Minnedosa Ethanol Plant
CO_2 Sequestration Test Well

Pilot Project Application

October 11, 2018

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1. OVERVIEW

Husky Oil Operations Limited (Husky) owns and operates the Minnedosa Ethanol Plant (MEP) located on the western edge of the Town of Minnedosa, Manitoba (Figure 1). The MEP creates fuel ethanol that is blended with gasoline and is then distributed to retail gas stations. During the fermentation process, approximately 120,000 tonnes of carbon dioxide gas (CO_2) is generated annually and vented to the atmosphere in accordance with an environmental license granted by Manitoba Sustainable Development (MSD). Husky is proposing to capture this CO_2 and dispose of it via deep well injection. Capturing the CO_2 rather than venting it to atmosphere has the benefit of lowering the MEPs carbon intensity (CI) thereby making the fuel ethanol from the MEP attractive to purchasers.

Husky's Geological Services group has completed a regional desktop feasibility study and found that the Red River Formation in the Minnedosa area is a good candidate for CO_2 sequestration. However, the local geologic conditions beneath the MEP have not been assessed.

Husky is requesting approval from MSD to operate a pilot project to test the suitability of the Red River Formation for CO_2 sequestration. The pilot project will consist of drilling a single test well into the Red River Formation and collecting the relevant geological and hydrogeological data to confirm subsurface conditions. Husky is also requesting to operate the pilot project until the end of 2020 to account for unanticipated changes in the drilling program timing and/or to allow for additional testing to be completed as required.

Assuming favorable subsurface conditions, Husky will seek Director's approval via completing a Notice of Alteration Application to operate the CO_2 sequestration injection well over the long-term.

2. PILOT PROJECT LOCATION

The Husky MEP is located on the western edge of the town of Minnedosa, Manitoba approximately 50 kilometres (km) north of Brandon, Manitoba (Figure 1). Husky is proposing to drill the CO_2 injection well (the Test Well) within the MEP located in 01-10-15-18W5M to allow for easy tie-in to the CO_2 vent stack (Figure 2).

The Husky MEP is also located within the Little Saskatchewan River valley at an elevation of 510 metres above sea level (masl). The Little Saskatchewan River flows from east to west and is located immediately south of the Husky MEP (Figure 1 and 2). Ground elevations increase to approximately 580 masl towards the north and to 540 masl towards the south (Google Earth, 2018). Test Well will be located 146 m north of the ordinary high-water mark for the Little Saskatchewan River, in compliance with the set-back distances specified in the *Oil and Gas Act – Drilling and Production Regulation* (Manitoba Government, 1994).

3. GEOLOGY

3.1. Desktop Feasibility

A regional desktop feasibility study was conducted by Husky in April 2018. The study included the following:

- A review of existing oil, gas and salt water disposal wells surrounding the Minnedosa and Brandon area (Figure 3);
- A review of representative well logs from in-house and publicly available databases;
- A review of literature and other publicly-available data;
- Construction of maps and cross-sections across the project area;
- Initial examination and review of well core and core data, porosity and permeability data; and
- A review of the regulatory and drilling/operational documents for the Brandon disposal wells, currently operated by Koch Fertilizer.

Following this desktop review, the Ordovician Red River Formation was identified as the target zone for CO_2 sequestration. A description of the regional geologic setting in the Minnedosa area is presented in Section 3.2 below.

3.2. Regional Geologic Setting

The regional geologic setting presented herein incorporates information obtained from various publicly available reports/references, namely Bezys and Conley (1998), and is supplemented with interpretations of subsurface data by Husky. The sections below provide a brief discussion of the regional geology from the Precambrian basement (stratigraphically oldest) to Quaternary deposits (stratigraphically youngest). The focus of the discussion is on the proposed injection interval (Red River Formation) and the overlying caprock providing containment (Gunn Member of the Stony Mountain Formation). A stratigraphic chart is provided as Figure 4 and incorporates stratigraphic nomenclature adapted, in part, from Nicolas (2008). Two reference wells near Minnedosa have been used by Husky to pick formation tops, 16-26-014-18W1 and 2-21-015-18W1 (Figure 3).

As the purpose of this pilot project is to collect geologic data and confirm subsurface conditions below the MEP, local geologic features are not discussed herein.

3.2.1. Precambrian Basement

The Precambrian basement in southwest Manitoba include crystalline rocks of both the Superior and Churchill (younger) Structural Provinces. The highly tectonized contact between the two Provinces is known as the Churchill Superior Boundary Zone (CSBZ) and runs north to south across most of Manitoba. This boundary, located to the west of the Minnedosa area, has exerted little control on depositional patterns in the overlying Phanerozoic sedimentary rocks at Minnedosa. The Phanerozoic edge is represented on Figure 5 (red line) as the contact between the Proterozoic granites and gneisses and the

Paleozoic rocks. The top Precambrian surface dips to the southwest uniformly at about 2.5 m/km and is encountered at around -530 masl at Minnedosa.

3.2.2. Upper Ordovician

3.2.2.1. Winnipeg Formation

The Winnipeg Formation is the oldest Upper Ordovician formation present in the subsurface of the Minnedosa region. It is comprised of two informal Members. The lowest Winnipeg Member is a quartzose basal sandstone, often porous, which unconformably overlies Precambrian rocks. This basal sandstone is about 10 m thick in the Minnedosa area and grades upwards into a light olive grey marine shale with thin interbeds of siltstone and sandstone. The upper shale member averages around 30 m in thickness, in the subsurface across much of Southern Manitoba, including at Minnedosa.

The thickness, continuity and lack of permeability to be expected within the shale portion of the upper Winnipeg Formation suggests it would have good potential as a base seal for CO_2 injected into the immediately overlying Red River Formation.

3.2.2.2. Red River Formation

The Red River Formation is recognizable, widespread and thick across most of the Williston Basin. It is mainly comprised of various proportions of limestone, porous to tight dolostone, and anhydrite. In the United States part of the Williston Basin and in southeast Saskatchewan, the Red River Formation is an important oil and gas reservoir, reaching a thickness of up to 200 m near the centre of the Williston Basin (Longman and Haidl, 1996). In Manitoba, the Red River Formation has a maximum thickness of about 175 m near the Canada-United States border and thins to a zero edge as an outcrop belt along and southwest of Lake Winnipeg. A structural contour map of the Red River Formation is presented as Figure 5.

In the Minnedosa area, the Red River Formation is consistently about 140 m thick. Regional dip on the top of the Red River Formation is generally uniform towards the southwest at about 4 m/km. At Minnedosa, the subsurface elevation on the top of the Red River averages about -340 masl.

For the purposes of this project, Husky proposes to subdivide the Red River Formation into an underlying Yeoman Formation and overlying Herald Formation as follows:

- Yeoman Formation – Using well 02-21-015-18W1 as a reference, the Yeoman Formation (Lower Red River) will be considered to extend from the top of the Winnipeg Formation, (1,072 m) to the log depth of 950 m. This top is interpreted by Husky to be correlative with the top of Red River C Zone, a recognizable unit elsewhere in the Williston Basin, and includes significant thickness of porous dolostone reservoir in wells in the Minnedosa area.
- Herald Formation – Using well 02-21-015-18W1 as a reference, the Herald Formation (Upper Red River), will be considered to extend from 929 m to the top of the underlying Yeoman Formation. The Herald Formation in the Minnedosa area is thus considered by Husky to contain interbedded

lithologies comprised of dolostone (locally porous), limestone (locally argillaceous, mainly tight) and thin anhydrite beds.

The stratigraphy of the Red River Formation will continue to be updated throughout the life of the Project. This will include:

- Incorporating recent publications dealing with regional Red River Formation sequence stratigraphy (such as Husinec, 2016); and
- Incorporating detailed descriptions on existing cores and any cores acquired throughout the Project.

Both approaches will enhance understanding of internal Red River Formation stratigraphy.

The consistent thicknesses and presence of porous dolostones within the bulk Red River Formation suggest to Husky that it is suitable for CO_2 sequestration.

3.2.2.3. Stony Mountain Formation

The Stony Mountain Formation is widespread throughout Southern Manitoba. It ranges in thickness from 30 to 50 m from south to north. The Stony Mountain Formation dips to the southwest at about 4.5 m/km.

The Stony Mountain Formation includes the Gunn Member comprised of marine shale, and the overlying Gunton Member comprised of fine crystalline nodular dolomite.

Using well 02-21-015-18W1 as a reference, the top of the Stony Mountain Formation in the Minnedosa area is interpreted by Husky to be at 894 m, with the top of the Gunn Member picked 912 m. The Gunn Member has a uniform thickness of about 20 m and is considered to be the caprock for the proposed CO_2 injection into the immediately underlying Red River Formation.

3.2.3. Upper Ordovician to Lower Silurian

3.2.3.1. Stonewall Formation

The Stonewall Formation is relatively uniform in thickness and lithology throughout much of southern Manitoba. The Stonewall Formation has a lower dolostone of Ordovician age, which is commonly about 10 m thick in the Minnedosa area. The Silurian-Ordovician boundary is marked by the informal T-Marker; a thin but widely recognizable sandy shale. Overlying the T-Marker is the Silurian portion of the Stony Mountain Formation which comprises a 10 m thick succession of interbedded dolostones and sandy shales.

3.2.4. Lower Silurian

3.2.4.1. Interlake Group

The Interlake Group in Southern Manitoba is a lithologically consistent dolostone interval with a few thin but widespread shaley sandstone beds. The Interlake Group generally thins from around 100 m in southwest Manitoba, to about 90 m in the Minnedosa area. This thinning is likely due to sub-Middle Devonian erosion.

3.2.5. Devonian

3.2.5.1. Ashern Formation

The Ashern Formation is a thin but widespread dolomitic shale which mantles an unconformity overlying Lower Silurian Interlake Group strata. As a result, the Ashern Formation is somewhat variable in thickness from more than 50m in southwest Manitoba and generally thins eastward towards a subcrop edge. In the Minnedosa area, the Ashern Formation averages about 10 m in thickness.

3.2.5.2. Winnipegosis and Prairie Evaporite Formations

These formations comprise an important carbonate bank system (Winnipegosis) and a partly time-equivalent to reciprocal evaporite basin fill system (Prairie). The important bank to basin transition is located southwest of Minnedosa. The Winnipegosis Formation, where fully developed as a carbonate bank, is typically 40 to 50 m thick, thinning to less than 20 m into the Elk Point Basin (southwest Manitoba). In the Minnedosa area, the Winnipegosis Formation is comprised of 35 m of porous dolostone, capped by 10 m of remnant Prairie Formation, which is comprised mainly of tight carbonate and probable thin beds of anhydrite.

3.2.5.3. Manitoba Group

The Manitoba Group is about 150 m thick in the Minnedosa area and includes the Dawson Bay and overlying Souris River Formations. It contains the Middle to Upper Devonian boundary, which occurs within the Souris River Formation.

At Minnedosa, the Dawson Bay Formation is about 53 m thick. The basal 10 m is composed of dolomitic mudstones of the Second Red Bed Member. The remainder of the Dawson Bay Formation is about 43 m thick, with a lower argillaceous limestone, capped by a variably porous dolostone. Similarly, the Souris River Formation is comprised of a thin basal dolomitic and calcareous mudstone called the First Red Bed. The First Red Bed is about 15 m thick and transitions upwards into nearly 75 m of interbedded evaporites and carbonates forming the remaining portion of the Souris River Formation.

3.2.5.4. Duperow Formation

The Duperow Formation is the youngest preserved Paleozoic section in the Minnedosa area. The Duperow Formation consists of a layered succession of carbonate and evaporites unconformably underlying the Lower Amaranth Formation. Due to erosion on the top of the Duperow, the thickness ranges from 30 to 44 m in the Minnedosa area.

3.2.6. Triassic/Jurassic

3.2.6.1. Lower Amaranth Formation

In the Minnedosa area, about 33 m of Lower Amaranth shales and minor redbeds unconformably overlie the Devonian Manitoba Group. The age of the Lower Amaranth remains uncertain. Most authors consider it to be Triassic, although biostratigraphic data is lacking.

3.2.6.2. Upper Amaranth Formation

In the Minnedosa area, the Upper Amaranth Formation is about 30 m thick and is comprised of redbeds and anhydrite. Biostratigraphic control is poor but the formation is generally considered to be Jurassic in age. The Upper Amaranth Formation unconformably overlies the Lower Amaranth Formation.

3.2.6.3. Melita Formation

The Jurassic aged Melita Formation, which comprises green to grey shales, unconformably overlies the Upper Amaranth Formation at Minnedosa. The Melita Formation is about 95 m thick at Minnedosa.

3.2.7. Cretaceous

Cretaceous aged rocks, approximately 400 m thick, underlie a thin Quaternary section in the Minnedosa area. Cretaceous formations unconformably overlie the Jurassic Melita Formation. The oldest Cretaceous strata are comprised of the Lower Cretaceous Swan River Formation, composed of shale with a prominent sandstone top. The uppermost Lower Cretaceous and Upper Cretaceous section is comprised mainly of shales and lesser amounts of sandstone and includes the Colorado Group (which contains Base Fish Scales and the Second White Specks Zones), overlain by the Pierre Shale Formation.

3.2.8. Quaternary

Quaternary deposits in the Minnedosa area consist of clay-till overlain by sand and gravel alluvium associated with the Little Saskatchewan River (Matile and Keller, 2004). Bedrock outcrop has been mapped by Pedersen (1973) immediately downstream of the MEP exposing the Pierre Shale Formation along the banks of the Little Saskatchewan River. Therefore, if present, clay-till deposits are expected to be thin underneath the MEP site and alluvial deposits could occur immediately above the bedrock surface. Alluvial deposits range from one to 20 m within the Little Saskatchewan River Valley (Matile and Keller, 2004).

4. TEST WELL CONSTRUCTION AND TESTING

The Test Well will be drilled vertically into the Red River Formation and reach a total depth of 1,042 m (FTD). Figure 2 shows the proposed location for the test well and the site survey is provided in Appendix A.

The Test Well construction will consist of four phases: conductor hole, surface hole, intermediate hole, and main hole, which will be executed in a sequential manner. A summary of each phase is presented in Section 4.1 below with additional drilling details provided in Appendix B. The information presented in Section 4.1 and Appendix B, may be modified as new information becomes available prior to drilling and/or based on the subsurface conditions encountered during the drilling program.

Following the Test Well installation, step-rate and long-duration injectivity tests will be conducted to characterize the hydraulic conditions within the Red River Formation and the overlying caprock. Further details are presented in Section 4.2 below.

4.1. Drilling

4.1.1. Well Site

Well site preparation is summarized as follows:

- The well site location will be cleared and leveled to accommodate the rotary drilling equipment.
- A +/- 1.5 m diameter corrugated steel cellar for spill containment will be installed +/- 1.0 m below ground level (bgl) and the perimeter back filled before moving in the rig.
- A self-contained tank system will be used to collect and store the spent drilling fluids and drill cuttings. The spent drilling fluid and cuttings will be taken off-site for disposal in accordance with environmental requirements. Waste management procedures during drilling are described in Section 6.

4.1.2. Conductor Hole

The first stage of the drilling operation involves drilling and conductor hole and installing a conductor pipe. The purpose of the conductor pipe is to provide the initial stable structural foundation for the borehole. Details for the conductor hole/pipe installation are summarized as follows:

- Conductor hole will be drilled to +/- 12 m with an auger rig.
- 406.4 mm conductor pipe will be set at +/-12 m and back filled with cement to surface prior to moving the rotary-drilling rig on location.

4.1.3. Surface Hole

After the conductor pipe has been installed, the borehole will be drilled deeper and surface casing will be installed. The surface casing purpose is to provide well control, hold back any unconsolidated sediments and prevent this material from entering the well bore, and isolate shallow groundwater from the contents of the borehole (i.e. drilling fluids).

Details for the surface hole/casing installation are summarized as follows:

- The surface hole will be drilled using a 311mm bit to a depth of 130m to satisfy 41(1) of the Manitoba Drilling and Production Regulation (Manitoba Government, 1994).
- Drilling fluids will consist of a fresh water gel slurry with density of +/- 1,050kg/m^3
- 244.5mm surface casing will be installed to 130m and cemented to surface.
- Surface casing cement will be allowed to cure for eight hours prior to drill out as per 41(3) of the Manitoba Drilling and Production Regulation (Manitoba Government, 1994).
- The surface casing will be pressure tested to as per 41(3) of the Manitoba Drilling and Production Regulation (Manitoba Government, 1994).

Additional details with respect to the surface hole drilling operations are included in Appendix B.

4.1.4. Intermediate Hole

After the surface casing has been installed, cemented and pressure tested, the borehole will be drilled to intermediate casing point and intermediate casing will be installed.

Details for the intermediate hole and casing installation are summarized as follows:

- A blow out preventer (BOP) will be installed to provide a secondary well control barrier.
- The intermediate hole section will be 222mm diameter and drilled vertically to a depth of 885 m terminating in the top of the Red River Formation.
- Drilling fluids will consist of a water-based calcium polymer with a minimum mud density of 1,160kg/m^3 (determined from offset well drill stem test data and drilling records)
- During this drilling phase, core samples will be collected from the Stony Mountain and Red River formations, which will provide information on the caprock immediately above the Red River Formation
- Following coring operations, geophysical logs will be run in the open-hole (i.e. prior to installing the intermediate casing).
- 177.8mm intermediate casing will be run to 885m and cemented to surface.
    - Corrosion resistant alloy intermediate casing will be used to cover the Red River Formation and will extend 15m above the top of the Red River Formation in the 222mm hole.
    - The Intermediate cement is designed to resist corrosion caused by CO_2 injection.
- The intermediate casing will be pressure tested as per 41(3) of the Manitoba Drilling and Production Regulation (Manitoba Government, 1994) after cement displacement.
- Intermediate cement will be allowed to cure for 12 hours prior to drill out as per 44(2) of the Manitoba Drilling and Production Regulation (Manitoba Government, 1994).
- A 7-mPa pressure pass cement bond log will be conducted on the 177.8mm intermediate casing cement to confirm the integrity of the cement. This operation is planned to occur after drilling the well to FTD allowing the cement to properly cure.

Additional details with respect to the intermediate hole drilling operations are included in Appendix B.

4.1.5. Main Hole

After the 177.8mm intermediate casing has been installed, cemented and pressure tested, the borehole will be drilled to a total well depth of 1,024m (FTD). The main hole portion of the well bore will remain open hole. Open hole completions (or barefoot completions) allow for the optimization of injection volumes as the maximum surface area of geologic formation is exposed to the bore hole.

Details for the main hole drilling operations are summarized as follows:

- A blow out preventer (BOP) will be installed to provide a secondary well control barrier.
- The main hole will be 156mm diameter drilled to the final total depth of 1,024 m terminating in the Winnipeg Formation.
- Drilling fluids will consist of a solids free brine with a minimum density of 1,100kg/m^3 (determined from offset well drill stem test data and drilling records)
- During this drilling phase, core samples will be collected from the Red River and Winnipeg formations, which will provide information on the proposed CO_2 injection interval (Red River Formation)
- Following coring operations, geophysical logs will be run in the open-hole.
- While on-site, the drilling rig will be used to install the injection packer assembly and the 88.9mm injection tubing.
- The well will then be handed over to the completions team to perform the step-rate and long duration injection test (see Section 4.2 below for more details).

Additional details with respect to the main hole drilling operations are included in Appendix B.

4.2. Injection Testing

An injectivity testing program will be conducted following the completion of the drilling program. Fluids used during the injectivity tests will consist of fresh water provided by fire hydrants located on the MEP site. Water will be diverted from the hydrants into storage containers that will be brought on-site specifically for the injectivity tests. Real-time downhole pressure recorders will be installed prior to the initiation of the injectivity test program to measure pressure changes observed during injection. Pressure recorders will also be installed at the surface to measure changes in wellhead pressures during injection.

The injectivity testing program will consist of two tests: a step-rate and long-duration injection test.

The main purpose of the step-rate injectivity test is to:

- Evaluate the formation fracture pressure thereby determining a maximum operating wellhead injection pressure;
- Evaluate the near borehole hydraulic parameters (i.e. hydraulic conductivity/permeability) for the Red River Formation;
- Confirm the injection rate for the long-duration injection test; and
- Facilitate the prudent design of long-term injection operations.

Table 1 provides a summary of the proposed step-rate injectivity testing program. The step-rate test is designed to reach and exceed the Red River Formation fracture pressure. However, as the subsurface conditions have not been confirmed, the step-rate program may be modified based on the information gathered during the drilling program and may also be modified based on observations collected in the field during the testing program.

Table 1: Proposed Step-Rate Injectivity Test

Step	Rate (m^3/day)	Step Duration (min)	Volume per Step (m^3)	Total Volume (m^3)
1	600	60	25	25
2	1200	60	50	75
3	1800	60	75	150
4	2400	60	100	250
5	3000	60	125	375
6	3600	60	150	525
7	4200	60	175	700
Recovery	-	420	-	-

As shown in Table 1, the step-rate test will consist of seven, one-hour steps where the injection rate will increase by 600 cubic metres (m^3)/day for each subsequent step. Following the seven-hour injection period, the Test Well be allowed to recover for a minimum of seven hours.

The long-duration injection test will be initiated immediately after completion of the step-rate test recovery period. The long-duration test will consist of injecting at a rate of 100 m^3/day for five days. Again, the long-duration injectivity testing program may have to modified based on the information gathered during the drilling program and the results of the step-rate injectivity test. Following the injection period, the well will be allowed to recover for a minimum of five days prior to removal of equipment. The primary purpose of the long-duration injectivity test is to collect information with respect to aquifer boundary conditions. In other words, Husky would like to confirm that sufficient permeability exists within the Red River Formation and that it extends beyond the near borehole environment.

Injection testing using CO_2 is not being proposed as part of this Pilot Project. The information gathered during the drilling and injection testing programs, as outlined above, will be sufficient to confirm subsurface conditions.

5. ENVIRONMENTAL IMPACTS

The potential for impacts to the environment during the drilling, completions and testing programs are minimal.

Table 2 summarizes the environmental risks that may be encountered during the Test Well installation and testing programs and associated mitigation measures.

Table 2: Environmental Risks and Mitigation

Risk	Potential Causes	Mitigation Measures	Monitoring	Remedial Actions if Required
Surface spills (contamination to soils)	• Hydraulic line breaks • Gasoline/diesel spills • Drilling fluid, mud or cement spills • Sourced from the drilling rig or other support vehicles	• Spill kits • On-site vacuum trucks	• Routine visual inspection of fluid containment piping and tanks • Electronic fluid level monitoring system on rig mud tanks	• Reporting of all reportable spills • Containment, clean up and removal of contaminated surface materials and transport to licenced waste management facility
Shallow groundwater contamination	• Toxic drilling fluid additives introduced to shallow groundwater aquifers during surface hole drilling and cementing activities • Poor surface casing cement integrity	• Maintain drilling fluid additives below toxic levels • Proper hole cleaning and minimizing borehole washout • Surface casing set below ground water aquifers • Surface casing cemented to surface with proper centralization • Proper cement type and placement • Following good cementing practices	• Design and test the toxicity of drilling fluid used for surface hole • Monitoring and reporting of cement returns • Surface gas migration and surface casing vent flow testing and monitoring	• Reporting of potential ground water contamination • Temperature or cement bond log (CBL) to determine cement top, if no cement returns on surface casing • If necessary, remedial cementing to prevent shallow groundwater contamination (as directed by Manitoba Petroleum Branch)
Surface gas migration	• Poor cement placement and integrity •	• Use of gas detector during drilling to identify gas charged zones • Proper hole cleaning and minimizing borehole washout • Casing cemented to surface with proper centralization • Proper cement type and placement • Following good cementing practices	• Monitoring and reporting of cement returns • Surface gas migration and surface casing vent flow testing and monitoring	• Reporting of potential ground water contamination • Temperature or cement bond log (CBL) to determine cement top, if no cement returns on surface casing • If necessary, remedial cementing to prevent shallow groundwater contamination (as directed by Manitoba Petroleum Branch)

Risk	Potential Causes	Mitigation Measures	Monitoring	Remedial Actions if Required
Loss of well control	• Shallow gas • Water flow • Loss circulation • Well control equipment malfunction • Human error	• Offset well review to determine presence of shallow gas in area • Offset well review to determine presence of water flows • Offset well review for formation pressures and historical mud weights used to drill. • Well has adequate casing design for burst, collapse and tensile loads expected. • Use of electronic rig equipment to monitor drilling parameters and well control indicators. • Husky and Drilling Contractor Supervisors are competent on identifying well control signs, shut-in procedures and well kill procedures (as per Husky, regulatory and industry recommended practices). • Well control drills to confirm competency of personnel on site • Adequate mud volume and mud products on site to manage mud losses or increasing mud weight if required. • Proper selection of rig and equipment for scope of well (including rig load rating, drill string, BOPs, manifold, degasser, flare tank, pumps, mud tank capacity etc.). • Selection of drilling contractors with adequate standards related to well control training and equipment. • Proper handover meetings to ensure well conditions (and controls) are properly communicated. • All well control equipment to have proper certification, inspection and maintenance.	• Well site supervision and Rig crew well control certification verified before spud. • Well control drills to test competency. • Equipment pressure and function testing conducted as regulatory requirements and witnessed/recorded in daily reports • Husky drilling supervisor observe, validate and report proper drilling practices related to well control • Real-time monitoring of drilling parameters including background gas, connection gas, trip gas, flow, mud tank volume, mud tank gain/loss, rate of penetration, pump rate/pressure, rotary rpm/torque, weight on bit and hook load. • Husky provides 24-hour drilling supervision on site (2 x 12 shifts).	• Reporting • Adjust mud weight as required based on indications of over pressure (gas response, flow, etc.). • Control mud losses using loss circulation material • Use of well control equipment to conduct well control procedures.

In the unlikely event of a large volume fluid release to surface, fluids would be collecting through the existing surface water run-off infrastructure. Fluids would accumulate in the drainage ditch located immediately south of the Test Well location. The fluids collected will be tested before being released into the surface water collection ponds (refer to the site survey provided in Appendix A). Any water collected onsite will be tested before it is released in accordance with regulatory requirements.

6. WASTE MANAGEMENT

Drilling waste is anticipated to consist of drilling fluids and drill cuttings associated with the freshwater-based gel-slurry (surface hole), freshwater-based calcium polymer (intermediate hole), and brine water systems (main hole). Refer to Sections 4.1.3 to 4.1.5 and Appendix B for more details.

Wastes associated with drilling the surface, intermediate and main hole sections will include rock cuttings from the freshwater-based and brine drilling fluids, and cement returns from the casing installations. The shale shakers and centrifuge will be used continuously to separate drilling cuttings from drilling fluid and minimize volume of solid waste. Drill cuttings might be mixed with sawdust to stabilize the waste for transport if liquid retention on cuttings is high. Paint filter tests will be conducted on drill cuttings. Drill cuttings and excess cement returns will then be sent to a license solid waste landfill.

7. TEST WELL ABANDONMENT

If the results of the drilling, completions and testing programs indicate that subsurface conditions are inadequate to support CO_2 injection, the Test Well will be abandoned in accordance with the Oil and Gas Act – Drilling and Production Regulation (Manitoba Government, 1994). Additional abandonment details are provided in Appendix B. Environmental risks associated with abandonment activities are minimal and include potential surface spills (see

Table 2 above for mitigation measures).

As the Test Well is located on the existing MEP site, surface reclamation would not be initiated following abandonment procedures. Rather, the surface footprint would be reclaimed in accordance with decommissioning procedures outlined in the MEP's existing Environment Act Licence (No. 2698R) .

8. ALTERATION APPLICATION

If the Pilot Project is successful and Husky chooses to proceed, Husky will seek the Director's approval for long-term CO_2 injection operations by submitting a Notice of Alteration Application. Husky understands that an approval would likely include a revision of the existing Environment Act Licence (No. 2698R) issued to the MEP.

9. CLOSURE

If additional information or clarification is required, please don't hesitate to contact the undersigned.

Sincerely,

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Nicolas, M.P.B., 2008. Williston Basin Project (Targeted Geoscience Initiative II): Results of the biostratigraphic sampling program, southwestern Manitoba (NTS 62F, 62G4, 62K3). Geoscientific Paper GP2008-1. Manitoba Geological Survey.

Pedersen, A., 1973. Groundwater Availability Study – Minnedosa Area (Rural Municipalities of Elton, Odanah, Saskatchewan and Minto). Groundwater Availability Studies Report No. 5. Manitoba Government – Department of Mines, Resources and Environmental Management – Water Resources Branch

Figures

Figures 1 - 5

MAP DESCRIPTION

Aerial photograph of Husky's Minnedosa Ethanol Plant (foreground) looking east towards the Town of Minnedosa, Manitoba.

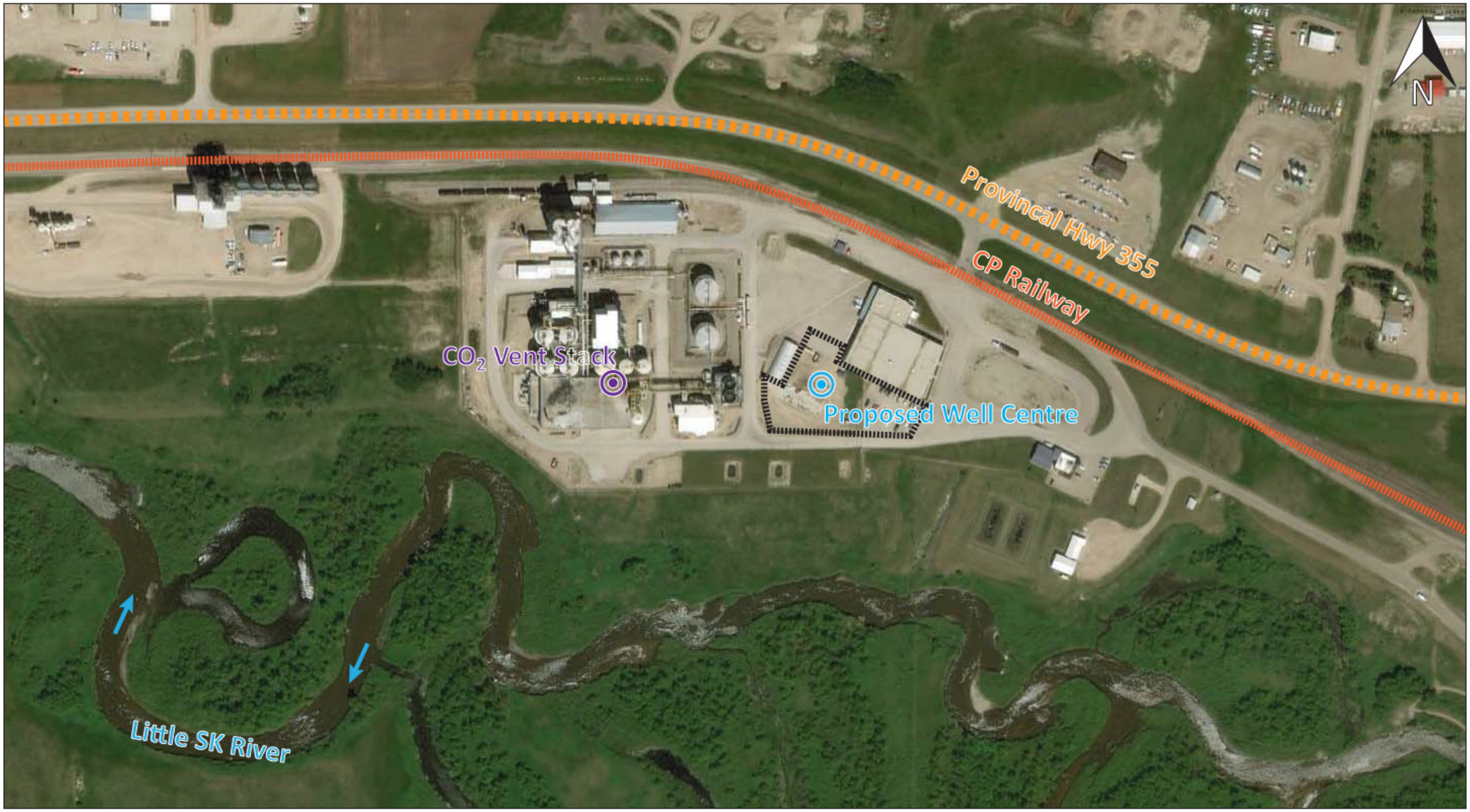
Husky Oil

PROJECT
Minnedosa Ethanol Plant
CO_2 Sequestration Test Well
Pilot Project Application

TITLE
FACILITY LOCATION

COMPILED BY: Ryan Bjornsen
DATE ISSUED: September 26, 2018
DATE REVISED: -

FIGURE 1



LEGEND

- Approximate Location of Hwy 355
- Approximate Location of CP Railway
- Approximate Drilling Rig Area
- Approximate Location of CO_2 Vent Stack
- Proposed Test Well Centre
- River Flow Direction

SCALE

0 50 100m

MAP REFERENCES

Google Earth Pro, 2018. Software Version 7.3.1.4507, Build Date February 6, 2018

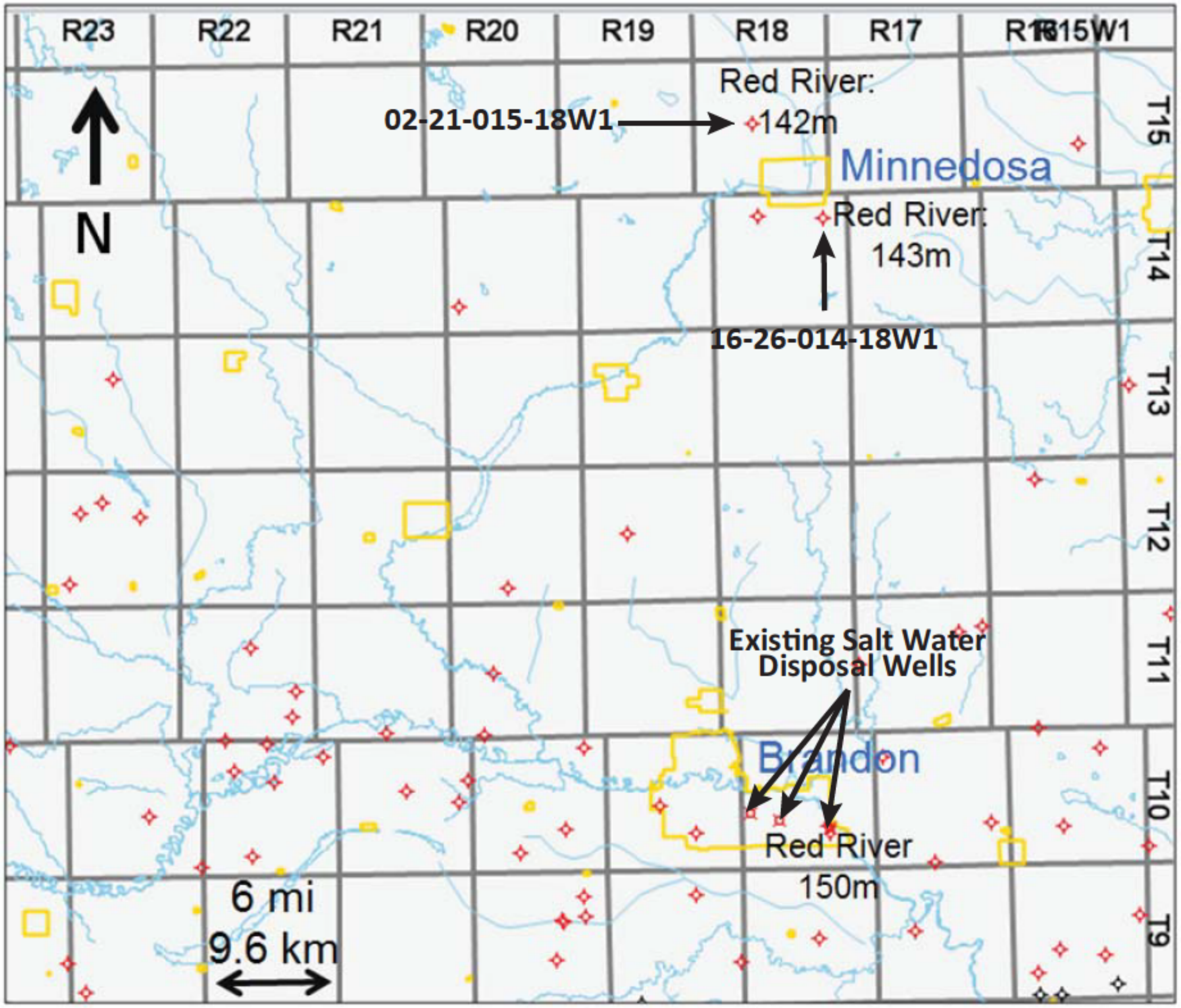
Husky Oil

PROJECT
Minnedosa Ethanol Plant
CO_2 Sequestration Test Well
Pilot Project Application

TITLE
PROPOSED TEST WELL LOCATION

COMPILED BY: Ryan Bjornsen
DATE ISSUED: September 26, 2018
DATE REVISED: -

FIGURE 2



LEGEND

- Approximate Industry Well Location
- Approximate City/Town Footprint
- River/Stream
- Red River 150m — Red River Formation Thickness

MAP REFERENCES

IHS Inc., 2018. *IHS AccuMap*. Software Version 28 04a

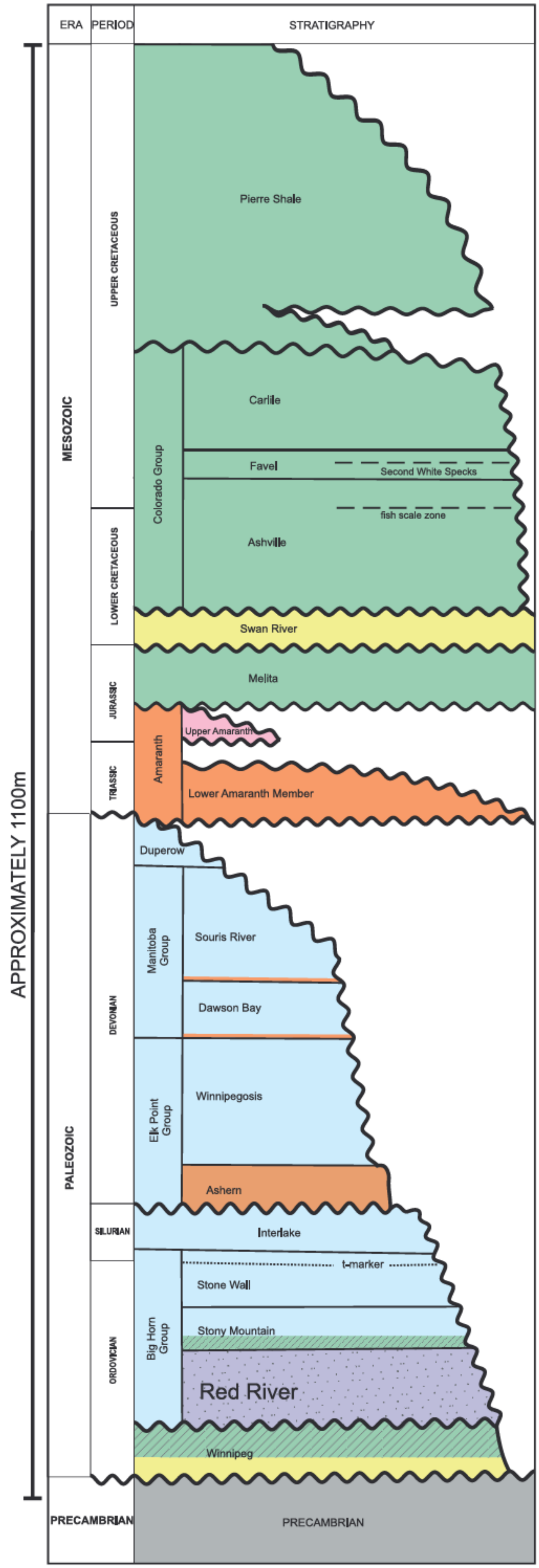
Husky Oil

PROJECT
Minnedosa Ethanol Plant
CO_2 Sequestration Test Well
Pilot Project Application

TITLE
EXISTING INDUSTRIAL WELLS

COMPILED BY: Ryan Bjornsen
DATE ISSUED: September 26, 2018
DATE REVISED: -

FIGURE 3



LEGEND

- SEAL
- PROPOSED DISPOSAL FORMATION
- SHALE
- EVAPORITE
- RED BED
- CARBONATE
- SANDSTONE/SILTSTONE
- METAMORPHIC GRANITE ROCKS
- UNCONFORMITY

REFERENCES

Adapted from: Nicolas, M.P.B., 2008. *Williston Basin Project (Targeted Geoscience Initiative II): Results of the biostratigraphic sampling program, southwestern Manitoba (NTS 62F, 62G4, 62K3).* Geoscientific Paper GP2008-1. Manitoba Geological Survey.

Husky Oil

PROJECT

Minnedosa Ethanol Plant
CO_2 Sequestration Test Well
Pilot Project Application

TITLE

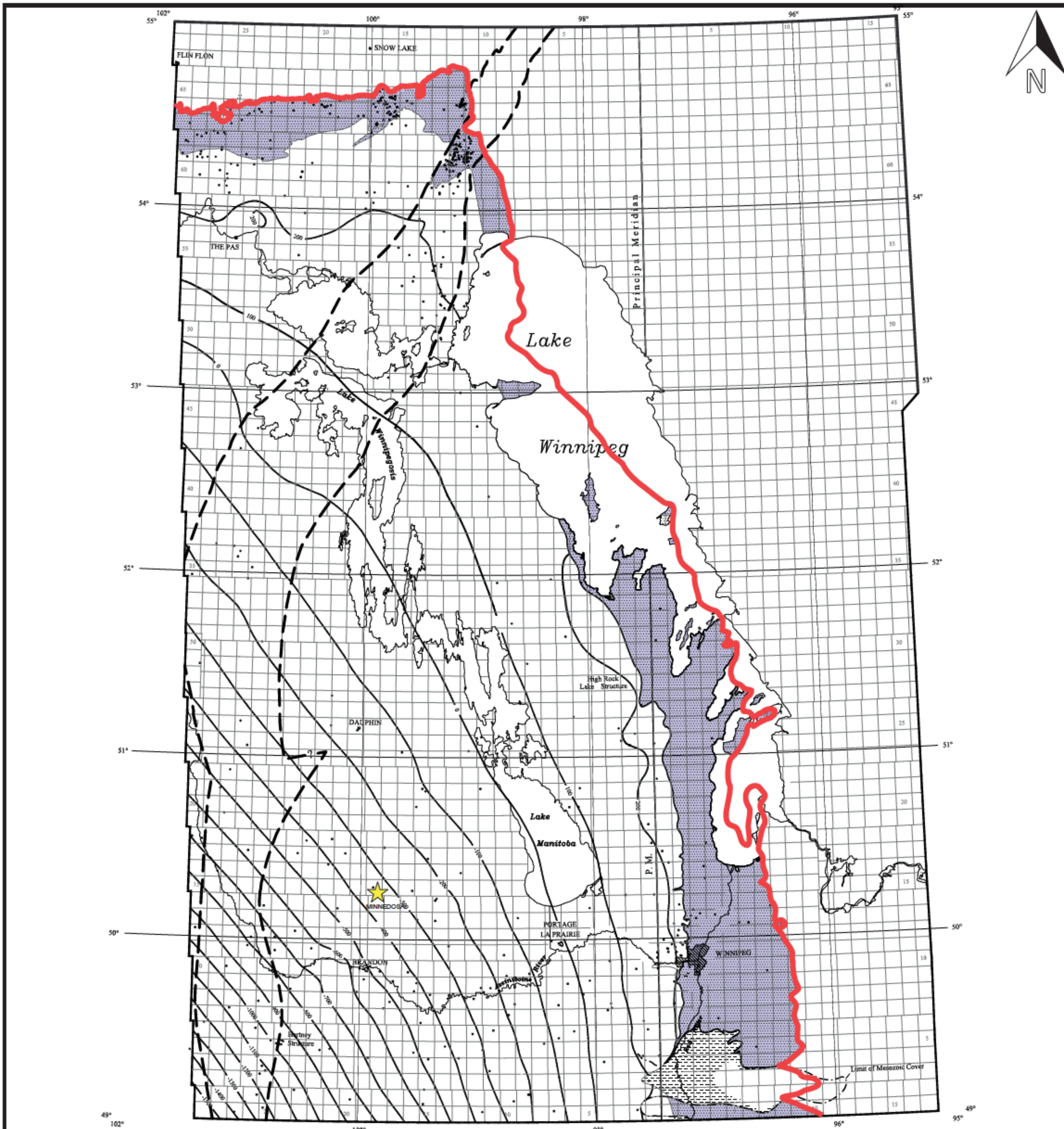
STRATIGRAPHIC CHART

COMPILED BY: Jennifer Tuomi

DATE ISSUED: September 26, 2018

DATE REVISED: October 9, 2018

FIGURE 4



LEGEND

- RED RIVER OUTCROP BELT
- REDRIVER SUBCROP BELT
- STRUCTURE MAP CI:100m (SEA-LEVEL DATUM)
- CHURCHILL SUPERIOR BOUNDARY
- WELL
- EDGE OF PHANEROZOIC
- M NNEDOSA

SCALE

0 25 50km

REFERENCES

Adapted from: Bezys, R.K. and Conley, G.G., 1998. Geology of the Ordovician red River Formation in Manitoba; Manitoba Energy and Mines, Stratigraphic Map Series, ORR 1, 1:2 000 000.

Husky Oil

PROJECT
Minnedosa Ethanol Plant
CO_2 Sequestration Test Well
Pilot Project Application

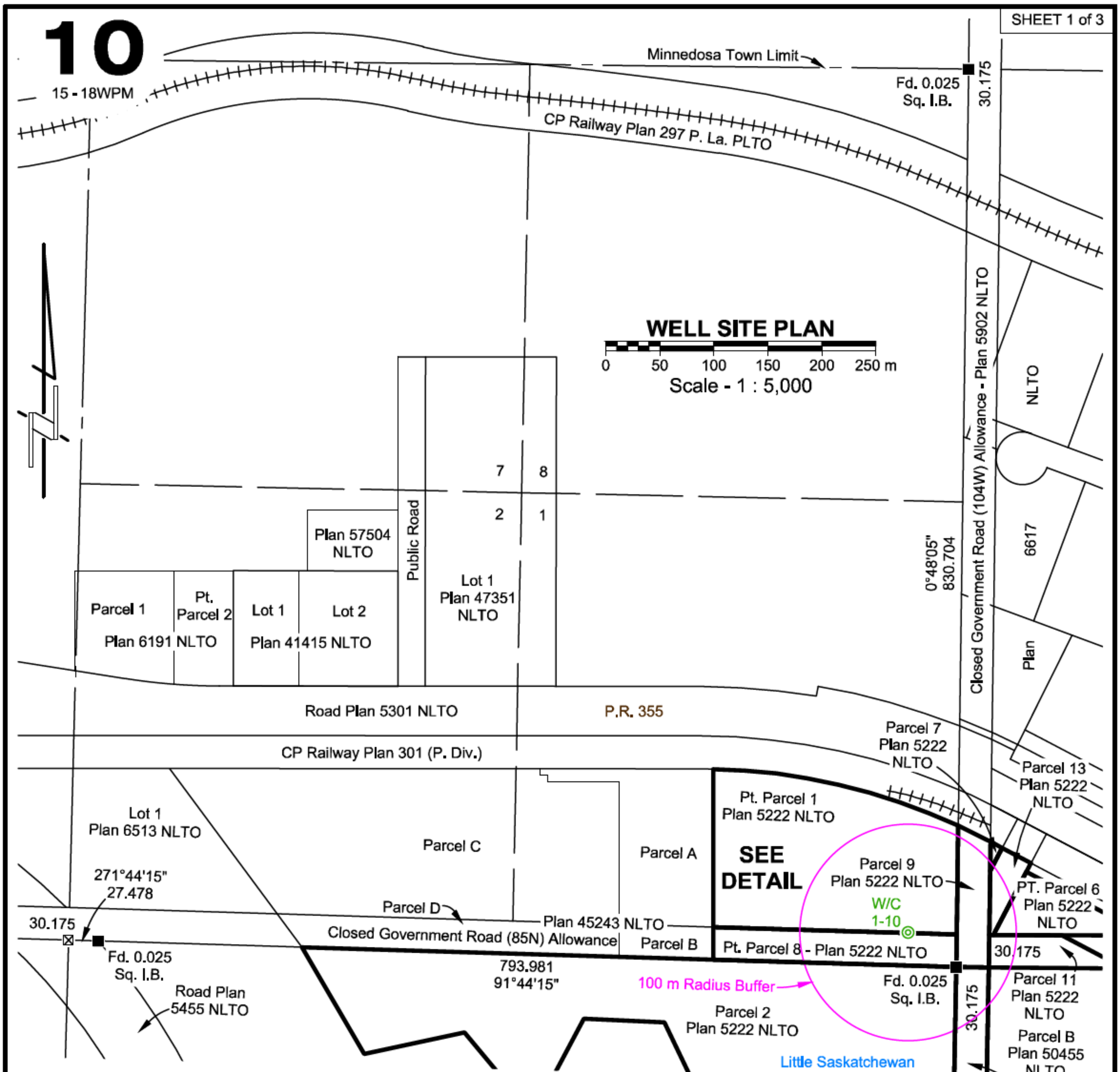
TITLE
RED RIVER STRUCTURE CONTOUR MAP (metres, subsea)

COMPILED BY: Jennifer Tuomi
DATE ISSUED: September 26, 2018
DATE REVISED: October 9, 2018

FIGURE 5

Appendix A

Site Survey



Plan Showing Survey of

HUSKY MINNEDOSA 1-10-15-18WPM

Well Location

L.S.1A Sec.10 Twp.15 Rge.18 WPM

Town of Minnedosa, Manitoba

ELEVATION ON GROUND
AT WELL LOCATION = **509.69**

CO-ORDINATES:

0.28 m N. of S. Bdy. } Sec. 10
45.19 m W. of E. Bdy. }

GEO Co-ordinates		UTM Co-ordinates
50°15'19.453" 99°51'44.242"	NAD 83	5567383.952 N 438530.659 E
50°15'19.417" 99°51'42.723"	NAD 27	5567163.616 N 438558.709 E

I, Brendan L. Wood, Manitoba Land Surveyor certify that the survey represented by this plan is correct to the best of my knowledge and was completed on the 15th day of August, 2018 and the 16th day of August, 2018.

This is a copy of an original plan, signed and sealed by Brendan L. Wood, Manitoba Land Surveyor, on September 20, 2018. The original plan is held on file in the Virden office of Altus Group Manitoba Land Surveyors Ltd.

This copy has been prepared for distribution via electronic and other means. Should there be a discrepancy between this document and the original document, the signed, sealed original shall govern.

AREAS:

No Areas Required

[redacted]
Manitoba Land Surveyor

[redacted]

Witness (Andrew Vogels)

ASSOCIATION OF MANITOBA LAND SURVEYORS
PERMIT
ALTUS Group
Manitoba Land
Surveyors Ltd.
No. 2017-10

CERTIFICATE OF TITLE:
SE 10-15-18WPM
CT No. 2945802/5 (2018-08-10)
CT No. 2945804/5 (Parcel Three, Four & Five) (2018-08-10)
CT No. 2945805/5 (Parcel One) (2018-08-22)
Husky Oil Operations Limited

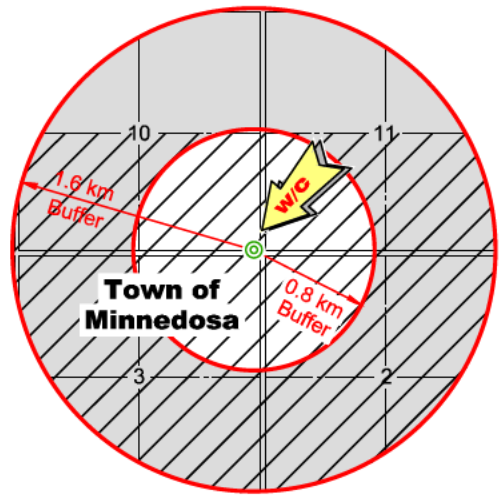
OPERATOR : HUSKY ENERGY

Altus Group

Altus Group Manitoba
Land Surveyors Ltd.
Toll Free: 1-800-465-6233
www.altusgeomatics.com

REV.	REVISION	DATE	INITIALS
0	Issued	Sept. 20, 2018	PM - AV - PS

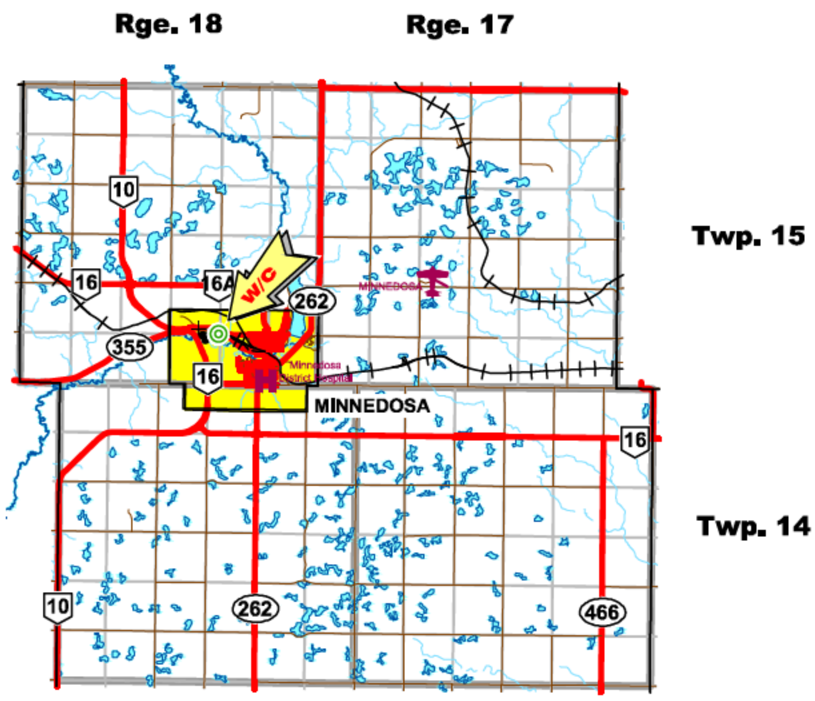
File: 210346W	Job No.: 210346
Client File No.:	AFE No.:



SURFACE DEVELOPMENT

0 0.5 1 1.5 2 2.5 km

Scale - 1 : 50,000



LOCATION MAP

0 2.5 5 7.5 10 km

Scale - 1 : 250,000

LEGEND:

- Surface Location - Horizontal / Directional / Slant
- 100 m Buffer outlined thus
- Legal Survey Posts (found / planted)
- Surveyed Well Centre

NOTES:

1. UTM and Geographic Co-ordinates are Derived from GNSS
2. Unless indicated otherwise, coordinates and bearings are referred to UTM Zone 14 NAD83 (CSRS) Epoch 1997, and were derived from GNSS observations to the Saskatoon base station of the Canadian Active Control System (965001).
3. Distances are ground and in metres and decimals thereof.
4. Combined Scale Factor used = 0.999570
5. Elevations are in metres, referred to CGVD28 (mean sea level) and were derived from the Saskatoon base station of the Canadian Active Control Network (965001) (Elev. = 600.674).

LICENSING INFORMATION:

The Proposed Well :

	YES	NO
- Is at least 1.5 km from the Corporate Limits of a City, Town or Village	☐	☒
- Is at least 100 m from a Water Covered Area	☒	☐
- Is at least 75 m from any Surface Improvements (Various)	☐	☒
- Is at least 45 m from any Surveyed Road	☒	☐
- Is at least 75 m from any Aircraft Runway or Taxiway	☒	☐
- Is at least 75 m from any Water Well	☒	☐

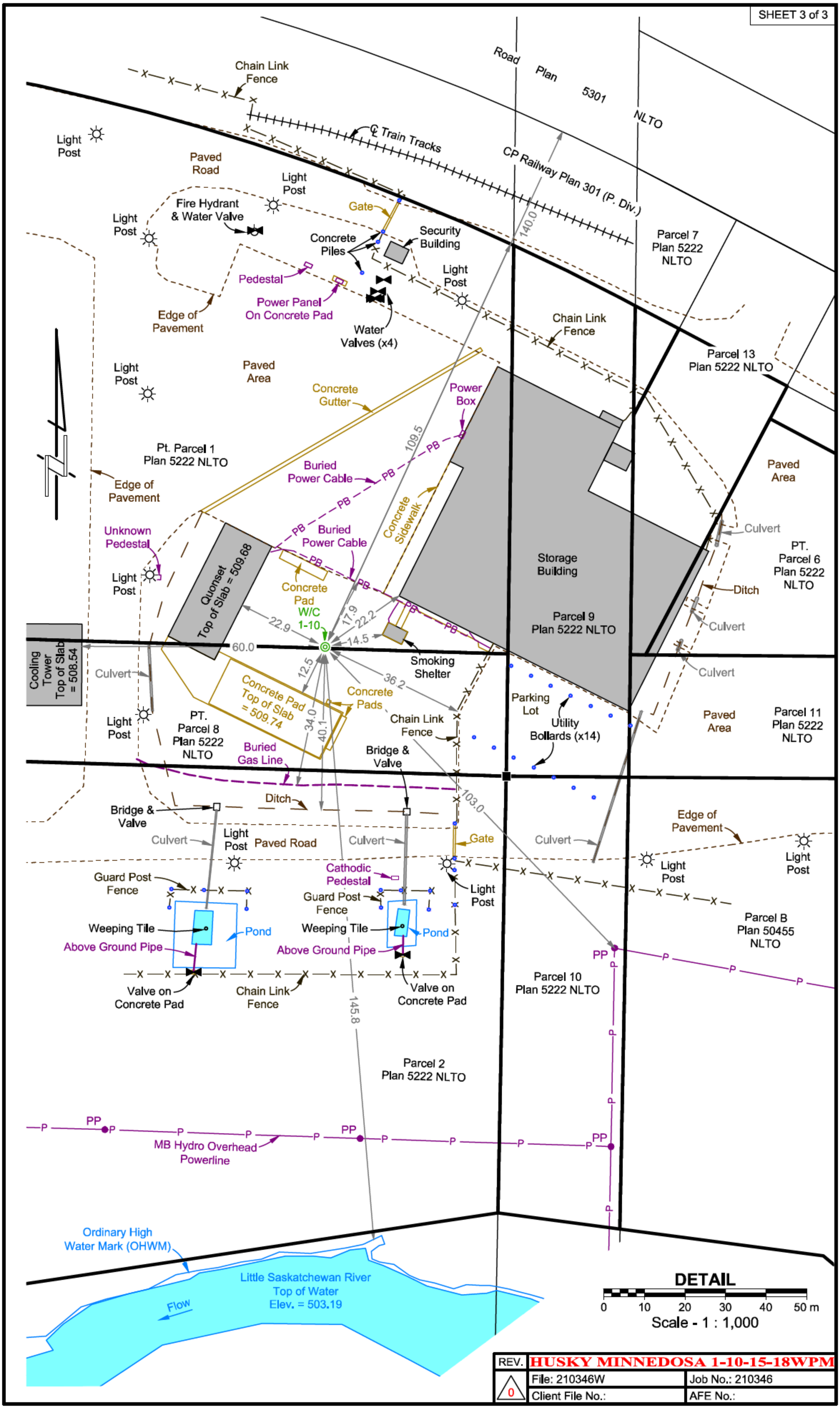
- Approximately 0.0 km from the nearest Urban Centre (Minnedosa)
- Approximately 0.9 km from the nearest Residence (SW ¼ 11-15-18WPM)

This plan represents the best information available at the time of survey. Altus Group Manitoba and its employees take no responsibility for the location of any underground pipes, conduits, or facilities, whether shown on or omitted from this plan. An additional search for specific buried facilities utilizing all resources must be performed just prior to construction.

Town of Minnedosa, Bell MTS, Manitoba Hydro, and Manitoba Hydro-Gas Operations **MUST** be contacted for location of any underground facilities that may exist.

CALL BEFORE YOU DIG

REV.	HUSKY MINNEDOSA 1-10-15-18WPM	
0	File: 210346W	Job No.: 210346
	Client File No.:	AFE No.:



SHEET 3 of 3
Road Plan 5301 NLTO
Chain Link Fence
℄ Train Tracks
CP Railway Plan 301 (P. Div.)
Light Post
Paved Road
Fire Hydrant & Water Valve
Gate
Security Building
Concrete Piles
Pedestal
Power Panel On Concrete Pad
Water Valves (x4)
Edge of Pavement
Parcel 7 Plan 5222 NLTO
Parcel 13 Plan 5222 NLTO
Paved Area
Concrete Gutter
Power Box
140.0
109.5
Pt. Parcel 1 Plan 5222 NLTO
Buried Power Cable
Concrete Sidewalk
Unknown Pedestal
Quonset Top of Slab = 509.68
Concrete Pad
W/C 1-10
Storage Building
Parcel 9 Plan 5222 NLTO
Culvert
Ditch
PT. Parcel 6 Plan 5222 NLTO
Cooling Tower Top of Slab = 508.54
60.0
22.9
17.9
22.2
14.5
12.5
36.2
34.0
40.1
Smoking Shelter
Concrete Pad Top of Slab = 509.74
Concrete Pads
Parking Lot
Utility Bollards (x14)
PT. Parcel 8 Plan 5222 NLTO
Buried Gas Line
Chain Link Fence
Bridge & Valve
Parcel 11 Plan 5222 NLTO
103.0
Paved Road
Cathodic Pedestal
Guard Post Fence
Weeping Tile
Pond
Above Ground Pipe
Valve on Concrete Pad
Parcel B Plan 50455 NLTO
Parcel 10 Plan 5222 NLTO
PP
145.8
Parcel 2 Plan 5222 NLTO
MB Hydro Overhead Powerline
Ordinary High Water Mark (OHWM)
Little Saskatchewan River Top of Water Elev. = 503.19
Flow
DETAIL
0 10 20 30 40 50 m
Scale - 1 : 1,000
REV.
0
HUSKY MINNEDOSA 1-10-15-18WPM
File: 210346W
Job No.: 210346
Client File No.:
AFE No.:

Appendix B

Detailed Drilling Program

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1. WELL SITE

Refer to Appendix A for the well site survey.

- The well site location will be cleared and leveled to accommodate the rotary drilling equipment.
- A +/- 1.5 m diameter corrugated steel cellar for spill containment will be installed +/- 1.0 m below ground level (bgl) and the perimeter back filled before moving in the rig.
- A self-contained tank system will be used to collect and store the spent drilling fluids and drill cuttings. The spent drilling fluid and cuttings will be taken off-site for disposal in accordance with environmental requirements.

2. CONDUCTOR HOLE

Details for the Conductor Hole installation are as follows:

- Conductor hole will be drilled to +/- 12 m with an auger rig.
- 406.4 mm conductor pipe will be set at +/-12 m and back filled with cement to surface prior to moving rotary-drilling rig on location.

3. SURFACE HOLE

- Move in and rig up rotary-drilling rig and equipment capable of drilling to total depth or more.
- An electronic drilling recorder system will be rigged up and operational throughout surface hole. A continuous record of gas show, flow, rate of penetration, hook load, pump pressure, pump strokes, rotary RPM, rotary torque, total mud tank volume and pit volume gain/loss will be maintained.
- A gas detector will be installed in the shale shaker box used for monitoring gas liberated from the drilling fluid to indicate any gas bearing formations.
- A riser pipe will be installed on the conductor to bring the drilling fluid and cuttings to surface while drilling the surface hole.
- Kelly bushing (KB) height above ground level will be measured and recorded and used as the depth datum during drilling operations.
- Surface hole drilling operations:
  - Surface hole will be drilled with a 311mm bit to a depth of 130m to satisfy 41(1) of the Manitoba Drilling and Production Regulation.
  - Drilling assembly will consist of:
    - Drill bit
    - Drill collars
    - Drilling jars
    - Heavy weight drill pipe
  - Wireline Totco surveys will be used to measure inclination deviation while drilling surface hole. Planned inclination will be less than 2 degrees per 30m drilled.
  - 244.5mm surface casing will be run to 130m and cemented to surface.
    - Plan to pressure test surface casing after plug down.
- A casing bowl will be installed onto the 244.5mm casing before installing BOPs and pressure testing all well control equipment as per section 3.4 prior to drilling out of the surface casing.

3.1. Drilling Fluid

Mud Type	Density	Additives
Fresh Water Gel Slurry	+/- 1,050 kg/m³	Fresh water + Viscosifier (bentonite) + loss circulation material (walnut shells, fibers, etc. as necessary to control any well losses) + Deflocculant (Desco CF)

- Material safety data sheets for all drilling fluid additives will be available on location during drilling operations.
- Solids control:
  - Shale shakers and centrifuge will be used to separate drill cuttings from drilling fluid.

3.2. Casing

Interval		Size (mm)	Weight (kg/m)	Tubular Grade	Thread Type	Pipe ID (mm)	Pipe Drift (mm)	Coupling OD (mm)
From	To							
0	130	244.5	53.6	J-55	LT&C	226.6	222.6	269.9
Minimum Performance Properties of Casing								
Pipe Body Burst Pressure Rating (kPa)				24,300				
Connection Burst Pressure Rating (kPa)				24,300				
Collapse Pressure Rating (kPa)				13,900				
Body Yield Strength (daN)				250,900				
Joint Strength (daN)				201,500				
Recommended Make-up Torque								
Optimum (ft-lbs)				4,530				
Minimum (ft-lbs)				3,400				
Maximum (ft-lbs)				5,660				

Load	AER Directive 10 Surface Casing Design Requirements	Internal Pressure	External Pressure	Tensile Load
Burst	Design factor = 1.0 for sweet wells or sour wells with pp H2S < 0.3 kPa. Design factor = 1.25 for sour wells where the surface casing is potentially exposed to an pp H2S ≥ 0.3 kPa. As a minimum, the casing burst pressure load (kPa) must be no less than 5 times the setting depth (metres true vertical depth [m TVD]) of the next casing string.	5 x 885mTVD = 4,425 kPa.	0 kPa/m gradient.	N/A
Collapse	Design factor = 1.0. The casing collapse pressure rating (API Bulletin 5C2) must exceed the external pressure acting on the casing at any given point. No allowance is made for internal pressure, as total evacuation of the casing is assumed. Axial loading reduces casing collapse pressure rating. The method used to calculate the collapse pressure reduction is outlined in the latest edition of API Bulletin 5C3. The ERCB will continue to accept casing designs where Appendix E has been used to calculate the reduced collapse pressure. The external pressure acting on the casing is	0 kPa/m gradient.	Maximum drilling fluid density while drilling surface hole = 1,200 kg/m³ = 11.77 kPa/m. therefore gradient of 12 kPa/m will be used. 130mTVD * 12 kPa/m = 1,560 kPa	N/A

	calculated using an external fluid gradient of 12 kPa/m. If the actual drilling fluid gradient is higher than 12 kPa/m, that higher gradient must be used. An acceptable design may be based on a lesser external fluid gradient, but not less than 11 kPa/m, provided that the actual drilling fluid gradient at the time of running casing does not exceed the design gradient. If the Simplified Method does not meet the minimum design collapse factors, the Alternative Design Method must be applied for collapse design.			
Tension	Design factor = 1.6. No allowance is made for buoyancy. The casing minimum tensile strength must exceed 1.6 times the design tensile load acting on the casing at any given point. The lesser of the pipe body yield strength or the joint strength (connection parting strength) must be considered in the casing minimum tensile strength. If the Simplified Method does not meet the minimum design tension factors, the Alternative Design Method must be applied for tension design.	N/A	N/A	Tensile force from weight of casing in air = 130m x 53.6 kg/m x 0.981kg-force = 6,836 daN.

Calculated Design Safety Factors		
Load	**Required**	**Calculated**
Burst	1.00	5.49
Collapse	1.00	8.79
Tension	1.60	29.48

Surface Casing String with Float Equipment and Casing Accessories	
Description	**Description and Centralization**
244.5mm Float Shoe	Contains 1st float.
244.5mm, 53.6 kg/m, J-55, LT&C Shoe Joint	Bow spring non-welded centralizer placed over stop collar 1 m above float shoe
Float Collar	Contains 2nd float
244.5mm, 53.6 kg/m, J-55, LT&C to surface	Bow spring non-welded centralizer to be placed over every 2nd casing collar to surface for adequate stand-off.

3.3. Cementing

Type	Composition	Density	Volume
Pre-Flush	Fresh Water + Viscosifier	1,100 kg/m³	5.0m³
Cement	Class C + Cement Accelerator + Cement Defoamer + LCM as necessary	1,575 kg/m³	+/- 75% XS from gauge

Wellbore preparation prior to cementing:

- Wellbore is to be static with all losses (if encountered) healed prior to cementing.
- To ensure effective drilling fluid removal, rheology of the drilling fluid will be reduced prior to the cement job.
- Once casing is on bottom, drilling fluid will be circulated at drilling annular velocity (>45m/minute) with pipe reciprocation to break gel strengths and clean the whole prior to cementing.
- A fluid caliper may be circulated to measure hole cleaning performance and validate cement volumes.
- Cement volumes will be adjusted based on loss circulation risk and hole conditions while drilling.

Cementing operation practices:

- Two samples of the cement blend and cement water will be collected and retained for verification testing if needed.
- Job data including densities of all fluids pumped, pump rates and pump pressures will be recorded during the cement job as well as displacement.
- Casing will be reciprocated while cementing.
- Top and bottom cement plugs will be used.
- Maximum over displacement from calculated volume will be limited to 50% of the shoe track volume to avoid a wet casing shoe.
- Upon the top cement plug landing on the float collar, displacement pressure will be further increased 3,500 kPa from the last circulation pressure and held for 5 minutes.

Surface casing drill out:

- Surface cement will be allowed to cure for 8 hours prior to drill out as per 41(3) of the Manitoba Drilling and Production Regulation.

3.4. Pressure Testing

Surface casing pressure testing:

- Pressure will be brought down to 0 kPa after bumping the top cement plug and the casing floats will be observed for bleed back to confirm floats are holding the hydrostatic pressure of cement.
- If there is no bleed back once pressure is released, the surface casing will be pressure tested to 7,000 kPa for 10 minutes as per 41(3) of the Manitoba Drilling and Production Regulation.

Summary of Pressure tests required as per 32(1) and 41(3) of the Manitoba Drilling and Production Regulation prior to drilling out of surface casing				
Equipment	**Low (kPa)**	**Time (Minutes)**	**High (kPa)**	**Time (Minutes)**
Annular	1,400	10	7,000	10
Rams	1,400	10	7,000	10
Bleed-off Line and Valves	1,400	10	7,000	10
Manifold Valves	1,400	10	7,000	10
Kill Line and Valves	1,400	10	7,000	10
Stabbing Valve	1,400	10	7,000	10
Inside BOP	1,400	10	7,000	10
Lower Kelly Cock	N/A	10	7,000	10
Surface Casing	N/A	N/A	7,000	10

3.5. Well Control and Blow Out Preventer Set-up

Based on offset well records there will be no use of a diverter system while drilling surface hole.

4. INTERMEDIATE HOLE

- A casing bowl will be installed onto the surface casing.
- An electronic drilling recorder system will be rigged up and operational throughout intermediate hole. A continuous record of gas show, flow, rate of penetration, hook load, pump pressure, pump strokes, rotary RPM, rotary torque, total mud tank volume and pit volume gain/loss will be maintained.
- A gas detector will be installed in the shale shaker box used for monitoring gas liberated from the drilling fluid to indicate any gas bearing formations.
- A riser pipe will be installed on top of the BOPs to bring the drilling fluid and cuttings to surface while drilling intermediate hole.
- Kelly bushing height above ground level will be measured and recorded and used as the depth datum during drilling operations.
- Well control equipment (BOP) will be installed on top casing bowl and pressure tested as per Sections 4.5 and 4.6 prior to drilling out of the surface casing shoe.
- Intermediate drilling operations:
    - 222mm vertical hole is planned to be drilled to core point #1 of 813m.
    - Drilling Assembly will consist of:
        - Drill bit
        - Drill collars
        - Drilling jars
        - Heavy weight drill pipe to surface
    - Wellbore surveys will be taken to measure inclination while drilling intermediate hole. Planned inclination will be less than 2 degrees per 30m drilled.
    - A coring assembly with 222mm core head, 6.75” core barrel with aluminum sleeves will be used to cut 3.50” or 4.00” (if JamBuster is used while coring) diameter core from 813m – 885m (ICP) = 72m of core in a single run.
    - 3 open hole logging runs will be conducted after coring.
        - Run 1: Platform express with resistivity and 4-arm caliper
        - Run 2: Sonic scanner
        - Run 3: Formation micro imager

- 177.8mm intermediate casing will be run to 885m and cemented to surface.
    - The intermediate casing that will be set into the Red River Formation and extending 15m above the top of the Red River Formation to ICP will be 28CR-110 corrosion resistant alloy material.
    - Intermediate cement is designed to resist carbonation from CO_2 injection.
        - Plan to pressure test intermediate casing after plug down.
- Once the intermediate cement has gained sufficient compressive strength the BOPs will be removed from the casing bowl to install the tubing spool. A double studded adapter will then be used to crossover the 279.5mm BOP flange to the 179.4mm tubing head flange.
- All well control equipment will then be pressure tested as per 4.5 prior to drilling out the intermediate casing shoe.

4.1. Drilling Fluid

Mud Type	Density	Additives
Water based Calcium Polymer	>1,160 kg/m³	Fresh water + calcium source (calcium nitrate) + fluid loss control additive (starch + PAC + lignite) + Viscosifier (xanthan + PAC) + Deflocculant (Desco CF)

- Material safety data sheets for all drilling fluid additives will be available on location during drilling operations.
- Solids control:
    - Shale shakers and centrifuge will be used to separate drill cuttings from drilling fluid.

4.2. Evaluation

Cutting Samples	Drill cuttings will be collected in 5m intervals from surface casing point to core point.	
Coring	Cored interval 813 – 885m = 72m.	
Mud log	Pason continuous gas reading will be monitored while drilling	
Cased Hole Logging	Cement bond log with 7 mPa pressure pass on 177.8mm casing cement	Estimate the quality of cement integrity and identify cement top
Open Hole Logging	Platform express with resistivity and 4-arm caliper	Identify formation fluids
	Sonic scanner	Identify lithology and porosity
	Formation micro imager	Identify naturally occurring fractures

4.3. Casing

Interval		Size (mm)	Weight (kg/m)	Tubular Grade	Thread Type	Pipe ID (mm)	Pipe Drift (mm)	Coupling OD (mm)
From	To							
0	845	177.8	34.2	J-55	LT&C	161.7	158.5	194.5
845	885	177.8	38.7	28CR-110 (CRA)	TMK UP Ultra FJ	159.4	156.2	177.8

Minimum Performance Properties of 34.2 kg/m, J-55, LT&C	
Pipe Body Burst Pressure Rating (kPa)	30,100
Connection Burst Pressure Rating (kPa)	30,100
Collapse Pressure Rating (kPa)	22,500
Body Yield Strength (daN)	162,800
Joint Strength (daN)	139,200
Minimum Performance Properties of 38.7 kg/m, 28CR-110, TMK UP ULTRA FJ	
Pipe Body Burst Pressure Rating (kPa)	68,672
Connection Burst Pressure Rating (kPa)	68,672

Collapse Pressure Rating (kPa)	42,954
Body Yield Strength (daN)	369,203
Joint Strength (daN)	233,087
Recommended Make-up Torque of 34.2 kg/m, J-55, LT&C	
Optimum (ft-lbs)	3,130
Minimum (ft-lbs)	2,350
Maximum (ft-lbs)	3,910
Recommended Make-up Torque of 38.7 kg/m, 28CR-110, TMK UP ULTRA FJ	
Optimum (ft-lbs)	15,300
Minimum (ft-lbs)	13,800
Maximum (ft-lbs)	16,800

Load	AER Directive 10 Intermediate Casing Design Requirements	Internal Pressure	External Pressure	Tensile Load
Burst	Design factor = 1.0 for sweet or sour wells with pp H2S < 0.3 kPa. Design factor = 1.15 for sour wells with pp H2S ≥ 0.3 kPa. No allowance is made for external pressure. The minimum burst pressure design load that the casing is exposed to must equal the maximum potential formation pressure taken from valid representative offset well data. The casing burst rating must equal or exceed the burst pressure design load times the design factor. In this directive, the design factor is defined as equal to the rating of the tubular divided by the design load on the tubular. If the maximum potential formation pressure is unknown and not expected to be abnormally overpressured, the minimum burst pressure design load must be equal to an internal pressure gradient of 11 kPa/m times the total depth (m TVD) of the well. The lesser of the pipe body burst strength or the connection burst strength must be used in the casing minimum burst strength. If the Simplified Method does not meet the minimum design burst factors, the Alternative Design Method must be applied for burst design.	Maximum offsetting pressure gradient = 11.38 kPa/m therefore we will use that for calculating internal pressure. 34.2 kg/m casing = 1,025m x 11.38 kPa/m = 11,665 kPa 38.7 kg/m casing = 1,025m x 11.38 kPa/m = 11,665 kPa	0 kPa/m gradient.	N/A
Collapse	Design factor = 1.0. The casing collapse pressure rating (API Bulletin 5C2) must exceed the external pressure acting on the casing at any given point. No allowance is made for internal pressure, as total evacuation of the casing is assumed. Axial loading reduces casing collapse pressure rating. The method used to calculate the collapse pressure reduction is outlined in the latest edition of API Bulletin 5C3. The ERCB will continue to accept casing designs where Appendix E has been used to calculate the reduced collapse pressure.	0 kPa/m gradient.	Possible maximum fluid density while drilling intermediate hole = 1,300 kg/m³ = 12.8 kPa/m. therefore gradient of 12.8 kPa/m will be used. 34.2 kg/m casing = 885m x 12.8 kPa/m = 11,286 kPa	N/A

	The external pressure acting on the casing is calculated using an external fluid gradient of 12 kPa/m. If the actual drilling fluid gradient is higher than 12 kPa/m, that higher gradient must be used. An acceptable design may be based on a lesser external fluid gradient, but not less than 11 kPa/m, provided that the actual drilling fluid gradient at the time of running casing does not exceed the design gradient. If the Simplified Method does not meet the minimum design collapse factors, the Alternative Design Method must be applied for collapse design.		38.7 kg/m casing = 885m x 12.8 kPa/m = 11,286 kPa	
Tension	Design factor = 1.6. No allowance is made for buoyancy. The casing minimum tensile strength must exceed 1.6 times the design tensile load acting on the casing at any given point. The lesser of the pipe body yield strength or the joint strength (connection parting strength) must be considered in the casing minimum tensile strength. If the Simplified Method does not meet the minimum design tension factors, the Alternative Design Method must be applied for tension design.	N/A	N/A	Tensile force from weight of casing in air. 34.2 kg/m casing = (840m x 34.2 kg/m x 0.981 kg-force) + (45m x 38.7 kg/m x 0.981 kg-force) = 29,915 daN 38.7 kg/m casing = 45m x 38.7 kg/m x 0.981 kg-force = 1,708 daN

Calculated Design Safety Factors of 34.2 kg/m, J-55, LT&C		
Load	**Required**	**Calculated**
Burst	1.00	2.58
Collapse	1.00	1.66
Tension	1.60	4.65
Calculated Design Safety Factors of 38.7 kg/m, 28CR-110, TMK UP ULTRA FJ		
Load	**Required**	**Calculated**
Burst	1.00	5.89
Collapse	1.00	3.80
Tension	1.60	136.44

Surface Casing String with Float Equipment and Casing Accessories	
Description	**Description and Centralization**
177.8mm, 38.7 kg/m, 28CR-110, TMK UP ULTRA FJ	Bow Spring non-welded placed over stop collar every joint
Float Collar	Contains float
177.8mm, 34.2 kg/m, J-55, LT&C	Bow spring non-welded centralizer to be placed over every 2nd casing collar to surface for adequate stand-off.

4.4. Cementing

Type	Composition	Density	Volume
Pre-Flush	Fresh Water + Viscosifier	+/- 1,200 kg/m^3	6.0m^3
Scavenger	Class G cement + Pozzolan + friction reducer + fluid loss additive + retarder + accelerator	1,250 kg/m^3	3.0 m^3

Lead Cement	Class G cement + Pozzolan + Latex + friction reducer + fluid loss additive + retarder + accelerator	1,600 kg/m^3	+/- 200% XS from gauge
Tail Cement	Class G cement + Pozzolan + Latex + friction reducer + fluid loss additive + retarder + accelerator	1,700 kg/m^3	+/- 75% XS from gauge

Wellbore preparation prior to cementing:

- Planned cement mix water to be tested by cementing company to confirm adequacy for use.
- Wellbore is to be static with all losses (if encountered) healed prior to cementing.
- To ensure effective drilling fluid removal, rheology of the drilling fluid will be reduced prior to the cement job.
- Once casing is on bottom, drilling fluid will be circulated at drilling annular velocity (>45m/minute) with pipe reciprocation to break gel strengths and clean the whole prior to cementing.
- A fluid caliper may be circulated to measure hole cleaning performance and validate cement volumes.
- Cement volumes will be adjusted based on loss circulation risk and hole conditions while drilling.

Cementing operation practices:

- Two samples of the cement blend and cement water will be collected and retained for verification testing if needed.
- Job data including densities of all fluids pumped, pump rates and pump pressures will be recorded during the cement job as well as displacement.
- Casing will be reciprocated while cementing.
- Top and bottom cement plugs will be used.
- Maximum over displacement from calculated volume will be limited to 50% of the shoe track volume to avoid a wet casing shoe.
- Upon the top cement plug landing on the float collar, displacement pressure will be further increased 3,500 kPa from the last circulation pressure and held for 5 minutes.

Intermediate casing drill out:

- Intermediate cement will be allowed to cure for 12 hours prior to drill out as per 44(2) of the Manitoba Drilling and Production Regulation.

4.5. Pressure Testing

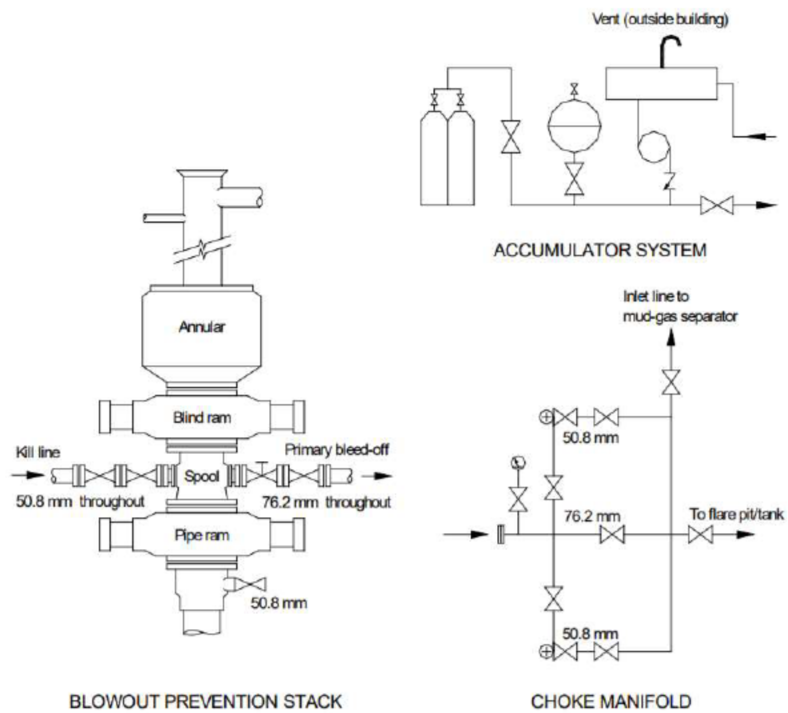
Intermediate casing pressure testing:

- Pressure will be brought down to 0 kPa after bumping the top cement plug and the casing floats will be observed for bleed back to confirm floats are holding the hydrostatic pressure of cement.
- If there is no bleed back once pressure is released, surface casing will be pressure tested to 7,000 kPa for 10 minutes as per 44(2) of the Manitoba Drilling and Production Regulation

Summary of Pressure tests required as per 32(1) and 44(2) of the Manitoba Drilling and Production Regulation prior to drilling out intermediate casing				
Equipment	**Low (kPa)**	**Time (Minutes)**	**High (kPa)**	**Time (Minutes)**
Annular	1,400	10	7,000	10
Rams	1,400	10	7,000	10
Bleed-off Line and Valves	1,400	10	7,000	10
Manifold Valves	1,400	10	7,000	10
Kill Line and Valves	1,400	10	7,000	10
Stabbing Valve	1,400	10	7,000	10
Inside BOP	1,400	10	7,000	10
Lower Kelly Cock	1,400	10	7,000	10
Intermediate Casing	N/A	N/A	7,000	10
Wellhead Primary & Secondary Seals	1,400	10	18,000 (80% of 34.2 kg/m, J-55, LT&C collapse pressure)	10

4.6. Well Control and Blow Out Preventer Set-up

AER Class III BOP – Minimum pressure rating 14,000 kPa. Wells not exceeding a true vertical depth of 1,800m.



5. MAIN HOLE

- A tubing spool, double studded adapter and drilling BOP will be installed and well control equipment pressure tested as per Sections 5.4 and 5.5 prior to drilling out of the intermediate casing shoe.

- An electronic drilling recorder system will be rigged up and operational throughout main hole. A continuous record of gas show, flow, rate of penetration, hook load, pump pressure, pump strokes, rotary RPM, rotary torque, total mud tank volume and pit volume gain/loss will be maintained.
- A gas detector will be installed in the shale shaker box used for monitoring gas liberated from the drilling fluid to indicate any gas bearing formations.
- A riser pipe will be installed on top of the BOPs to bring the drilling fluid and cuttings to surface while drilling main hole.
- Kelly bushing height above ground level will be measured and recorded and used as the depth datum during drilling operations.
- Main hole drilling operations:
    - 4 m of new 156mm hole will be drilled (885-889m = 4m). This will the starting point for core interval #2.
    - 3 x 45m coring runs will be conducted using a 156mm core head, 5.50" core barrel with aluminum sleeves to cut 3.50" diameter core from 889 – 1024m (FTD) = 135m.
    - 4 open hole logging runs will be conducted after coring.
        - Run 1: Platform express with resistivity and 4-arm caliper
        - Run 2: Sonic scanner / Formation micro imager
        - Run 3: Magnetic resonance
        - Run 4: Modular dynamic tester (MDT)
    - A bridge plug will be set close to the bottom of the 177.8mm intermediate casing prior to conducting a 7MPa pressure pass cement bond log on the 177.8mm intermediate casing cement.
    - The drilling rig will perform a clean out trip prior to circulating the well over to clean brine with corrosion inhibitor, oxygen scavenger and biocide.
    - A wireline unit will be brought in to locate and set a permanent CRA injection packer. A tubing plug will be placed into a seating nipple at surface prior to running the packer into the hole.
    - The drilling rig will be used to install the 88.9mm, 13.67 kg/m, Hunting TKC MMS EUE permanent injection tubing.
    - Prior to latching into the permanent packer with the permanent injection string, the wellbore, from the injection packer to surface will be circulated over to fresh water with corrosion inhibitor, oxygen scavenger and biocide.
    - Prior to removing the rigs BOPs a BPV will be installed into the BPV threads within the CRA extended neck tubing hanger.
    - The permanent 34,500 kPa (5,000 PSI) tubing bonnet, master valves, flow cross and swing valve will then be installed.
    - Drilling rig will be moved offsite.
    - The well will then be handed over to the completions team to perform the step-rate and long duration injection tests.

5.1. Drilling Fluid

Mud Type	Density	Additives
Solids free brine	> 1,100 kg/m³	Sodium Chloride Brine + calcium nitrate (density increase contingency) + oxygen scavenger + defoamer

- Material safety data sheets for all drilling fluid additives will be available on location during drilling operations.
- Solids control:
  - Shale shakers and centrifuge will be used to separate drill cuttings from drilling fluid.

5.2. Evaluation

Cutting Samples	No cuttings samples	
Coring	Cored interval 889 – 1,024m = 135m.	
Mud log	Pason continuous gas reading will be monitored while drilling	
Open Hole Logging	Platform express with resistivity and 4-arm caliper	Identify formation fluids
	Sonic scanner	Identify lithology and porosity
	Formation micro imager	Identify naturally occurring fractures
	Modular dynamic tester	Formation fluid and formation pressure

5.3. Cementing

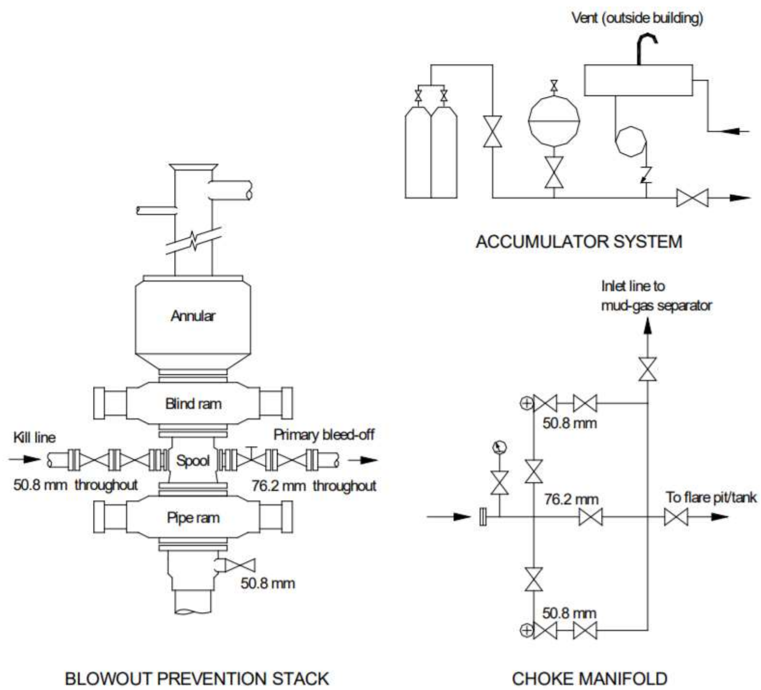
No cementing operations for this hole section.

5.4. Pressure Testing

Equipment	Low (kPa)	Time (Minutes)	High (kPa)	Time (Minutes)
Injection Tubing Annulus	1,400	10	10,000	10
Tubing plug in Tailpipe	1,400	10	10,000	10
Tubing Head RX Ring Gasket to Tubing Hanger	1,400	10	21,000	10
Tubing Hanger Seals	1,400	10	34,500	10

5.5. Well Control and Blow Out Preventer Set-up

AER Class III BOP – Minimum pressure rating 14,000 kPa. Wells not exceeding a true vertical depth of 1,800m.



6. INJECTION TUBING

- 88.9mm, 13.67 kg/m, L-80 with a premium connection.
    - Connection to be a gastight premium connection.

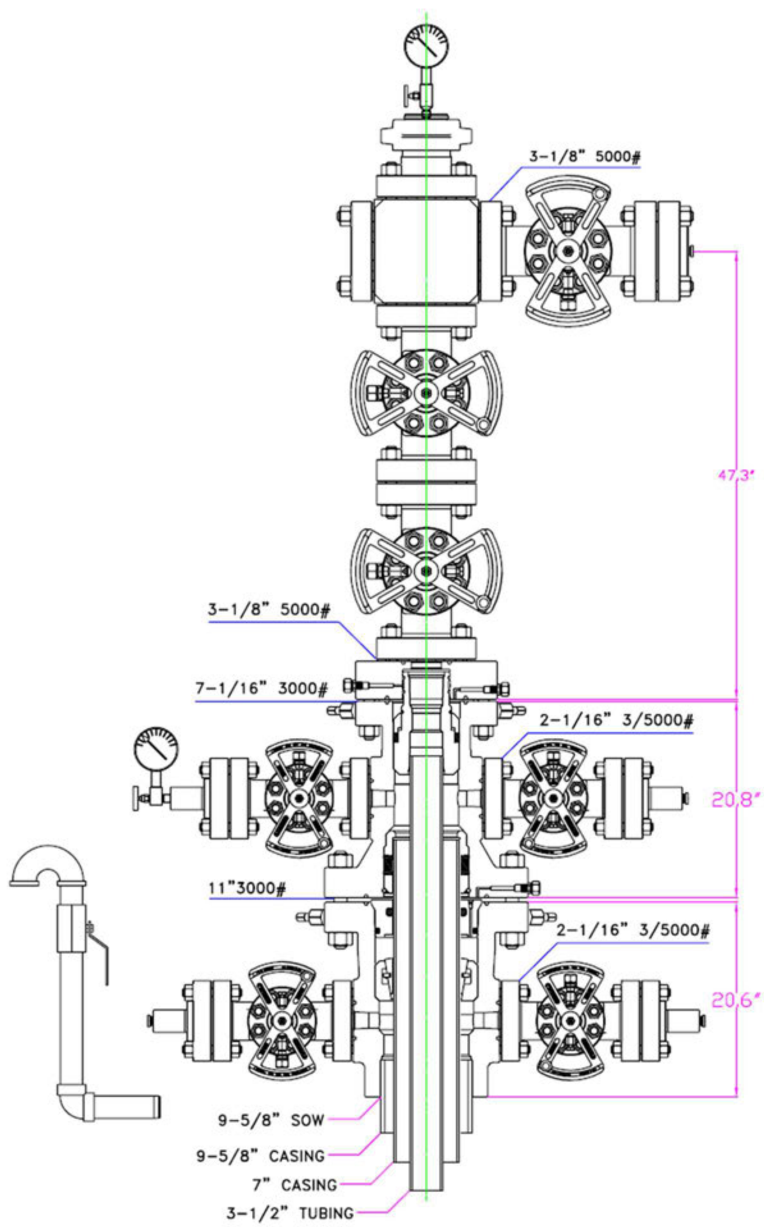
7. PACKER ASSEMBLY

- Coated tubing pup joint
- Baker E-22 anchor tubing-seal assembly (Inconel and V-RYTE seals) – Size 80-40 - 88.9mm, premium connection Box Up
- Baker Signature “FB” permanent packer, wireline set (Inconel, flow wet) – Size 587-400, HNBR Elastomer
- Pup joint (G3 CRA material) - 88.9mm x 3.00m, 13.84 kg/m, premium connection
- Genuine Otis “X” seating nipple (Inconel) – 88.9mm x 58.75mm Profile, premium connection
- Pup joint (G3 CRA material) - 88.9mm x 3.00m, 13.84 kg/m, premium connection
- Genuine Otis “XN” seating nipple (Inconel) – 88.9mm x 58.75mm x 56.01mm NO-GO Profile, premium connection x 88.9mm EUE Down
- Perforated Pup joint (coated with Impreglon 505) – 88.9mm x 3.00m, 13.84 kg/m, EUE
- Wireline re-entry guide (coated with Impreglon 505) – 88.9mm, 13.84 kg/m, EUE

8. WELLHEAD

Wellhead features:

- Prep in casing bowl for wear bushing
- Casing bowl and tubing head rated for 21,000 kPa (3,000 PSI)
- 88.9mm injection tubing
- Tubing bonnet, dual master valve, flow cross, wing valve rated for 34,500 kPa (5,000 PSI)
- Tubing hanger, tubing bonnet, lower master valve with Inconel wetted surfaces
- Upper master valve, flow cross and wing valve with electroless nickel coating



9. CORROSION CONTROL AND WELL INTEGRITY

- The wetted parts of the wellhead, tubing hanger, tubing head bonnet and lower master valve will be constructed of Inconel material.
- The upper master valve, flow cross and wing valve will be electroless nickel coated.
- 28CR-110 corrosion resistant alloy 177.8mm intermediate casing has been selected to be placed at the bottom of the intermediate casing string within the Red River Formation to mitigate the corrosive affects carbonic acid has on carbon steel. This is to provide an adequate host section for the permanent injection packer.
- Intermediate cement design is based on reducing the permeability to invasion and reducing the amount of reactive material in the blend that could react and degrade with carbonic acid from injected CO_2
- A 7MPa pressure pass cement bond log will be performed on the intermediate casing. This is to prove adequate zonal isolation for injection of CO_2 into the Red River Formation.
- The tubing annulus will be filled with fresh water mixed with corrosion inhibitor, oxygen scavenger and biocide.
    - Corrosion inhibitor and oxygen scavenger is added to prevent risk of galvanic corrosion between different metals in electrical contact.
    - Biocide is added to mitigate risk of microbial influenced corrosion in the annulus.
- The seal assembly, injection packer and tailpipe will be made from Inconel material to be able to withstand the corrosive environment for the life of the well.
- A coated tubing pup joint will be placed between the CRA anchor tubing-seal assembly and the 88.9mm, 13.67 kg/m, L-80 premium connection tubing to prevent galvanic cell corrosion between the dissimilar metals in contact.
- An Inconel flapper valve will be installed into the Genuine Otis “XN” seating nipple providing a float for the injection tubing string to prevent fluids from flowing up the tubing string. This will be installed prior to the start of CO_2 injection.

10. ABANDONMENT

As stipulated in Part 6; Section 56 – Cased hole abandonment of the Oil and Gas Act – Drill and Production Regulation (Manitoba Government, 1994), the following steps will be taken to ensure compliance in abandonment procedures.

- Set an approved mechanical plug above the base of the upper (Evaporite) member of the Amaranth Formation and place an 8m cement plug on top of the mechanical plug; or
- Set a cement plug by circulating to extend from below the perforations or, in the case of an open hole completion from the bottom of the well, to at least 15 m above the base of the upper (Evaporite) member of the Amaranth Formation, and probe the plug with a force of 18 kN or such other force as may be approved by an inspector after the cement cures for at least six hours;

After the plug is set:

- Pressure test the casing above the plug to 3,500 kPa;
- If pressure testing indicates a leak, test the plug for proper shut off:
- If the production casing cemented above the surface casing shoe, pressure test the annulus between the surface and production casing to 3,500 kPa;

- If the pressure test required under clause (e) is successful:
  - Set an approved mechanical plug in the production casing 5m below the surface casing shoe and place an 8 m cement plug on top of the mechanical plug; or
  - Set a cement plug inside the production casing to extend at least 15 m above and below the surface casing shoe;
- If the production casing is not cemented above the surface casing shoe, or if the pressure test under clause (e) fails:
  - Squeeze cement through perforations made in the casing to ensure the presence of a cement sheath outside the production casing and a plug inside the production casing for at least 15 m above and below the surface casing shoe;
  - Retest the annulus in accordance with clause (e); and
  - Probe the plug with tubing.
- If there is a hole in the casing above the plug set under clause (a) or (b), pressure test the casing above the plug set in accordance with clause (f) or (g) to 3,500 kPa and, if a cement plug is used, probe the plug with tubing;
- Fill the production casing and the annulus between the surface and production casing with a non-corrosive inhibited fluid;
- Cut off the surface and production casing a minimum of 1.5 m below ground level; and
- Weld a steel plate to completely close off the end of the surface and production casing.