance would therefore be evaluated from a comprehensive policy perspective, rather than being focused on the issue of the Board's legal jurisdiction.

Manitoba Hydro's Position

Manitoba Hydro argues that, based on the text, context, and purpose of The Crown Act, The Hydro Act, and The Board Act, the Board does not have jurisdiction to order the implementation of lower-income rates or other bill affordability programs. Although the Board has previously concluded that it does have such jurisdiction, Manitoba Hydro submits that this conclusion is inconsistent with the legislation, remains untested in the courts in Manitoba, and that the Board ought to reconsider the issue. In particular, Manitoba Hydro argues that none of the statutory factors which the Board may consider in reviewing rates explicitly permit consideration of affordability or ability to pay. Rather, the Board's rate-setting function must be interpreted as being limited to accomplishing Manitoba Hydro's mandate of providing for the supply of power adequate to meet the province's needs and to promote economy and efficiency in all matters related to the generation, transmission, distribution, and use of power. Finally, Manitoba Hydro submits that the amendments to The Hydro Act that brought in uniform residential rates were intended to create a single rate for residential electricity users. A program targeting First Nations living on reserve would necessarily classify customers based on geographic location in violation of subsection 39(2.2) of The Hydro Act.

Intervener Positions

The Assembly of Manitoba Chiefs takes the position that the Board has jurisdiction to order a bill affordability program and that this jurisdiction is affirmed by *Charter* values.

Similarly, the Consumers Coalition concludes that the Board does have jurisdiction to order implementation of a bill affordability program.

The Green Action Centre takes the position that the issue of Board jurisdiction to order a bill affordability program has long been decided and should not be revisited. It argues that the Board's constating legislation gives the Board wide latitude to take into consideration any compelling policy considerations that the Board considers relevant to setting rates, and any other factors that the Board considers relevant. This jurisdiction is similar to that of the Ontario Energy Board, which the Ontario Divisional Court concluded has the jurisdiction to consider "ability to pay" in setting rates. It argues further that, in order to achieve its mandate of supplying economic power to ratepayers at fair rates, Manitoba Hydro must deal with the issue of affordability.

Manitoba Keewatinowi Okimakanak also argues that the Board has jurisdiction with respect to bill affordability programs. It submits that the Board's mandate to set equitable rates must be governed by the direction set out in *The Path to Reconciliation Act*.

Board Findings

The Board finds that it has legal jurisdiction to order implementation of lower-income rate assistance. This issue was raised previously before the Board and addressed in Orders 116/08 and 73/15, in both of which the Board concluded that it has the legal jurisdiction. The previous position of the Board was supported by many of the parties in this hearing other than Manitoba Hydro. The Board continues to be of the view that it has jurisdiction.

The Board's jurisdiction with respect to Manitoba Hydro is derived from a suite of legislation, primarily consisting of The Board Act, The Crown Act, and The Hydro Act. While the Board's jurisdiction over Manitoba Hydro is largely limited to the review of rates, that jurisdiction is broad. As set out in paragraph 25(4)(a) of The Crown Act, in reaching a decision with respect to rates charged by Manitoba Hydro with respect to the provision of power, the Board has the discretion to take into consideration, in addition to factors relating to the revenue requirement of the Utility:

> *25(4)(a)*
>
> *viii. any compelling policy considerations that the board considers relevant to the matter, and*
>
> *ix. any other factors that the Board considers relevant to the matter.*

The considerations set out in paragraph 25(4)(a) serve as a guide to the Board in exercising its mandate under section 77 of The Board Act to fix just and reasonable rates. As the Manitoba Court of Appeal held in *Consumers' Association of Canada (Manitoba) Inc v Manitoba Hydro Electric Board*, 2005 MBCA 55, this requires the Board to balance two concerns: "the interests of the utility's ratepayers, and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest." Each of these two concerns support the ability of the Board to consider the affordability of Manitoba Hydro's rates, whether broadly or within a class or sub-set of its customers. Affordability is not only relevant to the interests of the Utility's ratepayers, but also to the financial health of the Utility as rates that are in excess of what customers can afford may lead to depressed revenues through a combination of reduced energy consumption, business closures or relocation, and as acknowledged by Manitoba Hydro, potentially an increase in arrears.

The scope of the Board's discretion in reviewing Manitoba Hydro's rates is not limited to Manitoba Hydro's mandate of providing for the supply of power adequate to meet the province's needs and to promote economy and efficiency in all matters related to the generation, transmission, distribution, and use of power, as set out in section 2 of The Hydro Act. Had it been the legislature's intention to narrowly circumscribe the Board's jurisdiction in this way, it would have done so expressly using the same statutory language contained in The Hydro Act. Instead, the legislature chose to grant the Board broad discretion to consider, "any compelling policy considerations" and "any other factors" that the Board considers relevant to the matter. Affordability is a factor that the Board may consider when setting rates.

As the Board held in Order 73/15, subsection 39(1) of The Hydro Act requires that the aggregate price of power realized by Manitoba Hydro achieve full cost recovery, but this is subject to the requirement that rates must be just and reasonable. Moreover, the Board's constating legislation does not prohibit the creation of a customer class that pays less than the average cost to serve such customers.

Amendments to The Hydro Act in 2001 resulted in the elimination of regional zone rates, which had charged higher rates for customers in Northern and rural Manitoba than for those in the City of Winnipeg based on lower customer densities having higher costs to serve. Subsections 39(2.1) and 39(2.2) of The Hydro Act provide as follows:

39(2.1) The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province.

39(2.2) For the purposes of subsection (2.1),

(a) grid customers are those who obtain power from the corporation's main interconnected system for transmitting and distributing power in Manitoba; and

(b) customers shall not be classified based solely on the region of the province in which they are located or the population density of the area in which they are located.

In defining a customer class, the classification of customers cannot be based solely on the region of the province in which the customers are located or the population density of the area in which they are located. However, once a customer class has been defined in accordance with subsection 39(2.2), the requirement is only that all customers within that class be charged the same rate. The classification of customers based on other characteristics, either instead of or in addition to region or population density, is not prohibited. For example, the legislation does not prohibit the creation of a lower-income customer class as such a class would not be based solely on region or population density, subject only to the limitation that all customers within the class be charged the same rates for power.

Manitoba Hydro argues that the Board should depart from its previous findings on jurisdiction based on the decision of the Nova Scotia Court of Appeal in *Dalhousie Legal Aid Service v Nova Scotia Power*, 2006 NSCA 74. In that decision, the Court found that the Nova Scotia Utility and Review Board does not have jurisdiction to implement a rate assistance program for lower-income customers, based on subsection 67(1) of the Nova Scotia Board's governing legislation. Manitoba Hydro submits that subsection

67(1) of the Nova Scotia legislation is similar to subsection 39(2.1) of The Hydro Act, and therefore this Board should follow the guidance of the Nova Scotia Court of Appeal.

The Board does not agree. Subsection 67(1) of the Nova Scotia legislation is considerably more restricted than the statutory framework contained in The Board Act, The Crown Act, and The Hydro Act. Subsection 67(1) of the Nova Scotia legislation provides:

> *67(1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.*

Due to the requirement that customers receiving "substantially similar" service, and the Nova Scotia Board's finding that lower-income residential customers receive substantially the same level of service as all other residential customers, the Nova Scotia Court of Appeal concluded that the Board was prohibited from ordering differential rates based on the customer's income.

Unlike the Nova Scotia Board, this Board is empowered to take into account "any compelling policy considerations" and "any other factors that the Board considers relevant to the matter". In Manitoba, there is no similar restriction as in Nova Scotia that all customers receiving substantially similar service "shall always" be charged the same rate. Rather, the only limitation on the Board's broad authority under *The Crown Act* is the requirement that customers not be classified solely based on region or population density. As detailed above, this does not prohibit the creation of a lower-income customer class.

Contrary to Manitoba Hydro's submission, this Board's jurisdiction is more closely aligned with the statutory framework in Ontario. In *Advocacy Centre for Tenants-Ontario v Ontario Energy Board* (2008), 293 DLR (4th) 684, the Ontario Divisional Court distinguished the Nova Scotia decision based on the restrictive wording of subsection 67(1) of the Nova Scotia legislation. In contrast, the Court in Ontario noted that section 36 of the Ontario Energy Board's governing legislation has broad language that empowers the Ontario Board to set "just and reasonable" rates. The Ontario Court concluded that the Board could, in setting rates, take into account income levels to achieve the delivery of affordable energy to lower-income consumers as this would meet the objective of protecting consumer interests.

The Ontario legislation does differ from the legislation in Manitoba in that subsection 36(3) expressly states that the Ontario Energy Board "may adopt any method or technique that it considers appropriate" in fixing just and reasonable rates. This provision provided greater flexibility to the Ontario Energy Board than it had previously under a statutory regime that required rate-setting on a very prescriptive cost of service basis. Similarly, the Manitoba legislation grants broad authority to this Board to take into account policy considerations and other relevant factors in rate-setting. Moreover, as the Supreme Court of Canada held in *Ontario (Energy Board) v Ontario Power Generation Inc*, 2015 SCC 44, "where a statute requires only that the regulator set "just and reasonable" payments… the regulator may make use of a variety of analytical tools in assessing the justness and reasonableness of a utility's proposed payment amounts." The Manitoba Court of Appeal has similarly determined that, in Manitoba, cost of service is a tool that may or may not be used in setting rates. Thus, although in Manitoba there is no express statutory provision akin to the Ontario subsection 36(3), the Board is empowered to employ a variety of analytical tools in fixing rates. Indeed, Manitoba Hydro itself in this GRA urges the Board to be guided by considerations in rate-setting beyond pure cost to serve. Thus, the Board does not accept the argument of Manitoba Hydro that this Board's jurisdiction is more limited than the Ontario Board because of the absence of a provision similar to subsection 36(3) in Ontario.

Therefore, the Board has jurisdiction under its governing statutory framework to order a bill affordability program such as a lower-income rate, and to take into account affordability as a factor in setting just and reasonable rates.

18.2 Bill Affordability for Manitoba Hydro Customers

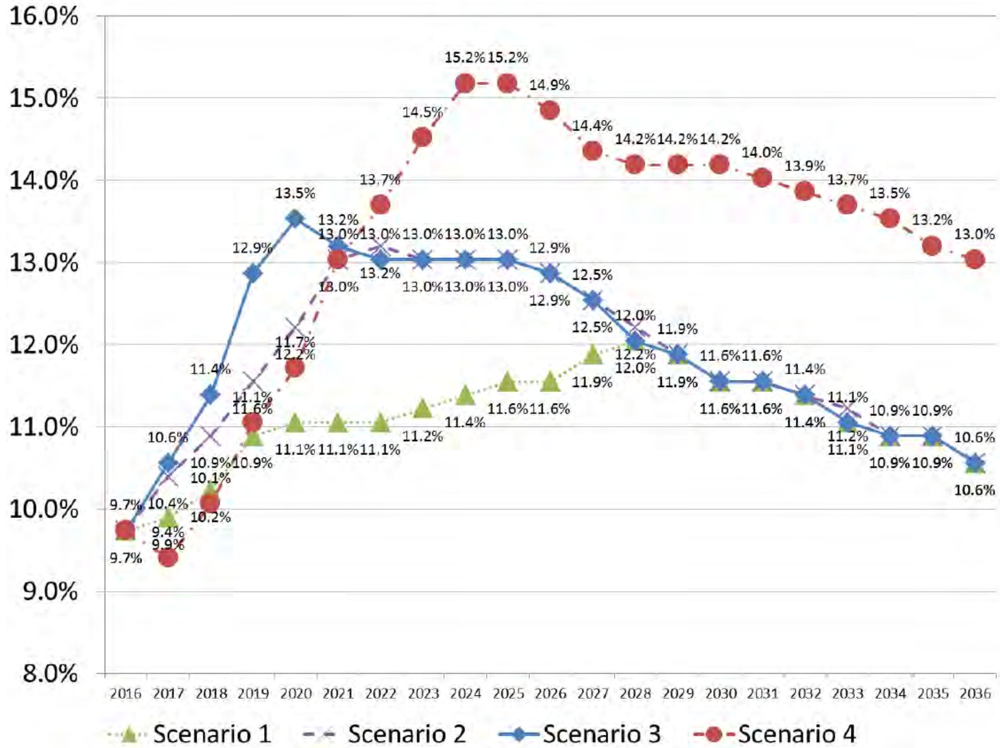
In the current GRA, which followed the completion of the Working Group Report, Manitoba Hydro did not propose an affordability rate or rate assistance program. In the GRA filing, Manitoba Hydro did provide a response to the specific recommendations of the Working Group, including actions to be taken with regards to each recommendation. However, with respect to an affordability rate or rate assistance program, Manitoba Hydro's position is that:

> *issues of poverty and distribution effects are complex and ought to be addressed through the setting of social policy which is within the purview of government. As such, Manitoba Hydro is of the view that of the provision of social assistance programs directed to low income customers is appropriately reserved for the Province of Manitoba.*

However, in testimony in the oral hearing, Manitoba Hydro's President and Chief Executive Officer stated his recognition that the matter of bill affordability will become increasingly important to resolve as Manitoba Hydro proceeds with higher rate increases and therefore, there is a need to find solutions to the issue.

The figure below depicts the impact of various Manitoba Hydro rate increases on the proportion of Manitoba Hydro's total number of residential customers (households) that are LICO-125 and above the 6% energy poverty threshold. In the figure, the plotted line for "Scenario 4" is based on the projected rate plan contained in MH16 Update with Interim. As illustrated in the figure below, the projected rate plan would result in the proportion of energy poverty increasing from 9.7% to 15.2% in 2024, and remaining at a permanently higher level through at least 2036.

Percentage of Households That Are LICO-125 and Above 6% Energy Burden Threshold



Scenario 1 - 3.95% nominal electricity rate increases for 12 years; *Scenario 2* - 5.95% nominal electricity rate increases for 6 years; *Scenario 3* - 7.95% nominal electricity rate increases for 4 years; *Scenario 4* - 3.36% nominal electricity rate increase in 2017, followed by 7.9% rate increases for 6 years and a 4.54% rate increase for 1 year

Source: AMC/MH II-23

The Board heard evidence from residential ratepayers who have to make sacrifices in their daily lives in order to be able to pay their electricity bills. As one ratepayer testified, rate increases add stress and, in the context of being on a fixed income, present difficult and limited opportunities for saving. Another ratepayer gave evidence that, if Manitoba Hydro receives the full amount of its planned rate increases, he may have to consider changing where he lives. He went on to explain that “I’m tired of working so I think it would be - - put more of a squeeze on us. I support my grandson right now. He’s out of work, lives with us - - I don’t know what else to say. It’s just getting tougher.”

A single mother of four children testified before the Board that, if Manitoba Hydro's planned rate increases are granted:

> *I will be forced to further dig in deeper into my food budget, decreasing the amount of groceries I am able to buy per month. And in terms of food, I will be looking at alternatives, cheaper, unhealthier alternatives in order to make my groceries last.*
>
> *It will reduce the amount - - it will reduce the amount that I'm able to engage in social activities with my children, social outings. It will negatively impact us … where it would not allow me to save up for the future or to have an emergency fund. It makes it more challenging for me to put money away in terms of getting a vehicle down the road and just saving - - saving money overall, it would be very challenging because I'm having a hard time with my utility bills as it is.*

In addition to the evidence of the real-life experiences of ratepayers in Manitoba, expert witnesses in the proceeding provided specific proposals for an affordability rate. In particular, the expert witness retained by the Green Action Centre, Paul Chernick, proposed inverted block rate structures both for LICO-125 ratepayers and for LICO-125 ratepayers with electric space heating.

For LICO-125 ratepayers, Mr. Chernick designed a rate based on estimates of energy consumption. His proposal is to eliminate the basic monthly charge and discount the energy charge for the first block of energy consumed by 4¢/kWh. The size of the first block for this rate design is maintained at 500 kWh in each month. Mr. Chernick recommended that the lost revenues that would result from this rate design be recovered from all non-LICO customers, including general service customers, not just non-LICO residential customers.

For LICO-125 ratepayers with electric space heating, Mr. Chernick based his rate design on the distribution of residential electric use among seasons. As with the LICO-125 rate design, the basic charge is waived and the discount for the energy charge for the first block of energy is 4¢/kWh, but the size of the first block varies by season, with the greatest discount being in the winter months. Again, Mr. Chernick recommends that the lost revenues be recovered from all non-LICO customers.

The expert witness retained by the Assembly of Manitoba Chiefs, Philip Raphals, recommended that the Board order Manitoba Hydro to present a ready-to-implement affordability rate for implementation in 2019/20, and that Manitoba Hydro do so with the assistance of a working group to develop the details of the rate. With respect to eligibility, Mr. Raphals' evidence was that coverage at this time should be limited to energy-poor customers with electric space heat, but that there should be *a priori* eligibility for First Nation residents on reserve who pay their own energy bills.

Dr. Wayne Simpson, an expert witness retained by the Consumers Coalition, recommended that, along with enhancements to affordable energy programming, Manitoba Hydro and its stakeholders continue research into energy poverty and its characteristics. Dr. Simpson recommended that Manitoba Hydro be ordered to develop an efficient rate assistance program that provides assistance to lower-income energy poor households that is not directly tied to the level of energy consumption, along the lines of fixed credit approaches taken by Colorado and Ontario.

Manitoba Hydro's Position

Manitoba Hydro's view is that the provision of lower-income social assistance programs is appropriately reserved for the Province of Manitoba. Government already administers income-based programs, has the resources, and provides these programs through a variety of existing mechanisms. While Manitoba Hydro offers programs to assist lower-income customers in lowering their energy bills through energy efficiency opportunities, it submits that the difficulties with the administration, implementation, and on-going operation of a rate assistance program pose significant challenges in identifying which customers truly require assistance. Unlike the Province of Manitoba, Manitoba Hydro does not have resources to administer a new income-based program, nor does it have access to pertinent data that would be necessary to successfully implement such a program.

Manitoba Hydro further argues that it is impossible to test Mr. Chernick's rate design proposal to ensure that it produces the appropriate level of revenue.

Intervener Positions

The Assembly of Manitoba Chiefs urges the Board to consider the goal of reconciliation, consistent with *The Path to Reconciliation Act*. The Assembly of Manitoba Chiefs states that on-reserve First Nations communities have higher rates of energy poverty, lower quality housing, lower incomes, and lower income growth than the rest of the province. Manitoba Hydro's rate increases will disproportionately affect First Nations communities. As such, the Board should order Manitoba Hydro to immediately implement bill affordability measures that offer discounts to residential customers in on-reserve First Nations communities.

Specifically, the Assembly of Manitoba Chiefs argues that Mr. Chernick's LICO-125 electric space heating rate should be ordered for implementation for on-reserve residential customers, with automatic eligibility for the first 500 kWh block of consumption, and an increased electric space heating discount that reflects the different consumption patterns on reserve. The resulting lost revenue should be recovered from all classes as the burden of the additional costs from major new generation and transmission projects which facilitate export power sales falls disproportionately on First Nations, whose Treaty rights are adversely affected. For off-reserve residents, the Board should order an engagement process for bill affordability measures and require Manitoba Hydro to report back on the chosen program within one year.

The Consumers Coalition submits that energy poverty should be addressed through a lower overall rate increase, coupled with effective provincial social benefit programs. The Consumers Coalition does not endorse a ratepayer-funded bill assistance program due to the evidence in the proceeding regarding the likelihood of unacceptably low participation rates. It also does not accept the use of an inverted block rate design for lower-income residential consumers, due to the gap between estimated marginal costs and the actual rate, nor does it support bill assistance targeted at only First Nations customers, as too many vulnerable consumers are left out. Rather, the Board should recommend that the Government establish a taxpayer-funded program to address energy poverty.

The Green Action Centre submits that, given the environment of rising rates, moving forward with implementing a bill affordability program should not be delayed by administrative concerns or differences of opinion regarding the design of the program. The Green Action Centre recommends that Mr. Chernick's LICO-125 electric space heating rate design should be selected for piloting in 2018/19, with first application to LICO-125 customers whose energy burden exceeds 6%. The program can be reviewed at the next GRA, limiting any risk associated with administration. The costs of the program should be funded by all ratepayers and Manitoba Hydro should implement a separate account to be funded at a sufficient level in addition to the revenue requirement. The Green Action Centre also suggests that there should be a single application process, amalgamated with other Manitoba Hydro assistance programs such as the Affordable Energy Program and arrears management.

Manitoba Keewatinowi Okimakanak argues that, consistent with the mandate under *The Path to Reconciliation Act*, the Board should create a separate class for First Nations residential and General Service Small and General Service Medium ratepayers – a class which can be easily identified with existing Manitoba Hydro data – and apply affordability measures to this separate class. Manitoba Keewatinowi Okimakanak suggests that lost revenues associated with the affordability measures implemented for a First Nations customer class should be allocated to all customer classes or natural gas heating customers or both. The Board should also recommend that the Government reduce the payments that Manitoba Hydro is required to make to the Government.

Board Findings

Provincial Government Bill Affordability Program

There is an important role for governments in advancing bill affordability for all Manitobans. The Board unanimously recommends that the provincial government introduce a comprehensive bill affordability program run by a government department to address energy poverty issues faced by Manitobans throughout the province. The Board heard evidence that there is a long-standing need to address this issue and the government is best situated to do so in a comprehensive fashion. The provincial government has social program infrastructure already in place.

The Working Group performed extensive research and analysis. On a consensus basis, the Working Group's Report identified three programs as options for rate assistance:

- A straight-rate discount, which would deduct a fixed percentage amount from the bills of qualifying customers. The Working Group identified three levels of discount: 25%, 35%, and 45%;
- A fixed charge waver, which would eliminate the basic monthly charge from the bills of qualifying customers; and
- A percentage of income payment plan, which would cap the energy bills of qualifying customers at a set level.

The program options identified by the Working Group provide a starting point for the provincial government's development of a bill affordability program. The Board recommends that the provincial government establish a stakeholder group to build on the research and analysis undertaken by the Working Group, as well as programs in other jurisdictions, such as the Ontario Energy Support Program.

Given Manitoba Hydro's expertise regarding its customers, billing system, and affordability issues, and the evidence of Manitoba Hydro's President and Chief Executive Officer of there being an increasing need to find solutions to the unaffordability of bills, the Utility should take initiative to work with the provincial government and other stakeholders to assist in the development of a comprehensive program.

As discussed elsewhere in this Order, the Board notes that there are new sources of revenues flowing to the provincial government and increased revenues from Manitoba Hydro – specifically as a result of the major capital projects – that can be used to fund a government bill affordability measure. This is consistent with the NFAT recommendation that the provincial government direct a portion of the incremental capital taxes and water rental fees from the development of Keeyask be used to mitigate the impact of rate increases on lower-income consumers.

First Nations On-Reserve Residential Customer Class

A majority of the Board directs Manitoba Hydro to establish a First Nations On-Reserve Residential customer class for existing First Nations reserves and that this customer class will receive a 0% rate increase for the 2018/19 Test Year, such that the rate for this customer class will be maintained at the August 1, 2017 approved Residential rate. The 0% rate increase for 2018/19 is also to apply to First Nations diesel zone residential customers. This decision is not unanimous and Board member Larry Ring provides dissenting reasons below. This section sets out the reasons of the majority on this issue.

The issue of bill affordability has been a matter of serious concern for this Board for over a decade. Yet, despite the long history of substantial evidence and discussion before the Board on bill affordability, there have been impediments that have limited the achievement of a concrete plan or program. Particularly in the context of the continuation of rising rates over the recent past, the situation must begin to be addressed.

As noted by Manitoba Hydro’s President and Chief Executive Officer, while Government has a role to play in addressing the issue of affordability, so too does Manitoba Hydro and rate design can assist the Utility in fulfilling its role. Under its mandate to set rates in the public interest, the Board can and should play a part.

The Board recognizes that there are potential administrative and program design hurdles associated with a bill affordability program, and that parties in this proceeding remain of the view that these hurdles give rise to impracticalities, inefficiencies, and cost ineffectiveness. However, the Board concludes that there are steps that must be taken today to address bill affordability.

An appropriate starting point for bill affordability in Manitoba is a program targeted at on-reserve ratepayers, specifically through the creation of a First Nations On-Reserve Residential customer class with a differentiated rate to address energy poverty on Manitoba reserves. Manitoba Hydro is kept whole because the cost of the 0% increase for this new customer class has been factored into the level of the average general rate increase granted for the Test Year to all other customer classes.

The creation of this customer class is justified by the need to address energy poverty on-reserve, supported by evidence that 96% of First Nations people on-reserve live in poverty and that reserves in Manitoba have the highest rates of child poverty in Canada. In addition, the poor housing stock on reserves in Manitoba and the fact that the vast majority of First Nations on-reserve residential customers (61 out of 63 First Nations communities) have no access to the more economical option of natural gas for heating exacerbate the issue of energy poverty. In his testimony, Manitoba Hydro's President and Chief Executive Officer described the housing conditions on First Nations reserves that he has visited as "abysmal". This results in residents on First Nations reserves having to use more energy to heat their homes. On average, First Nations on-reserve customers consume more energy than off-reserve residential customers, despite the efforts of Manitoba Hydro to use demand side management programming to improve energy efficiency for homes on reserves. Taken together, these factors lead to higher utility bills and a population of Manitobans that is disproportionately vulnerable to rate increases.

The customer class and related affordability measure of a 0% increase are also consistent with the principle of reconciliation. As defined in *The Path to Reconciliation Act*, reconciliation is the ongoing process of establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples in order to build trust, affirm historical agreements, address healing, and create a more equitable and inclusive society. The creation of a separate customer class is in response to the degree of poverty on reserves. This separate customer class is to continue until otherwise ordered. Shielding the customer class from the general rate increase in the 2018/19 Test Year recognizes the particular factors that make on-reserve ratepayers uniquely situated among residential consumers in Manitoba. As argued by the Assembly of Manitoba Chiefs, rate increases should not widen the existing gap between First Nations living on reserve and other Manitobans.

The First Nations On-Reserve Residential customer class is consistent with the requirements of The Hydro Act because this customer class is not defined solely on the basis of the region of the province in which the customers are located or population density. As a creation of Canadian Aboriginal law, reserves are tracts of land that are vested in and held by the Crown for the use and benefit of the respective bands for which they were set aside through treaties or agreements with the Crown. Reserves are defined by the legal relationship between the Crown and Indigenous peoples, not by the region of the province in which they are located. Beyond this, there are 63 First Nations reserves in Manitoba, located in regions throughout the province. There is no one region that can be isolated as being the location that gives rise to the classification of these customers. For this reason, an on-reserve customer class cannot be equated with the regional zone rates that were in effect prior to the amendments to The Hydro Act.

Moreover, the Board agrees with the Assembly of Manitoba Chiefs that many more factors distinguish on-reserve residents as electricity ratepayers, such that even if this classification were based in part on the region of the province in which the customers are located, it is not solely based on region. The circumstances of on-reserve residential customers include the particular housing infrastructure, energy consumption patterns, non-availability of natural gas heating, and poverty levels. The specific conditions of electricity needs, usage, and cost on First Nations reserves justifies the creation of a separate customer class.

This step in addressing bill affordability is also administratively simple and can be effectively implemented to reach the target recipients. As Manitoba Hydro already identifies on-reserve residential ratepayers in its billing system, the members of this new customer class are readily identifiable. No application process to determine eligibility is required. The new customer class can be created immediately and the affordability measure of a 0% rate increase can be applied at the same time with minimal administration.

Due to the administrative complexity and cost concerns raised by Manitoba Hydro regarding other bill affordability program options discussed in this proceeding, the Board will not, at this time, order Manitoba Hydro to implement a broader bill affordability measure. However, the Board views the 0% rate increase for the First Nations On-Reserve Residential customer class as a modest first step in addressing bill affordability. The Board is aware that there will be some obvious anomalies created where one household on-reserve will receive a lower rate than a nearby off-reserve household living in similar circumstances; however, this is a limited measure designed to reach a targeted group experiencing a high degree of poverty. The anomalies that result from this measure are best addressed by a more wide-reaching government bill affordability program. The Board envisions that, with the introduction of a comprehensive government bill affordability program, the new First Nations On-Reserve customer class and lower rate built into the 2018/19 Test Year may no longer be required.

18.3 Dissenting Decision and Findings of Board Member Ring

I agree with the majority of Board members that Governments should develop and implement a comprehensive bill affordability program to address the needs of First Nations, remote and Northern consumers, and lower-income ratepayers. However, having read the majority reasons by my Board colleagues with respect to their decision to create a separate First Nations On-Reserve Residential customer class and order a 0% rate increase, I cannot support this decision.

Deviation from Cost of Service Regulation

In my view, the decision of the majority departs from principles of utility regulation in this province and enters a realm that is reserved for the federal and provincial governments. In particular, the context of how Manitoba Hydro operates and is regulated is not recognized in the approach taken by the majority. Manitoba Hydro is an energy utility, not a social service agency of the provincial government.

Manitoba Hydro is regulated on a cost of service basis, with rates set to recover the Utility's costs of supplying power. Board Order 164/16 set out that cost causation is paramount.

Legislated Uniform Residential Customer Class

Prior to the 2001 amendments to The Hydro Act, this regulatory principle was reflected in the use of regional zone rates, which were set to recover the higher costs to serve customers in low population density regions of Manitoba. Through legislative action by the provincial government, uniform rates were implemented and a single Residential customer class was created. Customers in low density and high cost to serve regions had their electricity rates reduced to be equivalent to the electricity rate paid by customers in the high density and lower cost to serve area of the City of Winnipeg. In effect, a policy decision of the provincial government introduced intra-class subsidization, as the cost of serving rural and Northern customers is not equivalent to the cost of serving customers in the City of Winnipeg, but the rate is nonetheless equal.

The Creation of Another Separate Residential Customer Class Should be Legislated

If there is to be another significant deviation or change to the long-standing approach to cost recovery on a cost of service basis, that change should be made by the Government as it was in 2001, and not by Manitoba Hydro or its regulator. That is particularly so with respect to the matter of energy poverty, which is a complex social policy issue that is interwoven with other issues of poverty, income adequacy, and economic development. As such, the affordability of energy bills should be resolved by elected representatives in Government, not the Utility or its regulator. In particular, the approach taken by the majority of selecting a particular sub-set of residential ratepayers to pay less than may be required to serve those customers is making social policy. Social policy should be made by the provincial government.

While I acknowledge the concerns of the majority about reconciliation, *The Path to Reconciliation Act* mandates that it is the provincial government that is to take the lead in advancing measures to promote reconciliation, through the responsible minister's development of a strategy for reconciliation.

I also cannot agree with the majority's selection of a rate increase exemption for a new customer class of First Nations On-Reserve Residential ratepayers. Beyond the issue of this being a matter outside of the role of this Board, the approach taken is significantly under-inclusive. I agree with the Consumers Coalition that bill assistance targeted only at on-reserve First Nations customers excludes too many vulnerable consumers. First Nations customers on reserve are not the only ratepayers who experience energy poverty, nor are they the only ratepayers who have no choice but to heat with higher-cost options such as electricity as opposed to natural gas.

In addition, the selection of First Nations on-reserve residential ratepayers ignores the issue of competing provincial and federal government jurisdiction on reserves. The Board heard evidence that the federal government is already involved in bill assistance for some on-reserve ratepayers. In granting a 0% increase for on-reserve customers, the Board may actually be subsidizing the costs of the federal government and not providing a form of rate relief to ratepayers.

Geographic Regions

I accept that the Board has jurisdiction to create a lower-income customer class. It does not have jurisdiction to create a discriminatory customer class based on regions of the province. A glance at most Manitoba maps will show these geographic regions.

Creating a Permanent Separate Residential Class

I am also concerned that the new customer class will become entrenched in the regulation of Manitoba Hydro rates, such that the class will be difficult to remove or revise in future proceedings. Even if the 0% rate increase is only implemented for 2018/19, it will create a rate differential with the general Residential rate that will, for all practical purposes, be permanently entrenched absent a government program that specifically eliminates the differential. Otherwise, to eliminate the differential would require the Board to approve a rate increase targeted to the First Nations On-Reserve Residential class over and above any rate increase approved for the Residential customer class.

Over time, and in the context of projected annual rate increases, the gap in residential rates will continue to grow. This would become onerous on other ratepayers that will be responsible for subsidizing through their rates the lost revenues not recovered from the First Nations on-reserve residential customer class.

19.0 Solar Generation Program Rate

Solar energy is generated by photovoltaic ("PV") generating systems that produce direct current electricity from sunlight. The direct current electricity can in turn be used to power equipment or charge batteries, generally with the use of an inverter to convert the direct current electricity to alternating current electricity for residential use.

While solar PV systems can be configured as off-grid systems, residential solar PV installations are usually tied into the local electric grid system. This allows solar PV customers to benefit from reduced grid-electricity consumption while maintaining system reliability through access to the local grid for back-up electric energy. Similarly, any excess solar PV power not consumed by the solar PV customer can be sold back to the local utility, usually through a power purchase agreement. As a result, grid-connected solar PV installations incorporate a bi-directional electricity meter that records both the amount of energy supplied by the utility as well as the excess solar PV energy flowing back into the electricity grid. Such customers are typically known as net-metered customers.

To evaluate the opportunities, challenges, and technology requirements of solar PV in the Manitoba market, Manitoba Hydro introduced its Solar Energy Program in the spring of 2016 as an energy efficiency and load displacement program. This two-year pilot program, targeted at residential and small commercial customers with less than 200 kW of electrical load, offers incentives toward the capital cost of solar PV installations. Manitoba Hydro provides an incentive of $1 per watt installed, which can represent approximately one-third of the total installed costs. The incentive is limited to the PV capacity that, at a maximum, generates less energy than that customer's annual load. In addition, Manitoba Hydro's Residential Earth Power Loan program is offered to solar PV customers to assist with the up-front capital costs of solar PV installations.

Once participating customers successfully complete the required electrical inspection, Manitoba Hydro awards the program incentives and installs a bi-directional meter that monitors power imported from the grid as well as power exported from the customer site to Manitoba Hydro's electricity grid. The meter will record the amount of energy supplied by Manitoba Hydro each month. As Manitoba Hydro explained in evidence in this proceeding, for both residential and commercial customers, the billing system will charge for this monthly consumption at the Board-approved August 1, 2017 residential energy rate. The meter will also record the amount of excess energy put on the grid by the customer's solar PV system. A billing line item reflecting the corresponding value calculated at the Board-approved residential rate is applied to the customer's monthly bill. Under Manitoba Hydro's billing system, customers with non-utility generation systems do not bank energy credits for use in later periods. Rather, energy bills are reconciled monthly using the Board-approved residential electricity rate.

Manitoba Hydro's two-year pilot Solar Energy Program will end in April 2018. At that time, the installation incentives will no longer be offered but Manitoba Hydro will continue to offer financing for solar installations through its Earth Power Loan program. Those customers who participated in the pilot program will continue to get credit for surplus energy that is within their own usage, although Manitoba Hydro is currently reviewing its policy of crediting a customer's excess electricity at the full residential rate.

As a result of the pilot Solar Energy Program, Manitoba Hydro currently has 2.6 MW of installed solar generation, which results in 3.47 GWh of energy annually displaced from the electricity grid.

19.1 Board Findings

The Board is concerned that Manitoba Hydro implemented the Solar Energy Program with a rate for excess solar energy without prior Board approval. Rate designs for net metered customers must be brought before the Board for review and rate approvals.

The Board has legal jurisdiction to review and approve the electricity rate that Manitoba Hydro applies to customers participating in the Solar Energy Program, or to customers with any on-site generation, for the return of excess energy to the grid. All rates for services, changes in rates for services, and new rates for services provided by Manitoba Hydro must be reviewed and approved by the Board. The Board's jurisdiction with respect to reviewing and approving rates is framed broadly under The Crown Act and extends to all rates, rate changes, and new rates for electricity "howsoever generated". There is no exclusion for customer-generated electricity.

The price paid by Manitoba Hydro for excess customer-generated solar power is currently unilaterally set by the Utility, which has a retail monopoly in the Manitoba market. This unilateral fee is a price charged by Manitoba Hydro, as it is an expense or cost that Manitoba Hydro sets for the supply of excess solar power. While Manitoba Hydro ultimately pays the cost for the power, this does not detract from the fact that Manitoba Hydro is setting the price for the supply of a particular form of power. Therefore, the price for customer-generated solar power is a "rate for service" subject to the Board's review and approval under The Crown Act.

The Board's conclusion with respect to jurisdiction is supported by section 38 of The Hydro Act, which provides that any person who is required by the Manitoba Hydro-Electric Board to supply power to the Utility may apply to the Board to review the price computed by Manitoba Hydro for the power. This section does not directly apply to the purchase of customer generated solar power by Manitoba Hydro as customers are not "required" to supply the power; however, as Manitoba Hydro's Solar Energy Program includes the Utility purchasing customers' excess solar electricity, section 38 should be understood broadly as demonstrating the intention of the legislature to protect all persons who are paid a unilaterally set price in a monopoly market.

Moreover, the Solar Energy Program is a demand side management program. Demand side management programs introduced by Manitoba Hydro to support customer-generated renewable power, including the Solar Energy Program, are subject to review by the Board. This includes the rates paid for customer-generated energy.

Manitoba Hydro has not yet provided evidence demonstrating the appropriate rate for crediting of customers' excess energy. For all net metering installations, the Board approves Manitoba Hydro crediting customers' excess energy put on the grid at the rate of 8.196¢/kWh for 2018/19. For any future net metered rates or changes to the 8.196¢/kWh rate, Manitoba Hydro is directed to apply to the Board for approval. For the next GRA, Manitoba Hydro is directed to provide additional details on the Solar Energy Program and other net metering installations in Manitoba.

In future, rate designs for net metered customers must be brought before the Board for review and rate approvals.

20.0 Special Rates

As noted above, in addition to the general rate increase sought by Manitoba Hydro, the Utility is also seeking approval of a number of items related to special rates:

1. Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14, and approval of new LED rates for the Area and Roadway Lighting class (Sentinel Lighting) as discussed in Tab 9 of Manitoba Hydro's Application;

2. Approval to remove the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) rates from Manitoba Hydro's rate schedule, as discussed in Tab 9 of Manitoba Hydro's Application;

3. Endorsement of modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") that were accepted on an interim basis in Order 43/13, as outlined in Tab 9 of Manitoba Hydro's Application;

4. Final approval of all SEP interim *ex parte* rate Orders as set forth in Tab 10 of its Application, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of Manitoba Hydro's Application and prior to the Board's Order in this matter; and

5. Final approval of Curtailable Rate Program ("CRP") *ex parte* Order 54/16 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of Manitoba Hydro's Application and prior to the Board's Order in this matter.

20.1 Board Findings

The special rates were not contentious and were discussed by Manitoba Hydro during the oral hearing. The Board approves the special rates sought by the Utility, excluding finalization of the interim diesel zone rates which Manitoba Hydro is no longer seeking as part of this GRA.

Manitoba Hydro is directed to provide confirmation to the Board that the executed Settlement Agreement documents have been received by the Utility and that the documents are in proper form. With this confirmation, Manitoba Hydro is to advise the Board of its intention regarding finalization of the interim diesel zone rates.

21.0 Capital Project Review per Order in Council 92/2017

Order in Council 92/2017 assigned the Board the duty of considering Manitoba Hydro's capital expenditures as a factor in reaching a decision regarding rates for services. In the course of considering the evidence from Manitoba Hydro, Independent Expert Consultants, and Intervener Experts related to Manitoba Hydro's capital expenditures, the Board identified improvements that should be made to Manitoba Hydro's capital expenditure approval and execution processes in the future, as well as aspects that Manitoba Hydro has performed well and should therefore be continued.

21.1 Capital Project Cost Estimating

Manitoba Hydro, like all electric utilities, has significant capital assets and undertakes major capital projects in order to deliver reliable electrical service to Manitoba residents and businesses. Manitoba Hydro's initial capital cost estimates have often under-estimated the final in-service costs of these projects. The following table provides examples of changes in capital cost estimates from the original capital cost estimate to the most current estimate, and the percentage change.

Comparison of Original Cost Estimates to Current Cost Estimates for Major New Generation & Transmission Projects			
($ millions)	Original CEF* Estimate	Most Current CEF* Estimate	Percentage Change
In Progress			
Keeyask	3,700	8,726	136%
Bipole III	1,880**	5,042	168%
Manitoba-Minnesota Transmission Project	205	453	121%
Completed			
Pointe du Bois Spillway	318	576	81%
Wuskwatim (including transmission)	988	1,742	76%
Riel AC Station and Sectionalization	96	320	233%

* Manitoba Hydro's Capital Expenditure Forecast. The time between the development of the original CEF estimate and the most current CEF estimate varies for each project in this table.
** Original estimate in this table is based on the western routing with converter stations.

The above table shows the original approved cost estimate when it was first included in a Capital Expenditure Forecast. This original estimate is sometimes approved years in advance of the initiation of the project construction. As more detailed design, engineering, and project scope development are completed, the original estimates are revised – and approved – until such time as final pre-construction estimates are developed. For example, the original Keeyask estimate of $3.7 billion was approved in 2008 but construction did not commence until 2014. During that period, additional design and engineering were completed, resulting in the final pre-construction estimate for Keeyask – approved in early 2014 during the NFAT – of $6.5 billion.

METSCO, an expert for the Consumers Coalition, in an analysis of 49 generation, transmission, and distribution projects, similarly found that Manitoba Hydro significantly underestimated the capital cost of projects in comparison to the final actual costs. Compared to the original cost estimates used when the project is first approved by the Manitoba Hydro Executive, METSCO found the final actual costs to be 106% higher (when weighted by project cost). At the original cost estimating stage, Manitoba Hydro has not generally completed detailed design, engineering, and scope development.

In contrast to the original cost estimates, when compared to the final pre-construction estimates, METSCO found that the actual costs for these 49 projects were only 6% higher. In other words, the accuracy of the estimates is significantly enhanced once detailed design, engineering, and scope development are completed prior to construction.

In this GRA, MGF introduced the concept of a ‘stage gate’ approval process, specifically for MMTP but which could apply to other large projects such as Keeyask. This is a project management tool, common in the energy industry, that shepherds a project through five phases: conception, concept selection, tendering, execution, and operation, with a decision gate following each phase. The ‘stage gate’ concept is that a project does not move from one stage to the next – that is, receive approval to go to the next stage – until a set of criteria is satisfied. The criteria may be technical, financial, commercial, or other criteria. In some cases, a peer review by engineering, commercial, and project management professionals is completed to ensure that the risks associated with the project are addressed.

MGF recommends other improvements for Manitoba Hydro’s estimating processes on future projects. Those improvements include having the estimate team prepare the estimate with input from each department, providing supporting back-up, and providing a more detailed explanation outlining the structure and relationship between the physical scope of work and resources to complete the work. MGF also suggested that a higher contingency, such as a P95 contingency, be used when evaluating the business cases of future projects.

MGF explained that preparation of a Basis of Estimate document is an industry best practice. A Basis of Estimate helps define the project scope, identifies risks and opportunities, provides a record of documents used in development of the estimate, provides a record of communications made during development of the estimate, and facilitates the review and validation of the estimate. Manitoba Hydro prepared a Basis of Estimate for Bipole III which, in MGF's view, was extremely well done.

As explained earlier in this Order, MGF found Manitoba Hydro's cost estimating methodologies (with respect to the $4.65 billion and $5.04 billion Bipole III estimates) are consistent with industry standard and best practices. This finding is supported by the cost increase of 8%, which is in line with the 6% average cost increase from final pre-construction budget to actual cost as found by METSCO.

Manitoba Hydro's Position

Manitoba Hydro appears to agree with METSCO that the previous cost estimating and capital approval process that resulted in these inflated final costs is not acceptable. In response to METSCO's findings, Manitoba Hydro explained that its previous process for obtaining corporate approval required estimates of these projects to be developed and submitted for approval prior to any engineering or planning being done, and the initial estimate was completed without a clear definition of project scope. According to Manitoba Hydro, this past process has been replaced with new scope development and approval processes, which allow for the scope of the project to be developed in greater detail before the cost is estimated and the investment considered for approval to execute.

According to Manitoba Hydro, the role of the newly-created position of Director of Strategic Business Integration is to ensure that spending on Business Operations Capital is integrated into Manitoba Hydro's financial planning processes. Previously, each division – Generation, Transmission, and Marketing & Customer Service (or Distribution) – provided its list of proposed capital projects and corresponding budgets to the Executive Committee for corporate approval.

Board Findings

The Board finds that Manitoba Hydro has been approving projects too early in the process, without sufficient development of scope, design, and engineering. The Board recognizes that, with additional scope, design, and engineering development prior to advancing the capital project for financial and economic analysis and subsequent executive approval, there will be additional front-end costs. In the Board's view, these additional sunk costs would be money well spent as the additional work will allow a more informed decision by Manitoba Hydro's Executive.

The evidence shows that when Manitoba Hydro undertakes more thorough design, engineering, and project planning, the final costs of the project are closer to the estimated costs. With the sample of projects reviewed by METSCO, the final pre-construction estimate to actual cost variances were only 6%. However, the Board notes that Keeyask does not align with this sample, as Keeyask has experienced a variance between the final pre-construction estimate and the current estimate of 34%. As explained elsewhere in this Order, Keeyask has not experienced an undue number of design changes nor have the concrete or earthworks quantities driven the costs higher. As a result, Keeyask may not have benefited from additional design, engineering, and planning prior to construction the way other projects have.

Manitoba Hydro's prior capital estimating and approval process leads to the capital expenditure forecast being understated in future years, potentially resulting in inaccurate financial forecasts. It also potentially means that projects are approved without management knowing the full cost implications. It is not known how many projects would not have received approval, or that may have had their scope amended, if Manitoba Hydro's Executive had a more realistic forecast for the project costs prior to approval.

The impact of this on revenue requirements and rates is two-fold. First, for projects that are included in the capital expenditure forecast but are several years out, the underestimate of the capital cost can result in understated revenue requirements in those future years. With understated revenue requirements, Manitoba Hydro's financial ratios and metrics are more favourable and the projected rate increases beyond the Test Years may be understated. Second, and conversely, when the final actual costs are realized, the revenue requirements are higher – as will be the rates – in order for Manitoba Hydro to recover the costs of those projects and achieve its financial targets. If the final actual costs were more accurately known earlier in the process, projects may not proceed or alternatives may be considered which have a lower revenue requirement impact.

The Board notes that, with the creation of the position of Director of Strategic Business Integration, Manitoba Hydro appears to be embarking on a more robust planning, scoping, and engineering process for Business Operations Capital. The Board finds that in the area of Business Operations Capital, Manitoba Hydro has made structural changes to its organization that should improve how capital cost estimating is done. Such scrutiny should be extended to Manitoba Hydro's Major New Generation & Transmission projects. The Board recommends that Manitoba Hydro review and revise its capital project planning, scoping, and engineering processes to provide for a more certain in-service cost before such capital projects are economically and financially analyzed and presented to Manitoba Hydro's Executive for approval and, where required, subsequently to the Province of Manitoba.

There is a dilemma facing any project developer such as Manitoba Hydro, which is how much work – scope development, design, and engineering – should be completed before a decision is made whether to proceed with the project. Additional work to refine the cost estimate will result in increased costs being incurred prior to the final evaluation of the project. At the evaluation stage when the project is compared with alternatives, there is the issue of how to deal with these costs, which are also called "sunk costs".

As recommended above by the Board, more work should be done prior to making a final decision whether to proceed with a project, although this will necessarily result in greater sunk costs. However, the Board acknowledges that, as was done at the NFAT, sunk costs of any project are excluded from the economic comparison with alternative projects since these costs, having already been incurred, can no longer be avoided by choosing an alternative project. Exclusion of sunk costs from the analysis can distort the comparison of the project with alternatives. In its NFAT report, the Board recommended not only cessation of all activities and spending related to Conawapa but that existing sunk costs should not become a future justification of Conawapa.

To address the sunk cost dilemma, the Board finds there is merit in Manitoba Hydro considering the "stage gate" approach put forward by MGF, in order to improve its past performance on cost estimating and completing projects on budget. The Board recommends that Manitoba Hydro engage an external consultant to assist in studying this matter.

As explained earlier in this Order with respect to Bipole III, the Board finds that when estimating costs for a project that includes new, unproven technology, the contingency amounts should be increased, not decreased as was done by Manitoba Hydro.

Order 73/15 Directive 13 requires Manitoba Hydro to report quarterly to the Board as to the status and cost against budget in order to ensure the Board is informed of accurate and timely cost and schedule information. The Board directs that this reporting is to continue, and be amended to include not only the control budget and control schedule, but also the most current forecast at completion cost and schedule milestones based on weekly or monthly reports made by or to Manitoba Hydro. These reports are to be provided to the Board no later than 45 days following the last day of each quarter.

21.2 Potential Capital Project Approvals by the Board

The Board's review of the Manitoba-Saskatchewan Transmission Line project in this proceeding is a precedent for how independent reviews can be conducted of Manitoba Hydro's capital projects.

The Board's concern with approval of Manitoba Hydro's capital expenditures is long standing. In Order 116/08, the Board stated:

> *In prior Orders, the Board has recommended to Government, that The Public Utilities Board Act be amended to make the regulation of MH equivalent to the regulation of Centra Gas by removing the exemption now provided under Section 2(5) of the Act. In Order 143/04 the Board noted: "Given the risks related to the very significant additional plant investments and associated borrowings contemplated, the Board is of the view that the Province of Manitoba should re-evaluate the existing legislation." The Board reiterates its past recommendation.*

Also, as held in Order 73/15, in the context of Bipole III:

> *The Board has no inherent jurisdiction to review and approve the costs and economics of Bipole III. The Board agrees with the Coalition's suggested recommendation to the Province of Manitoba for a change in legislation and that the Board should have approval authority relative to Manitoba Hydro's major capital projects.*

The Board continues to be of the view that it should have legislative authority to approve Manitoba Hydro's capital expenditures. The current process whereby the Lieutenant Governor in Council approves the debt for the development of capital projects does not appear to involve a detailed review of the projects.

As discussed in the previous section, the shortcomings in Manitoba Hydro's previous capital approval process led to inaccurate financial forecasts. The original cost estimates - which generally understate the final costs - artificially depress the revenue requirement when projects are years away but then put upward pressure on the revenue requirement when the final costs - which are generally higher - are known and accounted for. As capital project costs have a substantial influence on Manitoba Hydro's revenue requirement and the resulting rates the Board approves to recover the revenue requirement from ratepayers, the Board recommends that Government grant the Board authority to review and approve Manitoba Hydro's capital projects and expenditures.

The Board envisions that, if it were granted authority to approve Manitoba Hydro's capital projects, it would require Manitoba Hydro to submit projects for the Board's review and approval that have a higher level of scope definition, design, and engineering completed. The Board expects that this will result in the final approval to proceed being based on a more accurate estimate of the final cost. As discussed above, the stage gate approval process could be used to improve the cost estimating at the approval stages while minimizing sunk costs.

21.3 Construction Contract Types and Structures

Manitoba Hydro uses contractors with specific expertise to design, engineer, procure, construct, and commission capital assets. Contracts let by Manitoba Hydro range in value from hundreds or thousands of dollars up to the largest contract for the Keeyask project, the General Civil Contract (“GCC”), which has a contract value in excess of $1 billion.

As explained earlier in this Order, there are several types of pricing structure that can be used in a contract. The pricing structure in the Keeyask GCC is a “cost reimbursable - target price” structure. In a contract with a cost reimbursable-target price payment structure, the owner (Manitoba Hydro) is at risk for quantities, productivity, and efficiency of the contractor, while the contractor is at risk for its profit. Other types of pricing structures include ‘fixed price’ or ‘unit price’ structures. In a fixed price contract (also known as a lump sum contract), the contractor is at risk for quantities and productivity. In a unit price contract, the contractor is paid a pre-defined unit rate (or rate per quantity) multiplied by the quantity of work and is at risk for productivity but not the quantities of work; the quantity risk resides with the owner.

In MGF’s view, the root cause of the billions of dollars of cost overruns for Keeyask is that the cost reimbursable payment structure of the GCC fails to provide sufficient incentive for the general civil contractor to be responsible for productivity. MGF also identified that Manitoba Hydro is managing the Keeyask GCC as if it were a lump sum or unit rate contract and not in a manner that is required to exert control over a contract with a cost reimbursable payment structure. MGF states that, to properly manage a cost reimbursable contract, the owner needs to hold the contractor accountable for its performance, hire experienced trades supervisors to assist the contractor with planning the work in a more efficient manner, understand why planned progress is not achieved, and develop realistic and achievable cost and schedule estimates.

Similarly, Klohn Crippen Berger found that the principal reason for the cost increase in the GCC and overall Keeyask budget is the nature of the payment structure in the GCC. Specifically, the general civil contractor is being paid in full for its actual costs for labour and materials rather than for quantities of work performed against fixed or unit prices.

Board Findings

As explained earlier in this Order, the Board agrees with Independent Expert Consultants MGF and Klohn Crippen Berger that the primary root cause of the cost overrun of the GCC, and the whole Keeyask project, relates to the nature of the cost reimbursable payment structure in the GCC. The reduction in profit that results from the contractor exceeding the GCC target price was not sufficient protection for Manitoba Hydro to ensure the contractor delivered the project on time and at the target price.

As explained earlier in this Order, the Board concludes that Manitoba Hydro did not exercise effective oversight of the Keeyask general civil contractor and did not manage the GCC as was required of a contract with a cost reimbursable payment structure. The Board therefore recommends that Manitoba Hydro use the services of an external construction management expert, particularly for high value projects and those with cost reimbursable payment structures, beginning with the initial study and planning through to project execution. Such a construction management expert would be able to assist Manitoba Hydro with effective project controls, enforcement of the contract terms, and identification of recourse in the event of contractor non-performance.

The Board finds nothing inherently wrong with the use of a cost reimbursable pricing structure, but the suitability of this payment structure depends on the circumstances in which it is used. If used, effective oversight of the contractor must be exercised, as explained by MGF.

The Keeyask GCC utilized a ‘cost reimbursable-target price’ payment structure for all aspects of the project work. The Board envisions a different approach be used in the future. When there are major portions of the construction project that involve below-grade construction – such as river management, removing earth and rock, and preparing the foundations for a generating station on bedrock – those below-grade aspects of the overall project cannot be known with certainty before the construction commences. Because of that uncertainty, it is more appropriate that the geological risk would be borne by Manitoba Hydro as the owner, and not the contractor in the contract. Unit price or cost reimbursable pricing structures are more appropriate for these portions of the project. Conversely, once the foundations are exposed and the remaining work is above grade, far more certainty can be obtained in the design of the project for which the contractor can and should bear more of the risk. A fixed price payment structure in the contract for this aspect of the work is therefore appropriate. There is no rule or requirement for the entire GCC to have the same payment structure.

The Board recognizes that the above approach would not solve all of Manitoba Hydro’s issues with capital cost overruns. Major construction projects throughout North America are frequently reported to be over budget. Contracts with fixed price or unit price payment structures are still susceptible to cost overruns, although these are usually related to design changes made by the owner in the case of the former and to uncertain quantities in the case of the latter. But, as identified by Klohn Crippen Berger, Keeyask did not experience significant issues with design changes or inaccurate quantities of concrete or earthworks.

21.4 What Went Well on Capital Projects

This Order identifies a number of problems, shortcomings, and issues with Manitoba Hydro's capital project estimating, planning, and execution. The evidence in this proceeding also identified a number of positives related to Manitoba Hydro's capital projects. The following is a list of the major positives:

- Issues with interfaces between contractors, as were experienced on Wuskwatim, appear to have been reduced or avoided with the inclusion of increased scopes of work under the Keeyask GCC,
- The Keeyask design and geotechnical investigations were reasonable,
- Keeyask design changes and extra work orders have not been excessive,
- Keeyask quantity estimates, in aggregate, were close to actual quantities,
- While Manitoba Hydro originally allowed over 1,000 activities in the Keeyask GCC schedule to have negative float, the Utility was able to eliminate the negative float in the most current schedule presented to the Board,
- The Bipole III transmission line was contracted with an appropriate mix of fixed price, unit price, and cost reimbursable contracts, providing cost certainty to project,
- The Bipole III transmission line project was well organized and managed,
- The Bipole III transmission line estimating team is knowledgeable and capable,
- Preparation of a Basis of Estimate is an industry best practice that helps define the project scope, identifies risks and opportunities, provides a record of

documents used in development of the estimate, provides a record of communications made during development of the estimate, and facilitates the review and validation of the estimate. Manitoba Hydro prepared a Basis of Estimate for Keeyask and for Bipole III, the latter of which MGF found to be well written and followed best practices,

- Bipole III converter stations were competitively tendered with appropriate pricing mechanisms, in particular a fixed price contract to engineer, procure, and construct the HVDC converter equipment, shifting much of the cost, schedule, and productivity risk to the contractor, and

- Together, the Bipole III converter stations and transmission line are only 8% over the final pre-construction budget.

Board Recommendations For Future Capital Projects

MGF made numerous recommendations which Manitoba Hydro could use to improve the execution of its existing projects as well which could be used in the planning, estimating, and construction of future projects. The Board recommends that Manitoba Hydro consider these recommendations, some of which are itemized below, along with other recommendations made by the Board.

- Where possible, tailor the payment structure for contracts such that risk is appropriately allocated between Manitoba Hydro and the contractor, including potentially having multiple payment structures within the same contract,

- Prepare economic evaluations of projects based on a higher probability contingency, such as at a P90 or P95 level,

- Retain external construction management expertise, particularly for high value projects and those that utilize cost reimbursable pricing mechanisms,

- Prepare a thorough Basis of Estimate document,

- Prepare a comprehensive Basis of Schedule document,
- Use estimate and schedule templates to promote consistency across groups preparing estimates and schedules,
- When developing estimates and schedules, provide supporting back-up and more detailed explanation outlining the structure and relationship between the physical scope of work and resources to complete the work,
- When developing estimates for projects that include new, unproven technology or construction methods, the contingency amounts should be increased, and
- Conduct periodic contract compliance reviews during execution of major projects to ensure the contractor is meeting its obligations.

22.0 Compliance with Board Directives

Manitoba Hydro recognizes that there is a backlog and history of not following Board directives, and that more can be and must be done by the Utility. As discussed above, directives related to depreciation, O&A benchmarking, asset condition assessment reports, and matters for further study in the Cost of Service Study have not been completed in a timely fashion.

22.1 Manitoba Hydro's Position

Manitoba Hydro's President and Chief Executive Officer advises that Manitoba Hydro takes the Orders and direction from the Board seriously, but recognizing the history of directives not being complied with, the Utility has to do a better job. In closing argument, Manitoba Hydro confirmed that, barring appeals, there will be compliance with Board directives. Manitoba Hydro states there can be no dispute that the objective of implementing a directive is to provide value to the regulatory process. Manitoba Hydro recommends that the Board contemplate follow-up or feedback mechanisms when directives are issued so that the work can proceed in a meaningful way and provide value to all parties that desire it.

22.2 Board Findings

The Board finds that the Utility has not complied with all or part of a number of past directives. If Manitoba Hydro disputes a directive issued by the Board, the Utility may choose to file a request for variance or seek leave to appeal from the Manitoba Court of Appeal. The Board has jurisdiction to impose financial penalties and stay any future applications in the event that the Utility does not comply with all or part of a Board Order.

The Board directs Manitoba Hydro to file with the Board on or before August 1, 2018 the status of compliance with all outstanding and ongoing directives. Manitoba Hydro is to provide with this filing the Utility’s comments on a process for feedback and clarification on Board directives.

23.0 Recommendations to the Provincial Government

In this Order, the Board makes the following recommendations to the provincial Government:

1. The Board should have legislative authority to approve Manitoba Hydro's capital expenditures;
2. Efficiency Manitoba's mandate should be amended to include explicit consideration of bill affordability. This would include targeting of lower-income consumers with demand side management programs, as well as consideration of the impact of demand side management costs being paid by non-participants;
3. The provincial government should introduce a comprehensive bill affordability program run by a government department to address energy poverty issues faced by Manitobans throughout the province;
4. The provincial government should establish a stakeholder group to build on the research and analysis undertaken by the Working Group, as well as programs in other jurisdictions, such as the Ontario Energy Support Program;
5. The provincial government should use some of the revenues it receives from Keeyask to fund a comprehensive bill affordability program, consistent with the NFAT report recommendations;
6. The provincial government should transfer a portion of the carbon tax revenues to Manitoba Hydro to further strengthen Manitoba Hydro's financial health, which may allow for lower consumer rate increases; and
7. The provincial government should suspend payment of the annual Bipole III debt guarantee fee and capital taxes made by Manitoba Hydro to the Province of Manitoba, starting with the 2019 fiscal year and until the $900 million burden of a

policy decision made by government is satisfied, which will occur in approximately 13 years.

24.0 Recommendations to Manitoba Hydro

In this Order, the Board recommends that Manitoba Hydro:

1. Defer $160 million of Business Operations Capital spending to a future period beyond 2018/19;
2. Continue to find reductions in Business Operations Capital spending during the current period of record spending on major capital projects such as Keeyask and Bipole III;
3. Update the Manitoba-Minnesota Transmission Project schedule more frequently than every two months once construction begins;
4. Make efforts to find further areas to reduce O&A costs, both in terms of staff reductions and Supply Chain Management, after the Voluntary Departure Program transition concludes;
5. Review and revise its capital project planning, scoping, and engineering processes to provide for a more certain in-service cost before such capital projects are economically and financially analyzed and presented to Manitoba Hydro's Executive for approval and, where required, subsequently to the Province of Manitoba;
6. Consider the "stage gate" project approval process and engage an external consultant to assist in studying the use of this process;
7. Use the services of an external construction management expert, particularly for high value projects and those with cost reimbursable payment structures, beginning with the initial study and planning through to project execution;
8. Consider the recommendations made by MGF to improve Manitoba Hydro's execution of its existing projects and in the planning, estimating, and construction of future projects; and

9. Review demand side management programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers.

25.0 IT IS THEREFORE ORDERED THAT:

1. The rate increase of 3.36% previously approved as interim effective August 1, 2016 **BE AND IS HEREBY APPROVED AS FINAL**.

2. The rate increase of 3.36% previously approved as interim effective August 1, 2017 **BE AND IS HEREBY APPROVED AS FINAL.**

3. Manitoba Hydro's Application for a 7.9% across-the-board rate increase effective April 1, 2018 **BE AND HEREBY IS DENIED** as filed.

4. A 3.6% average revenue increase to be recovered in Manitoba Hydro consumers' rates effective June 1, 2018 **BE AND IS HEREBY APPROVED**.

5. Manitoba Hydro implement differentiated rates to collect the approved revenue requirement for 2018/19 in order to begin to move the Revenue Cost Coverage ratios of the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV customer classes into the zone of reasonableness of 95% to 105%, using the alternative calculation methodology. Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness, using the alternative calculation methodology. The rate increase impact of doing so is to be shared across the Residential, General Service Small Demand, General Service Medium, General Service Large 0-30kV, and Area & Roadway Lighting classes.

6. Manitoba Hydro create a First Nations On-Reserve Residential customer class. This customer class is to receive a 0% rate increase for the 2018/19 Test Year, such that the rate for this class will be maintained at the August 1, 2017

approved Residential rate. A 0% rate increase is to also apply to First Nations Residential customers in the diesel zone communities.

7. Manitoba Hydro credit net-metered customers' excess energy put on the grid at the rate of 8.196¢/kWh for 2018/19. Manitoba Hydro must apply to the Board for approval of any future net-metered rate or changes to the 8.196¢/kWh rate.

8. Manitoba Hydro recalculate and file, for Board approval, a schedule of rates reflecting the overall rate increase and differentiated rates effective June 1, 2018 for all customer classes, together with all supporting schedules including proof of revenue, customer impacts, and revenue requirement, by May 15, 2018.

9. Manitoba Hydro participate in a technical conference hosted by Board Staff or an external consultant appointed by the Board for the consideration of the establishment of a minimum retained earnings or similar test to provide guidance in the setting of consumer rates for use in rule-based regulation.

10. Manitoba Hydro provide information about the Other Cash Payments included in the Cash Flow Statement in the next GRA filing.

11. Manitoba Hydro consider the areas recommended by the Independent Expert Consultants for improvement and enhancement of the load forecasting methodology and provide details of the implementation of these recommendations, or reasons for not implementing them, at the next GRA.

12. Manitoba Hydro file with the next GRA the details of its Operating & Administrative expenditures with an explanation as to how Manitoba Hydro is carrying on its operations with reduced staffing levels, including the details of the operational plan developed to continue running operations with a workforce that

has been reduced by 15%, and any advice or recommendations received from external consultants retained to assist with the restructuring and transition.

13. Manitoba Hydro file with the next GRA details of its actual Operating & Administrative expenditures dating back 10 years through to the date of the filing, along with forecast Operative & Administrative expenditures by cost element and business unit, including the details of the Utility's pension liability related to the reduced staffing levels. The actual Operating & Administrative expenditures are to include the compound annual growth both before and after accounting changes.

14. Manitoba Hydro retain an independent consultant to assess Manitoba Hydro's development of its asset management program and its progress in addressing the recommendations made by UMS, as well as the progress of the development of the Corporate Value Framework. Manitoba Hydro is to file with the Board by June 29, 2018 the Terms of Reference for the consultant for the Board's review and comment. Manitoba Hydro is directed to report back to the Board on its progress and the result of the consultant's assessment at the next GRA.

15. Manitoba Hydro consider implementing the recommendations made by the Independent Expert Consultants with respect to Keeyask, Manitoba-Minnesota Transmission Project, and Great Northern Transmission Line, including implementing the recommendations to improve productivity to meet the control budget and schedule for Keeyask. Manitoba Hydro is to report to the Board at the next GRA whether and the extent to which it has implemented these recommendations and the projected cost savings and schedule impacts.

16. Manitoba Hydro file detailed quarterly reports for all Major New Generation and Transmission projects currently under development. These reports are to outline the proposed budget and schedule (at time of contract), budget and schedule changes and reasons for such changes, and the current forecast at completion costs and schedule based on weekly or monthly reports made by or to Manitoba Hydro. Where actual or forecast capital costs have materially increased, Manitoba Hydro is to explain how such increases will impact domestic revenue requirements and projected impacts on Manitoba Hydro's financial forecasts and targets. Specific contract costs are to be detailed for any contracts in excess of $50 million. These reports are to be provided to the Board no later than 45 days following the last day of each quarter. This Directive replaces Order 73/15 Directive 13.

17. Manitoba Hydro continue to use its existing Average Service Life methodology for calculating depreciation rates for rate-setting purposes, without reversion to Equal Life Group in the financial forecast. Manitoba Hydro shall not amortize the difference between Average Service Life and Equal Life Group for rate setting.

18. Manitoba Hydro's request to hold an alternate process for discussion of the depreciation directives as set out in Order 43/13 **BE AND IS HEREBY DENIED**.

19. Manitoba Hydro's proposed treatment of the Conawapa costs **BE AND IS HEREBY APPROVED**.

20. Manitoba Hydro's request to cease the deferral of ineligible overhead in 2023/24 and amortize the regulatory account balance over 20 years **BE AND IS HEREBY DENIED**.

21. Manitoba Hydro continue the annual deferral of $20 million in ineligible overhead. The regulatory account balance is to be amortized over 34 years.

22. Manitoba Hydro's request to begin recognizing the Bipole III Deferral Account in domestic revenues following the in-service date of Bipole III, amortized over a five-year period **BE AND IS HEREBY APPROVED**.

23. Manitoba Hydro discontinue the accounting practice of recognizing a Demand Side Management Deferral Account.

24. Manitoba Hydro exclude non-tariffable transmission costs from the allocation of export revenues in its future Prospective Cost of Service Studies.

25. Manitoba Hydro allocate the activities of building moves & safety watches, contact centre-outages, line locates, and marketing research & development costs to all customer classes other than General Service Large 30-100kV and General Service Large >100kV in future Prospective Cost of Service Studies.

26. Manitoba Hydro complete the study of the Service Drops Allocator and the Common Costs study in time for its next Prospective Cost of Service Study.

27. Manitoba Hydro calculate Revenue to Cost Coverage ratios using the alternative methodology of treating export revenues as a reduction to class costs in future Prospective Cost of Service Studies filed with the Board.

28. Manitoba Hydro provide in its next GRA filing the rationale for the declining block rate design for the General Service customer classes and an evaluation of the block thresholds and charges.

29. Manitoba Hydro file with the next GRA a time-of-use rate design proposal, including the results of consultation undertaken with General Service Large customers prior to filing the proposal with the Board.

30. Manitoba Hydro provide with the next GRA additional details on the Solar Energy Program and other net metering installations in Manitoba.

31. Manitoba Hydro's request for final approval of the Light Emitting Diode rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14 **BE AND HEREBY IS APPROVED**.

32. Manitoba Hydro's requests for approval of new Light Emitting Diode rates for the Area and Roadway Lighting class (Sentinel Lighting) and for approval of the removal of the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from Manitoba Hydro's rate schedule **BE AND HEREBY ARE APPROVED**.

33. Manitoba Hydro's request for endorsement of the Terms and Conditions of Option 1 of the Surplus Energy Program that were accepted on an interim basis in Order 43/13 **BE AND HEREBY IS APPROVED**.

34. Manitoba Hydro's request for final approval of all interim *ex parte* Surplus Energy Program rate Orders as set out in Tab 10 of Manitoba Hydro's Application, as well as in Appendix 17.1 of Manitoba Hydro's Written Final Argument, and issued subsequent to Manitoba Hydro's Written Final Argument and prior to the issuance of this Order **BE AND HEREBY IS APPROVED**.

35. Manitoba Hydro's request for final approval of Curtailable Rate Program *ex parte* Order 54/16 as well as any additional *ex parte* Orders in respect of the

Curtailable Rate Program issued prior to this Order **BE AND HEREBY IS APPROVED**.

36. Manitoba Hydro provide confirmation to the Board that the executed diesel zone Settlement Agreement documents have been received by the Utility and that the documents are in proper form. With this confirmation, Manitoba Hydro is to advise the Board of its intention regarding finalization of the interim diesel zone rates.

37. Manitoba Hydro file with the Board on or before August 1, 2018 the status of compliance with all outstanding and ongoing directives, along with the Utility's comments on a process for feedback and clarification on Board directives.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure. The Board's Rules may be viewed on the Board's website at www.pubmanitoba.ca

THE PUBLIC UTILITIES BOARD
FOR THE MAJORITY ON ALL ISSUES:

"Darren Christle"
Secretary

"Robert Gabor, Q.C."
Chair

Certified a true copy of Order No. 59/18 issued by The Public Utilities Board

Darren Christle

Secretary

FOR THE DISSENT ON THE ISSUE OF THE RATE INCREASE TO THE FIRST NATIONS ON-RESERVE RESIDENTIAL CUSTOMER CLASS:

"Larry Ring, Q.C."
Member

Appendix A: Glossary of Terms and Acronyms

Acronyms

Acronym	Definition	Description
C10, C13, C23	N/A	The name given to a specific Prospective Cost of Service Study allocation table related to the customer cost classification. Each table will have a unique numeric code (e.g.: C10) that is then used as reference in the PCOSS calculations made by Manitoba Hydro. C10, C13, and C23 relate to general customer services costs.
CRP	Curtailable Rate Program	A program offered to Manitoba Hydro's industrial customers that gives credits on the customer bills in exchange for commitments to curtail their load during times of system emergencies.
DSM	Demand Side Management	A common utility strategy for reducing consumer demand (frequently through energy efficiency measures) for energy in order to defer the need for new generation assets. Manitoba Hydro's Demand Side Management Plan, marketed under the Power Smart brand, involves various education and incentive programs aimed to reduce domestic consumption of both electrical and natural gas.
GCC	General Civil Contract	The single largest contract with respect to the construction of the Keeyask generating station. The GCC encompasses work related to river management, earthworks to build dams and dykes, concrete structures, and electrical and mechanical work within the powerhouse and spillway structures.
GNTL	Great Northern Transmission Line	The American portion of a new 500 kV alternating current interconnection under construction between Dorsey converter station northwest of Winnipeg and a new station near Grand Rapids, Minnesota.

Acronym	Definition	Description
GRA	General Rate Application	PUB process to review Manitoba Hydro's proposed changes to electrical or gas rates and their impacts on various customer groups.
GWh	Gigawatt-Hour	An amount of electrical energy equivalent to 1,000,000 kilowatt hours (kWh), or 1,000 megawatt hours (MWh). As an example, a typical non-electrically heated home uses 10,000 kWh per year. One GWh is enough to power 100 homes for one year.
HVDC	High-Voltage Direct Current	An electric power transmission system that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems. HVDC transmission is point-to-point, as opposed to the interlaced networks that are possible with AC systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.
IFF	Integrated Financial Forecast	Provides projections of Manitoba Hydro's financial results and position over a multi-year forecast period, typically 20 years. The Integrated Financial Forecast serves as the primary forecast to determine the need for rate increases that are necessary for Manitoba Hydro to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets. The most current forecast is MH16 Update with Interim.
IFRS	International Financial Reporting Standards	Accounting standards adopted by Manitoba Hydro in April 2015 which replace Canadian Generally Accepted Accounting Principles.

Acronym	Definition	Description
kV	Kilovolt	An amount of electromotive force equivalent to 1,000 volts. A volt is unit of measure for the electromotive force, and representative of the difference of potential that would drive one ampere of current against one ohm of resistance. It is roughly analogous to pressure in a water pipe.
kW	Kilowatt	An amount of electrical power equivalent to 1,000 watts. A watt is unit of measure for electrical power, corresponding to the power in an electric circuit in which the potential difference is one volt and the current is one ampere.
kWh	Kilowatt-Hour	The basic unit of electric energy equal to one kilowatt of power supplied to, or taken from, an electric circuit steadily for one hour (e.g.: ten 100 W lightbulbs left on for 1 hour would use 1 kWh, or 1000 W for one hour). A typical home without electric heat uses about 10,000 kWh each year.
LICO	Low-Income Cut-Off	A poverty measure used by Statistics Canada that represents an income threshold below which a family is likely to devote a larger share of its income on food, shelter and clothing than the average family. LICO is calculated based on total pre-tax household income, as well as family and community sizes.
LICO-125	125% of Low-Income Cut-Off	The eligibility threshold used by Manitoba Hydro for its Affordable Energy program. LICO-125 is based on 125% of Statistics Canada's Low Income Cut-Off (LICO) threshold for the large urban centre (i.e., a community with 500,000 or more inhabitants).
MH16	Manitoba Hydro Integrated Financial Forecast 2016	The original integrated financial forecast presented by Manitoba Hydro in support of its 2017/18 & 2018/19 General Rate Application.

Acronym	Definition	Description
MH16 Update	Manitoba Hydro Integrated Financial Forecast 2016	An update to Manitoba Hydro's integrated financial forecast reflecting more current forecasts of export prices, water flow conditions, domestic loads, and economic and financial indicators.
MH16 Update with Interim	Manitoba Hydro Integrated Financial Forecast 2016	An update to Manitoba Hydro's integrated financial forecast reflecting the MH16 Update forecasts of export prices and domestic loads as well as the impact of the Public Utilities Board's interim approval of rates effective August 1, 2017.
MMTP	Manitoba-Minnesota Transmission Project	The Canadian portion of a new 500 kV alternating current interconnection under construction between Dorsey converter station northwest of Winnipeg and a new station near Grand Rapids, Minnesota.
MW	Megawatt	An amount of electrical power equivalent to 1,000,000 watts, or 1,000 kilowatts (kW). Manitoba Hydro's peak generating capability from its hydroelectric generating stations is approximately 5,200 MW.
NEB	National Energy Board	Canadian federal regulator for international electricity exports and imports.
NFAT	Needs For and Alternatives To	Extensive review of Manitoba Hydro's Preferred Development Plan by the PUB with final recommendations made to the Province of Manitoba as to which development option should proceed. Last undertaken in 2014 to review Manitoba Hydro's Keeyask, Conawapa, US Intertie, and expanded DSM project investments.

Acronym	Definition	Description
P50, P90	Probability 50%, Probability 90%	A value at which the expected outcomes have a 50% probability of being higher than the value and 50% chance of being lower than the value. A P90 value is a value for which the expected outcomes have a 90% probability of being lower and a 10% probability of being higher.
PCOSS	Prospective Cost of Service Study	An embedded cost of service study in that it is based on forecast financial costs for a single test year period from the Integrated Financial Forecast. PCOSS18 refers to the PCOSS with a test year of 2017/18, which is based on IFF16 and the methodology changes directed in Order 164/16
PV	Photovoltaic	Equipment used to generate direct current electricity from solar radiation (i.e. sunlight).

Terms

Term	Description
Arrear	An amount owing, generally from unpaid bills or a portion thereof. Arrears can lead to service disconnection.
Bipole	An electrical power transmission line, within a high voltage direct current system, having two direct current conductors in opposite polarity. Manitoba Hydro implemented a high voltage direct current system in order to economically and efficiently transmit power generated by hydroelectric stations on the Lower Nelson River to southern Manitoba.
Business Operations Capital	A category within the Capital Expenditure Forecast. Capital projects in this category relate to expenditures to renew existing assets and facilities (also referred to as “sustainment”) replacements, to expand the electrical system to new customers, and to address load growth and requirements for additional capacity.
Capital Expenditure Forecast	A projection of the capital expenditures needed annually for new and replacement equipment and facilities to meet the electricity requirements in Manitoba and firm export sale commitments outside the province.
Conawapa	A potential hydroelectric generating station on the Nelson River, most recently proposed by Manitoba Hydro as part of its Preferred Development Plan in 2013 and reviewed at the NFAT in 2014. The Board recommended that Manitoba Hydro cease its development and this recommendation was accepted by the provincial government.
Conservation Rates	See Inverted Block Rates.
Control Budget	A formal budget for a capital project developed by the project team and approved by management.

Term	Description
Converter Station	A high voltage direct current (HVDC) converter station is a specialized type of substation which forms the terminal equipment for a HVDC transmission line. Converter station equipment converts alternating current to direct current, or the reverse. Manitoba Hydro currently operates, or has in construction, three northern converter stations (Henday, Radisson, and Keewatinohk) to convert from alternating current (AC) collected from nearby generating stations to direct current (DC) power for transmission. As well, Manitoba Hydro operates, or has in construction, two southern converter stations (Dorsey and Riel) to convert DC to AC for downstream customer transmission and distribution.
Corporate Value Framework	A systematic means of understanding the value of all investments in an organization. The Manitoba Hydro value framework consists of 28 value measures that span five categories: financial (including the cost of the investment), reliability, environmental, safety, and corporate citizenship. Each investment's value is assessed using these measures and the net present value is then used to determine both its independent merit and its standing among other investments competing for resources in a constrained optimization process. The value framework helps identify the optimal set of investments that deliver the greatest value to the organization while respecting funding, resource, and timing constraints.
Cost-of-Service	A process undertaken to determine the responsibilities that each customer class has for Manitoba Hydro's total revenue requirement and to assist in determining whether domestic rates are fair and reasonable.
Cost-of-Service Study	A method of allocating a utility's costs to the various classes of customers that it serves. Its purpose is to determine a fair sharing of the utility's revenue requirement among the customer classes.
Curtailable Rate Program	A program offered to Manitoba Hydro's industrial customers that gives credits on the customer bills in exchange for commitments to curtail their load during times of system emergencies.

Term	Description
Customer Class	A category of similarly situated customers. Customers are categorized into customer classes according to the characteristics of the equipment and assets that serve them as well as the characteristics of how they consume power.
"Customer" Cost Classification	A classification within the cost of service study. Utility costs that tend to vary with the number of customers. These include asset costs related to meters and service drops, as well as billing, meter reading, and customer service costs.
Customer Service	In the Cost of Service Study, customer service costs are associated with service provided to the customer after delivery of energy.
"Demand" Cost Classification	A classification within the cost of service study. Utility costs associated with consumption of electricity at peak periods and the maximum size (capacity) of facilities to serve those demands. These would generally include assets such as transmission lines and substations.
Demand Side Management	A common utility strategy for reducing consumer demand (frequently through energy efficiency measures) for energy in order to defer the need for new generation assets. Manitoba Hydro's Demand Side Management Plan, marketed under the Power Smart brand, involves various education and incentive programs aimed to reduce domestic consumption of both electrical and natural gas.
Dependable Energy	Energy that can be produced by Manitoba Hydro even during drought conditions. It is based on water levels and flows experienced in the lowest flow year on record. This includes the minimum expected generation from the hydroelectric generating stations plus continuous operation of the Selkirk and Brandon thermal generating stations, plus the minimum expected wind generation from St. Leon and St. Joseph, plus contracted imports.
Dependable Sales	Export sales made from dependable energy resources. These are also referred to as firm sales.

Term	Description
Distribution	Utility assets used to distribute lower voltage electricity to individual customers. These assets include distribution lines operating at less than 30 kV along with associated low voltage portions of substations, as well as low voltage transformers and metering.
Energy Burden	The percentage of household income that goes toward energy costs (e.g., electricity and gas).
"Energy" Cost Classification	A classification within the cost of service study. Utility costs that vary with the consumption of electricity are classified as "energy".
Energy Poverty	As defined by the Bill Affordability Working Group, energy poverty refers to circumstances in which a household is, or would be, required to make sacrifices or trade-offs that would be considered unacceptable by most Manitobans in order to procure sufficient energy from Manitoba Hydro." For the purposes of the Working Group Report, the Working Group considered a household to be energy poor if it spends more than 6% or 10% of pre-tax income on energy and also has a level of income lower than the current Low Income Cut-Off 125 ("LICO-125"), which is 25% above the Statistics Canada lower-income measurement.
Firm Sales	Export sales made from dependable energy resources.
Functionalization	The first of three main steps in a cost of service study (the others being classification and allocation) where the annual costs of a utility's assets and operations are separated according to the function performed by each asset or operation. Manitoba Hydro's cost of service study has five main functions: Generation, Transmission, Sub-Transmission, Distribution, and Customer Service.

Term	Description
Gas Available Area	Regions of Manitoba where Centra Gas Manitoba Inc. (a subsidiary of Manitoba Hydro) holds a franchise agreement with the local municipality to distribute natural gas, which is generally consumed for space and water heating. Gas available areas are generally found in the southern areas of Manitoba (mostly adjacent to the TransCanada Mainline pipeline).
General Service Large	Customer class containing predominantly industrial customers. These customers make use of customer-owned voltage transformation assets. This customer class is divided into three sub-categories, 0-30kV, 30-100kV, and >100kV, to reflect the voltage supplied to the customer by Manitoba Hydro.
General Service Medium	Customer class containing predominantly large commercial customers. These customers use Manitoba Hydro-owned transformation assets and have loads exceeding 200 kW.
General Service Small	Customer class containing predominantly small commercial customers with loads less than or equal to 200 kW. This customer class is divided into two sub-categories, Demand and Non-Demand. Demand customers pay a Demand rate based on the peak demand each month, in addition to a basic monthly charge and an energy (per kWh) charge.
Generation	Utility assets used to generate electricity. Manitoba Hydro considers all generating facilities, northern collector transmission lines, and HVDC facilities (such as Bipoles and converter stations) as generation in its cost of service studies.
Generation Outlet Transmission	Electrical conductors, and related switching and control equipment, linking electrical generators to transmission substations or converter stations.

Term	Description
Independent System Operator	An independent organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission in the United States or other Canadian provincial regulator, that operates a region's electricity grid, administers the region's wholesale electricity markets, and provides reliability planning for the region's bulk electricity system.
Integrated Financial Forecast	Provides projections of Manitoba Hydro's financial results and position over a multi-year forecast period, typically 20 years. The Integrated Financial Forecast serves as the primary forecast to determine the need for rate increases that are necessary for Manitoba Hydro to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets. The most current forecast is MH16 Update with Interim.
Interconnection	The physical linking of a utility's electrical network with equipment or facilities not belonging to that network. The term may refer to a connection between a utility's facilities and the equipment belonging to its customer, or to a connection between two (or more) utilities.
Inverted Block Rate	A rate design that uses a tiered pricing structure in which higher-usage customers pay an increasing marginal rate for the commodity that is consumed. The increasing pricing structure is intended to provide a price signal to customers to encourage energy efficiency. Inverted block rates are also sometimes called inverted rates or conservation rates.
Keeyask	Manitoba Hydro’s newest and fourth largest hydroelectric generating station under construction on the Nelson River. It is projected to enter service in August 2021.

Term	Description
Line Loss	While transmitting from generating stations to the end users, electricity passes through a complex transmission and distribution network, consisting of transformers, switches, and conductors. As it passes through the system, some of the energy is consumed by various system components or is dissipated due to the physical properties of the equipment. As a result, the total amount of electric energy measured at customer meters is always less than the total amount of electric energy measured at generation stations. The difference between the two is known as line loss.
Major New Generation & Transmission	Refers to capital projects that are utilized to both generate electricity and transmit this electricity to remote load centres (i.e. populated areas). Major New Generation & Transmission is a category within the Capital Expenditure Forecast that includes projects that provide significant new generation and transmission capacity and are of a substantial cost.
Marginal Value	The marginal value is the value to the Manitoba Hydro's system of deferring an increment of load growth (i.e. 1 kWh) to Manitoba Hydro's integrated system. Marginal value is determined based on each of the components of serving residential load: generation supply, bulk transmission capacity, and distribution capability.
Midcontinent Independent System Operator	A regional electricity transmission organization that assures unbiased regional grid management and open access to the transmission facilities. The Midcontinent Independent System Operator serves as a link in the safe, reliable, and cost-effective delivery of electric power across all or parts of 15 U.S. states and the Canadian province of Manitoba. It is the principal market that Manitoba Hydro exports power to.
National Energy Board	Canadian federal regulator for international electricity exports and imports.
Network Transmission	A system of interconnected electrical transmission lines that minimizes the probability of grid instability and failure. Network transmission also facilitates the exchange of electrical power amongst utilities.

Term	Description
Non-Tariffable Transmission	A sub-function in Manitoba Hydro's cost of service study that captures costs of transmission lines and substations that are not eligible to be included in the Open Access Transmission Tariff. Non-tariffable transmission includes radial transmission lines.
Off-Peak	Off-peak refers to periods when lower electricity prices are generally expected, coinciding with periods of low electricity usage. Manitoba Hydro's off-peak periods are defined as all night time hours from 11pm to 7am.
On-Peak	On-peak refers to periods when higher electricity prices are generally expected, coinciding with periods of high electricity usage. Manitoba Hydro's on-peak periods are defined as Monday to Friday (excluding Statutory Holidays) 12pm-8pm (May-October), as well 7am-11am and 4pm-8pm (November-April).
Opportunity Sales	Export sales made from surplus generation, typically hydraulic generation that is available in most water flow conditions except drought conditions.
Peak Demand	The instantaneous maximum amount of electricity required by a customer or group of customers.
Radial Transmission	Radial transmission refers to transmission lines feeding high voltage power to regions of the province using a single path without a redundant transmission line, as opposed to network transmission which provides multiple redundant paths. For example, a radial transmission line feeds the Town of Churchill.
Rate Design	The process of determining the rates charged to each customer class in order to recover the utility's revenue requirement. The cost of service study is an input to the rate design. Rates for each customer class can have basic monthly charges, demand charges, and energy rates, or a subset of these three charges.
Revenue to Cost Coverage	The ratio of class revenues and costs. Generally, the objective is to obtain a ratio close to 1 (or 100%) for each customer class.

Term	Description
Surplus Energy Program	The Surplus Energy Program is a Manitoba Hydro rate program that enables a qualifying customer to purchase surplus energy at export market prices that are determined on a weekly basis for peak, shoulder, and off-peak periods, if Manitoba Hydro has surplus energy to sell.
Test Year	The year which is the subject of the Public Utilities Board's review and approval of a rate increase. For this GRA and this Order, the Test Year is Manitoba Hydro's fiscal year beginning April 1, 2018 and concluding March 31, 2019.
Time of Use Rates	A rate design concept that varies the cost of electricity based on when it is used. The aim is to promote energy conservation and load smoothing in order to reduce overall system peak loads, thus deferring the need for new generation assets and to maximize the value of electricity exports during on-peak periods.
Transmission	Utility assets used to transmit electricity between load centres. In the cost of service study, Manitoba Hydro considers all transmission lines and high voltage portions of substations operating in excess of 100 kV as transmission. With respect to capital expenditures, transmission refers to assets operating in excess of 33 kV.
Uniform Rates	In 2001, legislation mandated uniform rates in Manitoba (also known as "postage stamp rates"). Previously, residential customers in Northern Manitoba and in rural areas paid higher rates than those in Winnipeg. Under the uniform rates legislation, the previous geographic rate zones were eliminated and the costs to serve urban customers were pooled with the costs to serve rural customers.
Water Rentals	Fees paid by Manitoba Hydro to the Provincial Government based on the amount of electricity produced from hydraulic generation.

Term	Description
Working Group	The Bill Affordability Working Group, established in response to the Board's directive in Order 73/15. The Working Group was comprised of a variety of stakeholders who represent, work with, or provide services to lower-income Manitoba Hydro customers.
Zone Of Reasonableness	An established tolerance zone around the COSS RCC target of 100% for each class. Manitoba Hydro's RCC Zone of Reasonableness currently has a range of 95 to 105 percent. A RCC ratio outside of the ZOR is one factor to be considered in the possible differentiation of rate increases.

Public Utilities Board — Régie des services publics

Appendix B: Order in Council 92/17

MANITOBA

ORDER IN COUNCIL

Finance

DATE: **April 05, 2017**

ORDER IN COUNCIL NO.: **00092 / 2017**

RECOMMENDED BY: **Minister of Finance**

ORDER

1. The Public Utilities Board (the "PUB") is assigned the duty of considering capital expenditures by The Manitoba Hydro-Electric Board ("Manitoba Hydro") as a factor in reaching a decision regarding rates for services under Part IV of *The Crown Corporations Public Review and Accountability Act* to support setting rates for services in a manner that balances the interests of ratepayers and the financial health of Manitoba Hydro.

2. For the purpose of the PUB's consideration of capital expenditures as a factor in the next review of Manitoba Hydro rates for services, Manitoba Hydro shall provide to the PUB the following information:

(a) Capital Expenditure: existing records related to planned capital expenditures, such as details on new, current committed, and proposed, planned or forecast major capital expenditures and base/sustaining capital expenditures, including copies of contracts, current and previous cost estimates, cost overrun justifications, schedule change justifications, current and future scheduled capital expenditure commitments and forecasts;

(b) Explanatory: existing records related to project justification, such as capital project justification forms, cost-benefit analyses, business case and other supporting information related to Manitoba Hydro capital expenditures identified by the PUB, including Asset Condition Assessments for previous, current and proposed major capital expenditures and base/sustaining capital expenditures;

(c) Revenue and other: existing records related to revenues and income, such as any correspondence, agreements, term sheets, export contracts, externally commissioned or internally created reports, studies or analyses, including forecasts (capital, capital structure, financial, export, import, load and power resource).

3. Manitoba Hydro may request that information it deems to be commercially sensitive be held in confidence by PUB. The PUB shall conduct the rate review in accordance with its Rules of Practice and Procedure, including determining the access of any person to information received in confidence.

4. This Order comes into effect immediately.

AUTHORITY

The Public Utilities Board Act, C.C.S.M. c. P280, states:

Power of board to perform assigned duties
107 The board may perform duties assigned to it
...
(b) by order of the Lieutenant Governor in Council; or

and Part I, in so far as it is applicable, applies to the carrying out of duties so assigned.

BACKGROUND

1. No change in rates for services shall be made and no new rates for services shall be introduced without the approval of the PUB under Part IV of *The Crown Corporations Public Review and Accountability Act*.

2. Manitoba Hydro intends to submit a general rate application to the PUB in 2017.

Appendix C: Summary of Presenter Evidence

In the GRA hearing, the Board heard evidentiary public presentations. As with other witnesses before the Board, those giving public presentations were sworn and subject to questioning by all parties and the Board. Written public presentations were provided by members of the public who registered with the Board to give an oral presentation but who were not available for the times scheduled for oral presentations during the hearing. The written public presentations were certified by the authors.

The summary of presenter evidence below is provided in the order in which presenters appeared in front of the Board.

Consumers Coalition Ratepayer Panel

Mr. Dan Mazier

Mr. Mazier resides in the rural municipality of Elton, Manitoba, on a farm property with a primary residence as well as a farm operation of 1,000 acres and a rental home. While Mr. Mazier's electricity costs for his primary residence are essentially zero due to his investments in renewable energy, he is concerned about the effect electric rate increases will have on his farm operation and on their renters in the rental home. Mr. Mazier indicated that Manitoba Hydro's projected rate plan could make Manitoba businesses uncompetitive globally. His preference is, rather than having higher rate increases in the short-term followed by lower rate increases, to have lower rate increases over a longer period of time as this is more predictable and realistic. He also stated that ratepayers do not know where the money Manitoba Hydro receives from ratepayers goes, and expressed concern that there is a lack of transparency.

Ms. Rebecca Trudeau

Ms. Trudeau is a resident of Winnipeg. Ms. Trudeau would prefer lower rate increases for a longer period of time, because this is consistent and reliable, which allows her to have an expectation of her monthly bill charges. As she lives paycheque-to-paycheque, Manitoba Hydro's proposed rate increases would affect her ability to save a portion of her income, potentially cause her to find employment that is less fulfilling but pays more, and would give rise to anxiety and stress. Her view is that Manitobans should not spend more than 5% – 6% of their annual income on energy bills, with 10% being the upper limit. She is supportive of a program to assist lower-income Manitobans in paying their electricity bills and is willing to pay a few dollars extra each month for such a program. Ms. Trudeau also noted that she finds many of Manitoba Hydro's energy efficiency programs to not be accessible for renters.

Mr. Gordon Barton

Mr. Barton is from Anola, Manitoba. He does not agree with Manitoba Hydro's proposed rate increases and feels that forecast rate decreases in 10 years cannot be relied on as Manitoba Hydro is unable to control its money today. Mr. Barton does not believe Manitoba Hydro needs the rate increases it is seeking. As well, if Manitoba Hydro receives all of the proposed rate increases, it would be a disaster for his spending and budget and he may have to consider changing where he lives. Mr. Barton's view is that rates should be increased slowly, over a longer period of time, and at a steady pace over time. Mr. Barton believes that Manitobans should not have to spend more than 3% of their income on energy bills.

Ms. Lyndie Bright

Ms. Bright lives in Winnipeg, Manitoba. She explained that she has cut back on her energy bills by lowering the heat in her apartment to 65 degrees Fahrenheit. When rates are increased, and because she is on a fixed income, Ms. Bright has to look at what in her budget she can cut back on or ways she can reduce consumption at home. This adds more stress for her. Ms. Bright advised that, if there are rate increases, she would also like there to be transparency on Manitoba Hydro's part to show what they are doing to keep rates down as much as possible. Ms. Bright's preference is for lower rate increases over a longer period of time. She would also like to see more energy efficiency programs for renters.

Ms. Emily Mayham

Ms. Mayham resides in Winnipeg, Manitoba with her four children. She finds paying her utility bills challenging at current rates. She gave evidence that, if Manitoba Hydro receives its proposed rate increases, she will have to cut her food budget by decreasing the amount of groceries she purchases and buying cheaper and generally less healthy food. She will also have to reduce the extent of her social activities with her children. In addition, Ms. Mayham explained that she would not be able to save money or have an emergency fund. Her preference is for lower rate increases over a longer period of time because it is predictable, allowing her to adjust and adapt as needed. Her view is that there should be a sliding scale based on income for utility rates. Ms. Mayham would like to see more energy efficient programs targeted to renters. Ms. Mayham also indicated that she would like to see more accountability and transparency from Manitoba Hydro as she feels consumers are being held responsible for financial irresponsibility or mismanagement by the Utility.

Oral Public Presentations

Mr. Jonathan Alward, Canadian Federation of Independent Business

Based on feedback received from its Manitoba members, the Canadian Federation of Independent Business expressed concern that the proposed 7.9% rate increases would severely affect the global competitiveness and provincial economic contributions of business and their employees, as energy costs are already among the top three cost pressures faced by Manitoba small business owners. Business owners surveyed said that the rate increases may significantly increase their electricity costs, increase prices of their products or services, delay investments in their business, or may even result in future hiring plans being put on hold and reductions in staff or staff hours. The Canadian Federation of Independent Business would like Manitoba Hydro to further its efforts to curb operating spending first instead of pursing significant rate increases.

Mr. Tim Sale

Mr. Sale identified concerns with inaccurate forecasts and cost estimates on the part of Manitoba Hydro, the difficult market for the Utility with the economics and improved technologies of wind and solar energy, and low export prices for Manitoba's hydroelectric power. He recommends that the Utility stop pursuing firm export contracts, start measures to increase electrical energy consumption in Manitoba, work with Manitoba businesses and property owners to use renewable technologies, and work with Saskatchewan to provide that province with "green" energy.

Ms. Bonnie Sheppard

Ms. Sheppard expressed her belief that Manitoba Hydro has been mismanaged for over a decade and is now asking consumers to bail out the Utility through rate increases. She suggested that Manitoba Hydro correct failures within its organization before rates are increased in order to bring an end to bad decisions, poor management, and fiscal irresponsibility, which she believes will eventually result in privatization of the Crown Corporation.

Mr. Haimana Romana

Mr. Romana spoke in opposition to a rate increase, but stated that, if an increase is approved, it should be only half of the requested amount. He questioned the need for a rate increase and suggested that ratepayers should not have to pay for the blunders of the Utility, including capital project cost overruns and increased debt, at a time when other organizations are having their budgets and funding cut. Mr. Romana expressed concern about accountability on the part of Manitoba Hydro, and questioned whether privatization is the ultimate goal.

Mayor Chris Goertzen, Association of Manitoba Municipalities

Mayor Goertzen spoke on behalf of the Association of Manitoba Municipalities to voice concerns of municipalities regarding the proposed rate increase. In particular, Mayor Goertzen raised concerns about the negative impact on the operations of public recreation facilities and municipal operating budgets due to limited means to raise funds to offset rising costs, including in the context of the provincial government's freeze on municipal operating funds. He stated that the result will be increased user fees and reduced services.

Dr. Garland Laliberte, Bipole III Coalition

Dr. Laliberte gave evidence that, in his view, the current Manitoba Hydro load forecast artificially and significantly inflates projections of future domestic revenue by approximately $2.3 billion over a future 20-year period. Dr. Laliberte recommended that the Board direct Manitoba Hydro to revise its load forecast downward to reflect recent historic experience, price elasticity impacts, and insights from other North American jurisdictions.

Dr. Laliberte estimated that the additional impact on domestic revenue as a result of the legislated demand side management target for Efficiency Manitoba is approximately $5.1 billion over a 20-year future period. In addition, Manitoba Hydro will also have to cover additional program delivery costs. Dr. Laliberte therefore concluded that the combined cumulative impact of load forecast choices and the more aggressive demand side management plan mandated by *The Efficiency Manitoba Act* is $7.4 billion over the next 20 years. Dr. Laliberte recommended that the Board direct Manitoba Hydro to conduct an analysis of the impact on its balance sheet of the Government's legislated plan for electric demand side management and report its findings at the next GRA.

Dr. Laliberte submitted that Manitoba Hydro should devote more effort to making use of its post-Keeyask energy glut, such as through advancing electric transportation and promoting a Western Canadian transmission grid.

Mr. John Greenaway

Mr. Greenaway voiced his concern with Manitoba Hydro rate increases over the years as the increases are above the cost of living and likely also above average employment wage increases. He suggested that, rather than over a three-year period, Manitoba Hydro be given a 21% rate increase over a seven-year period.

Mr. Chris Mravinec, Canadian Union Of Public Employees Local 998

Mr. Mravinec appeared on behalf of the Canadian Union of Public Employees ("CUPE"), Local 998, which represents Manitoba Hydro employees. Mr. Mravinec stated that the members of CUPE Local 998 have experienced unrealistic workloads and increased stress due to staff reductions at Manitoba Hydro. He stated that arbitrary targets for staff reductions are not feasible to operations and have a negative effect on employee well-being, safety, and customer service levels. At the same time, Manitobans are facing futures of wage increases at levels lower than inflation and rate increases at the level of 7.9% will negatively affect consumers. Mr. Mravinec recommended a balancing of interests and suggested that, rather than granting the full rate increase sought, the Board recommend that Government pursue new market opportunities within Manitoba through increased electrification, as well as in other provinces.

Mr. Allan Ciekiewicz

Mr. Ciekiewicz presented his view that ratepayers are burdened with Manitoba Hydro's capital development for the purpose of supporting Manitoba Hydro's export business. He indicated that this burden is heightened given the risk and possible repercussions of a drought. Mr. Ciekiewicz suggested that the construction of Keeyask and Bipole III should have been halted, with the savings used to finance the construction of efficient gas turbines in order to ensure a secure supply of energy for Manitobans. He also stated that rate increases above the rate of inflation are unacceptable.

Mr. Dennis Woodford, Bipole III Coalition

Mr. Woodford expressed his view that Manitoba Hydro has to be more responsive to unexpected external conditions that have and continue to occur. Mr. Woodford stated that Manitoba Hydro had ample opportunity to reassess the need for Keeyask and to stop construction, especially in light of the aggressive Demand Side Management program that it was proposing in 2016 and a soft U.S. export market. Additionally, Mr. Woodford identified that the disruptive technology of solar power may lower the domestic demand for energy produced by Keeyask. Manitoba Hydro also failed to act on opportunities to limit the project costs for Bipole III, which was not approved by the Board at the NFAT, and has also made decisions that have increased the costs.

By contrast, Mr. Woodford observed that there is a potential for a significant increase in the use of electric vehicles, which would increase domestic usage of Manitoba Hydro's surplus electricity and generate higher revenues for Manitoba Hydro than lower priced exports.

As a result, Mr. Woodford recommended that the Manitoba Hydro grid should be changed to "open access" allowing competitive marketing of electricity between consumers and producers of electricity to provide needed competition and address Manitoba Hydro's inability to adjust quickly to changing times. Furthermore, the Manitoba Hydro debt for generation and transmission should be assumed by the provincial government and not the ratepayers.

Mr. Murray Taylor, Business Council of Manitoba

Mr. Taylor, appearing on behalf of the Business Council of Manitoba, expressed his concerns regarding the current and future financial condition of Manitoba Hydro, including growing debt and the need to incur additional borrowing costs as rates are insufficient to pay for ongoing operating costs. Mr. Taylor observed that Manitoba Hydro's rates are among the lowest relative to other locations in Canada and the U.S. and questioned why rates in Manitoba are held below the costs of running the Utility. Mr. Taylor identified risks in what he sees as optimistic forecasts of Manitoba Hydro's forecast net income levels, as well as in the likelihood that interest rates will increase from the current record-low levels.

Mr. Taylor also advanced that, since the 2008 financial crisis, credit agencies have become more rigorous and continue to tighten their analysis of each entity that they examine. As a result, Mr. Taylor stated that showing leadership to increase rates substantially for the next two years will be important.

Mr. Taylor appealed to the Board to consider a path to ensuring financial stability and the lowest costs over future years collectively, and not be so focused on near-term rates at the expense of overall future costs for Manitobans. In the view of the Business Council of Manitoba, such considerations are well represented by the proposal made by Manitoba Hydro.

Ms. Andrea McLandress, Mining Association of Manitoba

Ms. McLandress presented evidence on behalf of the Mining Association of Manitoba. She testified that members of the Mining Association of Manitoba are typically the largest private employers and economic drivers in their regions. Together, Manitoba's mining operators have over 3,100 employees, largely located in the North and in rural communities, and make over $130 million in total annual purchases from Manitoba suppliers. Moreover, Manitoba's mining operators make annual electricity purchases in excess of $82 million, which for the large northern operators, represents approximately 10% to 15% of annual cash requirements.

Mining companies compete in an intense global market and are heavily affected by the cost of labour, transportation, regulations, and energy. With the exception of low electricity rates, these mining operating costs are generally higher in Manitoba than in other jurisdictions. Therefore, eroding Manitoba's only competitive advantage in mining (i.e., low electricity rates) could be disastrous for the entire mining sector of Manitoba's economy.

According to Ms. McLandress, the importance of the mining industry to the economy of Northern Manitoba makes it a vital public interest consideration when reviewing Manitoba Hydro's electric rate increase proposal. Ms. McLandress therefore advocated for a 0% rate increase as the only electric rate increase that would be acceptable to Manitoba's mining operators.

Mr. Michael Velie, International Brotherhood of Electrical Workers, Local 2034

Mr. Velie testified on behalf of the International Brotherhood of Electrical Workers, Local 2034. He gave evidence that, largely as a result of the Voluntary Departure Program and workforce reductions done numerically without planning for future operational needs, Manitoba Hydro's employees are feeling pressured to accomplish more and more work with fewer resources, resulting in shortcuts that are dangerous to both Manitoba Hydro's employees and customers. Additionally, Mr. Velie stated that Manitoba Hydro's restricted ability to employ sufficient internal resources will directly affect the reliability of the electrical service provided to Manitobans. Mr. Velie also maintained that Manitoba Hydro continues to increase its use of external contractors, which he identified as being two to three times more expensive than Utility employees.

Mr. Velie expressed support for Manitoba Hydro's 7.9% rate increase request for a period of one year to help Manitoba Hydro overcome its manpower shortage and to reduce safety risks to persons and property. However, Mr. Velie urged the Board to give Manitoba Hydro the direction it needs to curtail any further reductions in staffing levels and explore creative options for reducing the exorbitant costs of engaging contractors

Mr. Chris Hornby, Interlake Recreation Practitioners

Mr. Hornby gave evidence that there are approximately 100 recreation facilities across the Interlake and that utility costs represent about 25% to 30% of total expenses. Given the magnitude of Manitoba Hydro's planned rate increases for the next five years, the Interlake Recreation Practitioners Association is strongly against the proposed rate increase. Together with recent provincial funding cuts to community recreation and services programs, Manitoba Hydro's proposed rate increase plan will make sustaining recreation programs very difficult. Moreover, Mr. Hornby estimated that between 20 and 50 recreation facilities in the region could be expected to close as a result of Manitoba Hydro's proposed five-year rate increase plan.

Mr. Hornby also noted that Manitoba Hydro recently cut long-standing advertising at rural arenas and curling clubs. While Manitoba Hydro is still funding many local festivals, events, and non-profits, Manitoba Hydro now advertises with large private organizations such as the Winnipeg Jets.

Manitoba Industrial Power Users Group Panel Presentation

Mr. Dale Bossons, Chair of the Manitoba Industrial Power Users Group

The Manitoba Industrial Power Users Group is an association of 12 major industrial companies that belong to the three Manitoba Hydro General Service Large customer classes. On behalf of the members of the Manitoba Industrial Power Users Group, Mr. Bossons gave evidence that the difference between Manitoba Hydro's proposed 7.9% rate increase plan, compared to the previous 3.95% baseline scenario, is almost $850 million higher for the General Service Large customer classes over the next 10 years. These additional costs will affect decision-making regarding future operational investments and, for some, threaten their very future.

While the members of the Manitoba Industrial Power Users Group are not opposed to rate increases, Mr. Bossons clarified that it is important for Manitoba Hydro's revenue requirement to be based on true costs, that rates are fairly distributed across customer classes, and that options to manage electricity bills are offered and expanded. Furthermore, member companies are seeking stable and predictable energy rates that will allow them to manage their businesses and plan for their futures.

Mr. Bossons also stated that despite other operational challenges associated with Manitoba, low energy costs was the reason why member companies initially invested in this province. Additionally, there is little opportunity to pass along Manitoba Hydro's rate increases as member companies produce globally-traded commodities.

Mr. Michael St. Pierre, Chemtrade Logistics

Mr. St. Pierre explained that Chemtrade Logistics' ("Chemtrade") facility in Brandon has operated for 50 years and is the largest sodium chlorate plant in the world. For the Brandon plant, electrical power accounts for 70% of Chemtrade's variable plant manufacturing costs. Chemtrade's Brandon facility consumes approximately 5% of the province's electrical load and provides Manitoba Hydro with over $70 million in annual revenues. As a result, Chemtrade estimates that, for the coming year, Manitoba Hydro's proposed 7.9% rate increase would correspond with a $5.6 million increase in costs.

Chemtrade's decisions to further invest and grow the Brandon facility are now being re-evaluated, including due to announcements in other competing jurisdictions which will have either no or modest electric rate increases for 2018. While Chemtrade has publicly announced an additional $50 million investment in its Brandon facility, the company is finding it difficult to proceed in light of Manitoba Hydro's planned rate increases.

Mr. St. Pierre testified that Manitoba Hydro's significant and multiple rate increases will drive industry out of the province, thus decreasing baseload electricity demand and placing even more burden on those who live and work in Manitoba. Mr. St. Pierre insisted that electricity rates must be kept as low as possible to ensure a relative cost advantage for industry and to offset geographic disadvantages.

Mr. Darren MacDonald, Gerdau Long Steel North America

Mr. MacDonald gave evidence on behalf of Gerdau Long Steel North America ("Gerdau"), which currently operates 20 facilities in North America and 60 steel mills worldwide. Gerdau's facility in Selkirk makes products from recycled steel. Gerdau employs 436 people in Selkirk, with an additional 300 employees at downstream locations. Gerdau's Selkirk operations also use over 721 Manitoba vendors.

Mr. MacDonald testified that the Selkirk facility has annual electricity costs of $8 million. Gerdau has no ability to pass through incremental costs to customers as its products are traded globally. As a result of increasing electricity costs and the potential carbon tax impact, Gerdau is concerned about the Selkirk facility's competitiveness and cost structure relative to its other North American facilities. The impact of Manitoba Hydro's rate increases may cause Gerdau to limit investments made into its Selkirk facility and to shift production to other facilities. In 2007, for example, Gerdau shut down a steel mill in New Jersey, mainly as a result of high electricity cost forecasts.

Mr. MacDonald expressed support for reduced rate increases (e.g., 3.46%), reduced payments to Government, and maintaining a 20-year plan for Manitoba

Hydro to reach a 25% equity level. Manitoba Hydro should develop additional programs or rate options that would allow customers to further manage their electricity costs.

Mr. Gerald Samuel, Koch Fertilizer Canada

As Mr. Samuel explained in his presentation, the Koch Fertilizer Canada ("Koch") facility in Brandon produces anhydrous ammonia, urea, and other fertilizer products. Koch's Brandon facility provides employment for over 215 people and over 1,000 contractors, and is part of a network of five Koch fertilizer plants in North America. As electricity and natural gas are used as process feedstock, Koch has minimal opportunities to reduce its electric load. Mr. Samuel stated that Manitoba Hydro's proposed rate increase plan will cost Koch over $20 million in the next 10 years.

Mr. Samuel testified that the Brandon facility needs to remain competitive relative to the internal rate of return of Koch's other facilities. Together with the implementation of a carbon tax and federal air pollution regulations, Manitoba Hydro's proposed electric rate increases will directly affect Koch's competitiveness and will have an adverse impact on the long-term viability of the Koch Brandon plant.

Mr. Morgan Curran-Blaney, Maple Leaf Foods

Mr. Curran-Blaney testified that Maple Leaf Foods' ("Maple Leaf") operations in Manitoba employ approximately 4,000 people and represent approximately $753 million in direct economic benefits to Manitoba ($1.25 billion in indirect benefits). Its Brandon facility produces chilled pork products for the Japanese market, which is labour and energy intensive. Maple Leaf's electricity costs for the Brandon facility are approximately $4.6 million annually (or roughly 7% of its total budget overhead costs).

Mr. Curran-Blaney gave evidence that one of the few advantages of being located in Manitoba is low electricity rates. Manitoba Hydro's proposed rate increase plan will have a $4 million impact to Maple Leaf's operations in Manitoba over the next five years - a $2 million increase for the Brandon facility alone. Since Maple Leaf operates in a commodity based market, cost increases cannot be passed on to customers. Consequently, Maple Leaf estimates that in the short term, Manitoba Hydro's electric rate increases will likely lead to reductions in discretionary spending, employee headcount, capital spending, and community donations. In the long term, Maple Leaf may scale down the work done in Brandon or look at alternate sources of power generation in order to reduce grid electricity costs.

Mr. Benoit Lentz, Roquette

Mr. Lentz presented evidence that Roquette, a France-based family-owned company that produces specialty foods around the world, decided in 2017 to invest in a new $400 million pea processing facility in Portage la Prairie. As part of its investment decision, Roquette assessed its possible options using criteria that included a reliable, sustainable, and competitive electricity source. This is because, after raw input materials, electricity is, by far, Roquette's highest production cost. As a result, Manitoba's low and stable electricity costs represented an opportunity to compete against competitors located in jurisdictions with a higher carbon energy mix. In making their final investment decision, Roquette considered Manitoba Hydro's previous 3.95%

electric rate increase plan on the understanding that future rate increases would likely be between 0% and 3.95%.

Mr. Lentz stated that Manitoba Hydro's proposed 7.9% rate increase plan will significantly affect the operation and profitability of Roquette's Portage la Prairie facility. The rate increases would also undermine the Manitoba advantage of reliable and competitive electricity supply. In addition, Manitoba Hydro's rate increase plan would cause Roquette to be less likely to make further investments in Manitoba.

Dr. John Gray

Dr. Gray stated that Manitoba Hydro's proposed rate increases would have a disproportionate impact on electric heating customers. In Dr. Gray's view, Manitoba Hydro's illustrative residential electric heat rate is insufficient as it only provides minimal rate relief and pits one set of customers against another. Dr. Gray also expressed concern that Manitoba Hydro's proposed 7.9% rate increase plan will have a significant impact on the budgets of Manitobans, which are already stretched. As well, Manitoba Hydro's five-year rate plan will affect the economy in terms of job losses, reductions in consumer spending, and increased inflation.

In the short term, Dr. Gray suggested that there will be little opportunity for customers to reduce their electricity consumption but that in the long term, Manitoba Hydro's electricity sales will be significantly affected. In Dr. Gray's opinion, Manitoba Hydro under-estimates the revenue impacts of its rate increase plan.

To address Manitoba Hydro's financial situation, Dr. Gray stated that Manitoba Hydro has a huge opportunity to support electric cars, which would help increase domestic revenues, and could divest some its non-core assets such as Centra Gas.

Certified Written Public Presentations

Manitoba School Boards Association

The Manitoba School Boards Association represents Manitoba's 38 public school boards. For the 2016/17 school year, the total annual electricity costs of all 38 member school boards were $28.4 million. Manitoba Hydro's proposed rate increases over the next six years would result in additional costs of $16.4 million.

School boards are publicly funded and any additional school operation costs need to be paid by local taxpayers. As many taxpayers are also Manitoba Hydro ratepayers, Manitoba Hydro's proposed rate plan will result in a far greater personal investment from the average ratepayer. These increases would be in addition to the direct increases in the personal or business electric bills of Manitoba Hydro's ratepayers.

Given the anticipated level of impact of Manitoba Hydro's rate increase plan on school boards, and since school boards are restricted from incurring deficits or overruns, the Manitoba School Boards Association has limited options available to absorb significant increases in energy costs. As a result, reductions to the level of programs, supports, and services provided are likely.

David Sattler, Portage Regional Recreation Authority

The Portage Regional Recreation Authority is a non-profit corporation responsible for the provision of recreation and leisure facilities as well as programs for the benefit of citizens in the Portage la Prairie region. The Portage Regional Recreation Authority believes that Manitoba Hydro needs to look at other options to repair its financial position that do not involve levying a 70% increase on electricity costs over the next seven years.

Manitoba Hydro's potential annual electricity rate increases of 7.9% until 2024 are of concern to the Portage Regional Recreation Authority. There are significant electricity costs associated with the operation of recreation facilities. Manitoba Hydro's 7.9% rate increase plan will increase the Portage Regional Recreation Authority's annual electricity costs from $265,900 in 2017 to $452,760 by 2024.

To absorb Manitoba Hydro's rate increases, ignoring any other inflationary pressures or cost increases, the Portage Regional Recreation Authority would be required to increase rental fees for ice, pool, and meeting rooms. As the facility user fee increases would ultimately be combined with increases in the facility users' home utility bills, Manitoba Hydro's proposed rate plan will result in fewer individuals being financially able to participate in recreation activities that Manitobans have come to enjoy.

Josh Brandon, Social Planning Council of Winnipeg

If Manitoba Hydro's 2018/19 rate increase proposal is approved, it would mark the largest rate increase in a generation and would mean that many low-income Manitobans would be forced to choose between keeping their power on and paying for other basic necessities. Furthermore, the Manitoba Hydro Board has indicated that the 2018/19 proposed rate increase will be the first in a series of large rate increases that would raise the price of electricity by 60% by 2024. This would risk the affordable energy advantage that Manitobans have enjoyed for many years.

The Board should consider what impacts these proposed rate increases will have on the economy, on Manitoba households, and especially on low-income Manitobans. The Manitoba Government should also consider its role in protecting residents from unaffordable price increases, which would intensify energy poverty and act as a drain on the Manitoba economy. Alternative options are available that would preserve

Manitoba's affordable energy advantage and benefit all Manitobans. These options would include reducing the need for new large-scale generation, distributing the rate increases differently among the different customer classes, and the implementation of a low-income electric rate affordability program. The Social Planning Council of Winnipeg also recommends that the rate burden of any energy poverty reduction measure should be shared among all customer classes since all customers benefit from Manitoba's shared energy resources and all must therefore pay the costs required to ensure that these remain affordable for everyone.

Appendix D: Appearances

PARTY	LEGAL COUNSEL
The Public Utilities Board	Bob Peters, Dayna Steinfeld
Manitoba Hydro	Patricia Ramage, Odette Fernandes, Helga Van Iderstine, Janet Mayor, Doug Bedford, Marla Boyd, Matthew Ghikas, Brent Czarnecki
Independent Expert Consultants	William Haight, William Gardner, Kimberley Gilson
Assembly of Manitoba Chiefs	Senwung Luk, Corey Shefman
Business Council of Manitoba	Kevin Williams, Douglas Finkbeiner, Carrie Ho
Consumers Coalition	Byron Williams, Katrine Dilay
Representatives of the General Service Small & General Service Medium Customer Classes and Keystone Agricultural Producers	Christian Monnin
Green Action Centre	Bill Gange, David Cordingley Dr. Peter Miller, Coordinating Member
Manitoba Industrial Power Users Group	Antoine Hacault
Manitoba Keewatinowi Okimakanak Inc.	George Orle Q.C. Kelvin Lynxleg, Executive Director
Winnipeg (City of)	Daryl Ferguson

Appendix E: Parties of Record and Hearing Witnesses

PARTY	WITNESSES
Manitoba Hydro	**Policy Panel** Kelvin Shepherd, President and Chief Executive Officer, Manitoba Hydro; Jamie McCallum, Vice-President, Finance & Strategy, Manitoba Hydro; **Revenue Requirement Panel** Jamie McCallum, Vice-President, Finance & Strategy, Manitoba Hydro; Sandy Bauerlein, Corporate Controller, Corporate Controller Division, Finance & Strategy, Manitoba Hydro; Liz Carriere, Manager, Strategic & Financial Planning Department, Manitoba Hydro; David Cormie, Director, Wholesale Power and Operations Division, Manitoba Hydro; Terry Miles, Director, Power Planning, Manitoba Hydro; Lois Morrison, Director, Marketing and Sales, Marketing and Customer Service, Manitoba Hydro; Gerald Neufeld, Director, Transmission Planning and Design Division, Manitoba Hydro; Chuck Steele, Director, Engineering & Construction, Manitoba Hydro;

Susan Stephen, Treasurer, Manitoba Hydro;

David Swatek, Manager, System Planning Development, Manitoba Hydro;

Hal Turner, Director, Generation Asset Management, Manitoba Hydro;

Joel Wortley, Director, Strategic Business Integration, Finance & Strategy, Manitoba Hydro;

Greg Barnlund, Director, Rates & Regulatory Affairs, Manitoba Hydro;

Cost of Service, Rate Design, and Bill Affordability Panel

Greg Barnlund, Director, Rates & Regulatory Affairs, Manitoba Hydro;

Lois Morrison, Director, Marketing and Sales, Marketing and Customer Service, Manitoba Hydro;

Paul Chard, Director, Customer Care, Manitoba Hydro;

Colleen Galbraith, Manager, Bill Affordability Department, Manitoba Hydro;

Dr. Gregory Mason, Senior Consultant, Prairie Research Associates;

	<u>Major Capital Projects Panel</u> Lorne Midford, Vice-President, Generation & Wholesale, Manitoba Hydro;
	David Cormie, Director, Wholesale Power and Operations Division, Manitoba Hydro;
	Glenn Penner, Director, Transmission Construction and Line Maintenance, Manitoba Hydro;
	Dave Bowen, Project Director, Keeyask Project, Generation & Wholesale, Manitoba Hydro;
	Jeff Strongman, Business Manager, Keeyask Project Division, Manitoba Hydro;
	Alastair Fogg, Manager, Converter Stations Commercial & Controls Department, Manitoba Hydro;
Assembly of Manitoba Chiefs	Philip Raphals, Executive Director, Helios Centre;
Business Council of Manitoba	Murray Taylor, Chair of Fiscal Issues Committee, Business Council of Manitoba;
Consumers Coalition	Pelino Colaiacovo, Managing Director, MPA Morrison Park Advisors Inc.;
	Dr. Wayne Simpson, Professor, Department of Economics, University of Manitoba;
	Dr. Janice Compton, Assistant Professor, Department of Economics, University of Manitoba;

William O. Harper, President, Econalysis Consulting Services;

Thor Hjartarson, Managing Partner and Chief Executive Officer, METSCO Energy Solutions Inc.;

Alexander Bakulev, Vice-President, Strategy and Assets, METSCO Energy Solutions Inc.;

Dmitry Balashow, Director, Utilities Strategy and Economic Regulation, METSCO Energy Solutions Inc.;

Dan Mazier;

Rebecca Trudeau;

Gordon Barton;

Lyndie Bright;

Emily Mayham;

Representatives of the General Service Small & General Service Medium Customer Classes and Keystone Agricultural Producers

A.J. Goulding President, London Economics International; LLC.;

Jerome Leslie, Consultant, London Economics International; LLC.;

Green Action Centre

Paul Chernick, President, Resource Insight, Inc.;

Manitoba Industrial Power Users Group	Pelino Colaiacovo, Managing Director, MPA Morrison Park Advisors Inc.; Patrick Bowman, Principal, InterGroup Consultants Ltd.; Cameron F. Osler, Chair/Principal/Senior Consultant, InterGroup Consultants Ltd.; Gerry Forrest, Management Consultant, Forkast Municipal and Regulatory Consulting;
Manitoba Keewatinowi Okimakanak Inc.	(No Witnesses)
Winnipeg (City of)	Tyler Markowsky, Economist, City of Winnipeg;
Independent Expert Consultants	Dr. Adonis Yatchew, Professor, Department of Economics, University of Toronto; Kathleen A. Kelly, Vice President and Principal Consultant, Daymark Energy Advisors; Dr. Suman Gautam, Economist and Senior Consultant, Daymark Energy Advisors; Daniel E. Peaco, Principal Consultant, Chairman, and Past President, Daymark Energy Advisors; Douglas A. Smith, Managing Consultant and Treasurer, Daymark Energy Advisors; Kieran Flanagan, Managing Director, MGF Project Services;

Campbell Adams, Chartered Quantity Surveyor, MGF Project Services;

Ryan Devereux, Professional Quantity Surveyor, MGF Project Services;

Valerie Musfelt, Lead Scheduler, MGF Project Services;

Les Brand, Director and Principal Consultant, Amplitude Consultants;

Jim Potter, Transmission Group Manager/Senior Engineer, Stanley Consultants;

Duane Phillips, Constructability Lead, Stanley Consultants;

Dan Campbell, Manager Hydro Projects, Principal, Klohn Crippen Berger.

Tab 35

MANITOBA	**Board Order 5/12**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**January 17, 2012**

Before: Graham Lane CA, Chairman
Robert Mayer Q.C., Vice-Chair

A FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

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1.0.0 EXECUTIVE SUMMARY

In this Order, the Public Utilities Board (Board or PUB) finalizes Manitoba Hydro's (MH or the Corporation or the Utility) April 1, 2010 average consumer rate increase at 1.9% and also finalizes MH's April 1, 2011 average consumer rate increase at 2.0%.

MH requested finalization of a 2.9% average consumer rate increase effective April 1, 2010 and a further 2.9% rate increase effective April 1, 2011. Since those two dates, MH has been charging Board-approved interim rates of 2.9% and 2.0% respectively.

This final Order should be read in conjunction with Order 99/11 – which, along with all Board Orders, is available through the Board's office or by viewing its website www.pub.gov.mb.ca.

As indicated by the Board in Order 99/11, MH failed to discharge its statutory and legal onus in its substantiation of its requested rate increases. The Board therefore finalizes the rate increases at a level less than applied for by MH.

Based on the evidence before the Board, for MH's fiscal 2010/11 and 2011/12 years, the finalized rate increases in this Order, which are aligned to MH's forecast rates of inflation, yield just and reasonable rates that are in the public interest. MH also put before the Board its plans for the ten-year period to 2020, a period which is described by MH as its 'decade of investment', during which MH's major capital investments – namely new generating stations and transmissions line – are forecast to total approximately $20 billion. MH's 'Business Model' includes building new generating stations in the expectation of being able to export the energy generated by these stations prior to the output being gradually required by Manitoba consumers.

The Board finds MH's business model to parallel MH's development of the Limestone Generating Station. History records Limestone G.S. as producing electricity at a cost of approximately 3¢ kWh but selling it for 1.5 - 2¢ kWh on the export market. MH lost money during the early years of Limestone's generation.

Based on MH's most recent estimates of the capital costs to construct Wuskwatim G.S. (scheduled to come into service in 2012), Keeyask G.S., and Conawapa G.S., the unit cost of electricity when these generating stations will be in service approximates 10¢ kWh. There will also be additional annual costs of approximately $150 Million per year for Wuskwatim, $500 Million per year for Keeyask and $700 Million per year for Conawapa. All of these fixed costs, along with operating expenses, will appear on MH's Operating Statement and will have to be recovered from export revenues and domestic customers. If the revenue generated is insufficient to recover the costs, higher consumer rates would be expected.

While MH has yet to file the detailed pending export agreements (the Board's request is being contested by MH in the Courts), from the record it is apparent that the export prices will not recover 100% of the costs incurred by MH to export that electricity. Therefore, it would fall to Manitoba's domestic ratepayers to subsidize the export sales commitments made by MH.

Even though MH forecasts domestic rate increases in the 'decade of investment' that are in excess of expected inflation, it appears the projected rate increases are considerably too low to support the required subsidization.

The Board is unable to approve the higher rate increases requested by MH because the Utility's business plan is incomplete, lacks required detail and has not been tested through what has been promised as a "Needs For And Alternatives To" (NFAAT) review by an independent tribunal that will have full access to the economic and financial assumptions which underpin MH's business plan.

Such a broad-scope NFAAT was last held in conjunction with MH's plans to construct Conawapa G.S. as a merchant plant. At the time, the plan was to sell the output from the plant to Ontario Hydro. Under the applicable business plan, approved by the Board in the early 1990s, MH's forecast costs to build and operate Conawapa were lower than the forecast payments expected to be received from Ontario Hydro. There was no expectation of subsidization by domestic ratepayers. Rather, there was an expectation of a net benefit to MH and its ratepayers over the entire term of the export contract with Ontario Hydro. That plan was not actualized as Ontario Hydro withdrew, leading to a negotiated settlement (Ontario Hydro compensated MH for the vast majority of its actualized development).

In addition to providing a detailed review of the economic and financial assumptions of MH's preferred development plan, an NFAAT for MH's proposed investment would also test a number of viable alternative development plans, which is necessary to ensure that electricity rates for Manitobans remain just and reasonable and in the public interest.

The Chairman and Vice Chair differ in their opinion as to whether such an NFAAT should include the planned Bipole III transmission line. The Chairman hopes that any alternative plans to be reviewed would include the use of natural gas-generated electricity to improve on reliability issues and avoid or at least delay the requirement for a Bipole III Transmission Line (Bipole III). The Vice Chair does not share this view. In the Vice Chair's view, Bipole III is required for reliability purposes in any case and its construction should not be delayed any more than necessary. This difference in opinion does not affect the Board's Directives.

The Chairman and Vice Chair agree that the seemingly ever increasing forecast in-service costs of Bipole III are likely to add approximately 3¢/kWh to every kWh transmitted from Northern Manitoba. MH seeks to assign 100% of the currently forecast (by MH) $3.2 Billion cost of Bipole III to Manitoba's domestic customers despite the fact that Bipole III will be used to meet export demand if new generation capacity is built.

It greatly concerns the Board that without having had its capital plans reviewed through an NFAAT proceeding, and without the US transmission lines required to transmit MH's electricity exports south of the border having been constructed or even been committed to, and without MH having obtained the required regulatory approvals in Canada, MH continues to spend $1-$2 Million per day on its currently favoured development plan.

A significant aspect of the scope of MH's General Rate Application was the review of MH's risks and risk management. The Board has long requested MH to provide an in-depth and independent study of MH's risks (see Order 32/09). The study was to be a thorough and quantified risk analysis that included probabilities of all identified operational and business risks. Unfortunately, and disappointingly, MH failed to provide a comprehensive quantified risk analysis. Instead, MH unilaterally changed the terms of reference to instruct an external consultant to prepare a report, and opted for a legal strategy to try and rebut the findings of a former risk consultant previously retained by MH but subsequently terminated. However, even without the expected comprehensive risk analysis, the Board was able to gain a better understanding of the Utility's risk. For this risk, MH presently reports $2.4 Billion of retained earnings.

This Order also approves and finalizes MH's Surplus Energy Program Rate Orders and Curtailable Rate Program Orders. Due to insufficient information provided by MH, the Board has denied MH's request to 'forgive' what were approved as temporary demand billing concessions to a limited number of commercial and industrial customers.

This Order also provides the Board's comments and findings with respect to other aspects of MH's GRA, as further set out below.

The Board was ably assisted in its extensive review by interveners and their witnesses.

2.0.0 PROCEDURAL HISTORY, INTERVENERS, AND PRESENTERS

2.1.0 PROCEDURAL HISTORY

When MH filed its 2010/11 and 2011/12 GRA with the PUB, its main request was Board approval of an average consumer rate increase of 2.9% effective April 1, 2010 together with a further 2.9% average consumer rate increase of 2.9% effective April 1, 2011.

In light of a lengthy prehearing scoping and discovery process, together with a lengthy oral evidentiary hearing, the Board initially addressed MH's rate increase request on an interim, but not final, basis.

In Order 18/10, the Board approved an average 2.9% interim rate increase to all customer classes (except Area and Roadway Lighting) effective April 1, 2010. In Order 40/11, the Board approved an average 2.0% rate increase to all customer classes (except Area and Roadway Lighting) effective April 1, 2011.

The Board's stated intention was to re-examine the interim rate increases prior to finalization after hearing all of the evidence and submissions in the GRA and, if the Board concluded that the underlying facts did not justify the imposition of rate increases as sought by MH – or as approved by the Board on an interim basis – the Board would adjust the rates in the final GRA Order. Any amounts collected through interim rates that were found to be in excess of the rate in the final order would then be refunded or credited back to domestic customers.

Following the oral evidentiary portion of the GRA and the closing submissions, the latter of which extended over three days (July 4, 5, and 7, 2011), the Board issued Order 99/11 on July 29, 2011, which was envisioned to be the first of two Board Orders to be issued arising out of MH's 2010/11 and 2011/12 GRA. This Order is the second of the two Board Orders issued in respect of MH's 2010/11 and 2011/12 GRA and should be read as a companion Order to and in conjunction with Order 99/11, as well as Orders 18/10, 30/10 and 40/11.

All Board Orders can be found on the Board's website www.pub.gov.mb.ca or by contacting the Board's office.

2.2.0 INTERVENERS

2.2.1 Overview

The Board received requests for intervener status from the Consumer's Association of Canada (Manitoba) Inc./Manitoba Society of Seniors (CAC/MSOS), the Manitoba Industrial Power Users Group (MIPUG), Resource Conservation Manitoba/Time To Respect Earth's Ecosystems (RCM/TREE), the City of Winnipeg, the Manitoba Keewatinowi Okimakanak (MKO), the Southern Chiefs Association (SCO), the New York Consultant (NYC), whose name Board decided not to publicize, and from Mr. Ciekiewicz.

By way of Board Order 17/10, the Board granted intervener status to CAC/MSOS, MKO, MIPUG, the City of Winnipeg, and RCM/TREE, and denied intervener status to Mr. Ciekiewicz.

By way of Board Order 30/10, the Board granted intervener status to SCO and denied intervener status to NYC.

The submissions of CAC/MSOS, MIPUG, RCM/TREE and the City of Winnipeg are set out in the respective "Intervener Positions" sections of this order.

The submissions of MKO and SCO were very limited in scope and are set out below.

2.2.2 MKO

While MKO has been a regular Intervener in MH's proceedings before the Board, MKO chose not to actively participate during MH's 2010/11 and 2012 GRA despite having been granted Intervener status.

2.2.3 SCO

SCO represents the interests of 32 Southern Manitoba First Nations and was granted Intervener status in this hearing.

SCO questioned the openness and transparency of MH's responses to information requests regarding environmental impacts associated with MH's operations.

SCO submits that the Board must not dismiss or negate claims of cumulative impacts and adverse effects on Southern Manitoba First Nation, due to MH's ongoing operations of its Integrated Power System.

SCO stated that Lake Winnipeg, Cedar Lake, South Indian Lake and other secondary sources such as Lake Manitoba, Lake Winnipegosis and Lake of the Woods are considered by MH as "energy in storage" (EIS). These EIS sites are used to calculate and regulate the main reservoirs, which in turn generate revenue for MH at the expense of SCO's First Nations' Aboriginal and Treaty rights and interests.

SCO submits that if the Board increases the rates, any increases should be set aside in a deferral account, to be used for the benefit of all Manitoba First Nations to offset any compensation required to be paid as a result of negligent operations of MH's projects and facilities.

2.3.0 PRESENTERS

The Board also heard from several presenters. Presenters did not have the right to participate in the hearing or cross-examine witnesses, but were given the opportunity to make brief submissions to the board. The submissions of the Presenters are summarized below.

2.3.1 Dr. Leonard Simpson and Mr. Blair Skinner

Dr. Simpson and Mr. Skinner presented information to the Board respecting potential development of a nuclear power generating station at the former Atomic Energy Canada Limited nuclear research site located near Pinawa, Manitoba.

Dr. Simpson stated that MH has set forth very ambitious and expensive plans for future development which are focused on our northern rivers and involve the expenditures of billions of dollars.

Dr. Simpson suggested that MH be directed to undertake a feasibility study of the potential development of a nuclear facility to determine whether it would be economic to have a major source of power close to the market. According to these Presenters, MH has not shown interest in building an infrastructure of nuclear expertise, however MH has indicated a willingness to buy and market the power if it is produced by a private vendor who would build and operate the station.

Dr. Simpson stated that the Whiteshell facility has been under nuclear license for 45 years, and because of that license, the development of a nuclear generating station on the site would require a shorter development time frame than other sites. Dr. Simpson compared the economic and employment benefits of a nuclear facility, which would result in long-term high-quality employment compared to a northern generating station which would have significant employment while being built, but with limited sustained employment once completed.

Dr. Simpson stated that the Pinawa location would be well-suited for the CANDU 6E nuclear generator which has been demonstrated in Korea, China and Argentina. A nuclear facility at the Pinawa site would have access to cooling water from the Winnipeg

River system, would be 100 km from the new converter station, close to an existing transmission corridor and could produce 700 MW of electricity.

Dr. Simpson stated a delay in Bipole III would save $4 billion and would cover more than half the capital cost of nuclear plant with the creation of 500 well-paid jobs to operate the plant with increased tax revenue and restored prosperity to the region.

MH's generation is 96 percent hydraulic, and thus susceptible to drought. According to these Presenters, the inclusion of nuclear power in MH's supply portfolio would create a more diverse generating system which would translate into greater system reliability.

2.3.2 Manitoba Chamber of Commerce – Mr. Starmer

Mr. Starmer appeared on behalf of the Manitoba Chamber of Commerce (MCC). MCC has long been a leading advocate of assisting citizens in need. It has proposed numerous changes to government to improve the lot of less fortunate citizens and is active in the poverty community, working in such areas as housing, food supply, and disabilities.

The MCC opposes the PUB being placed in a position of having to implement social policy through the setting of MH rates. The MCC is not taking a position related to whether a rate increase is justified, but if support for low-income users is included, which would impact upon the cost of electricity to other users, then MCC would oppose such an initiative.

The MCC believes that making Manitoba a better place to work and live is best achieved by keeping a number of principles in mind. Three principles advocated by MCC are:

- Representatives are elected by voters to manage the government and develop public policy.

- The basic responsibility of government is to assist those in society who are in need through social programs;

- A fundamentally accepted principle is that those in need be assisted by those who have the capacity to do so. This is the basic reason for progressive tax rates where government taxes those with the capacity to pay and give to those in need.

MCC submitted that as a public utility, MH should not be involved in social programs, nor does it have the expertise or mandate to institute public policy programs.

2.3.3 Gerdau Ameristeel – Mr. Forsyth

Mr. Forsyth appeared on behalf of Gerdau Ameristeel (Gerdau). Mr. Forsyth stated that Gerdau's steel mill in Selkirk is one of the largest manufacturers in the Province and is one of the largest shippers in the region, averaging over 150 truck loads and 25 rail cars per week. Mr. Forsyth noted the significant economic contribution Gerdau makes to the Province, which includes 770 direct jobs, spending more than $49 million with local suppliers and service companies, and generating indirect employment.

Gerdau is the largest recycler in the province, processing scrap metal collected from throughout the region, recycling approximately 400,000 tonnes of scrap each year. Mr. Forsyth stated that the processes followed by Gerdau are environmentally responsible, noting that making steel from scrap metal reduces energy use by 70% and emissions by 60% when compared to steel made from iron ore by a steel mill. The manufacturing process is energy- and capital-intensive, with electricity costs being second only to scrap steel costs as an input cost.

Energy efficiency is one of the tools that assisted Gerdau’s Manitoba facility in improving its competitiveness. Low-cost, stable, and reliable electricity is essential to Gerdau's operations in Manitoba. While energy costs in Manitoba are generally favorable, other input costs such as labor and transportation and fuel costs have countered some of the advantage offered by lower-cost electricity.

Mr. Forsyth stated that energy rates have increased substantially since 2004, increasing by over 20% since that time. With respect to the 2.9% rate increase request for 2011 and 2012, Mr. Forsyth noted that the PUB had provided interim approvals for the 2.9% increase for 2010 and the increase of 2.0% for 2011 fiscal year. Gerdau requested the Board to reconsider the contemplated increase and modify it to reflect the cost of service to the industrial customer class. Gerdau submitted that during these difficult economic times, costs must to be reduced, not increased, as they cannot be passed along to customers.

During the depths of the economic downturn in 2009, the Gerdau Manitoba facility saw production orders fall dramatically. Notwithstanding the significant economic downturn, Gerdau undertook initiatives to maintain employment by using a work share program and initiated new plans to operate the plant as efficiently as possible at the reduced operating rate. One component of costs that stood out immediately was the average price of electricity. With the reduced load at the plant, the average unit cost of electricity skyrocketed overnight by over 40% and became a major issue for continued operation. Gerdau entered into discussions with MH to rectify this unintended consequence. With the demand billing concessions provided by MH, Gerdau avoided making some relatively hard decisions with respect to the continued operation of the plant.

Mr. Forsyth recommended that the demand billing concession granted to Gerdau should be made permanent, consistent with MH's Application. He noted that the demand billing concession reacted as expected to the needs of energy consumers impacted by the economic downturn. The affected customers were able to keep people employed while ensuring that MH's revenue stream was secure.

2.3.4 The Bipole III Coalition – Mr. Derry

Mr. Derry, a retired professional engineer who spent 20 years with MH, presented on behalf of the Bipole III Coalition, which advocates for routing the transmission line down the east side of Lake Winnipeg rather than the west side.

Mr. Derry stated the east side route is preferable because of greater economic, social, technical and environmental benefits for all Manitobans. According to the Bipole III Coalition, the western route will cost at least $1 billion more for ratepayers than the more direct eastern route. The longer line will cause line losses equivalent to all wind energy generated annually in Manitoba and equivalent to the annual energy consumption of 40,000 cars.

Mr. Derry further noted that the east and west routes traverse about the same length of the boreal forest zone. However, the western route also traverses several hundred kilometers of the best agricultural soils and the most favourable agro-climatic zone in the Province. With respect to the impact on First Nations communities, 16 communities would be affected by the eastern route and 15 by the western route, i.e., essentially the same number. Neither route traverses any Aboriginal reserve land, although both traverse the traditional lands of Aboriginal people. Mr. Derry stated that First Nations Chiefs on the east side of Lake Winnipeg are expressing increased interest in the eastern route for Bipole III.

The Coalition questioned the alleged impact of the eastern route on having the region designated as a UN World Heritage site, noting that winter roads are being upgraded to all-weather roads along the east side of Lake Winnipeg and the right-of-ways will have a greater impact than a power line. Once roads have been established, a common corridor that includes the road and the Bipole III makes sense.

Mr. Derry also noted that a route on the east side of the province provides much higher reliability and protection against risk from wind and ice storms than a west side route. He stated that if Bipole I and II are damaged, the eastern route for Bipole III is twice as effective as the western route for supplying electricity to Southern Manitoba and meeting the export commitments to the United States.

Mr. Derry summarized that the HVDC Bipole III transmission line route along the west side of the province was dictated by the provincial government. Based on technical, environmental and social and economic grounds, the Coalition considers the selection process for the western route to be seriously flawed and urges the eastern route be selected as the preferred route for Bipole III.

2.3.5 Amsted Rail – Mr. Shirley

Mr. Shirley, the Chief Operating Officer of Amsted Rail, stated that as a result of the worldwide economic downturn, Griffin Wheel Company's business environment has changed dramatically. It had to idle its Winnipeg wheel plant in October 2009, and also reduce the operating schedules of its remaining three facilities. He mentioned that since the market has not yet recovered, further actions must be taken to ensure the viability of the Winnipeg operation. Amsted Rail's plan is to restart the Winnipeg facility.

Amsted Rail is asking for MH's consideration to make the demand concession a permanent concession rather than leave it as the existing temporary loan. This Presenter further asked that consideration be given to extending the concession until May of 2010 for Griffin Wheel Company and other companies in Manitoba who are still struggling with the economic recovery.

Mr. Shirley stated his company is a large user of energy, but that the peak demand charges that must be paid during periods of reduced plant operation erodes the company's ability to compete with offshore competitors. Amsted Rail is moving ahead with implementation of its plan to restart its Winnipeg plant based on the assumption that the PUB will assist with the aforementioned requests.

2.3.6 Canexus – Mr. Turner

Mr. Turner, the plant manager at Canexus in Brandon, presented on behalf of both Canexus and MIPUG, of which Canexus is a member. He requested the demand billing concessions be made permanent, as requested by MH. He also urged the Board to implement cost-based rates.

Mr. Turner noted some of the benefits that MIPUG industries bring to Manitoba. They employ in excess of 4,000 people directly in the Province, at more than twice the average industrial wage in Manitoba. They have assets with a replacement value of over $2 billion dollars. They support countless numbers of regional networks of secondary industries, retail companies and hospitality services in their communities. Most of the MIPUG industries account for a large part of the employment opportunities in rural and northern areas of the Province. Corporate taxes are estimated to be in the range of $75 to $100 million, and individual employees of MIPUG industries pay in excess of $50 million collectively to the Provincial and Federal governments in personal income taxes.

Mr. Turner stated that the purpose of MIPUG is to allow industries to work together on issues related to rates and electricity supply in Manitoba. He noted that the challenges faced by MIPUG industries, for the most part, relate to being geographically isolated from markets. The steadily appreciating Canadian dollar also makes it difficult to keep manufacturing costs low and continue to be competitive.

In order to remain competitive in external markets, Mr. Turner stated that key interests must be protected, such as access to a reliable supply of energy, as well as stable and predictable energy rates, which are critical to running production processes. MIPUG industries must estimate their product prices based on their production costs, knowing that they can rely on paying a certain amount for energy in a given year.

MIPUG has expressed an interest in keeping firm power rates relative to the cost of providing service to the specific class. Revenue-to-cost-coverage (RCC) ratios for each class should be moved within the zone of reasonableness at 95 to 105 percent. Currently, the RCC ratio is 112 percent. To keep rates predictable and stable, the Cost of Service Study (COSS) should be a reliable, verifiable method of assessing the costs for each class.

The downturn of markets all over the world in the fall of 2008 placed significant market pressures on MIPUG's members. Some members had to implement efficiency measures to remain competitive and, in another case, a plant closure was scheduled.

Canexus, as well as all other chlorate producers utilizing the electrolytic process, needs electricity to boil off water in order to produce its product, and electricity accounts for approximately 65 to 70 percent of its variable costs.

Mr. Turner stated that chlorate competitiveness is determined by three key considerations, namely power price stability and availability, salt price and availability, and transportation to markets. Power is the most important factor due to the large amount required for electrolysis. Canexus consumes about $49 million per year of MH power, and strives to utilize power efficiently. Mr. Turner noted that Canexus is continually trying to upgrade its process and was able to reduce the power brought into the plant by about 250 kilowatt hours per tonne over the years by implementing energy efficiency measures within the plant site.

2.3.7 Individual Presenters

Mr. Carriere

Mr. Carriere presented his views on what he considered MH's abusive rate increases. He mentioned there are over 136,000 people in Manitoba who rely on electric heat in the winter to heat their homes and it can be very costly for a senior on a modest pension. Mr. Carriere stated MH should look at giving people who use electric heat in the winter their own lower rate during the winter months. He suggested another option would be to offer a rebate at the end of winter on the use of electric heat.

He stated he would like to see the PUB refuse Manitoba Hydro any more increases since MH is doing well financially. If MH is having a financial problem, he suggested it should look at cuts to management and the workforce to keep the rates at a reasonable cost. In his opinion, it is time for MH to look into efficiencies in its own backyard and stop asking for increases every year.

Mr. Gray

Mr. Gray presented his comments related to the inverted rate structure of MH. Mr. Gray stated that he had converted his personal household from a gas furnace, dryer, and hot gas hot-water heating to an all-electric system. The reasoning behind this decision was that hydroelectricity provides far less environmental damage, less pollution, and much lower production of greenhouse gases. In addition, hydroelectricity, unlike natural gas, is a renewable resource, and under MH, provides stable long-term pricing.

Customers with electric heating are necessarily users of greater amounts of electricity. The introduction of the inverted rate structure has impacted disproportionately and unfairly on those customers who have chosen electric heating, as well as on many rural customers that have no access to natural gas.

Mr. Gray proposed that the PUB consider excluding the inverted rate structure step rate for those residential customers using electric heating. The same rate treatment could also be applied to residential customers with geothermal heating as an additional incentive to adopt geothermal heating, one of MH's objectives.

Mr. Gray also noted that for an increasing rate structure or peak-load pricing to be effective, customers need to know two things: what their energy consumption is on an ongoing basis, and, in addition, what to do in order to reduce their energy consumption. Residential customers would require something like an energy meter mounted adjacent to thermostats showing energy consumption and cost on a continuing basis.

Mr. Gruhn

Mr. Gruhn stated his objection to the increase being sought by MH due to the ongoing financial problems with the Corporation. Mr. Gruhn spoke of the need for a public hearing to be held in Brandon, to allow the PUB to hear from ordinary rural consumers as well as those in the city.

Mr. Jones

Mr. Jones provided comments on how he was being penalized for having installed electric heat. Special consideration should be given to those households that use electricity for heating.

Mr. Jones stated the rate structure should be set at a fair and realistic level according to the average consumption of an electrically heated house rather than an arbitrary 900kWh limit. Otherwise, electrically heated homes should have a separate rate structure. MH has a responsibility to customers they convinced to install electric heat and that responsibility should be recognized by the PUB in any planned rate adjustments.

Mr. Ciekiewicz

Mr. Ciekiewicz provided the Board with a written presentation together with his oral presentation. The presentation by Mr. Ciekiewicz covered a variety of topics – from MH's new office tower to risks, including an emphasis on inverted rates and the impacts on the MH customer using electricity for space heat.

Mr. Ciekiewicz also provided the Board with a series of recommendations that can be found starting at page 387 of the Transcript.

3.0.0 FINALIZED RATES

3.1.0 ORDER 99/11

Of particular significance and drawn from Order 99/11 is the Board's continued finding that MH failed to discharge its statutory and legal onus in the substantiation of its GRA rate increase requests:

> *"… the Corporation either refused or failed to provide the Board information that the Board considers critical to it reaching a comprehensive and final perspective on the prudency of MH's actions and plans, and the implications for domestic rates of MH's operations and plans.*
>
> *In particular, MH not only failed to provide the Board a fully updated 20-year Integrated Financial Forecast (IFF) – to include recognition of presently very low spot, opportunity and average export prices, and financial scenarios, with stated assumptions, based on capital expenditure differing from MH's "preferred development plan", but also refused to comply with a subpoena issued by the Board on July 6, 2011 that seeks the filing of MH's export contracts." (Order 99/11 – page 4)*

As a consequence, the Board denied MH's request to finalize the 2.9% interim rate increases which were implemented on April 1, 2010 and also denied MH's request to finalize the 2.0% interim rate increases which were implemented on April 1, 2011. MH's requested Board approval of a further finalized average consumer rate increase of 0.9% as of August 1, 2011, which was also denied.

On January 4, 2012, the Manitoba Court of Appeal granted MH leave to appeal the issuance of the Board's subpoena for MH's export contracts. This appeal is currently pending, and the export contracts have not been provided by MH. Therefore, the Board remains of the view that to date MH has either failed or refused, and continues to fail or refuse, to provide information that the Board considers critical to its mandate of fixing just and reasonable rates for the services provided by MH.

3.2.0 RATES AND MH'S 75:25 DEBT TO EQUITY TARGET

Beyond debate is the Board's jurisdiction and mandate to set just and reasonable rates for MH that are in the public interest. The public interest includes consideration of the fiscal health of the Utility as well as the impact of rates on consumers.

MH defends its requested rate increases of 2.9% for 2010/11 and another 2.9% for 2011/12 as maintaining the appropriate balance between customer sensitivity and fiscal responsibility. The fiscal responsibility includes taking note of MH's plans for $20 billion of major investments in new generation and transmission systems in MH's self-described "decade of investment" to the year 2020. It is during this "decade of investment" that MH foresees its debt-to-equity ratio eroding from the current 74:26 level to 80:20, even with annual rate increases in excess of the forecast rate of inflation.

Since 2004, the Board has continually approved rate increases for MH that have been in excess of inflation and also in excess of MH's own rate increase requests. These rate increases have in large measure contributed to the annual Net Income of the Utility and therefore to the Retained Earnings of MH. The rate increases further enabled MH to achieve its financial target of a 75:25 debt-to-equity ratio a full four years ahead of the target date sought by MH's Board of Directors.

The intention of reaching a debt-to-equity target of 75:25 was to afford consumers rate relief aligned to the rate of inflation once the ratio had been met – together with prudent management of MH's operating and other expenses. While the Board has had, and continues to have, serious concerns with the composition of what MH categorizes as "Equity", the overall target of 75:25 remains valid.

3.3.0 BOARD FINDINGS

3.3.1 Final Rates for 2010/11 and 2011/12

The Board is not prepared to finalize the existing interim rate increases of 2.9% effective April 1, 2010 and 2.0% effective April 1, 2011. The Board further denies the requested

0.9% average rate increase effective August 1, 2011. Rather, and based on the totality of the evidence before the Board, including MH Senior Vice President Mr. Warden's testimony that MH is now in its best financial position in the Utility's history, the Board finds that rate increases aligned to the forecast rates of inflation for 2010/11 and 2011/12 are just and reasonable and in the public interest. The Board will therefore approve, on a final basis, a 1.9% average rate increase effective April 1, 2010 and a further 2.0% average rate increase effective April 1, 2011.

The Board does not accept MH's contention that the rates proposed by MH represent a proper balance between customer sensitivity and fiscal responsibility. MH states that it is important that MH maintain an adequate level of retained earnings and that rates be raised gradually even during periods of exceptional water-flows. MH's application also seeks a higher level of retained earnings to provide funding for capital investments and reduce the need for borrowing, which MH states will in turn reduce the financing costs that ultimately must be recovered from ratepayers.

In the Board's opinion, MH's view of fiscal responsibility is skewed by blind adherence to a future major capital plan that has not been fully tested before an independent tribunal considering the "Needs For And Alternatives To" such a major capital expenditure plan (NFAAT). Such an NFAAT should include all facets of MH's capital expenditure plans, including the export contracts MH has entered into or plans to enter into to allow for the advancement of its capital expenditure plans.

The Board was reminded by CAC/MSOS to go back to first principles regarding its rate-setting jurisdiction with respect to MH. CAC/MSOS submitted that the Board's jurisdiction to fix just and reasonable rates carries with it the need to meet the general public interest made up of (1) the interests of ratepayers and (2) the financial health of the utility.

CAC/MSOS submitted that the final rate order should address both short-term test year revenue requirements and the long-term issues facing MH that are of concern to the

PUB, in particular respecting the “decade of investment.” CAC/MSOS further submitted that rate-setting at this time must also take into account the ongoing economic uncertainty and financial stresses existing in Manitoba on all consumers, including individuals, businesses and large industry.

The Board’s role, according to CAC/MSOS, must involve ensuring that MH’s forecasts are reasonably reliable, ensuring that actual and projected costs incurred are necessary and prudent, assessing the reasonable revenue needs of the Corporation in the context of the overall general health of MH, determining an appropriate allocation of costs between classes, and setting just and reasonable rates in accordance with statutory objectives.

The Board endorses these principles and the objectives as set out above that must inform it in the present circumstances when fixing rates for the test years in question. As set out in this Order, the Board is not satisfied that it has sufficient proof from MH, upon consideration of all of the evidence, to support a final approval of rate increases as sought by MH. In this GRA proceeding, MH has failed to substantiate the reasonableness of its capital plans and the expected revenues to support such a capital plan. As such, the Board cannot, and will not, endorse MH’s rate increase requests as applied for. However, the Board has determined that MH must receive inflationary increases for the test years to avoid erosion of its capital structure in the test years.

While MH has not made its case for the higher rate increases it requested, its financial position, arising from its Operating Results for the years ending March 31, 2010, 2011, and 2012 is significantly better than when MH filed its GRA in both MH’s own assessment and the assessment of the Interveners. For the fiscal year ending March 31, 2010, MH was forecasting $121 million of Net Income. Actual Net Income was $43 million greater, at $164 million. For the fiscal year ending March 31, 2011, MH was forecasting $78 million of Net Income. Actual net income was $65 million greater, at $143 million. Finally, for the fiscal year ending March 31, 2012, MH was forecasting

$87 million of Net Income. In its latest Financial Report, MH now projects Net Income at least $42 million greater, at $130 million.

The finalized rates for the 2010/11 and 2011/12 test years do not equate to the interim rate increases that were approved in Board Orders 18/10, 30/10 and 40/11. The Board is of the view that the most expeditious way to account for the differences between the interim and final rates is for MH to establish a deferral account to track, by customer class, the difference between what was collected under the interim rates and the amount that would have been collected pursuant to the rates now finalized. That difference is to accrue interest at MH's short term borrowing rate, for the benefit of MH's consumers.

Rather than requiring MH to immediately reduce its rates, the Board orders that the rate differential between what was approved on an interim basis and what has now been finalized shall be quantified by MH and remain as an interim rate, with its associated revenues being accumulated by customer class, with accrued interest, in the previously prescribed deferral account.

The reasons for not immediately requiring rate decreases and refunds extend beyond the administrative expense and potential inequities due to customer class changes. MH had indicated that the Utility would likely be seeking further rate increases, effective April 1, 2012 – subject to confirmation by the Board of Directors of Manitoba Hydro.

While the PUB is aware that no new GRA has been approved for filing as of the date of this Order, the PUB will need to know definitively of MH's intentions in that regard to enable it to further consider its approach to what will be a new interim rate and an accumulating deferral account. As always, MH and Interveners are at liberty to make submissions to assist the Board in its deliberations on this issue.

3.3.2 Final Surplus Energy Program (SEP) Rates

Included in MH's GRA Application is the Utility's request for final Board approval of all weekly SEP *ex-parte* rate orders (as listed in Appendix 10.7 in MH's GRA filing and outstanding to the date of this Order). There was no opposition to MH's request.

The SEP achieved sales of approximately 20 GWh in the November 2009 to October 2010 time period. It appears that the SEP was only modestly profitable (less than 5%) at an average revenue rate of 3¢/kWh. Historically, SEP revenue has exceeded MH's marginal cost by 10-20%, indicating that this current situation will continue to be monitored.

The Board approves as final all outstanding SEP weekly interim rate Orders from and including Order 67/08, up to and including the SEP Order issued in the week before this Order was issued.

3.3.3 Final Curtailable Rate Program (CRP) Orders

MH seeks final Board approval of CRP Orders 46/09 and 63/11, which provided interim approval of reference discount rates effective on and after April 1, 2009. No opposition to MH's request was raised during the GRA. The value MH places on CRP apparently relates primarily to winter capacity relief in years when domestic peak demand approaches system capacity.

While the Board will approve as final all interim CRP Orders (Orders 46/09 – 63/11), the Board does note that because MH normally markets its expected summer surplus capacity by the preceding February, there is a low, yet still real probability of export-related summer capacity shortfalls. Accordingly, the Board will seek additional information on this issue at the next GRA.

3.3.4 Temporary Billing Demand Concessions

MH has requested final approval of Order 126/09, which resulted from MH's Application for Temporary Billing Demand Concessions for General Service Medium (GSM) and

General Service Large (GSL) customers. The apparent impetus for this rate relief program was the economic downturn. MH sought concessions for industrial customers when the single ‘unit cost’ of their energy increased by more than 10% due to demand charges that would be incurred regardless of the energy consumed.

Unlike residential electric customers, GSM and GSL customers pay a monthly demand charge that is not directly scalable with reductions in electricity consumption. This means that even when these customers temporarily close production facilities or otherwise reduce consumption due to the global economic downturn in demand for their products, their energy bill does not decrease proportionally to the reduction in electricity consumption. MH’s rate structure for these GSL and GSM customers includes recovery of MH’s fixed costs (for property, plant and equipment) through the demand charge levied to high-volume customers.

While the Board granted temporary relief through Order 126/09, MH requested that the temporary concessions be made permanent under the program and not subject to being repaid by the GSL and GSM customers.

While under MH’s proposal, the GSL and GSM customers would not have to repay the temporary concessions, those fixed charges must still be attended to by MH. In essence, the Board concludes that other customer classes would be expected to make up the shortfall in MH’s retained earnings.

In Order 126/09 the Board indicated that for the temporary relief to be finalized, and perhaps forgiven, additional information would have to be made available to the Board. In that Order, the Board even set out a list of the types of additional information that were to be provided should MH seek finalization or forgiveness of the temporary demand billing concessions. MH either chose not to, or was unable to, obtain and provide such additional information to the Board. As such, the Board is not persuaded to grant the relief requested. Based on the evidence before the Board, and considering the submissions from parties choosing to address this issue (with Interveners on each side of this issue), the Board will not approve the forgiveness of the temporary demand billing concessions.

That portion of the qualifying customers' electricity bills that was temporarily deferred and carried at the equivalent of MH's cost of short-term borrowing as interest is now required to be repaid to MH. At the next GRA, MH is to report on the collections of the previously and temporarily deferred amounts.

4.0.0 MH'S DEVELOPMENT PLANS

4.1.0 MH'S CURRENT PREFERRED DEVELOPMENT PLAN

In defining its preferred and alternative Development Plans, MH relied on information from its various electricity planning documents, which are typically prepared annually and include:

- Integrated Financial Forecasts (IFFs);
- Capital Expenditure Forecasts (CEFs);
- Domestic load forecasts;
- External consultant panel survey on export pricing expectations;
- Power Resource Plans (PRP);
- Existing export contracts; and
- Pending export sales contracts (Term Sheets).

A key component of the PRP process involves defining "minimum dependable energy". Minimum dependable energy arises primarily from hydraulic generation but can also be sourced from non-hydraulic generation such as MH thermal, MH-purchased windpower generated in Manitoba, demand reductions resulting from efficiency improvements, demand side management (DSM), and imports from American counterparties. In MH's plans, projected domestic load (i.e., the electricity requirements of MH's Manitoba customers) is to be provided only from defined dependable energy resources. To the extent that minimum dependable energy exceeds the projected domestic load, any projected surplus becomes available for "firm" export contract sales, as opposed to opportunity exports. Firm export contracts are usually of relatively short duration relative to the life expectancy of a hydraulic generating station.

Circa 2007, MH indicated that Term Sheets had been entered into with American utilities calling for the following firm sales to export customers for various years, commencing in 2015:

- Northern States Power (NSP) - 375/325MW (2015-2025);
- Wisconsin Public Service (WPS) - 500 MW (2018-2033); and
- Minnesota Power (MP) - 250 MW (2020-2035).

To facilitate these projected export contract sales, MH's PRPs involve projected "in-service" (projected construction completion) dates for new facilities allowing for "dependable" hydraulic generation for MH's preferred and alternative development plans for various vintages of MH's PRPs.

Under the 2009/10 PRP, which was reviewed by the Board at this GRA, MH showed a proposed plan to expend capital to construct the following:

- Bipole III transmission line;
- Keeyask G.S; and
- Conawapa G.S.;

These three capital projects were to be undertaken together with other major new generation and transmission capital expenditures for:

- A 500 KV USA Interconnection;
- An expansion or upgrade of transmission facilities south of the U.S. border;
- Additional north-south AC transmission capacity in Manitoba; and
- The reconstruction of the Pointe du Bois spillway and powerhouse.

Prior to the conclusion of the GRA Hearing, MH advised of changes to its plans, most notably the recognition of a reduction in the WPS commitment from 500 MW to 100 MW, with the 15 year agreement being pushed back to 2021.

4.2.0 EVOLUTION OF MH'S DEVELOPMENT PLANS

In MH's 2004/05 PRP, MH modelled the following alternative new resource concepts, each assuming a 2024 in-service date that would follow the 200 MW Wuskwatim Generating Station's (G.S.) then-projected 2010/11 in-service date:

- Equivalent outputs from single cycle combustion turbines (SCCTs);
- A 10 turbine 1250 MW Conawapa G.S. to generate 4,500 GWh of dependable energy;
- A 5 turbine 625 MW Conawapa G.S.[1] to generate 4,500 GWh of dependable energy; and
- A 600 MW Keeyask G.S. to generate 2,900 GWh of dependable energy.

Anticipating about 3,500 GWh of firm contract commitments with its American counterparties, MH concluded that a 10 turbine Conawapa G.S. represented the most cost-effective next plant in service. There is no mention in the 2004/05 PRP as to how Combined-Cycle Combustion Turbines (CCCTs) would compare to either SCCTs or the hydraulic alternatives.

In its 2008/09 PRP, MH reconsidered the next plant in-service sequence and, based on projected higher 2008 domestic load forecasts and new export contracts beyond 2015 (500 MW to Northern States Power (NSP) / 100 MW to Minnesota Power (MP) / 500 MW to Wisconsin Public Service (WPS)), suggested the following builds:

[1] A 5 turbine Conawapa G.S. was projected as providing for sufficient capacity for full utilization of dependable river flows.

- Keeyask G.S. 630 MW 2018/19 in-service; and
- Conawapa G.S. 1,300 MW 2022/23 in-service.

This same PRP presented an alternative development plan in case the WPS and MP sales did not materialize. The alternative development plan projected:

- Additional contracted imports up to and including 2015;
- The construction of a 400 MW CCCT plant for a 2019 in-service date; and
- A 1,300 MW Conawapa G.S. for a 2021 in-service date.

In its 2009/10 PRP**,** MH projected:

- Construction of a 630 MW Keeyask G.S. for a 2018/19 in-service date;
- A 1,300 MW Conawapa G.S. for a 2022/23 in-service date;
- A 1,000 MW export inter-connection for 2018/19;
- A 750 MW import inter-connection for 2018/19; and
- Additional Manitoba north-south transmission (in support of Bipole III), to address a drought scenario similar to the one encountered in 2003/04.

This new recommended development plan was deemed necessary by MH to service its pending and/or projected Term Sheet sales of 500 MW to WPS and 250 MW to MP (which is the same scenario as was contained within MH's 2008/09 PRP). The construction of a 400 MW CCCT facility for 2018/19 was deleted, presumably reflecting a 1,000 GWh reduction in MH's domestic load forecasts.

In the absence of WPS and MP Term Sheet sales, MH's 2009/10 alternative development sequence would presumably have been:

- No Keeyask G.S.;
- Construction of a 1,300 MW Conawapa G.S. for 2021/22 in-service; and
- Deferral of the construction of a 400 MW CCCT facility to a 2033/34 in-service date.

In its 2010/11 PRP, MH deferred both Keeyask G.S. and Conawapa G.S. by one year (2019/20 and 2023/24 respectively) in its recommended plan, and Conawapa G.S. by one year (to 2022/23) in its alternative plan. The export interconnection was also set back by one year (to 2019/20). In the alternative plan, with no MP/WPS contracts and only a 375/325 MW sale to NSP, only Conawapa would be built by 2022/23, with a 460 MW CCCT plant to be added in 2033/34.

In June 2011, MH filed with the Board its 20-year financial outlook (OL 10-2), updated to reflect its most recent accepted revised capital cost estimate for Bipole III.

In July 2011, referencing a Manitoba Government press release of May 25, 2011, MH confirmed that the amount of export power for the proposed long-term sale agreement with WPS had been reduced from 500 MW to 100 MW. This reduction reduces the immediate need for a 1,000 MW export and 750 MW import intertie capacity. The reduction, if not reversed, could allow for a further deferral of the anticipated in-service date for Conawapa G.S. to a date beyond 2024/25.

4.3.0 FIRST NATION INVOLVEMENT IN THE DEVELOPMENT PLAN

4.3.1 Wuskwatim

Wuskwatim G.S. represents Manitoba's first new hydroelectric development since the late 1980s, and the first in Manitoba structured as a partnership between MH and a First Nation, namely the Nisichawayasihk Cree Nation (NCN). The project is to be developed by the Wuskwatim Power Limited Partnership (WPLP), an equity partnership between NCN and MH.

The two limited partners (MH and NCN) are to invest equity in the WPLP by subscribing for ownership units to represent 25% of the total capital cost of the project. The WPLP agreement allows for NCN, through its wholly owned Taskinigahp Power Corporation (TPC), to subscribe for up to a 33% stake in the equity partnership units.

MH, through a holding company that serves as general partner, would hold a 0.01% interest in WPLP, with MH in its capacity as limited partner holding the balance of 65.99% directly.

The assets of the WPLP are to consist of the Wuskwatim G.S. and required working capital. MH is to lend WPLP the funds required to build the generating station. Based on the Corporation's current estimated cost of constructing Wuskwatim, and excluding the transmission component, MH projects lending WPLP $927 million. The funds are to be required to build the generating station, and represent approximately 75% of the cost of the project (the remaining funding to be through WPLP's equity partnership units).

MH assumes that TPC will subscribe for the full 33% of the equity ownership interest permitted. Based on the current construction cost estimate for the generating station, TPC's cost for the partnership units would be $102 million. According to the agreements, TPC will invest up to $34 million of its own capital and can borrow up to $68 million from MH to fund the balance. MH advised that NCN has yet to commit to the full 33% ownership interest in WPLP and will not be required to make a decision on its stake in the partnership until the dam is put into service.

Revenues generated from the project are to be allocated to WPLP from MH's overall revenues, based on an agreed-to (between NCN and MH) formula utilizing average export prices for on-peak and off-peak sales. MH indicated that the determination of the average export price will include the export revenue from the new NSP agreement as well as from contracts reached with Wisconsin Public Service and Minnesota Power, along with any opportunity sales.

Revenues are to be adjusted as changes in export prices are experienced and realized, and are to be based on the actual output of Wuskwatim G.S., reduced by the average system line loss rate for the MH system (currently 10%). WPLP is to pay MH 3% of the WPLP's gross revenues, to contribute towards the marketing and transmission costs and risks borne by the Corporation.

MH will be fully responsible for the operation of the generating station and related transmission facilities, and will charge WPLP for its incremental operating costs. MH will make no cost allocation to WPLP for system generation and transmission. Control Center costs will not be directly charged to the project but be included in the overhead charge to the project.

The Wuskwatim Project Development Agreement allocates MH's overhead costs at a rate of 21% as opposed to the "normal" 29%, this reduction allowing for the exclusion of a share of costs related to MH's Winnipeg facilities and computer systems not expected to be utilized by the project.

Finance costs incurred by the Corporation related to the loans it will take on to allow it to make loans to WPLP to build the generating stations are to be recovered, at cost, from WPLP. The financing cost related to loans to WPLP has been estimated at 6% interest, based on MH's expected long-term cost of borrowing of 5% plus a 1% Provincial debt guarantee fee.

The WPLP must maintain a 75:25 debt-to-equity ratio, except for the first 10 years of operations during which an 85:15 debt-to-equity ratio will be allowed. If the partnership's debt-to-equity ratio falls below the above parameters, there is a requirement for further cash contributions from WPLP partners based on their respective ownership interest in the partnership.

The development agreement between Hydro and NCN allows for advances on dividends to NCN, even during loss years and/or when the equity threshold test has not been met. The advances are to be limited to 5% of the actual cash invested by NCN, and are to be repaid by NCN out of forecast future distributions.

In addition to the generating station, Wuskwatim requires incremental transmission facilities. MH is to build the required transmission, at an estimated cost of $320 million, the cost of which will be recovered from WPLP by way of repayment of principal and interest over a 50 year term. In addition, the operating costs of the transmission facilities will be charged to WPLP.

4.3.2 Keeyask

Like Wuskwatim (see section 4.3.1), Keeyask G.S. is to be developed through a First Nations partnership. In this case, the project will be developed and operated through the Keeyask Hydropower Limited Partnership (KHLP), a partnership between MH on the one hand and (1) the Tataskweyak Cree Nation and War Lake First Nation, acting as Cree Nation Partners, (2) the York Factory First Nation, and (3) the Fox Lake Cree Nation (collectively, the Keeyask Cree Nations or KCN) on the other hand.

The limited partners (MH and each of the four KCN) are to subscribe for equity units in the limited partnership, which is to represent 25% of the total capital cost of the Keeyask G.S. The partnership agreement allows for the KCN to collectively subscribe for up to 25% of equity units in the partnership. MH, through holding company acting as general partner, would have a 0.01%. In its capacity as a limited partner, MH would hold the remaining balance of 74.99% directly.

Each of the KCN partners can choose different ownership positions in the Limited Partnership by way of a combination of common equity and or a preferred equity share ownership. KCN partners have the option to acquire preferred equity shares amounting up to a 2.5% equity interest. MH will not provide financing for preferred equity share investments.

The minimum cash investment to be made by the KCN partners is $12.5 million, with a maximum cash requirement of $25 million. MH will lend the KCN a maximum amount equal to the difference between $25 million and the amount it takes to acquire a 17.5% common equity ownership in KHLP, financed by both KCN and MH equity loans. If KCN invests only the minimum cash investment, equity loans will be available to take an 8.75% common equity interest. The equity loans are to be at a 30-year loan rate plus 2%, payable over a 50-year term.

The assets of the Limited Partnership will consist of the Keeyask G.S and required working capital. MH is to lend KHLP the funds to build the generating station. Based on the Corporation’s current capital cost estimate of constructing Keeyask, excluding transmission investments, MH will be required to lend KHLP $4.2 billion to build the generating station, representing 75% of the cost of the project. The balance of approximately $1.4 billion is to be funded by the equity contributions of the partners.

MH will be responsible for the operation and maintenance of the Keeyask G.S. and related transmission facilities. KHLP will be assigned the costs related to management and operations of the Keeyask G.S., including all indirect costs and expenses, in a manner consistent with how Hydro allocates its indirect costs and expenses to other generating stations that are wholly owned by MH.

KHLP will attract no water rental fees, amortization or finance costs related to MH’s operations. However, KHLP will be assessed the finance costs incurred by MH related to the loans required to build the generating station. During the construction period, the loan will bear interest at the floating rate plus 2% and the debt guarantee fee. Upon completion of construction, the loan will be converted to a 30-year rate plus 2% and the debt guarantee fee. Repayment will be made be from a share of the revenue generated by the facility over a 50-year term.

MH will provide an Operating Credit Line to fund any cash calls that may occur to keep the capital structure of the Limited Partnership within established parameters of a 75:25

debt-to-equity ratio, which is allowed to rise to an 85:15 ratio during the first ten years of operations. Advances made under the Operating Credit Line would bear interest at the ten-year rate plus 2% and the debt guarantee fee.

With respect to the transmission costs that are to be paid by KHLP, the full extent of the transmission arrangements have not been fully determined, but the partnership agreement envisions that to the extent that any incremental transmission facilities are required for the Keeyask G.S. KHLP will be responsible for their capital and operating costs, including OM&A costs.

KHLP will not be responsible for any of the capital or operating costs, including OM&A costs, of Bipole III (if built), nor any costs to build or operate additional AC transmission or associated stations related to north / south transmission. KHLP will also not be allocated any costs related to interconnection between Manitoba and other jurisdictions. Such costs may be incurred to allow Keeyask-generated power to be delivered to export markets.

4.4.0 DEPENDABLE ENERGY RESOURCES

In defining its recommended development approach, MH contended that its "Dependable Energy" resource should include:

- Hydraulic Generation

  (21,100 GWh, to increase to 22,300 GWh in 2012/13 when Wuskwatim is expected to be in service);

- Thermal Generation

  (4,100 GWh, to decrease to 3,300 GWh after 2018/19, when the Brandon Coal plant is to be decommissioned);

- Wind Generation

(800 GWh, with both St. Leon and St. Joseph in-service);

- Reductions in required supply due to DSM measures

  (800 GWh in 201516, to increase to an expected 1,000 GWh by 2019/20); and

- Imports

  (2,700 GWh, this from a combination of contracted (firm) and opportunity market purchase (non-firm) imports).

MH has not specifically defined its "acceptable" levels of non-hydraulic resources that may be employed in satisfying domestic load requirements under the Utility's projected "Dependable Flow" scenario. However, from the various PRP sequences filed, it appears that a 5,000-5,500 GWh shortfall of dependable hydraulic generation relative to base domestic load would "trigger" or require new hydraulic generation to be brought into service.

When the Utility's firm energy export obligations, which are typically 2,000-3,000 GWh per year, are factored in, MH forecasts a dependable hydraulic energy shortfall of 7,000 to 8,500 GWh, which, for both economic and scheduling reasons, may require up to 8,000 GWh of imports and other power purchases in the worst-case year (i.e. in drought conditions).

In the absence of new firm export contracts, Keeyask G.S. could possibly be deferred by five or six years, the deferral to be provided for by maximizing imports. Similarly, in such a circumstance, Conawapa would only be required for domestic requirements circa 2030/31.

4.5.0 OTHER SCENARIOS

4.5.1 Overview

Circumstances have changed since MH, in its 2008/09 PRP, projected that new hydraulic generation would be required in 2018/19. Domestic consumption has declined by more than 1,500 GWh/year at a time the export market has “shrunk”. As a result, in the absence of new developments requiring large additional load, the limited deferral of new hydraulic generation may be possible without curtailing the NSP/MP/WPS sales agreements. Further, if these prospective agreements were not consummated, MH might be able to defer new generation until 2025/26 by serving domestic load only from existing domestic hydraulic/thermal/wind generation and present import arrangements.

In MH’s 2008/09 Alternate Development Scenario, MH considered the construction of a 400 MW CCCT plant in lieu of constructing Keeyask G.S. for an in-service date of 2018/19. With the then-prevailing natural gas price of $8.00/GJ, the unit operating output cost for the CCCT option was estimated at 5.50¢/kWh. However, at current natural gas prices, those being in the range of $4.00/GJ, the unit operating cost would be significantly lower, perhaps less than half the 10¢/kWh expected on-line cost of Keeyask G.S. production.

MH has included Bipole III in all of its development scenarios, and Bipole III must be in place to accommodate Conawapa G.S. output. However, it may not be required for Keeyask G.S. output, assuming average flow levels.

MH contends that Bipole III is required for domestic reliability reasons, particularly as such relate to the potential for an extended outage of both Bipoles I and II. In MH’s CEF03 and CEF04, MH contemplated building an east-side transmission facility without new HVDC converters at a cost of $0.5 billion, to deal with reliability concerns. But in its 2004/05 PRP, MH included HVDC converters, and MH’s CEF05 included a provision of $1.8 billion for Bipole III in anticipation of building Conawapa G.S. (or Keeyask G.S.) for a 2024/25 in-service date, to meet then-projected future domestic load requirements and, initially, to provide about 4,500 GWh of “surplus” firm energy for the export market.

In MH’s 2004/05 PRP, the Utility employed a SCCT thermal generation scenario as a base for comparison of its new generation alternatives. As well, Bipole III costs were excluded from the analysis. The construction of a CCCT plant was not considered, despite the typical operating costs (including fuel) of such a plant being 3-5¢/kWh lower than for a SCCT plant.

Since 2004, MH’s planning has not considered any non-hydraulic generation, such as possibly lower-cost gas plants or more wind generation to augment hydraulic capacity scenarios to meet both domestic load and reliability concerns. A wider consideration of options could include:

- Revisiting an east-side HVDC transmission line without HVDC converters as a means of improving transmission reliability for existing northern hydraulic generation;

- Examining the possible role of a 400/800/1,200 MW CCCT natural gas thermal generation plant, which, potentially, could allow for the further deferral of not only new hydraulic generation but also Bipole III, for at least a decade; and

- Firm price import contracts, focused on natural gas rather than coal- or gas-generated electricity.

The end product of the information from all these planning documents is MH’s “road map” as to future major capital projects (generating stations and transmission lines) that will be required to meet MH’s future domestic loads and firm export commitments. There is subjective decision making involved – together with numerous assumptions – that underpins any current version of MH’s Preferred Development Plan.

The significance/importance of examining and testing those assumptions and decisions cannot be overemphasized. With capital costs and financing costs in the tens of billions of dollars, the stakes are high for the domestic ratepayer who is at risk to bear the costs.

4.5.2 Keeyask G.S. without Bipole III

It is MH's position that Keeyask G.S. cannot proceed without Bipole III in place to transmit the full Keeyask plant capacity when water levels are well above dependable flow levels. MH indicates that Bipole I and II cannot operate on an extended-time basis at their full capacity of 3,854 MW, as 500 MW of Bipole capacity should be kept in reserve for maintenance and/or forced outages of valve groups. As such, the existing HVDC lines are only capable of 3,354 MW, delivering 29,400 GWh/year. This, in effect, means that the combined 4,200 MW capacity of the Keeyask/Kettle/Long Spruce/Limestone generating stations could only operate at an 80% capacity level.

It appears that other than in 2005/06 MH's output from the three existing lower Nelson River Plants has not exceeded 80% of their capacity.

Recently, MH has also suggested that an additional 208 to 838 MW of transmission capacity would be required once Keeyask is in service to match total generation capacity and provide system reserves. In MH's OL 10-2, MH's alternative to a 2,000 MW Bipole III was 2,000 MW of natural gas generation. Staggered in-service dates of individual 400 MW CCCTs to postpone the need for Bipole III do not appear to have been considered.

4.5.3 Natural Gas Generation Instead of Bipole III

In MH's 20 year financial outlook (OL10-2), MH provided a comparison of two reliability alternatives, namely Bipole III vs. a gas-only scenario. The brief analysis covered only the initial capital costs and annual fixed operating costs for SCCT plants, not a CCCT plant. It did not contemplate and model finance, depreciation and OM&A costs and revenue from a CCCT natural gas generation system, or the advantages of such additional capacity. As well, the stepped additions of 400 MW CCCT units were not considered. MH similarly did not provide a net present value analysis dealing with different service lives of the various components or the incremental revenue potential that CCCT units could achieve.

It appears that MH has not to date reviewed and considered a CCCT generation scenario that could supplement Keeyask G.S. while deferring Bipole III for at least a decade. Without the 500 MW WPS contract, the timeframe for Conawapa G.S. could conceivably be extended beyond 2029/30. Without Conawapa, the full capacity of Bipole III may not be required.

4.6.0 CARBON FOOTPRINT

4.6.1 Energy Conservation in Manitoba

Energy conservation measures by MH's customers are the most cost-effective for ratepayers when they displace thermal generation for domestic consumption. Because MH's system does not allow large seasonal or year-to-year energy transfers, conservation has a comparatively low financial value whenever MH's annual hydraulic generation is above average. In below-average flow years it can increase the availability of clean energy for export sales.

However, within the MISO marketplace, MH's hydroelectric energy has not been provided carbon premiums. MH's clean energy may well displace natural gas generation. Natural gas generation carries a lower CO_2 footprint than coal generation.

4.6.2 Demand Side Management (DSM)

DSM has generally been considered a cost-effective means of achieving energy conservation. High export prices prior to 2009/10 provided MH with a net gain on most industrial DSM measures. However, at current market prices many DSM initiatives may not be favourable to MH's bottom line. An unexpected fallout from the economic downturn sees MH unable to sell all of its surplus hydraulic energy to the limits of generation and transmission tie-line capacities even at prices that cover only water rentals and transmission charges. With 12 out of the last 15 years being relatively high-flow years, MH's acquisition of DSM energy may at times have resulted in spilling excess hydraulic capacity.

4.6.3 CO_2 Emissions

MH currently anticipates that thermal generation will be limited to 200 to 400 GWh/yr and that imports will reflect about a 50:50 split between coal and natural gas generation. Other than in drought years, this picture seems realistic. The CO_2 emissions on a combined basis (thermal and imports) are now forecast to be at least 1.3 million tonnes/year.

In drought years the CO_2 emissions could be much higher. 2003/04 saw an emission level of 9.5 million tonnes of CO_2. Most of the imports in that year apparently came from coal-fired generation, which was the lowest cost off-peak supply.

MH takes the position that responsibility for emissions rests with the generator, as MH should receive credit for the reduction of indirect emissions. As such, and on a net basis, MH's exports should result in a CO_2 reduction of about 4.5 million tonnes/year. There appears to be a counterposition that has been advanced by the Western Climate Coalition (WCC), one that would provide "ownership" of emissions credit to the utility purchasing the energy. This is consistent with the concept of ownership of clean energy credits.

4.7.0 INTERVENER POSITIONS

4.7.1 CAC/MSOS

CAC/MSOS agreed that the PUB is correct to be concerned about MH's proposed development plan, as it is yet untested. The financial impact of new generation and transmission resource development on domestic rates as illustrated in IFF09-1 is of concern to CAC/MSOS.

CAC/MSOS is uneasy about the capital cost escalations associated with the major projects envisioned in MH's "decade of investment" and is looking to achieve cost impact reductions. Ultimately, CAC/MSOS took the position that MH's development plan with respect to building for export will be subject to a full review and testing and will not proceed unless the benefits can be clearly demonstrated and substantiated in a forthcoming and promised NFAAT hearing. CAC/MSOS submitted that it is confident such a review will be held, be thorough, and will adequately address the risks involved.

4.7.2 MIPUG

In general, MIPUG was supportive of MH's Recommended Development Plan and accepting of the rate implications as forecast by MH. MIPUG submitted that the recommended development scenario advanced by MH under its PRP appears to mitigate the risks associated with the financial impacts of a drought. MIPUG viewed this conclusion, provided by KPMG, as being both credible and supportive of MH's continued planning toward its planned development sequence.

MIPUG further submitted that the degree of capital investment which is required will cause the relevance of the debt-to-equity ratio to be diminished and will have the negative effect of driving a requirement for materially higher equity levels than needed. Further, since MH's retained earnings and equity are not in the form of cash and are largely intangible, they are not available to mitigate the financial adversity of a severe drought. MIPUG submitted that in the next GRA, in light of this development, the PUB should move to investigate and implement a more developed form of financial reserve target for MH.

MIPUG's assessment of the preferred and alternative development scenarios is that they do not lead to materially different rate increase outcomes for domestic ratepayers over the long term, in accordance with MH's IFF period. MIPUG therefore submitted that PUB can be satisfied that the rates being sought in the test years are sufficient regardless of the ultimate plan selected.

MIPUG's experts Messrs. Bowman and McLaren also concluded that the PRP, with the preferred development sequence, is credible enough and would deliver enough possible benefits that MH should continue to protect the option to pursue it. In order for a final decision to be made, MIPUG supports a review and testing of the merits of all reasonable alternative development scenarios by an independent body, be it the PUB or another hearing body, as long as the process is open and transparent and permits full participation by interested parties and leads to independent conclusions.

4.7.3 RCM/TREE

While RCM/TREE offered no commentary on MH's short-term planning and supported the rate increases requested in the test period, it raised concerns over the risk report information available in the hearing process respecting long term planning and risks faced by MH.

RCM/TREE did not offer a specific perspective on the factors affecting future costs and revenues faced by MH under the development scenarios which were examined in the GRA process. They commented that these questions ought to be the subject of a proper risk review in a future hearing into the need for and alternatives to (NFAAT) the portfolio of projects, and ought to have been applied earlier in the planning process. In the view of RCM/TREE, confidentiality claims prevented a proper analysis.

Finally and as recommended by Mr. Wallach, RCM/TREE sought a much broader review of potential development scenarios, with such a review to take into account reliance on increased wind and DSM resources.

Mr. Wallach also opined that risk associated with drought is increased by virtue of MH's preferred development plan. A way to mitigate the risk, he offered, is to diversify the sources of power generation. However, RCM/TREE acknowledged KPMG's conclusion that transmission enhancement achieved via new long-term contracts reduced risk and offered that perhaps the complete dependency on hydroelectric resources and new transmission access would act as a counterbalance to greater risk.

4.8.0 BOARD FINDINGS

MH's power resource plans impact capital expenditures, which in turn impact consumer rates through finance expenses and depreciation and amortization expenses related to those capital expenditures.

The Board is not satisfied that MH has explored all reasonable power resource scenarios, including:

- Domestic customers being the focus, with limited exports;
- Domestic customers and export customers as equal embedded cost participants; and
- Exports as an independent profit centre, separate from domestic customers revenues and costs.

In particular the Board finds it troubling that MH has not explored, in any depth, a Combined Cycle Combustion Turbine (CCCT) natural gas thermal generation supply alternative to new major hydraulic generation and transmission projects.

MH chose to compare its Keeyask and Conawapa hydraulic options with a Single Cycle Combustion Turbine (SCCT) natural gas plant. Single cycle gas plants are not nearly as cost efficient as combined cycle natural gas plants (CCCT).

The failure of MH to flesh out the potential diversification of supply through the construction of a CCCT generating plant, as part of MH's future development sequence, ignores the current competitive position of CCCT generation in the MISO Market.

In light of the collapse of MISO spot market energy prices, MH should have carried out and disclosed a due-diligence assessment of its business plan. This should now be carried out, whether or not an NFAAT approval process that considers the CCCT alternative, is established by the Province.

In the Board's view, MH's apparent decision to proceed with the Keeyask G.S. to serve the 125 MW (NSP)/250 MW (MP)/100 MW (WPS) additional export sales instead of proceeding with Conawapa G.S. is a significant departure from both MH's Recommended Development Plan and MH's Alternative Development Sequence. It would appear to contemplate a power resource scenario that leaves out Conawapa G.S. if the additional 400 MW (WPS) contract is not achieved. As such, the full benefits of Bipole III would not be realized. With the considerable escalation of project costs – each successive update of MH's capital expenditure plans has shown material increases in the forecast cost of expansion - the Board is looking for MH to justify, and an independent tribunal to comprehensively review, each of the projects on a net present value basis within an NFAAT (while the Board Chairman would prefer Bipole III be included in the NFAAT review, the Vice-Chair would not).

While 100% of Keeyask G.S. capacity under maximum flow conditions requires additional transmission capacity, the Board is of the view that the Keeyask G.S. would still be able to operate at about 80% of maximum capacity even if Bipole III were delayed. A net present value analysis of natural gas (CCCT) generation for reliability purposes should explore the full range of possibilities for deferral of Bipole III.

When Drs. Kubursi and Magee suggested to the Board that MH should be focused on 'least cost scenarios' in exploring future power resource and export initiatives, it suggests that with current natural gas prices and low MISO Market prices, a natural gas (CCCT) generation scenario should be examined.

The Board is concerned about MH's inability to achieve significant (if any) premiums for clean energy in its pending export contracts When MH commits to providing substantially CO_2-free energy without a defined premium, future environmental protection costs can be expected to flow to MH's domestic customers via higher rates.

A further concern of the Board is that MH may be routinely selling hydraulic energy and purchasing mostly coal-generated energy in the same year. When MH accesses the

MISO market for the lowest-price energy, coal energy would, in off-peak periods, be the most likely source. This effectively negates the benefits of restricting the operation of the Brandon Coal Plant. The Board understands that under the WCC initiatives, the coal-fired imports would be assigned to MH. In these circumstances a natural gas CCCT could in effect, reduce, MH's GHG footprint.

Without a fully tested business case, through a detailed NFAAT proceeding, the Board will not support rate increases for recovery of future expenses related to MH's untested, and as of yet unapproved, capital plans.

5.0.0 CAPITAL EXPENDITURES

5.1.0 CONTEXT

MH's capital expenditures result in costs that must be paid through domestic consumer rates and/or export revenues. MH filed its Capital Expenditure Forecast (CEF) with the Board in support of MH's proposed rate increases. MH's major generation and transmission project capital costs stood at $16.0B in CEF-08 with essentially the same listing of specific projects as now contained in MH's proposed development plan. The budgets have now grown to an aggregate of $22.5B (and possibly to $23.5B).

The primary contributors to a $7.5B increase from CEF08 are:

- Bipole III – up $0.95B to $3.2B (40% increase / possibly 80% if Bipole III cost goes to $4.0B);
- Keeyask G.S. – up $1.94B to $5.64B (53% increase);
- Conawapa G.S. – up $2.79B to $7.77B (56% increase); and
- Pointe du Bois – up $1.1B to $2.94B (120% increase).

Bipole III with an east side alignment was proposed initially in 1990 to accommodate a 1,000 MW sale to Ontario at a cost of $1.7B. After that deal fell apart, MH explored HVDC wires only (no converters) on the east side to reduce Bipole I and II failure impacts from events such as occurred in October 1996.

However in CEF04, Conawapa G.S. resurfaced, along with a need for a Bipole III containing both wires and converters. In CEF07 a routing west of Lake Winnipeg was adopted with a budget of $2.25 billion. This budget remained unchanged for three years until March 2011, when a revised budget of $3.2 billion was issued as approved by MH.

There still remains doubt as to whether the Bipole III budget, with its current cost estimate of $3.2 billion, will prove accurate, or whether the forecast costs will again increase, to, say, $3.9 billion or $4.1 billion, or even higher.

The cost implications associated with the building and operating of Bipole III could be upwards of 3¢/kWh (maybe as high as 4.5¢/kWh) for moving 11,500 GWh of additional energy from Northern Manitoba to the south. These costs would be realized as Bipole III is constructed and would be recorded on MH's annual Operating Statement immediately upon Bipole III coming into service. In today's market conditions, it seems most probable that it would be domestic customers rather than MH's export customers that would pay for these costs. This would likely result in domestic rates for all customer classes materially increasing if or when Bipole III comes into service.

When MH was negotiating with NSP prior to 2009 to extend its contracts beyond 2015 and both MP and WPS were to sign new sales contracts extending beyond 2020, the average output cost of 4,400 GWh of new energy generated by a $3.7B Keeyask G.S. was estimated to be in the range of 7¢ to 8¢/kWh. Subsequently, in MH's latest forecasts, Keeyask G.S's projected cost increased by 25% in CEF10 and another 18% in CEF11. This constitutes an aggregate increase of 50%, which translates into a unit cost for produced energy of 10¢/kWh.

Similarly, in 2009 the average projected cost of 7,700 GWh of average new energy coming from a $5.0B Conawapa G.S. was 7¢/kWh. Subsequently, with the projected cost of building Conawapa having increased by 25% in CEF 10 and by another 25% in CEF11 (an aggregate increase of 56%), the cost of produced power from the proposed new plant has risen to about 9-10¢/kWh.

There were indications raised in the current hearing that the Term Sheet negotiations carried out in 2007/08 provided for contract prices associated with the expected NSP/WPS/MP sales that have not been increased in recent negotiations to reflect the increasing capital costs. Accordingly, those cost increases will not be recovered through higher export prices.

It appears to this Board that future project cost escalations between today's date and the in-service dates for the new facilities would similarly not be recovered by increases in average export contract prices. The Board faces the dilemma that without access to the export contracts, it has to rely on publicly available information. This information suggests that averaging the pricing of firm sales and opportunity sales will result in unit sales prices of no more than 6-7¢/kWh, reflecting both fixed prices and variable market-based prices. Such pricing would not recover the current estimated cost of producing power at either Keeyask G.S. or Conawapa G.S.

MH does not agree with the use of the initial in-service annual revenue requirement to define current rate impacts and suggests that longer term (50-100 year) levellized costs should be employed in determining the impact on domestic rates. This approach, if adopted by MH and PUB, has two implications:

- It would assign all new project costs to domestic customers; and
- It would result in the new export sale contracts enjoying the longer-term average prices despite the fact that the actual contract terms currently only extend to 10-15 years.

In short, it appears that MH prefers to consider revenue flows from export contracts linked to the construction and operation of new hydro-electric generating stations to be considered "incremental" revenue that is not subject to the full costing that usually applies to the consideration of new plants.

The Board is of the view that before proceeding with the construction of any of the new hydro-electric plants, and following an NFAAT, the Board should determine the potential rate impacts for domestic Manitoba customers with respect to these projects.

Otherwise, there is a genuine risk that domestic rates will rise sharply as the new generation and transmission assets currently planned come into service.

With respect to Bipole III, the views of the Chairman and Vice Chair differ. The Chairman is of the view that the same reasoning set out in the preceding paragraph applies to Bipole III. The Vice Chair accepts that Bipole III is required for reliability reasons at this point in time and that a delay until an NFAAT has been completed is not warranted.

5.2.0 CAPITAL FORECAST HISTORY OF MAJOR GENERATION AND TRANSMISSION PROJECTS

MH's capital estimates for major generation and transmission projects have shown significant periodic upward adjustments. This is illustrated in the following Table.

COST ADJUSTMENTS FOR MAJOR CAPITAL PROJECTS

Progression of Project Costs in $ M								
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF Mar/11
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275
Wuskwatim Transmission		199	200	257	320	316	316	291
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566
Herblet Lake Transmission	56	55	54	54	95	93	93	75
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	2,248[1]
Riel G.S.	96	101	103	103	105	268	268	268
Kelsey G.S.	121	121	166	166	184	190	190	302
Kettle G.S.		61	61	61	61	76	76	166
Pointe du Bois G.S.	421	288	692	834	818	818	318	398[2]
Pointe du Bois Transmission					83	86	86	86
Slave Falls G.S.				179	192	198	198	223
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771
Keeyask G.S.						3,700	4,592	5,637
500 KV Dorsey U.S. Border						205	205	205
Additional N-S Transmission								313
Total						16,034	17,781	20,524

[1] MH's currently approved Bipole III estimate stands at $3.2B.

[2] MH's latest Pointe du Bois estimate includes:

Spillway	$ 398M (2015/16 in-service)
Power House	$1538M (2030/31 in-service)
Total	$1936M

In total, the estimated major generation costs have risen from $16B in CEF-08 to $20.5B in the March 2011 CEF and more recently to approximately $22.5B.

5.3.0 CAPITAL COST INCREASES FOR EXPORT-DRIVEN PROJECTS

5.3.1 Overview

MH's Business Plan seeks to achieve about 40% of foreseeable future total corporate revenues from the export market. To do this, it is deemed essential by MH that the following projects proceed within the next 10-15 years:

- Bipole III (circa 2018/19)
- Keeyask G.S. (circa 2018/19)
- Conawapa G.S. (circa 2023/24)

MH's Recommended Development Plan was first defined in the 2008/09 Power Resource Plan and in CEF-08 focused on these 3 projects. Since then the costs have been adjusted upward as follows:

	CEF-08	CEF-09	MAR/2011 CEF	LATEST
BIPOLE III	**$ 2.25B**	**$ 2.25B**	**$ 2.25B**	**$ 3.20B to $4.1B [1]**
KEEYASK G.S.	**$ 3.70B**	**$ 4.59B**	**$ 5.64B**	**$ 5.64B**
CONAWAPA G.S.	**$ 4.98B**	**$ 6.33B**	**$ 7.77B**	**$ 7.77B**
TOTAL	**$10.93B**	**$13.17B**	**$15.66B**	**$16.61B to $17.5B**

[1] Not an officially endorsed estimate, but based on internal MH calculations.

5.3.2 Bipole III

Bipole III was originally identified (circa 1990) as a component of the Conawapa G.S. project to support a 1,000 MW major energy sale to Ontario Hydro. The intended route for Bipole III at that time was down the east side of Lake Winnipeg.

The project estimate was $1.7B for transmission lines and converter stations. When in the early 1990's energy demand and energy prices fell short of earlier expectations, Ontario Hydro elected to withdraw from the sales agreement and pay compensation for costs (access roads, cofferdams, etc.) that MH had incurred relative to the generating station. No decision had been made on the specific east side alignment for Bipole III.

In September 1996 a severe wind event (tornado or wind shear) destroyed towers on both Bipoles I and II. Given a favourable low demand time of year and a quick response by MH there was no "brown-out" and the revenue consequences were relatively low. However, the event did change MH's view of the reliability of and risk with respect to Bipoles I and II. In the subsequent years MH looked to achieve additional transmission capabilities that would reduce the risk of brown-outs.

In CEF03 and CEF04 MH proposed building HVDC transmission lines without converters on the east side of Lake Winnipeg. The lines were intended to address reliability concerns about a Bipole I or II failure and to reduce HVDC line losses. Project costs were estimated at $350 to $400M.

At the time of that proposal, concerns were raised with respect to the environmental and public acceptability of an east side alignment for Bipole III. Subsequently, MH began to explore the costs and implications of a Bipole III alignment west of Lake Winnipeg. The alternative of another HVDC line through the Interlake paralleling Bipoles I and II was rejected as possibly compounding the risks to existing facilities.

CEF-05 and CEF-06 both carried a $1.88B cost estimate for an east side routing. CEF-07 raised the costs to $2.248B to reflect a longer west-side location. MH did not revise the Bipole III cost estimate in CEF-08 or CEF-09 even though MH raised the capital cost estimates for Keeyask G.S. by $0.9B and for Conawapa G.S. by $1.3B. At the time MH cited 'sticker shock' as one of the reasons for the 25% jump in costs.

A September 2009 capital cost estimate for Bipole III surfaced in Q4 of 2010/11. It indicated that costs had risen to $3.9 B. This Capital Justification Addendum (CJA) estimate was initially deemed to have no official status. It was subsequently found to have been signed by MH vice-presidents on September 10, 2009. Reportedly, the CJA was not put forward to MH's Board.

In the spring of 2011, a new summer 2010 capital cost estimate of $4.1B was leaked to the media. At this hearing, MH denied that that estimate reflected the new projected capital cost. In January 2011 MH sought an independent review of Bipole III costs by Rashwan and Associates. Mr. Rashwan had previously been an employee of MH. The summer 2010 estimate was provided to him for his review. Rashwan (et al) reviewed the design concept and costs for the converter station and collector lines but not the HVDC transmission line. They concluded that MH could reduce costs by the elimination of contingencies that were to cover synchronous converters and the usually employed escalation costs. Incorporating these changes, MH provided a revised Capital Justification Addendum with a $3.2B total cost for Bipole III. This addendum was also signed by the vice-presidents of the same division within MH.

5.3.3 Keeyask G.S.

In the 2004/05 PRP MH's cost estimate for Keeyask G.S. was $1.7B. This cost was subsequently increased twice. The first increase was from CEF-08 at $3.7B to CEF-09 at $4.59B, representing a 25% increase. The second increase was from CEF-09 at $4.59B to CEF-10 at $5.64B. This represents a further 18% increase, for a total increase over the original estimate of 47.5%.

MH cited material supply and labour shortages (sometimes referred to as "sticker shock") as the primary cause of the pre-CEF-09 cost escalation. No specific causes have been identified for the most recent increases.

5.3.4 Conawapa G.S.

When (circa 1990) MH looked to building Conawapa G.S. in order to provide electricity to Ontario Hydro, the estimated construction cost for Conawapa G.S. was $3.8B. This cost was similar to the cost of $4.0B reflected in CEF-04.

CEF-05 and CEF-06 escalated the projected cost to $4.5B and $5.0B respectively. MH did not escalate the cost further in either CEF-07 or CEF-08. However, CEF-09 saw a 25% escalation from CEF-08 to $6.3B and CEF-10 saw a further 25% increase from CEF-09 to $7.8B. This represents a total increase of 56% over the CEF-06 estimate. MH has not provided any specific details to support these large increases.

5.3.5 Wuskwatim G.S. and Transmission

The CEC hearings circa-2004 on the Wuskwatim generation and transmission project dealt with a capital cost estimate of $900M. At the planned average output of 1,500 GWh per year, the electricity cost would have been approximately 6¢/kWh after the in-service date. As the project nears completion in 2011/12, the capital cost has risen to about $1.6B. The impact of this increase is that the cost to generate electricity will have risen to approximately 9¢/kWh when the Wuskwatim facilities come in service.

5.3.6 Pointe du Bois G.S. and Transmission

After MH purchased Winnipeg Hydro in 2001, it was anticipated that the Pointe du Bois G.S. could be upgraded circa 2011 at a cost of about $400M. The upgrade would have resulted in a modest increase in capacity and energy output. In the 2010/11 PRP, MH is looking at about $2.0B for a total rebuild of the power house and spillway by 2030/31. This would provide a 50% increase in capacity and an additional 150 GWh/yr of energy output for a total average output of 800 GWh/yr, but at cost increase of 300% compared to the 2003 estimate.

Assuming the existing Pointe du Bois G.S. would otherwise be decommissioned and written off, the average initial year new plant output cost at in-service would be 20-25¢/kWh. It should be noted that the spillway-related costs of $0.5B are essentially unavoidable even if the powerhouse were to be decommissioned.

5.3.7 Other Hydraulic Generation Upgrades or Retrofits

MH has plans to undertake the following additional capital projects:

- Kelsey G.S. Rerunning, with a capital cost increase of more than 50% in CEF Mar/2011 relative to CEF08. Limited capacity and energy gains are expected.

- Slave Falls Upgrade with a capital cost increase of only 12% from CEF08. No capacity or energy gains have been identified.

5.3.8 Wind Energy Purchases

MH currently purchases the entire output from the 100 MW St. Leon and 138MW St. Joseph wind farms. The contracts call for MH to buy the entire output from both farms at undisclosed but defined prices which are significantly higher than the current average price of MH's opportunity export sales.

5.3.9 Transmission Additions

MH has identified a need for the following additional transmission projects:

- Additional north-south transmission to supplement Bipole III operations at an initially estimated $313M.

- A 500KV Dorsey to US border intertie initially estimated at $205M in CEF08, a cost that has not changed through March/2011.

5.4.0 REVENUE REQUIREMENTS TO SUPPORT EXPORT-DRIVEN PROJECTS

When a generating station (or a unit of a generating station) comes into service, MH no longer capitalizes the related costs. Rather, the costs, including financing charges, operating and maintenance costs and depreciation expenses are charged through to consumers by way of MH's Operating Statement. MH then proposes rates to recover the costs as set out in the Operating Statement.

The Board calculates the likely annual in-service costs for the new major capital projects that that will be recorded on MH's Operating Statement to be as follows:

- Keeyask - approximately $500 million – in 2018/19;
- Conawapa - approximately $700 million – in 2024/25;
- Bipole III Transmission - approximately $300 million – in 2016/19.

While MH correctly points out that their annual costs will decrease over time, such a decrease is usually very gradual.

To the extent MH's real costs with respect to these projects are not recovered from export customers, it will fall to Manitobans to bear financial responsibility through reduced annual net income of MH (and reduced overall retained earnings) and increased electricity rates for Manitobans.

The Board does not accept that "levellized costs" should be used to assess cost impacts when major capital projects come into service. The Board understands that MH uses levellized costing in its long range planning. However, the Board must have regard to how costs are paid for by consumers. Consumer rates are not based on levellized costs – they are based on actual and real costs as reflected in MH's Operating Statement.

5.5.0 INTERVENER POSITIONS

In general, the Interveners in this hearing, citing the Board's restricted jurisdiction over approval of MH's capital expenditures, did not challenge the validity of MH's estimates for the cost of major generation and transmission projects. Despite the very substantial cost projection increases since 2004/05, none of the Interveners took issue with MH's calculation of potential additional revenue requirements over the next 20 years.

5.5.1 CAC/MSOS

CAC/MSOS took issue with MH's apparent lack of foresight and unwillingness to address in a timely fashion the substantial escalation of Bipole III capital costs.

CAC/MSOS recommended that in order to assist the PUB in understanding the risks associated with MH's planned capital projects and the extent to which these risks are addressed through contingency allowances in MH's capital cost estimates, it would be useful if the PUB required, as part of MH's initial filing in a GRA, the capital project justification forms established for each project with costs in excess of $100 million dollars. This would ensure that the Board is fully informed regarding the risks associated with a particular capital project and any allowances that MH has incorporated in the project's costs to address these risks.

However, citing the Board's lack of jurisdiction, CAC/MSOS did not specifically address the increased capital cost of either Keeyask G.S. or Conawapa G.S. and the potential rate implications.

5.5.2 MIPUG

Although MIPUG did inquire into the nature of the capital cost increases, MIPUG did not specifically explore the issue of the substantial capital cost escalation and the impact of that escalation on MH's customer rates.

5.5.3 RCM/TREE

RCM/TREE did not specifically explore the issue of capital cost escalations and the potential cost implications for domestic customers. RCM/TREE continued to support maximizing export sales through expanded DSM, inverted rates and discouraging domestic electricity use for home heating.

5.6.0 BOARD FINDINGS

5.6.1 Rate Implications of the Recommended Development Plan

The Board is of the view that with the substantial capital cost escalations currently known, MH's IFF09-1 portrayal of domestic rate implications is no longer valid. Further cost escalations cannot be ruled out, and given the current state of the export market, there are no foreseeable offsetting net export revenue gains.

It would appear obvious that Bipole III costing $3.2B instead of $2.3B would require an additional rate increase in 2019, and Bipole III costing $4.0B instead of $2.3B would require an even larger rate increase in 2019.

Similarly, the Board is of the view that Keeyask costing $5.64B instead of $4.59B would require an additional rate increase in 2019, and that Conawapa costing $7.77B instead of $6.33B would require a substantial further rate increase in 2026.

5.6.2 Capital Cost Escalation

The Board views, with considerable concern, MH's lack of a defined approach to updating major project costs. Delaying the use of updated cost estimates for administrative process reasons reflects poorly on the validity of MH's recommendations for future power resource developments.

Outdated estimates can make potential export contracts look overly favourable and subsequently have the potential to lead to higher domestic rates than envisioned. Furthermore, one would not expect to see commitments entered into with respect to major projects and large export contracts when the capital budget for the underlying projects has not been changed for three or four Capital Expenditures Forecasts to reflect cost increases.

As the Board understands it, when MH initiates export sales negotiations that require new generation and transmission facilities, the price of capacity and energy is a major component of the term sheet conditions. For MH and others to suggest that the project cost and subsequent escalations are not material to export contract prices would lead to the conclusion that all cost escalations are to be paid for by Manitoba ratepayers. The public record with respect to the project cost escalations discussed in this Order shows that the rate risk to ratepayers is high when capital cost updates are deferred.

5.6.3 Capital Cost Recovery from Export Sales

The Board is unaware of any explicit MH policies or procedures to ensure adequate capital cost recovery on facilities built or advanced for export purposes. If two- or three-year old capital estimates are used as the basis for export price negotiations, there is a significant potential for revenues and costs to be misaligned.

MH and its consultants have demonstrated reluctance to the premise that MH's in-service unit output costs from new generation and transmission projects should be fully recovered from the average price of energy in any firm energy export contract. In the Board's view, a failure to achieve full recovery amounts to an acceptance of inevitable increases in domestic rates.

The Board cannot understand how a portion of capital or finance costs related to a project can reasonably be deferred to allow for lower domestic rates in the absence of export pricing sufficient to fund the capital expenditures.

MH's position that Bipole III costs should entirely be paid for by domestic customers is not consistent with the reality that the building of Conawapa G.S., for which Bipole III would be built, in the time frame contemplated is in large part to satisfy export commitments. In the Board's view, it also ignores the reliability benefits that are extended to existing and future export contracts and ongoing market sales.

Prior to the construction of the Wuskwatim Generating Station, which comes into service this year, the last major generating station constructed by MH was Limestone G.S. some twenty years ago. Limestone G.S. has, with hindsight, turned out to be an excellent investment for Manitoba. However, the "Business Model" used with regards to Limestone may be a dangerous business model to use with regards to Keeyask G.S., Conawapa G.S. and the Bipole III transmission line.

When Limestone was constructed earlier than needed for Manitoba's domestic load, the output from Limestone was to be exported on the "spot market". Unfortunately, the cost of producing electricity from Limestone G.S. when it came into service in 1992 was approximately 2 ½ to 3¢/kWh at a time when the export market was returning less than that, so MH suffered a loss in its Net Income. Limestone only became a wise investment over time, as inflationary pressures and an increasing unregulated wholesale electricity market drove up prices – MH holds that the same result can be expected with the construction of Keeyask G.S. and Conawapa G.S., although many factors have changed over the past two decades that make that assumption questionable.

From a rate setting perspective, once a generating station (or any unit of a generating station) is placed in service, all of the fixed costs can no longer be capitalized and are added to the rate base to be recovered from domestic customers or from export sales. It is by the same rate setting principles that when Wuskwatim G.S. comes into service, MH's Operating Statement will record an additional $153 million per year of costs associated with producing about 1,500 GWh of energy per year. The unit cost of energy approximates 10¢/kWh.

Because Wuskwatim's output is not immediately needed for Manitoba load, its output is to be sold on the export market. Presently there is no fixed-price export contract for Wuskwatim G.S.'s output, which means that such output will be sold on the 'spot market' – a market currently returning prices approximating 3¢/kWh during peak hours and less than half of that amount during off-peak hours.

Because the $153 million per year of costs are real, and the spot export revenues will only cover less than a third of those costs, it falls to domestic Manitoba customers to cover the financial losses flowing from the operation of Wuskwatim G.S. Those losses will result in reduced Retained Earnings, higher consumer rates, or both.

While the Board acknowledges that the in-service costs will gradually decline over the years the generating station is in service, as the financing costs will fall as the principal balance of the debt assumed declines (and the annual amortization of the initial capital cost represents non-cash expenditures), such cost decreases are very gradual.

Manitobans will be responsible for any losses incurred on the reliance of the export market until the electricity is actually needed by Manitobans.

The very same accounting and regulatory principles apply to Keeyask G.S. and Conawapa G.S. With in-service unit costs of approximately 10¢/kWh for generation and export prices returning considerably less than that, Manitobans are to bear responsibility for the losses.

As for the Bipole III transmission costs, which will approximate 3¢/kWh for every kWh of electricity transported, without having access to the export contracts the question is whether all or some of the costs will be met by net profit from export contracts or will have to be entirely paid for by Manitoba customers.

MH's Business Plan of 'building for exports' contains serious, real and significant risks and costs for domestic Manitoba customers. The current Business Plan can be contrasted with MH's pre-2000 Business Plan when it proposed and planned to construct a 'merchant plant' (i.e., a plant built to serve the export market) to export the output to a counterparty by way of a fixed-price long term contract.

Because of the near-decade of lead time required to build a large hydraulic generating station, beginning in the early 1990s MH was considering building the Conawapa G.S. as a merchant plant and selling 100% of the plant's output to Ontario Hydro. MH's Business Plan at the time incorporated provisions whereby Ontario Hydro's payments would exceed the costs incurred by MH to construct and operate Conawapa, such that there was an expected net benefit (profit) to MH over the entire term of the export contract.

While this Board's jurisdiction does not extend to the approval of MH's capital expenditures, this Board does have jurisdiction over the approval of MH's rates in which MH seeks to recover the financing, operating and amortization expenses directly attributable to MH's capital expenditures. MH has taken the position that it is important that MH maintain an adequate level of retained earnings and that rates be raised gradually even during periods of exceptional water flows. It also stated that an adequate level of retained earnings provides funding for capital investments, which in turn reduces the need for borrowing and reduces the financing costs that ultimately must be recovered from ratepayers.

Against the backdrop of different types of business plans, together with the apparently skyrocketing capital costs of Keeyask G.S., Conawapa G.S. and Bipole III, together with a depressed export market and Manitoba consumers being held financially responsible for any losses, the Board is of the view that MH's capital projects require careful and detailed scrutiny. The Chairman is of the view that this scrutiny should apply to both generation and transmission facilities. In the Vice Chair's view, while scrutiny is required for all projects whose primary current purpose is to meet export demand, Bipole III should not be delayed as it is required for reliability purposes.

Scrutiny of MH's projects has, in essence, been promised by MH when it produced confirmation from the Province of Manitoba that an NFAAT hearing similar to the one held for Conawapa G.S. in the early 1990s and Wuskwatim G.S. in the early 2000s is to occur.

Due to the hundreds of millions of dollars the Province derives from MH, the risks that will be borne by MH's domestic customers, and due to the economic and financial factors to be tested, such an NFAAT ought to be conducted by an independent tribunal with considerable expertise in the subject issues.

6.0.0 OPERATING RESULTS

6.1.0 OVERVIEW

In support of its GRA Application, MH filed its Integrated Financial Forecast (IFF) 09-1 for its electric operations, as well as its Capital Expenditure Forecast (CEF) CEF 09-1, both covering fiscal year periods 2009/10 to 2019/20. Updated forecasts (IFF 10-1, IFF 10-2 and CEF 10) were also filed over the course of the hearing. IFFs and CEFs are prepared to provide an indication of the long-term financial direction and plans of the Corporation, and are based on numerous assumptions.

MH's actual results for fiscal year 2009/10 and its updated forecast for fiscal year 2010/11 reports or forecasts that accumulated net income for the fiscal years from 2009/10 up to and including 2011/12 will be $148 million higher (pursuant to IFF 10-1) than was indicated in IFF 09-1. IFF 09-1 forms the basis of the Application before the Board.

The projected improvement in accumulated net income and retained earnings (retained earnings represent MH's "equity" or invested capital) was attributed primarily to lower than forecast depreciation, finance expenses and fuel & power purchase costs. The forecast results also represent a continuation of MH's accounting practice of capitalizing and deferring expenses incurred in current and past periods associated with the Corporation's plans to construct additional generation and transmission assets. The following table provides an overview of MH's actual and forecast revenues and expenses.

Manitoba Hydro's Revenues and Expenses, 2008-2012

Statement of Operations & Retained Earnings ($ Millions)	Actual			IFF10-1		
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**Total 2008-2012**
Revenue						
Domestic	1,006	1,014	980	1,006	1,048	
Estimated PUB Approved Increases	77	130	162	195	224	788
Export	625	623	427	444	461	
Total Revenue	1,708	1,766	1,569	1,645	1,733	
Expenses	1,371	1,478	1,409	1,496	1,612	
Non Controlling Interest					4	
Net income(loss) Actual/[IFF 10 -1]	337	288	160	149	125	
Compared to 2008 GRA Forecast						
Net income (loss) [IFF 10 -1]	264	156	105	116	114	
Net income difference	73	132	55	33	11	304
Retained earnings Actual[IFF 10 -1]	1,790	2,078	2,238	2,354	2,479	
Retained earnings [IFF07-1]	1,735	1,891	1,996	2,112	2,226	
Cumulative Retained Earnings difference						
2008 GRA vs. 2011 GRA	55	187	242	242	253	
Debt:Equity Ratio	76:24	75:25	74:26	74:26	74:26	

Note: Board-approved increases granted in prior Applications: 5% effective August 1, 2004 (a $48 million addition to annual revenue); 2.25% effective April 1, 2005 ($21.8 million of additional annual revenue); and 2.25% effective February 1, 2007 (an additional $23.0 million of annual revenue). The interim increases provided as of April 1, 2010 and 2011 represent a further addition to annual revenue of, in aggregate, approximately $62 million.

MH's financial position since the 2008 GRA is projected by MH to have improved by approximately $253 million for the fiscal years 2007/08 up to and including 2011/12. A major contribution to this improved financial position has been Board-approved rate increases which have generated over $788 million in accumulated additional revenue. Since 2004/05, over $950 million in additional revenue has been realized by MH from Board-approved domestic rate increases (this represents over one-third of MH's retained earnings).

6.2.0 FORECAST UPDATE

Two forecast updates were provided during this hearing. IFF10-1 reflected a reduction in the near term for interest rates, but the most significant change was material increases in the capital costs for both the Conawapa G.S. and Keeyask G.S. The capital cost estimate of Keeyask was increased from $4.6 billion to $5.6 billion. For Conawapa G.S., the estimated cost of construction increased from $6.3 billion to $7.7 billion. On an overall basis, the capital costs for MH's major generation and transmission projects have increased in excess of $2.6 billion dollars in IFF10-1 compared to IFF09-1.

This second update, set out in IFF10-2, reflects increases to the projected capital cost of Bipole III. The capital cost projection for Bipole III forecast in IFF09-1 and IFF10-1 was $2.2 billion. The forecast was revised to $3.2 billion over the course of this hearing, an increase of $1 billion from previous forecasts. Although other forecasts prepared internally by MH saw the cost exceeding $4 billion, MH adopted the lower estimate. The implications of this $1 billion increase capital costs were reflected in IFF 10–2. The following chart provides a comparison of the net income forecast during the outlook period in IFF09-1 with the updates provided as follows:

NET INCOME FORECAST CHANGES – IFF09-1 TO IFF10-2

Net Income- Electric ($ Millions)				
Year Ending March 31	MH09	MH10-1	MH10-2	Comparison MH10-2 vs. MH09
2010	$121	$163	$163	$42
2011	$78	$149	$149	$71
2012	$87	$125	$125	$38
2013	$72	$120	$121	$49
2014	$125	$184	$187	$62
2015	$113	$142	$145	$32
2016	$248	$217	$219	($29)
2017	$263	$267	$267	$4
2018	$235	$273	$218	($17)
2019	$244	$225	$111	($133)
2020	$276	$292	$187	($89)
2021	$299	$109	($1)	($300)
2022	$439	$351	$233	($206)
2023	$544	$443	$319	($225)
2024	$732	$512	$382	($350)
2025	$791	$631	$493	($298)
2026	$911	$597	$449	($462)
2027	$1,005	$692	$538	($467)
2028	$1,116	$796	$637	($479)
2029	$1,224	$906	$741	($483)
Total	**$8,923**	**$7,194**	**$5,683**	**($3,240)**

The successive increases in capital costs have resulted in an increase in long-term debt and related increase in finance expenses. Long-term debt was forecast in IFF09-1 to be $17.7 billion in 2029. The estimate was revised up to $21.2 billion in 2029 in IFF 10–1 and was further increased to $23.0 billion in IFF 10–2. The capital costs and the respective debt to support the increased costs result in increased operating and finance costs over the outlook period. Finance expenses in 2029 were forecast to be $980 million. Since then, they have increased to $1.2 billion in IFF10-1 and further increased to $1.4 billion in IFF10-2. Between IFF09-1 and IFF10, finance expenses in 2029 (by which time all major generation and transmission projects will have come into service) have increased by over $403 million annually.

The forecast increase in expenses from IFF09 to IFF10-2 has led to a reduction of forecast net income over the period from 2010/11 to 2028/29 by over $3.2 billion.

MH has established the export price assumptions used in its forecasts from independent forecasts provided by ICF and others. During this hearing, ICF presented information indicating a forecasted reduction in natural gas prices of 40% from previous forecasts due to abundant shale gas that can now be extracted through new technology. Shale gas is a source of natural gas that was previously uneconomic to extract. However, with new technologies, shale gas is now capable of being extracted in large quantities at low costs.

MH exports into the MISO market. Electricity generated from natural gas forms the basis of establishing marginal peaking prices in the MISO market 10% to 50% of the time. The balance of the time, MH's opportunity export prices are established by the coal generation prevalent in the MISO region.

Prior export price forecasts provided by ICF were predicated on the establishment of a U.S. carbon regulatory regime, which would increase the cost of electric coal generation. No such regime has emerged to date, and ICF has revised the timing and extent of any carbon regulatory pricing in the future downward materially.

This change in perspective on natural gas pricing and a carbon regulatory regime is not reflected in the current IFFs presented at this hearing. The issues related to export pricing are discussed further in section 5.6.0 of this Order.

6.3.0 INTERVENER POSITIONS

6.3.1 CAC/MSOS

CAC/MSOS noted that the improved actual net income for 2009/10 was $164 million. This compares to only $121 million forecast in IFF09-1, which formed the basis of MH's application. Net income in IFF10-1 for 2011/12 is now forecast to be $149 million versus $78 million in IFF09-1 and $125 million versus $87 million (IFF09-1) in 2011/12. The combined forecast improvement of $109 million more than what was forecast for those years in IFF09-1 suggests that the interim rate increases granted by the Board should be reduced.

6.3.2 MIPUG

MIPUG submitted that it does not oppose final confirmation of the two interim rate orders granted by the PUB in this proceeding. MIPUG did recommend that MH be directed to do a small rebalancing of rates, on a go-forward basis from the date on which rates are finalized, among domestic rate classes in recognition of differences in revenue to cost ratios. MIPUG's experts Mr. Bowman and Mr. McLaren opined that in general terms, rate increases in the order of inflation are understandable, so long as they are merited and defensible in terms of MH's cost structure and fairly distributed across the different rate classes.

6.3.3 RCM/TREE

RCM/TREE submitted that the interim rates should be approved as the final rates, and a further 0.9% increase from the date of the final order should be allowed. RCM/TREE further submitted that the PUB should also consider an interim rate increase for 2012/13 of 3.5% subject to a hearing for the April 1st 2013 period.

RCM/TREE also sought reintroduction of an inclined rate structure, with a change in the block size to reduce the first block. RCM/TREE further sought MH to identify electric heat customers by using a methodology suggested by this Intervener, and that MH implement a larger first block structure for these customers over the winter heating period, as proposed by Mr. Chernick.

6.4.0 BOARD FINDINGS

These findings need be read in conjunction with the Board's findings on Rates as set out in section 3.0.0 of this Order.

The Board notes the marked improvement in net income in the test years from what was forecast in IFF09, which formed the basis of the Utility's application. With the finalized rate increases approved in this Order, the fiscal health of MH in the test years (2010/11 and 2011/12) has never been stronger in MH's 60-year history.

The Board notes that MH has attained its 75:25 debt-to-equity target, a target it will "slip away from" in the next several years. The Board has grave concerns with the long-term outlook reflected in IFF 10–2.

The Board notes that over the course of two successive updates to IFF09, the increase in capital costs of Keeyask, Conawapa and Bipole III and related increased debt levels now see a 'build' price tag in excess of $20 billion, with long-term debt previously forecast to be $17 billion now over $23 billion. This higher forecast debt level and higher associated carrying cost (now to reach over $1.4 billion) has eroded the forecast profitability during the forecast period by $3.2 billion.

The Board understands that MH's forecasts are used to underpin the justification for the new major generation and transmission projects. While they reflect increased capital costs, they do not reflect the downward change in export prices that has occurred since 2008. The forecasts further do not reflect a sustained strengthening of the Canadian dollar or the lower prospects for export prices given the new realities of inexpensive and abundant shale gas, which is a common feedstock for low-cost electric generation in the markets into which MH exports. Nor does the forecast reflect the potential new reality of a low- or no-carbon regime in the export markets into which MH sells its electricity.

Abundant coal with no carbon adder and abundant natural gas will have a dampening effect on export prices in the MISO market. Given that MH is a price taker in the MISO market, lower generation costs in the export markets could have a material impact on MH and its potential export revenue. Neither of these potential realities are reflected in the forecasts presented to the Board at this GRA.

The Board requested MH to provide additional IFF scenarios, to explore the impact of such circumstances on ratepayers. They were not provided, and as noted in section 5.6.0 of this Order, MH's capital plan has not yet been tested by an NFAAT.

7.0.0 EXTRA-PROVINCIAL REVENUES

7.1.0 OVERVIEW OF SALES AND REVENUES

As can be seen from MH's IFFs, extraprovincial revenues are to constitute a significant percentage of MH's total revenues.

MH'S sales into the U.S. MISO Market and into other Canadian provinces over the last decade are summarized in the following table.

MH'S EXPORTS INTO MISO/CDN PROVINCES (GWh)

	MISO Dependable	MISO Opportunity	MISO Total	Non Merchant CDN Sales	Total Sales
2000/01	4895	4511	9406	3047	12453
2001/02	4767	5083	9850	2449	12299
2002/03	4947	2713	7660	2075	9735
2003/04	5245	507	5752	1214	6966
2004/05	5683	3218	8851	1680	10431
2005/06	4044	8879	12923	1424	14347
2006/07	3654	5877	9531	373	9904
2007/08	3921	7332	11053	682	11735
2008/09	4087	6071	10158	418	10576
2009/10	2613	6218	8831	336	9167

To supplement its own generation, MH has typically imported wind and thermally generated energy at the range of 1,500 to 3,000 GWh per year. Major exceptions were 2002/03, when the total imported was 3,800 GWh and 2003/04 when the total imported was 10,500 GWh.

With existing transmission intertie bottlenecks and constraints due to MISO capacity and hydraulic generation capacity, MH is typically limited to about 7,000 GWh/year of peak energy export sales. Except for 2008/09, the peak firm and opportunity sales have, over the last 10 years, accounted for approximately 2/3 of MH's annual exports. The remaining 1/3 were off-peak sales to the MISO market and within Canada.

During the past ten years, MH achieved average annual export prices of about 5¢/kWh. From 2004/05 to 2008/09, firm contract prices were 5 to 6¢/kWh, opportunity peak prices were 6.5 to 7.0¢/kWh and opportunity off-peak prices were 2.5 to 3.5¢/kWh. The situation changed in 2009/10, after MH's IFF09-1 was prepared. In IFF09-1 and IFF10 MH assumed average export revenue rates as follows:

COMPARISON OF AVERAGE EXPORT REVENUE RATES
IFF09-1 VS. IFF10-2

	Actual (¢/kWh)	IFF09-1 (¢/kWh)	IFF10-2 (¢/kWh)	Difference (¢/kWh)
2006/07	5.86			
2007/08	5.64			
2008/09	4.37			
2009/10	3.93			
2010/11	3.84	4.10	3.26	- 0.84
2014/15		7.40	6.63	- 0.83
2015/16		9.09	8.11	- 0.98
2019/20		10.56	10.84	+0.28
2020/21		10.66	11.12	+ 0.46
2021/22		10.94	11.13	+ 0.19
2025/26		12.25	12.20	- 0.05
2026/27		12.64	12.58	- 0.06
2028/29		13.45	13.45	Ø

IFF09-1 export price assumptions reflect the input provided to MH by a panel of external consultants in 2008. ICF, one of the consultants on the MH panel, provided evidence at this hearing that the natural gas prices employed by ICF's forecast in 2008 would currently be about 30-40% lower, and that electricity prices in the MISO market would also be lower. However, MH did not adjust these variables from IFF09-1 to IFF10-2.

7.2.0 THERMAL GENERATION COST ASSUMPTIONS

A comparison of MH's IFF assumptions on Single Cycle Combustion Turbine (SCCT) thermal generation costs leads the Board to conclude that MH did not significantly reduce the energy prices in IFF10 from IFF09-1 and may have increased that price from 2021 onward.

7.3.0 MH INFLUENCE ON EXPORT/IMPORT PRICING

MH has suggested that in the broader MISO market, a substantial decline in MH's energy surplus would not be noticed and hence no shortage pricing would develop. This does not seem consistent with the 2002/03, 2003/04 and 2006/07 drought events when prices did increase significantly. MH's argument that opportunity sale prices are depressed during extended high flow periods would also suggest the opposite, namely that less energy in the market should translate into higher prices. In recent years, MH has been regularly selling off-peak energy into the MISO market at prices as low as 0.5¢/kWh.

7.4.0 EXISTING 500 MW NSP EXPORT CONTRACT

MH's existing contract with NSP calls for MH to supply and NSP to purchase 2,086 GWh in each 12-month period. This amount equates to 5x16[2] energy on an annual basis or an average of 174 GWh per month. Payment for this power is based on both an energy charge and a demand charge.

In 2010/11 it appears that MH sold 2,960 GWh of firm energy into the MISO market at an average price of 5.14¢/kWh, including NSP sales of 1,970 GWh.

[2] Power supplied for the 5 weekdays, between 6 AM and 10 PM (16 hours)

7.5.0 OTHER REVENUES/COSTS

7.5.1 Merchant Trading

MH has in the past purchased energy in the MISO market for resale into Ontario by employing committed transmission services. The Board understands that MH has or will be discontinuing this low net revenue activity.

7.5.2 Ancillary Services

With the advent of an ancillary service market in MISO, MH is anticipating a high level of activity in providing capacity support within the MISO Market. The profitability of these services is currently uncertain. MH's IFF is apparently treating this as a break-even activity.

7.5.3 Transmission Tariffs

Under the open access transmission tariff, MH receives revenue for energy flowing through Manitoba, but MH also pays for transmission which flows through other transmission systems. Overall, this is resulting in a small net revenue gain.

7.5.4 NEB/MISO/FERC/NERC Costs

MH incurs membership costs with respect to business activities in the US. These can be related to both exports and imports, even though the level of export activity typically greatly exceeds the import activities. MH contends that an equal sharing is appropriate.

7.6.0 INTERVENER POSITIONS

7.6.1 CAC/MSOS

CAC/MSOS submitted that it is concerned with the significant variance of export revenue forecasts from actual export revenues.

7.6.2 MIPUG

There were no direct challenges by MIPUG of MH export revenue pricing. Rather, MIPUG supported MH's process of determining future export market prices and the need for secrecy with respect to firm contract pricing.

7.6.3 RCM/TREE

RCM/TREE noted that all of the risk experts appeared to be using out-of-date term sheets as the basis of MH's potential exports revenue position. It also noted that rather than adopting a skeptical review approach, the risk experts accepted the positions adopted by MH in conducting the risk analyses.

It was RCM/TREE's view that there should be a transparent correlation of MH's export pricing (contract and opportunity) to energy production costs. A rate-rider to track MH's unit export revenue in excess of costs was suggested.

7.7.0 BOARD FINDINGS

Going back to Board Order 116/08, the Board had concerns that MH's export revenue pricing forecasts, provided in the preceding 2008 GRA and in the 2008 EIIR application, were overly optimistic. Those forecasts assumed high natural gas supply prices in the future (up from $10.30/GJ in 2005) and, perhaps more significantly, an early introduction of substantial CO_2 emissions pricing.

Based on current market conditions and ICF's forecasts, it is the Board's view that the potential average export sale price may be substantially below MH's IFF09-1 and IFF10 assumptions over the next decade. Faced with continuing to make off-peak sales at under 1¢/kWh on a protracted basis, and contract prices likely below 6¢/kWh until 2015, MH's prospects for average export prices appear to be in the 3 to 4¢/kWh range.

Going forward, without any CO_2 pricing and a continuation of low shale gas prices, MH must compete with off-peak coal energy at 2-3¢/kWh (or wind at possibly even lower prices) and natural gas CCCT generation in the peak periods at prices in the 5-7¢/kWh range. Even with new contract prices of 8-9¢/kWh for peak energy volumes equal to about 1/3 of MH's exportable energy, the average export prices could be dragged down to around 5¢/kWh by low opportunity sale prices.

The IFF09-1 export revenue pricing (based on advice from an external consultant panel) prepared in 2008 did not reflect the lower natural gas prices (with shale gas availability already being experienced) or the major resistance to CO_2 emissions pricing in the US. Despite the ICF testimony at this hearing, which laid out a significantly lower future natural gas price outlook for October 2010 than in February 2009 and confirmed the suggested deferral of CO_2 emission pricing, MH did not significantly alter the IFF10 export revenue assumptions from those used in IFF09-1. This places the reliability of the IFF10 forecasts into doubt.

The Board notes that MH has, to date, declined to provide any alternative IFF scenarios based on lower natural gas prices and the absence of CO_2 emissions regulations. Overall the Board does not accept MH's export revenue forecasts to date as representing a realistic basis for determining the economic viability of the proposed new major generation and transmission facilities such as Keeyask, Conawapa and Bipole III.

The Board no longer considers IFF09-1 as providing a 'valid' picture of MH's financial position. If MH continues with its preferred development plans, the Board concludes ratepayers will undoubtedly pay higher future domestic rates than indicated in IFF09-1 or IFF10-2.

Without access to MH's export contracts, and given the current market conditions, the Board is not convinced that MH will achieve the export revenue assumed in the existing IFFs. IFF09-1 electricity export revenue forecasts were based on 2008 circumstances, presumably by using ICF's predicted natural gas prices at the time. These predated the advent of shale gas pricing, the collapse of the planned CO_2 emission charges regime and the economic downturn in the economy.

With ICF's revised natural gas prices being 30-40% lower (based on its revision made on Oct.20, 2010), the forecast electricity prices for CCCT generation could be significantly lower, as the fuel cost portion of those prices would decrease materially.

While MH has declined to provide an IFF based on PUB/MH/PREASK-4 export electricity pricing assumptions, MH has not refuted the proposed pricing scenario. About 65% of IFF09-1 pricing assumptions are relatively consistent with the implications of ICF's revised natural prices, when applied to CCCT generation variable prices.

In the Board's view the IFF09-1 and IFF10-2 export revenue assumptions are not reflective of the current and near term energy market. As such, the suggested progression of rate increases would be inadequate to cover MH's CEF09 Major Capital Expenditure Program. When the major project cost escalation is also considered, the insufficient revenue is substantially magnified. The Board would suggest that the cumulative rate increase requirements by 2025/26 would be significantly greater than the 57% forecast by MH, and quite possibly roughly double MH's forecast.

The Board acknowledges that MH could look to lesser rate increases by accepting lower annual net incomes, lower retained earnings and higher debt levels. However, such actions and results would negatively affect MH's financial ratio targets.

In the Board's view it is crucial that expert analysis and independent scrutiny of the major capital projects be undertaken before making any irreversible commitments, as MH has attested that it has been spending $1-2M per day on its "preferred development plan" even though that plan has yet to be tested.

8.0.0 FINANCE EXPENSES

8.1.0 INTEGRATED FINANCIAL FORECAST 2009 (IFF-09)

MH's borrowings result in its finance expense being the Utility's single largest expense item. Finance expenses were $401 million in 2009, representing over 29% of total operating expenses. They were forecast in IFF09-1 to be $417 million in 2010. Actual finance expenses decreased to $373 million in fiscal 2009/10. MH had forecast finance expenses to be $413 million in 2011 and increase to $468 million in fiscal 2012, representing 25% of annual operating expenses.

In IFF09-1, MH's typical practice is to base the forecast level of finance expenses on anticipated levels of borrowings exclusively based on 30-year fixed term debt. Such an approach does not recognize that a portion of the debt issued would be shorter-term floating debt with lower interest rates than 30-year debt. In the normal course of operations, MH issues both floating rate debt and long-term fixed rate financing. This reality was addressed in IFF10-1, whereby MH has now assumed that 20% of its forecast debt issues would be floating rate debt issues. MH has a target range of maintaining 15% to 25% of debt in floating rate instruments to minimize debt costs without undue interest rate exposure.

MH capitalizes interest on all capital projects during the construction phase until the project is in service. Based on IFF09-1, by 2029 Manitoba Hydro is forecasting to capitalize over $4.8 billion in interest costs.

As the major new generation and transmission projects commence construction, MH will be capitalizing a greater proportion of interest costs. Gross interest expense is forecast to be over $1 billion in 2018, of which $449 million or 43% will be capitalized. Once all major projects are completed, this high level of interest cost will need to be recovered through rates, supported by higher levels of revenue from the new generation capacity.

8.2.0 IFF10-2

MH provided an updated IFF10-2 which indicates the capital costs of the major generation and transmission projects have increased by $3.6 billion. Higher levels of debt, now to exceed $23.4 billion by 2026, will support this higher level of capital spending. This represents an increase in debt of over $5.4 billion from what was forecast in IFF09-1.

Based on IFF10-2, the updated forecast reflects reduced interest rates in the near term. Finance expense is forecast to grow by $411 million to over $1.5 billion by 2026 (up from $1.1 billion forecast in IFF09-1) when the last of the major new Generation and Transmission projects, Conawapa, is expected to be in-service.

Based on the updated cost estimates in IFF MH10-2, MH's debt is forecast to grow from $8.7 billion in 2011 to $22.9 billion in 2030, an increase of $14.2 billion. This is $5.2 billion higher than the debt level forecast in IFF09-1.

8.3.0 INTERVENER POSITIONS

CAC/MSOS noted that the level of finance expenses represents the largest component of expense in the forecast and is expected to grow. CAC/MSOS adopted the evidence of Mr. McCormick, which recommended that the Board reject the assumption used in IFF09-1 that all new debt issues would be long-term 30-year fixed rate debt and incorporate a forecast that recognizes a policy to maintain a range of short-term debt in determining interest rate forecasts. Incorporating a short-term debt component as a forecasting element would result in a significant interest rate reduction in the forecast. Mr. McCormick acknowledged that changes made in the forecasting methodology employed in IFF10 addressed this concern. However, the GRA, which is based on IFF09, does not reflect this change.

Mr. McCormick identified four elements which are required to adequately forecast financing expenses, including:

(a) reconsideration of the composition of fixed and floating debt;

(b) assumptions respecting interest rates;

(c) currency of the debt issue; and

(d) term to maturity of the underlying debt.

In MH's IFF10-2 there is reference to an enhancement to MH's longstanding forecasting approach of assuming all new debt is to be fixed for 30 years at 10 years plus rates. However, the 20% floating rate, argued CAC/MSOS, will still tend to bias the results. Mr. McCormick opined that he would much rather see consumers paying rates in the 2011/12 test year based on what we know today about the forecast rates, as they are much more current rates, as opposed to superseded rates. Further, noted Mr. McCormick, updated rates are indicative of significant excess interest costs being forecast in the revenue requirement. Mr. McCormick noted in his report that there is no "free money", and that excessive reliance on the certainty of long-term fixed debt comes at a material cost in terms of lost opportunity for lower debt costs.

CAC/MSOS recommended the establishment of an interest rate deferral mechanism as proposed by Mr. McCormick. The interest rate deferral account would capture the difference between forecast and actual finance costs, addressing forecast differences in interest costs. CAC/MSOS proposed that MH be advised that the extent of any corporate recoveries from the deferral account mechanism would be contingent on a determination that MH has been managing its financing costs prudently.

8.4.0 BOARD FINDINGS

MH plans on borrowing an additional $15 billion to support its development plan, thereby increasing MH's overall debt level to over $23 billion.

The Board notes that in IFF09-1, MH planned on increasing borrowings by $10 billion to over $17.7 billion. The revisions in IFF10-1 and IFF10-2 have increased the borrowing requirement by 50%. These borrowings come at a cost to MH in terms of carrying costs, a significant percentage of which is currently being capitalized.

The situation is exacerbated by continued cost escalation of the major generation and transmission projects. Capitalized interest may well be over $5 billion when all developments are complete. Once developed, the ratepayers will have to cover both higher interest carrying costs as well as higher amortization charges related to the developments, regardless of the income generated from the new assets.

As stated in Order 99/11, current ratepayers are being spared the increased finance expense in rates, yet decisions made currently will impact future ratepayers. These financing costs, which are currently being capitalized, will have to be supported by higher domestic rates when the projects come online and the capitalization of finance expense is no longer appropriate.

The Board remains concerned that interest rates at historical lows will likely increase when spending ramps up on the developments, resulting in higher than forecast levels of capitalized interest and finance expense.

The Board remains concerned with the impact of further capital cost escalations. As it now stands, annual carrying costs that will need to be covered from rates will top $1.5 billion in 2029, $400 million more per year than what was contemplated in IFF09-1.

As the cost of the major capital expenditures program escalates (as demonstrated in the recent updates which saw an increase of over $3.6 billion from the IFF 09-based estimate), the escalations will result in debt levels being increased by over $5.4 billion, and, ultimately, in higher finance costs which will have to be recovered from domestic ratepayers.

The forecast level of interest costs, when these projects are in service, has increased materially while the capacity to service these additional costs has not changed. MH negotiated much of the new contracts before the escalation in capital costs appeared. It is unlikely that the counterparties to the deals would be interested in paying any more than what has been negotiated due to an increase in the costs for MH to deliver the power.

There are no assurances that the current capital cost estimates will hold. Given the successive annual updates, the Board remains concerned that the economics related to these developments may be diminished. As such, it is important that MH be involved in an NFAAT process which will independently look at the economics of the proposed plans before any final development commitment are made.

The Board believes that the adoption of an interest rate deferral account is not appropriate at this time. The Board further believes that the changes in the assumed debt financing in IFF10-2 are an improvement to forecasting finance expense.

9.0.0 OPERATING AND ADMINISTRATIVE EXPENSES

9.1.0 OVERVIEW

Operating and maintenance expense (also referred to as O&A, OM&A, or operating, maintenance and administration costs) is one of MH's three largest expense categories in any given year. Over 75% of MH's O&A relate to labour costs, including employee benefits. The actual and forecast operating and administrative expenses for fiscal years 2008 to 2012 are as follows:

Operating and Administrative Costs ($Millions)

	Actual			IFF10-01	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Labour and Benefits	$477.8	$509.9	$541.0	$556.3	$569.1
Other Expenses	$160.8	$177.30	$182.0	$183.9	$186.5
Total Costs	**$638.6**	**$687.2**	**$723.0**	**$740.2**	**$755.6**
Operating and Administration Charged to Centra	($56.3)	($59.0)	($61.0)	($63.4)	($64.0)
CICA Accounting Changes		$5.0	$9.0	$9.0	$9.0
Provision for Accounting Changes				$18.0	$13.5
	$582.3	**$633.1**	**$688.0**	**$703.8**	**$714.1**
Capital Order Activities	($192.3)	($203.1)	($224.3)	($235.0)	($239.7)
Capitalized Overhead	($67.3)	($65.7)	($69.2)	($71.0)	($72.5)
Total Capitalized	($259.6)	($268.8)	($293.5)	($306.0)	($312.2)
O&A Attributable to Electric Operations	**$322.7**	**$364.3**	**$377.6**	**$397.7**	**$401.9**

O&A, before capitalized expenditures, has increased from $582.3 million in 2008 to $688 million in 2010. O&A expenditures were forecast to grow from $703.8 million in 2011 to $714.1 in 2012.

MH capitalized $259.6 million in 2008 or over 55% of O&A costs in that year. The level of capitalized O&A increased to $293.5 million in 2010 and MH is forecast to capitalize $306 million (43%) in 2011 and $312.2 million (44%) in 2012.

From 2005 through 2010, MH's O&A expenses have grown at a compound average growth rate of almost 5% annually while inflation for that period has been under 2%.

MH had forecast O&A to be $380 million in 2011 and $403 million in 2012 based on IFF09-1, the basis for this Rate Application. MH provided an update at the hearing with IFF MH10-1, where O&A expenses are revised to $397.7 million in 2011 and $401.9 million in 2012, as reflected in the above table. MH attributed the increases in part to accounting changes since 2009 to comply with International Financial Reporting Standards (IFRS).

9.2.0 STAFFING LEVELS

A major driver in the increase in O&A expense is due to increased staffing levels which are projected to grow from 5,769 Equivalent Full Time (EFTs) in 2004 to 6,669 EFTs, an increase of 900 EFTs or over 15%. The change in MH staffing by division since 2004 is as follows:

**EQUIVALENT FULL TIME EMPLOYEES –
ANNUAL RESULTS BY BUSINESS UNIT**

Fiscal Year March 31,	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011 & 2012 Forecast**	**Change 2004 to 2012**
President & CEO	86	84	82	84	87	87	97	99	13
Corporate Relations	43	49	62	67	69	75	69	69	26
Corporate Planning & Strategic Analysis	18	18	19	20	19	20	23	38	20
Finance & Administration	1,025	1,032	1,029	999	986	999	1042	1,043	18
Power Supply	1,287	1,344	1,366	1,405	1,470	1,576	1,757	1,785	498
Transmission	1,207	1,208	1,221	1,233	1,255	1,298	1,355	1,358	151
Customer Services & Distribution	1,565	1,605	1,647	1,617	1,640	1,671	1,708	1,711	146
Customer Care & Marketing	538	527	552	563	545	550	561	566	28
Total	**5,769**	**5,867**	**5,978**	**5,988**	**6,071**	**6,276**	**6,613**	**6,669**	**900**

This increase in staffing levels was defended by MH as due to increased work requirements. The staffing level increases are due in part to the capital expansion plans of the Corporation, as a large number of those hired were to work on capital projects.

The last time MH expanded its generation capacity was in 1993/94 with the building of Limestone G.S.. At that time, MH had an EFT complement of 4,232, including 940 construction employees. Since then, the complement has grown significantly, well beyond the increases arising out of the acquisitions of Centra and Winnipeg Hydro. As at March 31, 2011, MH had a staffing complement of 6,299, which included 1,439 construction employees. The employee level has grown by over 2,067 EFT (over 48%) since 1993, with the number of construction related positions increasing by 499 EFT (over 53%) from 1993 levels.

9.3.0 CAPITALIZATION OF OPERATING AND ADMINISTRATIVE EXPENDITURES

MH capitalizes certain operating and administrative expenditures. MH segregates costs between operating activities (which are a direct charge against the operating income for the year) and capital activities (which are charged to future periods and amortized over the future life of a respective capital project). MH indicated that employees' timecards docket their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, MH also capitalizes overhead by applying the predetermined overhead rates to all capital projects.

MH had total operating and administrative expenses before capitalization of $543 million in 2003/04, which grew to over $688 million in 2010 and is forecast to be $703.8 million in 2010/11 and $714.1 million in 2011/12, before capitalized activities and overhead. In 2003/04 MH capitalized approximately 28% of labour and benefits. The amount of labour and benefits capitalized has increased since then, where MH now capitalizes over 32% of its labour and benefits. The increase in amounts capitalized mutes the growth in O&A expense recorded on an annual basis.

Including overhead, in total MH is forecast to capitalize $306 million of O&A expenses in 2010/11 and over $312 million in 2011/12, representing over 43% of its annual electric operating expenses in both test years.

MH also capitalizes Demand Side Management (DSM) expenditures from its Power Smart program. DSM program costs are deferred and amortized on a straight-line basis over 10 years. DSM costs are forecast at over $39 million for 2011 and $40 million for 2012. The capitalized carrying value for DSM was $168 million on March 31, 2010 and is forecast to be approximately $200 million at the end of fiscal 2012.

For fiscal 2010 MH has $591 million of deferred charges recorded as assets, including $299 million in rate-regulated assets. If MH were not subject to rate regulation, the costs would be charged to operations in the period that they were incurred.

The balances of the regulated assets at March 31, 2010 were as follows:

Regulated Assets ($ millions)	March 31, 2010
Power smart programs – electric	$168
Power smart programs – gas	32
Site restoration costs	37
Deferred taxes (CGMI)	35
Acquisition costs	23
Regulatory costs	4
Total	$299

9.4.0 MITIGATION COSTS

MH is party to an agreement dated December 16, 1977 with Canada, the Province of Manitoba and the Northern Flood Committee Inc., the latter of which represents the five First Nations communities of Cross Lake, Nelson House, Norway House, Split Lake and York Landing. This agreement, in part, provides for compensation and remedial measures necessary to ameliorate the impacts of the Churchill River Diversion and Lake Winnipeg Regulation projects. Comprehensive settlements have been reached with all communities except Cross Lake. Expenditures incurred to mitigate the impacts of the Churchill River Diversion and Lake Winnipeg Regulation projects were $26 million during fiscal 2010. As of March 31, 2010, $701 million has been spent in mitigating and compensating the project-related impacts. MH is forecasting to spend an additional $30.5 million in fiscal 2011 and $29.9 million in fiscal 2012. In recognition of the anticipated mitigation payments to be incurred, the Corporation has recorded a liability of $129 million as of March 31, 2010.

MH has also entered into agreements with the Province whereby MH has assumed obligations of the Province with respect to certain northern development projects. MH assumed obligations totalling $145 million for which water power rental charges were fixed until March 31, 2001. The remaining liability outstanding as of March 31, 2010 was $12 million. All mitigation cost obligations, including those Provincial obligations assumed by MH, are capitalized and amortized over the remaining life of the generation and transmission assets to which they pertain.

9.5.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

9.5.1 IFRS Transition

International Financial Reporting Standards (IFRS) will be adopted by Canadian Generally Accepted Accounting Principles (GAAP) to be implemented effective January 1, 2011. Canadian utilities have been granted an optional one-year deferral of the implementation of IFRS to years commencing on or after January 1, 2012. This allows for a transition of accounting standards that do not recognize rate-regulated assets and liabilities. MH will be required to prepare IFRS-compliant financial statements for its fiscal year 2012/13 with comparative financial information for 2011/12.

The implementation of IFRS has prompted MH to delay undertaking Board-requested studies, including an independent benchmarking study of key performance metrics comparing MH's operations with other utilities as well as an Asset Condition Assessment Report. These studies were ordered in Directive 4 and Directive 7, respectively, of Order 150/08.

9.5.2 Rate-Regulated Assets & Liabilities

IFRS does not currently recognize rate-regulated accounting. If standards remain unchanged, MH will be required to write off the accumulated balance of its rate-regulated assets against retained earnings and expense expenditures previously deferred due to rate regulation as incurred.

MH stated that its rate-regulated assets were $299 million as of March 31, 2010, of which $229 million relate to electric operations and $70 million to gas operations. A major component of rate-regulated assets is approximately $40 million in annual Power Smart DSM program costs. Currently, DSM expenditures are amortized over a 10-year period. Under IFRS, the amount would be expensed in the year incurred.

With respect to the implications of conversion to IFRS on the rate-setting process, MH believes that any changes in accounting practices can be accommodated within the rate-setting framework. Since IFRS result in changes to the timing when certain costs will be recognized in its operating accounts, MH believes that some mechanism may be required to defer certain costs for rate-setting purposes. MH stated that it would provide the Board with alternatives to consider at the appropriate time.

9.5.3 Other Accounting Impacts

Canadian GAAP converged with IFRS related to accounting for Goodwill and Intangible Assets in fiscal 2010. IFRS does not allow planning studies to be capitalized, which were previously amortized over 15 years, unless there is assurance that the facilities will be built. As a result, MH was required to write off $37 million in deferred costs including computer development, general advertising and promotion and planning studies to retained earnings, impacting MH's 2008/09 retained earnings. Included in the write off were $25.2 million in unamortized planning studies.

IFRS also has more restrictive requirements for the type of expenditures that can be capitalized. IFRS does not allow advertising and promotional activities, administrative and other general overhead expenditures, property and business taxes and interest on common assets to be capitalized. MH adjusted its overhead capitalization policy accordingly by reducing the amount of overhead capitalized to capital projects from 24% to 17% for 2010/11.

As a result of the accounting policy changes, MH reduced its total capitalized overhead by $5 million in 2008/09 and an additional $4 million in 2009/10. It also made a provision of $18 million in 2010/11 and $14 million in 2011/12, reflecting a reduction in the overhead rate.

9.6.0 O&A COST CONTROL PROCESS

MH's forecast provides for a productivity factor in the order of 0.5% to 1% annually in the setting of its business unit O&A targets. In response to the economic downturn, MH has put in place measures to constrain the increase of O&A, including a freeze on hiring of new positions (with the exception of line trades trainees), restrictions on out-of-province travel, rationalization of fleet vehicles, extension of service lives of computers and equipment and reduction of overtime costs where possible.

MH indicated that such measures were short-term and that cost containment measures would not compromise system safety and reliability. MH stated that such steps had resulted in reducing the year-over-year changes in O&A by 5% or $16 million in the first 10 months of the current fiscal year.

In Order 116/08 the Board stated:

> *"Although Hydro's operating and administrative expenses appear reasonable, the Board urges Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies. Corporate Performance measures such as operating and administration cost per customer or per kW.h targets are of great assistance in*

assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements of its operations as compared to other utilities."

In that Order the Board directed:

"MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most current available data and including:

a) Primary key drivers of OM&A in each operational division [Board preferences to allow for a comparison with a greater number of other utilities].

b) Comparable other Canadian Utility data for each of the drivers.

c) Key comparison indicators including staffing levels.

d) A comparison with and discussion of industry best practices.

e) Potential improvement areas."

The Board expects to be apprised of the scope of the study and advancement being undertaken, and will anticipate the opportunity to provide direction.

The Board is convinced that both the Province and ratepayers will benefit from the development of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance and particularly because of, the proposed major capital expansion program.

MH has deferred undertaking the Board-directed benchmarking study until after the implementation of IFRS in fiscal 2013.

9.7.0 INTERVENER POSITIONS

9.7.1 CAC/MSOS

CAC/MSOS questioned the growth in O&A expenditures, citing internal memos from the President of Hydro in which concerns were raised about the annual increases in O&A. Such concerns were not properly externally acknowledged in the GRA, which undermines MH's argument of ongoing expenditure controls in the 2008/09 through 2010/11 being prudent and reasonable. CAC/MSOS questioned MH's cost containment efforts, noting that they were only short-term measures that cannot be relied upon to restrain the growth in O&A in the long term.

9.7.2 MIPUG

MIPUG encouraged the Board to provide MH direction to ensure a continued restraint and tight controls on O&A spending. MIPUG recommended that the Board require MH to provide detailed reports to the Board and Interveners on corporate-wide efforts to restrain O&A and that MH continue to document and report on quantitative improvements in efficiency.

MIPUG recommended that the Board require MH to provide budget scenarios and options considered for maintaining O&A spending at inflation or at zero levels, providing a transparent process to review choices.

MIPUG further commented on the growth in personnel, whereby MH had added over 600 employees during a recessionary time, contrary to what other companies would be doing related to hiring during a downturn.

9.8.0 BOARD FINDINGS

The Board notes that the Corporation has shown some interest in undertaking cost-containment measures. However, such measures are far too modest and short-lived. MH's annual operating costs top $700 million, with targeted measures expected to deliver only $13 million of savings, or 2% of the total.

Given the corporation's current development plans, MH has seen material increases in staffing levels. MH has added over 900 employees since 2004, the majority engaged in one capacity or another in implementing the utility's development plan, well ahead of an NFAAT, regulatory approvals and firm export contract commitments. If the projects do not go ahead, MH faces the likelihood of having to expense expenditures currently deferred or capitalized.

The Board, in past Orders, has recommended that MH find ways to control the growth in operating expenses. The Board continues to believe that MH should look internally to find efficiencies and control the growth in operating expenses. To do otherwise increases the risks faced by ratepayers of paying higher rates than required.

The Board notes that during the last expansion phase in 1992, MH had an employee complement that peaked at 4,232 EFTs, with fewer than 900 dedicated to capital construction. Since then, staffing has ballooned to over 6,300 EFTs, with over 1,400 EFTs dedicated to construction-related efforts.

The impact of the large staff complement is muted by MH's capitalization policies. A significant portion of MH's operating expenses (in excess of 40%) are capitalized each and every year, masking the impact of the significant staffing levels at MH. There remains a risk that if the projects do not proceed or become economically not profitable, a significant amount of capital costs, now well in excess of $400 million will have to be written off.

It is also vitally important that MH undertake a benchmarking of its operations against peers with the goal to control the growth in operating expenses and foster practices, which improve efficiencies.

10.0.0 DEPRECIATION AND AMORTIZATION

10.1.0 OVERVIEW

In the test years, depreciation and amortization is the second-largest expense category to be recovered through rates. Depreciation expenses were $358 million in fiscal 2010 and have grown to $366 million in fiscal 2011.

MH last instituted new depreciation rates on April 1, 2007. MH's last Depreciation Study by Gannett Fleming dated March 31, 2005 was filed at the 2008/09 GRA. Although a 2010 Depreciation Study was previously anticipated for this GRA, MH deferred the study pending integration of the IFRS requirements. MH at that time also deferred the Board-directed Asset Condition Assessment to circa 2013.

MH's depreciation and amortization expense is forecast to be $405 million in fiscal 2012, an increase of $47 million since fiscal 2010. MH attributed the increase to a higher level of net assets. Depreciation and amortization is now forecast to grow to over $830 million by 2030 with the new major generation and transmission projects.

10.2.0 DEPRECIABLE ASSETS

MH's IFF10-2 has 2010/11 gross electrical utility asset values of $12.6 billion which have been depreciated down to $7.8 billion.

Going forward, IFF10-2 projects the gross assets and depreciated assets to be as follows:

Net Plant In-Service ($Billions)

	Plant in Service	Accumulated Depreciation	Net Plant In Service
2015/16	17.4	6.8	10.5
2020/21	28.7	9.5	19.2
2025/26	39.9	13.0	26.8
2029/30	42.5	16.4	26.1

MH’s 2005 depreciation study apparently uses industry standards for the life expectancy of various facility components e.g.:

- Hydraulic Generation Facilities:
  - Civil Works – 100 years life with the extensive rehabilitation works required on most of the Winnipeg River plants over the last 2-3 decades. A reconsideration of the 100 year life expectancy might be acceptable.
  - Turbines and Generation - 65 years life. The significant remedial works required in the last two decades on Grand Rapids/Jenpeg generation units suggest a shorter life expectancy could be appropriate for all.
  - Accessory Equipment - 50 years life. Shorter life expectancy could also be suggested.

- Thermal Generation Facilities:
  - Steam plants - 65 years life. MH's ongoing investments in the Brandon and Selkirk plants may not support the notion of a 65 year life.
  - Natural gas combustion turbine - 25 years life. Some questions of the true economic value of these plants remain.
- Transmission Lines:
  - Towers - 75 to 85 years life. Events on Bipoles I and II in 1996 and 2011 suggest remediation of failed or damaged facilities could reduce the effective life cycles.
  - Conductors - 60 years life. Aside from the former Winnipeg Hydro transmission upgrades, MH has indicated a need for early replacements.
- HVDC Converter Stations:
  - Structures - 57 years life. No indication of problems exists.
  - Serialized equipment - 37-43 years life. Indications from prior evaluations are that the serialized equipment (synchronous condensers) may need replacement in 20 to 50 years.

10.3.0 BOARD FINDINGS

Depreciation (amortization) expense is forecast in this application based on an out-dated 2005 depreciation study. The Board is aware that a result of IFRS requirements for componentization will likely lead to an increase in depreciation expense, as components will have to be carved out and depreciated over their respective shorter service lives rather than over a longer service life of the asset as a whole. The Board understands that a new depreciation study is being prepared.

The Board remains concerned that an Asset Condition Assessment Study has been delayed and notes that several of the assets, which are being depreciated over long periods of time, may require major repairs in the interim.

There does not appear to be any explicit recognition of the physical condition and ongoing repairs associated with the individual generating stations or transmission facilities. This suggests that MH may not have an adequate history of physical plant conditions and rehabilitation needs such as would be included in an "Asset Condition Assessment". The Board will require MH to file an Asset Condition Assessment and depreciation study at the next GRA.

11.0.0 PAYMENTS TO GOVERNMENTS

As a Crown Corporation, MH does not pay income tax, provincial sales tax or the Goods and Services Tax. MH does, however, pay the Provincial Corporations Capital Tax, similar to other privately held corporations employing capital in Manitoba. The Province of Manitoba also levies a number of other fees to be paid by MH. Forecast payments to the Province were $ 240 million in 2010, $ 244 million in 2011 and $236 million in 2012.

The total payments to the Province from fiscal 2005 through 2012 are summarized as follows in the following table:

PAYMENTS TO THE PROVINCE ($MILLIONS)

	Actual					IFF09-1		
Fiscal Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Corporations Capital Tax	35	36	37	39	44	45	47	44
Payroll Tax	7	7	8	8	9	9	9	9
Water Rentals	104	124	106	117	115	111	102	100
Debt Guarantee Fee	68	66	68	70	70	72	78	83
Sinking Fund Admin Fee	1	-	-	1	1	1	-	-
Provincial Mitigation or Settlement Obligations	13	2		2	-	2	8	-
Total Payment	**228**	**235**	**219**	**237**	**239**	**240**	**244**	**236**
Total Payments as a Percentage of MH's Gross Revenue	14%	13%	13%	14%	14%	15%	15%	13%

MH is forecasting paying $380 million to the Province in 2020, which is approximately $150 million higher than current levels. Payments to the Province will increase when the new generation and transmission projects are built.

MH pays Corporations Capital Tax to the Province based on 0.5% on its invested capital. The Corporations Capital Tax is a function of the level of debt of MH. The Corporations Capital Tax has been phased out for all corporations effective January 1, 2011 except for Crown Corporations, Banks and Trust Companies. As such, MH will remain subject to Capital Tax.

Water rentals relate to the use of provincial water resources, and are paid on a monthly basis to the Province based the greater of:

- Energy produced, at a current rate of $3.341 per MWh, or
- The installed capacity of the facility at a rate of $8.13 per installed horsepower.

The Provincial Debt Guarantee Fee is 1.0% of the sum of the balance of MH Bonds, provincial advances to MH and provincial short-term promissory notes outstanding to guarantee MH long-term debt.

The Sinking Fund Service Charge is 0.075% of the amount of the sinking fund balance, and is paid to the Province for managing MH's sinking fund balance. MH's sinking fund is a covenant related to its bond issues.

In addition to the payments to the Province, MH makes Grants in Lieu of Taxes (GILT) to municipalities on buildings and structures throughout the Province. In 2009 MH made $11 million in GILT payments. The payments are forecast to increase to $15 million in 2010, as a result of the new Corporate Head Office inclusion in the tax rolls. MH indicated the property and business tax on Corporate Head Office to be $3.8 million per year.

11.1.0 BOARD FINDINGS

The Board notes that MH makes a significant contribution to the Province and to Manitoba municipalities. The payments to the Province in particular represent 15% of the gross revenue of the utility, a significant amount. The total amount to be paid to the Province is expected to grow substantially over the next twenty years, primarily due to the now-planned new major generation and transmission investments, these through increases in borrowings, increased capital, and higher water rentals as the new generating stations are built.

The Province's financial interest in the contemplated generation and transmission investments due to potentially higher government underscores the need for an independent arm's-length review of the economics of these projects.

12.0.0 FINANCIAL TARGETS

In September 1995, MH adopted the following financial targets, which were reviewed by the Board at prior GRAs and the current hearing:

1. To achieve and maintain a minimum debt-to-equity ratio of 75:25 by no later than 2005/06;

2. To achieve and maintain an annual gross interest coverage ratio of 1:20 to 1:35 annually; and

3. To fund all new capital construction requirements except major new generation and/or major new transmission facilities, plus the new head office, from internal sources.

MH's financial targets have varied over the years due to changing circumstances and priorities. Since the original 1995 date, the targets have changed as follows:

Year	Financial Target
1995	75:25 debt equity ratio by 2005/06, interest coverage ratio of 1.20 to 1.35 and fund all capital expenditures, except major new facilities, from internally generated funds
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new facilities, from internally generated funds
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new facilities, from internally generated funds
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new facilities, from internally generated funds

As of March 31, 2002, MH had a debt/equity ratio of 77:23. MH stated that the largest single factor contributing to the delay in the achievement of the 75:25 debt/equity target was the 2002 to 2004 drought. The drought resulted in an approximate $600 million reduction to net export revenues relative to a normal flow period and severely impeded

MH's progress toward its financial targets. In 2002, the target year was changed from 2005/06 to 2011/12 to allow for a more gradual rate impact on customers.

12.1.0 DEBT-TO-EQUITY RATIO

The debt-to-equity ratio measures the relationship of long-term and short-term debt less short term and sinking fund investments to equity (retained earnings including AOCI and unamortized customer contributions). This ratio is used to assess the overall financial risk to MH by examining the level of debt in relation to the amount of equity held. MH has established a debt-to-equity ratio target of 75:25 by fiscal 2012.

MH attained the 75:25 debt-to-equity ratio target in 2010, an accomplishment not contemplated at the last GRA. Since the 2004 drought, the capital structure has improved from 87:13 in 2004 to 73:27 in 2010. The improved financial position relates to higher-than-expected extra-provincial revenue and rate increases granted by the Board, which on a cumulative basis have totalled 22% since 2005.

MH is now forecasting increases of 3.5% annually for the years 2013 tto 2021 (a cumulative 39% increase) but due to its planned spending on major new generation and transmission projects, MH's capital structure is forecast to weaken from the 75:25 target to a debt-to-equity ratio of 84:16 in 2021.

In support of its application, MH had filed IFF09-1 and CEF09-1. MH had anticipated capital spending of $ 13.1 billion on its three major generation and transmission projects (Keeyask G.S., Conawapa G.S and Bipole III). With the upward revised capital cost of these three projects reflected in IFF10-2, the capital cost has increased to over $16.6 billion, which is over $3.5 billion higher the cost forecast in CEF09-1.

Long-term debt was forecast to grow from $7.8 billion in 2010 to $17.7 billion in 2029. Based on the revised capital forecast, long-term debt is to balloon to over $23 billion in 2029, an increase in long-term debt of $5.0 billion from the previous forecast. The higher debt level will result in materially higher debt servicing costs, which over the forecast period has reduced the net income by $3.2 billion from the amount forecast in IFF09-1. The change in forecast net income and the debt-to-equity ratio from IFF09-1 to IFF10-2 is as follows:

	Net Income ($ Millions)			Debt : Equity Rato	
Fiscal Year Ending March 31,	**Iff09-1**	**IFF10-2**	**Difference**	**IFF09**	**IFF10-2**
2010	129	163	$34	74:26	73:27
2011	88	158	$70	75:25	74:26
2012	98	134	$36	76:24	74:26
2013	83	132	$49	76:24	77:23
2014	137	198	$61	78:22	78:22
2015	122	155	$33	79:21	79:21
2016	260	230	($30)	80:2	81:19
2017	271	278	$7	80:2	81:19
2018	246	227	($19)	80:2	82:18
2019	257	120	($137)	80:2	83:17
2020	287	198	($89)	79:21	83:17
2021	307	12	($295)	79:21	84:16
2022	450	244	($206)	78:22	83:17
2023	554	332	($222)	76:24	83:17
2024	744	392	($352)	73:27	82:18
2025	805	504	($301)	70:3	80:2
2026	922	462	($460)	66:34	79:21
2027	1019	552	($467)	61:39	77:23
2028	1127	648	($479)	56:44	74:26
2029	1237	753	($484)	51:49	72:28
Total	**9441**	**5892**	**($3 549)**		

The debt-to-equity ratio in 2029 has changed from 51:49 in IFF09-1, a particularly strong balance sheet, to 72:28 in IFF10-2, representing a materially negative financial change from one forecast to the next. Changes in GAAP with the move to IFRS in fiscal 2013 will likely further hinder MH's progress to its debt-to-equity target.

12.2.0 INTEREST COVERAGE RATIO

The Interest Coverage Ratio is calculated to measure the degree to which net income before interest exceeds finance expense. The interest coverage ratio indicates the extent to which net income is sufficient to pay gross interest on debt. An interest coverage ratio below 1 indicates that a company cannot support interest-servicing costs from operations and may require further borrowings to cover the interest charges. MH has established a target interest coverage of 1.20 in all years.

In IFF09-1 the target is not achieved, with shortfalls from fiscal 2011 to 2015. The interest coverage ratio falls within the range of 1.11 to 1.19 during that period. The interest coverage was forecast to be 2.22 in 2029.

MH filed an update based on IFF10-2, which reflected lower than forecast interest rates in the next few years. As a result of this change, MH now forecasts to meet its interest coverage ratios during each of the years 2011 through 2018. However due to the increase in capital costs of $3.6 billion and additional borrowings of over $5 billion, in the years 2019 through 2022 the interest coverage ratio will be below target. In particular, the forecast indicates that in 2021 MH will have an interest coverage ratio of 1.01.

In 2029, the interest coverage ratio has now been revised down from 2.22, based on IFF09-1, to 1.50. This is above target, but materially lower than what was indicated in IFF09-1. Further upward revisions in the capital cost of the major generation and transmission projects and any upward movement in interest rates above what is forecast could negatively impact the interest coverage ratio.

12.3.0 CAPITAL COVERAGE RATIO

The Capital Coverage Ratio measures MH's ability to make capital purchases without additional borrowings, measuring the extent to which internally generated funds are sufficient to fund capital expenditures during the year. The Capital Coverage Ratio does not include the major generation and transmission projects in its determination. If such projects were included, it would indicate that MH has a Capital Coverage Ratio well below 1.0 and that the funding for the new projects is supported primarily if not solely by new debt issues.

12.4.0 INTERVENER POSITIONS

12.4.1 CAC/MSOS

CAC/MSOS stated that in the short term the overall retained earnings and debt ratio for 2011/12 is better than originally forecast in IFF 09–1, and that the current outlooks in IFF 10–2 for 2010/11 and 2011/12 in terms of the debt ratio are both better than what was forecast in IFF 09-1. The current outlook for the test years does not support the need for rate increases greater than those already approved on an interim basis. CAC/MSOS noted that it could even be argued that the interim rate increases approved could be rolled back and would still result in a financial position at least as favourable as those originally expected in IFF 09–1.

CAC/MSOS further noted that the cost of construction of the major generation and transmission projects as they progress affects MH's balance sheet and its debt-to-equity ratio. To the extent that assets are funded through debt, it will affect the debt-to-equity ratio. Since the Board uses of the target ratio as a measure of financial soundness, this puts pressure on rates to increase to maintain the target.

CAC/MSOS adopted the evidence of Greg Matwichuk, who stated that less reliance should be placed on retained earnings and the debt-to-equity ratio for the purpose of rate-setting on a go-forward basis. Mr. Matwichuk stated that changes in MH’s debt-to-equity ratio have no apparent impact on the Province’s credit rating, noting that after the drought in 2003/04, the debt-to-equity ratio was 88:12, which resulted in no reduction to the Province’s bond-rating grade.

Mr. Matwichuk recommended that MH establish a Rate Stabilization Reserve (RSR), a regulatory mechanism to stabilize rates that may otherwise sharply increase due to the effects of unanticipated events. The RSR would provide MH ratepayers some level of protection against large rate increases that may become unavoidable due to sudden or unanticipated adverse conditions. Mr. Matwichuk noted that a similar mechanism is in place at Manitoba Public Insurance.

RSRs exist at regulated entities such as hydroelectric utilities, water utilities, local gas distribution companies and insurance companies and are typically utilized by utilities which are subject to weather- or and/or water-related factors that complicate forecasts and result in variances.

CAC/MSOS submitted that the establishment of an RSR for regulatory purposes is appropriate for MH due to significant variances in forecasting, observed volatility in export revenue, and MH's vulnerability to known contingencies with uncertain timing and impact. Mr. Matwichuk stated that an RSR would assist in managing the impact of risk to domestic ratepayers. Under his proposal, when export revenues exceed forecast export revenues, the excess would be set aside to be amortized over five years The same approach would be taken to years in which export revenues fell below the forecasted level, meaning that deficits would also be amortized over a five-year period. Under such a mechanism, the net unamortized equity or deficit arising out of export revenue differentials from forecasts would remain on the balance sheet as a form of a RSR, segregated from the general equity.

12.4.2 MIPUG

MIPUG stated that MH is in the best financial position that it has been in its history, exceeding the 75:25 debt-to-equity ratio with close to $2.5 billion in retained earnings. Based on the most current forecast, retained earnings should be increased to $4.3 billion.

With respect to the debt-to-equity target of 75:25, MIPUG stated that the true value of Hydro's assets is significantly higher than their book value. While the 75:25 debt-to-equity target is important, it is an artificial number and does not show the true strength and value of MH and its assets. MIPUG submitted that such information should provide some comfort to the Board.

Bowman & McLaren stated that the planned increase in net plant in service is a key driver in the change in the forecast debt-to-equity ratios and that the impact of a higher level of capital expenditures will have increasing cumulative impacts on the level of net income in the future. The current 75:25 debt-to-equity ratio is reflective of a retained earnings level approximately equal to the benchmark of a five-year-drought. However in the latter part of the IFF, given the capital spending proposed, the 75:25 debt-to-equity ratio target may generate retained earnings levels that may exceed the calculated cost of a five-year-drought at that time.

As the degree of capital investment increases, the relevance of the debt-to-equity target will diminish. Given the provincial debt guarantee, the debt-to-equity ratio is not as important for a public utility as opposed to what it would be for a private enterprise.

MIPUG submitted there is nothing in the evidence that indicates that MH cannot handle a five-year drought and will not have the cash flow to survive it. MH has one of the lowest electricity rates in North America, so there would be a lot of room to adjust rates, and all the forecasts show that MH would recover from a net loss without having to impose rate shock on customers.

MIPUG did not agree that water reservoir levels should be used as a rate stabilization mechanism as proposed by KM, nor did MIPUG believe that an RSR mechanism as proposed by CAC/MSOS should be implemented. The utilization of water levels as a reserve may result in suboptimal use of the resource and lead to a reduction in revenues in some cases. Adjusting lake levels by one or two feet would not be a good strategy if money ends up being lost each year because water is spilled instead of being used to sell energy on the export market.

MIPUG further submitted that the RSR mechanism as proposed by CAC/MSOS would not improve transparency and is not required because the Board's rate-setting process is effective. If the Board were to consider establishing an RSR, Bowman & McLaren noted that an orderly process as identified by the Board in Order 116/08 would have to start with the step of identifying and properly quantifying MH's risks in advance of addressing the appropriate form of reserves. This would be a matter for future consideration. Should a financial reserve target be desired in the future, the value may be derived based on targeting a long-term rate stability criterion which would include periods leading up to, during and following a benchmark drought. Such an analysis could be completed using probabilistic tools as identified in the KM report.

12.5.0 BOARD FINDINGS

Despite the concerns the Board has with respect to the "firmness", if not validity of the equity components of MH's debt-to-equity target ratio, the Board notes that MH currently has achieved its debt-to-equity target and that to maintain the 75:25 ratio it will require rate increases far higher than that currently contemplated in the IFF.

The current view of capital spending for major generation transmission, with current estimates $3.6 billion higher than in IFF 09–1, reflects an ever-increasing debt load, higher forecast carrying charges, lower income approximating $3.2 billion and a further deterioration in the capital structure of the Corporation over the next 20 years. This deterioration is predicated on increasing rates over the forecast time frame by approximately 60%.

The Board remains concerned that export revenues, which were negotiated when the capital costs of the major projects were projected to be much lower, have been locked in, yet the projected capital costs have increased unabated. These increased costs will have to be paid for somehow, and in the absence of export customers paying them, the burden will fall on domestic customers. An NFAAT process should be established to review the implications of the proposed development plans on MH's capital structure.

The Board notes that the financial capital structure of MH was to peak at 80% debt and 20% equity in 2019. Based on updated estimates, the debt portion has grown to over 84% in 2021 and is not to return to current target (and currently attained) levels at the end of the forecast period 2030. In IFF 09–1, the 75:25 debt-to-equity financial target was reached in 2024 and, optimistically, a debt-to-equity ratio of 51:49 was projected for 2029. The Board questions whether the debt-to-equity financial target of 75:25 for rate-setting purposes should be revisited, given that it is currently forecast not to be attained over the 20-year financial outlook.

Any further increase in capital costs for the major capital projects will come at the price of a further deterioration in MH's capital structure. This may require greater rate increases from domestic customers than those currently projected.

As for the interest coverage target of 1.20, the Board remains concerned that a decline in export revenues due to a structural change in the markets into which MH delivers its electricity could have grave consequences to MH's ability to meet its debt obligations. These are currently forecast to be $23 billion when the projects are completed. Interest rates, if they increase beyond forecast levels during the development and construction of the major generation and transmission projects, could further increase the debt and associated carrying costs incurred by MH. To the extent that projected revenues will not materialize, MH would still be required to meet its debt obligations.

The Board notes with concern that under the most recent forecast, the interest coverage ratio comes very close to 1.0 during one of the years of the planning horizon. This suggests that MH may come close to being unable to meet its interest obligations from its operations and will be, if the ratio falls below 1.0, in the position of having to borrow additional funds to meet its interest obligations.

Interest costs will be over $1.5 billion on an annual basis once the projects have been completed, which will have to be met by revenues from both domestic and export customers. To the extent the export revenues do not materialize as planned, the burden will fall to the domestic ratepayer. It is vitally important that the economics of the proposed generation and transmission investments be subject to a thorough review to ensure that the developments, if they proceed, will benefit and not overly burden domestic ratepayers.

The Board does not see merit in establishing an RSR based on excess or deficient export revenue. While the Board remains concerned about MH's ability to achieve its export forecasts, an RSR mechanism would not assist in smoothing out the rate implications of a shortfall.

The Board believes that the current rate-setting mechanism, including the presentation of forecasts that are tested in a rate hearing, provides an appropriate mechanism for setting rates. The Board does, however, see merit in exploring whether establishing an RSR is appropriate for other reasons.

The Board believes that having reviewed the risks faced by MH, sufficient information exists to move one step further towards assessing whether a mechanism such as an RSR would be appropriate in establishing future rate sufficiency. While the Board does not believe that an RSR mechanism should be established at this time, it should be one of the mechanisms to be considered by this Board at a future GRA.

The Board further believes that since MH's proposed capital expenditure plan is subject to material escalations, some consideration should be given to de-linking rate requirements from the debt-to-equity ratio target of 75:25. Instead, rate requirements should be more focused on an amount sufficient to meet the risks faced by the Corporation.

13.0.0 LOAD FORECASTS

13.1.0 OVERVIEW

MH's Load Forecast is used to predict when new generation and transmission assets are needed to serve MH's load. MH's 2010 GRA was premised on a May 2009 Load Forecast which only partially reflected the economic downturn. In PUB/MH II 194(a), MH confirmed a domestic load reduction of 1,000± GWh from May 2008. This did not include any plant closure impacts.

MH's Updated Domestic Load Forecasts indicate a significant downward trend in the forecasts from 2008 onward. This trend reflects the economic downturn after 2008/09 and the closure of the pulp and paper plant at Pine Falls. However, according to MH these forecasts do not include the impact of pending closures of smelter operations in Flin Flon and Thompson, which according to MH's testimony would reduce consumption by about 500 GWh after 2015/16.

13.2.0 INDUSTRIAL CUSTOMER CONSUMPTION

The table below provides an industrial energy consumption history and forecast from 2005/06 to 2009/10 and beyond. It is apparent that the total industry consumption totals are very similar to MH's total Top Consumer usage.

Industrial load growth has essentially stalled since 2005/06. Even without the pulp and paper plant shutdown, MH's industrial load would have shown little or no growth in the last 5 years. From the table below it is apparent that MH's expectations of high industrial load growth in the chemical and petroleum sectors will not be realized in the short term.

In the most recent Load Forecast, MH is looking for growth of 100 GWh per year in Top Consumer load. If correct, this would add about 700 GWh to energy consumption and offset the smelter closures by 2015. If this new load does not materialize, MH's total industrial consumption would remain near the 5,000 GWh/year level.

MH's industrial customers were targeted for higher rates during the Energy Intensive Industrial Rate (EIIR) hearing. The logic employed suggested that Manitoba industries were paying less than market value for energy consumed. Consequently, MH considered that the utility was losing money for all increases in energy sold at approved rates to GSL and GSM customers.

In Board Order 112/09, MH was directed to limit the new EIIR to new peak energy consumption. This reflected the circumstances of 2007/08, when average MISO Market prices were in excess of 4¢/kWh during peak periods but were at the 2¢/kWh range during the off-peak periods.

The market circumstances in 2009/10 and 2010/11 have shown that GSL and GSM customers are paying at least peak MISO Market prices and considerably more than off-peak MISO Market prices. MH has yet to abandon the EIIR concept, but has seen some industrial customers move to higher levels of consumption than contemplated in the EIIR hearing.

13.3.0 RATE IMPACTS ON LOAD GROWTH

It is the Board's understanding that all GSL & GSM customers are subject to the same (unchanging) demand charge per kVA and the same (progressively increasing) energy charge per kWh regardless of peak or off-peak consumption. To date, MH has declined to offer time-of-use rates to these customer classes. Apparently industrial customers are not entitled to access low cost off-peak energy on the same basis as MH's export clients.

Given the low MISO market prices, a potential problem looming for MH's industrial customers is that they may be paying significantly more for energy in the next 10 to 20 years than utility customers in the adjoining MISO states. If that ends up being the case, cheap electricity may no longer be an economic advantage of doing business in Manitoba.

13.4.0 DOMESTIC LOAD DEMANDS FOR NEW GENERATION

MH's 2008/09 Power Resource Plan contemplated a Keeyask G.S. in-service date of 2018 and a Conawapa G.S. in-service date of 2022. The 2008 Base Load Forecast along with existing NSP sales, an NSP sales extension, and the new WPS-500 MW/MP-250 MW term sheets were the apparent drivers for these in-service dates.

Domestic energy consumption, rather than peak winter demand, was viewed as the critical factor, with energy shortfalls anticipated as early as 2011/12. A need was seen for contracted imports until 2015 when the level of contract sales to NSP would be reduced.

The 2008 Base Load Forecast foresaw a domestic load of 28,100 GWh by 2015/16, reflecting 8,040 GWh of energy usage by Top Consumers.

MH's IFF10-2 lowered the 2015/16 domestic load forecast to 25,700 GWh (including 6,666 GWh of Top Consumer load, which may still be too optimistic). This differs significantly from the 27,300 GWh projection for 2015/16 set out in IFF08-1 when MH saw a need for Keeyask G.S. by 2018/19 to allow the new export sales.

13.5.0 INTERVENER POSITIONS

13.5.1 CAC/MSOS

CAC/MSOS did not take issue with MH's overall domestic load forecast. Some concerns were expressed about:

- the level of electric car growth included in general service;
- the residential load growth projections;

- the lack of growth in commercial sector load; and
- the decline in industrial sector load.

13.5.2 MIPUG

MIPUG did not offer any new insight on the recent loss of industrial load and the potential for existing customer growth and/or new industries coming to Manitoba. It appears that following another round of consultation, MIPUG now supports MH's pending EIIR initiatives.

13.5.3 RCM/TREE

RCM/TREE continues to express concern about the limited achievements with respect to energy conservation and continues to favour increased exports over higher levels of domestic load growth.

13.6.0 BOARD FINDINGS

It is the Board's view that MH's most recent domestic load forecasts for the longer term:

- do not adequately recognize the longer-term implications of the recent economic downturn;
- may well be overly optimistic given the stagnation and/or lack of growth over the last five years in the industrial sector; particularly when coupled with the actual pulp and paper plant closure and imminent smelter closures; and
- do not support the significantly advanced dates for new generation, but rather, in the absence of the new contracts, suggest a 2024/25 in-service date for domestic load only.

The Board understands that the recent MP & WPS contract announcements essentially commit MH to building Keeyask G.S. by 2020/21. This is about five years earlier than domestic need only would indicate.

While the Board appreciates that MH's domestic revenue growth from the residential and commercial sectors has largely offset the revenue decline experienced to-date in the industrial sector, it does not share MH's optimistic view of any early dramatic recovery in the latter. And, the continuing prospect of the future implementation of an EIIR could well hinder such a recovery.

The Board is still awaiting MH's re-filing of the EIIR, as directed in Board Order 112/09.

14.0.0 POWER SUPPLY

14.1.0 DC TRANSMISSION SYSTEM

14.1.1 Reliability Case for Bipole III

MH holds that Bipole III is required for domestic system reliability, and that the significant costs that would be expended on its construction, including the cost of converter stations, should not be attributed to any degree to either the planned new generation projects on the lower Nelson River (Keeyask G.S. and Conawapa G.S.) or to export customers. The coincidental outage of Bipoles I and II that occurred in the fall of 1996 has been cited as an example of the reliability risks that currently exists and needs to be addressed.

MH did not provide an analysis of any of the various events that could lead to the loss of HVDC power. Tornadoes, wind shear, forest fires and ice storms have, at various times, been identified as the most likely triggers of such an outage. All of these extreme events are more likely to occur in either the spring, summer or fall, rather than in the winter. In mid-winter, the biggest risk that has been identified is an ice storm that "takes out" some of the transmission towers.

In January 2011, a large number of Bipole I and II towers were threatened by ice formation within flooded right-of-ways. This presented a real risk. The transmission towers appear to need to be flood-proofed as soon as possible, whether or not Bipole III, or another reliability upgrade, is put in place.

It is unlikely that Bipole III, if constructed, would be built to less than a capacity of 2,000 MW. While the Board's Vice Chair accepts MH's evidence that Bipole III is required for reliability purposes, the Chairman suspects that an alternative reliability measure that could potentially replace Bipole III would be the addition of CCCT natural gas generation capacity (perhaps to be developed in "smaller steps", e.g. 400 to 500 MW at a time) to address the risk of an outage of either or both existing Bipoles.

MH compared the available aggregate Bipole I and II capacity of 3,354MW to the maximum 3,562MW generation capacity of the three existing Lower Nelson River generating stations, noting a 208MW deficiency. It is not clear what circumstance would require 100% output from these three plants to meet only domestic demand. Force majeure provisions in existing and new export contracts should allow for curtailment of export contract commitments in the event of a Bipole outage.

14.1.2 Reliability Alternatives

In June 2011, MH filed a 20-year Financial Outlook that included a comparison of the current plan for the construction of a 2,000 MW Bipole III (to be on-line in 2017/18) with a 2,000 MW natural gas generation plant to serve as an alternative. From the information provided by MH, it appears that comparison involved an SCCT plant rather than a CCCT plant, although a CCCT plant is clearly preferable due to its higher efficiency. The analysis that was provided was not detailed, and neither set out annual finance and depreciation costs nor recognized the potential revenue stream from a natural gas generation alternative.

As set out above, the Board's Vice Chair accepts MH's reasoning that Bipole III is required for reliability purposes. For the Vice-Chair, without Bipole III, the value of all lower Nelson River generation facilities (existing and planned) are jeopardized, in as much as a catastrophic failure of Bipole 1 and 2 would eliminate access to 75% of MH's hydro-electric power to southern Manitoba and export customers.

The Chairman, on the other hand, is of the view that there could be several advantages associated with a CCCT natural gas plant instead of Bipole III, which involve economics, risk management and the environment. A CCCT plant can be constructed at a fraction of the cost of Bipole III, and would provide MH with resource diversity that is currently absent. In the event of Bipole I and II being out of service, CCCT production and/or imports could be employed. MH's current diversity agreements with its American counterparties involve the receipt of coal-fired generation electricity in the winter. A

Manitoba-based CCCT plant would involve approximately half the emissions of coal-fired generation. The Chairman accordingly recommends that before Bipole III is constructed, the CCCT natural gas generation alternative should be investigated thoroughly.

In a prior Power Resource Plan, MH examined the cost of CCCT natural gas generation and concluded that a 400 MW CCGT produces about 3,100 GWh of dependable energy per year, which is slightly more than the projected dependable output of Keeyask G.S. Its capital cost was estimated at $471M and, because of its high efficiency, such a plant could produce energy at an operating cost of $55/MW or $8.40/GJ. (If, in the future, a price was put on carbon, a $30/tonne carbon cost would add less than $10/MW to the cost of operation.) Currently, natural gas is priced at $3.00 per GJ on the spot market, a mere 20% of the commodity's peak price. The reduction can be attributed partially to the slow recovery from the recession and partially to the availability of shale gas.

In its 2011 analysis, MH priced the capital cost of a 2,000 MW CCCT plant at almost $3.0B (25% higher than in 2008/09). With current natural gas costs at less than $5.00/GJ, the total on-line costs including finance, depreciation, maintenance and fuel costs would now be in the 5 to 6¢/kWh range.

14.2.0 AC TRANSMISSION SYSTEM

14.2.1 North-South Transmission

MH forecasts a need for "additional (AC) transmission from Northern Manitoba to Winnipeg" when Conawapa goes into service, now slated for 2023/24. MH's CEF-10 projection of capital costs budgeted $313 million for such a facility but did not specifically define its function or purpose.

MH has not explained its rationale for the additional AC transmission or its timing. A question that, among others, remains to be answered is whether this proposed AC addition is related to the west side siting of Bipole III and/or Bipole III capacity with or without export commitments.

14.2.2 Dorsey to U.S. 500kV AC Transmission.

CEF-10 also provides $205 million for additional Manitoba sited AC transmission to the U.S., to be in service by 2018. Presumably, this allocation was in anticipation of a 500 MW sale to WPS and a 250 MW sale to MP. With the WPS sale reduced to 100 MW, it may be that the expanded capacity could be deferred.

14.3.0 BIPOLE III FOR EXPORTS

MH notes that in the absence of the 2,000 MW Bipole III transmission line the construction of Conawapa G.S. should not occur. And, now seemingly without the 500 MW WPS sale, MH has decided to defer the construction and in-service date of Conawapa G.S., but still plans to proceed with Bipole III.

MH asserts that the planned Keeyask G.S. could not operate at maximum output in high-flow conditions without Bipole III. The assumption of a deemed requirement for 100% of Keeyask's potential generation in high flow conditions to be transmitted on Bipole III involves the prospect of opportunity export sales as well as both domestic load and firm export contracts. The availability of "dependable energy" does not require 100% of Keeyask's output.

Under the assumption that hydraulic generation is to be used to supply all firm/dependable energy in an average-flow year, MH holds that the existing Bipole I and Bipole II capacity is insufficient to convey the output from Keeyask G.S. plus the power generated from the three existing Lower Nelson River generating stations.

As set out above, the Chairman and the Board's Vice Chair are of two views with respect to MH's reliability arguments. The Chairman is of the view that MH's assumptions, which support a requirement of Bipole III if Keeyask is built, should be fully tested prior to MH making a final commitment to both Keeyask and Bipole III. The

Board's Vice Chair is of the view that Manitoba Hydro has established that Bipole III would be required for reliability purposes in any case.

14.4.0 INTERVENER POSITIONS

Recognizing that the Board was not asked or tasked to approve Bipole III, the Interveners only expressed concern with the seemingly ever-increasing costs of Bipole III and Keeyask, and with the cost revision process itself.

14.5.0 BOARD FINDINGS

The findings of the Chairman and the Board's Vice Chair differ with respect to MH's reliability case for Bipole III.

The Vice Chair is of the view that MH has established that Bipole III is required for reliability purposes even absent any additional export commitments, as the concurrent outage of Bipoles I and II presents a significant risk to MH's customers. The fact that a concurrent outage of both transmission lines is not without precedent (as it happened in 1996), and the fact that ice formations again threatened both existing Bipoles in 2011, indicates that an outage of the lines is a distinct possibility. It is also clear that the existing capacity of the three existing Lower Nelson River generating stations at 100% output already exceeds the capacity of the existing two Bipoles.

The Chairman, on the other hand, is of the view that MH has not sufficiently re-evaluated the Utility's initial view that Bipole III is required and that its construction will not "drive up" Manitoba's domestic rates, given reduced domestic demand, reduced overall exports and export pricing, and scaled down WPS export commitments.

While the Board lacks a mandate to approve MH's capital expenditures, particular capital expenditure plans predicated on export sales, the Board has to consider the economics of such expenditure plans because, in the absence of assured additional, profitable and sufficient export revenue, domestic rates could well increase materially.

To date, the Board has not been provided with any cost/benefit and domestic rate analyses supportive of the level of capital expenditure now being contemplated. In the Chairman's view, there are identified alternatives that should be thoroughly vetted before spending more funds and committing Manitoba consumers to meet any shortage of revenue that may arise with respect to meeting the projected costs of Bipole III. To that extent, MH's contention that Bipole III is being built for domestic reliability needs would best be supported by a review that includes the development of a clear definition of the various seasonal situations that could trigger the failure of Bipole I and/or Bipole II. If lower domestic rates could be expected to develop without Bipole III (or without Keeyask and/or Conawapa) within the long-term planning horizon of twenty years without any additional reliability risk, then the plans that would support such an outcome should be seriously entertained, certainly before further commitments are made to the planned capital projects.

Similarly, in the Chairman's view, if the construction of a CCCT natural gas generation plant of sufficient size can be found to provide a higher net present value than MH's current preferred development plan (Bipole III, Keeyask and Conawapa), then ratepayers should be made aware of this opportunity, as well as the projected domestic rate differential between MH's preferred plan, towards which MH has already spent and continues to expend significant funds, and a different plan, such as one that involves a CCCT natural gas generation plant in southern Manitoba.

Exports appear to be the primary driving force for the "early" (ahead of domestic need) in-service date for Keeyask G.S.. The Chairman is of the view that the export revenues expected to be generated by the new generation plant appears to also represent the impetus for an early in-service date of Bipole III. The Vice Chair does not share this view. As set out above, the Vice Chair is of the view that Bipole III is a required reliability measure even in the absence of additional export capacity.

Both the Chairman and Vice Chair believe that absent Keeyask, the construction of Bipole III can be expected to increase domestic rates. The question that remains is whether if Keeyask is built, the construction of Bipole III will still increase domestic rates. The Chairman is hopeful that both capital projects will be subjected to a full NFAAT hearing. The Chairman notes that if an economic case can be made for the deferral of Bipole III, Manitoba ratepayers would be the beneficiaries of lower electricity rates, as 100% of Bipole III's costs (not only the capital costs, but also the finance and operating costs associated with it) will, under MH's cost allocation, be borne by MH's domestic consumers. The Vice Chair does not share this view, and believes that while an NFAAT may be warranted for any new generation capacity, Bipole III should not be delayed. MH has advised, and has filed with a Board a letter from the Provincial government confirming, that an NFAAT review will be scheduled for the major capital projects.

15.0.0 ENERGY SUPPLY

15.1.0 HYDRAULIC GENERATION

15.1.1 Watershed Components

MH's hydraulic generation relies on flows originating in five large watersheds, as follows:

	Drainage Area (sq. mi.)
Lake Winnipeg Watershed	380,000
Winnipeg River	53,000
Saskatchewan River	157,000
Red River	110,000
Local Tributaries	60,000
Burntwood & Churchill (CRD) Watershed	115,000
Total Lower Nelson River Watershed (incl. Churchill River Diversion)	540,000

Since 1972, calculated and recorded inflows into Lake Winnipeg have fluctuated on an annual basis from 50% to 180% of the long term average/mean of 70,000 cfs. These represent about 70% of the total drainage system area, and about 67% of the total average annual flows on the lower Nelson River.

Because the Winnipeg River watershed contribution to total hydraulic generation output of 38% exceeds the contributions of the other watersheds, it is the most critical watershed for MH's hydraulic output.

The next largest contributor to hydraulic output is the Lake Winnipeg local drainage system, which includes Lake Manitoba/Lake Winnipegosis, with a combined surface area of 14,000 sq. mi. plus direct inflow from gauged and ungauged tributary streams. On average, this watershed accounts for another 24% of MH's hydraulic output. Seasonable run-off predictions are further complicated by the limited number of smaller stream gauging stations currently in use.

Both of the above watersheds tend to experience the same ups and downs of flows, as they typically experience the same weather systems. A drought is likely to affect both.

The Red and Saskatchewan River watersheds, respectively, account for 22% and 32% of watershed areas and 7% and 14% of MH's average annual hydraulic generation output. With 23% of the total watershed area, the Churchill River Diversion (CRD) and the Burntwood River account for 17% of MH's total average annual hydraulic generation.

While MH manages its hydraulic resources on an overall watershed basis, the foregoing suggests a more focused approach on the Winnipeg River and local Lake Winnipeg watershed have merit.

The Winnipeg River watershed is already well-monitored and controlled. This allows for reasonable spring run-off predictions. However, the local Lake Winnipeg watershed would require the resumption/expansion of tributary flow gauging stations, and a considerable effort to track net precipitation-/evaporation (as it occurs) for purposes of predicting Lake Winnipeg water levels.

15.1.2 Hydraulic Generation Output History

Since the implementation of Lake Winnipeg regulation and the construction of the Churchill River Diversion, MH has experienced cyclical variability of both river flows and hydraulic generation. There have been extended periods of low flow, as experienced from 1980/81 to 1984/85 and again from 1987/88 to 1991/1992. Most recently, an extended period of mostly high flows started in 1996/97 and continued to 2010/11 (a period that includes the drought of 2002-2004).

Since the construction of Limestone G.S., total annual watershed flows and hydraulic generation output have averaged 115,000 CFS (3,230 m^3/s) and 29,000 GWh. During that period, the minimum annual Lower Nelson River flow of 76,000 CFS (2,160 m^3/s) and the minimum annual hydraulic generation of 18,500 GWh occurred in 2003/04. The highest annual hydraulic generation of 37,200 GWh occurred in 2005/06, with an annual Lower Nelson River flow of 180,000 CFS (5100 m^3/s). It is noteworthy that flows above 150,000 CFS (4300 m^3/s) are, essentially, spilled without producing additional hydraulic output.

Over the last 19 years, MH's hydraulic output has been

- above 30,000 GWh in 11 years;
- 27,500 to 39,000 GWh in 7 years; and
- below 27,500 GWh in 1 year.

In the preceding 14 years, the hydraulic output was:

- above 30,000 GWh in 5 years;
- 27,500 to 30,000 in 1 year; and
- below 27,500 GWh in 9 years (8 years below 25,500 GWh).

While high flow years can be associated with flooding, hydraulic output above 30,000 GWh essentially ensures favourable export sales (assuming "normal" pricing – which has not been the case since the credit crisis and recession of 2008/09). The important question is: how long can above average flows be expected to continue?

Revisiting the 100 years of recorded flows into MH's overall watershed suggests that extended periods (up to 2 decades) of average and above-average flows are unprecedented. Historical experience does not preclude an extended (12 of 14 years) low flow period, as occurred from 1929/30 to 1942/43.

MH indicates that after deducting a 500 MW reserve capacity, Bipole I and Bipole II could, theoretically, transmit up to 29,400 GWh of energy per year to the common bus -

this exceeds the existing Lower Nelson River maximum achievable output of 26,100 GWh.

15.1.3 More Conservative Hydraulic Operations

In recent years, MH has been faced with high reservoir levels and the necessity of spilling water. Conserving water as energy-in-storage does not have the appeal it usually does in some years. And, provision must be made for sudden reversals in water flow conditions, such as occurred in 2002/03, 2003/04 and 2006/07.

With domestic energy requirements now exceeding dependable hydraulic generation, the risk of excessive summer demand rises. A consideration of minimum energy-in-storage levels was recommended by the independent consultants, Drs. Kubursi and Magee.

15.1.4 Supply Constraints on Lower Nelson River Generation

MH's energy supply is currently not constrained by transmission capabilities within Manitoba. The existing Lower Nelson River plants are adequately served by Bipole I and II transmission, even in high-flow years.

However, this could change if Keeyask G.S. were to proceed without or in advance of Bipole III. MH contends that without Bipole III, the full output of Keeyask and the existing Lower Nelson generations could not be transmitted to the Southern Common Bus. Bipole I and II, with an upper transmission capability of 29,400 GWh, could transmit up to 80% of the upper limit of achievable annual hydraulic generation of 32,000 GWh from a constructed Keeyask and from the three existing Lower Nelson plants. MH disagrees with the use of an energy comparison and "looks" only to the installed capacity in defining the potential shortfalls of Bipole I and II.

15.2.0 NON-HYDRAULIC RESOURCES

15.2.1 Thermal Generation

MH's present thermal (non-renewable) resources are as follows:

- Brandon coal plant – 105 MW with a maximum output of 811 GWh/year (now available to meet a drought but expected to be decommissioned in 2018/19 for environmental reasons);
- Brandon SCCTs – 298 MW with a 2,350 GWh maximum output (generally not price competitive with imports); and
- Selkirk natural gas – 132 MW with a 953 GWh maximum output (again, generally not price competitive with imports).

The thermal resources have value as a dependable energy resource, but their limited availability because of either environmental or economic reasons contributes to MH's risk when the Utility sells energy in excess of hydraulic generation. Additional imports, beyond diversity imports, are likely to be substituted for MH's thermal production in almost all years, going forward.

15.2.2 Wind Generation

Post-2010/11, MH will have 236 MW of contracted wind energy with an estimated average annual output of 700 GWh. This equates to about a 35% on-line factor (the wind does not always blow).

With current average opportunity export prices consistently being below 3¢/kWh, MH may not see a positive revenue stream from its committed wind energy purchases from the Manitoba suppliers for many years.

15.3.0 DEMAND SIDE MANAGEMENT

MH's DSM programs are intended to provide an economical energy resource, one that either reduces imports (which represents coal or gas-fired generation) or increases exports. These programs were last evaluated at various times when the marginal cost of electricity, as defined by opportunity (spot) export prices, was upwards of 5¢/kWh. Going forward, with average opportunity export prices under 3¢/kWh, some of these programs may no longer be cost-effective, although they continue to have environmental value.

15.4.0 IMPORTS

MH typically expects to import some energy from its American utility counterparties in order to maximize its export sales, not only to American utilities but also to Ontario and Saskatchewan. The imports may be linked to firm contract provisions under Export Contract Agreements, or be non-firm and sourced from the MISO market. The price of imported energy is either that established for firm imports or tied to spot MISO market prices.

Other than in apprehended or actual drought situations, MH reports that it does not depend on imports.

15.5.0 TOTAL DEPENDABLE ENERGY SUPPLY

MH's Power Resource Plans (PRP) tend to use the total of its dependable energy (from hydraulic, thermal, wind, DSM and imports) to derive an approximate limit for the Utility's firm energy obligations. The aggregate of non-hydraulic generation resources (thermal, wind, DSM and imports) over the next 6 years will be in the annual range of 8,000 to 9,000 GWh.

Were MH to actually "sell" the 8,000-9,000 GWh of non-hydraulic resources in dependable or low-flow conditions, a significant revenue shortfall would likely arise.

Even if MH relied primarily on spot-priced imports, the marginal revenue could still be negative.

15.6.0 INTERVENER POSITIONS

Interveners did not focus on hydraulic resource planning.

15.7.0 BOARD FINDINGS

In section 4.8.0 the Board has already recommended that alternative development plans be considered, including CCCT natural gas thermal generation. MH's supply system seems to lack diversity, which could mean that it is overly exposed to drought risk. With CCCT generation, domestic production could replace potentially higher priced imports in either a drought or the rare occasion that one or both of the Bipole lines were down.

16.0.0 CARBON TRADING IN MH'S MARKETS

16.1.0 RENEWABLE ENERGY MANDATES

Within the MISO region, as across North America, the previous prospects for a substantial carbon tax or a cap-and-trade system that would be beneficial to MH and its hydro-based generation appear to have, at least until the economy has fully recovered, largely evaporated. One sign of this new reality is that the Chicago Climate Exchange market has been closed.

The focus of American utilities in the MISO region is now, as it has been in the past, on providing minimum-cost and reliable energy, with environmental attributes ignored except as mandated under renewable energy targets.

Various states, including Minnesota and Wisconsin, have renewable mandates that range up to a requirement that 25% of generation must be from renewables. This has led to a rapid expansion of wind generation within the MISO region. The sudden expansion in wind resources is in large part related to the ability of utilities to typically pass through the capital recovery costs directly to ratepayers, assisted by a 1.7¢/kWh federal U.S. Government subsidy on all wind energy generated. To qualify as renewable energy for MISO purposes, hydroelectric power generated by MH must come from new "small hydro" facilities. Specifically, Wisconsin would accept power imports from MH's 200 MW Wuskwatim project, while Minnesota presently has a cap of 50 or 100 MW to define new "small hydro".

MH has advised that its new (or pending) sales contracts with American counterparties transfer any "environmental attribute" associated with renewal hydro generation to the importer.

The very competitive wind energy now in place within the MISO market (24,000 GWh in 2010, up from only 3,000 GWh in 2008) constrains the limits of MH exports. It appears that back-stopping wind (wind power is not available about 65% of the time) in peak and off-peak periods or out-bidding CCCT natural gas generation during peak periods represent MH’s most likely prospects in the export opportunity sales market.

16.2.0 CARBON CREDITS WITHIN FIRM CONTRACTS

MH’s hydraulic energy is generally acknowledged to have a very low carbon footprint. Compared to coal-fired and natural gas thermal generation, CO_2 emissions can be almost negligible for run-of-the-river hydro plants.

Within MH’s primary MISO market area, many states do not accept large hydro generation (greater than 50 to 100 MW) as qualifying for renewable energy credits. This does not preclude MISO utilities from claiming CO_2 emissions reductions for imported hydraulic energy for “public relations” purposes.

Currently, it is the Board’s understanding that MH’s MISO region customers are not willing to pay a premium for MH’s “clean” renewable power. Instead, MH is faced with offering free carbon credits for at least the bulk of its exports (non-firm as well as firm).

The “free” inclusion of carbon credits in export sales may, at times, be compounded by MH’s regular use of imports from thermal generation to either support its export sales or replace lost hydro generation in drought conditions. When MH employs lower cost off-peak imports, the probable source is coal-fired generation, which has twice the emissions than natural gas generation.

16.3.0 INTERVENER POSITIONS

Because RCM/TREE’s view is globally oriented, for RCM/TREE MH’s potential negative position with respect to giving up any environmental attributes attached to its “clean” exports to the purchaser is of no immediate concern. MH’s clean energy is beneficial globally, as it likely displaces fossil fuel-based electricity.

Other Interveners did not take a position on this issue.

16.4.0 BOARD FINDINGS

The Board notes that MISO currently does not recognize MH's clean energy as a distinct product with a higher market value than regular energy. As such, MH is currently not realizing any premium from the fact that its electricity is generated hydraulically.

17.0.0 DEMAND SIDE MANAGEMENT

11.1.0 GENERAL

MH's Demand Side Management (DSM) initiative, "Power Smart", consists of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. The most current plan is the 2010 Power Smart Plan, which was filed during this hearing.

For electric operations, the initiative plays an important role in the Corporation's overall integrated resource plan. DSM initiatives assist customers in meeting their energy needs through energy-efficiency measures. Such initiatives enable MH to serve domestic customers with less energy. Reduced domestic load requirements allow for either reduced or deferred capital expenditures or increased energy exports.

17.1.0 PROGRAM EVALUATION

To evaluate new programs, a high level assessment (Marginal Resource Cost Screen) compares the expected benefits to the incremental capital costs. If a program passes the initial screening, a more detailed assessment is undertaken, which involves developing program concepts and designs and projecting costs and benefits.

MH determines the cost effectiveness of DSM programs using the Total Resource Cost (TRC) and Rate Impact Measure (RIM) Tests. The primary economic indicator for evaluating the effectiveness of both electricity and natural gas incentive-based programs is the TRC test. TRC measures the cost-effectiveness of a product or program, and a TRC benefit/cost ratio greater than one (>1.0) indicates that a program is cost-effective.

The secondary economic indicator for evaluating the effectiveness of programs is the RIM test. RIM indicates the cost effectiveness of a program from the Utility's perspective. All DSM-related savings and costs incurred by the Utility, including revenue loss and incentive payments, affect the RIM benefit/cost ratio. The results provide an indication of a program's expected long-term impact on rates.

As a guideline, MH attempts to design electricity-based DSM programs that have a RIM of 1.0 or greater. However, a program with a RIM of less than 1.0 may result in a program redesign, and may still proceed if the program is judged to provide overall benefits.

Established DSM programs are evaluated to determine the net program load savings and costs as well as the cost-effectiveness of the savings. Net savings take into consideration factors such as free riders (benefits derived that carry no specific cost), interactive effects of heating and cooling, as well as system peak coincidence and persistence effects. Customer data and market information are used to assess the impacts of these factors on the overall savings attributable to incentive-based Power Smart programs.

MH employs the Present Value of marginal benefits in three of their cost-effectiveness tests, namely the MRC (Marginal Resource Cost), TRC and RIM. These marginal benefits include revenues realized by MH from conserved electricity being sold in the export market, avoided cost of new infrastructure (e.g. transmission facilities) and measurable non-energy benefits (e.g. water savings). MH has yet to define the specific marginal benefits (or marginal cost savings) employed in the Utility's DSM evaluation process. At prior hearings, MH indicated that the energy value for DSM initiatives was primarily derived from the export market price. Energy value could alternatively be derived from the avoided cost of new infrastructure (generation or transmission). During the PUB's earlier EIIR hearing, MH suggested a proxy value for DSM energy savings (one related to the firm peak export energy prices of about 6¢/kWh) in lieu of defining the actual energy value (deemed to be commercially sensitive and confidential).

MH's most recent IFFs do not acknowledge that the export prices for energy have dropped substantially.

In evaluating DSM programs, MH attributes no value to delayed generation in its TRC test, nor does it consider the full benefit of displacing carbon in export markets.

17.2.0 PROGRAM COSTS AND AMORTIZATION

According to MH's 2010 Power Smart Plan, the Corporation forecasts spending $414.2 million over the next 15 years (through 2024/25) on DSM expenditures, including $23.2 million to be drawn from the Affordable Energy Fund (a fund established by legislation following the peak export price year, during which natural gas prices spiked).

Cumulative spending on electric DSM from 1989 to 2024/25 is projected to be $747.3 million. MH reported that it had budgeted to spend $37.8 million in fiscal 2011 and $38.8 million in fiscal 2012 on DSM initiatives.

MH amortizes its DSM costs over a 10-year period. This approach is similar to other Crown power utilities in BC and Québec. While the deferral of DSM costs, for subsequent amortization, is not allowed under new IFRS accounting standards, the approach can be maintained for rate-setting purposes.

MH's unamortized balance of DSM expenditures was $17 million as of March 31, 1994, and is forecast to grow to $214.2 million by 2011/12. The amortization of DSM expenditures was $978,000 in fiscal 1993/94, and is forecast to increase to $24.8 million in 2011 and $28.7 million in fiscal 2012.

The IFRS requirement will require MH to write off to retained earnings the unamortized balance of DSM expenditures in MH's 2011/12 fiscal year (the forecast balance to be written off is $214.2 million). MH has stated that the IFRS requirement to annually expense DSM expenditures rather than defer and amortize those costs will have very little rate impact.

17.3.0 DSM PROGRAM SAVINGS

According to MH's 2008-2009 Power Smart Annual Review, by the end of 2008/09 MH's Power Smart Programs would have achieved an annual load reduction of 1,510 GWh in energy, and the equivalent of a 406 MW reduction in winter peak demand. This level of "saved power" was reported by MH to represent an annual reduction of approximately $46 million in electricity customer bills (with a cumulative savings for customers of $352 million since the inception of the program).

MH reports indirect greenhouse gas emission reductions of approximately 1,019,000 tonnes of carbon dioxide equivalent emissions (plus 70,000 tonnes related to Natural Gas DSM programs).

In theory, domestic energy reductions through DSM initiatives contribute to the development of surplus generation capacity, which in turn contributes to the level of energy sales in the export market. In practice, additional export sales cannot always be made and MH has "spilled" water when the maximum capacity of its generating stations has been reached and storage cannot be increased due to lake regulation provisions. Furthermore, if export prices are below domestic rates, which has been the case since the 2008/09 credit crisis and recession, there is a negative revenue impact on MH from successful DSM initiatives. This negative revenue development does not reduce the environmental values of DSM, as DSM programs help instill a conservation mentality amongst MH's customers.

The cumulative energy and demand reduction achieved (including savings to date) through the Corporation's DSM efforts was forecast to achieve 3,048 GWh/year of energy savings and 915 MW of Winter Demand by 2023/24. These targets represent the expected impact of electricity efficiency codes and standards, customer service initiatives and incentive-based program activities. MH noted that the majority of the savings are to be realized from MH's incentive-based programs.

17.4.0 CITY OF WINNIPEG DSM PROGRAM

As a condition of MH's acquisition of Winnipeg Hydro, MH and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002. The objective was to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. MH guaranteed the City an annual savings of $800,000 from the measures. If the savings were not met, MH was required to make a payment for the balance. The ten-year agreement includes a total savings commitment of $8.8 million.

MH has actually invested $10.6 million into DSM measures under the agreement. This includes $3.2 million in "commitment" payments, $6.4 million in energy efficiency project costs and $1.0 million in program administration and management fees.

MH stated that due to the energy savings realized from the initiatives undertaken, MH will be economically better off, as the energy saved is available for export.

17.5.0 CARBON TRADING

In 2002, MH became a founding member of the Chicago Climate Exchange (CCX). CCX required participants to reduce emissions relative to historic baselines. Each participant was provided an annual allowance of CCX units, which decreased each year from the historic baseline. If a participant's emissions exceeded the participant's allowance, the participant was required to buy additional units through the exchange. Conversely, if their emissions were below their allowance, they were able to sell the surplus units.

The CCX market permanently closed on December 31, 2010. An active carbon trading regime has not materialized. Without carbon legislation in the U.S. jurisdictions into which MH exports, coal-fired electricity generation remains the least-cost base load option for most American utilities.

17.6.0 LOWER INCOME DSM PROGRAM

In its 2006 Power Smart Plan, MH introduced a new residential program, the "Hard To Reach" (HTR) program. The HTR program targets lower income residential households on an integrated basis (i.e. for both natural gas and electric consumption). The program has since been modified into the Lower Income Energy Efficiency Program (LIEEP), which leverages MH's Power Smart programs, the Affordable Energy Fund (AEF), the Federal Government ecoENERGY Program, provincial government programs and existing community-based infrastructure.

The objective of LIEEP is to ensure that the financial benefits associated with implementing Power Smart energy efficiency measures will be realized by low income consumers. The program targets both lower income Manitoban homeowners and tenants. MH provided an update during the hearing, which indicated that participation of electric households in the LIEEP through 2010/11 totalled 720 households.

Rental buildings for which the landlord pays the energy bills are not eligible for participation in the LIEEP, as the landlord would be realizing the benefits of lower energy bills rather than the low income tenant. In the case of lower income tenants who do pay energy bills, an agreement must be reached between MH and the landlord or building owner to ensure that a substantial portion of the benefits associated with retrofit measures funded by MH's program will be passed on to tenants.

Non-profit social housing organizations, including the Manitoba Housing Authority (MHA) and other non-profit subsidized housing organizations, are eligible to participate in the program. An agreement has been reached between MH and MHA, whereby MHA will pay the AEF portion of the cost of the upgrades in cases where the tenant is not directly paying the energy bill.

Eligibility for households pursuant to the program was established by the Corporation at 125% of the Low Income Cut-Off (LICO) established by Statistics Canada. MH undertook a 2009 residential survey which indicated that 74,938 households meet the LICO standard and 105,784 households meet the LICO-125 criteria.

Targeted measures to be addressed by the program include:

- low or no-cost basic energy efficiency measures, such as compact fluorescent lights;
- faucet aerators, low-flow showerhead, pipe wrap, hot water tank set-back, and caulking/air-sealing;
- insulation for basement, attic and crawlspace installations; and
- high-efficiency natural gas furnaces.

MH intends to deliver the program through both Community Based Organizations (CBO) and individual household participation. Both approaches require pre- and post-completion audits to identify energy efficiency opportunities and verify that the work was completed.

17.7.0 HOME ENERGY BURDEN

Home energy burden represents energy bills as a percentage of household income.

The concept of the customers' "energy burden" is not employed in the design or assessment of MH's affordable energy programs. MH's stated position is that issues surrounding affordability are outside the scope of MH's mandate and is a matter of policy for legislators and government agencies responsible for these issues.

Since the commencement of LIEEP in 2005/06 through to 2009/10, MH has spent $1.9 million on electric LIEEP, including $0.7 million from Power Smart and $1.2 million from the AEF. MH had forecast to spend $3.8 million in 2009/10 on electric LIEEP, including $3.2 million from the AEF, but only spent $0.5 million in total including $0.4 million from the AEF. MH attributed the $3.3 million shortfall to low participation levels in the program.

17.8.0 THE AFFORDABLE ENERGY FUND (AEF)

Following a spike in oil and natural gas prices in the summer and fall of 2005 on the heels of hurricanes Katrina and Rita, which damaged energy availability from south-east American production and distribution sites, and also following the Board's action on November 1, 2005 when it deferred costs and restrained natural gas rates for Centra Gas' residential customers to recognize what the Board deemed to be a price spike, the Province of Manitoba introduced *The Winter Heating Cost Control Act*, which was subsequently passed, proclaimed and implemented in 2006. Among other provisions, the Act established the Affordable Energy Fund (AEF), requiring MH to contribute 5.5% of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of $35 million to be utilized for various energy efficiency initiatives which were to primarily assist low-income electricity and natural gas customers.

MH indicated that $19 million of the AEF's $36.8 million was earmarked for province-wide low-income initiatives. MH indicated its intention that the $19 million reserved for low-income programs would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from MH/Centra's rate-based DSM programs.

A breakdown of the allocation of the AEF and the spending to 2009/10 is as follows:

Projects	**Allocated**	**Actuals to December 31, 2010**
Low – Income / Community Based Initiative	**$19.0**	**$5.1**
Geothermal Support	**$6.0**	**$1.4**
Community Energy Development	**$8.0**	**$0.8**
Oil and Propane Heated Residential Homes	**$0.25**	**$0.2**
Residential Energy Assessment Service	$0.5	$0.5

Oil and Propane Furnace Replacement	$0.2	$0.1
Residential Solar Water Heating Program	$0.3	$0.3
Power Smart Residential Loan	$1.2	$1.2
Unallocated Interest Accruals	$0.6	-
Special Projects	**$2.8**	**$2.0**
Total	**$36.8**	**$9.7**

17.9.0 FIRST NATIONS/ DIESEL COMMUNITIES

MH has employed a dedicated team and partnership approach to pursue energy efficiency opportunities in First Nations communities. The approach includes identification of ten homes in the community for which an initial home audit will be conducted. MH then trains First Nations members to undertake required retrofits, supplies the materials, and assists the First Nations in obtaining any Federal government ecoEnergy grant programs funds that may be available.

MH reported that it had completed work on 10 homes on two First Nations communities, and was shipping material to retrofit 15 homes in three other communities. It was also working with other communities, including communities served by diesel generated electricity, to see if they were interested in participating in the program.

17.10.0 DSM PROGRAM EVALUATION

MH contracted Phillipe Dunsky to undertake a Power Smart Portfolio Review. Mr. Dunsky made several recommendations to reinvigorate and expand the DSM program of MH. Some of the recommendations were to close program gaps by creating and expanding programs for:

- multifamily residential housing;
- manufactured new homes;
- consumer electronics and office equipment;

- appliance retirement;
- new commercial construction; and
- commercial custom retrofit.

MH has acted on many of the above initiatives by expanding its program offerings, including, among others, the development of a Refrigerator Recycling Program and a Commercial New Buildings Program.

Mr. Dunsky also recommended that MH:

- provide market training in the residential sector, beginning with the review of opportunities and needs for all programs;
- utilize upstream incentives in both residential and commercial/industrial sectors, beginning with the comprehensive review of the potential for upstream incentives in all programs; and
- consider options for encouraging limited third-party ideas or implementation. MH should evaluate the effectiveness of variety of options for encouraging innovation within the Province. Third-party set-asides such as those in California and Minnesota were one option to consider.

MH cited several examples where it has sought collaboration with third parties to deliver programs and where it intends to continue to pursue third-party collaboration whenever the option is assessed to be the most efficient and effective.

MH did not agree with establishing third-party set-asides as being an effective and efficient strategy for achieving the Corporation’s energy-efficiency objectives. It thought that such an approach could lead to implementing some programs in a more costly manner and simply spending the set-aside funds as opposed to undertaking initiatives in a more cost-effective manner.

Mr. Dunsky also recommended that MH establish aggressive energy savings targets such as 1 to 2% per year, in line with those of leading regions. In response to this recommendation, MH agrees with establishing aggressive energy conservation targets. However, MH believes that it is more appropriate to base the targets on identifiable economic potential for achieving energy savings rather than basing targets on arbitrary percentages. MH indicated that it is going to undertake a market potential study to identify current energy savings potential remaining in the province and will conduct a detailed comparison of MH's Power Smart Plan to BC Hydro's Power Smart plan to assess potential gaps in targeted energy savings.

Mr. Dunsky also recommended that DSM programs should be screened by the Program Administrator Cost Test (PACT), Total Resource Cost (TRC) or Societal Cost Test (SCT). Mr. Dunksy stated that the RIM test is likely leading to lost opportunities. At the last GRA, Mr. Dunsky opined that the RIM test should not be utilized to screen for justification of DSM programs. While TRC should remain the primary test for DSM programs, under MH’s current approach there will be proposed measures that will fail the TRC test that should still be pursued if they pass the “utility cost” test. The utility cost test compares money invested in a program with the value of expected energy savings for the utility. If MH can generate cost-effective kWh savings, the program initiative should proceed. In his review of the Power Smart Program, Mr. Dunsky urged MH to reconsider its screening process as a whole to ensure that it is in line with common leading practices.

MH did not agree with this recommendation. MH uses a number of cost effectiveness tests to assess energy efficiency opportunities, preferring to use the Levellized Utilities Cost test rather than PACT. MH also stated that it uses a more inclusive version of the TRC than the SCT, and also considers various qualitative factors including equity (e.g., reasonable participation by various ratepayer sectors) and overall contribution towards having a balanced energy conservation strategy and plan. MH also disagreed that the use of the RIM test was restricting its ability to pursue energy efficiency opportunities.

Lastly, Mr. Dunsky recommended that MH

- screen alternative program designs for total program cost effectiveness;
- reconsider its screening process as a whole to ensure it is in line with common and leading practices; and
- consider an expert-supported stakeholder advisory group in which stakeholders are funded supported by independent experts in a non-adversarial setting.

MH stated that stakeholder meetings to share policy and conceptual information provide some value but that such a process proves to be ineffective for establishing detailed program designs, which involve specific marketing concepts, product delivery channels, and undertaking complicated computer assessments to provide program metrics. MH further does not support the recommendation for funding external consultants for stakeholders, as this would result in a duplication of resources and be a very costly approach. MH stated that the regulatory process allows for a reasonable amount of oversight with respect to MH's DSM programs through the hiring of consultants, and that the extent of this investment is already controlled through the regulatory process.

17.11.0 INTERVENER POSITIONS

17.11.1 CAC/MSOS

DSM Program

CAC/MSOS acknowledged that MH's staff involved with DSM has a commitment to energy demand reductions and that the Corporation has a historical reputation in offering strong programming within the Canadian context. However, CAC/MSOS holds that MH attributes savings to some of its residential plans which are more optimistic than those adopted by other well-respected bodies in the area of energy efficiency (such as the Ontario Power Authority).

CAC/MSOS urged the Board to make a finding that the Power Smart residential incentive-based programs are lagging relative to the plan as a whole, with a major factor being low participation rates. CAC/MSOS noted that the low participation rate was most evident in the LIEEP and the low spending from the AEF.

CAC/MSOS recommended the Board accept the evidence of Mr. Chernick, who concluded that the 2009 and 2010 DSM plans appeared to be deficient insofar as they involve spending less and aiming lower in terms of their savings targets and spending targets compared to previous levels. For CAC/MSOS, MH's DSM program has not demonstrated a commitment to maximizing benefits for consumers.

CAC/MSOS accepted the conclusion of Mr. Dunsky that MH will need to be more ambitious with its electricity savings goals and should reconsider its current portfolio of programs and strategies to maximize energy efficiency. CAC/MSOS recommended that the Board make a finding that given the poor performance of the 2009/2010 Power Smart Plan, there is a demonstrated need to make major changes in the DSM program.

CAC/MSOS further urged the Board to determine that there is a broader need for independent third-party audit of Power Smart. MH should be required to consult with the Board and interested interveners prior to finalizing the terms of such a review.

Low Income Programs

Of particular concern to CAC/MSOS is the low participation rate in the LIEEP and the low spending of the AEF. CAC/MSOS recommended that the Board find that the challenges faced by the LIEEP suggest the need for a strategic review of the program to be provided by an independent third party who would undertake an evaluation and audit of MH's operations, to be filed with the next GRA. CAC/MSOS recommended that MH, prior to undertaking the review, consult with stakeholders as well as the Board to finalize its scope.

Dr. Tom Carter appeared on behalf of CAC/MSOS and spoke to issues related to energy poverty and low income rate affordability in Manitoba. Dr. Carter listed four approaches to energy poverty:

- the demand-side approach, where funds, loans, or grants are provided to households so they can purchase more energy efficient appliances or retrofit or weatherize their homes;
- the supply-side approach, where direct payments or subsidies are made to households to increase their income to help them cover the cost of energy;
- the bill management approach, which may involve the negotiation of late payment charges, a plan to pay down arrears, equalized payment plans, or forgiveness plans; and
- the regulatory requirements and frameworks that are set in place.

CAC/MSOS submitted that the problems of energy affordability facing low income Manitoba residents have severe social, economic, and business consequences that permeate throughout all sectors of the province. From a social perspective, unaffordable home energy not only threatens the ability of low income customers to maintain access to their utility service, but also imposes a range of adverse consequences threatening the health, housing, and general welfare of those households. Unaffordable home energy bills mean that low income Manitoba residents will go without food, medical care or other life necessities.

Dr. Carter stated that addressing the energy affordability of low income homes will generate positive social benefits. It will improve public health and safety and bolster the competitiveness of local business and industry. It will also reduce the cost of non-payment and improve the efficiency and effectiveness of utility collection efforts.

Demand and supply-side programs, according to Dr. Carter, can help reduce the cost of credit collection, bad debts, as well as termination and reconstruction costs for the utility.

In spite of the positive aspects of these programs, Dr. Carter does not think they are sufficient to make much of a difference when it comes to poverty alleviation, and states that these programs are not integrated with other programs that should help address the long-term and systemic causes of poverty.

In reviewing U.S. bill assistance programs, Dr. Carter noted particular challenges associated with the delivery of energy poverty programming, with the biggest problem being the low participation rate of many of these programs. Other challenges include difficulty in identifying the working poor, high mobility rates, the apprehension and suspicion about dealing with government, and the fact that people in poverty are so occupied with everyday existence that they cannot devote the time to avail themselves of these programs.

Dr. Carter stated that low participation rates create real problems with respect to horizontal equity. In particular, if programs are paid for through charges to the ratepayers of the utility, there is a subgroup of people that is eligible for the programs but does not avail themselves of them, yet has to help pay for the programs for the other subgroup that does use them.

In general, Dr. Carter suggested that MH was not as well-placed as some other departments in government to deliver energy affordability alleviation programs or poverty alleviation programs in general.

Dr. Carter indicated that utilities are not the best source of broad strategic poverty alleviation policies. These policies are the mandate of government, which has to build a package on the basic planks that government has in place to deal with poverty. To be effective, programs have to be integrated as part of a broad strategy that includes money for education, money for skills development, and programs to get people back in the workforce. According to Dr. Carter, the integrated approach that is currently in place fails in large degree because the levels of assistance under Social Assistance and minimum wage do not ensure that households have a level of income that will provide them with a good quality of life and opportunities to improve their potential in society. Energy poverty alleviation programs are not sufficient. Although such programs serve an important role, they should not be considered as poverty alleviation vehicles because they are not long-term, do not provide deep levels of assistance, and are not integrated with other program vehicles.

Dr. Carter stated that there are three sides to the energy poverty equation, these being price stability, energy efficiency and income stability. CAC/MSOS submitted that the best way to assist all vulnerable consumers through the regulatory process is to insist upon ongoing prudence in the operations of MH in order assist MH to achieve just and reasonable rates and invest significantly in low income energy efficiency.

CAC/MSOS endorsed recommendations made by RCM/TREE's witness Mr. Colton that MH adopt a crisis intervention and arrears management program, while rejecting Mr. Colton's recommendation for a Low Income Rate Assistance Plan. In objecting to the Low Income Rate Assistance Plan recommended by Mr. Colton, CAC/MSOS cited several concerns, including that:

- the program is unlikely to assist the poorest of the poor, as those individuals on income assistance are already receiving help with respect to their utility bills;
- the program's participation targets will not be met;
- the program runs the risk of a diverting scarce resources away from other programming such as LIEEP; and
- in light of low participation rates, they program would be horizontally inequitable.

CAC/MSOS also raised the question of the Board's jurisdiction to impose such a program given Manitoba's statutory framework.

17.11.2 MIPUG

Low-income programs

MIPUG has no issue with any bill assistance program that is funded on a voluntary basis. To do otherwise would be, in MIPUG's view, discriminatory. MIPUG noted that unless there is 100% participation in the low-income programs, the low-income customers that do not participate in the program indirectly get penalized.

With respect to the role of MH in low income programming, MIPUG cited Dr. Carter, who suggested that MH participate in an integrated strategy but not a funder of programs to alleviate poverty.

17.11.3 RCM/TREE

DSM Programs

RCM/TREE adopted the evidence of Mr. Paul Chernick. RCM/TREE acknowledged the excellent work on DSM efforts made by MH in the past. RCM/TREE approves of the recently unveiled refrigerator program and the efforts being made in the First Nation communities served by diesel generation. RCM/TREE expressed concern that MH is not planning to continue its DSM efforts as aggressively in the future.

RCM/TREE noted that Mr. Chernick had graphed MH's projected DSM savings to 2025, observing a precipitous decline in both DSM efforts and annual incremental savings. For Mr. Chernick, MH's DSM efforts are modest compared to those of many other North American jurisdictions. He noted that other jurisdictions target DSM energy savings of 1% to 2%, while MH's forecast begins at 0.6% and declines to 0.2%.

Also, when compared to other jurisdictions, for Mr. Chernick MH's spending on DSM per MWh was insufficient. Mr. Chernick concluded that MH should be able to double or triple its energy efficiency spending and savings from current levels and maintain such efforts throughout the planning period. RCM/TREE recommended that the Board benchmark its DSM programs to the programs of the three leading providers as identified by Mr. Dunsky, namely Pacific Gas and Electric (California), Efficiency Vermont and Xcel Energy Minnesota.

RCM/TREE also recommended that the Board establish DSM targets for MH to require the Corporation to increase its energy efficiency investments to reach the 90th percentile of North American jurisdictions, and that the RIM test be abandoned for program design screening.

RCM/TREE proposed that MH establish a link between DSM programs and Power Smart rates. RCM/TREE noted that rates and rate structures that fail to provide appropriate price signals undermine the performance of Power Smart DSM programs by offering contrary incentives that, in effect, subsidize higher consumption by applying embedded cost savings and export earnings volumetrically. If incremental use of electricity is underpriced, the true cost of growth imposed on other users, the utility, the province and the global environment is hidden and conservation and self-generation options become less cost-effective or suffer a longer payback period.

RCM/TREE cited past Board Orders which supported conservation incentives in rates and questioned the Board’s interim rate Order 40/11, which effectively eliminated the block differential for residential rates and provided no change to the basic charge. RCM/TREE noted that a reading of Order 40/11 illustrates a tight link between affordability goals, conservation goals and rate-setting. RCM/TREE submitted that MH's mandate to promote economy and efficiency in the end use of electricity cannot be adequately fulfilled without supportive Power Smart rate structures. RCM/TREE also stated that the energy system must mitigate the potential impacts of higher marginal rates on those customers who are least able to afford the energy. In summary, RCM/TREE submitted that MH cannot deliver on its mandate to provide its domestic customers with the benefits of electric power economically and efficiently unless it can also deliver effective measures to mitigate unaffordable energy burdens among its low income electricity customers.

RCM/TREE supports MH's initial proposal to reduce the Basic Monthly Charge by $2.00 over two years. RCM/TREE also supports Mr. Chernick's recommendation that the Board re-establish a rate inversion by making the tail-block 5% higher than the first block at the outset. In subsequent years, the first block should be reduced to no more than 600 kWh/month and the tail-block rate moved towards marginal costs. To mitigate the heating burden of existing electric heat customers, Mr. Chernick proposed offering a larger first block of lower cost energy in the winter months. The size of the first block would be set with the objective that the average heating and non-heating customers would end up paying the same blended energy rate over the two energy blocks.

RCM/TREE urged the Board to instruct MH to modify rates in the following ways over the next several years:

- increase tail block energy rates to marginal cost, including environmental costs;
- implement marginal cost-based rates for larger general service customers, using a two-part rate if necessary;
- use the increased revenues from tail block energy sales to reduce customer demand and fund enhanced energy-efficiency programs, low income customer discounts, and economic development, and improve MH's financial structure; and
- implement time-of-use energy charges, starting with the largest customers, and move revenue collection from demand charges to time-of-use energy charges.

RCM/TREE indicated that the implementation of these initiatives can take place at MH's next rate proceeding.

Low Income Programs

RCM/TREE submitted that MH should institute an affordability program as recommended by Roger Colton, who appeared on behalf of RCM/TREE. Mr. Colton stated that energy bills impose a substantial burden on low income households served by MH. Current home heating, cooling and electric bills in Manitoba have driven the home energy burdens for households living with incomes at or below 125% of LICO to crushing levels. Mr. Colton stated that the Board should be concerned when the energy burden of consumers exceeds 6% of household income. According to Mr. Colton, an affordable home energy burden is 6% of income as compared to a “severe” energy burden of 15%.

Dr. Colton proposed a four-part low income affordability program, consisting of :

1. A rate affordability component that brings the bills of low-income customers (LICO-125) within a range of affordability (6% of income) through offsetting credits. The annual credit is determined by first establishing a burden-based payment set at 6% of income. That amount is then compared to an estimate of the projected annual energy bill for the household. The credit would be based on the difference between the burden-based payment and the total projected annual energy costs. The credit would be applied to monthly energy bills and would be fixed to provide an incentive for conservation.

2. An “arrearage” management program, which retires a customer's arrears over three years in exchange for monthly contributions by the customer to his arrearage retirement. The program is designed to reduce pre-program arrears to a manageable level over an extended period of time. The customer earns credit towards the arrearage balance, so long as the customer remains on the affordable rate. The payment under the scheme is to be set at $5 per month or $60 per year to go towards the arrearage balance.

3. A crisis intervention component that addresses the income fragility of low income households. The crisis intervention component should not be based on income eligibility and should provide administering agencies with flexibility to distribute assistance on an as-needed emergency basis. The program should be limited in time and the funding should be distributed through existing crisis intervention programs.

4. An energy-efficiency component, similar to MH's LIEEP, with improved integration and other components and accelerated roll-out.

The cost of operations and administration of the first three components of the program should be recovered through meter charges and late fees. Mr. Colton estimated the cost of the proposed program to be $44.2 million, including the provision of rate discounts sufficient to reduce energy burdens to no more than 6% for LICO–125 households. Mr. Colton provided a set of scenarios with differing program energy burden thresholds between 6% and 10%, with a cost ranging from $24.9 million (10% energy burden threshold) to $44.2 million (6% energy burden threshold).

RCM/TREE stated that the Board has a responsibility to consider the special circumstances of low-income ratepayers when deciding what is considered to be just and reasonable rates. It would be inappropriate for the Board to ignore energy poverty as described by Mr. Colton in determining just and reasonable rates. It would appear to be self-evident that what is a just and reasonable rate for a person living below the poverty line is different than it would be for a family, for example, that spends less than 2% of its household income on energy.

RCM/TREE cited the case of *Advocacy Centre for Tenants - Ontario v. Ontario Energy Board* 293 D.L.R. (4th) 686 as judicial authority that the PUB has the jurisdiction to order the implementation of the low-income energy affordability program.

17.12.0 BOARD FINDINGS

17.12.1 DSM Programs

The Board recognizes that MH has been making an increasingly significant investment in DSM programs.

The Board encourages MH to continue to pursue environmental objectives on an integrated natural gas-electricity basis, and, in particular, to consider the difficult position of low-income customers that may be increasingly faced with higher energy costs while too often lacking the funds, if not the know-how, to achieve needed upgrades that would reduce their energy bills and GHG emissions.

The Board, as stated in Order 116/08, remains of the view that MH's DSM focus should be four-fold:

- Environmental: Wasted energy and greenhouse gas emissions should be reduced in Manitoba and in the export markets, as climate change is a global challenge.

- Economic: Energy not consumed by Manitobans should be available for sale on the export markets, ideally during peak hours and at peak prices.

- Economic: Energy not consumed by Manitobans and not sold on the export market, either due to transmission capacity issues or unfavourable pricing, can assist in the deferral of new generation and transmission.

- Social: Increasing the energy efficiency of low-income households will allow more families to remain in their homes and to have more disposable income available for necessities other than energy. The total cost of energy (gasoline, natural gas, electricity, propane, etc.) has soared for all households, but the cost increases have been particularly devastating for households in the bottom four deciles of household income levels.

The Board continues to question the appropriateness of MH's current approach of deferring DSM costs and amortizing them over ten years, and notes that this approach will no longer be allowed under IFRS. IFRS will require DSM expenditures to be expensed in the period in which they are incurred. Actual DSM expenditures are currently forecast to be $37.8 million in 2010/11 and $38.8 in 2011/12 while amortization of DSM spending is forecast to be $24.8 million and $28.7 million respectively. The difference will have to be expensed under the current IFRS pronouncements, thus putting further pressure on rates.

The unamortized balance of DSM costs is forecast to grow to over $214 million by 2011/12. This amount will likely not meet the criteria of an asset under IFRS and will have to be written off against retained earnings. Nonetheless, the Board believes that the manner in which program expenses are accounted for should not change the manner in which MH evaluates DSM programs.

The Board notes the evidence of Mr. Dunsky, who provided recommendations to MH to improve its DSM program. The Board is encouraged that MH has listened to many of Mr. Dunsky's recommendations and has proposed program changes. The suggested changes put forward by Mr. Dunsky, including changing the economic screening test to the PACT, has merit and should be considered by MH in its design of current and new low-income programs. The Board shares the view that the current screening process may be resulting in some opportunities being missed. The Board would like to see expanded program delivery to assist in conservation.

17.12.2 DSM Program Evaluation

The Board notes that MH projects that by fiscal 2023/24 it will have achieved 3,048 GWh of DSM savings for its electricity operations. If achieved, this would represent a 200% increase in DSM energy saving over 12 years, representing a growth rate of almost 17% per year. Power savings are expected to reach 915 MW, an increase of 230% over 12 years or almost 19% per year.

There is projected to be a drop in savings in later years of the program. The Board shares the concerns raised by Mr. Chernick of a decline in both investment and savings. The Board suspects that the opportunity for further reductions is significant. However the Board also realizes that projections extending fifteen years into the future are highly subjective.

During the EIIR hearing in 2009, MH offered a proxy value (related to the firm peak export energy prices) of about 6¢/kWh for DSM calculation purposes in lieu of defining the actual energy value, which MH deemed to be commercially sensitive and confidential. The Board suspects that MH's marginal benefit value in the cost effectiveness tests set out above also employs a similar proxy value, and it is clear that MH's most recent IFFs do not yet acknowledge that the export prices for firm peak energy have dropped substantially in recent years. The actual 2009/10 price was 2.83¢/kWh for peak opportunity export sales. There is reason to believe that prices under 3¢/kWh may still be the reality for years to come.

In the current circumstances, where MH's generation and transmission expansion plans appear to be moving forward despite an unfavourable export market, the Board is concerned about the level of economic benefits to be achieved by MH's existing and new DSM initiatives. To export DSM energy savings at prices below domestic rates does not seem totally logical from a financial perspective.

17.12.3 Lower-Income Energy Efficiency Programs

The Board commends MH for the broadening of its low-income programs and the inclusion of programs specifically targeting First Nation communities. However, the Board is concerned at the slow pace of delivery on the programs and notes that with respect to the LIEEP and AEF, MH has struggled to meet budgeted spending targets to date.

The Board understands that MH is working on a tenant-focused LIEEP but has yet to implement it. The Board understands that there may be resistance for landlords to take part in the program due to split incentives and the low-cost business models under which many landlords operate. MH should make every reasonable effort to increase participation rates by eligible landlords, as this benefits both low-income tenants and the environment. The Board further believes the LIEEP should be subject to an external review to ensure that all opportunities are being adequately met. To that extent, the Board will expect MH to provide the Board and interested stakeholders with draft terms of reference for a program review.

Although MH is beginning to address the issue of energy poverty, more is required. The Board is very concerned with the slow pace of the overall energy poverty relief effort. MH indicated that the current program is anticipated to provide relief to only 1,700 low-income households by the end of 2010/11. The current low-income population in Manitoba seems to comprise at least 105,000 households, meaning the program only targets about 1.6% of potentially eligible households annually. The Board agrees with the views expressed by CAC/MSOS and RCM/TREE that more should be done.

As for the AEF, the Board notes that $1.4 million in interest has accrued on the balance in 2009/10, thereby allowing the AEF balance to grow. This additional amount can be used to fund further low-income programs. The Board recognizes that capacity issues may exist in program delivery. However, the material budget variances which have become apparent indicate that capacity constraints may not be the only obstacle. This, too, warrants an independent external review of the program.

Overall, the Board continues to remain concerned (as expressed in previous Board Orders) with the pace of delivery of low-income programs for the First Nation diesel communities. Although MH has reported progress with respect to First Nation programs as a whole, the progress made to date does not address the full extent of energy efficiency issues on First Nation communities. In particular, more needs to be done with respect to energy efficiency measures for the First Nation diesel communities, where energy costs are significantly higher than in communities connected to the grid. The Board urges MH to work together with First Nationals and Aboriginal Affairs and

Northern Development Canada to expedite the delivery of energy efficiency measures in remote communities.

Bill Assistance

The Board notes that the low-income energy burden is high in Manitoba. This was confirmed by the 2009 residential survey which indicates that now over 105,000 Manitoba households are considered low-income, falling into Statistics Canada's LICO-125 category. The Board further notes that a substantial portion of the LICO-125 group has an energy burden in excess of 9% of household income.

Currently, MH relies solely on a voluntary program to alleviate energy burden. The program, known as Neighbours Helping Neighbours and administered by the Salvation Army, allows MH customers to donate to an energy relief fund. From a program delivery perspective, the amount of money in the fund is inadequate. While it allows families and seniors who are unable to pay their natural gas or electricity bill due to personal hardship or crisis to receive support from the program, that support is only available if there is sufficient money in the fund.

In Manitoba, adequate energy for heating is a necessity of life. As such, it should be both abundantly available and affordable. Programs that reduce the energy burden faced by low-income customers and provide significant societal benefits would likely return dividends to the Province above the cost of delivering such a program. Those benefits would include lower health care costs and other benefits such as reduced debt write-offs, improved customer service and avoided reconnection costs borne by the utility.

Before the Board is prepared to require MH to develop a definitive bill assistance program along the lines of the program proposed by RCM/TREE, the Board needs further information as to existing funding made available by government and the programs available to directly or indirectly alleviate energy poverty.

The Board is firmly of the view that MH should participate in an integrated strategy with respect to low-income programs. This could, and likely would, include a defined role in education, promotion, monitoring and perhaps delivery of such a program in conjunction with CBOs. However, until the Board has additional information as general and specific government funding available, the Board is not in a position to determine whether MH should be a “funder of programs to alleviate poverty” as suggested by RCM/TREE.

18.0.0 RISK

Similar to other large corporations, MH faces risk issues daily. All facets of MH's operations contain risk. To the extent that risk cannot be avoided, it must be managed. In order to set itself up to withstand adverse events and demonstrate the Corporation's financial strength to rating agencies and lenders, MH established its target debt-to-equity ratio of 75:25 further discussed in section 12.1.0 of this Order. MH applies this target ratio at all times except for periods when major new investments are in process that have yet to be placed "in-service" and start generating income. The Board and the Interveners have supported the target ratio. While the Board has expressed some concerns about the composition of MH's equity, as set out in section 12.1.0 of this Order, MH has met its target as of March 31, 2011 based on its own definition of equity.

To provide greater certainty as to the quantum of the equity "cushion" being sufficient to withstand the risks faced by MH, the Board has long requested MH to provide an in-depth and independent study of all operational and business risks facing the Utility. The study was to be a thorough and quantified risk analysis that included the probabilities of all identified operational and business risks. To that extent, this GRA was expressly stated to include a review of MH's risks and risk management.

Unfortunately and disappointingly, MH failed to provide the quantified risk analysis sought by this Board. In the words of one of the interveners, it was an "opportunity wasted". Rather than provide the risk analysis sought, MH incurred external costs of approximately $4 million to embark on the production of a report and the employment of a legal strategy to rebut the allegations of a risk consultant previously retained but subsequently terminated by MH.

What follows is the Board's own assessment of various risk issues based on the extensive record before it.

18.1.0 DROUGHT RISK

18.1.1 Historical Droughts

Hydraulic generation accounts for 80% of MH's average annual energy output. MH relies on river water flows and lake levels as sources of hydraulic energy. Since MH relies so heavily on water power, drought is one of the greatest risks faced by the Corporation, especially when a drought extends for several years.

Historically there have been approximately seven periods when MH would, given current domestic and export commitments, have been faced with rather substantial energy supply shortfalls. That fact suggests a theory, worthy of being tested, that total reliance on hydraulic generation may not be in the best interests of MH's ratepayers. A system dominated by hydro generation but with a significant natural gas (CCCT) thermal component would, it appears, ameliorate drought impacts and their financial consequences.

18.1.2 Drought Frequency

MH contends that it is not possible or appropriate to calculate a frequency of recurrence of various drought events. Instead, MH chose to declare and employ 1936/37 to 1942/43 hydraulic conditions as its worst-case scenario and 1987/88 to 1991/92 hydraulic conditions as a basis to determine an appropriate drought reserve target.

Attempts by various consultants to define a frequency for droughts of a five-year duration ("five-year-drought") produced a variation of opinions but no specific recurrence period. Drs. Kubursi and Magee (KM) indicated a 1.35% frequency, which suggests that a five-year-drought should be expected to occur only once in 65 years. It can be reasonably argued that the actual drought events that were recorded over the last 100 years could reoccur in the next 100 years. With hydro-electric generating stations having a potential service life of 100 years or more, it is unrealistic to assume that future years will not include substantial droughts similar to those experienced in the past century.

More recently, MH has suggested a 2% frequency for a five-year-drought. As MH's retained earnings (hopefully) increase, these retained earnings could be annually tested against each of the historical drought periods. This would provide ongoing drought event coverage ratios which could be employed in evaluating potential long-term contract commitments. MH's five-year-drought scenario could be treated as a baseline for comparison purposes.

18.1.3 Supply Commitments

When hydraulic generation in a given year exceeds committed domestic load, surplus energy is available for export sales. Over the last decade, MH has looked to long-term and annual short-term firm export contracts for the sale of surplus energy totalling approximately 6,000 GWh per year. MH's total annual commitment between domestic load and firm export sales has typically been in excess of the minimum annual dependable energy level of 21,000 GWh, with a key assumption that other non-hydraulic resources (thermal/wind/DSM/imports) could provide up to about 8,000 GWh of energy if required.

It is important to note that the non-hydraulic resources involve substantial costs due to:

- SCCT thermal generation costs being uneconomic (MH loses money operating its inefficient SCCT plants);
- Wind and DSM "tied" to MISO market prices and not readily dispatchable; and
- Imports being non-firm and, possibly, involving high market prices.

Consequently, from a financial perspective MH appears to count on each year being an average or above-average water flow year, as this would avoid the Utility having to rely on either its SCCT thermal generation or market priced imports. When MH employs imports to fulfill firm or opportunity sales, at best MH's profit margin is much smaller than when the Utility's own hydraulic generation resources are used. At worst, it is a money-losing proposition.

18.1.4 Potential Drought Costs

The actual net revenue loss associated with extended drought events is dependent on the value of:

- Foregone export sales (primarily high-value peak opportunity sales); and
- Additional fuel and power purchases.

18.1.5 Overselling

Total dependable energy, as defined by MH, consists of about 75% hydraulic generation resources (the major factor in MH's embedded cost structure) and 25% non-hydraulic generation resources.

Circa 2003/04, MH anticipated that a domestic load of 19,000 GWh and dependable export sales of about 6,000 GWh could be served from average hydraulic generation output. Unfortunately, and with a low level of energy-in-storage in April 2003, hydraulic output was only 18,500 GWh in MH's 2003/04 fiscal year. MH was faced with a 9,000 GWh shortfall that had to be met at largely very unfavourable prices. The very low April 2003 energy-in-storage level was largely the result of a high level of off-peak opportunity sales undertaken by MH in its fiscal 2002/03 year. These opportunity export sales made in the year prior to the drought, and at low sale prices, had substantial negative consequences once the drought set in.

Circa 2006/07, MH was expecting a domestic load of about 23,500 GWh and dependable export sales of 3,500 GWh, again to be served by hydraulic generation. MH's opportunity sales made early in the fiscal year, again at relatively low prices, subsequently necessitated 1,800 GWh of energy purchases at prices much higher than the Utility obtained through the earlier opportunity exports.

Overselling leads to the depletion of energy-in-storage, which can magnify a subsequent energy shortfall and drive up the negative financial impact of a drought situation.

18.1.6 Board Findings

When MH looked to calculate what it would consider to be appropriate reserves or retained earnings levels to protect against the financial consequences of drought, a five-year-drought (based on 1987/88 to 1991/92) was selected as representing what was, in essence, a financial stress test.

The Board has heard from various consultants that a five-year drought is "stressful enough" for MH, but the Board has not been convinced that the drought events extending from 1929/30 to 1942/43 (including both a five-year and a seven-year drought) would not serve as a more appropriate stress test.

With respect to MH's drought impact evaluation, and in particular the five-year and seven-year droughts, the Board finds that MH's quantitative analysis reasonably defines the energy shortages that would impact MH's energy supply. However, should MH be faced with shortage pricing such as was experienced in 2003/04, this would impact import pricing to meet any shortfalls.

The Board accepts the need for a defined drought risk reserve in establishing a retained earnings target as proposed by MH. The Board expects MH's next IFF to address the risk of, if not the reality of, a lower potential export revenue situation.

18.2.0 EXPORT MARKET RISK

18.2.1 Supply Variability

In mean (or average) flow years, and assuming no major equipment failure, MH's hydraulic generation should be adequate to meet domestic load and about 3,000-4,000 GWh/year of export sales. These export sales would typically consist of 2,000-3,000

GWh/year of firm price contract sales and a further 1,000 GWh/year of peak opportunity sales. Prior to 2005/06, these peak opportunity sales prices tended to equal or exceed the firm fixed prices. Currently, the peak opportunity sales achieve about 50% of firm prices.

In above-average flow years, MH looks to import electricity from time to time to expand peak opportunity sales to the limit of peak transmission tie line capacity and sell electricity at peak prices when available. Nonetheless, currently, under on-going high flow conditions, MH's average opportunity sales are achieving less than 3.0¢/kWh (peak and off-peak average).

In below-average flow years, MH's hydraulic generation can barely meet domestic demand. As a result, in such circumstances MH's exports mostly come from purchased energy. Consequently, net export revenues tend to be low, and can even be negative if the price of export commitments is lower than the purchase price.

Transmission constraints on exports in above-average flow years mean that MH can only export a maximum of 7,000-8,000 GWh/year during peak periods. Additional energy surpluses must be sold during the off-peak period (at prices as low as 0.5¢/kWh). The total tie line capacity limit for sales into the U.S. MISO region is 15,000 GWh/yr, including peak and off-peak sales.

18.2.2 Decreasing Export Market Demand

In the absence of low-flow and drought situations, MH can still be faced with low export revenues as a result of weak export demand. Recent MH IFF's assume that all surplus energy can be sold into the U.S. MISO market at favourable prices. This is not necessarily the case.

At the beginning of the 21st century, MH was able to readily sell 9,000 to 10,000 GWh of energy into the MISO market. These sales took place in the context of an environment that involved natural gas prices rising well above $5.30/GJ, no new coal thermal plants coming into the market due to threats of CO_2 pricing, and a "booming" U.S. economy. At that time, MH could reasonably anticipate an ever increasing demand for its surplus energy.

Circa 2004/05, the prospects for selling all of the energy output from Keeyask G.S. and Conawapa G.S. (estimated to total 12,000 GWh in average flow years) seemed certain. However, with many MISO states moving to renewable energy mandates, and with wind energy currently being eligible for a 1.7¢/kWh federal subsidy in the U.S., MH is now faced with substantial additional competition for market volume.

Prior to 2003/04, approximately 25% of MH's contracted export sales were inter-provincial Canadian sales. Since that time, MH appears to have focused almost entirely on MISO. That focus on MISO was initially successful, partly because the U.S dollar was about 1.2 times the Canadian dollar. More recently, with the economic downturn, the advent of shale gas, a Canadian dollar more or less at par and a no longer "booming" American economy, the U.S. market for MH's energy has become much less favourable.

18.2.3 Export Market Price Trends

MH's export sales into the MISO Market were initially quite profitable. This was in large part due to a very favourable foreign exchange rate (the Canadian dollar fell at one point to well below $0.65 USD) and seemingly ever-increasing natural gas prices. From the currency exchange alone, MH derived an average of $85M/year of additional revenues at the time.

This favourable situation no longer exists. However, MH's IFF09-1 still assumed a U.S. dollar equal to $1.10 CAD and to increase to $1.20 CAD. Consequently, on this factor alone, MH faces a substantial downside risk on export prices. The currency factor may, however, be partially offset by the resulting "depreciation" of that portion of MH's debt that is owed in U.S. dollars.

MH faces a combination of negative export circumstances in the current market environment. These circumstances include lower demand, subsidized wind in the U.S., reduced attention to carbon emissions, and the advent of shale gas. On the spot market, natural gas is presently selling for $3/GJ, which is only 20% of the peak price encountered in the last decade. In recent years, MH has made, and still is making on-peak and off-peak sales at an average price of less than 3¢/kWh. This represents ongoing pricing risk as a result of eroding export profitability.

The relative pricing of peak period opportunity sales and contract sales has changed since 2008/09. Day-ahead and spot prices used to be higher than fixed long-term contract prices. That is no longer the case. To the contrary, spot pricing is now up to 40% lower than contract pricing. This, too, represents an ongoing pricing risk.

18.2.4 Future Export Revenue Prospects

There continues to be significant excess energy supply in the MISO market, and expanding wind resources and new CCCT natural gas thermal generation constructed within the MISO area may maintain the excess resource situation for a considerable period ahead.

MH's new generation (from Wuskwatim and from the planned Keeyask and Conawapa generating stations) will carry fully-costed initial in-service costs in excess of 10¢/kWh. That indicated cost is almost double the current net cost of not only wind resources but also the cost of shale gas-driven CCCT generation.

With a U.S.-Canada exchange rate near parity, MH may be faced with an extended period of lower export revenues than is forecast in either MH's IFF09-1 or IFF10-2, and an extended period before a return, if it ever occurs, to the US dollar being worth $1.20 CAD (as assumed in IFF09-1).

18.2.5 Board Findings

In the Board's view, MH may be facing close to its worst-case export market scenario, particularly relative to the situation anticipated in IFF09-1, because of such factors as:

- projected major generation and transmission project costs 50% higher than initially forecast;
- natural gas generation costs having decreased by 30%-40% or more;
- the U.S./Canada exchange rate decreasing revenues by 20% (offset in part by depreciated value of MH's debt held in U.S. dollars);
- a complete lack of carbon pricing as opposed to the $20-30/tonne of CO_2 apparently once forecast by MH; and
- continued U.S. wind subsidies along with decreasing wind generation costs due to technical improvements and efficiencies.

Furthermore, the Board does not see how all of these negative market scenarios will be reversed for many years to come. The obvious risk faced by MH is that the current status quo prevails for the foreseeable future.

18.3.0 INFRASTRUCTURE FAILURES

18.3.1 Context

MH has experienced, on a periodic basis, the loss of generation and transmission system components due to both natural forces and the deterioration of parts or components. In large part, MH has been able to respond to such losses in an expeditious manner and has avoided substantial power outages to date.

The loss of various distribution system components due to natural forces, accidents and deterioration has been more frequent than the loss of generation and transmission system components. However, the extent of these failures is typically localized and blackouts have been limited to days (if not hours) rather than weeks or months.

MH's infrastructure failure risk is primarily focused on the major generation and transmission systems and the potential for broad-scale power outages. MH has frequently suggested that a failure of major generation and transmission components represents a greater financial risk than that occasioned by an extended drought period. MH looks to system redundancies to mitigate and/or preclude any inability to meet domestic load and firm export obligations.

18.3.2 Historical Events

The failure of both Bipole I and II occurred in October 1996, but the main north-south Manitoba AC lines were not affected. Subsequently, MH has progressively moved towards the implementation of a Bipole III concept, able to meet domestic loads without Bipole I and II.

A partial failure of MH's HVDC or HVAC transmission system would be more serious than a partial loss of generation capacity.

18.3.3 Dam Safety

The Board understands that like other hydro utilities, MH periodically reviews the potential for various failure modes of its hydroelectric generating stations. To date MH has not produced the Asset Condition Assessment Review requested by the Board in the 2008 GRA.

18.3.4 Consequences of Failure

A catastrophic total failure of MH's generation and/or transmission infrastructure appears to be a remote possibility. More likely is a partial failure, where the greatest cost implications will arise not from the requirement to repair or replace the failed infrastructure, but from lost revenue from exports sales or, perhaps, domestic sales that cannot be fulfilled from MH's own generation.

18.3.5 Board Findings

MH has experienced a wide array of infrastructure failures within the various components of its generation, transmission and distribution systems. Undoubtedly, similar events may be expected in the future.

With respect to the Bipole I and II tower failures, it would have been prudent for MH to conduct a comprehensive post-mortem analysis of the failures, and, as well, a cost/benefit analysis to justify the Bipole III project. The Board is of the view that to date, alternative scenarios to Bipole III have neither been adequately explored nor documented.

18.4.0 OPERATIONAL RISKS

18.4.1 MH's Forecasting Process

With upwards of 95% of MH's annual energy supply now coming from hydraulic resources, an ability to anticipate river flows and forecast hydraulic generation is essential. MH apparently relies primarily on antecedent stream flows conditions to estimate current-year and upcoming flows and hydraulic output.

A key element of MH's water supply management involves the ongoing prediction of flows and hydraulic generation for 6, 12 and 18 months in advance. This is to ensure adequate energy supply for domestic load and firm committed exports for both the current year and the upcoming year.

The Board understands that MH does not attempt to predict annual water flows via specific hydrologic parameters (such as winter precipitation, snow pack, snow melt, spring run-off and precipitation) but rather employs antecedent regression relationships to forecast annual system inflows based on actual flows. In calculating generation forecasts for the year, MH appears to assume average levels of energy-in-storage as both the starting point and end-point. This approach may not raise concerns in average or above-average flow years, when excesses or shortfalls can be managed at low cost.

However, in below-average flow years the negative cost consequences of over-prediction could be substantial.

The practical limit of MH's existing hydraulic generation capacity is about 37,000 GWh/year under high flow conditions as experienced in 2005/06 (the 2007/08 Q4 output was 9,700 GWh over a three-month period).

18.4.2 Concerns about MH's Forecasting Process

MH's reliance on actual April system inflows to define potential hydraulic generation for the upcoming year does have some merit, but only if used in conjunction with a consideration of actual April 1st energy-in-storage and a quantitative assessment of precipitation during the preceding winter months (October to March). A high April system inflow may, in some years, be the result of an early spring melt rather than an indication of high flow volumes to follow. Conversely a low April system inflow, in some years, could reflect a late spring melt. A correlation of energy-in-storage and winter precipitation with MH's existing factors should provide an additional and better indication of potential hydraulic generation surpluses.

MH's response to favourable April flows can have significant implications. Maximizing export sales in April and May can be a high-risk venture if subsequent summer flows end up being low. This applies to all opportunity sales and to bilateral summer contract sales for June-September period.

MH apparently does not carry out an annual back-testing of its hydraulic generation forecasting process and assumptions. Such a test would be extremely useful as a means of confirming the reliability of MH's current procedures and assumptions.

18.4.3 Drought Events of 2002/03 and 2003/04

Leading up to the 2003/04 drought year, MH exported about 9,900 GWh in 2002/03. 4,800 GWh of that amount was exported in the first six months of the year and 3,900 GWh in the second six months. According to the Board's calculation, these export transactions involved 7,900 GWh purely from hydraulic resources and 2,000 GWh from imports. As a result, energy-in-storage decreased from 6,300 GWh in April 2002 to 4,200 GWh in April 2003.

As a result of this decrease of energy-in-storage, in 2003/04 MH was only able to achieve 4,400 GWh of physical exports while requiring 7,000 GWh of imports. Another 2,500 GWh of firm contract exports were bought back and never delivered. About 2,600 GWh of energy imports were required to meet the domestic load shortfall.

If a similar drought were to occur in the 2011 to 2015 period, the results would likely be quite different. While the total energy obligations (both for domestic load and for firm exports) and energy shortfalls would be quite similar, the resulting costs would reflect higher energy prices and the resultant deficit would be substantially larger.

18.4.4 Board Findings

MH's Prediction Process

MH's IFF process apparently provides hydraulic generation estimates for:

- Year 1 - based on 6 month actual generation + 6 months median projected generation;
- Year 2 - based on actual April energy-in-storage adjustment + 12 month median projected generation; and
- Year 3 - based on average energy-in-storage + 12 month mean projected generation.

The Board understands that MH does not use the IFFs to make its actual operational decisions.

It appears to the Board that MH looks to April hydraulic generation (river flows) to confirm, on an antecedent basis, the hydraulic generation resource and hence energy available for export for the next 12 months. A September review based on September hydraulic generation is also used to verify the available MH energy and the need (if any) for winter imports.

Regulatory Reviews

MH's American utility customers are faced with rigorous reviews by the State Public Utility Commissions with respect to their proposed import contracts with MH (i.e., MH's export contracts). MH's export contracts, and the volumes and prices involved, are significant in determining domestic consumer rates; and, as such, need to be reviewed by the PUB even if they are filed in confidence as opposed to being placed on the public record.

2003/04 Drought

While MH contends that its management of the events leading up to and including the 2003/04 drought were totally appropriate, there has not been a detailed back-testing (post-mortem) of MH's water supply management and flow prediction system to date. The Board sees a need for MH to enhance its modeling forecast by adding a comprehensive hydrologic component.

It is apparent that MH's model employs antecedent forecasting and does not look to a hydrologic prediction in preparing annual hydraulic generation estimates. Evidence from external experts and the independent consultant indicates that the models are less accurate in replicating actual low-flow periods (such as 2003/04) than they are in replicating average or above-average flow scenarios. The Board sees this as a significant risk issue.

When MH suggests that it does not look to anticipate or predict pending drought situations, the Board can only ask why MH would not attempt to reduce energy consumption as soon as accumulated precipitation data in any year indicates that watershed runoff could be significantly below average. Reducing energy sales a month or two earlier could significantly alter the level of losses during a drought period.

The need for new hydraulic generation within MH's system is apparently determined by domestic load growth and export contract commitments. In the Board's view, MH should revisit the rationale for determining dependable energy resources and the acceptable level of non-hydraulic resources that should be used to establish firm export contract commitments.

In 2003/04, the energy shortfall resulting from a drought scenario was entirely covered by imports at unfavourable market prices. This suggests to the Board that MH does not have adequate firm resources to meet MH's firm supply obligation under droughts as historically experienced.

A renewed focus on serving domestic load first in MH's "Business Plan" could, while potentially limiting MH's export operations, ultimately benefit Manitoba consumers. The Board sees some merit in further researching and testing such an alternative focus.

18.5.0 JOINT FREQUENCY RISK CONSIDERATIONS

18.5.1 Retained Earnings Reserves

Currently MH's retained earnings reserves are expected to buffer the financial consequences of a five-year drought and shield consumers from other potentially coincident events such as:

- lower export revenues or, alternatively, shortage import prices;
- potential infrastructure failures;
- lack of domestic load or industrial growth;
- power resource planning that relies on substantial non-hydraulic resources;
- capital cost escalation;
- operational risks such as drought anticipation/overselling in spring; and

- regulatory risks.

Nonetheless, the reserves are not necessarily adequate. The quantification of the reserve will remain an issue for future GRA hearings.

18.5.2 Dedicated Reserves

MH is essentially opposed to segregating specific drought reserve requirements for particular risks. However, it could be argued that MH's overall global retained earnings reserve is subject to the independent risk of depletion due to non-drought factors such as:

- market price collapse;
- "sticker shock" capital cost escalations; and
- lack of domestic load growth.

The suggestion by the independent consultants (KM) that MH create an EIS reserve is not without merit and is worthy of further investigation. Constraints on the withdrawal of EIS could be seasonally defined, so as to reduce the likelihood or magnitude of a supply shortfall. This would not preclude MH's management of energy resources, but would ensure a minimum hydraulic resource level at all times.

18.5.3 Intervener Positions

The interveners concluded that MH's current approach of having one global retained earnings reserve was adequate.

18.5.4 Board Findings

In the Board's view, the entire issue of multiple interdependent risks has not been satisfactorily reviewed or resolved. There is a reasonable concern that the Utility's forecast retained earnings will not be realized or, if realized, maintained.

With the potential for multiple claims on a global retained earnings reserve, there exists risk that the reserve could be substantially depleted in advance of any future drought, meaning that a drought could impair MH's capital position by far more than now expected. This, in turn, could lead to higher consumer rates.

18.6.0 RISK EXPERTS

18.6.1 KPMG

The Board directed, in Order 32/09, that an independent comprehensive risk study be undertaken and filed, with the specific terms of reference for the study to be approved by the Board.

In late 2009, the Board was asked for input by MH towards establishing terms of reference for what the Board expected to be an independent comprehensive risk study, one which would address all of the risks identified by the Board in Order 32/09. The Board provided this input, and KPMG was retained by MH to carry out the study in November 2009. However, the final terms of reference were not as sought by the PUB and previously agreed to by MH.

MH advised that its Audit Committee authorized the changes to the terms of reference for the KPMG risk review and specifically approved removal of the requirements requested by the PUB for an independent and comprehensive risk study. As such, while the KPMG reports (and the cost of KPMG's representatives, who were assisted by the firm's external legal counsel at the hearing) cost MH approximately $4.0M, the work performed was not broad enough to address the Board's concerns. The terms of reference MH provided to KPMG focused on a review of the allegations of the New York Consultant (NYC) previously employed by MH rather than the identification and costing of MH's risks.

KPMG, as directed by MH, concentrated on the NYC's allegations and the development of an analysis with respect to those allegations. KPMG acknowledged in response to pre-hearing information requests and upon cross-examination during the oral hearing that it never intended to respond to any of the specific assertions of the NYC regarding MH's operations, risk management or risk governance. KPMG considered the NYC assertions, identified major issues arising from those allegations, and then analyzed those issues using the review process set out below. KPMG confirmed (on cross-examination) that the NYC had not missed identifying any of the major risk issues faced by MH.

KPMG reviewed existing risk review studies, obtained explanations of operational and planning methodologies from MH, and limited its analysis to a consideration of whether MH was operating reasonably in respect of the issues under review as defined by KPMG. KPMG did little independent verification of MH's underlying data as part of its work. For example, KPMG's Net Present Value (NPV) analysis of MH's preferred future development scenario compared to one alternative development scenario was based on MH's data, and KPMG did nothing to verify the underlying data assumptions that supported the particular stress test runs to generate the NPV outputs. Also, KPMG confirmed that with respect to its review of MH's price forecasts, it made no attempt to examine the validity of the forecasts. Rather, KPMG focused on examining the method used by MH of purchasing a number of forecasts and creating an average of the forecast values.

KPMG recognized that the original terms of reference as approved by the Board included the need for consultation with the Board and its advisors as necessary. KPMG determined that this consultation was not necessary to complete its work, even though the work was envisioned to fulfill a Board directive arising from Order 32/09.

Based on difficulties KPMG encountered with the NYC, it chose not to attempt to make contact with the NYC to obtain an explanation from the NYC as to any assertions which appeared inconsistent, unclear or ambiguous. In the circumstances that existed, which included legal action undertaken by MH against the NYC, it appears unlikely in any case that KPMG would have received any cooperation if had made such an attempt.

Following a court application by MH against the NYC on the issue of publication and use of the KPMG report, it became clear to the Board in its pre-hearing process that the KPMG report would not be tabled with the Board unless the Board served a subpoena on MH.

Accordingly, a subpoena was served on MH for production of the KPMG report on April 15 2010, the date the report was issued. MH complied with the subpoena and the KPMG report was tabled with some redactions, in compliance with the subpoena. In the course of a redactions motion before the Board, the Board approved several redactions in the KPMG report. These are set out in PUB Order 95/10. A final redacted KPMG report was then put on the record of this proceeding.

KPMG also performed an adjunct risk governance / risk management process review for MH between March and May 2010 and issued a separate report on May 2010. The KPMG risk governance / risk management process review report was tabled at the commencement of KPMG's testimony in this hearing on February 28, 2011.

The Board finds that KPMG's report is not an independent assessment of MH's material risks as was originally envisioned by the PUB. Given the somewhat narrow approach adopted by KPMG and the limited nature of KPMG's analysis, this work has limited value despite its steep price tag.

In oral testimony, KPMG's panel addressed the major topics its considered as part of its review process. KPMG's key findings were as follows (the first two conclusions were not contained in KPMG's draft report but were added to the final report after a review by MH's Audit Committee):

- There is no material risk of bankruptcy for MH as a direct consequence of MH's export power sales practices.

- There is no evidence to support an assertion of losses approaching one billion dollars in the five years preceding KPMG's review based on analysis of MH's modelling, export sales contracts and risk management practices.

- MH's strategy of entering into long term contracts and securing transmission rights in development of its system is a prudent strategy.

- MH has operated in accordance with its legislative mandate.

In two places in KPMG's draft report, KPMG made the statement that

> *"MH's core business objective is to provide its domestic customers low-cost and reliable energy service."*

On cross-examination as to why MH's Audit Committee requested that statement removed from the final version of the KPMG report (from which it was in fact removed), MH's Chief Financial Officer responded that MH never described its core business objective in this manner and that it was a truncated interpretation of MH's core business made by KPMG that MH did not agree with.

As part of its review, KPMG concluded that a legislative mandate for MH, and thus a key MH goal, was to provide low-cost power to MH's domestic customers. Given the process used by KPMG to complete its assignment, KPMG would have been informed in its interviews with MH's executive staff that this was indeed an objective of the utility. Furthermore, MH's Corporate Strategic Plan 2009-10 filed with its GRA application states that a defined target is to provide the lowest retail electricity rates in North America.

MH's testimony and submissions clearly support a long term plan which supports stable, low annual rate increases (said to be projected to remain close to inflation) for domestic customers over the 20-year time horizon shown in MH's IFFs. Indeed, MH's intention to add new generation in advance of the need of its domestic customers, as part of its decade of investment and in accordance with its preferred development scenario, is premised on export sales creating net revenues that over time will result in reduced domestic rates.

With respect to MH's risk governance structure, while KPMG generally concluded that MH's corporate risk management function is consistent with leading and prevailing practices, KPMG identified a number of risk policy areas where MH rated sub-par and made recommendations for improvement. MH subsequently reported to the PUB in the hearing process as to progress on these recommendations. Among other things, MH reported on an increased role for its Middle Office as well as increased staffing and expertise for its Middle Office. Improvements undertaken by MH include establishing a role for the Middle Office in the review of long-term export contracts. KPMG also recommended improved risk analytics technology, which appears to implemented on an ongoing basis as part of MH's improvement to its risk management infrastructure.

KPMG concluded that MH's financial risk management function is consistent with leading practises.

KPMG concluded that MH's actions, as understood by KPMG, demonstrate prudent power risk management practices as related to major export contracts and term sheets, including a conservative stress testing methodology, transaction processing controls to mitigate against human error and operational risk, compliance and risk monitoring by the Middle Office, and a comprehensive suite of reports.

KPMG also indicated that it reviewed MH's "HERMES" and "SPLASH" modelling programs. HERMES is used to plan operations of a system in the near term. SPLASH is used for long-term planning processes and to establish a business case for new generating plant additions. SPLASH also provides input for medium- to long-term financial forecasting. KPMG further concluded that MH has taken appropriate care and due diligence in developing, operating and maintaining the models. On the key issue of forecasting water flows, KPMG endorsed antecedent forecasting methods in use by MH as a useful and reliable approach to this type of forecasting.

KPMG also noted that with respect to the SPLASH model, the use of perfect foresight allows for certain conservative projections which are reasonable for the purposes for which the model is used by MH. In considering the trade-offs with respect to the perfect foresight methodology, KPMG also concluded that financial losses associated with droughts are in fact inevitable.

KPMG noted that the use by MH of the 1937-1942 drought periods is appropriate for MH's planning to determine dependable energy. KPMG acknowledged that the appropriate approach for determining dependable energy depends on the Corporation's risk tolerance. A more stringent definition of dependable energy would result in less risk of financial loss in the event of a drought, but such a strategy also has the prospect of lowering MH's revenues, on average, to the extent that it must spill water or sell on the opportunity market for less certain return.

KPMG looked at pricing in the long-term export contracts and Term Sheets as well as the structure of the long term contracts and risk capital reserves. KPMG analyzed the pricing process and concluded that MH has an appropriate methodology for arriving at the sales prices in its long-term contracts. KPMG did recommend that MH clarify the role of the premium applied to its long-term contracts, confirm the appropriate magnitude, and also that it should do a better job of documenting its pricing analysis and its future avoided cost analysis. More explicit use of the avoided cost analysis in future pricing methodology is also recommended. KPMG further recommended that in the process of reviewing export contracts and terms sheets, MH's Middle Office should have a defined role to perform a challenge function.

KPMG supported MH's long term contract strategy and found that it has the potential to mitigate market risk for MH through diversification. KPMG concluded that MH's drought risk will be mitigated because of returns (revenue) to be generated under the export contracts and the extra transmission capacity to support required imports in drought situations.

KPMG also performed a net present value (NPV) analysis to compare the Sales Scenario (being MH's preferred development sequence) to a No Sales Scenario which included an alternate expansion plan with no long-term contracts. MH redacted all of the supporting data in the KPMG report, so that there was no opportunity for the Board or Interveners to examine the NPV analysis in the report.

To perform the NPV analysis, while KPMG provided data run requests to MH, it confirmed that it performed no independent analysis of the inputs for the NPV calculation, but instead relied on MH for that information.

Based on the assumption inputs in the analysis, KPMG concluded that under all scenarios, including drought stress test cases, the NPV of MH's Sales Scenario/preferred option was greater than the No-Sales NPV. KPMG acknowledged that with the escalating costs of capital projects, a downward adjustment in the NPV of the preferred scenario would be required. Likewise, with export prices declining as projected by Mr. Rose of ICF, there would be further downward pressure on the NPV of the Sales Scenario.

KPMG also assessed net income and retained earnings over the long term with respect to the Sales and No Sales Scenarios for MH. The picture was less clear with respect to differences in net income between Sales and No Sales in the shorter term, but KPMG concluded that in the long term, net income and retained earnings were better under the Sales Scenario.

KPMG acknowledged that its NPV analysis was limited to input values for various components as available at the time of the report. Significant increases to the estimate of the capital costs of the proposed capital projects at the heart of the scenarios, being Keeyask, Conawapa and Bi-Pole III, were not available to KPMG and would materially change the analysis. KPMG confirmed that all other things being equal, higher capital costs would lead to a lower NPV in their analysis.

Given the limitations of KPMG's final terms of reference and its approach to the preparation of the report, it is useful to consider several of the risk management and risk governance issues brought forward by KPMG (and other experts before the Board) in response to the NYC's assertions. The filing of KPMG's adjunct risk governance / risk management report, the testimony of the KPMG panel, and cross-examination of the KPMG panel all added value to the engagement. KPMG's evidence suggested the following:

- The NYC identified all significant risk issues facing MH, although no specific NYC reference to quantification of MH's operational losses could be verified by KPMG. By and large, KPMG did not attempt to respond to the specific assertions of the NYC.
- The system models developed by MH for production and for long-term planning are similar to models used by other utilities, and the models are doing what they are required to do. The models are being upgraded and calibrated on a continuous basis.
- MH should proceed with its planned enhancements of the models. MH should better quantify and communicate to stakeholders, including the PUB, the impacts of the perfect foresight assumption in the calculation of drought costs. Further, MH should explicitly consider uncertainty in future water flows in the modeling process used to identify optimal production decisions. MH should consider assessing the financial impacts of drought events worse than those found on the historical record.
- MH should conduct more scenario analyses, and should do more stress testing and back-testing to evaluate risk exposure and model accuracy. MH should also formally document its in-house models, which will mitigate the risk for the time when the experienced, highly knowledgeable staff that has the knowledge about

the models leaves MH. Independent peer review of the models is also recommended.

- MH needs to continue to develop its risk management capabilities, and specifically the role of the Middle Office in risk management.

- MH must take a careful approach to future development to take advantage of the opportunities available based on Manitoba's hydrologic resources. MH must ensure that costs of the development plan "don't go way out of whack", make sure good prices are achieved in the final long-term export contracts, and make sure that the benefits flow back to Manitoba ratepayers and are not shared too widely with other parties.

- MH should create a defined risk management philosophy and create risk management objectives and a mission statement respecting risk policy. It should define its risk appetite by articulating a statement that reflects strategic growth goals and desired returns from a strategy. MH should differentiate risk appetite from risk tolerances, the latter being acceptable variations relative to the achievement of objectives. Better documentation of the risk management function through management and governance in MH are also recommended. Specific recommendations regarding monitoring and reporting of various risk issues are detailed in KPMG's May 2010 report.

- MH would benefit from completion of a final documented drought preparedness plan. Although KPMG found that MH is prudently managing its approach to drought as one of MH's biggest risks, a written plan would be an improvement as the plan would then be documented in one place, and available for the purpose of communicating it to all stakeholders and interested parties.

- MH's capital structure should continue to be formally reviewed on a regular basis. Of particular significance at this time are the major capital expansion to MH's generation and transmission system and MH's risk management improvements, which may affect MH's optimal capital structure. Better information would assist decision makers on the optimal capital structure for MH through future periods of significant change and ongoing uncertainty. The appropriate capital structure will continue to be an ongoing issue for the company, the PUB, the Province, ratepayers and lenders.

18.6.2 Dr. Kubursi and Dr. Magee

After consultations with MH and the Interveners in the pre-hearing process, and having been aware of the limited terms of reference provided to KPMG by MH, the Board determined that it would retain independent experts to perform a study of MH's material risks, in accordance with the scope of the GRA and the Terms of Reference which were attached as a Schedule to Board Order 30/10. As a result, Drs. Kubursi and Magee (KM) were retained and accepted the assignment to fulfil the assignment under the terms of reference. They retained their own counsel and proceeded with their investigation and analysis. KM also met with a number of the Interveners and, as required, provided general guidance to the Interveners and answered inquiries on risk principles.

KM worked with MH pursuant to a confidentiality agreement and spent significant time gaining knowledge of MH's operations, its models, and its risk governance and risk management processes. This knowledge was used by KM to prepare its own statistical analyses of revenue results for MH's electricity operations under various scenarios, using the same computer software which is the basis of MH's PRISM model. KM's statistical distributions were produced to assist the Board and hearing participants with a better understanding of risks faced by MH and the related implications for the financial health of the utility, its ratepayers, and the Province of Manitoba.

As a result of the limitations imposed by the confidentiality agreement, KM chose to use publicly available data, from Statistics Canada, to conduct its data analyses. Ultimately, both MH and a number of the Interveners challenged the validity of the data runs and distribution curve outputs generated by KM based on the Statistics Canada data, as well as subsequent refinements presented by KM to their initial calculations.

KM submitted that it could assist the PUB and inform the ongoing discussion of the risks faced by MH and decisions arising therefrom, in particular in the following areas:

- evaluating MH's risk governance systems and risk management strategies;
- quantification of risk;
- review of MH's operational and planning models, pricing options, investment decisions, and MH's overall business performance; and
- suggesting statistical methods for dealing with uncertainty, for example, in future water flow predictions.

While the Board is not certain that it can rely on the accuracy of the particular distribution curve graphs included in the KM report or KM's quantification of MH's drought costs, it is satisfied that the broader insights drawn by the independent experts from their data analyses are instructive as to the matters identified in the terms of reference and the MH risk review as part of the GRA.

The independent experts were qualified as experts to provide opinions in the areas of econometrics and statistics, including time series analysis, economics, production systems, risk analysis and optimization models.

In preparation for their work, KM also reviewed numerous reports and studies respecting other public utility systems and the risk assessment and risk management processes at different utilities. Dr. Kubursi in particular studied water and drought prediction models, operation research in power generation, operation and planning systems, as well as optimization systems and software.

Dr. Kubursi and his counsel Mr. Wood also met with the NYC in New York in June 2010 in an effort to understand the NYC's concerns and supporting analysis respecting those concerns. During the meeting, the NYC was prepared to identify high level issues and repeated its general assertions regarding problems in MH's risk governance and risk management areas, as well as alleged operational deficiencies and mismanagement. However, the NYC was not prepared to engage in a more detailed discussion or review of its supporting information which backs up its assertions. The NYC was not willing to share the explanation for the quantification of specific losses alleged to have occurred.

Although Dr. Kubursi concluded that the NYC displayed a strong scientific intellect and had a sound educational background along with experience in risk analysis, the NYC was reticent to share information to assist KM in their completion of their assigned tasks under the terms of reference. Further attempts to reconnect with the NYC thereafter proved fruitless.

KM generated its primary report in November 2010, which report was supplied in a redacted form based on redactions requested by MH. The redactions primarily relate to MH's long-term contract pricing and other contractual provisions, as well as certain water flow data.

KM generated a further Reply submission, which became the document used as the basis of their direct oral evidence in the hearing. KM testified before the PUB and were subject to cross examination by Board Counsel, the Interveners and MH.

The Board has identified the following findings and conclusions of KM, based upon their reports and testimony:

- There may be benefits derived by MH in integrating its operating and planning models.
- MH is a Crown Corporation, seeking to pursue maximum revenues and strong net income while serving the best interests of the Province of Manitoba and

domestic ratepayers. This is identified as a duality of interests within MH. The regulatory regime in Manitoba vests authority in the PUB, which is tasked with moderating the monopoly power which MH enjoys to ensure balance. Prices should be equal to marginal cost and only reasonable rates should be charged to Manitoba customers.

- MH is likely prone to the "principal/agent" dilemma, the principle being that there is a difference in risk tolerance between the utility and its customers. Citizens are risk-averse based on well-known and studied general principles of economic behaviour. MH as a corporate entity may be less risk-averse.

- There are naturally existing information asymmetries between MH and its stakeholders.

- Moral hazard may be an issue for MH. The Utility may be tempted to undervalue risk and to pass the cost of its risk-taking onto domestic customers.

- Risk management best practices require a continuous and systematic process. Beyond identifying and prioritizing risks, procedures must be established to estimate probability density functions and ranges in systematic, transparent, and replicable ways.

- Statistical procedures should be verified and validated by subject matter experts in the Front and Middle Offices of MH.

- Once strategies for assessing risk are in place, procedures to deal with them must be established to reduce risks to the enterprise.

- Individual responsibility and accountability for defined risk matters is required. KM confirmed on cross-examination that MH appears to have an individual responsibility/accountability system in place.

- There must be a vested defined internal authority to implement risk management processes, along with properly allocated resources, necessary expertise and appropriate oversight in the process.

- There must be a process for monitoring and tracking outcomes and learning from mistakes as part of the risk management regime at MH. The process is optimized as a continuous exercise.

- MH has shown good effort in implementing a risk governance and risk management system that is still evolving.

- As a result of the 2003/04 drought, MH recognized that it needed a comprehensive risk management plan.

- Gaps in the MH risk management system include the need for one group to undertake valuation of risk and another group, in the Middle Office, to validate the assessment.

- Qualitative analysis of MH risk can be improved. Middle office validation of quantification is necessary. Quantification should use market values, such as mark to market measures, which are preferred over other benchmark evaluations of financial risks.

- Greater expertise of statisticians and actuarial experts would assist the Middle Office and added risk analysis expertise is required.

- Risk management must take place at the highest level in the organization for MH and must continue to report to the CFO. The Middle Office must be given importance in the MH hierarchy which is necessary to allow it to function effectively with this recommended structural change.

- Risk preparedness plans are needed for all costly risks, including a written drought preparedness plan.

- One of the benefits of a drought preparedness plan is to avoid a well-established phenomenon of reaction lag time to deal with future droughts. This includes lags in recognition, diagnosis, response, action and outcome. A good plan would take into account all components and identify a set of criteria, responses and responsibilities to eliminate the lag.

- All business transactions must include a risk assessment that would be first prepared by the business unit and then reviewed by the Middle Office. Specifically, long-term contracts must fall into this review process.

- MH should introduce statistic uncertainty to its models, which are operating on deterministic structures. The current structures do not optimize assessment of risk.

- Outside peer review for the validation and audit of MH's models is important. MH should proceed to implement processes for validation and audit.

- MH's electric load forecast is reasonable, and to improve it MH should move to integrate probabilistic variables. The group responsible for the load forecast should be integrated formally into the MH model staff community. This supports greater integration of the models and is of benefit to all of the modelling staff at MH.

- MH should reconsider its use of variables for multiple forecasts in its economic outlook preparation. The practice of drawing individual variables from various forecasts may lead to incorrect outcomes.

- With respect to prediction of water flows, MH's should consider methods beyond the currently used historical simulation methods to predict droughts of greater severity than those in the historical record.

- Upon review of the NYC public document respecting high level assertions, and upon review of various related reports prepared by MH, KPMG and ICF, KM is unable to confirm any specific assertions of losses alleged by the NYC or any specific allegations of mismanagement. KM saw no evidence to support such allegations during its study.

- With respect to general issues of risk identified by NYC, areas for improvement were identified in detail in the KM report and elaborated on by KM in testimony. Included in recommendations are subject areas of model governance, model utility and relevance, model output and predicted accuracy, water flow analysis, drought risk, and risk governance and management in the MH middle office.

- Numerous benefits may accrue to MH as a result of entering into new long term contracts with its counterparties.

- High import prices are a threat in drought periods, but the long-term contracts are structured to define price limits and offer greater curtailment protection to MH under certain drought conditions.

- NYC's drought calculations are of a magnitude that is glaringly low. However, there is a need for adequate risk capital to mitigate against MH's long term contract risk exposures, which are a serious concern.

- KM has a generally positive review of MH's approach to capital planning, but there is room for improvement. KM encourages use of a comprehensive model that integrates financial, hydrological, and electric generation components, along with jointly modelling unknown future values by specifying them as random variables.

- MH will benefit from continuing to consider the merits of different rates of capital expansion as the uncertain future for the electricity export market continues to unfold. The Middle Office should play a leading role in approving the process for long term contracts. As a corollary point, KM favours a concrete valuation of a variety of expansion timelines and their implications for the long term financial health of MH.

- MH should move forward cautiously with several potential development sequences to keep its options open in the medium term and obtain the best indication of long term viability for its new capital generation system program.

- MH should complement retained earnings as a risk mitigation measure with other methods of mitigation, including but not limited to additional water storage. MH should adopt a minimum regret strategy to plan for very adverse water situations. It cannot rely only on retained earnings as protection against the severe drought event.

- PUB's role as regulator of MH is to make sure rates are justified, and that MH is not seeking increased rates for recovery of losses for mistakes, errors and inefficiencies. MH must ensure efficiencies are maximized, and that it exercises a discipline of maintaining lowest costs. A more meaningful objective for MH is to minimize costs and create the greatest efficiencies, instead of maximizing net revenues.

18.6.3 Intervener Submissions

CAC/MSOS submits that a number of important contributions have been made by KM resulting from their report and testimony before PUB, notwithstanding the fact that the data and probability distributions contained in Chapter 6 of the KM report are significantly flawed and unreliable. CAC/MSOS recommends that MH adopt the modern scientific approach to risk management outlined by KM as part of MH's risk management strategy and its justification to the PUB for resources to manage risk. CAC/MSOS identified the new risk approach as including:

- The identification of risk factors which have associated probability distributions of outcomes;
- the analysis of the probability distribution of each risk factor based on updated historical data, including the nature of any correlation between risk factors;
- the development of an integrated model of MH's operations that links the risk factors and the financial incomes of interest (net revenues); and
- the performance of Monte Carlo simulations to assess the impact of risk on MH outcomes.

As a result of the flawed analysis in Chapter 6 of the KM report, CAC/MSOS submits that no reliance can be placed on the estimates of the five-year-drought and the seven-year-drought flows produced by KM.

MIPUG identified a number of directional questions upon which it sought to engage during the hearing, related to risk. The questions defined by MIPUG included examination of MH's capabilities, internal organization, policies, procedures, oversight and governance needed to appropriately manage risk.

MIPUG submitted that upon review of all of the evidence on these subjects, MH's approach to risk, while evolving, is appropriate and prudent for a Crown utility.

The concept of risk tolerance was considered by MIPUG's experts. Messrs. Bowman and McLaren concluded that the key benchmark for MH willingness to accept risk in its operations must be the risk tolerance of its Manitoba ratepayers. MH's established risk thresholds do align its risk tolerance to ratepayers and are appropriate, they asserted. Moreover, Bowman and McLaren suggested that where MH pursues long term opportunities which are sufficiently examined and bounded, and provide the means for ratepayers to benefit from the risks of the planned endeavour, through comparatively lower and more stable rates, these actions are viewed as suitable activities underlying regulated rates and are within an acceptable tolerance.

RCM/TREE noted that all of the risk experts appeared to be using out of date Term Sheets as the basis of MH's potential exports revenue position. It also noted that rather than adopting a sceptical review approach, the risk experts accepted the positions adopted by MH in conducting the risk analyses. Particularly troubling, noted RCM/TREE, was the failure of KPMG to involve the PUB in the charting of the risk review which they were engaged to undertake. Finally, the redactions and non-disclosures in the filed material limited the ability of RCM/TREE and its expert Mr. Wallach to properly test the risk information, which limited the benefit of the process for all of the parties.

18.6.4 Board Findings

In addition to the KPMG and KM reports now reviewed, the Board also received other "risk reports". Copies of these reports are on the public record of this GRA.

In these Board findings, the Board provides its findings related to those additional risk reports, as well as its findings with respect to the KPMG and KM reports.

Risk Advisory Reports

Risk Advisory's involvement with MH through the early stages of the then pending 2003/04 drought suggest that MH was not well-prepared to modify its operations in Q3 and Q4 of the 2002/03 fiscal year. The Board notes that MH should have recognized the potential for energy supply problems in the second half of 2002/03 but did not move to deal with these until May of 2003. MH's 2002/03 annual report acknowledged the onset of drought conditions, yet "applauded" the favourable financial results despite those drought conditions.

Risk Advisory's subsequent January 2005 review of energy supply issues did not address the drought recognition aspects and MH's continuation of exports in excess of contract levels. Despite requests, MH has not filed an appropriate post-mortem of the 2003/04 drought event.

Water Stewardship – Peer Review

While the peer reviews on behalf of Manitoba Water Stewardship were generally favourable, the Board notes that the concerns and improvement suggestions are similar to those of other external experts and KM. In particular the Board notes the weak simulation of Lake Winnipeg outflows during low flow years.

Power Export Risks – Dr. N. Bhattacharyya (2007)

The 2007 report by Dr. N. Bhattacharyya flagged some serious issues with respect to the profitability of some of MH's energy trading practices. While MH has attempted to minimize the impact of the results, the Board is concerned that MH may be understating the potential for trading losses.

NYC Allegations

The process of achieving an independent review of the NYC's allegations was very convoluted. The Board looks at this exercise as being largely unsatisfactory. However, it is somewhat disconcerting to find Risk Advisory, ICF and KPMG flagging potential areas of improvement for MH that in many cases mirrored areas that the NYC was critical of, and where in some instances the NYC accused MH of mismanagement.

The contribution of the NYC to the debate on MH's Power Resource Management was significantly flawed. However, it did open a number of avenues to scrutiny. It may well be that MH's Power Sales Operations will have benefited from the public review of MH's operational structure and its business plan. The Board certainly sees that MH has been given insights to a significant number of areas that need improvement.

ICF Report and Presentation

In the Board's view there does not appear to be any direct evidence to support ICF's view that new long-term contracts and new generation and transmission will see a positive impact on domestic rates in the next decade. Publicly available information on contract pricing and conditions is not sufficient to conclude that MH's ratepayers will benefit. Furthermore, substantial capital cost escalation of new generation and transmission projects have not been factored into the process.

Given ICF's forecast of 30-40% reductions to its previous natural gas commodity price forecast, the Board can only conclude that MISO market prices for electricity in ICF's advice to MH (via the Consultant Panel Forecast Updates) will be proportionally lowered. This might confirm that MH's new contract prices are much better than MISO market prices, but increases the concern that MH's opportunity sales will not generate sufficient revenue to cover new plant costs. In an average year, opportunity sales represent more than 50% of MH's overall export sales.

On the basis of information provided, the Board does not share ICF's ready acceptance of the positive risk features associated with MH's long-term contracts. It appears that these features are somewhat favourable in the event of a "worse than the worst recorded" drought, but they do not appear to provide any substantive benefit for drought events of lesser magnitude than the maximum recorded.

ICF did not provide any analyses or evidence on the appropriate rules and volumetric limitations that should be applied to merchant and other short-term trading. The Board is uncertain as to what value can be placed on ICF's conclusions with respect to MH's acceptable management of merchant trading vs. market trading or bilateral sales. All of these activities involve MH's volumetric commitment of at times scarce energy resources without a clear understanding of the financial risks.

Without actually testing MH's modeling inputs/outputs, ICF concluded that these are adequate. This does not provide much assurance to this Board. Rather, it casts doubt on other conclusions that are based on hydrological assessment of the volumetric components of MH's energy supply.

In concluding that MH's defined five-year drought test is an adequate stress test, ICF is dismissing the possibility of other logically coincidental factors adding to drought costs. In the Board's view, more evidence would be required to support that conclusion.

In the absence of specific evidence that the impacts of the 2003/04 drought would have been reduced under the new contracts (if the Adverse Water Clause were applicable) the Board does not see much useful drought risk mitigation. Even if the Adverse Water Clause had been applicable, MH's new generation and transmission capacity may not reduce drought risks if MH continues to aggressively sell all remaining surplus energy.

KPMG Report

When the Board looks at KPMG's contribution to this hearing on risk issues, the Board concludes that the overall time, opportunity and monetary resources available to KPMG did not result in the due diligence review that the Board expected or that MH might have found useful going forward. Certainly, the Board would have expected a more in-depth analysis of MH's actual water resource utilization and the market price scenarios during 2003/04 and 2006/07.

KPMG did suggest that MH's antecedent forecasting process could be improved by adding hydrological components to the overall modeling system. However, when asked to define the specific components that should be added, KPMG indicated that it did not have the hydrological expertise necessary to provide those factors.

When revisiting MH's various development scenarios, KPMG relied totally on MH's existing models and MH's energy pricing forecast. KPMG did not see its role as challenging MH's operational decisions or MH's interpretation of the energy market.

With respect to MH's Middle Office – Front Office relationship, KPMG was concurrently retained to define the appropriate Middle Office role and structure to best augment MH's Power Sale Office operation. This supplementary report offered useful direction on Middle Office staffing and responsibilities. However, it did not provide any significant insights on the Front Office operation under drought situations such as existed in 2003/04 or on market situations such as existed in 2009/10.

In the Board's view, the value of KPMG's review was constrained by the consultant's exclusive reliance on MH's modeling assumptions and MH's export price forecasting. This degree of reliance raises concerns about the independence of KPMG's review and advice.

KPMG's acknowledgement that KPMG did not look to challenge MH's operational decisions, (presumably due to a lack of hydrological expertise) or to challenge MH's management decisions with respect to export market price forecasts does not speak well for KPMG's conclusions that "MH demonstrated prudent risk management". This also raises questions about how KPMG could dismiss most of the NYC allegations as having little or no foundation.

MH indicated that KPMG was only asked to review post-2006 operations. As such, the Board is at a loss to understand how a risk review could be accomplished without serious attention to the most significant drought in the last decade.

In a similar vein, the Board concludes KPMG did not fully address the issue of the SPLASH model's over-statement of longer term hydraulic generation as a result of perfect foresight.

KPMG has implied that MH's operations are conservative but did not look at MH's habit of typically selling up to 115% of its annual hydraulic generation and the risk of winter buy-backs relative to summer off-peak sales. The Board sees MH's actions as being somewhat aggressive rather than conservative in practice.

The Board is concerned that KPMG did not critically explore the inter-relationship of drought risks and price risks, yet concluded that MH has a "conservative" approach to power resource management and marketing.

Further, KPMG acknowledged that it did not possess the technical expertise to actually carry out:

- an independent review of hydrological issues and how these should be integrated into MH's forecasting process;
- an independent assessment and/or back-testing of MH's HERMES or SPLASH models; and
- a comparative analysis or critique of MH's market forecasts of the value of export or import energy.

In the Board's view, many of KPMG's observations and recommendations would require a high level of expertise in hydrology, water supply management modeling and energy market pricing.

Independent Consultant (KM)

The KM report provided much useful insight into MH's energy supply and power sales operations and to the NYC allegation with respect to those operations. It is the Board's view is that KM's review usefully re-defined the circumstances that were addressed by various MH consultants and provided a degree of clarity on many issues.

While KM's overall process of examining the NYC allegations was constrained by various legal challenges and the apparent need for extensive data redactions, the Board believes that useful information was gleaned from the various opinions on the validity of the allegations. There has been a strong indication that MH has or intends to strengthen the operational structure of MH's power supply and sales ventures. A stronger Middle Office with a more clearly defined Front Office interface seems to be in the making.

Various reports have identified concerns and weaknesses in MH's marketing strategies, particularly as they were enacted in 2003/04 and in 2006/07. Despite MH's current reluctance to acknowledge the potential need for operational improvement and a written Drought Preparedness Plan, KM (and other experts) were looking forward to MH's documentation of potential drought risk mitigation strategies in that plan. The Board still expects MH to file such a written plan.

Concerns raised by the NYC about the very limited number of in-house experts to run MH's key models and to direct power sales operations apparently have some merit. Most of external experts have alluded to the need for more formal documentation of these key models and the need for regular independent back-testing of operational results.

The Board sees merit in some of KM's findings on the NYC allegations, but does take issue with the narrow interpretation placed on some concerns and the reliance on other experts' opinions.

When KM (and others) suggested that MH's five-year-drought analysis represents an adequate valuation of MH's overall risk, the Board would have expected that KM (and others) would have done a detailed assessment of both the five-year- and seven-year-droughts. That apparently was not the case. KM performed various single-year-drought assessments (which conceivably would have mirrored the worst year in the five- or seven-year-droughts), but did not specifically evaluate the five-year-drought.

KM suggested that the idea of non-financial water reserves (the holding back of water against the risk of a future drought) in addition to financial reserves (adequate retained earnings) merits serious consideration, but the Board has not seen any detailed analysis of how such a reserve would beneficially function under actual historical drought scenarios.

19.0.0 COST OF SERVICE

19.1.0 OVERVIEW

The 2006 Cost of Service Review led to Board Order 117/06, which contained the Board's findings on various aspects of MH's cost allocation. MH's 2008 General Rate Application included COSS08 (prepared by MH in Aug. 2007) which only partially complied with Board Order 117/06.

As directed in Board Order 116/08, MH filed a March 2009 version of COSS08 that was in large part compliant with that Order. MH, however, continued to object to specific components of the Board Directives in Board Order 116/08. These were:

- a single export class with fully allocated embedded costs in addition to direct assignment of fuel and power purchase costs;
- direct assignment of fixed and variable thermal generation costs to exports;
- use of actual prior year export pricing instead MH's IFF forecast pricing;
- assignment of all NSB/MISO/Trading Desk costs to the export class; and
- assignment of all DSM costs to the export class.

MH has not in recent years proposed any rate increase differentials based on revenue to cost coverage (RCC) ratios for Residential and General Service Small/General Service Medium/General Service Large. Only Area and Roadway Lighting has seen rate freezes to reduce its RCC.

In the current General Rate Application MH filed COSS10 which deviated in a number of allocation aspects from Board Order 116/08.

In early 2010, MH filed COSS11 based on the 2010/11 fiscal year. However, MH recommended that both COSS11 and COSS10 be received by the Board for information only.

In light of the post-COSS11 industrial load reductions and the potential for lower export revenues, there may well be the need for a COSS12 or COSS13 to be filed before a full review of the Cost of Service is usefully undertaken.

MH has, subsequent to filing its GRA, engaged an external consulting service to "review the Cost of Service methodology for consistency with cost causation, utility economics and the range of regulatory practices in North America, and pursuant to that review, to make appropriate recommendations with respect to either maintaining or varying those methodologies."

MH did file the preliminary Terms of Reference with the Public Utilities Board in early 2010. The final terms of reference of this study have not yet been shared with the Board.

The Board expects that MH will present the "Cost Of Service Review" findings along with a detailed comparison to the March 2009 PCOSS08. Proposed changes should be accompanied by an item-by-item detailed explanation, justification, quantification and rate impact explanation. Likewise, a similar comparison should be provided for any marginal cost based cost of service study scenarios.

19.2.0 COMPARISON OF COSS08 TO COSS10 AND COSS11

The hearing record contains a line-by-line comparison of revenues and costs associated with the single export class for each of the above COSSs. That information illustrates the strong correlation between unit export revenue and the net export revenue available for customer class subsidies.

19.3.0 GENERATION AND TRANSMISSION COSTS

Generation and transmission costs (assigned and allocated) in the various COSS scenarios flow to domestic and export classes.

It is noteworthy that the two most recent versions of COSS11 show a significant increase in the domestic cost allocations compared to the PUB-approved March 2009 COSS08. Much of this increase results from the reduction in costs directly assigned to exports.

MH's COSS11 movement of all thermal costs and about 50% of NEB/MISO/Trading Desk costs to domestic classes involves a $64M shift in costs to domestic customers which is not in compliance with the Board's directives and the March 2009 COSS08.

The proportion of allocated generation and transmission costs going to exports compared to domestic remains constant at 60-70%. This disparity in allocated costs therefore seems to be largely related to the treatment of HVDC and other transmission costs.

19.4.0 DISTRIBUTION COSTS

In COSS10 and COSS11 the total allocated costs to sub-transmission/distribution plant/distribution services appears to have grown in step with sales. The cost per kWh has remained fairly constant at 2.2 to 2.3¢/kWh since 2007.

19.5.0 MARGINAL COST TREATMENT OF COSS

In Board Orders 117/06 and 116/08, MH was directed to create a Marginal Cost (MC)-based COSS and examine means to reflect environmental values within such an MC-COSS. These directives have, to date, not been adequately addressed. Initial attempts by MH to build a free-standing version of an MC-COSS were unsuccessful.

A considerable difficulty exists in defining the appropriate MC in an export market-driven utility where the actual export price-based MC could be viewed as commercially sensitive and hence confidential. This means that MC must be replaced by a proxy or some variation of embedded costs.

19.6.0 COSS TREATMENT OF NET EXPORT REVENUE

In the extended period of relatively high export prices prior to 2008/09, the impact of net export revenue credits to various domestic classes was substantial. By calculating the credit on the basis of total class costs, Residential and General Service Small receive a favourable adjustment to their Revenue Cost Coverage (RCC) ratios.

With the more recent decline in export prices, the available net export revenue (to be credited to domestic consumers) has dropped markedly. With Uniform Rates and the Affordable Energy Programs flowing largely to the Residential class, its RCC should increase relative to other classes.

Despite this treatment, Residential RCCs have remained in the 0.90 to 0.95 range compared to the GSL 30 to 100 and GSL >100 subclasses' RRCs, which are within a 1.05 to 1.10 range.

19.7.0 COSS TREATMENT OF HVDC COSTS

In recent Power Resource Plans MH indicated that new HVDC transmission costs will not be assigned or allocated to the export class. This seems to go well beyond the previous COSS process that treated a portion of the existing HVDC as a generation asset to be cost shared by export on a net export share basis. While Bipole III has reliability benefits for domestic customers, Bipole III is also needed to fulfil export commitments.

It is not clear whether COSS10 and/or COSS11 have made any adjustment to how Bipole I and II costs have been dealt with to date.

MH seems to be departing from true cost causation principles. The on-going functional usage of transmission by exports is not being considered.

19.8.0 INTERVENER POSITIONS

19.8.1 CAC/MSOS

To date CAC/MSOS has opposed the use of current COSS methodologies in rebalancing or setting differential rate increases for MH domestic customers. More robust marginal cost based analysis is suggested.

19.8.2 MIPUG

In MIPUG's view the current methodologies adequately calculate the class RCCs and should be used to assign lower differential rates to the GSL >100 class.

19.8.3 RCM/TREE

As in the past, RCM/TREE continues to support the use of an MC-based analysis in the cost allocation process and in rate-setting. With respect to low income and other social policy issues, it is RCM/TREE's position that the PUB unquestionably has jurisdiction to impose such an approach.

19.9.0 BOARD FINDINGS

MH has chosen not to seek differential class rate increases other than for Area and Roadway Lighting. MH's principles of rate design and cost allocation should be kept current. That said, the Board's position should not be interpreted to imply any support for the Cost of Service methodology changes employed by MH in PCOSS10 and PCOSS11.

In previous Board Orders, MH has been directed to treat all exports as a defined business venture obligated to share fully in the Utility's embedded costs. The Board has not accepted and does not accept the concept of any exports being a free by-product of domestic power operation.

Exports come with a cost, and that cost needs to be recognized in calculating net export revenue and in developing a business plan for new generating stations and transmission assets.

Reliability benefits associated with the HVDC system flow to export customers as well as domestic customers. Allocation of zero Bipole III costs to exports ignores these benefits and the role that Bipole III plays in facilitating exports from northern generation.

In the Board's view, MH's Export Business Model cannot transfer all operational and market risks to domestic customers. Because export contracts and opportunity sales carry greater risks than domestic sales, such export sales must provide a contribution to MH's fixed costs.

As the Board anticipates that the external Cost of Service review may not be available before mid-2012, there may be merit in a separate COSS review hearing if MH is seeking changes to the currently approved Board methodology.

Should marginal cost be a significant consideration in a future COSS, the Board's review would require MH to fully disclose its derivation of MC components. Whether any such disclosure would be on the public record will be a procedural matter to be determined.

20.0.0 RATE DESIGN

In addition to various rate matters addressed in section 3.0.0 of this Order, there are other rate and rate design issues to be addressed.

20.1.0 INVERTED RATES

Board Order No. 116/08 directed MH to file a report on Inverted Rates (in particular dealing with electric heating customer impacts) by January 15, 2009. There has been no action by MH to date with respect to that directive. MH has acknowledged that a rate accommodation will be required for electric heating customers, but has not provided any specific proposals that would mitigate a significant inverted rate strategy.

Aside from the Residential class, where prior to the Board's interim April 1, 2011 rate Order, there was only a modestly higher second block rate, the only movement toward inverted rates and toward eliminating the rate discount for higher levels of consumption appears to lie in the multi-year freeze of demand charges. However, for GSS/GSM customers energy rate adjustments are still applied on an equal percentage basis to all energy blocks in the ongoing consolidation of GSS and GSM subclasses. There has been no indication of the elimination of declining block prices for these subclasses.

20.2.0 RATE REBALANCING

MH continues to hold the demand charge at constant levels and is seeking the entire approved class rate increase via the energy charge. This process may have a limit short of fully rebalancing rates, but MH has not defined it to date.

20.3.0 CLASS CONSOLIDATION

MH continues to move the GSS and GSM subclasses toward a common rate structure. Apparently this process will be completed, within a few years, on a revenue neutral basis.

20.4.0 WINTER RATCHET ELIMINATION

The elimination of the Winter Ratchet by MH in lieu of the introduction of time-of-use may be useful in:

- consolidating GSS and GSM subclasses (only GSM had a winter ratchet);
- rate rebalancing (average demand revenues will be reduced for specific customers and subclasses and the resulting cost will be offset by higher energy charges);
- Limited Use Billing Demand (could see some reversions to normal billing); and
- Demand Concessions (lower demand charges for some GSM and GSL customers could mitigate impacts of economic downturns).

MH did not file a formal application for the elimination of the Winter Ratchet or provide a report detailing its impacts, but has proceeded with the elimination of this rate feature.

20.5.0 LIMITED USE BILLING DEMAND

The Limited Use Billing Demand (LUBD) program was initially developed for low load factor customers who were heavily impacted by the application of the winter ratchet. The LUBD in effect allowed customers with an 18% or lower load factor to opt for paying higher energy charges and reduced demand charges.

Contrary to initial expectations, LUBD attracted many seasonal customers with high summer/low winter demand. The program was not intended to be revenue neutral and now has an annual utility cost impact of $200,000 to $300,000.

20.6.0 BASIC MONTHLY CHARGE

The Board has denied MH's recently proposed reduction in the Basic Monthly Charge (BMC), citing a lack of appropriate justification. This is a cost-causation issue, because the current BMC does not nearly meet allocated customer costs.

20.7.0 TIME-OF-USE BILLING

MH has not provided any update on the status of time-of-use (TOU) rates. The elimination of the Winter Ratchet may have accomplished some time-of-use objectives. The Board's request for a September 30, 2008 planned implementing strategy report has not been answered. The Board understands that MH has been consulting MIPUG members on this issue. The content and extent of these consultations should be provided to the Board.

MIPUG's industrial customers are the most likely initial targets for TOU given the presence of appropriate metering. However, in light of current export market prices, TOU may actually have negative revenue impacts for MH. This should be considered further.

20.8.0 AREA AND ROADWAY LIGHTING

As in the previous GRA, MH's rate application did not call for ARL rate increases. The Board concurred with this in its approval of the interim and finalized rate increases.

20.9.0 ENERGY INTENSIVE INDUSTRY RATE

MH initially filed and then withdrew a revised proposal for the Energy Intensive Industry Rate (EIIR) which was being considered by MH's Board of Directors in January 2011. Beyond an indication of further consultations with industry there has been no further update on MH's intended actions.

The Board has some concerns about this issue remaining unaddressed. Until MH comes up with a revised program, the existing Board Directives on the nature of a future EIIR and a Service Extension Policy would seem to represent the current reality for MH and to new customers.

The Board notes that uncertainty with respect to the EIIR may not be attractive to potential new industrial loads.

20.10.0 SERVICE EXTENSION POLICY

Since the Board's last Order on EIIR, MH has been silent on the future of the service extension policy. The service extension policy issue is seen by the Board as independent of the EIIR. Nonetheless, the service extension policy has serious implications for industrial customers even in the absence of EIIR, especially for potential remote loads.

20.11.0 INTERVENER POSITIONS

20.11.1 CAC/MSOS

The Rate Design interests of CAC/MSOS can be succinctly indicated as being primarily focused on:

- Inverted Rates (CAC/MSOS has concerns about winter heating);
- Basic Monthly Charge (CAC/MSOS is in favour of reductions for the benefit of low-income consumers); and
- Temporary Billing Demand Concessions (CAC/MSOS is opposed to granting permanent relief as requested by MH).

20.11.2 MIPUG

The Rate Design interests of MIPUG can be succinctly indicated as being primarily focused on:

- Inverted Rates (MIPUG needs clarification before it can finalize a position);
- Rate Rebalancing (MIPUG is opposed to larger energy rate increases);
- Time-of-Use Rates (MIPUG thinks they may be of limited benefit but would want to receive a detailed study of any MH proposal);
- Energy Intensive Industry Rate (MIPUG appears satisfied with MH's consultative approach even if no proposal has been publically advanced); and
- Temporary Billing Demand Concessions (MIPUG strongly supports MH's request for "forgiveness" of the temporary deferral relief).

20.11.3 RCM/TREE

The Rate Design interests of RCM/TREE can be succinctly indicated as being primarily focused on:

- Inverted Rates (RCM/TREE want aggressive action, including higher winter thresholds for electric heating);
- Basic Monthly Charge (RCM/TREE submits that this should be eliminated as soon as possible); and
- Time-of-Use Rates (RCM/TREE is very supportive of MH advancing such rates).

20.11.4 City of Winnipeg

The ongoing rate and rate design interest for the City of Winnipeg was Area and Roadway Lighting, with an emphasis on limiting any rate increases.

20.12.0 BOARD FINDINGS

The Board notes that MH's responses on the various special rate issues remain outstanding and should receive more timely attention. The Board invites MH to provide all stakeholders (including the Board) with an overall strategy to co-ordinate the changing of rate structures for MH's various customer classes.

The Board requires MH to file preliminary reports (and status updates on):

- Inverted Rates, with a view to creating a significantly higher-priced second energy block, but providing an accommodation to electric heat customers, some of which do not have access to natural gas for heating;
- GSS and GSM Class consolidation with a view to defining the end-product and the specific timeframe for completion;
- Demand/Energy Rate Rebalancing with a view to defining the optimum balance and timeframe to achieve that balance through the allocation of Class Rate increases to the energy component;
- Time-of-Use Rates with a view to applying these in the near future to Top Consumers and industrial customers that already have the necessary metering capability;
- Limited-Use Demand billing with an update of the continued need for this rate in light of the elimination of the Winter Ratchet;
- the Energy Intensive Industry Rate, with justification for either abandoning the rate proposal or providing an alternative on-peak rate scenario as directed in Board Order 112/09; and
- the Service Extension Policy, including a proposal for the Board's review and possible acceptance in accordance with Order 112/09.

Board decisions may be appealed in accordance with the provisions of Section 58 of The Public Utilities Board Act, or reviewed in accordance with section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

21.0.0 IT IS THEREFORE ORDERED THAT:

1. A 1.9% average consumer rate increase for all of MH's domestic customer classes (except Area and Roadway Lighting) effective April 1, 2010 **BE AND IS HEREBY APPROVED AS FINAL**;

2. A 2.0% average consumer rate increase for all of MH's domestic customer classes (except Area and Roadway Lighting) effective April 1, 2011 **BE AND IS HEREBY APPROVED AS FINAL**;

3. MH's requests to finalize a 2.9% average consumer rate increase effective April 1, 2010; a 2.0% average rate increase effective April 1, 2011; and a further 0.9% average rate increase effective August 1, 2011 **BE AND ARE HEREBY DENIED**;

4. MH recalculate and refile, for Board approval, a schedule of rates reflecting a 1.9% average increase for all customer classes (except Area & Roadway Lighting) effective April 1, 2010, together with all supporting schedules including proof of revenue and customer impacts;

5. MH recalculate and refile, for Board approval, a schedule of rates reflecting a further 2.0% average rate increase for all customer classes (except Area & Roadway Lighting) effective April 1, 2011, together with all supporting schedules including proof of revenue and customer impacts;

6. MH calculate and file, for Board approval, a new interim rate that quantifies the difference between the April 1, 2010 and April 1, 2011 interim rates and the rates

finalized in this Order, together with all supporting schedules including proof of revenue and customer impacts;

7. MH is to forthwith advise this Board and the parties to this GRA of MH's intention respecting a GRA for the 2012/13 fiscal year;

8. MH is to calculate, and file for Board approval, a deferral account that tracks the difference between revenues calculated pursuant to the interim rates (in Orders 18/10; 30/10 and 40/11) and the rates finalized in this Order, together with accrued interest at MH's short-term borrowing rate;

9. All weekly Surplus Energy Program interim *ex-parte* rate orders – from Order 67/08 up to and including all SEP Orders issued prior to this Order – **BE AND ARE HEREBY APPROVED AS FINAL**;

10. Curtailable Rate Program Orders from Order 46/09 until current – including Order 63/11 – **BE AND ARE HEREBY APPROVED AS FINAL**;

11. MH's request that the Temporary Billing Demand Concessions granted pursuant to Order 126/09, be made permanent, and forgiven, under the program **BE AND IS HEREBY DENIED**.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE CA"
Chairman

"HOLLIS SINGH"
Secretary

Certified a true copy of Order No. 5/12 issued by The Public Utilities Board

Secretary

LIST OF ABBREVIATIONS

AC	-	Alternating Current
AEF	-	Affordable Energy Fund
AOCI	-	Accumulated Other Comprehensive Income
ARL	-	Area and Roadway Lighting
BMC	-	Basic Monthly Charge
CAC/MSOS	-	Consumers Association of Canada/Manitoba Society of Seniors
CBO	-	Community-Based Organization
CCCT	-	Combined-Cycle Combustion Turbine
CCX	-	Chicago Climate Exchange
CEF	-	Capital Expenditure Forecast
CFS	-	Cubic Feet per Second
CJA	-	Capital Justification Addendum
CO_2	-	Carbon Dioxide
COSS	-	Cost-of-Service Study
CRD	-	Churchill River Diversion
CRP	-	Curtailable Rate Program
DC	-	Direct Current
DSM	-	Demand-Side Management

EFT	-	Equivalent to Full-Time
EIIR	-	Energy Intensive Industrial Rate
EIS	-	Energy In Storage
FERC	-	Federal Energy Regulatory Commission (United States)
GAAP	-	Generally Accepted Accounting Principles
GILT	-	Grants in Lieu of Taxes
GJ	-	Gigajoule
GRA	-	General Rate Application
G.S.	-	Generating Station
GSL	-	General Service Large (Customer Class)
GSM	-	General Service Medium (Customer Class)
GWh	-	Gigawatt-Hour
HTR	-	Hard-to-Reach
HVDC	-	High-Voltage Direct Current
ICF	-	ICF International (Consulting Firm)
IFF	-	Integrated Financial Forecast
IFRS	-	International Financial Reporting Standards
KCN	-	Keeyask Cree Nations
KHLP	-	Keeyask Hydropower Limited Partnership

kV	-	Kilovolt
kVA	-	Kilovolt-Ampere
kWh	-	Kilowatt-hour
KM	-	Drs. Kubursi and Magee (Independent Consultants & Report Authors)
KPMG	-	KPMG (Accounting Firm)
LICO	-	Low Income Cut-Off
LIEEP	-	Lower Income Energy Efficiency Program
LUBD	-	Limited Use Billing Demand
LWR	-	Lake Winnipeg Regulation
MC	-	Marginal Cost
MCC	-	Manitoba Chamber of Commerce
MC-COSS	-	Marginal Cost-based Cost of Service Study
MH	-	Manitoba Hydro
MHA	-	Manitoba Housing Authority
MIPUG	-	Manitoba Industrial Power Users Group
MISO	-	Midwest Independent (Transmission) System Operator
MP	-	Minnesota Power
MRC	-	Marginal Resource Cost

MW	-	Megawatt
NBF	-	National Bank Financial
NCN	-	Nisichawayasihk Cree Nation
NERC	-	North American Electric Reliability Corporation
NFAAT	-	Needs For And Alternatives To
NEB	-	National Energy Board
NPV	-	Net Present Value
NSP	-	Northern States Power
NYC	-	New York Consultant
O&A	-	Operation and Administration (Expenses)
OL	-	(Financial) Outlook
OM&A	-	Operation, Maintenance and Administration (Expenses)
PACT	-	Program Administrator Cost Test
PCOSS	-	Prospective Cost of Service Study
PRP	-	Power Resource Plan
PUB	-	Public Utilities Board
RCC	-	Revenue to Cost Coverage (Ratio)
RCM/TREE	-	Resource Conservation Manitoba (now Green Action Centre) / Time to Respect Earth's Ecosystems

RIM	-	Rate Impact Measure
RSM	-	Rate Stabilization Mechanism
RSR	-	Rate Stabilization Reserve
SCCT	-	Single-Cycle Combustion Turbine
SCT	-	Societal Cost Test
SEP	-	Surplus Energy Program
TPC	-	Taskinigahp Power Corporation
TOU	-	Time-of-Use (Ratio)
TRC	-	Total Resource Cost
WCC	-	Western Climate Coalition
WPLP	-	Wuskwatim Power Limited Partnership
WPS	-	Wisconsin Public Service

APPENDIX A - APPEARANCES

R. Peters A. Southall	Counsel for The Manitoba Public Utilities Board (Board)
M. Boyd P. Ramage O. Fernandes	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams M Bowman	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc (CAC/MSOS)
A. Hacault	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson (np)	Representing *Manitoba Keewatinowi Okimakanak.* (MKO)
W. Gange P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Pambrun	Counsel for the City of Winnipeg
J. Rath D. Coad	Southern Chiefs Organization (SCO)
G. Wood	Independent Experts (KM)

(np)- not present at the hearing

APPENDIX B – WITNESSES FOR MANITOBA HYDRO

MH Personnel

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Senior Resource Planning & Special Studies Engineer, Resource Planning and Market Analysis Department
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
D. Cormie	Division Manager, Power Sales and Operations Division
L. J. Kuczek	Vice-President, Customer Care and Marketing
D. Rainkie	Corporate Controller, Corporate Controller Division
M. Schulz	Corporate Treasurer

KPMG Panel

W. Lipson	Partner
F. Chen	Director, Financial Risk Management
J. Erling	Managing Director, Toronto
A. Gupta	Senior Manager

ICF International Panel

J. Rose	Managing Director

APPENDIX C – INTERVENERS OF RECORD

Interveners of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors (CAC/MSOS)

Manitoba Industrial Power Users Group (MIPUG)

Manitoba Keewatinowi Okimakanak (MKO)

Resource Conservation Manitoba (now Green Action Centre)/Time to Respect Earth's

Ecosystems (RCM/TREE)

City of Winnipeg (CITY)

Southern Chiefs Organization (SCO)

APPENDIX D – INTERVENER AND INDEPENDENT WITNESSES

Intervener Witnesses

CAC/MSOS

T. Carter	Professor, University of Winnipeg
W. Harper	Manager, Econalysis Consulting Services, Inc.
G. Matwichuk	Stephen Johnson Chartered Accountants
J. McCormick	McCormick Financial Services Inc.

MIPUG

P. Bowman	Consultants, InterGroup Consultants Ltd.
A. McLaren	

RCM/TREE

P. Chernick	President, Resource Insight Inc
J. Wallach	Vice-President, Resource Insight Inc.
R. Colton	Fisher, Sheehan & Colton

Independent Expert Panel

Dr. Atif Kubursi	Professor Emeritus, Dept. of Economics McMaster University
Dr. Lonnie Magee	Professor, Dept. of Economics McMaster University

APPENDIX E - PRESENTERS

Mr. Art Carriere (written only)	Citizen
Mr. Allan Ciekiewicz	Citizen
Mr. Art Derry	Bipole III Coalition
Mr. David Forsyth	Gerdau Ameristeel Corporation
Mr. John Gray	Citizen
Mr. Norm Gruhn (written only)	Citizen
Mr. Lynn Jones (written only)	Citizen
Mr. Mark Shirley (written only)	COO, Amsted Rail
Dr. Leonard Simpson and	Citizen
Mr. Blair Skinner	Citizen
Mr. Graham Starmer	Manitoba Chamber of Commerce
Mr. Bill Turner	Canexus/ Chair, Manitoba Industrial Power Users Group

Tab 36

Bipole III: Past, Present and Future

David Jacobson, Section Head- Interconnection Planning,
System Planning, Manitoba Hydro

November 13, 2019

2019 Minnesota Power Systems Conference

Manitoba Hydro

Outline

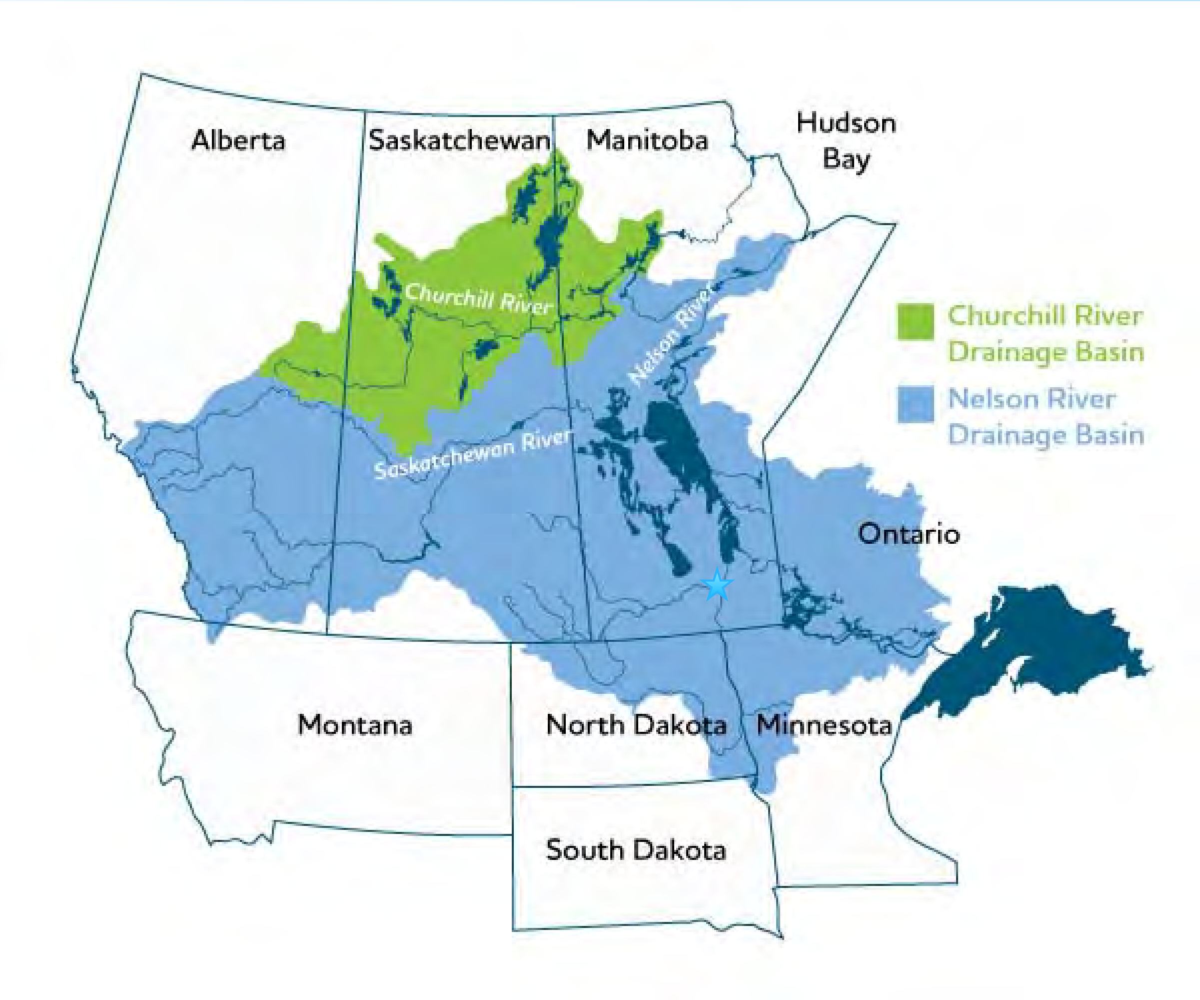
- Introduction
- Early Planning Studies
- Bipole III Need
- Bipole III Project Scope
- Bipole III Future
- Video
- Q&A

Manitoba Hydro

Introduction

Manitoba Hydro

Manitoba Hydro



- Crown Corporation (owned by Prov. MB) with head office at Winnipeg.
- Services for over 580,000 electricity and 280,000 gas customers.
- A total generating capacity about 5700 MW produced mainly by 15 hydroelectric stations, 2 wind plants and 2 thermal stations.

https://www.manitobahydropower.com/who-we-are/

Manitoba Hydro

1 Burntwood River -

Wuskwatim -	200 MW
First Rapids -	210 MW
Manasan -	270 MW
Early Morning -	80 MW

2 Laurie River -

Laurie River 1 -	5 MW
Laurie River 2 -	5 MW

3 Saskatchewan River -

Grand Rapids -	480 MW

4 Nelson River -

Jenpeg -	129 MW
Kelsey -	250 MW
Kettle -	1,220 MW
Long Spruce -	1,010 MW
Limestone -	1,340 MW
Keeyask -	695 MW
Conawapa -	1,485 MW
Gillam Island -	1,080 MW
Birthday -	380 MW
Redrock -	250 MW
Whitemud -	310 MW

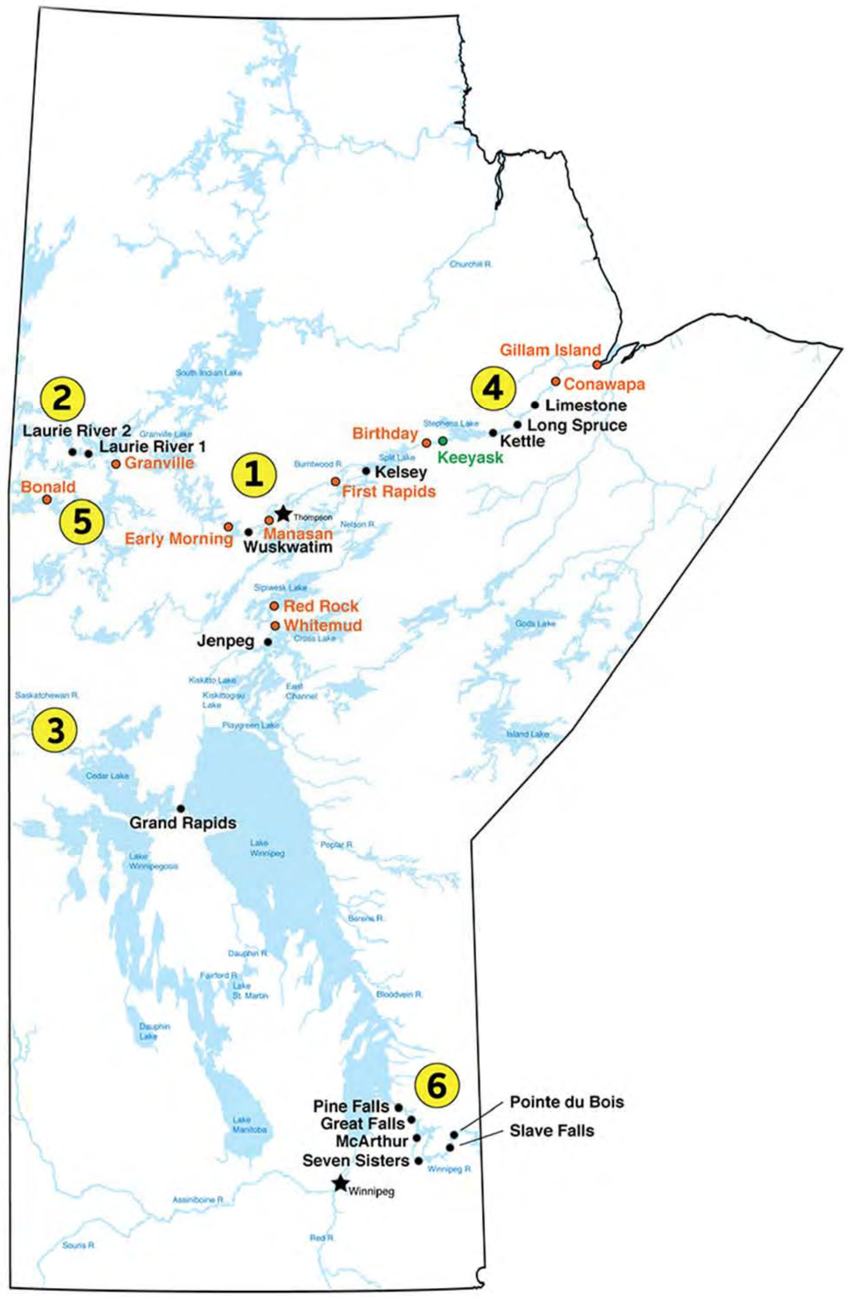
5 Upper Churchill River -

Granville -	120 MW
Bonald -	110 MW

6 Winnipeg River -

Pine Falls -	89 MW
Great Falls -	136 MW
McArthur -	55 MW
Seven Sisters -	165 MW
Pointe du Bois -	77 MW
Slave Falls -	67 MW

• Current sites-	5,228 MW
• Under development-	695 MW
• Potential sites-	4,295 MW

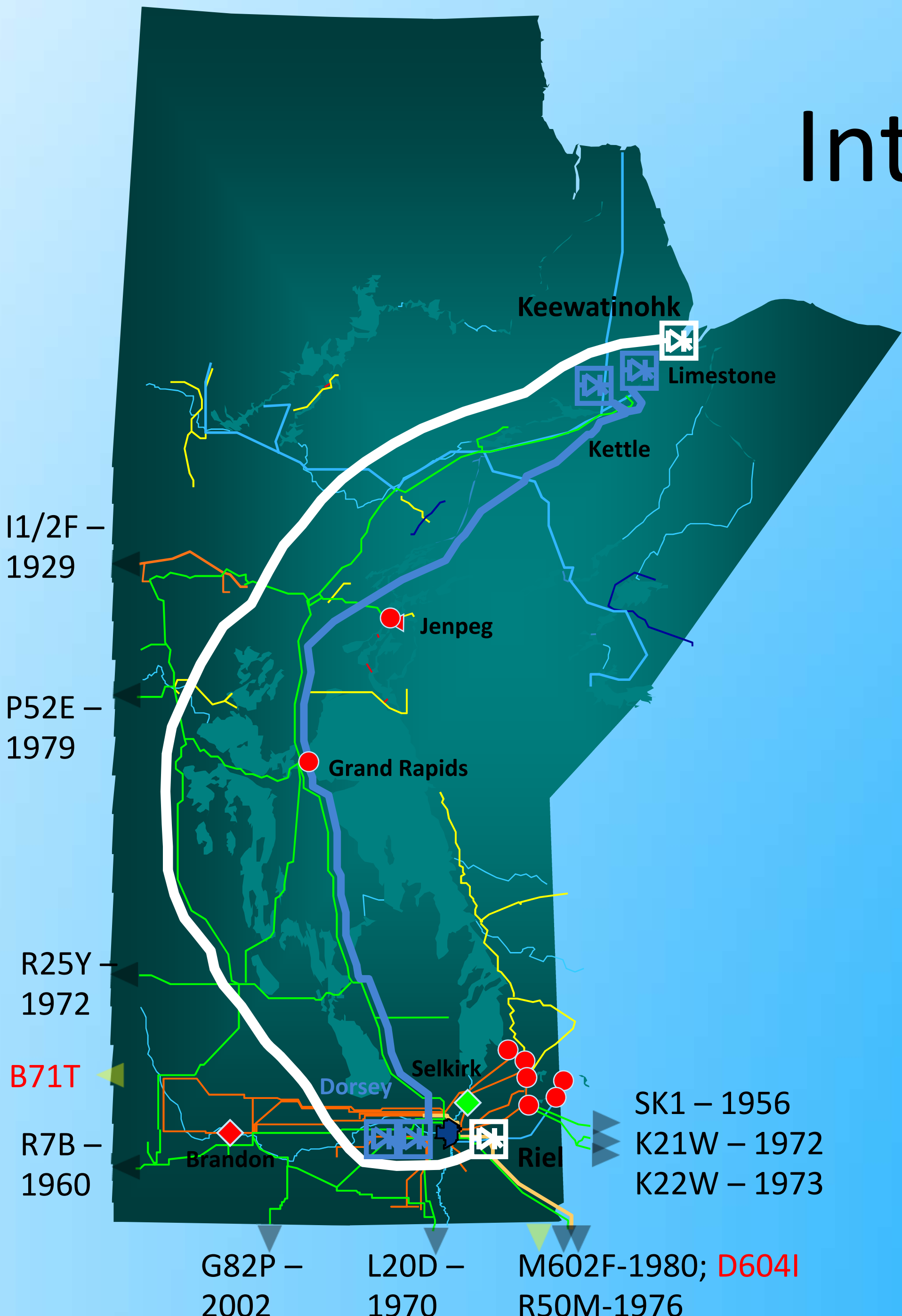


- Current Hydro sites: 5228 MW
- Under development (Keeyask) 695 MW
- Potential 4300 MW

Manitoba Hydro

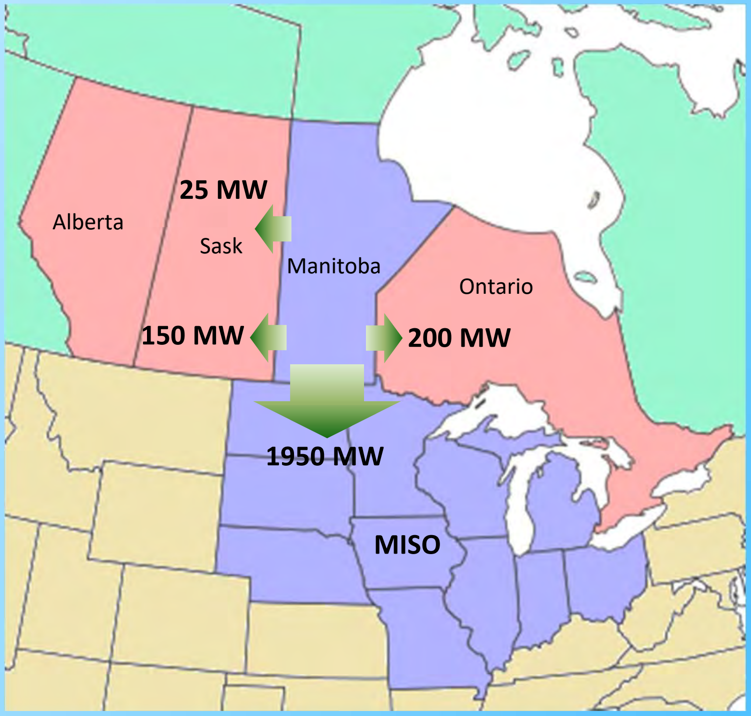
Interconnections

- B71T - Birtle to Tantallon 2021
- D604I – Dorsey to Iron Range 2020 (MMTP/GNTL)



Manitoba Hydro

Firm Export/Import Capability



https://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/2016_Transmission_Interface_Capability_Report.pdf

	Export	Import
U.S.*	1950 MW 2833 MW	700 MW 1398 MW
Ontario	200 MW	0 MW
Sask-south	150 MW 290 MW	0 MW 0 MW
Sask-north	25 MW	60 MW

*** Excludes 150 MW CRSG**

Manitoba Hydro

Early Planning Studies

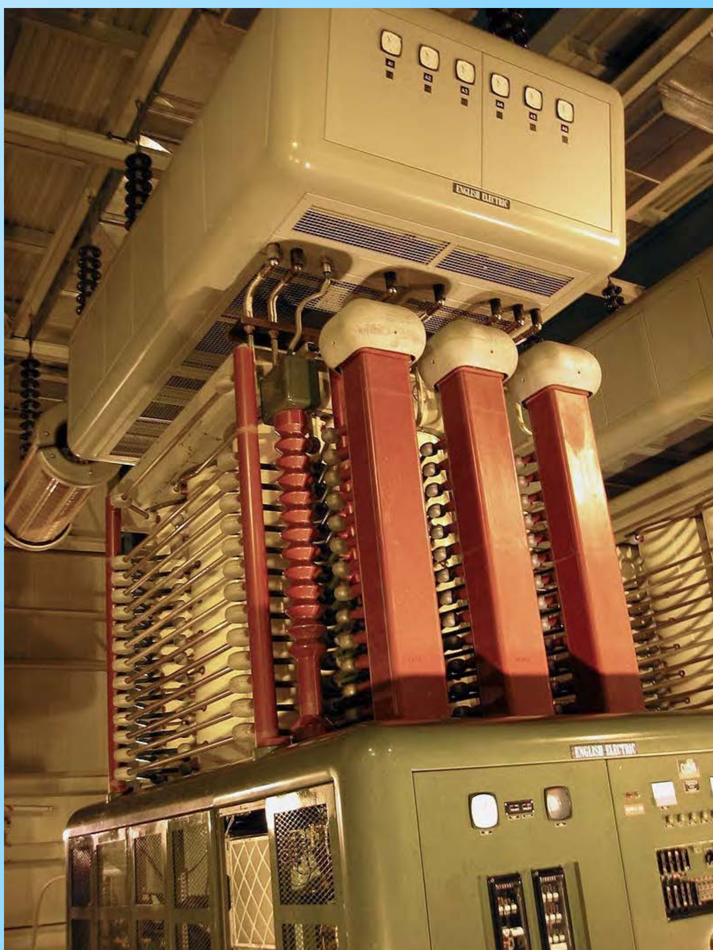
Manitoba Hydro

1960's

- 1963 – Government of Canada/Manitoba shared cost of study looking at development of the Nelson River.
- 1966 – Agreed to jointly develop Phase 1 – "Birth of HVDC in Manitoba"
- Phase 1 – 1272 MW Kettle (ISD 1974), two 900 km HVDC lines, Bipole I (ISD June 1972),

Manitoba Hydro

AC vs DC Decision

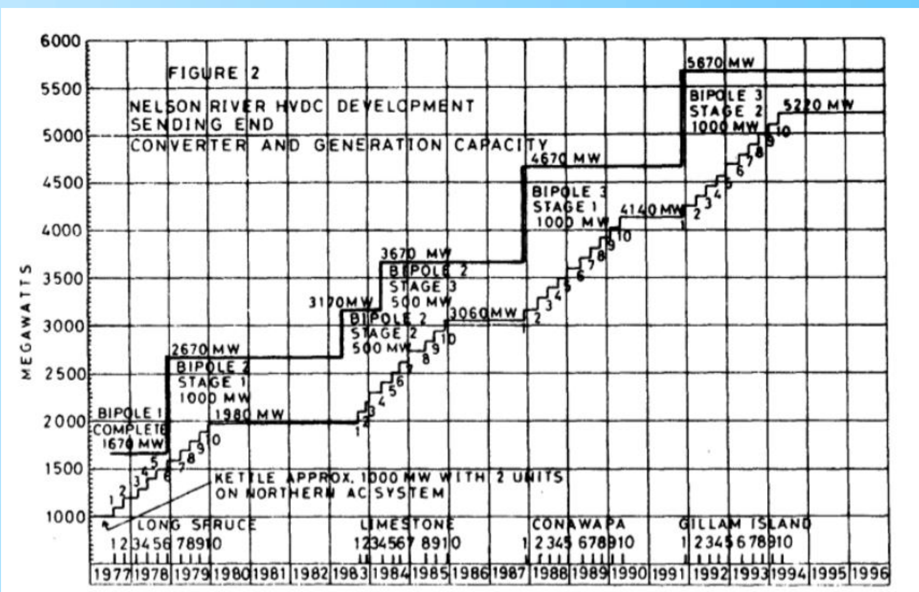


https://en.wikipedia.org/wiki/Nelson_River_DC_Transmission_System

- 500 kV AC with 70% series compensation was compared with HVDC. Series comp had about 15 years of history.
- HVDC selected – lower cost, lower losses and better performance.
- Four bids – one mercury arc only, two thyristor only and one mercury arc and thyristor. ASEA's first thyristor project (30 MW) only went into service in 1970.
- IEEE Milestone in EE – At 150 kV, they were largest mercury arc valves ever developed.

Manitoba Hydro

1970s Projections



C.V. Thio, "Nelson River HVdc Bipole-Two Part 1-System Aspects, IEEE Trans. PAS, Vol. PAS-98, No. 1, Jan/Feb 1979.

- High load growth projected need for Bipole III as early as 1988.
- A nuclear engineering department was formed in 1974.

Bipole I

Bipole II

Bipole III

Manitoba Hydro

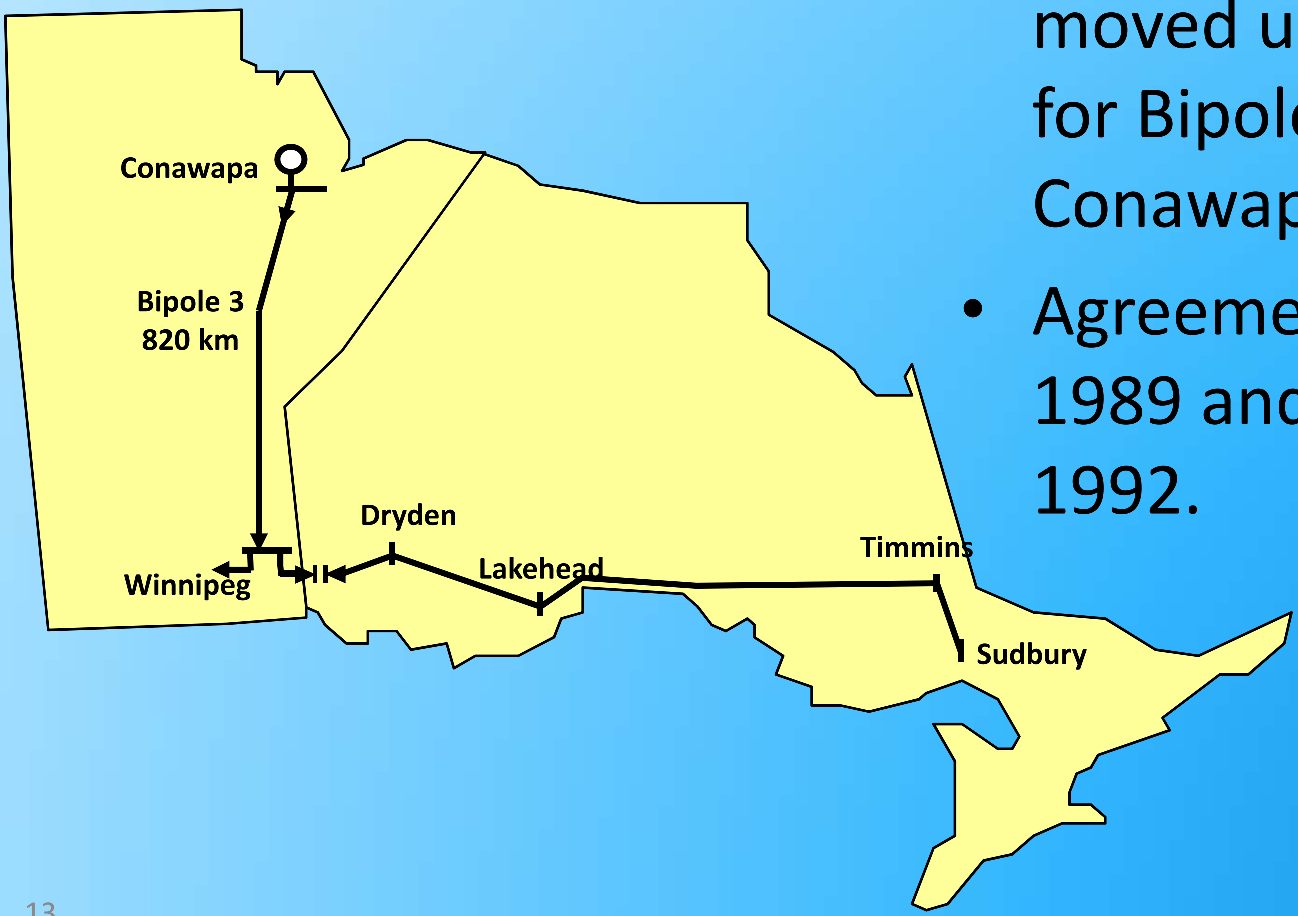
1980's

- Load growth slowed
- Completed development of Bipole II in June 1985.
- 2000 MW, 500 kV thyristor technology
- Long Spruce completed 1979.
- Limestone's original target year was 1983 – deferred to 1990.

https://en.wikipedia.org/wiki/Nelson_River_DC_Transmission_System

Manitoba Hydro

Early 1990s



- Potential for a 1000 MW to sale to Ontario moved up the schedule for Bipole III and Conawapa.
- Agreement signed in 1989 and cancelled in 1992.

Manitoba Hydro

Features of the Bipole I and II System

- Link to 70% of the Province's generating capacity
- Bipole I and II HVdc lines constructed on the same Right-of-way
- 900km overhead lines, difficult terrain and access in the north
- Terminated at a common station – Dorsey (inverter)
- Highest percentage of power concentrated in a single facility - "Too many eggs in one basket"

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External Asynchronous Resource (EAR)

- Bipoles I and II allows for hydro to look like a battery. Allows for hydro-wind synergy. Very fast ramping capability.
- EAR is a market-designated resource separated from the main MISO market by a DC tie.
- EAR is very flexible and can provide energy, spinning, supplemental regulating reserves, regulation, ramp products, capacity.
- Currently, EAR is bidirectional and limited to 375 MW. Available since ~2010.

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Bipole III Need

Why is Bipole III required now?

- Bipole III is required for reliability
  - Bipole I & II DC transmission line corridor loss
  - Only one southern converter station (Dorsey)
  - Long restoration times
- We’ve experienced loss of corridor before and near misses (downbursts, ice, forest fires and etc.).
  - *Real risks, not theoretical*

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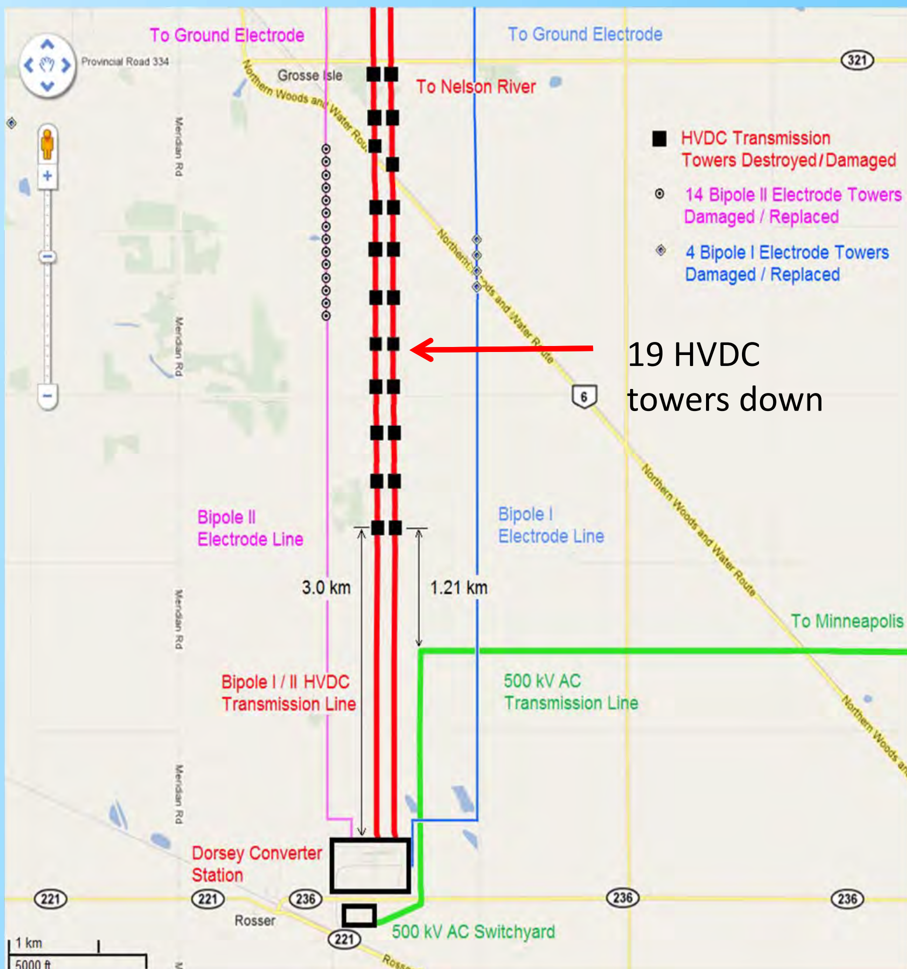
Reliability Risk – Sept. 5th 1996 Wind Event
1.5 miles away from Dorsey Converter Station



- Public appeal for power reduction
- All generation units on maintenance returned to service
- Rotating blackout planned

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Reliability Risk – Dorsey Converter Station

Elie F5 Tornado

Storm hits portions of Dorsey, Aug. 10, 2007;
Lost BPI followed by D602F 60 seconds later

- Dorsey is a single terminus point for HVDC system
- Significant weather events (tornados, etc.) in the vicinity of Dorsey in the past
- A complete loss at Dorsey could mean loss of connection to northern generation for up to 3 years.

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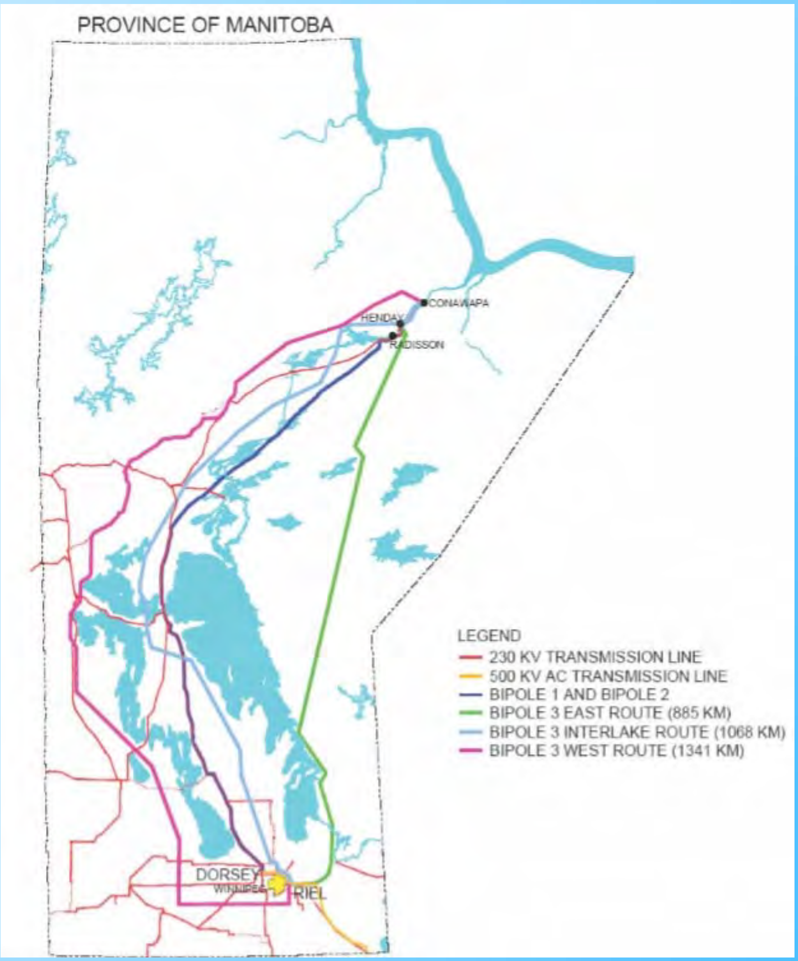
Probabilistic Analysis – Weather Hazards



Manitoba Hydro has worked closely with field experts/consultants to evaluate weather hazards (Tornados, wide front wind, ice) and other risks of losing the HVDC system after the 1996 event.

Events	Return Period of Failure (years)	
	Pre-Bipole III	Post-Bipole III
Tornados	17	3700
Synoptic Wind (wide front)	90	560
Combined Wind and Ice	20	200+

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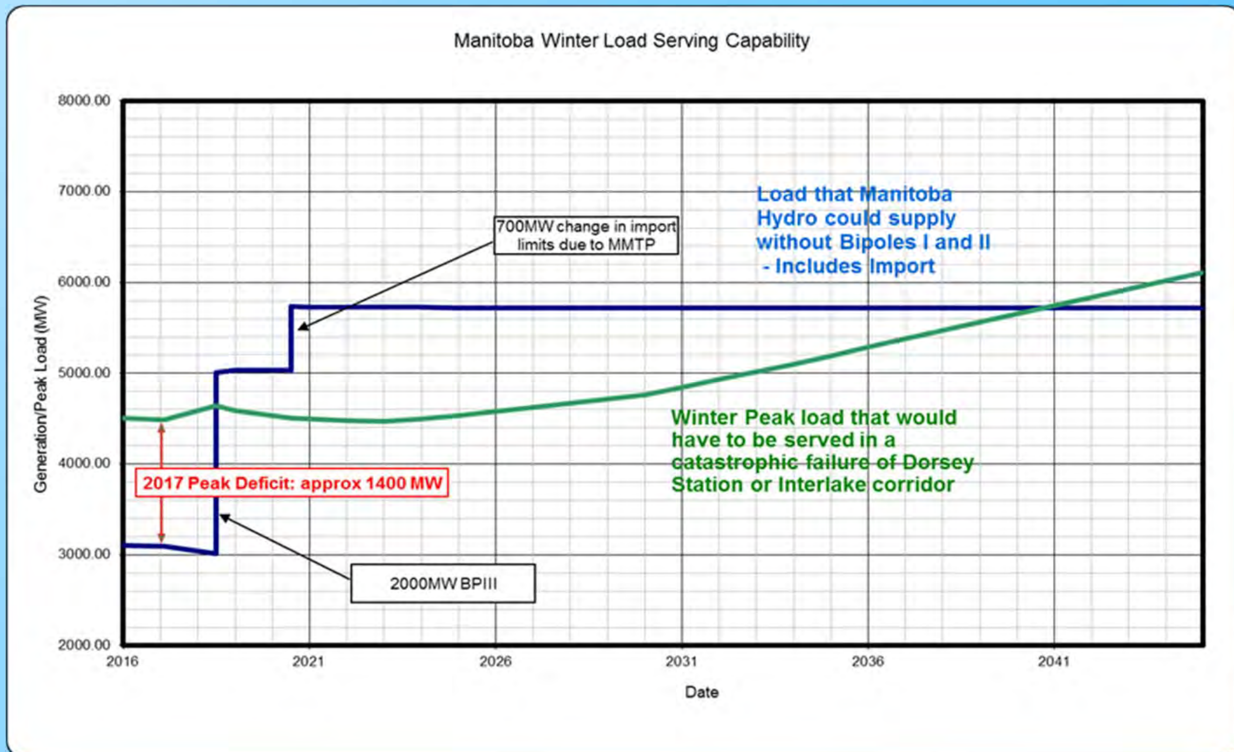
Deterministic Analysis – Supply Deficit



- Manitoba Hydro assesses the reliability risk of low-probability high-impact events according to NERC Standard TPL-001
- Supply deficit of about 1400MW for the loss of existing Bipole I/II system in the winter of 2017 (pre-Bipole III).

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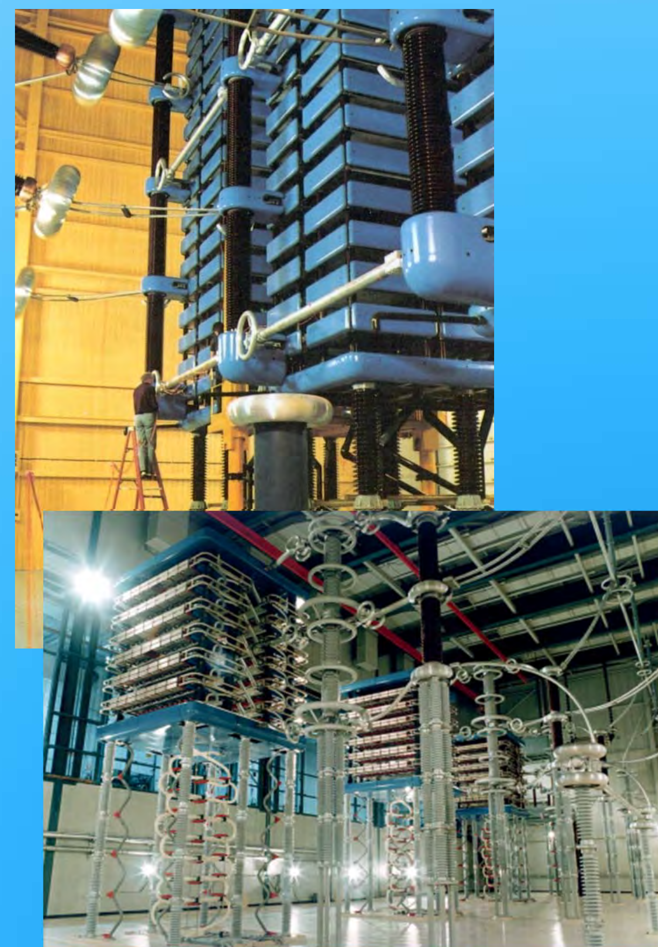
Additional Benefits of BPIII

- Aging BP I and BPII converters (>30 years in service) require life extension upgrades: $1B.
- BPIII offers adequate DC transmission spare to facilitate & optimize BPI/II refurbishment and save outage costs.
- Reduce HVDC transmission loss: about 80MW
- Provide HVdc capacity for future renewable energy development



Pole1 refurbished with thyristor valves -1992

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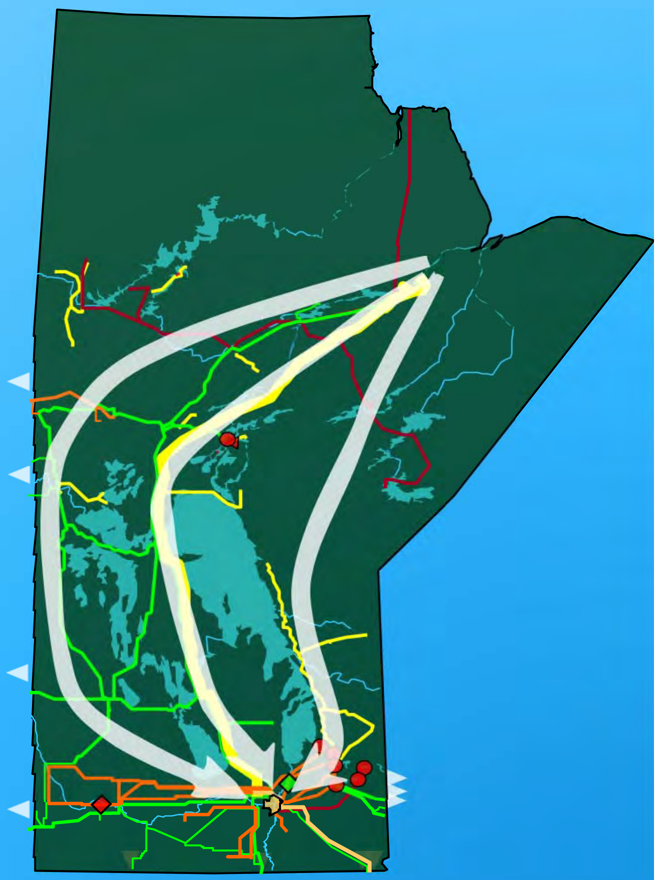
2000's

- 2001: Internal report recommends:
  - Building 800 km East side HVdc line by 2010
  - Sectionalization of D602F at Riel in 2008.
  - Bipole I and II lines would be paralleled on BP I. Bipole III line would terminate at Dorsey on BP II.
- In 2005, East side becomes unavailable as an application to designate area as a UNESCO world heritage site in progress.
- Decision made in 2007 to proceed with Western route. New DC converters added to scope as impedance of 1388 km route expected to be difficult for Bipole II analog controls.



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Bipole III Project Scope

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Bipole III Planning Studies

- Power flow studies
- Fault studies
- Stability studies
- Ac and DC harmonic studies
- Small signal stability assessment
- Feasibility studies of VSC technology

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Outcome of Bipole III Planning Studies

- Determine BPIII size and operation modes
- Ac system reinforcement for integration of BPIII (new lines/stations, location, upgrades, etc.)
- Static/dynamic reactive power requirements
- Determine equipment rating (breakers, switches, grounding and etc.)
- Estimation of ESCR and MIESCR for dc performance and determine mitigation
- Determine impact on the nearby systems (ac and dc in multi-infeed schemes)
- Determine special requirements (supplementary damping /fast dc reductions)

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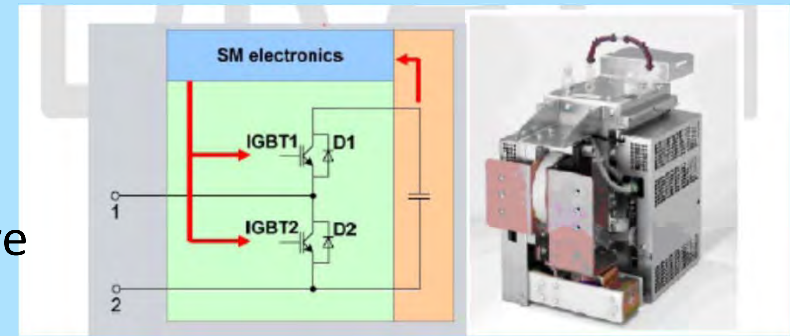
Feasibility Study - VSC Option

- No synchronous condensers
  - Cost savings : Capital /O&M
  - Reduce system fault levels
  - VSCs can provide voltage and reactive power support, but not inertia that synchronous condensers do



- No commutation failure

  - Large infeed of HVdc schemes in proximity: If all LCC links fail commutation at the same time, it can lead to potential (although very short) loss of significant power to southern system.

  - VSC improves this situation by not failing commutation and ability to maintain power flow.

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Feasibility Study - VSC Option

- Disadvantages
  - Not implemented at 500 kV and 2300 MW; Skagarak 4 planned for 2014
  - Limited number of vendors
  - Dc fault clearing requires ac breakers (half bridge technology)
  - Converter losses slightly 1% vs 0.7%

- Decision
  - Permit VSC bids as an option
  - Included price break as 4x250 MVAr synchronous condensers not required.
  - Required dc faults to be cleared on dc side (full bridge or dc breaker needed).

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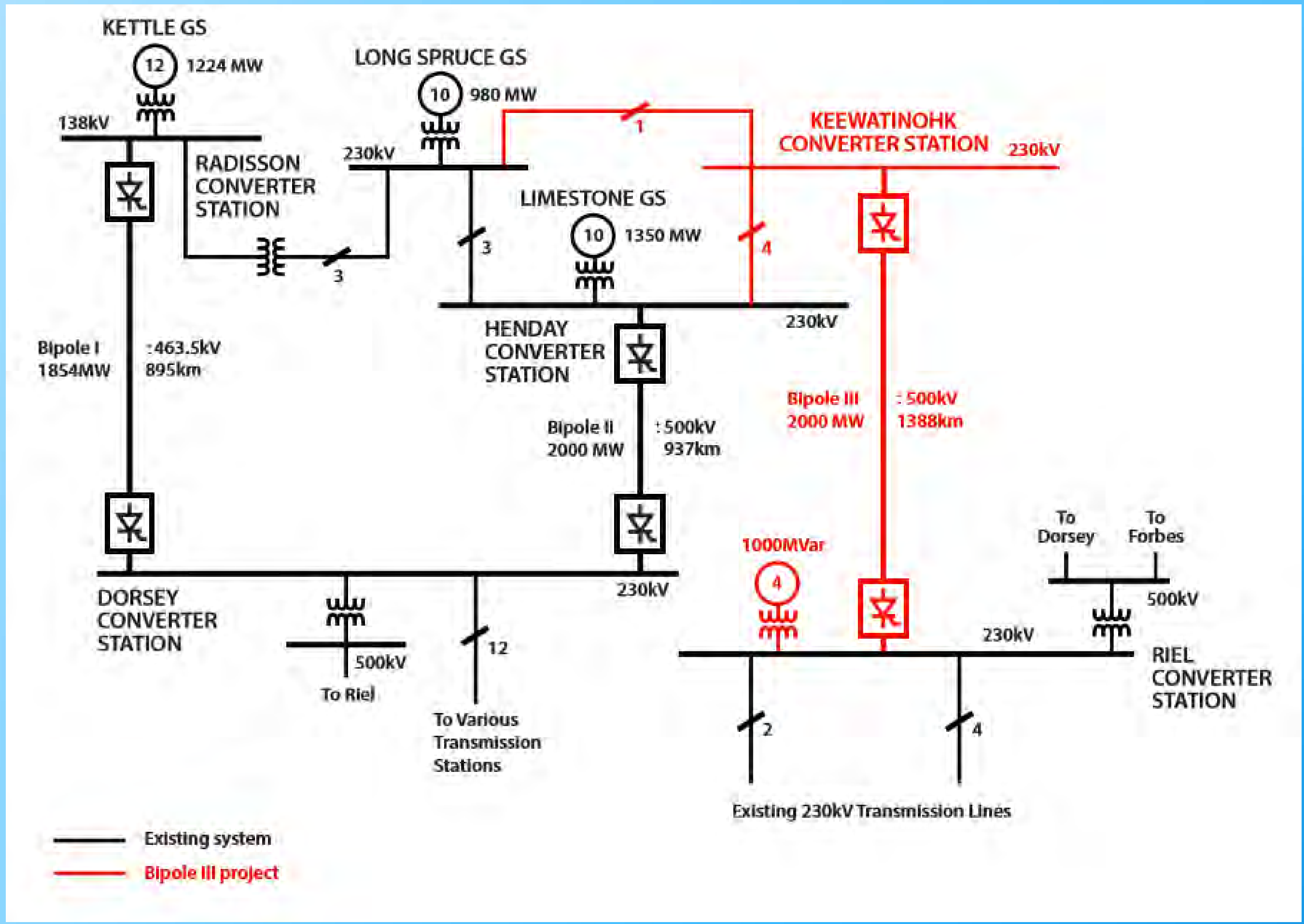
Bipole III Project Scope - ISD 2018
LCC, ±500 kV, 2000 MW



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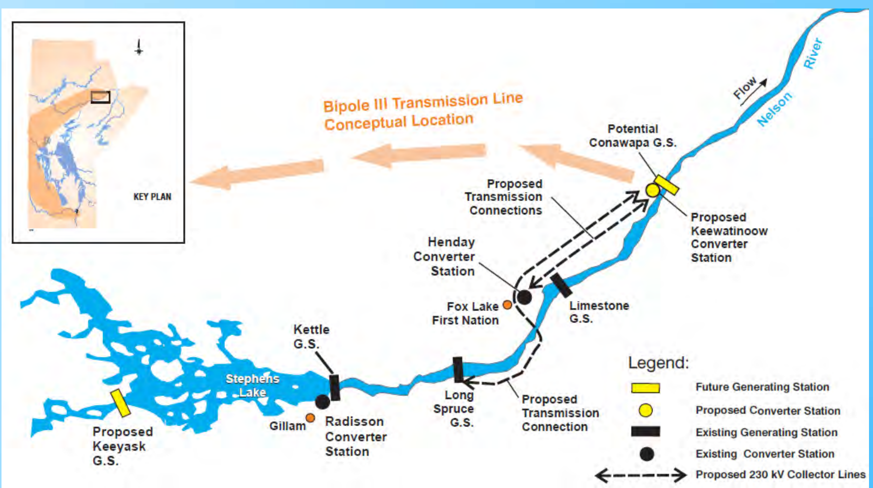
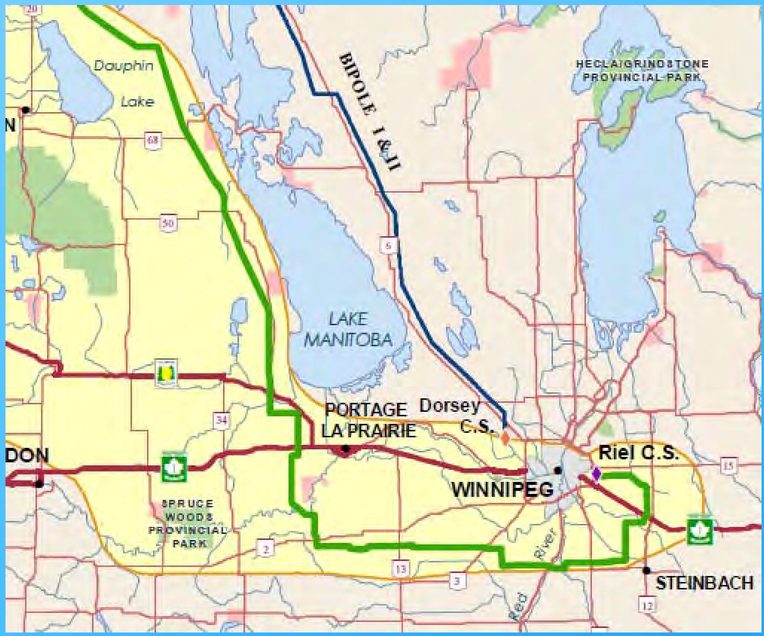
Locations of BPIII Converters





- Rectifier KCS: The location is physically separated from existing Bipole I and II converter facilities at Radisson and Henday stations
- Inverter RCS: about 40km away from Dorsey Station
- Considerations of separation to eliminate the common mode failure

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Bipole III Project Implementation

Turnkey Contracts:

- Keewatinohk and Riel converter stations & HVDC equipment (> $800M)
- Keewatinohk ac switchyard (~ $112M)
- 4x250MVar, Riel Synchronous Condensers (>$200M)

Managed by MH:

- 1388 km transmission line
- AC system upgrades (north/south)
- Other interface components

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Project Scope - Converter Stations

- LCC technology with Direct-light Triggered Thyristor (LTT)
- High levels of availability & reliability
  - Two series connected 12-pulse valve groups (VG) per pole
  - physical separation of valve group & pole controls on a per-pole basis
- -50C to +40C outdoor equipment design

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Project Scope - Converter Stations

- Nominal power transfer capacity of 2000 MW with 115% continuous overload
- Transient overload capability of 1.27pu for damping purposes
- Reduced (0.8 pu) dc voltage operation for forest fires conditions.
- De-icing operation : 2 poles transmit power in opposite directions (P6 in forward & P5 in reverse) to allow high DC current flow for melting ice on the HVdc line
- Paralleling with BPII – control capability tested
- Up to 80Hz frequency excursions at the rectifier – permits HVDC reduction

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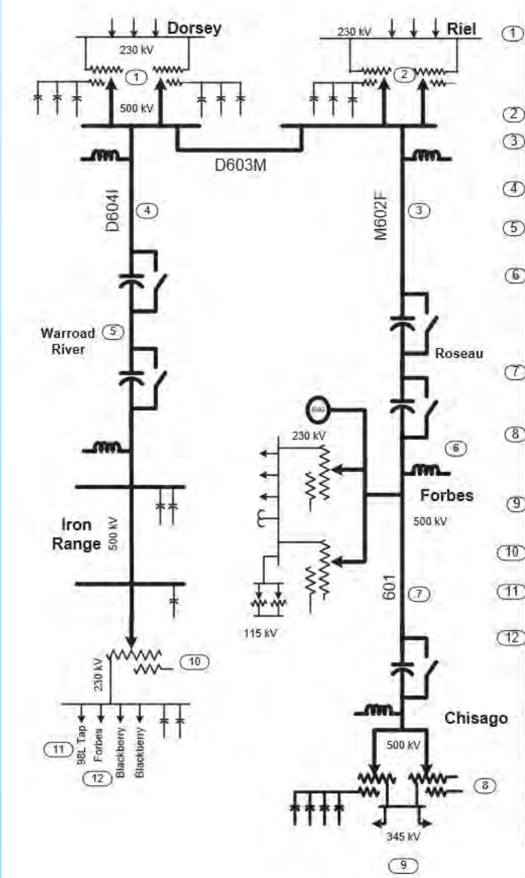
DC reduction



HVDC REDUCTION SCHEME

	TRIGGER	AMOUNT	Pmin (MW)
	(% of M602F MW unless otherwise specified)		
1	a) Loss of both Dorsey 500/230 kV transformers	60%	M602F > 1200
	b) Overload of one Dorsey 500/230 kV transformer	40%	M602F > 1200
2	Overload of one Riel XFMR	20%	M602F > 30
3	M602F 3-ph trip		
	a)	100%	M602F > 900
	b)	100%**	M602F > 1300
4	D604I 3-ph trip	100%*	D604I > 500
5	Bypass both Warroad River Series Cap.	30%*	D604I > 900
6	a) ~~Forbes SVC trip or failure of TSC 3 (236 Mvar)~~	~~20%~~	~~M602F > 750~~
	b) ~~Forbes SVC unable to control (overload > 10 sec) or (undervoltage > 10 sec)~~	~~60%~~	~~N.A.~~
7	601 3-ph trip		
	a)	60%	601 >1200
	b)	50%	601 > 900
8	Loss of both Chisago 500/345 kV transformers		
	a)	60%	601 > 1200
	b)	50%	601 > 900
9	Loss of both Chisago 345 kV lines	50%	601 > 900
10	Loss of Iron Range XFMR	100%*	D604I > 500
11	Loss of Iron Range to 98L 230 kV line	50%*	D604I > 800
12	Loss of Iron Range to Forbes 230 kV line	50%*	D604I > 800

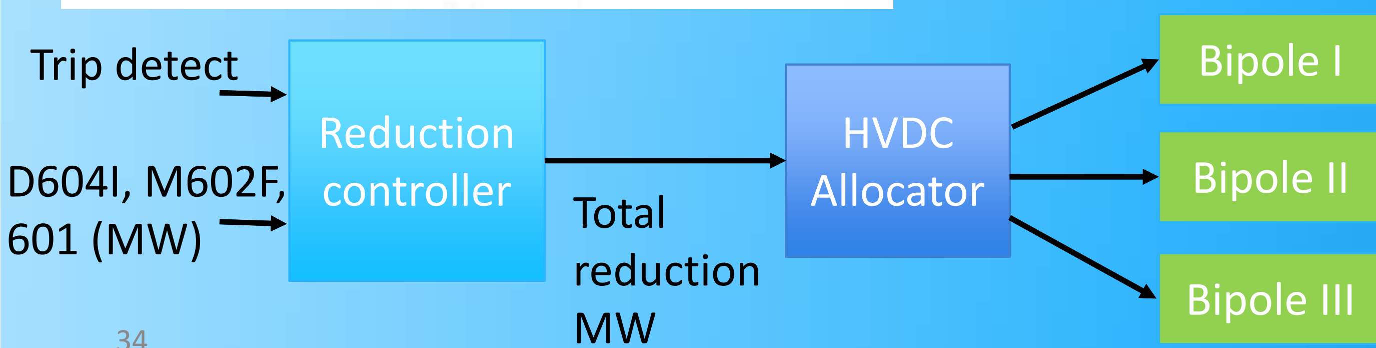
Note:

The above amount is the required reduction at inverters.

The reduction amount with a "*" is based on D604I flow.

The reduction with a "**" will also bypass both series cap at Warroad.

- Monitors status of key components of 500 kV tie lines
- Monitors pre-contingency MW flow at key locations
- Calculates dc reduction required
- Changes power order at rectifier of each Bipole
- Total time delay around 50-100 ms. Modelled as 200 ms



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Project Scope - Converter Stations

- Total of 20 converter transformers including spare units
- Controlled switching for energizing two parallel converter transformers (3-phase 5-limb): Pre-insertion resistors at Rectifier and Point-on-Wave (POW) controllers at Inverter (world first!).
- Both POW and PIR can meet the requirements of mitigating transient inrush (typically less than 0.1pu, 1.5 kA base)
- Controlled switching reduced inrush current such that they could be released for operation in 2 minutes rather than 10 minutes.

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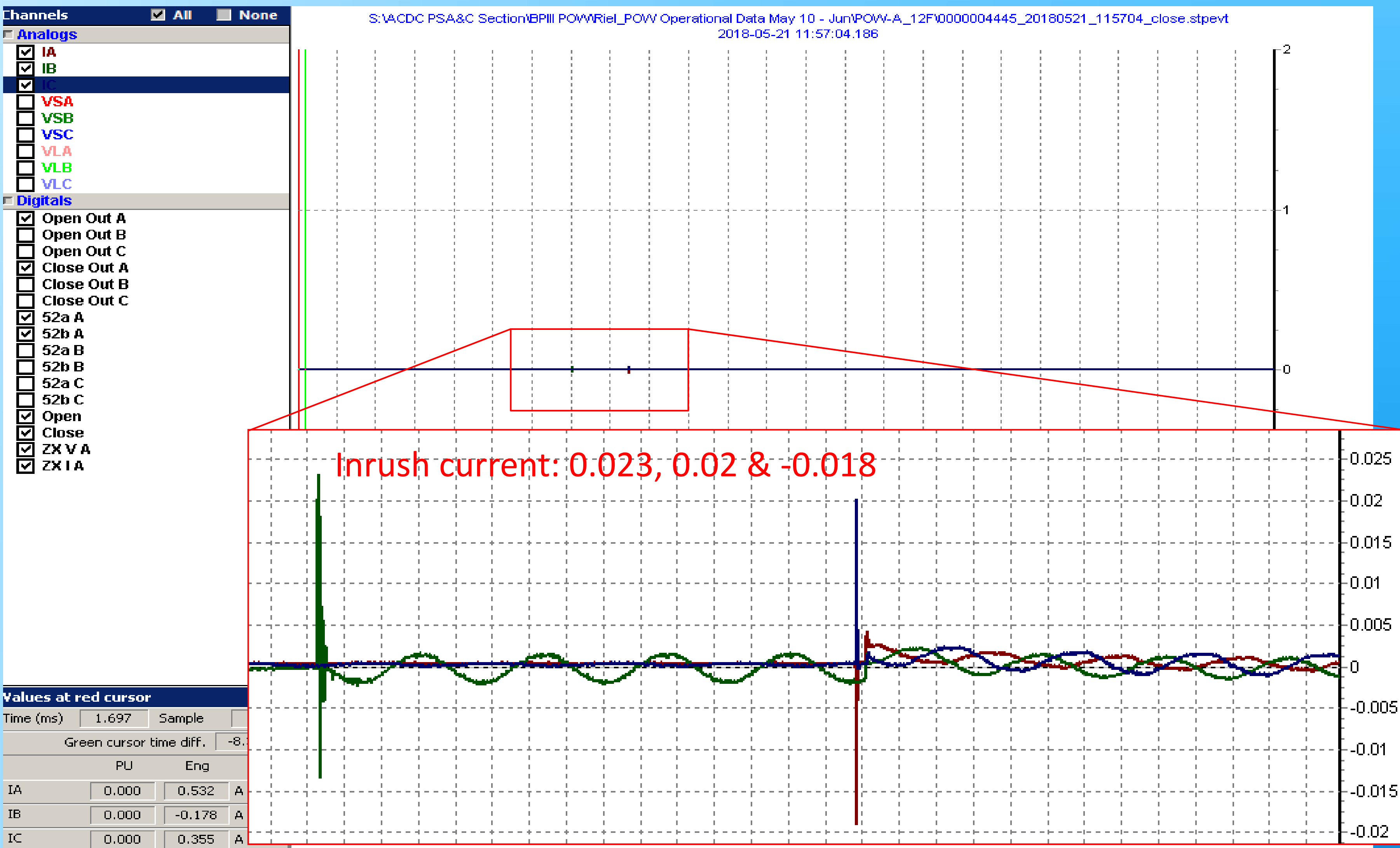
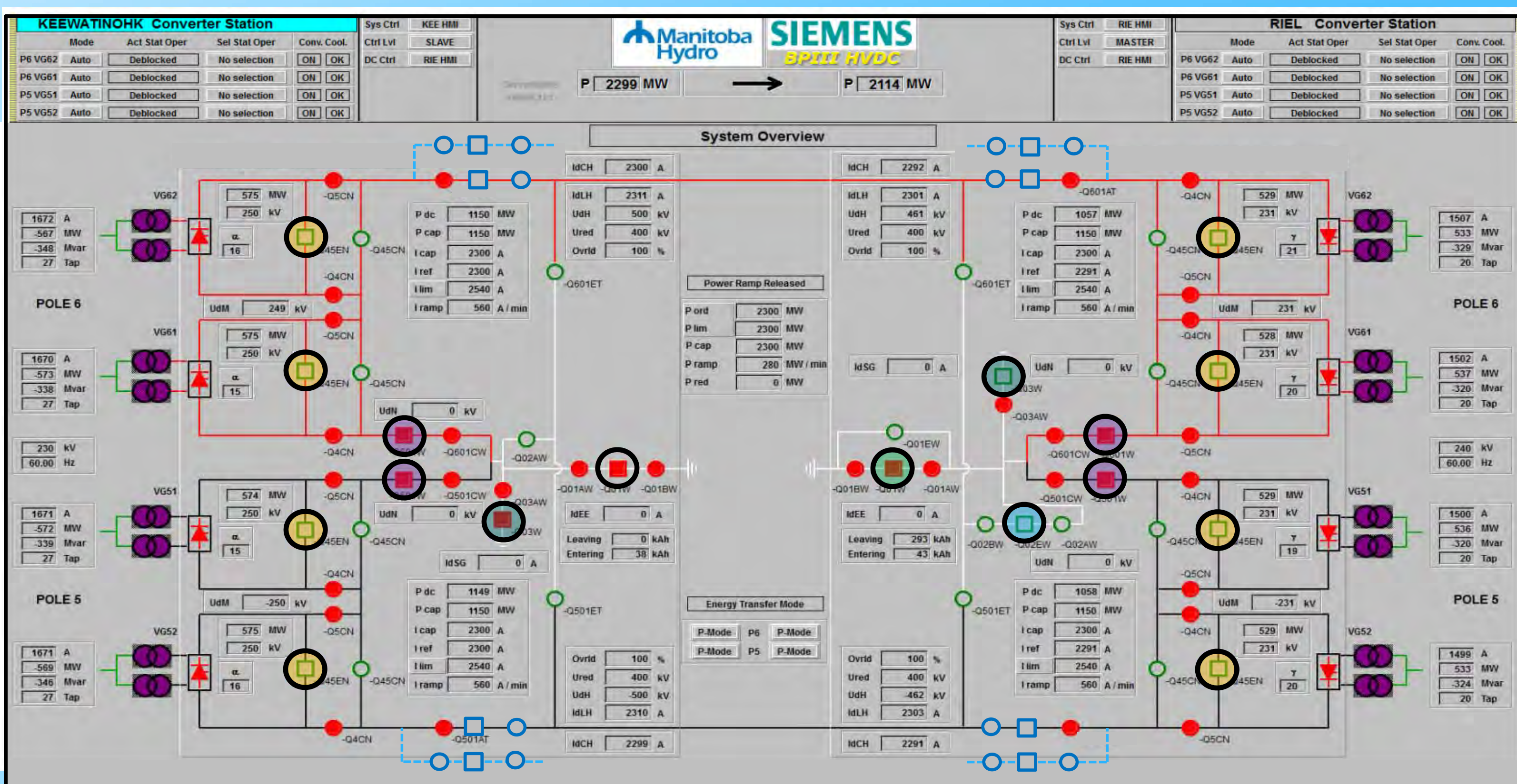
Field Commissioning & Results

Riel CS Operation: Optimal Scenario



Project Scope - Converter Stations

- Highly flexible operation modes (bipolar, monopolar ground return, monopolar metallic return, combinations of different VGs) achieved with dc yard design



- MRTB (1)
- GRTB (1)
- NBGS (2)
- NBS (4)
- ELTS (1)
- BPS (8)

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Project Scope - Converter Stations

- DC switchyard
- DC filter banks (multi-turned, N-1)
- Smoothing reactors (two individual units for redundancy)

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Project Scope - Converter Stations

- 230 kV Air Insulated Switchyard (AIS)
- New 230 kV bays & apparatus at KCS
- Expansion of 230kV yard at RCS
- Four AC filter banks at each station (with controlled switching)

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Project Scope - Riel Synchronous Condensers

- Four +250/-125 MVAr synchronous condensers; hydrogen cooled.
- Each synchronous condenser requires a unit transformer
- Provide voltage , reactive support and system inertia: critical for HVDC operation in Manitoba southern weak ac system
- Minimum MIESCR of 2.5 at Riel
- Multi-infeed Effective Short Circuit Ratio (MIESCR) – considers the closeness of converters via an impact factor. If the inverters are on the same bus, the factor is 1; if they are infinitely far away the factor is 0.

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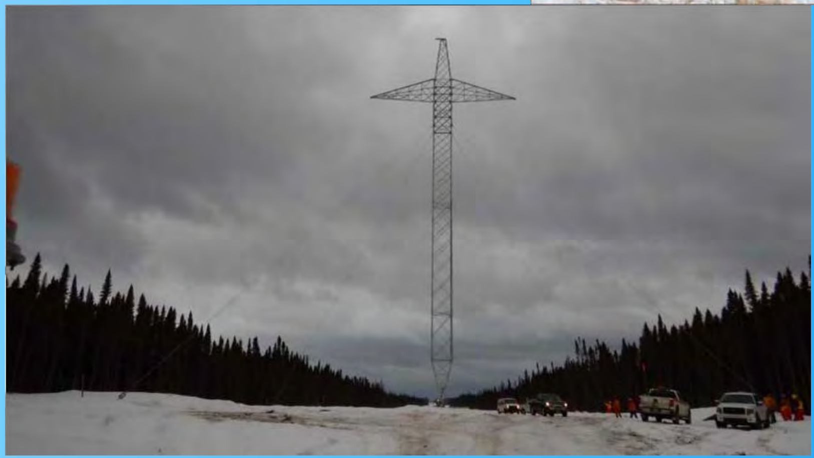
Project Scope – HVdc Line

- 1388km, 500KV overhead
- Self-supporting and guyed towers
- Base reliability level of 150 year return period for weather loads and increased to 500 year return design at some sections
- Anti-cascading towers (every 5-10 km)



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Project Scope – HVdc Line

- 3-bundle Configuration vs. 2-bundle of existing Bipole I&II lines
- Conductor surface gradient less than 23kV/cm.
    - Bipole II is 28 kV/cm. Reduced noise, corona loss and hopefully reduced risk of anomalous (pseudo-random fair weather on negative pole) flashovers.
- OPGW for Lightning protection and communication; 4 repeater stations

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Project Scope – AC System Upgrades

- Five new 230kV ac lines (north) and sectionalization of one 230kV ac line in the south
- Upgrades of two existing ac stations for line terminations
- Breaker upgrades at various stations due to fault level increases

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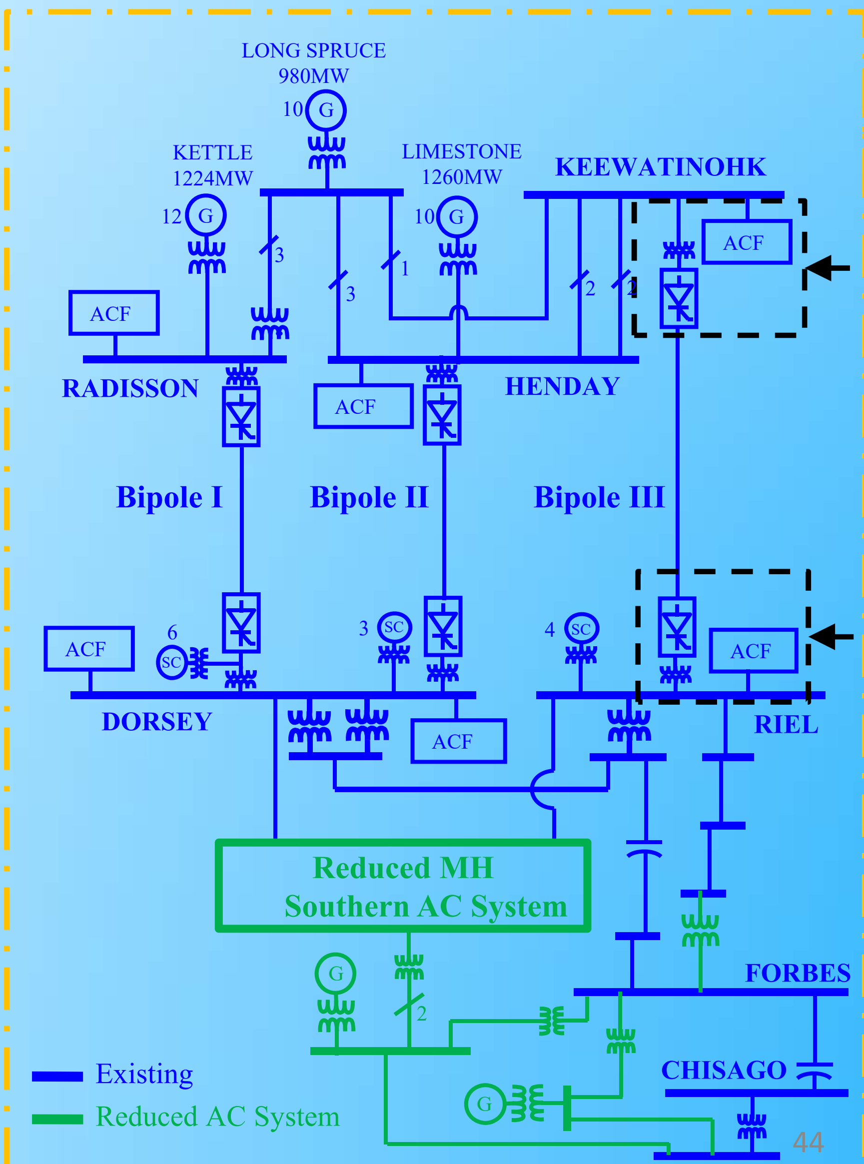
BPIII Replica C&P HIL Testing



real-time
simulation

RTDS (PB5)

Bipole III C & P Replica

Model Improvements
- o In-house Bipole I&II model
- o Freq-Dependent TLine
- o Transformer saturation & OLTC
- o 55 µs time-step; 6 racks

MH SPS & supplementary controls
- o HVDC reduction allocator, 500 kV SPTR
- o Custom SC exciter & JVC

MH & US ac dynamic equivalent

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Bipole III Project Timeline

- EIS was filed in 2011 for western route and Environmental License was received in August 2013.
- Various RFP packages were released after 2013.
- Line construction started in 2013.
- Converter contract was released and awarded in 2014 . Both VSC and LCC were considered in the HVDC converter station tendering process – only LCC bids received.
- System commissioning tests in 2018 (4 months, ~250 tests, ~400 transformer energizations, 5 staged faults with drone/pendulum)
- ISD of July 2018

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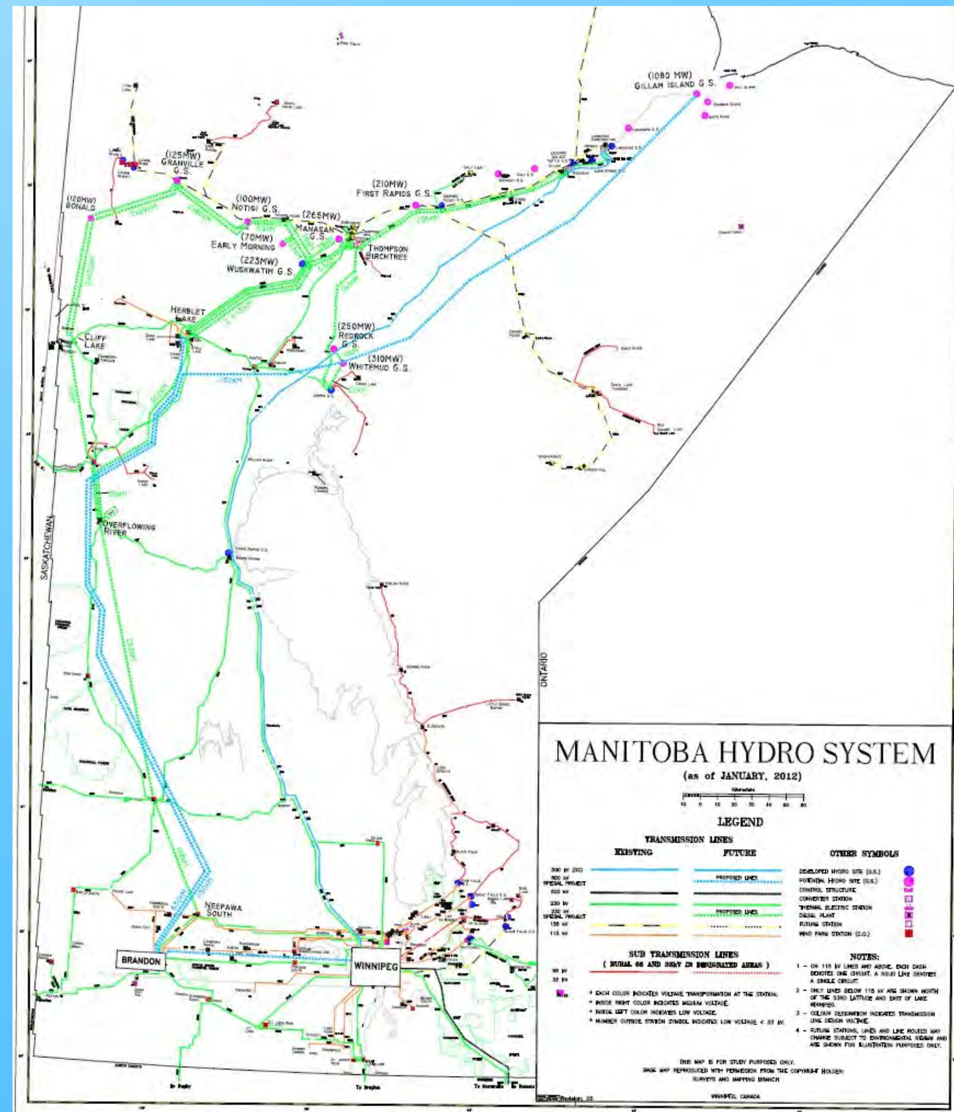
Bipole III Future

Business as Usual

- Conawapa will utilize Bipole I-III. Full 2300 MW rating of Bipole III will be utilized (6x250 MVAr syncs). Maintain a minimum valve group spare above generation.
- Statcom with or without energy storage will be considered instead of syncs.
- After Conawapa, northern generation will be integrated using new north south 230 kV and 500 kV ac.
- Bipole IV (LCC or half-bridge VSC) not permitted.



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With BPIII VSC taps (full bridge)

- Stage 1 – Integrate 680 MW Burntwood River; 700 MW VSC near Thompson plus new collector system (370 km)
- Stage 2 – Integrate 500 MW of Upper Nelson generation; 500 MW parallel VSC tap at Thompson and 500 MW tap at Brandon

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With BPIII VSC taps

- Stage 3 – Integrate 1130 MW Conawapa plant; 700 MW parallel VSC tap at Brandon; Conawapa connects to Riel via east side Bipole. Salvage and relocate DC lines. End up with a 1200 VSC point to point link to Brandon and a 2000 MW LCC link between NCS and Winnipeg, which creates three north-south corridors.

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Summary

- Bipole III has a long history!
- Bipole III is a large investment ($B) by Manitoba Hydro to address the lack of redundancy in the HVdc system and load serving deficiency under catastrophic HVdc contingencies
- The in-service of Bipole III reliability project significantly enhances our system reliability and resilience.
- BP3 offers adequate HVdc transmission spare to facilitate & optimize BPI/II refurbishment .
- Provides additional HVdc capacity for future renewable energy development in northern Manitoba.

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Video

Questions?

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