Proposed South Pierson Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

Lower Amaranth/Mission Canyon

Pierson, Manitoba

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Canadian Natural Resources Limited

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Introduction

The Pierson field, located in Townships 1-3 Ranges 28 and 29 west of the prime meridian, first produced in 1985. The main target in this area is the Lower Amaranth (Spearfish) formation although some Mission Canyon (Alida) production exists throughout the field. In 1993 Home Oil, as operator of the area, unitized a portion of the field and implemented a 40 acre waterflood. The unit was named South Pierson Unit No. 1 (SPU No. 1) (Figure 1). Canadian Natural Resources Limited (CNRL) acquired the lands in 2002 and received approval to down space the unit to a 20 acre waterflood in 2004. The majority of the injector conversions for the 20 acre waterflood were completed between 2007 and the first six months of 2008. Although a typical waterflood response has not yet been observed, the flattening decline may indicate reservoir pressure support.

In 2010, CNRL received approval for a second unit named South Pierson Unit No. 2 (SPU No. 2) (Figure 1), which became effective November 1, 2010. The development plan for the unit consisted of 27 horizontal wells to be drilled as producers, as well as the conversion of the existing vertical wells into injectors. Development has started in this area and so far the results have been encouraging. There have been 21 vertical injector conversions completed to date, however water injection has not yet commenced due to delays in implementing a better water filtration system; it is expected to be injecting by fall, 2012. This new system is expected to allow for better injectivity and reduce potential for damage to injectors. Refer to Figure 11 for the most up to date process flow diagram.

Keeping with the idea of enhancing oil recovery from the existing reservoir with optimally spaced wells for waterflooding, CNRL is proposing that a third unit, South Pierson Unit No. 3 (SPU No. 3) be created directly offsetting the existing SPU No. 1 to the east. This unit would be comprised of one full section and five partial sections for a total of 56 legal subdivisions (LSD's) or three and a half sections (Figure 2). Within the proposed unit boundary there are 36 producing or suspended vertical wells, 3 abandoned wells (these wellbores themselves will not be included as part of the unit), 8 horizontal wells and 1 triple leg horizontal well.

Summary

1. The proposed South Pierson Unit No. 3 will include 36 existing vertical wells, 8 horizontal wells and 1 triple leg horizontal well that are completed in the Lower Amaranth (Spearfish) and/or the Mission Canyon (Alida) formations.

2. The proposed unit will include 56 legal subdivisions (LSD's), of which 47 have had wells drilled on them and 9 of which are still undeveloped. The boundary of the proposed unit will be adjacent to the east boundary of SPU No. 1.

3. The original oil in place (OOIP) for the proposed unit is 4,884 e^3m^3 or 87.2 e^3m^3/LSD on average.

4. Cumulative production from the proposed unit up until the end of April 2012 is 223.4 e^3m^3, which represents a 4.6% recovery factor of the total OOIP within the proposed unit boundary.

5. The estimated ultimate recovery (EUR) using decline analysis, if no further development occurred within the proposed unit boundary, would be 278.2 e3m3, with 54.8 e^3m^3 remaining oil reserves as of May 1, 2012. This equates to a recovery factor of 5.7% of the OOIP.

6. Peak production from the proposed unit was 63.02 m^3/d of total oil in August, 1994 from 12 wells. The most recent production rate from April 2012 was 14.81 m^3/day of total oil from 35 wells, with average water cuts varying from 50.5% to 79.3% over the last two years.

7. The initial pressure of the reservoir was approximately 11,000 kPa. Pressures collected in August 2011 from three shut in wells were measured at 4,433 kPa, 3,7254 kPa and 2,124 kPa (Appendix 14). It is suspected that these wells were not shut in long enough to stabilize and that the pressures observed likely represent only near wellbore conditions. It can be assumed, therefore, that overall reservoir pressure has not been as drastically depleted as these numbers would indicate.

8. The existing South Pierson Units No. 1 and No. 2 can be used as analogies to help predict the expected recovery factor for the proposed development plan. Spearfish recovery factors have been estimated to be 13.9% and 13.4% for units No. 1 and No. 2, respectively. South Pierson Unit No. 3, developed with horizontal producers and future water injection, should behave similarly, with a projected recovery factor of 13.3% equating to 640.8 e3m3 of recoverable oil.

9. The development plan includes drilling 35 horizontal wells to be completed with multi-stage hydraulic fractures over a time span of five and a half years. Of the 35 horizontal wells to be drilled, 24 will be producers and 11 will produce until the oil rate reaches approximately 1 m^3/d (estimated to occur within 3-4 years), at which time they will be converted to injectors. Of all the existing wells within the proposed unit, two horizontal wells and 24 vertical wells will be converted to injectors and the remaining will produce until they are uneconomic (Table 4). Additional horizontal wells may be drilled at a tighter spacing in order to further ensure a reasonable waterflood response period.

Reservoir Properties and Technical Discussion

Geology

The main target for the proposed SPU No. 3 is the Spearfish (Lower Amaranth) formation, although the Alida (Mission Canyon) formation is perforated or penetrated in several of the existing wells. The Spearfish is a dolomitic siltstone to fine sandstone with slightly calcareous but mainly anhydritic cement. It was deposited in a tide dominated delta environment and sits unconformably above the Mississippian beds. In Appendix 1 a stratigraphic cross-section of the Spearfish and Alida within the proposed unit boundary and into the South Pierson Unit No.1 is included to show the extent of both formations throughout the units.

A subsea structure map on the top of the Spearfish Sandstone as well as a Mississippian structure map is provided in Appendix 2 and 3 respectively, illustrating the slight dip of the beds to the southwest.

The Spearfish pay interval is defined between the Spearfish Sandstone (as seen on cross-section) and the Mississippian Unconformity (top of Alida). Spearfish pay (reservoir within the zone that is capable of economic production) was determined and mapped (Appendix 4) using a cutoff of 10% porosity (Phi); roughly equivalent to 0.5 mD of permeability (K). With recent development by competitors in the Lyleton/Coulter area, it was found that using a 12% porosity cutoff was too pessimistic and areas with potential reservoir would have been left undeveloped. The overall average porosity for the area using this new cutoff is 13.3%. Individual porosities were calculated per well, and when mapped (Appendix 5), allowed us to assign porosities on a per LSD basis to be used in tract factor calculations. These porosity values were also used to calculate and map the product of porosity and pay (Phi*h) (Appendix 6), an indication of reservoir quality.

After further development of the area and new production results, it was decided that there must be more variation in initial water saturation (Sw_i) than applying a blanket average Sw_i of 45% accounts for. Several digital logs throughout the area were acquired in order to evaluate the water saturations petrophysically. The Simadoux equation was used in order to account for the shale volumes present in this silty sandstone. Using a cutoff of less than 60% water saturation, an overall average Sw_i of the area was found to be 47% within the zone and the range in individual values can help to account for varying water cuts as seen in historical production. From these values, an initial water saturation map was created (Appendix 7), and when coupled with the Phi*h values, were used to calculate hydrocarbon pore volume (HCPV) (Appendix 8).

Similar to SPU No.1, SPU No. 3 shows no obvious directional Spearfish permeability trend. Included in Appendix 9 is a map detailing the product of permeability and net pay (K*h) for the Spearfish formation, which depicts several pockets of higher average permeability throughout the reservoir of the proposed unit.

Alida pay was determined using a 7% porosity cutoff on rock below the effective cap rock and above the interpreted oil water contact or bottom seal, with a Sw_i of 29% and an average porosity of 11.8%. Contoured maps detailing the net pay, Phi*h, and HCPV for the Alida can be found in Appendices 10-12. There is a lack of core data for the Alida formation, therefore no K*h maps were created for this zone.

From these maps it is evident that the reservoir is continuous from SPU No. 1 to SPU No. 3 and is of similar quality. With this information it is concluded that SPU No. 1 can be used as an analogy to the proposed SPU No. 3 and should respond in a similar manner to tighter well spacing and waterflooding. A summary of all reservoir properties can be found in Table 1.

Original Oil in Place (OOIP) Estimates

Volumetric calculations were done to determine the OOIP within SPU No. 3 for the Alida and Spearfish formations using CNRL internally created maps. Based on these calculations, it was estimated that the Alida has 76.2 e^3m^3 of OOIP and the Spearfish has 4,808 e^3m^3 of OOIP for a total of 4,884 e^3m^3. The tabulated parameters for each LSD used in these calculations can be found in Table 6.

OOIP values were calculated using the following equation:

$$OOIP = \frac{Porosity * Net\ Pay * (1 - Water\ Saturation) * Area}{Formation\ Volume\ Factor\ of\ Oil}$$

or

$$OOIP = \frac{\phi * h * (1 - S_W) * A}{B_O} * 3.28084 \frac{ft}{m} * 7758.367 \frac{bbl}{acre \cdot ft} * \frac{1\ mbbl}{1000\ bbl}$$

Where:

OOIP	= Original Oil in Place (mbbl/LSD)
$\phi * h$ or $phi * h$	= porosity (fraction) * net pay (meters)
B_O	= formation volume factor of oil (m^3/m^3)
S_w	= Water Saturation (fraction)
A	= Area (40 acres/LSD)

and OOIP (m^3) = OOIP (mbbl) * 1000 bbl/mbbl * 6.289811 m^3/bbl

The porosity, net pay and initial water saturation values were determined for each well based on logs using the cutoffs discussed in the geology section by Tara Mailandt, Geo. I.T., overseen by Bob Ogilvie and Doug Gardner, P. Geol.. These values were contoured and hand manipulated in Petra. Petra was used to calculate the average phi, h and Swi values for each LSD and these numbers were used to calculate OOIP values. The formation volume factor of oil was determined from special core analyses. The calculations were done by Brittany Trask, E.I.T.

Historical Production

The first well drilled within the proposed unit boundary was rig released in 1982 but was never put on production. The two subsequent wells drilled in 1986 were also abandoned without producing. The first well to actually produce within the proposed unit boundary was drilled in 1987 and is still producing. Between 1987 and the end of 2005, eighteen wells were drilled, seven of which were drilled in 1994 where a peak in production rate of 63.02 m^3/d of oil can be seen (Figure 4). All of the wells drilled up to this point were drilled through the Spearfish and down into the Alida with the exception of the three horizontal wells that targeted the Spearfish. The next peak in oil production (59.45 m^3/d) was seen in 2006 when 19 vertical wells were drilled down to the Spearfish but did not penetrate the Alida. Since that time two vertical wells, one Alida horizontal well and five Spearfish horizontal wells (completed with multi-staged fractures) were drilled. When the first two multi-stage fractured horizontal wells came on production in June 2010, the production spiked again to 50.41 m^3/d of oil.

<u>Primary Recovery (Current)</u>
Cumulative production within the proposed unit boundary is 223.4 e^3m^3 of oil and 566.6 e^3m^3 of water based on the available public production data to the end of April, 2012 (Figure 3). This production is equivalent to a 4.6% recovery factor of the total OOIP. The most recent calendar daily production rate from April 2012 was 14.81 m^3/day of oil and 31.48 m^3/day of water.

Based on decline analysis of the wells currently on production, coupled with the expected performance of the most recently drilled horizontal wells, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be 278.2 e^3m^3. This represents a recovery factor of 5.7% of the total OOIP. In Figures 4 and 5, the green lines represent the historical oil production up to April 30, 2012 and the pink lines show the forecasted oil production for the existing wells. The difference between the current EUR for the proposed unit and the cumulative oil production is 54.8 e^3m^3, which is the remaining recoverable oil from the current wells on primary production.

<u>Horizontal Development with Enhanced Oil Recovery (Future)</u>
The historical development of SPU No. 1 from primary production to 20 acre waterflood, as described in the introduction of this application, can be seen in Figure 6. Over the last several years, the decline from the first unit has become more stable and it is predicted, that the ultimate Spearfish oil recovery from SPU No. 1 will be about 1,000 e^3m^3 (Figure 7), which is equivalent to a 13.9% recovery factor of the 7,174 e^3m^3 Spearfish OOIP, calculated internally by CNRL.

SPU No. 2 was unitized based on the performance of SPU No. 1 under 20 acre waterflood, but is being developed with horizontal producers and mainly vertical injectors. The results thus far indicate that the unit is behaving as expected with an approximate recovery factor of 13.4% of the 4,133 e^3m^3 of Spearfish OOIP. This was determined using decline analysis and estimated performance of the future horizontal wells. Figures 8 and 9 show the historical oil production (green line), the forecasted oil production with no further development (pink line) and the forecasted oil production of SPU No. 2 once it is fully developed with water injection (blue line).

Geology supports the belief that SPU No. 3 and the existing SPU No. 1 are a continuous reservoir and therefore, the performance of SPU No.1 under waterflood can be used as an analogy to estimate how the SPU No. 3 will perform when it is developed with horizontal wells and a waterflood is eventually implemented. By implementing the described development plan, SPU No. 3 is expected to recover 640.8 e^3m^3 of oil from the Spearfish formation at a recovery factor of 13.3% of the 4808 e^3m^3 of Spearfish OOIP. These numbers were arrived upon using an estimated production profile for each infill well along with decline analysis of the currently producing wells. The estimated recovery factor for the proposed unit is comparable to those of SPU No. 1 and No. 2. The expected performance is summarized for each of the units in Table 2. The forecasted production for the proposed unit is represented by the dark blue lines in Figures 4 and 5 and takes in to account the timing of the development plan.

It is anticipated that the Alida will contribute only a small amount of production to the total ultimate recovery because the OOIP is so small. However, the Alida is supported by an active natural aquifer drive and the recovery factor can be expected to be around 25% based on the Gainsborough area in Saskatchewan where Alida production is prominent.

The total recoverable oil in place from the proposed unit is estimated to be 656.6 e^3m^3, which is an incremental 378.4 e^3m^3 over the forecasted ultimate oil from the currently existing wells.

Unitization

The basis for unitization is to develop the lands in an effective way that will be conducive to waterflooding. Unitizing will make sure that the reservoir will have the greatest recovery possible by allowing horizontal wells to be optimally spaced and for water injection to be implemented to maintain reservoir pressure for increased oil production.

Unit Name
Canadian Natural Resources Limited (CNRL) proposes that the name of the new unit shall be South Pierson Unit No. 3 (SPU No. 3).

Unit Operator
CNRL will be the Operator of South Pierson Unit No. 3.

Unitized Zones
The unitized zones will be the Lower Amaranth (Spearfish) and the Mission Canyon (Alida).

Unit Wells
The 45 existing wells to be included in the proposed South Pierson Unit No. 3 are outlined in Table 3 with their current status. The development plan found in Table 4 includes the existing wells to be converted to injectors and the 35 horizontal infill wells that will be drilled upon approval of the unit. The timing of the proposed injector conversions is also included in Table 4. The full development plan is included in Figure 10.

Unit Lands
The South Pierson Unit No. 3 will consist of LSD's in the northwest quarter of section 3, all of section 10, the west half and northeast quarter of section 11, the south half of section 14, 14 LSD's in Section 15, and 2 LSD's in section 16 in Township 2-29W1. The

total number of LSD's included in the unit will be 56. CNRL has 100% working interest in the proposed unit and therefore will have 100% working interest in each tract. The lands are outlined in Table 5.

Tract Factors

South Pierson Unit No. 3 was divided into 56 tracts, which is based on the number of LSDs to be included in the unit. Tracts factors were determined by using the total OOIP calculated from the Spearfish and Alida maps created internally by CNRL and then subtracting the cumulative production to date for each LSD. The variables used in the calculation of the tract factors can be found in Table 6 for each individual LSD.

Working Interest Owners

CNRL is 100% working interest owner in all of the lands included in the proposed unit boundary and therefore will have 100% working interest in the proposed South Pierson Unit No. 3. This is also summarized in Table 5 for each of the tracts.

Waterflood Development

The South Pierson Unit No. 3 will be developed with horizontal wells over the next five and a half years. The initial spacing between horizontal producing wells will be a maximum of 400 meters, where the current development and boundaries permit. Horizontal future injection wells will be drilled between the producers giving an approximate spacing of 200 meters between injectors and producers as outlined in the development plan (Figure 10). Horizontal injectors will produce before they are converted to injection; it is expected that when the oil production of an individual horizontal well drops to a rate of approximately 1 m^3/d the conversion will occur. The majority of the existing vertical wells will be converted to injectors as well. The estimated development plan timing, which includes drilling and conversions of wells, can also be observed in Figure 10 and is summarized in Table 4. The actual development of the unit may vary from the proposed development plan as further reservoir studies and modeling are done. The result of these studies may lead to tighter well spacing to further improve oil recovery via both primary and secondary recovery techniques. Also, several horizontal wells have been drilled within the Pierson area with plans of being converted into future injectors. The performance of these injectors, compared to the vertical injectors, will be monitored closely to determine which scenario will result in the best sweep efficiency. Any changes to the original development plan will be discussed in the annual enhanced oil recovery report submitted to the Manitoba Government.

Waterflood Operating Strategy

South Pierson Unit No. 3 will be tied into the South Pierson Unit No. 1 injection system. Pierson's current injection system uses mainly produced water from the Alida and Spearfish formations with make-up water from a licensed source well at 102/03-16-002-29W1 that is perforated in the Tilston formation. All of the production is sent to the Pierson battery at 14-09-002-29W1 where the water is separated, filtered and distributed to the injection system. A simplified process flow diagram of the current system, with modifications to include the proposed unit, can be found in Figure 11.

It is felt that compatibility testing for the injection water is unnecessary because it is largely sourced from the formations that will be receiving injection. Also, there have been many years of waterflooding with no compatibility issues in the South Pierson Unit No. 1.

All surface facilities and wellheads will have cathodic protection to prevent corrosion. All producing and injection flowlines and tubing will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set below the top of the injection formation, and the annulus between the tubing and casing will be filled with inhibited fluid. Refer to Appendix 13 for additional corrosion control details.

Reservoir Pressure

Pressures from three shut in wells were collected in August 2011 ranging from 2,124 kPa to 4,433 kPa, averaging 3,427 kPa (Appendix 14). These wells were shut in between 94 days and 114 days; it is suspected that this time period was not long enough to get an accurate measurement of the current reservoir pressure and more likely a near wellbore pressure was observed. The original reservoir pressure of the area was approximately 11,000 kPa and the saturation pressure (bubble point pressure) from PVT analysis done for 6-19-2-29W1 is 4,551 kPa. If the reservoir pressure was as low as the survey indicated, a substantial increase in the gas-oil-ratio (GOR) would be observed in the production history as the reservoir pressure dipped below the saturation pressure. This observation cannot be made from the historical production data so therefore it is assumed that the pressures were still building up in the surveyed wells.

The plan is to increase the current reservoir pressure closer to the original pressure by maintaining an instantaneous voidage replacement ratio (VRR) of approximately 1.5 until a cumulative VRR of 1.0 is reached. This is assuming surface pressures stay below the maximum allowable wellhead pressures.

Waterflood Surveillance and Optimization

The waterflood surveillance of South Pierson Unit No. 3 will consist of the following:

- Regular production well testing to monitor fluid rate and water cut, as done in South Pierson Unit No. 1, to watch for waterflood response, breakthrough or viscous fingering
- Comparison of daily injection rates and pressures to the targeted values
- Evaluation of Hall Plots to look for positive or negative skin indicating plugging or channeling/out-of-zone injection, respectively
- Monitor instantaneous and cumulative voidage replacement ratio by pattern and for the overall unit
- Injection targets will be sent to the field on a regular basis

Injector Conversions

The wells indicated in Table 4 will be converted from producing wells to injectors between 2015 and 2018. The tubing and rods will be removed and replaced with fiberglass tubing. See Appendix 15 for a typical injector schematic.

Injection Rates and Pressures

CNRL anticipates injecting water into the Spearfish formation within the next several years to re-pressurize it after having been depleted from primary production since 1987. To make up the voidage and pressure depletion from primary production, initial targets for instantaneous VRR will be between 1.25 and 1.75. At peak production rates, assuming an average water cut of 60%, the total water injection requirements will be between 400 m^3/d and 550 m^3/d over the entire field. This is equivalent to an average of 10 m^3/d and 15 m^3/d for each of the 37 injectors, 13 of which will be horizontal injectors and the remaining 14 will be vertical injectors. It should be noted that at the peak rates of the horizontal producers it may be difficult to maintain a VRR greater than 1.0 on an individual pattern basis, but overall the VRR should be very close to 1.0. Once the horizontal producers have more stabilized production rates, VRR should increase again to the targeted 1.25 to 1.75 range until the cumulative VRR approaches 1.0. At this point the injection targets will be set based on maintaining reservoir pressure with a VRR of 1.0.

The majority of the wells in the area have been stimulated by fracturing; from this information the fracture gradient is estimated to be 18 kPa/m or approximately 18,000 kPa sandface fracture pressure. The requested maximum injection pressure at the sandface will be 85% of the fracture pressure, which is 15,300 kPa or 5000 kPa at surface.

Economics

Using the outlined development plan and an estimated production profile with a cutoff of 0.16 m^3/day per producing well, it was determined that this enhanced oil recovery project will be both viable and profitable.

Notifications

CNRL will notify all surface and mineral owners within the unit and the surrounding 0.5 km of the unit boundary about the unitization and EOR scheme application by mail. A complete listing of the mineral owners within the proposed unit boundary and mineral owners within the notification area will be provided to the Manitoba Government. A copy of the registered mail notifications will be also sent to the Manitoba Government when they are received.

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