PROPOSED KOLA UNIT NO. 3

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (62A)

Daly, Manitoba

June 18th, 2013
Tundra Oil and Gas Partnership

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INTRODUCTION

The Kola Units No. 1 and No. 2, located in Township 10 Range 29 west of the prime meridian, first produced in October 1985 (Figure 1). The main production targets in the units are the Middle Bakken and Three Forks A pools.

For the lands adjacent to Kola Unit No. 1 and Kola Unit No. 2, 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 Oil and Gas Partnership (Tundra) to establish Kola Unit No. 3 (LSD's 7-10, 14-16 Sec 28-10-29W1) (KU3) 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 01-62A Bakken-Three Forks A Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Kola Unit No. 3 will include 2 producing wells within 7 Legal Sub Divisions (LSD's) of the Middle Bakken/Three Forks producing reservoir. The project is located east of Kola Unit No. 1 and south of Kola Unit No. 2 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Kola Unit No. 3 has been calculated to be 340.6 E^3m^3 for an average of 48.5 net E^3m^3 OOIP per 40 acre LSD.

3. Cumulative production to the end March 2013 from the 2 productive wells within the proposed Kola Unit No. 3 project area was 11.2 E^3m^3 of oil, and 41.5 E^3m^3 of water, representing a 3.3% Recovery Factor (RF) of the OOIP.

4. Estimated Ultimate Recovery (EUR) of current wells with Primary Proved Producing oil reserves in the proposed Kola Unit No. 3 project area is estimated to be 26.7 E^3m^3, with 15.5 E^3m^3 remaining as of the end of March 2013.

5. Ultimate oil recovery of the proposed Kola Unit No. 3 OOIP, under the current Primary Production method, is forecasted to be 7.8%.

6. Figure 4 shows the production from the Kola Unit No. 3 which peaked in August 1997 at 8.25 m^3 of oil per day (OPD). As of February 2013, production was 0.63 m^3 OPD, 4.68 m^3 of water per day (WPD) and an 88.1% watercut.

7. In August 1997, production averaged 4.12 m^3 OPD per well in Kola Unit No. 3. As of March 2013, average per well production has declined to 0.32 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 25% in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Kola Unit No. 3 has been calculated to be 106.9 E^3m^3, with 95.7 E^3m^3 remaining. An incremental 80.2 E^3m^3 of proved oil reserves, or 23.5%, are forecasted to be recovered under the proposed Unitization and Secondary EOR production versus the existing Primary Production method.

9. Total RF under Secondary WF in the proposed Kola Unit No. 3 is estimated to be 31.4%. Primary accounts for 7.8% and secondary for 23.6%.

10. Based on waterflood response in the adjacent existing Kola Units Nos. 1 & 2, the Three Forks and Middle Bakken Formations in the proposed project area are believed to be suitable reservoirs for WF EOR operations.

11. Future horizontal injectors, potentially left openhole or completed with multi-stage hydraulic fractures, will be drilled in the proposed Unit (Figure 7), to complete waterflood patterns with alternating horizontal producers, for an effective 40 acre spacing, similar to that of Kola Unit No. 2.

TECHNICAL DISCUSSION

The proposed Kola Unit No. 3 project area is located within Section 28 in Township 10, Range 29 W1 of the Daly Sinclair oil field. The proposed Kola Unit No. 3 currently consists of 2 producing vertical wells within an area covering LSD's 7-10, 14-16 in Section 28-10-29W1 (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 existing Kola Units Nos. 1 and 2 demonstrates potential for incremental production and reserves from a WF EOR project in the subject Middle Bakken and/or Three Forks oil reservoirs in the proposed Kola Unit No. 3.

Geology

Stratigraphy

The stratigraphy of the reservoir section of the proposed Kola Unit No. 3 is shown on the stratigraphic cross section A – A' attached as Appendix 1. Cross-section A – A' spans northwest to southeast and centers on Kola Unit No. 3. The producing sequence seen in the cross-section from youngest to oldest is: the Upper Bakken Shale, the Middle Bakken fine grained sand/siltstone, the Lyleton Shale (not seen in the cross section), the Lyleton B siltstone, and the Lyleton C silty shale. The Lyleton Shale sub-crops west of the unit and the Middle Bakken directly overlies the Lyleton B in the unit. There is an angular unconformity between the Mississippian Middle Bakken and Devonian Lyleton (or Three Forks) units – where the Lyleton sequence thins from west to east.

The main productive zone is considered to be the Middle Bakken and there may be some contribution of oil from the underlying upper Lyleton 'B' reservoir when present. The overlying Upper Bakken Shale forms a top seal for the Bakken and Lyleton sequence and is 3 to 3.5m thick, composed of black, platy, organics – rich shale. The underlying upper Lyleton B reservoir appears to sub-crop in proposed Kola Unit No. 3 (Refer to Appendix 2 for the Kola Three Forks Sub-crop Edges map).

Sedimentology

The Middle Bakken reservoir consists of fine to coarse grained siltstone to sandstone (often tan colored when oil stained). It can be divided into two units – the upper Middle Bakken and the lower Middle Bakken. The upper Middle Bakken is mainly considered non–reservoir. It is composed of heavily bioturbated grey siltstone with small brachiopod shells and the occasional crinoid and coral fragments. Pyrite nodules are common. The environmental interpretation of the upper Middle Bakken is a marginal marine environment.

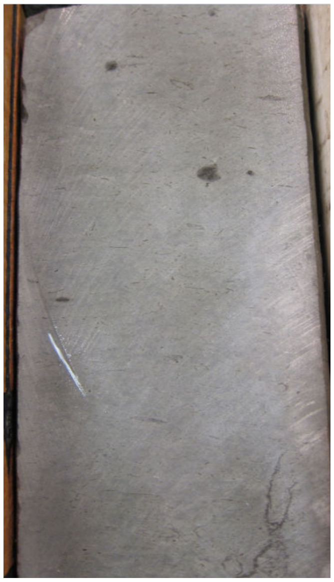

Figure 1: Photo of Upper Middle Bakken at 9-29-10-29W1

The lower Middle Bakken consists of finely laminated grey and tan colored siltstone and fine grained sandstone inter-beds with occasional bioturbation. Where there is a higher sand content, bioturbation is rare. The environmental interpretation of the lower Middle Bakken is of a low relief, dissipative shoreface/foreshore. This is the main reservoir unit. On logs it appears that in some portions of Kola there are two highly permeable and porous cycles. The lower cycle, when present, usually has the highest permeability and porosity (with some exceptions).

Figure 2: Lower Middle Bakken at 9-29-10-29W1


Figure 3: Lower Middle Bakken at 9-29-10-29W1

The Middle Bakken unconformity overlies the Lyleton B unit as the Lyleton wedges and becomes thinner eastwards. The upper Lyleton B reservoir unit is at the top and is composed of inter-bedded grey/green tight siltstones in between tan colored heterolithic, inter-bedded siltstone and fine grained sandstones that have the odd trace fossil and salt crystal casts. The sands within the Lyleton B often look deformed. The upper Lyleton B is interpreted to have been deposited in a brackish bay type environment.


Figure 4: Upper Lyleton 'B' Reservoir Sandstone/Siltstone in between tight grey siltstone beds

The mid to lower Lyleton B and underlying Lyleton C of the Three Forks Group are often called the 'Torquay' Formation. They are generally brick red, light green, and light brown and are mainly composed of very fine dolomitic siltstone and are considered non – reservoir. The lower Lyleton B and C are interpreted to have been deposited in a sabkha environment.

Structure

Appendix 3 is a Top Middle Bakken Subsea Structure map. No other structure maps are provided because the strata of the Upper Bakken Shale to the Three Forks succession layer cake over each other and there are no significant changes to the structural trend between the stratigraphic units. The Middle Bakken structure map integrates well control with proprietary 3-D seismic for greater accuracy.

The highest portion of the Kola pool is located in the northeast corner of the proposed Kola Unit No. 3 at about -319 to -318m subsea. Structure then drops to the north, east, west, and south. Regional dip is towards the southwest. The high is thought to be a result of post Three Forks dissolution of the underlying Prairie evaporates over Winnipegosis reefs leaving the remnant high. At the time of Bakken deposition the Kola Unit No. 3 area could have been relatively low leaving sufficient accommodation space for the well-developed lower Middle Bakken sands.

Reservoir Continuity

Appendix 1*:* Kola Cross Section A – A' and Appendix 4: Kola Middle Bakken Net Porous Sand > 12% Porosity (petro-physically defined) both show that there is good lateral continuity of the Middle Bakken reservoir over Kola Units 1 through proposed Kola Unit No. 3. Vertical continuity between the two lower Middle Bakken sands and the underlying Lyleton B reservoir are questionable but may be enhanced due to the nature of horizontal drilling and possible fracturing later on in the life cycle of the wellbores.

Reservoir Quality

The main reservoir in Kola Unit No. 3 is the Middle Bakken sand. Porosity (Phi – h in % porosity-m) and Permeability (K-h in mD-m) maps have been generated for the Middle Bakken and are attached as Appendices 6 and 7, respectively. The permeability values were defined by petrophysics, and the core kmax*h values are annotated on Appendix 7 in red. Appendix 5 shows the average porosity as defined by petrophysics. The porosity and permeability maps were generated based on a 12% limestone scale porosity cutoff and a 1mD permeability cutoff. The permeability was inferred from comparison with wells with core analysis and by using petrophysics. Petrophysical logs and spreadsheets are attached in Appendices 9 through 11*.* The intervals that exceeded the cutoffs were then multiplied by the interval thickness and then summed to get the Phi – h and K – h values. It should be noted that there may be moveable oil with permeability as low as 0.2 to 0.99 mD.

The underlying Lyleton B reservoir may contribute a little bit of oil but is less than 1m thick (with the exception of 2-28-10-29W1 at 1.8m thick) and has Kmax*h values surrounding Kola Unit No. 3 of less than 1mD-m. Lyleton B net pay and Kmax*h from core can be found in Appendix 8*.* The Lyleton B is likely thinner than mapped because it is difficult to directly evaluate on logs. Core analysis is the best way to evaluate the Lyleton B due to the thin reservoir units interbedded with the tight green siltstones not being resolved on logs. Evaluation is made more difficult because of the poor sample interval on most core in the pool. Pay was considered in the Lyleton B reservoir when the resistivity was greater than 2 ohm-m and there was either mud cake or an SP response. As such it has not been included in the reservoir or OOIP sections of this application.

Fluid Contacts

The oil/water contact for the Middle Bakken and Lyleton reservoir is estimated from production in the area to be at approximately -525m subsea structure, with a transition zone (due to the tight nature of the reservoir) up to -490m subsea. Both of these contacts are far south and west of the area mapped for this application. There may be some sort of a hydrodynamic barrier such as a fault or permeability barrier to the north, roughly at the Township 11 – Township 10 boundary based on the different behaviors and apparent oil/water contacts between Kola and the wells to the north in Kirkella.

OOIP Estimates

Total volumetric OOIP for the Middle Bakken within the proposed Kola Unit No. 3 has been calculated to be 340.6 E^3m^3 (2142.6 MSTB) using Tundra internally created maps. Net porous sandstone greater than 12% porosity was used as defined by petrophysics, and local core analysis shows that the majority of the Middle Bakken reservoir with porosity greater than 12% has greater than 1mD permeability in the pool. 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 16hectares, 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)

Volumetric inputs were estimated by Bill Clow, P. Eng, and Jennifer Tremblay, P. Geol., and technically vetted by Justin Robertson, P. Eng. Net pay (h) values were derived using petrophysics for Middle Bakken net sand greater than 12% porosity, independent of Sw cutoffs, and were hand contoured to generate average net pay values by LSD. 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.

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

Historical Production

A historical group production history plot for the proposed Kola Unit No. 3 is shown as Figure 4. Oil production commenced from the proposed Unit area in February 1996 and peaked during August 1997 at 8.25 m^3 OPD.

As of February 2013, production was 0.63 m^3 OPD, 4.68 m^3 WPD and an 88.1% watercut.

Oil production is currently declining at an annual rate of approximately 25% under the current Primary Production method.

The field's production rate indicates the need for pressure restoration and maintenance, and waterflooding is deemed to be the most efficient means of re-introducing energy back into the reservoir system and to provide areal sweep between wells.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Kola Unit No. 3 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 Kola Unit No. 3 project area, to the end of March 2013, was 11.2 E^3m^3 of oil, and 41.5 E^3m^3 of water for a recovery factor 3.3% of the calculated Net OOIP.

Based on decline analysis of the two wells currently on production, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be 26.7 e^3m^3 (167.9 Mbbl), with 15.5 e^3m^3 (97.5 Mbbl) remaining as of end March 2013. This represents a recovery factor of 4.6% of the total OOIP.

Primary production plots of the expected production decline and forecasted oil rate v. time and rate v. cumulative oil production are shown in Figures 5 and 6, respectively.

Secondary EOR Production Forecast

Based on the geological description, primary production decline rate and the waterflood response indicated by Kola Units Nos. 1 and 2, it is expected that a pattern waterflood would be successful in Kola Unit No. 3. Implementing secondary with primary could result in a total recovery of 31.4% for the proposed Unit area.

Tundra supports the thinking that the reservoir is laterally continuous in the proposed Kola Unit No. 3, based on the waterflood response indicated by Kola Units Nos. 1 and 2, initial pressure and interpreted 3D seismic. As a result, Tundra thinks decent areal sweep and flood efficiency will be attained.

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 5 and 6, respectively. Total Secondary EUR for the proposed Kola Unit No. 3 is estimated to be 106.9 e3m3 (672.4 Mbbl), with 233.7 e3m3 (1,470.0 Mbbl) remaining representing a total secondary recovery factor of 31.4% for the proposed Unit area.

An incremental 80.2 e^3m^3 (504.5 Mbbl) of oil, or incremental 23.5% recovery factor, are forecasted to be recovered under the proposed Unitization.

Technical Studies

The waterflood performance predictions for the proposed Kola Unit No. 3 are based on performance in Kola Units Nos. 1 and 2, documented annually in enhanced oil reports submitted to the Petroleum Branch.

Internal reviews included analysis of available open-hole logs; core data; petrophysics; seismic; drilling information; completion information; and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed Kola Unit No. 3 OOIP (Table 2).

Unitizing the proposed Kola Unit No. 3 will provide an equitable means of maximizing ultimate oil recovery in the project area, which is otherwise not currently achievable given the constraints on drilling full-length horizontals.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the current development by 23%. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have the greatest recovery possible by allowing the development of additional drilling and injector conversions over time, in order to maintain reservoir pressure and increase oil production.

Unit Name

Tundra proposes that the official name of the new Unit covering LSD's 7-10, 14-16 Sec 28-10-29W1 shall be Kola Unit No. 3.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Kola Unit No. 3.

Unitized Zone

The Unitized zone(s) to be waterflooded in the Kola Unit No. 3 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 3 vertical wells to be included in the proposed Kola Unit No. 3 are outlined in Figure 4.

Unit Lands

The Kola Unit No. 3 will consist of 7 LSD's as follows:

LSD's 7-10, 14-16 of Section 28 of Township 10, Range 29, W1M

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

Tract Factors

The proposed Kola Unit No. 3 will consist of 7 tracts based on the 40 acre LSD's containing the existing 2 vertical producing wells.

The OOIP minus Cumulative Production by LSD Method was used to generate the proposed Unit tract factors.

Unit tract factor calculations for all individual LSD's based on the above methodology are outlined within Table 5.

Working Interest Owners

Table 6 outlines the working interest (WI) for each individual tract within the proposed Kola Unit No. 3, and 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 Kola Unit No. 3.

WATERFLOOD EOR DEVELOPMENT

Injector Conditioning

Primary production from the producing wells in the proposed Kola Unit No. 3 has declined significantly from peak rate to current rate, indicating a need for secondary pressure support. Through the process of developing other waterfloods in Manitoba, Tundra has measured a significant and ever increasing incidence of variation in reservoir pressure depletion by existing primary vertical producing wells. Existing development in the proposed KU3 area is such that additional development is required, with both primary and secondary in mind. In general, Tundra has found that placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been particularly problematic in the Bakken. As a result, the following conditions have been observed which Tundra believes negatively impact the ultimate total recovery factor of OOIP:

- Lower initial and peak water injection rates
- Rapid increases in injection wellhead pressures to the maximum allowable
- Lower sustained water injection rates at maximum allowable pressure
- Lower monthly instantaneous and cumulative voidage replacement ratio
- Delayed secondary oil production response
- Secondary oil production response of lower magnitude
- Early water breakthrough issues

Tundra makes the case that when future horizontal wells are drilled, they should be produced for a period of time (12-24mos) to address the above issues.

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate a low end fracture pressure gradient of approximately 17.0 kPa/m true vertical depth (TVD). Tundra's injection strategy will be implemented using an upper limit pressure gradient approximately 14.5 kPa/m at the sandface, by applying a factor of 0.85 to the fracture gradient. This equates to a maximum operating wellhead pressure of 6.0 MPa. Tundra will be mindful of areas with fracture gradients possibly deviating from the stated norm, when inter-Unit horizontals are drilled and fracture stimulated to limit the chance of fracturing into the overlying Basal Lodgepole, known to be a pervasively permeable and porous thief zone in the area.

Reservoir Pressure

As the producing wells in the proposed KU3 are in a pumped off state, it is difficult to determine the current reservoir pressure of the producing wells. Tundra has not recently shut in production to gather a pressure build up, or otherwise run a static gradient to obtain a pressure. Most likely, there has been some pressure support provided via the adjacent waterflood schemes implemented in Kola Units Nos. 1 and 2, although the level of support is unknown. An estimate of the original reservoir pressure is 8.5MPa, using a normal pressure gradient of 10kPa/m for the Bakken in the area.

A DST was run by Tundra on January 25th, 1996 for the drilling of the 100/15-28-010-29W1/0 well (Appendix 12). An inflate straddle was placed over the interval 852.0-862.0m, and initial and final flow/shut-in periods of 10/56 and 59/121 minutes were obtained, respectively. The reservoir pressure P* for the final shut-in period extrapolates to 6,230kPa at a Horner time of 1.0. At an average run depth of 857.0m, this equates to a gradient of 7.3MPa/m. Early DST's collected from verticals in the existing Kola Units Nos. 1 and 2 were of higher values in the Bakken, indicating pressure depletion over time and perhaps more importantly, decent reservoir continuity.

Tundra's plan is to develop the remaining undrilled LSD's, evaluate pressure (via fall-off tests, static gradients and fluid levels) to estimate the level of reservoir communication with the existing Kola Units Nos. 1 and 2. Should the wells be sufficiently depleted, the plan would be to convert such wells to waterflood, to increase the current reservoir pressure closer to the original pressure. This would be done by maintaining an instantaneous voidage replacement ratio (VRR) of 1.25 to 2.0 until a cumulative VRR of 1.0 is reached, as long as sandface pressures stay below the maximum allowable wellhead pressures previously stated.

Water Source and Injection Wells

Injection water for the proposed Kola Unit No. 3 will be supplied from the Jurassic source water well at 100/2-25-010-29W1. Tundra recently submitted an application to the Petroleum Branch detailing its plans to use the 2-25 well as a source water well for waterflood operations. Once approved, Jurassic-sourced water will be pumped from the 2-25 source well to the Daly 12-24-10-29 battery, where it will be filtered and then pumped up to injection system pressure. A diagram of the Daly 12-24 water injection system and new pipeline connection to the project area injection wells is shown as Figure 8.

Tundra has collected a Jurassic source water sample with which to conduct compatibility testing with varying mixtures of produced water in the existing and proposed Kola Units. The testing has been and will be conducted by a highly qualified third party. All potential mixture ratios between the 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. Tundra is considering a scale inhibitor application to be maintained into the source water stream out of Daly 12-24 injection system. It is thought that the Jurassic sourced water from 2-25 will overall be compatible with waters found in the existing and proposed Kola Units. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

Water injection well conversions for the proposed Kola Unit No. 3 will be selected on the basis of maximizing oil recovery, sweep efficiency between wells, and learning. Wells to be considered for conversion to downhole injection are depicted in Figure 7. Tundra's plan is to target areas that are as yet undrilled, with both primary and secondary development in mind. Tundra intends to put newly drilled wells on production to determine candidacy for converting to water injection.

For wells that are converted, Tundra will target suitable injection rates subject to staying well below fracture gradients, to reintroduce energy into the reservoir system. Tundra will evaluate these areas to determine whether additional drilling will increase the overall recovery of the pool. Tundra has extensive experience drilling in the area and elsewhere, and any new wells are rigorously programmed and monitored during execution. This helps ensure optimum placement of each lateral in zone, to prevent or minimize the potential for out-of-zone lateral placement that could otherwise increase the potential for future out-of-zone injection and/or flood conformance. Any changes to the development plan will be discussed in the annual enhanced oil recovery report submitted to the Manitoba Government.

New water injection wells will be placed on injection once approval to inject has been received. 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 will be surface equipped with injection volume metering and rate/pressure controls (Appendix 13). 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 Kola Unit No. 3 horizontal water injection well rates are forecasted to average 150-300 bbls WPD per well, based on expected reservoir conditions and fill-up volumes.

Schedule/Timing for Conversion of Wells to Water Injection

Tundra has designed the following well development schedule to allow for the most expeditious development of the waterflood within the proposed Kola Unit No. 3:

- Immediate Unitization of the project area provides a mechanism for primary production allocation during the pre-production period, regardless of oil rate or time on production
- Unitization allows the Unit Operator to convert existing wells to injection in the most expeditious and operationally efficient manner, and evaluate for possible additional drilling
- Calculate and/or obtain reservoir pressures and observe production rate profile characteristics on new wells and existing producing wells from 2013–2014
- Secondary oil rate response at producing wells is forecasted to begin within 1 to 12 months following conversion of wells to water injection service

Criteria for Conversion to Water Injection Well

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

- Measured reservoir build-up pressures measured by shutting in production

- Fluid production rates, cumulative volumes, and any changes in decline rate over time
- Any observed production interference effects with adjacent wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

The above schedule allows for the proposed Kola Unit No. 3 project to be developed equitably, efficiently, and moves the 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.

Waterflood Surveillance and Optimization

Kola Unit No. 3 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate, WOR and WCT testing to monitor waterflood response, breakthrough or fingering
- Daily water injection rate and pressure monitoring v. target
- Evaluation of Hall plots to observe positive or negative skin indicating channeling or out of zone injection
- Gas measurement at individual wells to monitor changes to GOR with waterflood
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Instantaneous and cumulative VRR by pattern and in the overall Unit
- Potential use of chemical tracers to track water injector/producer responses
- Use of some or all: 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 Kola Unit No. 3 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 Kola Unit No. 3.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Kola Unit No. 3 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 Kola Unit No. 3 waterflood operation will utilize the Tundra operated well 100/2-25-10-29W1, sourced from the Jurassic, and water plant (WP) facilities located at the Daly 12-24-10-29W1 battery.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Appendix 13. All surface facilities and wellheads will have cathodic protection to prevent corrosion. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set above the Middle Bakken and Three Forks formations, and the annulus between the tubing and casing will be filled with inhibited fluid. Refer to Appendix 13 for additional corrosion control details.

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 Kola Unit No. 3. 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 Kola Unit No. 3 Application.

Kola Unit No. 3 Unitization, and execution of the formal Kola Unit No. 3 Agreement by affected Mineral Owners, is expected before the end of June 2013. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Kola Unit No. 3 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. June 14th, 2013

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