PROPOSED EWART UNIT NO. 10

Application for Enhanced Oil Recovery Waterflood Project

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

August 14, 2015
Tundra Oil and Gas Partnership

INTRODUCTION

The Sinclair portion of the Daly Sinclair Oil Field is located in Ranges 28 and 29 W1 in Townships 7 and 8. Since discovery in 2004, the main oilfield area was developed with vertical and horizontal wells at 40 acre spacing on Primary Production. Since early 2009, a significant portion of the main oilfield has been unitized and placed on Secondary Waterflood (WF) Enhanced Oil Recovery (EOR) Production, mainly from the Lyleton A & B members of the Three Forks Formation. Tundra Oil and Gas (Tundra) currently operates and continues to develop Sinclair Units 1-3, 5-8, 10-13 and Ewart Units 1-8 as shown on Figure 1.

In the eastern part of the Sinclair field, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. The following represents an application by Tundra to establish Ewart Unit No. 10 (LSDs 13-16 Section 27, N/2 Section 28, Sections 32, 33, 34-7-28W1, SW/4 Section 3, S/2 Section 4, SE/4 Section 5-8-28W1) and implement a Secondary Waterflood EOR scheme within the Three Forks and Middle Bakken formations as outlined on Figure 2.

The proposed project area falls within the existing designated 01-62B Bakken-Three Forks B Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Ewart Unit No. 10 will include 21 horizontal wells and 8 vertical wells, within 76 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located north of Ewart Units No. 2, 6 and 8 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Ewart Unit No. 10 has been calculated to be **2,655** e^3m^3 (**16,702** Mbbl) for an average of **34.9** net e^3m^3 **(219.5** Mbbl) OOIP per 40 acre LSD based on a 0.5 md cutoff for the Middle Bakken & Lyleton 'B' and a 1.0 md cutoff for the Upper & Lower Lyleton 'A'.

3. Cumulative production to the end of May 2015 from the 29 wells within the proposed Ewart Unit No. 10 project area was 98.8 e^3m^3 (621.9 Mbbl) of oil, and 444.2 e^3m^3 (2795.3 Mbbl) of water, representing a **3.7%** Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Ewart Unit No. 10 project area has been calculated to be **125.8** e^3m^3 (**791.6** Mbbl), with **27.0** e^3m^3 (**169.8** Mbbl) remaining as of the end of May 2015.

5. Ultimate oil recovery of the proposed Ewart Unit No. 10 OOIP, under the current Primary Production method, is forecasted to be **4.4%**.

6. Figure 4 shows the production from the Ewart Unit No. 10 peaked in October 2010 at 120.2 m^3 (OPD). As of May 2015, production was 10.1 m^3 OPD, 48.4 m^3 of water per day (WPD) and an 82.7% watercut.

7. In October 2010, production averaged 4.8 m^3 OPD per well in Ewart Unit No. 10. As of May 2015, average per well production has declined to 0.53 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **25.0%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Ewart Unit No. 10 has been calculated to be **181.7** e^3m^3 **(1,143.2** Mbbl), with **82.9** e^3m^3 (**521.4** Mbbl) remaining. An incremental **55.9** e^3m^3 **(352.2** Mbbl) of proved oil reserves, or **2.0%**, are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

9. Total RF under Secondary WF in the proposed Ewart Unit No. 10 is estimated to be **6.4%**.

10. Based on waterflood response in the adjacent main portion of the Sinclair field, the Three Forks and Middle Bakken Formations in the proposed project area are believed to be suitable reservoirs for WF EOR operations.

11. Existing horizontal wells, with multi-stage hydraulic fractures, will be converted to injection wells (Figure 5) within the proposed Ewart Unit No. 10, to complete waterflood patterns with effective 40 acre spacing similar to that of Ewart Unit No. 6.

DISCUSSION

The proposed Ewart Unit No. 10 project area is located within Townships 7-8, Range 28 W1 of the Daly Sinclair oil field. The proposed Ewart Unit No. 10 currently consists of 21 horizontal and 8 vertical wells, within an area covering 76 LSDs (Figure 2). A project area well list complete with recent production statistics is attached as Table 3.

Tundra believes that the waterflood response in the adjacent main portion of the Sinclair field demonstrates potential for incremental production and reserves from a WF EOR project in the subject Middle Bakken and/or Three Forks oil reservoirs.

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section attached as Appendix 1. The section runs W to E through the proposed Unit area. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton A Siltstone (broken into Upper and Lower members), the Red Shale Marker, Lyleton B Siltstone and the Torquay silty shale. The reservoir units are represented by the Middle Bakken, Lyleton A and Lyleton B Siltstones. The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken/Lyleton B reservoirs. The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved adjacent to the proposed unit (Sinclair Unit 2, Sinclair Unit 12, Ewart Unit 2 and Ewart Unit 6) as noted on the Offsetting Units Map at Appendix 2.

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to fine sandstone which may be subdivided on the basis of lithologic characteristics into upper and lower units. The upper portion is very often heavily bioturbated and is generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of well-worn brachiopod, coral and occasional crinoid fragments suggesting deposition in a marginal marine environment. The lower part of the Middle Bakken is generally finely laminated with alternating light and dark laminations with occasional bioturbation. Reservoir quality is highly variable within the Unit area. Within the proposed unit, the Middle Bakken ranges from about 1.0m in the Northwest to just over 4.0m in the Southeast (Appendix 4).

The Lyleton A reservoir within the proposed unit area consists of buff to tan medium to coarse siltstone (occasionally fine sandstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. Clays do not generally occur as pore filling material, but rather as discrete grains within the siltstone. The Upper part is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones are interbedded with finer grained grey-green siltstone similar in composition to the reservoir siltstone, but generally with lower permeability (i.e. < 0.1mD). These finer grained siltstones show evidence of haloturbation producing smeared siltstone clasts floating in a fine grained grey-green siltstone matrix. The lower part of the Lyleton A generally shows a greater proportion of the grey-green fine-grained siltstone than the Upper and is generally a poorer reservoir. It also tends to exhibit greater amounts of haloturbation and pseudo-breccia of siltstone clasts in a finer grained siltstone matrix. Because of the fine grained matrix in this pseudo-breccia the connectivity between the clasts is much lower than the bedded siltstone and the Lower part of the Lyleton A is generally a poorer reservoir than the Upper part of the Lyleton A. Within the proposed unit area, the Upper Lyleton A has a limited occurrence in that it pinches out near the Western and Northern boundaries of the proposed unit (Appendix 5). The Lower Lyleton A pinches out just slightly East of the Upper Lyleton A, and as such, has a greater presence in the proposed unit, but has been eroded away in the East portion (Appendix 6).

The Red Shale Marker can form an aquitard between the overlying Middle Bakken / Lyleton A and the underlying Lyleton B reservoir. It consists of brick red dolomitic siltstone which is highly water soluble. The Red Shale Marker is about 3.5m thick on the West side and pinches to 0m in the East of the proposed unit (Appendix 7). The effectiveness of the Red Shale Marker unit as a permeability barrier is reduced from West to East across the proposed unit area in direct correlation with the reduction in thickness of the Red Shale. As such, over most of the Eastern half of the proposed unit, the Red Shale Marker is most likely not an effective barrier to flow between the Middle Bakken and the Lyleton B.

The Lyleton B reservoir consists of buff to tan fine grained siltstone (occasionally very fine siltstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. The Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones are interbedded with dark grey-green very fine grained siltstone which is generally non-reservoir. The Lyleton B is 4.0-5.0m thick within the proposed unit where the Red Shale exists and thins to 3.0m by the edge of the Eastern unit boundary (Appendix 8).

The Torquay (Three Forks) forms the base of the reservoir sequence and is a brick red or mint green dolomitic very fine siltstone similar to the Red Shale Marker and it forms a good basal seal to the Lyleton B reservoir (Appendix 9).

Structure:

Structure contour maps are provided for the top of each major unit (Appendices 10 through 16). The structure within the proposed unit area generally consists of an overall dip to the South. Structural variations in the area are interpreted as being caused by dissolution of the underlying Prairie Evaporites. Structural variations cause by dissolution are common in the Sinclair Field but do not appear to represent continuous barriers to lateral fluid flow within the reservoir as they do not appear to interrupt the lateral continuity of the reservoir beds (see Cross-Section Appendix 1).

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood. As demonstrated by the cross-section (Appendix 1) and the isopach maps, the lateral continuity of the Middle Bakken / Lyleton A reservoir within the proposed unit is very good in the Western 2/3 of the proposed unit.

Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir is also good in LSDs 15-27-07-28W1 and 04-34-07-28W1 where they are in direct contact. There is no evidence that the contact between the two units will reduce flow between the two zones. The only possible break in vertical continuity between the Middle Bakken and Lyleton B would be in the Western 2/3 of the proposed unit from the presence of the Red Shale between these zones. Any planned injection wells will be completed with multi stage fracture treatments and as such, vertical communication across the less than 1m thick Red Shale is anticipated.

Reservoir Quality:

Permeability (k-h in mD*m) and porosity (Phi-h in por*m) maps for all four reservoir units are provided (Appendix 17 through 24). These maps are generated using core data and are generated as follows. First the core is divided into the reservoir units present. This data is then subject to a permeability cutoff. Intervals that meet or exceed the cutoff are multiplied by the interval thickness and then summed to get the total value for the Phi-h or k-h for that particular reservoir unit. The value of the permeability cutoffs for each formation are the same values used by GLJ for third party reserve evaluations on Tundra's Sinclair properties. The permeability cutoffs applied are as follows:

- Middle Bakken = 0.5 md
- Upper Lyleton A = 1.0 md
- Lower Lyleton A = 1.0 md
- Lyleton B = 0.5 md

As can be noted from the Phi-h and k-h maps the bulk of the reservoir in the proposed unit is contained in the Middle Bakken and Lyleton B formations. It is important to note that the 0.5 md cutoff effectively ignores pore volume with permeability between 0.2 and 0.49 md that may contain moveable oil.

Fluid Contacts:

The oil/water contact for the Middle Bakken and Lyleton reservoir is estimated from production to be at about -525 m subsea. In tight reservoirs such as these the transition zone could be considerable and the top of the transition zone is estimated to be at about -490 m subsea based on production and simulation studies of the reservoir. The postulated oil/water contact at -525 m subsea is below the lowest contour on any of the attached structure contour maps.

Gross OOIP Estimates

OOIP were calculated by Tundra Chief Geologists Barry Larson. Barry hold a BSc. in Geology from the U of S, and has 35 years of industry experience, 19 of which are in the Williston Basin. The dataset used to determine the OOIP values for Ewart Unit No. 10 was originally compiled by Barry Larson. It consists of conventional core analysis of all available core in the Sinclair area.

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **2,655** e^3m^3 (**16,702** Mbbl) using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the Sinclair area (Appendix 25).

Net pay for each cored well is calculated using the formation specific permeability cut off discussed above. Representative intervals that had a measured permeability greater than the formation specific cutoff were considered pay. The weighted average porosity (phi) of all pay intervals for each formation was calculated for each cored well. The height of pay (h) was derived by summing the heights of each representative sample that met the permeability cut off. From these two parameters, a phi*h value was calculated for all four productive horizons in all wells with core over each respective formation.

The phi*h values for all cored wells were contoured using Golden Software's "Surfer 9" program using a 500 m grid node spacing. Phi*h values for each LSD were calculated off the associated Surfer 9 grid by determining the values at the center of each LSD.

Tabulated parameters for each LSD from the calculations can be found in Table 2.

OOIP values were calculated using the following volumetric equation:

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

or

$$OOIP(m3) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * \frac{10{,}000m2}{ha}$$

or

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

where

OOIP	= Original Oil in Place by LSD (Mbbl, or m3)
A	= Area (40acres, or 16.187 hectares, per LSD)
h * Ø	= Net Pay * Porosity, or Phi * h (ft, or m)
Bo	= Formation Volume Factor of Oil (stb/rb, or sm3/rm3)
Sw	= Water Saturation (decimal)

The initial oil formation volume factor was adopted from a PVT taken from the 3-3-8-29 Sinclair Bakken well, thought to be representative of the fluid characteristics in the reservoir.

Table 4 outlines the proposed Ewart Unit No. 10 volumetric OOIP estimates on an individual LSD basis by formation. Average OOIP by individual LSD was determined to be **34.9 e^3m^3** for Ewart Unit No. 10.

A complete listing of Middle Bakken/Three Forks formation rock and fluid properties used to characterize the reservoir are provided in Table 5.

Historical Production

A historical group production history plot for the proposed Ewart Unit No. 10 is shown as Figure 4. Oil production commenced from the proposed Unit area in March 2005 and peaked during October 2010 at 120.2 m^3 OPD. As of May 2015, production was 10.1 m^3 OPD, 48.4 m^3 WPD and an 82.7% watercut.

From peak production in October 2010 to date, oil production is declining at an annual rate of approximately **25.0%** 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.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area.

Unit Name

Tundra proposes that the official name of the new Unit shall be Ewart Unit No. 10.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Ewart Unit No. 10.

Unitized Zone

The Unitized zone(s) to be waterflooded in the Ewart Unit No. 10 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 21 horizontal wells and 8 vertical wells to be included in the proposed Ewart Unit No. 10 are outlined in Table 3.

Unit Lands

The Ewart Unit No. 10 will consist of 76 LSDs as follows:

> LSDs 13-16 Section 27 of Township 7, Range 28, W1M
> N/2 Section 28 of Township 7, Range 28, W1M
> Section 32 of Township 7, Range 28, W1M
> Section 33 of Township 7, Range 28, W1M
> Section 34 of Township 7, Range 28, W1M
> SW/4 Section 3 of Township 8, Range 28, W1M
> S/2 Section 4 of Township 8, Range 28, W1M
> SE/4 Section 5 of Township 8, Range 28, W1M

The lands included in the 40 acre tracts are outlined in Table 1.

Tract Factors

The proposed Ewart Unit No. 10 will consist of 76 Tracts based on the 40 acre LSDs containing the existing 21 horizontal and 8 vertical wells.

The Tract Factor contribution for each of the LSD's within the proposed Ewart Unit No. 10 was calculated as follows:

- Gross 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 Gross OOIP)
- Tract Factor by LSD = the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP

Tract Factor calculations for all individual LSDs based on the above methodology are outlined within Table 2.

Working Interest Owners

Table 1 outlines the working interest (WI) for each recommended Tract within the proposed Ewart Unit No. 10. Tundra Oil and Gas Partnership holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Partnership will have a 100% WI in the proposed Ewart Unit No. 10.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Ewart Unit No. 10 Bakken project are based on internal engineering assessments. Project area specific reservoir and geological parameters were utilized and then compared to Sinclair Unit No. 1 parameters, yielding the WF EOR response observed there to date.

As Tundra has a direct comparison of waterflood performance in Sinclair Unit 1, Tundra does not feel it is crucial to construct a simulation model for this area.

Pre-Production of New Horizontal Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Ewart Unit No. 10 has declined significantly from peak rate indicating a need for secondary pressure support. It is anticipated that nine of the existing producing horizontal wells will be converted to horizontal injection wells upon approval as shown in Figure 5. This will result in effective 40 acre waterflood patterns within Ewart Unit No. 10. Since the proposed horizontal injection wells have already been on production for a period of time there will not be a need for an additional pre-production period within this unit.

Tundra monitors reservoir pressure, fluid production and decline rates in each pattern to determine when the well will be converted to water injection.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Ewart Unit No. 10 are based on oil production decline curve analysis, and the secondary predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Primary Production Forecast

Cumulative production in the Ewart Unit No. 10 project area, to the end of May 2015 from 29 wells, was 98.8 e^3m^3 of oil and 444.2 e^3m^3 of water for a recovery factor of **3.7%** of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Ewart Unit No. 10 has been estimated to be **125.8** e^3m^3, or a **4.4**% Recovery Factor (RF) of OOIP. Remaining Producing Primary Reserves has been estimated to be **27.0** e^3m^3 to the end of May 2015.

The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 7a and 7b.

Pre-Production Schedule/Timing for Conversion of Horizontal Wells to Water Injection

Tundra will plan an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Ewart Unit No. 10, while maximizing reservoir knowledge.

Criteria for Conversion to Water Injection Well

Nine (9) water injection wells are required for this proposed unit as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for each individual horizontal well to be converted from primary production to water injection service.

- Measured reservoir pressures at start of and/or through primary production
- Fluid production rates and any changes in decline rate
- Any observed production interference effects with adjacent vertical and horizontal wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

The above schedule allows for the proposed Ewart Unit No. 10 project to be developed equitably, efficiently, and moves to project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production vs. cumulative oil are plotted in Figures 8a and 8b, respectively. Total Secondary EUR for the proposed Ewart Unit No. 10 is estimated to be **181.7** e^3m^3 with **82.9** e^3m^3 remaining representing a total secondary recovery factor of **6.4%** for the proposed Unit area. An incremental **55.9** e^3m^3 of oil, or an incremental **2.0%** recovery factor, are forecasted to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method.

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate an actual fracture pressure gradient range of 18.0 to 22.0 kPa/m true vertical depth (TVD).

WATERFLOOD OPERATING STRATEGY

Water Source

The injection water for the proposed Ewart Unit No. 10 will be supplied from the existing Sinclair 3-4-8-29W1 Battery source and injection water system. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-7-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Sinclair Units Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Sinclair water injection system and new pipeline connection to the proposed Ewart Unit No. 10 project area injection wells is shown as Figures 9-10.

Produced water is not currently used for any water injection in the Tundra operated Sinclair Units and there are no current plans to use produced water as a source supply for Ewart Unit No. 10.

Since all producing Middle Bakken/Three Forks wells in the Daly Sinclair areas, whether vertical or horizontal, have been hydraulically fractured, produced waters from these wells are inherently a mixture of Three Forks and Bakken native sources. This mixture of produced waters has been extensively tested for compatibility with 102/16-32 source Lodgepole water, by a highly qualified third party, prior to implementation by Tundra in Sinclair Unit 1. All potential mixture ratios between the two waters, under a range of temperatures, have been simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors has also been conducted and minimum inhibition concentration requirements for the source water volume determined. At present, continuous scale inhibitor application is maintained into the source water stream out of the Sinclair injection water facility. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

Injection Wells

The water injection wells for the proposed Ewart Unit No. 10 have been drilled, are currently producing and plans are in progress to re-configure the wells for downhole injection after approval for waterflood has been received (Figure 11). The horizontal injection wells have been stimulated by multiple hydraulic fracture treatments to obtain suitable injection. 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 and thereby limit the potential for future out-of-zone injection.

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

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

Tundra has a thorough understanding of area fracture gradients. A management program will be utilized 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 are surface equipped with injection volume metering and rate/pressure control. 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 Ewart Unit No. 10 horizontal water injection well rate is forecasted to average **10 – 40** m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Ewart Unit No. 10 project area in the Bakken producing zone. The extremely long shut-in and build-up times required to obtain a possible representative reservoir pressures were economically prohibitive at the time of drilling these locations.

Reservoir Pressure Management during Waterflood

Tundra expects it will take 2-4 years to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial monthly Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 2.00 within the patterns during the fill up period. As the cumulative VRR approaches 1, target reservoir operating pressure for waterflood operations will be 75-90% of original reservoir pressure.

Waterflood Surveillance and Optimization

Ewart Unit No. 10 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring vs target
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern 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

The above surveillance methods will provide an ever increasing understanding of reservoir performance, and provide data to continually control and optimize the Ewart Unit No. 10 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 Ewart Unit No. 10.

On Going Reservoir Pressure Surveys

Any pressures taken during the operation of the proposed unit will be reported within the Annual Progress Reports for Ewart Unit No. 10 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Ewart Unit No. 10 will be deemed uneconomic when the net oil rate and net oil price revenue stream becomes less than the current producing operating costs. With any positive oil production response under the proposed Secondary recovery method, the economic limit will be significantly pushed out into the future. The actual economic cut off point will then again be a function of net oil price, the magnitude and duration of production rate response to the waterflood, and then current operating costs. Waterflood projects generally become uneconomic to operate when Water Oil Ratios (WOR's) exceed 100.

WATER INJECTION FACILITIES

The Ewart Unit No. 10 waterflood operation will utilize the existing Tundra operated source well supply and water plant (WP) facilities located at 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 in Figure 12.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of this proposed EOR project and formation of Ewart Unit No. 10. Copies of the notices and proof of service, to all surface and mineral rights owners will be forwarded to the Petroleum Branch when available to complete the Ewart Unit No. 10 Application.

Ewart Unit No. 10 Unitization, and execution of the formal Ewart Unit No. 10 Agreement by affected Mineral Owners, is expected during Q3 2015. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Ewart Unit No. 10 Application.

Should the Petroleum Branch have further questions or require more information, please contact Abhy Pandey at 403.767.1247 or by email at abhy.pandey@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Abhy Pandey, August 14, 2015, in Calgary, AB