PROPOSED DALY UNIT No. 12

Application for an Enhanced Oil Recovery (EOR) Waterflood Project

Lodgepole Formation

Daly Sinclair – Lodgepole A (01 59A)

Daly Sinclair Field, Manitoba

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Tundra Oil and Gas Partnership

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INTRODUCTION

The Daly Oil Field is located in Ranges 27, 28 and 29 W1 in Townships 8, 9 and 10 (Figure 1). Figure 2 shows the outline of the proposed Daly Unit No. 12 (DU#12) boundary within the Daly oilfield targeting the Lodgepole formation. Wells in DU#12 have been on 40 acre primary production since the early 1950's, coincident with primary developments in the offset Daly Unit Nos. 1 & 3.

Within the proposed DU#12 boundary, potential exists for incremental production and reserves from a Waterflood Enhanced Oil Recovery (EOR) project in the Lodgepole A oil reservoir. The following is an application by Tundra to establish the Daly Unit No. 12 and implement a Secondary Waterflood EOR scheme within the Lodgepole formation as outlined in Figure 2.

The proposed project area falls within an existing designated Lodgepole A 01-59A Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Daly Unit No. 12 consists of 50 Lodgepole wells, 48 of which are vertical and 2 of which are horizontal. Of the vertical wells, 22 have producing status and the remainder are abandoned/suspended/standing/disposal. The area of the proposed Fairway Unit comprises 68 Legal Sub Divisions (LSD), and is located East of Daly Unit No. 1 and West of Daly Unit No. 4 (Figure 2).

2. Total Original Oil in Place (OOIP) in the project area is estimated to be 10,532.4 e3m3 (66,279.2 Mbbl) for an average of 154.9 e3m3 (974.7 Mbbl) OOIP per 40 acre LSD. OOIP values were estimated by contouring phi*h values and applying volumetric methods.

3. Cumulative production to the end of December 2014 from the 50 Lodgepole wells within the proposed Daly Unit No. 12 project area is 207.2 e3m3 (1,303.8 Mbbl) of oil and 676.8 e3m3 (4,258.8 Mbbl) of water, representing a 2.0% Recovery Factor (RF) of the OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Daly Unit No. 12 project area is estimated to be 240.4 e3m3 (1,512.8 Mbbl), with 33.2 e3m3 (209.0 Mbbl) remaining as at the end of December 2014 (Figures 5A & 6A).

5. Ultimate oil recovery of the proposed Daly Unit No. 12 OOIP, under the current Primary production method, is forecasted to be 2.3%.

6. Figure 4 shows that the oil production rate in the Daly Unit No. 12 area peaked during November 1954 at 55.6 m3 (350.0 bbl) of oil per day (OPD). As of December 2014, average production was 7.16 m3 (45.1 bbl) OPD, 19.3 m3 (121.3 bbl) water per day (WPD) per well for a 75.7% water cut (WCUT).

7. In November 1954, production averaged 2.5 m3 (15.7 bbl) OPD per well in the proposed Daly Unit No. 12. As of December 2014, average per well production has declined to 0.3 m3 (2.0 bbl) OPD. Decline analysis of the Primary production data forecasts the oil rate to continue declining at an annual rate of approximately 5.8% in the project area.

8. Estimated Ultimate Recovery (EUR) of oil under Secondary Waterflood EOR for the proposed Daly Unit No. 12 is estimated to be 659.1 e3m3 (4,147.3 Mbbl). An incremental 451.9 e3m3 (2,843.5 Mbbl) of oil is forecasted to be recovered under the proposed Unitization and Secondary EOR production, versus the existing Primary production method (Figures 5B & 6B)

9. Total RF under Secondary WF in the proposed Daly Unit No. 12 is estimated to be 6.3%.

10. Based on waterflood response in the adjacent Daly Unit Nos. 1, 3, & 4, the Lodgepole formation in the proposed project area is thought to be suitable reservoir for successful EOR operations.

11. Proposed future horizontal injectors with multi-stage hydraulic fractures will be drilled between existing vertical producing wells (Figures 7A & 7B) within the proposed Daly Unit No. 12, to complete waterflood patterns with an effective 20 acre spacing.

DISCUSSION

The proposed Daly Unit No. 12 project area is located in Townships 9 and 10, Range 28 W1 within the Daly Field Boundary (Figure 1). The proposed Daly Unit No. 12 consists of 22 producing wells and 28 abandoned/suspended/standing/disposal wells within a 68 LSD area (Figure 2). A project area well list with current well status and well type is attached in Table 3.

Within the proposed Unit, potential exists for incremental production and reserves from a Waterflood EOR project in the Lodgepole oil reservoir.

GEOLOGY

Geology Introduction

The proposed Daly Unit No. 12 (Appendix 1) is located on the carbonate slope of the Mississippian Lodgepole Formation on the eastern edge of the Williston Basin (Appendix 2). It has produced oil on a primary recovery scheme since 1952, with the first well spud at 16-03-010-28W1 on July 6th, 1952. The Lodgepole lies conformably on top of the Bakken Formation. In the Fairway area, it is unconformably overlain by the Lower Member of the Jurassic Formation which consists of evaporites and red beds. This geology section focuses on the methodology and data gathered to define the thickness of net reservoir, porosity and water saturation to estimate the OOIP's provided for this Unitization application. The reader is referred to the literature (Appendix 24) for a more detailed review of the stratigraphy, sedimentology and diagenesis of the Mississippian Lodgepole Formation (McCabe, 1963; Young and Rosenthal, 1991; Klassen, 1996; Nicola, 2008; Nicola and Barchyn, 2008).

Reservoir Geology

The Lodgepole Formation in the Fairway occurs between 712 and 851 mTVD in the subsurface, and is subdivided into seven members (examples given in Appendices 4A to 4C). In descending stratigraphic order, these are:

1. Unnamed
2. Upper Daly
3. Middle Daly
4. Cruickshank Shale
5. Cruickshank Crinoidal
6. Cromer Shale
7. Basal Limestone

Of the above seven members, the first five are productive and correlatable on logs and in cores across the study area, as shown in a set of north-south and east-west cross-sections

(Appendices 4A to 4C). The Cromer Shale is comprised of tight argillaceous mudstones, and appears as a higher Gamma Ray unit on logs compared to the overlying Cruickshank Crinoidal and the underlying Basal Limestone members. It is considered to act as the bottom seal for the overlying Lodgepole hydrocarbon-bearing reservoir zone.

The first occurrence of hydrocarbon-bearing Lodgepole reservoir occurs in the Unnamed, and the last occurrence is encountered in the Cruickshank Crinoidal, both of which define the top and bottom of hydrocarbon-bearing Lodgepole reservoir respectively. This is referred to as the "Lodgepole Reservoir Section" (Appendices 3, 4 & 5) in this application. The Basal Limestone commonly contains reservoir quality rock, but is observed to be wet. In contrast, the Lodgepole reservoir above the Cromer is observed to be oil-stained in cores across the Fairway area, and is oil producing. Dolostone predominates close to the Mississippian-Jurassic unconformity, and is typically observed down to the base of the Unnamed, with a few instances where it extends further down into the Middle Daly. The rest of the Lodgepole Reservoir Section is commonly limestone with high chert content in the Middle Daly. Key papers listed in the references (Appendix 24) provide further details on the stratigraphy, sedimentology and diagenesis of the Lodgepole Formation.

A combination of micro- (pin-point, intercrystalline, inter and intra-particle) and macro- (moldic and vuggy) pore types characterize the Cruickshank Crinoidal, the Cruickshank Shale and the Middle Daly. Moving up stratigraphically, the Upper Daly and Unnamed mark a change to a unimodal micro-dominated pore system, with common intercrystalline and fine pin-point porosity. These differences in pore types and pore distributions justified applying different cut-offs to different stratigraphic members, as explained in the following section.

Geological Mapping Input

a. Data Control and Quality

62 wells have been drilled with the proposed Daly Unit No. 12 boundary (Appendix 1), including 12 wells targeting Bakken production. 48 wells are vertical, and of these, 41 have produced from the Lodgepole, mostly from the Unnamed, Upper Daly and Middle Daly members. 22 of these Lodgepole producers are still active. 26 wells were drilled between 1952 and 1955; consequently, log quality for this group is rather poor (e.g. Appendix 4C). However, 14 of these provide core coverage which were examined to estimate net reservoir thickness and to approximate porosity cutoffs for each reservoir member in the Lodgepole Formation. The remainder of wells were drilled post-1980, including 12 horizontals targeting the Bakken. In total, 35 wells within the proposed Unit boundary provide a control point down to the base of the Lodgepole Reservoir Section to determine Phi-h (Appendices 12 & 13). The remainder either are not deep enough, or the data quality is too poor to be of use. Core and log information from an additional 61 peripheral wells were considered to constrain mapping contours.

b. Phi-h Estimation and Petrophysical Evaluation

By necessity, pay thickness and porosity were estimated using a number of techniques. In wells with old neutron and resistivity logs, net pay and porosity were estimated by examining the cores where available. A first batch of six vintage wells (1952 – 1955) with core analyses were selected and described. Porosity and permeability data were integrated with the core descriptions, and were used to calibrate visual identification of reservoir and non-reservoir rocks using a 0.5 mD permeability (k) cut-off. Subsequently, cores from older wells with no analyses were examined to visually estimate net pay thickness and average porosity. For wells drilled post-1980, petrophysical evaluation was incorporated to estimate net reservoir thickness, porosity and water saturation (Appendix 5). Three post-1980 wells outside the proposed Unit boundary provide excellent vertical core control in the Lodgepole: 102/15-27-009-28W1/00, 100/03-34-009-28W1/00 and 100/06-34-009-28W1/00. Data from these wells were examined in detail to calibrate core descriptions to petrophysical log evaluations. Nine wells within the proposed Unit boundary, and in close proximity to it, provide excellent vertical core coverage with porosity and permeability data. These were used to build porosity and permeability cross-plots for each key hydrocarbon-bearing Lodgepole reservoir members (Appendices 6A to 6F). Data points suspected to be affected by localized fractures were removed. Many of these core analyses give only one permeability value, or Kmax, and so porosity cutoffs equivalent to a Kmax of 0.5 mD are deemed most appropriate.

Overall, the relationship between core porosity and permeability is poor (Appendices 6A to 6F), highlighting the high level of heterogeneity within each reservoir member. However, general trends can be established and used to determine porosity cutoffs equivalent to a Kmax of 0.5 mD. Using this method, the following porosity cut-offs were derived for a Kmax of 0.5 mD (Appendices 6A to 6F):

- Unnamed Dolostone: 9%
- Unnamed Limestone 10%
- Upper Daly: 10%
- Middle Daly: 7%
- Cruickshank Shale: 7.5% (assumed porosity cutoff)
- Cruickshank Crinoidal: 6%

A cut-off of 7.5% was assumed for the Cruickshank Shale due to the significantly high scatter in the porosity-permeability data, which did not allow for a high value regression on the porosity-permeability relationship. This 7.5% assumption was based on qualitatively relating observations in cores with log data.

Appendix 5 provides an example of the petrophysics evaluated for wells with post-1980 data within the proposed Daly Unit No. 12. Using cut-offs for each stratigraphic members as listed above and in Table 3, a summation of effective net reservoir (h) and weighted average porosity (phi) was calculated on logs for the Lodgepole Reservoir Section (from

Unnamed to the top of the Cromer Shale). Weighted average water saturation (Sw) was also estimated for each well. To calculate Sw, salinity data from the Lodgepole Formation was examined in the Fairway area (Appendix 17). Data suspected to be contaminated by drilling or completion fluids was excluded. Salinity data from a total of 17 wells were examined and compiled to calculate an average salinity of 131,982 ppm for the Daly Unit No. 12 area (Table 4).

Appendix 7 was used to derive a formation water resistivity of 0.053 at reservoir temperature conditions (30 C), based on the 131,000 ppm salinity averaged for the Lodgepole wells in the Unit area. Archie's formula was then used to calculate Sw, assuming a=1, m=2 and n=2:

$$Sw = \sqrt[n]{\frac{a * Rw}{\text{Ø}^m * Rt}}$$

Where:

Rw	= Formation Water Resistivity (ohm-m) = 0.053 (Appendix 7)
Rt	= True Formation Resistivity (ohm-m)
Ø	= Log Porosity (v/v)
a	= Tortuosity Factor
m	= Cementation Exponent
n	= Saturation Exponent

Sw was derived for the 17 wells with modern logs. An average Sw of 44% was then calculated for wells within the Fairway (Appendix 18), and applied as a constant in the volumetrics to be discussed further in this application.

c. k-h Estimates

An attempt was made to establish a permeability-porosity relationship using the 100/06-34-009-28W1/00 well which has both Profile Permeameter data (PDPK KLIQ) and Routine Core Analysis (RCA KMAX). Appendix 8A is a crossplot of PDPK KLIQ v. Porosity for this well, and shows the computed best fit trend in red. As one can see, the regression is low as is the case with most carbonate reservoirs. Appendix 8B is a crossplot of RCA KMAX v. Porosity for all cored wells, with the same best fit trend plotted as Appendix 8A. Both plots show a similar scatter of data. This was as close a relationship that could be achieved given the variability in reservoir quality and heterogeneity in the Lodgepole Reservoir Section. Geometric average permeability values as described above were then calculated to estimate k-h values where available.

d. Reservoir Quality Codes

A legend of Reservoir Quality Codes can be found on the maps provided in Appendices 12 & 14. Because of the variation in data quality and vintage for wells in the Fairway, Reservoir Quality Codes were assigned for each porosity (phi), net reservoir thickness (h), and phi-h data points. For some wells, the TD is just above the base of the Lodgepole Reservoir Section. As an example, the 05-03-010-28W1 well TD's in the Cruickshank Shale; for this well, net reservoir thickness and phi values were extrapolated for the Cruickshank Crinoidal, and a Quality Code "PLCext" was assigned to indicate "poor log with core, and some extrapolation". This approach provided a means to include all available data for mapping.

e. Maps / Observations

Isopach, structural, net reservoir thickness and phi-h maps were constructed to illustrate controls on net reservoir distribution and/or depositional character of the Lodgepole (Appendices 9 to 15). A localized thickening of the Lodgepole to Cromer Isopach is observed along a NNE-SSW direction west of the proposed Unit boundary (e.g. 102/12-04-010-28W1, Appendix 9). This corresponds with a structural low offsetting the west side of the proposed Unit boundary (Appendix 10), and is captured on the map by increasing isopach and phi-h contours toward the NW area of the proposed Unit (Appendices 9, 12 & 14). Top Lodgepole coincident with top and bottom Lodgepole reservoir structure gradually increases toward the NE (Appendices 10, 11 & 16). Appendix 15 highlights variations in k-h across the unit, ranging from 7.3 to 70.7 mD-m and averaging 31 mD-m.

Thicker occurrences of net reservoir in each stratigraphic member result in thicker total net reservoir and higher phi-h values in SE33-009-28W1 and NE34-009-28W1 (Appendices 12 & 14). The porosity map indicates relatively uniform weighted average porosity across the Unit (Appendix 13). Hence, variation in phi-h is controlled predominantly by changes in net reservoir thickness (Appendix 12 & 14).

f. Fluid Contacts

As part of the review undertaken for this application, 18 Lodgepole cored wells were examined (blue wells in Appendix 1), several of which penetrate the Cromer Shale. Where the Cruickshank Crinoidal is cored, good to excellent oil staining is observed down to its base. Isolated lenses of oil-stained coarser porous debris occurs in Cromer shale cores. Appendix 20 provides an example of moderate to good oil staining observed in cores down to the top of the Cromer Shale member. This was used to define an "oil down to" value of -258.6 mSS at the base of the Cruickshank Crinoidal in the 15-03-010-28W1 well. Similarly, Appendix 21 shows an example further downdip of excellent oil staining down to the base of the Cruickshank Crinoidal at the 03-34-009-28W1 well. This corresponds to an "oil down to" value of -266.8 mSS at the 03-34 location, which has produced roughly 26,000 bbl oil and 68,000 bbl water. Some of the water production may be attributed to injection support from the nearby 102/15-27-09-28W1 WIW.

The logs for the 03-34-009-28W1 and 102/16-29-009-28W1 wells are comparable. The 102/16-29 well is located structurally downdip and has produced roughly 19,000 bbl oil and 32,000 bbl water. Cores at the 102/16-29-009-28W1 well penetrate the top of the

Middle Daly; as a result, oil staining could not be examined down to the Cruickshank Crinoidal. However, based on 102/16-29-009-28W1 logs and production performance, hydrocarbons are interpreted to occur and be producible at a minimum down to the base of the Lodgepole Reservoir Section at -275 mSS.

Appendix 18 highlights that there is some variation in water saturation across the Unit, however it does not indicate an increase in water saturation downdip. As there are no wells within the Unit boundary that produced only water volumes, and there are no logs that definitively indicate an oil-water contact, it is suggested that any contact that may exist is beyond the Fairway Unit boundary. A similar observation can be made on the producing water cut map (Appendix 19).

Based on the information above, the Lodgepole Reservoir Section appears to be hydrocarbon-bearing down to the bottom seal (top of Cromer Shale Member) within the proposed Fairway Unit boundary. High water production over time in several downdip wells suggests the Lodgepole Reservoir Section is in a transition zone; or the possibility of a fracture network accessing an aquifer of moderate to strong drive. In either case, an oil-water contact cannot be observed via logs, core or production within the Unit boundary.

OOIP ESTIMATES

Total volumetric OOIP for the Lodgepole formation within the proposed Fairway area is calculated to be 10,532.4 e3m3 (66,279.2 Mbbl). Table 6 provides volumetric OOIP estimates on both an individual LSD and total Unit basis. The OOIP values were estimated using Tundra internally created maps. Average OOIP by individual LSD was determined to be 154.9 e3m3 (974.7 Mbbl).

OOIP values were calculated using the following volumetric equation:

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

or

$$OOIP = \frac{A * h * \phi * (1 - Sw)}{Boi} * 3.28084\frac{ft}{m} * 7{,}758.367\frac{bbl}{acre * ft} * \frac{1Mbbl}{1{,}000bbl}$$

where:

OOIP	= Original Oil in Place by LSD (sm3, stb)
A	= Area by LSD (m2, acre)
h * ϕ	= Net Pay * Porosity, or Phi * h (m, ft)
Sw	= Water Saturation (dec)
Boi	= Initial Oil Formation Volume Factor (rm3/sm3, rb/stb)

OOIP values were calculated based on compiling log and core data as described in the previous geology section. Gille Montsion provided petrophysical expertise and performed advanced petrophysical analysis on every well in the Unit boundary. Gille has over 20 years of experience as a senior petrophysicist with Canadian Hunter, ConocoPhillips, and Nexen. OOIP values were estimated and vetted by Eva Drivet, P. Geol.; Kerri McNeil, P. Geol.; and Justin Robertson, P. Eng.; three senior professionals in good standing who combined have over 50 years of industry experience in the WCSB. Phi*h values were hand-contoured on maps, digitized and imported into Petra. Average phi-h values by drilling spacing unit or LSD were then exported into Excel for calculations of OOIP to be carried out. Water saturation was treated as a constant value, as outlined previously in the geology section of this application. The oil formation volume factor was estimated to be 1.11sm3/rm3 and treated equally for all OOIP calculations by tract. The OOIP calculations in Excel were carried out by Justin Robertson, P. Eng.

A listing of the Lodgepole formation rock and fluid properties used to characterize the reservoir are provided in Table 1.

The following maps provided support for OOIP estimation by LSD:

- Top Lodgepole to Top Cromer Shale Isopach (m), Appendix 9.
- Top Lodgepole Reservoir Structure (subsea TVD, m), Appendix 10.
- Bottom Lodgepole Reservoir Structure (subsea TVD, m), Appendix 11.
- Lodgepole Net Reservoir Isopach (m), Appendix 12.
- Lodgepole Reservoir Phi Map (m), Appendix 13.
- Lodgepole Phi-h, Appendix 14.
- Lodgepole K-h, Appendix 15.
- Top Lodgepole Structural Map (subsea TVD, m), Appendix 16.
- Lodgepole Salinity Map (ppm), Appendix 17.
- Water Saturation Map, Appendix 18.
- Water Cut Map, Lodgepole Formation, data averaged over the first 12 months of production, Appendix 19.

Historical Production

A historical group production history plot for the proposed Daly Unit No. 12 is shown in Figure 4. Oil production commenced in the proposed Unit area in August 1952 and peaked during November 1954 at 55.6 m3 (350.0 bbl) OPD. As of December 2014, average production was 7.2 m3 (45.1 bbl) OPD and 19.3 m3 (121.3 bbl) WPD for a 75.7% WCUT.

Oil production is currently declining at an annual rate of approximately 5.8% under the current Primary Production method.

The remainder of the field's production and decline rates indicate the need for pressure restoration and maintenance. Waterflooding is deemed to be the most efficient means of secondary recovery to introduce energy back into the system and provide areal sweep between wells.

Reserves Recovery Profiles and Production Forecasts

Primary performance forecasts for the proposed Daly Unit No. 12 are based on oil production decline curve analysis, and secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Based on the geological descriptions, primary production decline rate, and positive Lodgepole waterflood response in the adjacent analog Daly Unit Nos. 1, 3, and 4, the Lodgepole formation in the project area is deemed to be a suitable target for waterflood EOR operations.

Primary Production Forecast

Cumulative production to the end of December 31st, 2014 from the 50 Lodgepole wells within the proposed Daly Unit No. 12 project area is 207.2 e3m3 (1,303.8 Mbbl) of oil and 676.8 e3m3 (4,258.8 Mbbl) of water, representing a recovery factor 2.0% of the total OOIP recovered to date.

Based on decline curve analysis of the wells currently on production, the estimated ultimate recovery (EUR) for the proposed Unit with no further development is estimated to be 240.4 e3m3 (1,512.8 Mbbl), representing a recovery factor of 2.3% of the total OOIP.

Production plots of the forecasted base and waterflood oil rate v. time and oil rate v. cumulative oil produced are shown in Figures 5A, 5B, 6A & 6B, respectively.

Secondary EOR Production

The proposed project oil production profile under Secondary Waterflood has been developed based on the response observed to date in the analog offset Daly Unit Nos. 1, 3, & 4. Of particular note, in the mid-1970's Chevron successfully implemented a pilot waterflood focused in SE03-010-28W1, within the proposed Unit boundary. The pilot targeted the Lodgepole reservoir via an inverted 5-spot vertical pattern flood, whereby the 100/01-03-010-28W1 vertical was converted to injection to flood the offsetting 4 vertical producers. It appears the flood was successful in arresting decline rates and improving the overall recovery of the Lodgepole reservoir in this area (Figure 9).

Based on log cross-sections and core data, the Lodgepole Reservoir Section is laterally continuous in the proposed Fairway area. As a result, it is thought that decent areal sweep and efficiency will be attained under waterflood.

The proposed Daly Unit No. 12 Secondary Waterflood oil production forecast over time is plotted on Figure 7. Total recoverable oil associated with the project under secondary waterflood is estimated to be 659.1 e3m3 (4,147.3 Mbbl), resulting in a 6.3**%** overall recovery factor of total OOIP.

An incremental 451.9 e3m3 (2,843.5 Mbbl) of oil is forecast to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method. This relates to an incremental 4.0% recovery factor as a result of secondary EOR implementation.

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 12 Lodgepole project are based on internal engineering assessments. Project area specific reservoir and geological parameters were used to guide the overall Secondary Waterflood recovery factor. Historical performance of heritage waterfloods in Daly Unit Nos. 1, 3 & 4 also provided an upper bound for potential.

Internal reviews included detailed analysis of all available open-hole logs; core data; petrophysics; seismic; drilling information; completion information; and production information. Including the data methodology as described in the geology section, the above data was then used to develop a suite of maps and establish reservoir parameters to support the calculation of Fairway OOIP (Table 6).

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecast to increase the overall recovery of OOIP from the proposed project area by 4.0%. The basis for unitization is to develop the lands in an effective and responsible manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have a higher recovery of oil by allowing the development of additional drilling and injector conversions over time. In addition, Unitizing will facilitate a pressure maintenance scheme, and overall will increase oil production over time.

Unit Name

Tundra proposes that the official name of the new Unit shall be Daly Unit No. 12 (Fairway).

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for the Daly Unit No. 12.

Unitized Zone

The unitized zone to be waterflooded in Daly Unit No. 12 will be the Lodgepole formation.

Unit Wells

The wells to be included in the proposed Daly Unit No. 12 are outlined in Table 3 with a listing of their current status. A proposed development plan is included in Figures 7A & 7B, with the timing of the development plan activity provided in Table 4.

Unit Lands

The Daly Unit No. 12 will consist of 68 LSDs as follows:

- LSD's 4 & 5 of Section 25 of Township 009, Range 28, W1M
- S ½ & NW ¼ of Section 26 of Township 009, Range 28, W1M
- SW ¼ and LSD's 1, 2, 12 & 13 of Section 27 of Township 009, Range 28, W1M
- N ½ of Section 28 of Township 009, Range 28, W1M
- LSD's 09 & 16 of Section 29 of Township 009, Range 28, W1M
- S ½ and NE ¼ of Section 33 of Township 009, Range 28, W1M
- NW ¼ and LSD's 4, 5, 10, 15 & 16 of Section 34 of Township 009, Range 28, W1M
- S ½ & NE ¼ of Section 03 of Township 010, Range 28, W1M
- LSD's 1, 7 & 8 of Section 04 of township 010, Range 28, W1M

The lands included in the 40 acre tracts are outlined in Table 5.

Tract Factors

The proposed Daly Unit No. 12 will consist of 68 Tracts, based on the 40 acre Legal Sub Divisions (LSD) within the proposed Unit boundary.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 12 was calculated as follows:

- OOIP by LSD, minus cumulative production to date for the LSD as distributed by the LSD specific Production Allocation (PA) % in the applicable producing horizontal or vertical well (to yield Remaining OOIP)
- Tract Factor by LSD = The product of Remaining OOIP by LSD as a % of total proposed Unit Remaining OOIP

Tract Factor calculations for individual LSD's based on the above methodology are outlined within Table 5.

Working Interest Owners

Table 5 outlines the working interest (WI) for each recommended Tract within the proposed Daly Unit No. 12.

Tundra Oil and Gas Partnership will have a 100% working interest in the proposed Daly Unit No. 12.

WATERFLOOD EOR DEVELOPMENT

Two horizontal wells were recently drilled in the S ½ Sec26-009-28 targeting the Lodgepole formation. Where there are existing undrilled DSU's, plans are to drill infill 40 acre verticals. Additional E-W horizontals will be drilled between existing rows of vertical wells, resulting in an effective 20 acre spacing over the Unit area. Every second horizontal will then be converted to water injection service after a period of production (expected 2-3 years after each well's first production).

Tundra will cease production from commingled Bakken-Lodgepole wells in the Fairway area, of which there are 3, after the effective date of the Unit is determined and prior to first water being injected.

WATERFLOOD OPERATING STRATEGY

Water Source and Injection Wells

The injection water for the proposed Daly Unit No. 12 will be supplied from the existing source and injection water system at the Sinclair 3-4-8-29 Battery. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-007-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Daly Sinclair water injection system and new pipeline connection to the proposed Daly Unit No. 12 project area is shown as Figure 8.

Produced water is not currently used for any water injection in the Tundra-operated Daly Sinclair Units and there are no current plans to use produced water as a source supply for Daly Unit No. 12.

The new future water injection wells for the proposed Daly Unit No. 12 will be drilled, cleaned out, and configured downhole for injection as shown in Appendix 23. Plans are for the injection wells to be cemented liner horizontals, stimulated via multiple hydraulic fracture treatments to obtain suitable injection rates. Tundra has extensive experience with horizontal fracturing in the area, and all jobs are rigorously programmed and monitored during execution. This helps ensure optimum placement of each fracture stage to prevent, or minimize, the potential for out-of-zone fracture growth thereby limiting the potential for future out-of-zone injection.

The new water injection wells will be placed on injection after a pre-production period and approval to inject. Wellhead injection pressures will be maintained below the least value of either:

1. the area-specific known and calculated fracture gradient, or
2. the licensed surface injection Maximum Allowable Pressure (MOP)

Tundra has a thorough understanding of area fracture gradients. A management program will be implemented to set and routinely review injection target rates and pressures vs. surface MOP and the known area formation fracture pressures.

All new water injection wells will be surface equipped with injection volume metering and rate/pressure controls. An operating procedure for monitoring water injection volumes and meter balancing will also be utilized to monitor the entire system measurement and integrity on a daily basis.

The proposed Daly Unit No. 12 horizontal water injection well rate is forecasted to average 10 – 30 m^3 WPD, based on expected reservoir permeability and pressure.

<u>Estimated Fracture Pressure</u>

The fracture pressure for the Lodgepole reservoir is estimated to be 23.9 MPa.

<u>Reservoir Pressure</u>

No representative initial pressure surveys are available for the proposed Daly Unit No. 12 project area in the Lodgepole producing zone. The extremely long shut-in and build-up times required to obtain a possible representative reservoir pressures are economically prohibitive. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection wells during the completion of the wells and prior to injection or production.

Tundra expects to inject water for a minimum 2 to 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion to date. The Instantaneous Voidage Replacement Ratio (IVRR) is expected to be approximately 1.25 to 1.75 within the pattern during the fill-up period. As the cumulative voidage replacement ratio (VRR) approaches 1, target reservoir operating pressure for waterflood operations will be 75 – 90 % of original reservoir pressure.

Waterflood Surveillance and Optimization

Daly Unit No. 12 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring v. target
- Water injection rate / pressure / time vs cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern IVRR and VRR
- Potential use of chemical tracers to track water injector / producer responses
- Use of some or all of: Water Oil Ratio (WOR) trends, Log WOR vs Cum Oil, Hydrocarbon Pore Volumes Injected, Conformance Plots
- Sulfur content and oil density testing

The above surveillance methods will provide an ever-increasing understanding of reservoir performance, and provide data to continually control and optimize the Daly Unit No. 12 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling or water breakthrough, or out-of-Unit migration. The monitoring and surveillance will also provide early indicators of any such issues so that waterflood operations may be altered to maximize ultimate secondary reserves recovery from the proposed Daly Unit No. 12.

Economic Limit / Justification

Due to the initial high capital investment, Tundra does not expect the project to be economic in the short-term using current oil price decks. However, if technically successful, this project will enhance the oil recovery and help prove up the area for EOR developments in the Lodgepole reservoir.

Water Injection Facilities

The Daly Unit No. 12 waterflood operation will utilize the existing Tundra-operated source well supply and water plant (WP) facilities located at the 3-4-8-29 W1M Battery. Injection wells will be connected to the existing high pressure water pipeline system supplying other Tundra-operated Waterflood Units.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown on Appendix 22.

Notification of Mineral and Surface Rights Owners

Tundra will notify all mineral rights and surface rights owners of the proposed EOR project and formation of Daly Unit No. 12. Copies of the Notices, and proof of service, to all surface rights owners will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 12 Application.

Daly Unit No. 12 Unitization, and execution of the formal Daly Unit No. 12 Agreement by affected Mineral Owners, is expected during Q2 2015. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 12 Application.

Should the Petroleum Branch have further questions or require more information, please contact Justin Robertson, P. Eng at 403.513.1024 or by email at Justin.Robertson@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Justin Robertson, P. Eng March 31st, 2015, in Calgary, AB

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