PROPOSED SINCLAIR UNIT NO. 17

Application for Enhanced Oil Recovery Waterflood Project

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

August 31, 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, 2, 3, 5, 6, 7, 8, 10, 11, 12 and 13 as shown on Figure 1.

In the northern 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 Sinclair Unit No. 17 (Sections 19, 30, 31-8-28W1) 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 Sinclair Unit No. 17 will include 12 horizontal wells and 7 vertical wells, within 48 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located north of Sinclair Unit No. 12 and between Ewart Unit No. 3 and Ewart Unit No. 4 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Sinclair Unit No. 17 has been calculated to be 2,005 e^3m^3 (**12,613** Mbbl) for an average of **41.8 net e^3m^3 (262.6** 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 19 wells within the proposed Sinclair Unit No. 17 project area was 133.3 e^3m^3 (838.6 Mbbl) of oil, and 209.3 e^3m^3 (1,316.9 Mbbl) of water, representing a **6.6%** Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Sinclair Unit No. 17 project area has been calculated to be **181.2** e^3m^3 (**1,139.4** Mbbl), with **47.9** e^3m^3 (**301.3** Mbbl) remaining as of the end of May 2015.

5. Ultimate oil recovery of the proposed Sinclair Unit No. 17 OOIP, under the current Primary Production method, is forecasted to be **9.0%**

6. Figure 4 shows the production from the Sinclair Unit No. 17 peaked in February 2011 at 121.3 m^3 (OPD). As of May 2015, production was 24.7 m^3 OPD, 71.3 m^3 of water per day (WPD) and a 74.3% watercut.

7. In February 2011, production averaged 7.6 m^3 OPD per well in Sinclair Unit No. 17. As of May 2015, average per well production has declined to 1.54 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **24.2%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Sinclair Unit No. 17 has been calculated to be **309.5** e^3m^3 (**1,946.7** Mbbl), with **176.2** e^3m^3 (**1,108.3** Mbbl) remaining. An incremental **128.3** e^3m^3 (**807.0** Mbbl) of proved oil reserves, or **6.4%**, 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 Sinclair Unit No. 17 is estimated to be **15.4%**.

10. Based on the 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. Future horizontal injectors, with multi-stage hydraulic fractures, will be drilled between existing horizontal/vertical producing wells (Figure 5) within the proposed Sinclair Unit No. 17, to complete waterflood patterns with effective 20 acre spacing similar to that of Sinclair Unit No. 5.

DISCUSSION

The proposed Sinclair Unit No. 17 project area is located within Township 8, Range 28 W1 of the Daly Sinclair Oil Field. The proposed Sinclair Unit No. 17 currently consists of 12 horizontal and 7 vertical wells, within an area covering 48 LSDs (Figure 2). This includes Sections 19, 30, 31-008-28W1. 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 S to N 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 and Lyleton 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 12, Ewart Unit 3 and Ewart Unit 4) 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 (Appendix 3). 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 3.0m in the Southeast to just over 4.0m in the Northwest (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 boundary of the proposed unit (Appendix 5). The Lower Lyleton A generally thins eastward, and as such, has a greater presence in the proposed unit, but has been eroded away in the North, South and 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 4.0m at its thickest and pinches to 0m in the North and South of the proposed unit (Appendix 7). The effectiveness of the Red Shale Marker unit as a permeability barrier is reduced from West to East and toward the North and South 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 3.5m-5.0m thick within the proposed unit (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 Southeast. 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 South-Central portion of the proposed unit and the Lyleton B reservoir is continuous throughout.

Vertical continuity between the Middle Bakken and underlying Lyleton A reservoir is good in the South-Central area of the proposed unit where they are in direct contact. Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir is also good in the North and South. 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 South-Central area of the proposed unit from the presence of the Lyleton A and Red Shale between these zones.

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.

<u>Gross OOIP Estimates</u>

OOIP were calculated by Tundra 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 Sinclair Unit No. 17 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 **2,005** e^3m^3 (**12,613** Mbbl) using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the greater 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.

Table 4 outlines the proposed Sinclair Unit No. 17 volumetric OOIP estimates on an individual LSD basis by formation. Average OOIP by individual LSD was determined to be **41.8 e^3m^3** for Sinclair Unit No. 17.

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.

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 Sinclair Unit No. 17 is shown as Figure 4. Oil production commenced from the proposed Unit area in September 2005 and peaked during February 2011 at 121.3 m^3 OPD. As of May 2015, production was 24.7 m^3 OPD, 71.3 m^3 of water per day (WPD) and a 74.3% watercut.

From peak production in February 2011 to date, oil production is declining at an annual rate of approximately **24.2%** 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 Sinclair Unit No. 17.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Sinclair Unit No. 17.

Unitized Zone

The Unitized zone(s) to be waterflooded in the Sinclair Unit No. 17 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 12 horizontal wells and 7 vertical wells to be included in the proposed Sinclair Unit No. 17 are outlined in Table 3.

Unit Lands

The Sinclair Unit No. 17 will consist of 48 LSDs as follows:

Section 19 of Township 8, Range 28, W1M
Section 30 of Township 8, Range 28, W1M
Section 31 of Township 8, Range 28, W1M

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

Tract Factors

The proposed Sinclair Unit No. 17 will consist of 48 Tracts based on the 40 acre LSDs containing the existing 12 horizontal and 7 vertical wells.

The Tract Factor contribution for each of the LSD's within the proposed Sinclair Unit No. 17 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 Sinclair Unit No. 17. 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 Sinclair Unit No. 17.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Sinclair Unit No. 17 Bakken project are based on internal engineering assessments. Project area specific reservoir and geological parameters were utilized and then compared to Sinclair Unit No. 5 parameters, yielding the WF EOR response observed there to date.

As Tundra has a direct comparison of waterflood performance in Sinclair Unit 5, Tundra does not feel it is crucial to construct a simulation model for this area.

Pre-Production of New Horizontal Injection Wells

New horizontal injection wells will be drilled between the existing vertical/horizontal producing wells as shown in Figure 5, which will result in an effective 20 acre line drive waterflood pattern within Sinclair Unit No. 17.

Primary production from the original vertical/horizontal producing wells in the proposed Sinclair Unit No. 17 has declined significantly from peak rate indicating a need for secondary pressure support. Through the process of developing similar waterfloods, Tundra has measured a significant variation in reservoir pressure depletion by the existing primary producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations, and has a negative impact on the ultimate total recovery factor of OOIP.

Considering the expected reservoir pressures and reservoir lithology described, Tundra believes an initial period of producing all 11 proposed horizontal wells prior to placing them on permanent water injection is essential and all Unit mineral owners will benefit.

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 Sinclair Unit No. 17 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 using Sinclair Unit No. 5 as an analogy because it is developed with a similar waterflood pattern design of a horizontal injector with offsetting horizontal producers.

Primary Production Forecast

Cumulative production in the Sinclair Unit No. 17 project area, to the end of May 2015 from 19 wells, was 133.3 e^3m^3 of oil and 209.3 e^3m^3 of water for a recovery factor of **6.6%** of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Sinclair Unit No. 17 has been estimated to be **181.2** e^3m^3, or a **9.0**% Recovery Factor (RF) of OOIP. Remaining Producing Primary Reserves has been estimated to be **47.9** 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 Figure 7.

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 Sinclair Unit No. 17, while maximizing reservoir knowledge.

Criteria for Conversion to Water Injection Well

Eleven (11) 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 Sinclair Unit No. 17 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

The proposed project oil production profile under Secondary Waterflood has been developed based on the response observed to date in the Sinclair Unit 5 Waterflood (Figure 6).

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production vs. cumulative oil are plotted in Figures 9 and 10, respectively. Total Secondary EUR for the proposed Sinclair Unit No. 17 is estimated to be **309.5** e^3m^3 with **176.2** e^3m^3 remaining representing a total secondary recovery factor of **15.4%** for the proposed Unit area. An incremental **128.3** e^3m^3 of oil, or a **6.4%** 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 Sinclair Unit No. 17 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 Sinclair Unit No. 17 project area injection wells is shown as Figures 11-12.

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 Sinclair Unit No. 17.

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

New water injection wells for the proposed Sinclair Unit No. 17 will be drilled, cleaned out, and configured downhole for injection as shown in Figure 11. The horizontal injection well will be 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 the pre-production period and 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 Sinclair Unit No. 17 horizontal water injection well rate is forecasted to average **10 - 30** m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Sinclair Unit No. 17 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

Sinclair Unit No. 17 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 Sinclair Unit No. 17 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 Sinclair Unit No. 17.

On Going Reservoir Pressure Surveys

Any pressures taken during the operation of the proposed unit will be reported within the Annual Progress Reports for Sinclair Unit No. 17 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Sinclair Unit No. 17 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 Sinclair Unit No. 17 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 13.

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 Sinclair Unit No. 17. 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 Sinclair Unit No. 17 Application.

Sinclair Unit No. 17 Unitization, and execution of the formal Sinclair Unit No. 17 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 Sinclair Unit No. 17 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 31, 2015, in Calgary, AB

Proposed Sinclair Unit No. 17

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

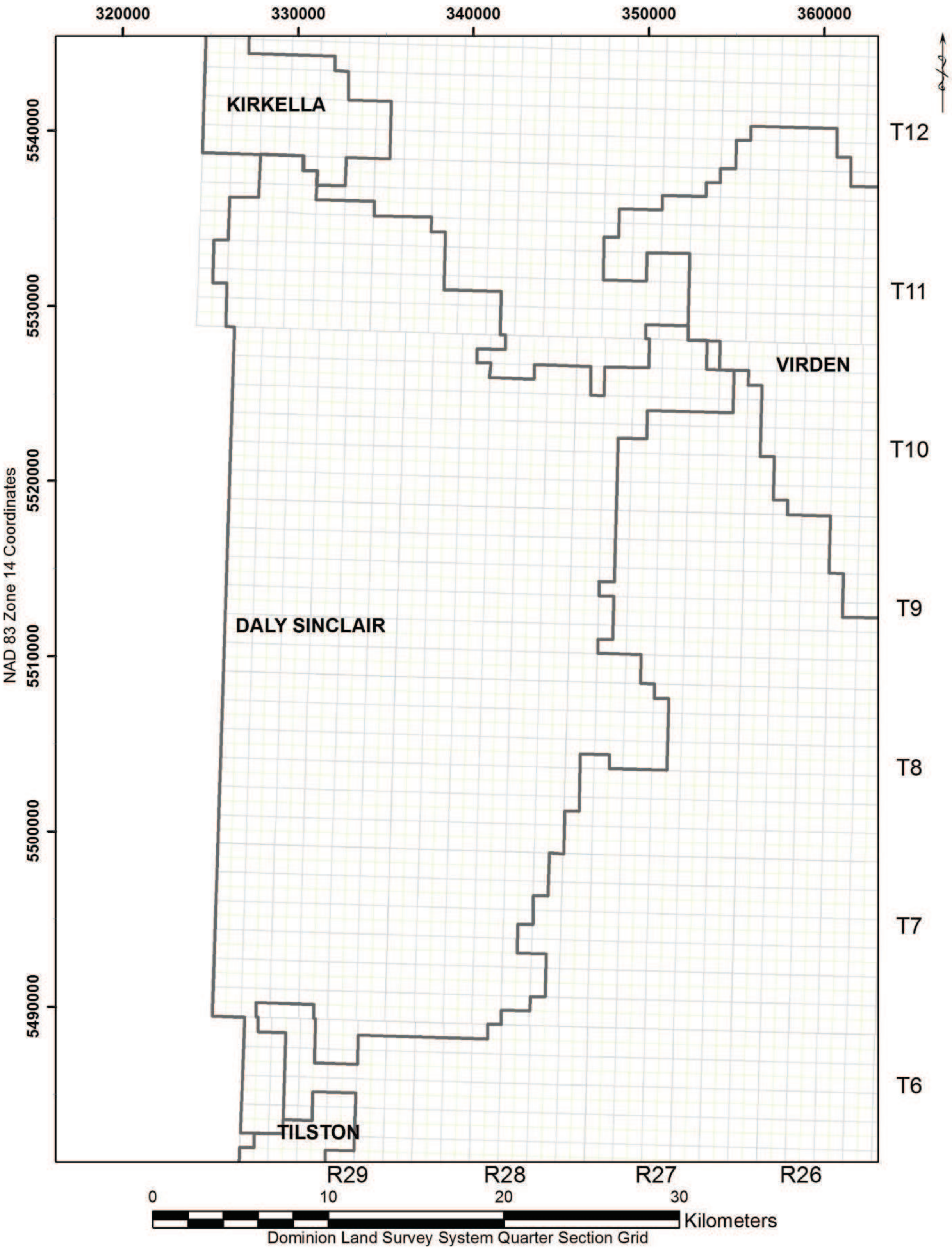


Figure 2 - Daly Sinclair Field (01)

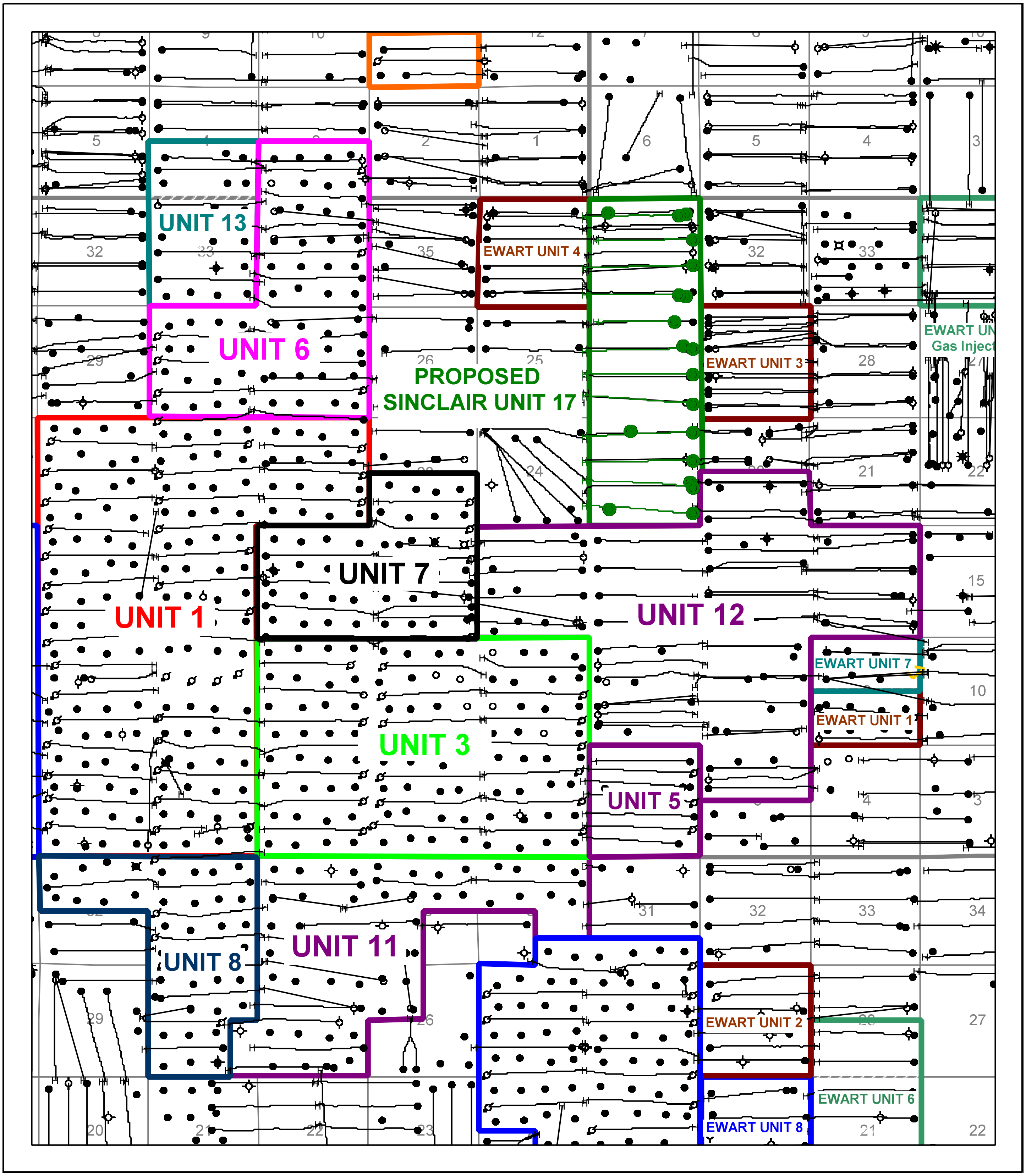


Figure 2
Proposed Sinclair Unit No. 17
July 06, 2015
\\FS02\AccuMapData$\Sharon.Baker\New_AccuMap\Sinclair Units\Tundra Approved Unit Map.accumap

FIGURE NO. 3

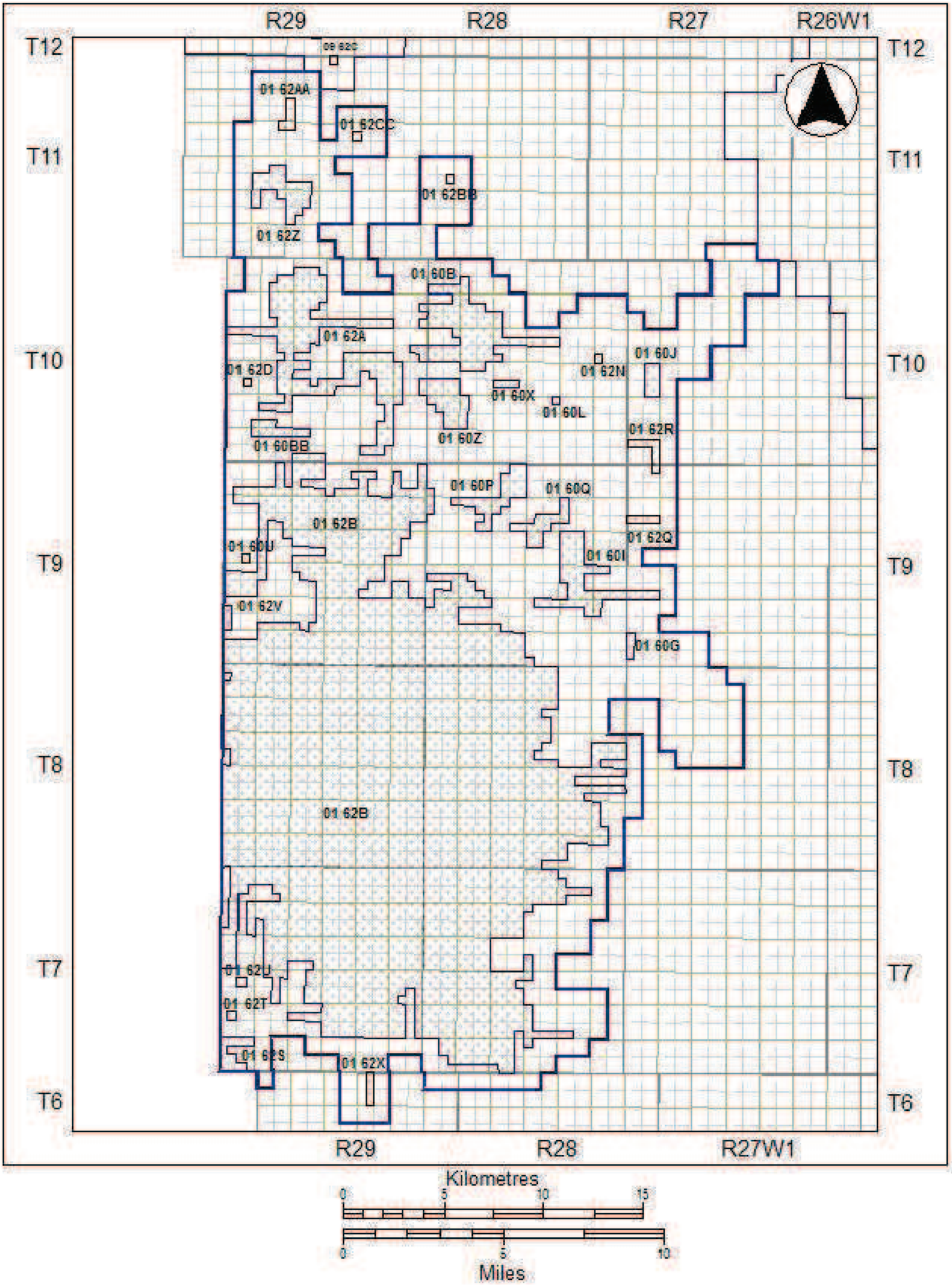
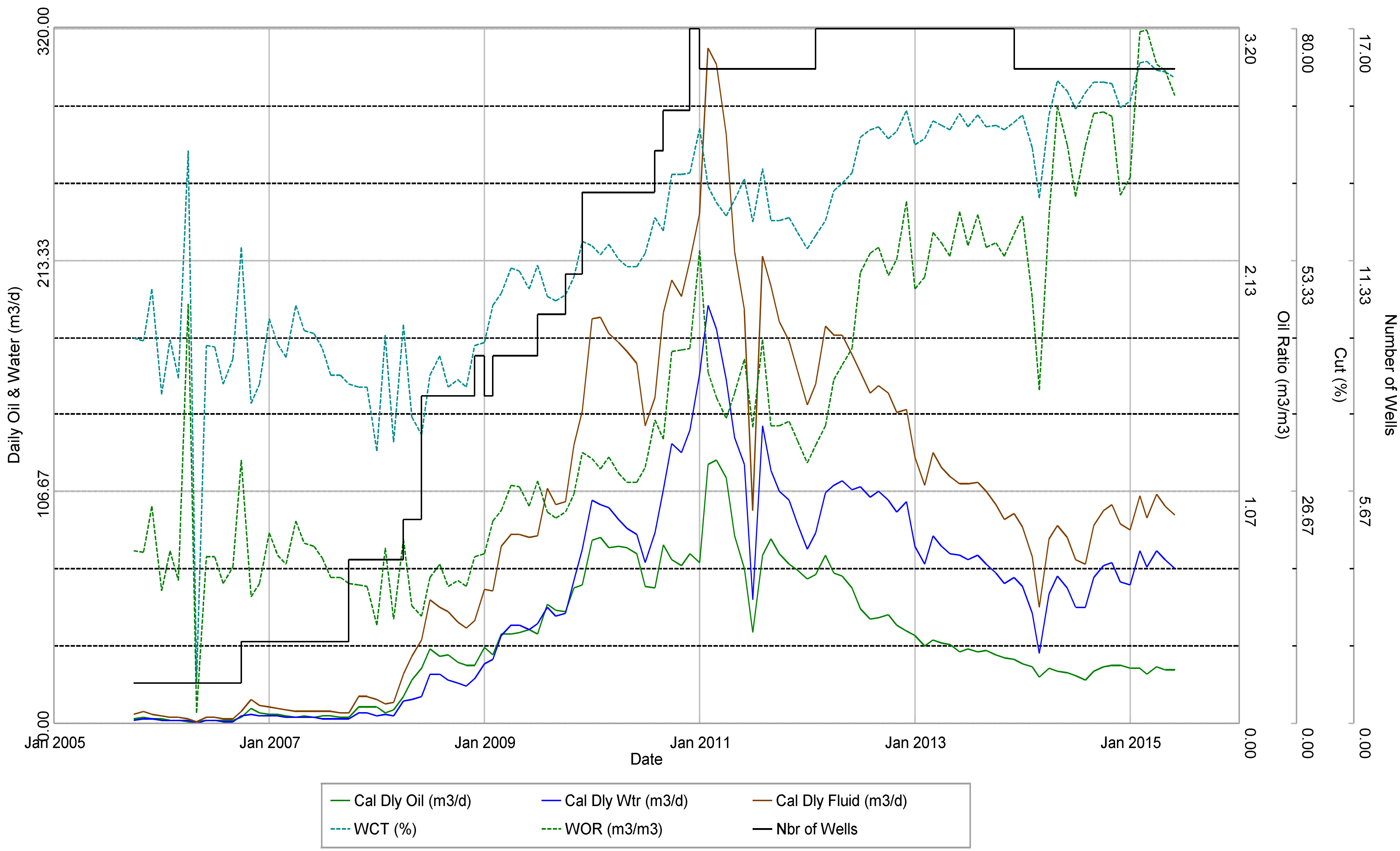


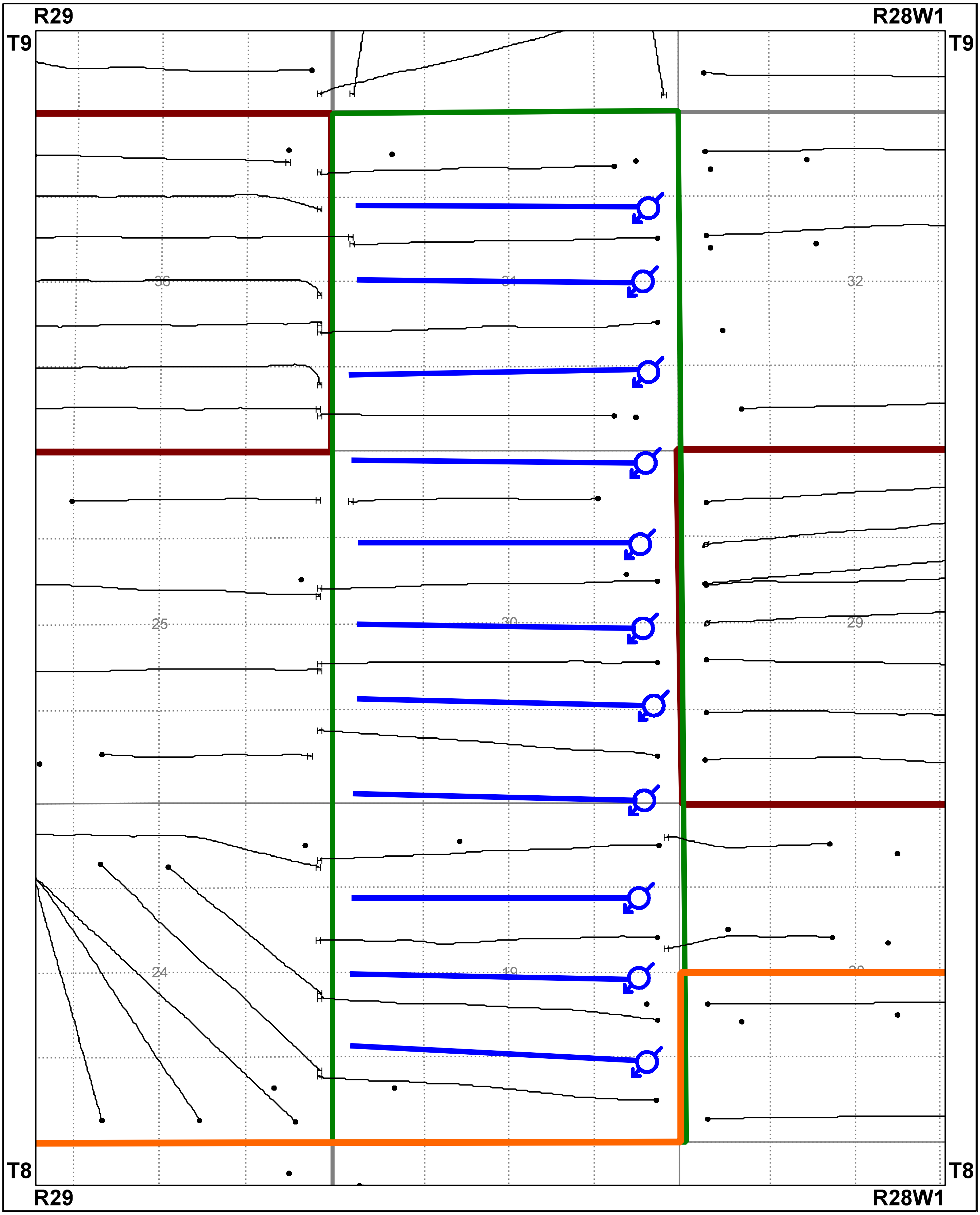
FIGURE 14 - DALY SINCLAIR BAKKEN & BAKKEN-THREE FORKS POOLS
(01 60A - 01 60BB & 01 62A – 01 62CC) (Drawn on the DLS System Quarter Section Grid)

Well Information as of 7/17/2015 - Group Well Report

Production Graph

Group:	sinclair unit no. 17 well list.lwell	**Prod Form:**	BAKKEN; THREEFK	**On Prod:**	2005-09 to 2015-05
# of Wells:	19	**Field:**	DALY (1)	**Cum Oil:**	133264.7 m3
Fluid:	Oil	**Pool Code:**	62B	**Cum Gas:**	0.0 E3m3
Mode:	Producing	**Unit Code:**		**Cum Wtr:**	209266.9 m3





Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Sinclair Unit No. 5 Analog

Figure No. 6

Production Graph

# of Wells:	10	**Prod Zone:**	TORQUAY; BAKKEN	**On Prod:**	2005-03 to 2015-05
		Field:	DALY (1)	**Cum Oil:**	76918.0 m3
Fluid:	Oil; Water Injection	**Pool Code:**	62B	**Cum Gas:**	0.0 E3m3
Mode:	Producing; Injection	**Unit Code:**	162B05	**Cum Wtr:**	53513.1 m3

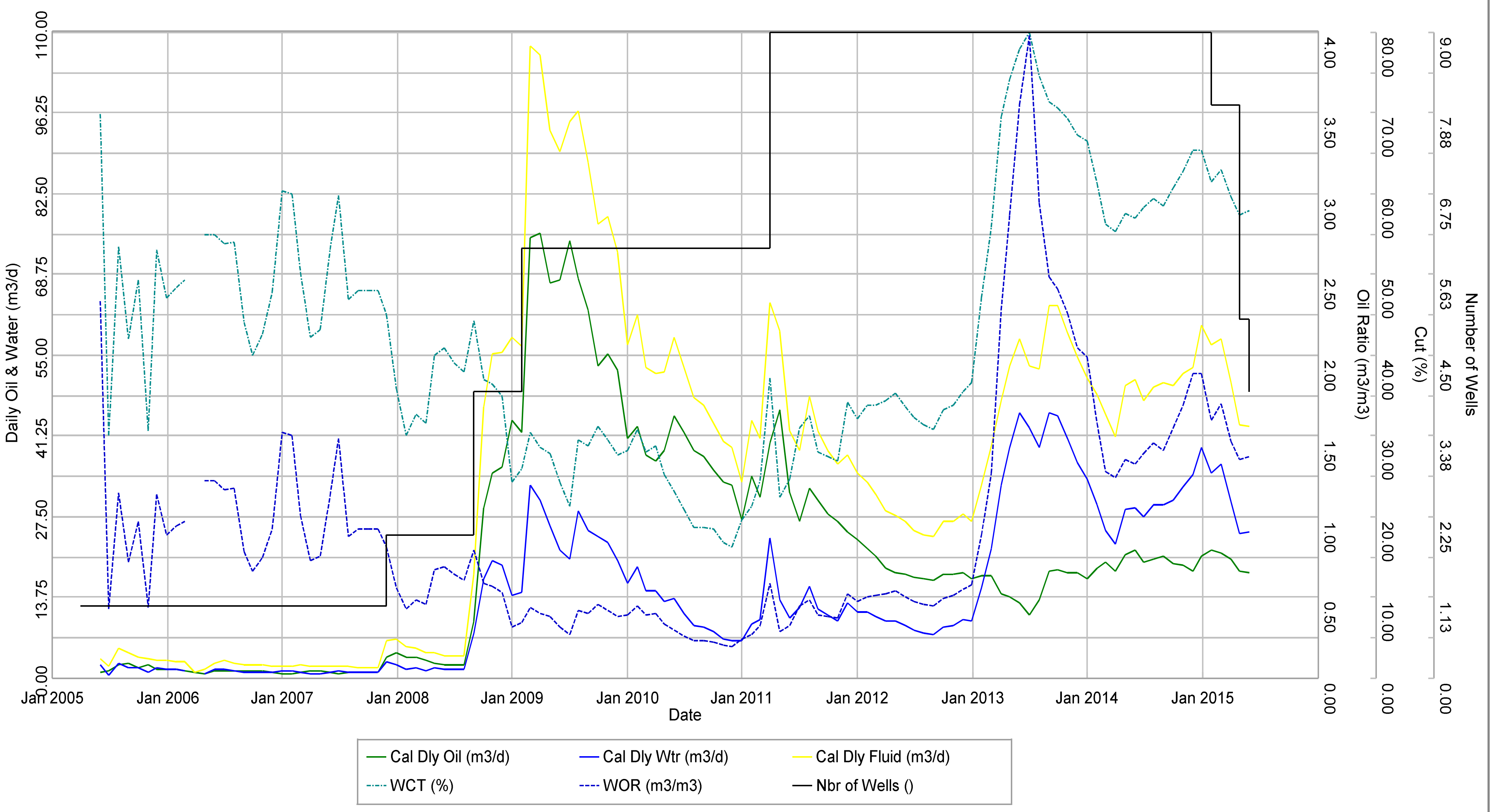
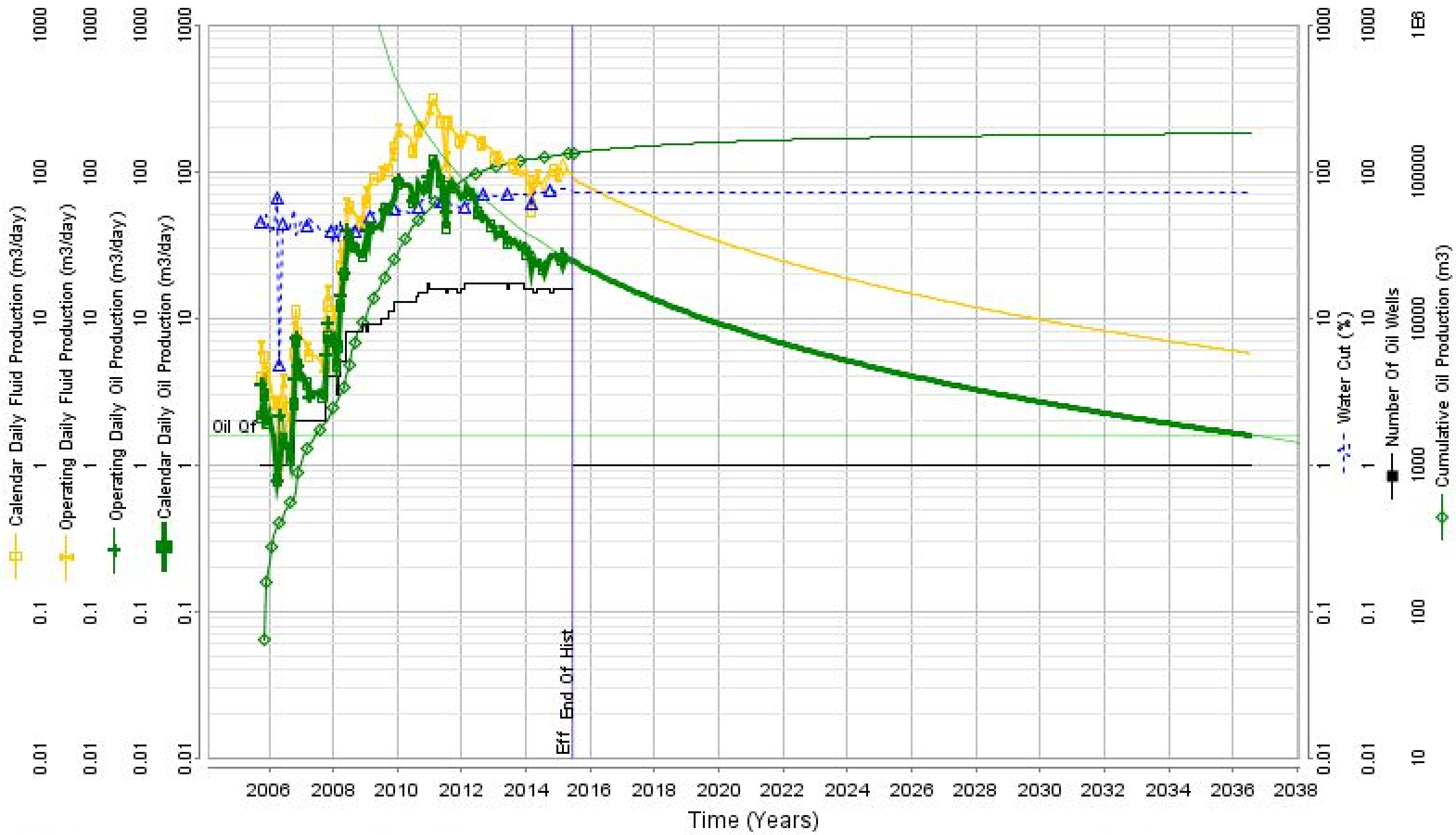


Figure No. 7

Province: Manitoba
Field: multi zone (2)
Pool: multi zone (2)
Unit: multi zone (19)
Status: n/a
Operator: TUNDRA OIL & GAS LIMITED

Primary

Sinclair 17
Sinclair 17 Unit Application
Base



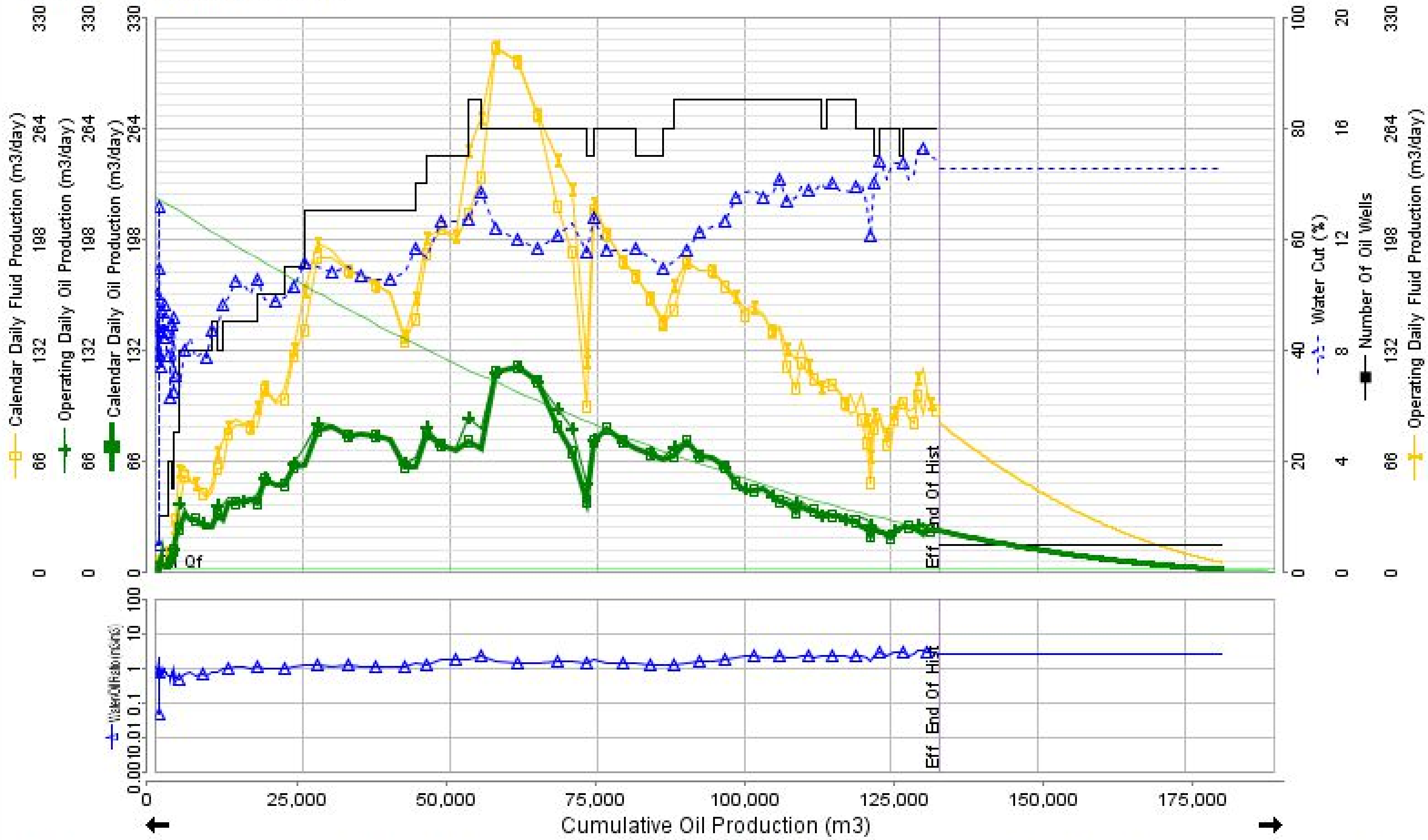
Cum Oil(m3):	133,265	Cum Gas(E3m3):	0	Cum Water(m3):	209,268	Cum Cond(m3):	0
Forecast Start:	06/01/2015	Calculation Type:	Undefined	Est. Cum Prod (m3):	133,265	Decline Exponent:	0.500
Forecast End:	06/19/2036	OVIP (m3):	0	Remaining (m3):	47,892	Initial Decline (%/yr):	24.2
Initial Rate (m3):	24.4	Recovery Factor:	0.000				
Final Rate (m3):	1.6	Ult. Recoverable (m3):	181,157				

Figure No. 8

Province: Manitoba
Field: multi zone (2)
Pool: multi zone (2)
Unit: multi zone (19)
Status: n/a
Operator: TUNDRA OIL & GAS LIMITED

Primary

Sinclair 17
Sinclair 17 Unit Application
Base



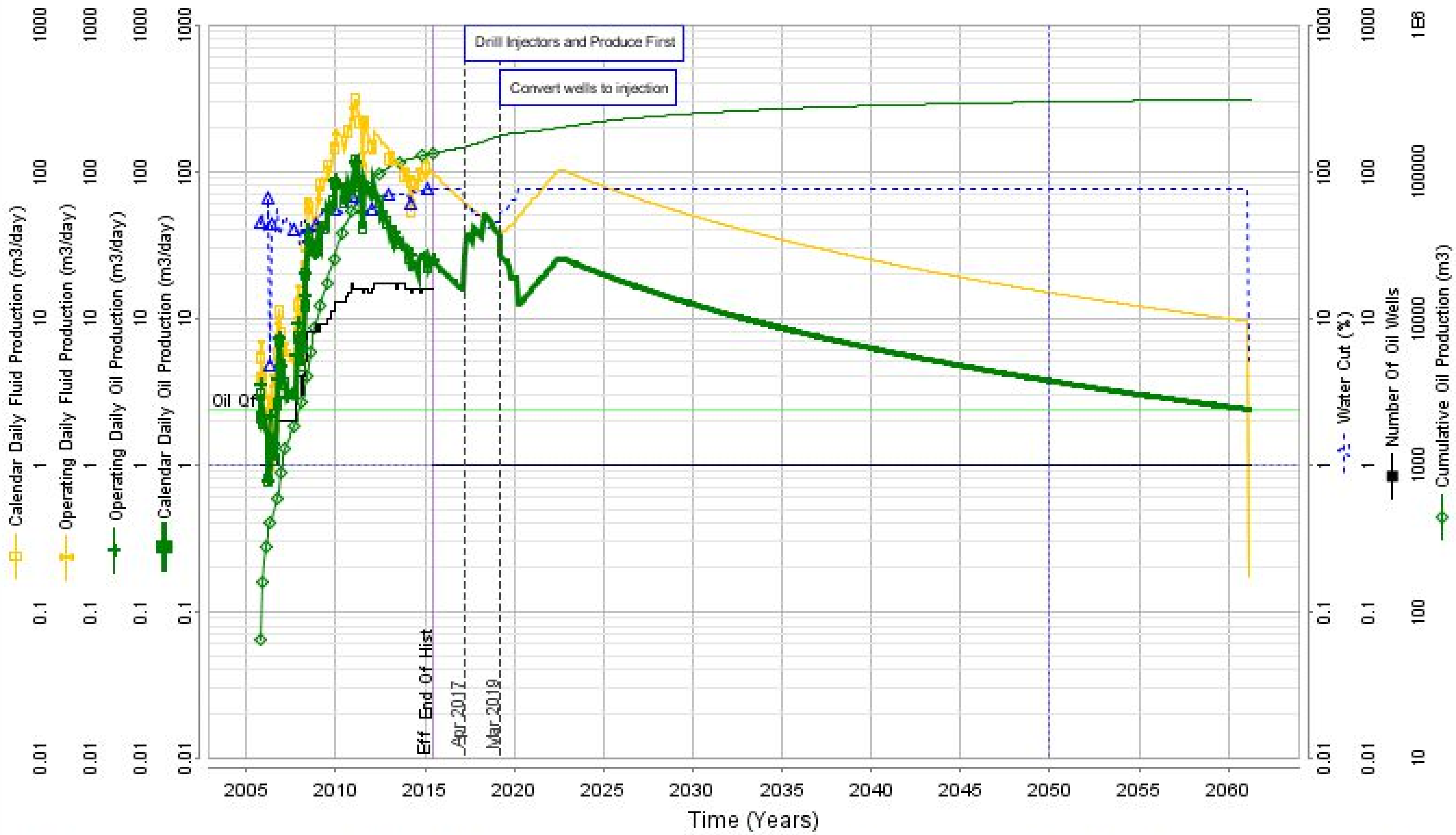
Cum Oil(m3):	133,265	Cum Gas(E3m3):	0	Cum Water(m3):	209,268	Cum Cond(m3):	0
Forecast Start:	06/01/2015	Calculation Type:	Undefined	Est. Cum Prod (m3):	133,265	Decline Exponent:	0.500
Forecast End:	06/19/2036	OVIP (m3):	0	Remaining (m3):	47,892	Initial Decline (%/yr):	24.2
Initial Rate (m3):	24.4	Recovery Factor:	0.000				
Final Rate (m3):	1.6	Ult. Recoverable (m3):	181,157				

Figure No. 9

Province: Manitoba
Field: multi zone (2)
Pool: multi zone (2)
Unit: multi zone (19)
Status: n/a
Operator: TUNDRA OIL & GAS LIMITED

Primary + Secondary

Sinclair 17
Sinclair 17 Unit Application
Base + Growth 1



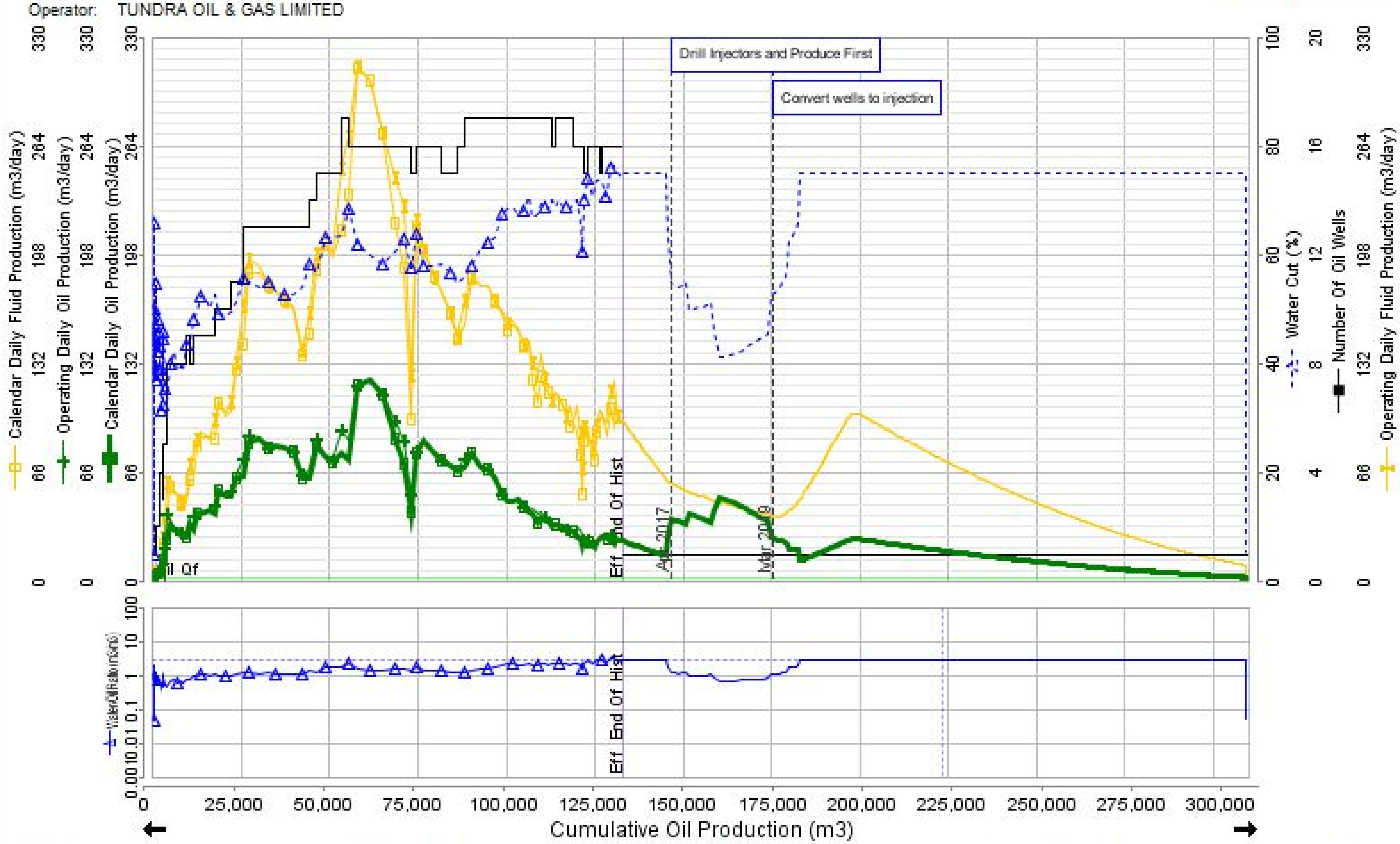
Cum Oil(m3):	133,265	Cum Gas(E3m3):	0	Cum Water(m3):	209,268	Cum Cond(m3):	0
Forecast Start:	06/01/2015	Calculation Type:	Undefined	Est. Cum Prod (m3):	133,265	Decline Exponent:	0.000
Forecast End:	02/28/2061	OVIP (m3):	0	Remaining (m3):	176,253	Initial Decline (%/yr):	0.0
Initial Rate (m3):	24.1	Recovery Factor:	0.000				
Final Rate (m3):	2.4	Ult. Recoverable (m3):	309,518				

Figure No. 10

Province: Manitoba
Field: multi zone (2)
Pool: multi zone (2)
Unit: multi zone (19)
Status: n/a
Operator: TUNDRA OIL & GAS LIMITED

Primary + Secondary

Sinclair 17
Sinclair 17 Unit Application
Base + Growth 1



Cum Oil(m3):	133,265	Cum Gas(E3m3):	0	Cum Water(m3):	209,268	Cum Cond(m3):	0
Forecast Start:	06/01/2015	Calculation Type:	Undefined	Est. Cum Prod (m3):	133,265	Decline Exponent:	0.000
Forecast End:	02/28/2061	OVIP (m3):	0	Remaining (m3):	176,253	Initial Decline (%/yr):	0.0
Initial Rate (m3):	24.1	Recovery Factor:	0.000				
Final Rate (m3):	2.4	Ult. Recoverable (m3):	309,518				

FIGURE NO. 11

Sinclair Water Injection System

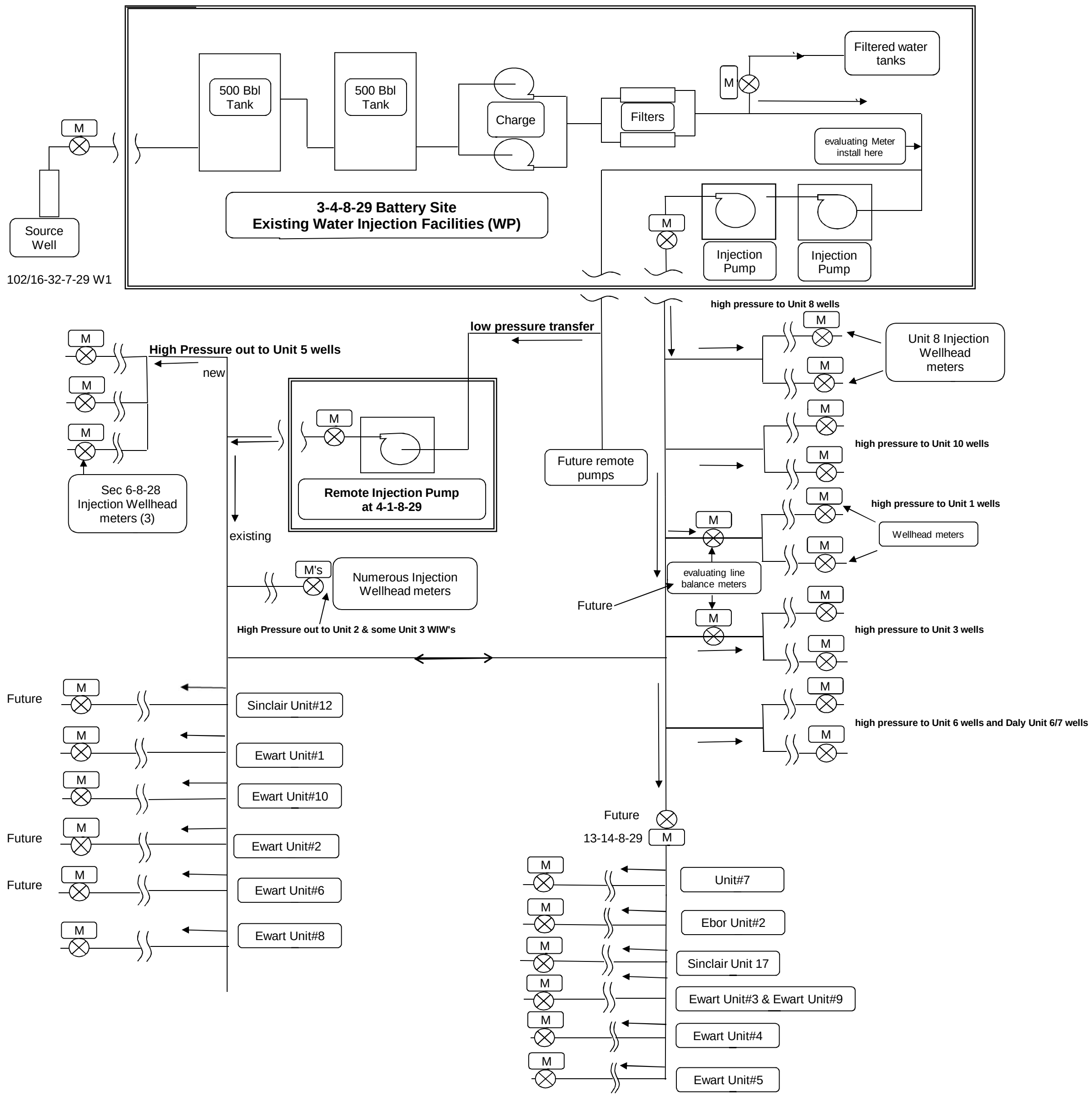


Figure No. 12

Tundra Oil And Gas Partnership

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	**Tundra Sinclair Unit 17 HZNTL Open Hole WIW**				**WELL LICENCE:**	
Prepared by	WRJ	(average depths)		Date:	2012	
Elevations :						
KB [m]			KB to THF [m]		TD [m]	2400.0
GL [m]			CF (m)		PBTD [m]	
Current Perfs:	**Open Hole**			950.0	to	2400.0
Current Perfs:					to	
KOP:	700 m MD		Total Interval		to	
Tubulars	**Size [mm]**	**Wt - Kg/m**	**Grade**	**Landing Depth [mKB]**		
Surface Casing	244.5	48.06	H-40 - ST&C	Surface	to	140.0
Intermed Csg (if run)	177.8	34.23 & 29.76	J-55 - LT&C	Surface	to	950.0
Open Hole Latera	none	none	none	950.0	to	2400.0
Tubing	60.3 or 73.0 - TK-99	6.99 or 9.67	J-55	Surface	to	940.0

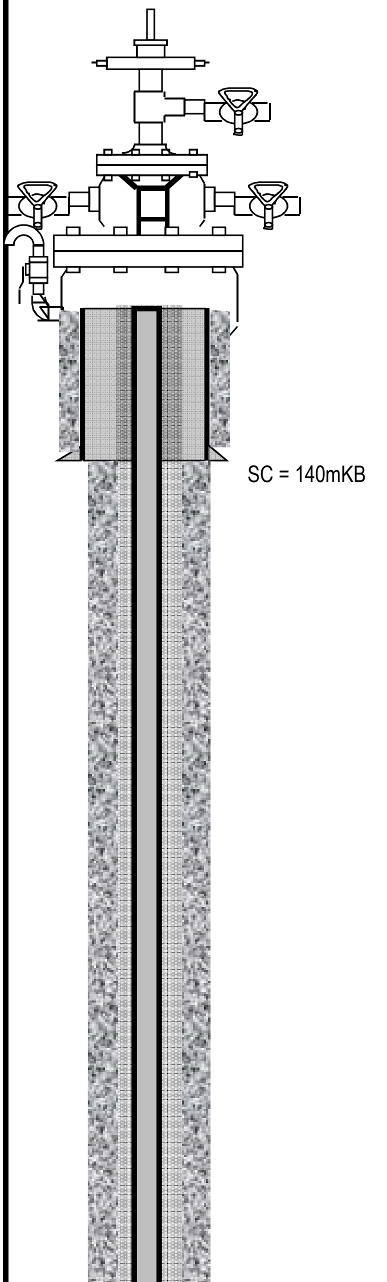
Date of Tubing Installation:			Length	Top @
Item	Description	K.B.--Tbg. Flg.	0.00	m KB
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)			
	60.3 mm or 73 mm TK-99 Internally Coated Tubing			
	TK-99 Internally Coated Tubing Pup Jt			
	Coated Split Dognut			
	Annular space above injection packer filled with inhibited fresh water			
	Bottom of Tubing mKB			

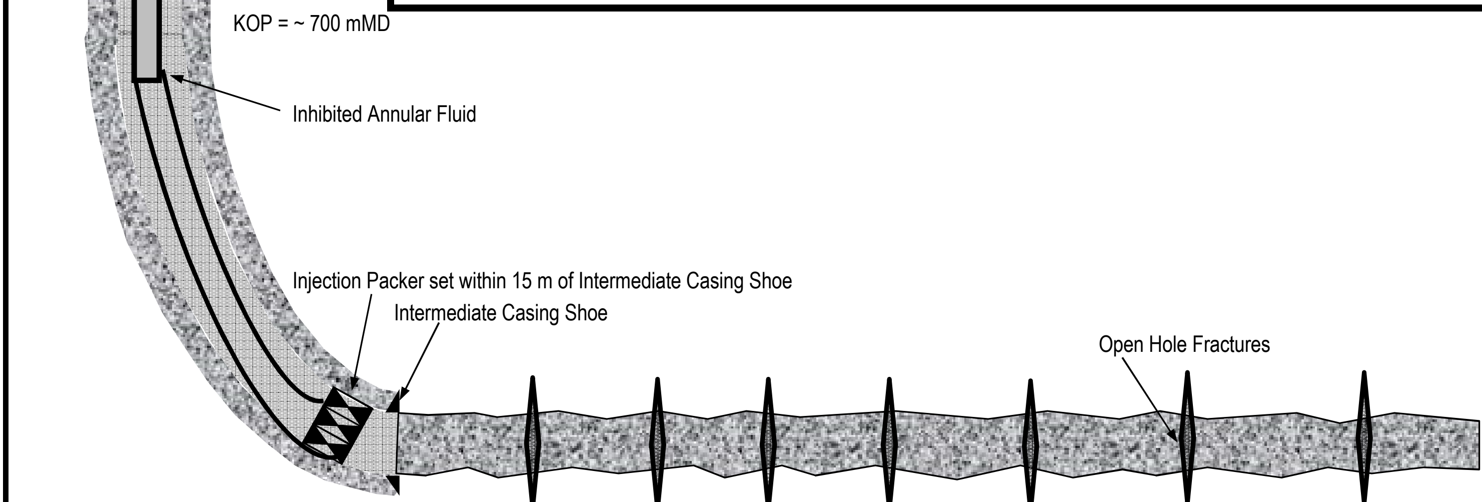
Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions:





Sinclair Unit No. 17

EOR Waterflood Project

Planned Corrosion Control Program **

Source Well
- Continuous downhole corrosion inhibition
- Continuous surface corrosion inhibitor injection
- Downhole scale inhibitor injection
- Corrosion resistant valves and internally coated surface piping

Pipelines
- Source well to 3-4-8-29 Water Plant – Fiberglass
- New High Pressure Pipeline to Unit 9 injection wells – 2000 psi high pressure Fiberglass

Facilities
- 3-4-8-29 Water Plant and New Injection Pump Station
  - Plant piping – 600 ANSI schedule 80 pipe, Fiberglass or Internally coated
  - Filtration – Stainless steel bodies and PVC piping
  - Pumping – Ceramic plungers, stainless steel disc valves
  - Tanks – Fiberglass shell, corrosion resistant valves

Injection Wellhead / Surface Piping
- Corrosion resistant valves and stainless steel and/or internally coated steel surface piping

Injection Well
- Casing cathodic protection where required
- Wetted surfaces coated downhole packer
- Corrosion inhibited water in the annulus between tubing / casing
- Internally coated tubing surface to packer
- Surface freeze protection of annular fluid
- Corrosion resistant master valve
- Corrosion resistant pipeline valve

Producing Wells
- Casing cathodic protection where required
- Downhole batch corrosion inhibition as required
- Downhole scale inhibitor injection as required

Figure 13

** subject to final design and engineering

Proposed Sinclair Unit No. 17

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 1: TRACT PARTICIPATION FOR PROPOSED SINCLAIR UNIT NO. 17

Working Interest				Royalty Interest		
Tract No.	**Land Description**	**Owner**	**Share (%)**	**Owner**	**Share (%)**	**Tract Participation**
1	01-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.083525681%
2	02-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.204438571%
3	03-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.210897982%
4	04-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	1.862318990%
5	05-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	1.946054861%
6	06-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.173559008%
7	07-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.247977986%
8	08-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.037226151%
9	09-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.043475332%
10	10-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.103730891%
11	11-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	1.930701278%
12	12-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	1.691288652%
13	13-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.134634270%
14	14-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	1.965879918%
15	15-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.237472484%
16	16-19-008-28W1M	Tundra Oil & Gas Partnership	100%	R.M. of Pipestone	100%	2.021017535%
17	01-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.001808283%
18	02-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.194458475%
19	03-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	1.917814875%
20	04-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.021619456%
21	05-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	1.783844261%
22	06-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.112530006%
23	07-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.372442222%
24	08-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.186676209%
25	09-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.280279960%
26	10-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.270655395%
27	11-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Smeltz Royalties Inc.	98.75%	2.315952457%
				University of Manitoba	1.25%	
28	12-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Smeltz Royalties Inc.	98.75%	2.038907809%
				University of Manitoba	1.25%	
29	13-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Smeltz Royalties Inc.	98.75%	2.156051071%
				University of Manitoba	1.25%	
30	14-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Smeltz Royalties Inc.	98.75%	2.385060917%
				University of Manitoba	1.25%	
31	15-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.240572984%
32	16-30-008-28W1M	Tundra Oil & Gas Partnership	100%	Minister of Finance	100%	2.560050160%
33	01-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.377512156%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
34	02-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.265311390%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
35	03-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	23.05625%	2.097924013%
				Minister of Finance	7.775%	
				Computershare Trust Company of Canada	28.8203%	
				GEM Oil Inc.	17.2922%	
				Computershare Trust Company of Canada	14.41016%	
				GEM Oil Inc.	8.64609%	
36	04-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	24.6375%	1.935587490%
				Minister of Finance	1.45%	
				Computershare Trust Company of Canada	30.7969%	
				GEM Oil Inc.	18.4781%	
				Computershare Trust Company of Canada	15.3984%	
				GEM Oil Inc.	9.2391%	
37	05-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	22.51875%	1.973680272%
				Minister of Finance	9.925%	
				Computershare Trust Company of Canada	28.1484%	
				GEM Oil Inc.	16.8891%	
				Computershare Trust Company of Canada	14.07422%	
				GEM Oil Inc.	8.44453%	
38	06-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.031838690%
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
				Computershare Trust Company of Canada	15.625%	
				GEM Oil Inc.	9.375%	

Working Interest				Royalty Interest		Tract Participation
Tract No.	Land Description	Owner	Share (%)	Owner	Share (%)	
39	07-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.101422078%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
40	08-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.268474990%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
41	09-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.908427094%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
42	10-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.891044894%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
43	11-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.979598845%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
44	12-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	24.88125%	2.127742060%
				Minister of Finance	0.475%	
				Computershare Trust Company of Canada	24.88125%	
				Computershare Trust Company of Canada	31.10160%	
				GEM Oil Inc.	18.66090%	
45	13-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	2.080303739%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
46	14-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.926568919%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
47	15-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.717223751%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	
48	16-31-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	25%	1.584415493%
				Computershare Trust Company of Canada	25%	
				Computershare Trust Company of Canada	31.25%	
				GEM Oil Inc.	18.75%	

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR SINCLAIR UNIT NO. 17

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) - CUMULATIVE PRODUCTION TO MAY 2015

LS-SE	Tract	OOIP (m3)	HZ Wells Alloc Prod (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	OOIP Tract Factor	Tract
01-19	01-19-008-28W1M	41,332	2,328.2	0.0	2,328.2	39,004	2.083525681%	01-19-008-28W1M
02-19	02-19-008-28W1M	43,595	2,328.2	0.0	2,328.2	41,267	2.204438571%	02-19-008-28W1M
03-19	03-19-008-28W1M	43,716	2,328.2	0.0	2,328.2	41,388	2.210897982%	03-19-008-28W1M
04-19	04-19-008-28W1M	40,887	2,328.2	3,696.3	6,024.5	34,863	1.862318990%	04-19-008-28W1M
05-19	05-19-008-28W1M	38,138	1,707.7	0.0	1,707.7	36,430	1.946054861%	05-19-008-28W1M
06-19	06-19-008-28W1M	42,397	1,707.7	0.0	1,707.7	40,689	2.173559008%	06-19-008-28W1M
07-19	07-19-008-28W1M	43,790	1,707.7	0.0	1,707.7	42,082	2.247977986%	07-19-008-28W1M
08-19	08-19-008-28W1M	42,152	1,707.7	2,307.6	4,015.3	38,137	2.037226151%	08-19-008-28W1M
09-19	09-19-008-28W1M	40,845	2,591.3	0.0	2,591.3	38,254	2.043475332%	09-19-008-28W1M
10-19	10-19-008-28W1M	42,097	2,715.0	0.0	2,715.0	39,382	2.103730891%	10-19-008-28W1M
11-19	11-19-008-28W1M	38,888	2,745.4	0.0	2,745.4	36,143	1.930701278%	11-19-008-28W1M
12-19	12-19-008-28W1M	34,088	2,426.8	0.0	2,426.8	31,661	1.691288652%	12-19-008-28W1M
13-19	13-19-008-28W1M	41,651	1,690.8	0.0	1,690.8	39,960	2.134634270%	13-19-008-28W1M
14-19	14-19-008-28W1M	39,818	1,794.0	1,222.9	3,016.9	36,801	1.965879918%	14-19-008-28W1M
15-19	15-19-008-28W1M	43,664	1,778.6	0.0	1,778.6	41,885	2.237472484%	15-19-008-28W1M
16-19	16-19-008-28W1M	39,553	1,719.5	0.0	1,719.5	37,833	2.021017535%	16-19-008-28W1M
01-30	01-30-008-28W1M	40,154	2,680.4	0.0	2,680.4	37,474	2.001808283%	01-30-008-28W1M
02-30	02-30-008-28W1M	43,895	2,815.2	0.0	2,815.2	41,080	2.194458475%	02-30-008-28W1M
03-30	03-30-008-28W1M	38,739	2,837.1	0.0	2,837.1	35,901	1.917814875%	03-30-008-28W1M
04-30	04-30-008-28W1M	40,475	2,629.9	0.0	2,629.9	37,845	2.021619456%	04-30-008-28W1M
05-30	05-30-008-28W1M	35,803	2,409.1	0.0	2,409.1	33,394	1.783844261%	05-30-008-28W1M
06-30	06-30-008-28W1M	42,133	2,586.9	0.0	2,586.9	39,547	2.112530006%	06-30-008-28W1M
07-30	07-30-008-28W1M	46,987	2,574.9	0.0	2,574.9	44,412	2.372442222%	07-30-008-28W1M
08-30	08-30-008-28W1M	43,356	2,421.1	0.0	2,421.1	40,935	2.186676209%	08-30-008-28W1M
09-30	09-30-008-28W1M	47,891	2,660.9	2,543.0	5,203.9	42,687	2.280279960%	09-30-008-28W1M
10-30	10-30-008-28W1M	45,292	2,785.6	0.0	2,785.6	42,507	2.270655395%	10-30-008-28W1M
11-30	11-30-008-28W1M	46,154	2,799.7	0.0	2,799.7	43,355	2.315952457%	11-30-008-28W1M
12-30	12-30-008-28W1M	40,770	2,601.2	0.0	2,601.2	38,168	2.038907809%	12-30-008-28W1M
13-30	13-30-008-28W1M	42,993	2,632.1	0.0	2,632.1	40,361	2.156051071%	13-30-008-28W1M
14-30	14-30-008-28W1M	48,624	3,975.4	0.0	3,975.4	44,648	2.385060917%	14-30-008-28W1M
15-30	15-30-008-28W1M	45,910	3,966.2	0.0	3,966.2	41,944	2.240572984%	15-30-008-28W1M
16-30	16-30-008-28W1M	48,899	975.1	0.0	975.1	47,924	2.560050160%	16-30-008-28W1M
01-31	01-31-008-28W1M	48,755	1,272.4	2,975.3	4,247.7	44,507	2.377512156%	01-31-008-28W1M
02-31	02-31-008-28W1M	45,289	2,882.3	0.0	2,882.3	42,407	2.265311390%	02-31-008-28W1M
03-31	03-31-008-28W1M	42,154	2,881.3	0.0	2,881.3	39,273	2.097924013%	03-31-008-28W1M
04-31	04-31-008-28W1M	38,896	2,662.1	0.0	2,662.1	36,234	1.935587490%	04-31-008-28W1M
05-31	05-31-008-28W1M	40,274	3,327.1	0.0	3,327.1	36,947	1.973680272%	05-31-008-28W1M
06-31	06-31-008-28W1M	41,514	3,478.1	0.0	3,478.1	38,036	2.031838690%	06-31-008-28W1M
07-31	07-31-008-28W1M	42,817	3,478.1	0.0	3,478.1	39,339	2.101422078%	07-31-008-28W1M
08-31	08-31-008-28W1M	45,790	3,324.3	0.0	3,324.3	42,466	2.268474990%	08-31-008-28W1M
09-31	09-31-008-28W1M	38,393	2,666.8	0.0	2,666.8	35,726	1.908427094%	09-31-008-28W1M
10-31	10-31-008-28W1M	38,218	2,817.7	0.0	2,817.7	35,400	1.891044894%	10-31-008-28W1M
11-31	11-31-008-28W1M	39,863	2,804.8	0.0	2,804.8	37,058	1.979598845%	11-31-008-28W1M
12-31	12-31-008-28W1M	41,471	1,639.2	0.0	1,639.2	39,831	2.127742060%	12-31-008-28W1M
13-31	13-31-008-28W1M	41,848	2,131.9	772.9	2,904.8	38,943	2.080303739%	13-31-008-28W1M
14-31	14-31-008-28W1M	38,430	2,365.0	0.0	2,365.0	36,065	1.926568919%	14-31-008-28W1M
15-31	15-31-008-28W1M	34,526	2,380.0	0.0	2,380.0	32,146	1.717223751%	15-31-008-28W1M
16-31	16-31-008-28W1M	32,340	1,051.3	1,628.7	2,680.0	29,660	1.584415493%	16-31-008-28W1M
		2,005,264	**118,118.0**	**15,146.7**	**133,264.7**	**1,871,999**	**100.000000000%**	

Table No. 3: Sinclair Unit No. 17

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Prod Date	Prod Date	Cal Dly Oil (m3/d)	Monthly Oil (m3)	Cum Prd Oil (m3)	Cal Dly Water (m3/d)	Monthly Water (m3)	Cum Prd Water (m3)	WCT (%)	UWI
100/01-19-008-28W1/0	007405	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2010	May-2015	1.8	56.5	9312.8	17.3	536.7	27642.4	90.48	100/01-19-008-28W1/0
100/04-19-008-28W1/0	005964	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2007	May-2015	0.5	16.2	3696.3	0.2	5.0	1374.3	23.58	100/04-19-008-28W1/0
100/08-19-008-28W1/2	006124	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2007	May-2015	0.4	11.9	2307.6	0.1	2.7	599.9	18.49	100/08-19-008-28W1/2
102/08-19-008-28W1/0	007406	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2010	May-2015	0.9	28.5	6830.6	2.0	62.9	14835.8	68.82	102/08-19-008-28W1/0
100/09-19-008-28W1/0	007013	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2009	May-2015	2.1	64.3	10478.5	3.9	121.8	18583.4	65.45	100/09-19-008-28W1/0
100/14-19-008-28W1/0	005472	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2005	Nov-2008	0.2	6.9	1222.9	0.2	7.1	859.5	50.71	100/14-19-008-28W1/0
100/16-19-008-28W1/0	007407	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	1/1/2012	May-2015	2.9	90.8	6982.9	25.3	783.9	37747.4	89.62	100/16-19-008-28W1/0
100/01-30-008-28W1/0	006799	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2008	May-2015	2.3	71.2	10962.6	3.7	113.2	14445.2	61.39	100/01-30-008-28W1/0
100/08-30-008-28W1/0	007075	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2009	May-2015	1.4	43.8	9992.0	2.1	64.1	11717.4	59.41	100/08-30-008-28W1/0
100/09-30-008-28W1/0	006037	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2006	Nov-2010	0.2	6.6	2543.0	0.1	2.9	1823.3	30.53	100/09-30-008-28W1/0
102/09-30-008-28W1/0	007365	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	7/1/2010	May-2015	2.7	84.6	10847.4	4.5	140.2	18822.0	62.37	102/09-30-008-28W1/0
100/16-30-008-28W1/0	006581	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2008	May-2015	1.1	35.1	11548.7	1.7	51.8	9067.9	59.61	100/16-30-008-28W1/0
100/01-31-008-28W1/0	006639	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	5/1/2008	May-2015	0.5	14.7	2975.3	0.1	2.1	924.9	12.50	100/01-31-008-28W1/0
102/01-31-008-28W1/0	006853	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	1/1/2009	May-2015	1.4	43.2	9698.1	2.6	80.9	13160.5	65.19	102/01-31-008-28W1/0
100/08-31-008-28W1/0	006940	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	6/1/2009	May-2015	2.8	86.1	13607.6	2.3	71.5	9680.3	45.37	100/08-31-008-28W1/0
100/09-31-008-28W1/0	007095	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2009	May-2015	2.0	60.8	9928.6	2.8	85.4	11767.6	58.41	100/09-31-008-28W1/0
100/13-31-008-28W1/0	006631	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	5/1/2008	May-2015	0.1	3.6	772.9	0.2	5.5	2328.5	60.44	100/13-31-008-28W1/0
100/16-31-008-28W1/0	006634	Vertical	BAKKEN-THREE FORKS B	BAKKEN,THREEFK	Producing	5/1/2008	Oct-2013	0.1	1.9	1628.7	0.1	2.1	1987.9	52.50	100/16-31-008-28W1/0
102/16-31-008-28W1/0	007548	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2010	May-2015	1.7	53.1	7928.2	2.7	84.1	11898.7	61.30	102/16-31-008-28W1/0
									779.8	**133264.7**			**209266.9**		

Table No. 4: OOIP Calculation

UWI	MBKKN OOIP 0.5 md	Lyleton UA OOIP 1.0 md	Lyleton LA OOIP 1.0 md	Lyleton B OOIP 0.5 md	Total OOIP (m3) GLJ cut offs	MB Phi-h 0.5 md	UA Phi-h 1.0 md	LA Phi-h 1.0 md	LB Phi-h 0.5 md
01-19-008-28W1M	12635	0	0	28697	41332	0.142	0.000	0.000	0.301
02-19-008-28W1M	12108	0	0	31488	43595	0.139	0.000	0.000	0.330
03-19-008-28W1M	12466	0	0	31250	43716	0.147	0.000	0.000	0.327
04-19-008-28W1M	11796	0	0	29091	40887	0.133	0.000	0.000	0.305
05-19-008-28W1M	11983	0	0	26155	38138	0.133	0.000	0.000	0.274
06-19-008-28W1M	12894	0	0	29503	42397	0.146	0.000	0.000	0.309
07-19-008-28W1M	12644	0	0	31145	43790	0.145	0.000	0.000	0.326
08-19-008-28W1M	13440	0	0	28712	42152	0.149	0.000	0.000	0.301
09-19-008-28W1M	13364	0	0	27481	40845	0.150	0.000	0.000	0.288
10-19-008-28W1M	12466	0	0	29631	42097	0.143	0.000	0.000	0.310
11-19-008-28W1M	12009	0	0	26879	38888	0.136	0.000	0.000	0.282
12-19-008-28W1M	11031	0	0	23057	34088	0.127	0.000	0.000	0.241
13-19-008-28W1M	10190	8816	2422	20223	41651	0.117	0.085	0.025	0.212
14-19-008-28W1M	11391	0	3450	24977	39818	0.130	0.000	0.036	0.262
15-19-008-28W1M	12158	0	4299	27208	43664	0.139	0.000	0.045	0.285
16-19-008-28W1M	12991	0	0	26562	39553	0.148	0.000	0.000	0.278
01-30-008-28W1M	12900	0	0	27254	40154	0.147	0.000	0.000	0.285
02-30-008-28W1M	11984	0	4555	27356	43895	0.136	0.000	0.048	0.287
03-30-008-28W1M	10805	0	3532	24402	38739	0.123	0.000	0.037	0.256
04-30-008-28W1M	9451	8607	2614	19802	40475	0.107	0.083	0.027	0.207
05-30-008-28W1M	9056	0	4293	22453	35803	0.103	0.000	0.045	0.235
06-30-008-28W1M	10656	0	4627	26850	42133	0.121	0.000	0.048	0.281
07-30-008-28W1M	11896	0	5213	29878	46987	0.136	0.000	0.055	0.313
08-30-008-28W1M	12934	0	0	30422	43356	0.147	0.000	0.000	0.319
09-30-008-28W1M	13664	0	0	34227	47891	0.155	0.000	0.000	0.358
10-30-008-28W1M	12276	0	0	33016	45292	0.140	0.000	0.000	0.346
11-30-008-28W1M	10902	0	5898	29354	46154	0.125	0.000	0.062	0.307
12-30-008-28W1M	9302	0	6008	25459	40770	0.106	0.000	0.063	0.267
13-30-008-28W1M	9426	0	7162	26405	42993	0.108	0.000	0.075	0.277
14-30-008-28W1M	11303	0	6990	30331	48624	0.129	0.000	0.073	0.318

UWI	MBKKN OOIP 0.5 md	Lyleton UA OOIP 1.0 md	Lyleton LA OOIP 1.0 md	Lyleton B OOIP 0.5 md	Total OOIP (m3) GLJ cut offs	MB Phi-h 0.5 md	UA Phi-h 1.0 md	LA Phi-h 1.0 md	LB Phi-h 0.5 md
15-30-008-28W1M	12932	0	0	32978	45910	0.148	0.000	0.000	0.345
16-30-008-28W1M	15042	0	0	33857	48899	0.171	0.000	0.000	0.355
01-31-008-28W1M	16643	0	0	32112	48755	0.184	0.000	0.000	0.336
02-31-008-28W1M	13311	0	0	31978	45289	0.151	0.000	0.000	0.335
03-31-008-28W1M	11535	0	0	30620	42154	0.131	0.000	0.000	0.321
04-31-008-28W1M	10321	0	0	28575	38896	0.117	0.000	0.000	0.299
05-31-008-28W1M	10683	0	0	29591	40274	0.122	0.000	0.000	0.310
06-31-008-28W1M	10838	0	0	30676	41514	0.124	0.000	0.000	0.321
07-31-008-28W1M	11684	0	0	31133	42817	0.139	0.000	0.000	0.326
08-31-008-28W1M	15067	0	0	30723	45790	0.177	0.000	0.000	0.322
09-31-008-28W1M	8898	0	0	29495	38393	0.103	0.000	0.000	0.309
10-31-008-28W1M	7857	0	0	30361	38218	0.093	0.000	0.000	0.318
11-31-008-28W1M	9122	0	0	30741	39863	0.104	0.000	0.000	0.322
12-31-008-28W1M	10881	0	0	30590	41471	0.124	0.000	0.000	0.320
13-31-008-28W1M	10484	0	0	31364	41848	0.120	0.000	0.000	0.328
14-31-008-28W1M	7665	0	0	30765	38430	0.087	0.000	0.000	0.322
15-31-008-28W1M	4860	0	0	29667	34526	0.055	0.000	0.000	0.311
16-31-008-28W1M	4030	0	0	28310	32340	0.053	0.000	0.000	0.296
					2,005,264	**m3**			

TABLE NO. 5

Sinclair Unit 17 - Section 19, 30 & 31-08-28W1
Middle Bakken/Three Forks Fm (Lyleton) Rock and Fluid Properties

Formation Pressure		9,400 kPa @ -452 mSS	Initial Average Reservoir Pressure
Formation Temperature		32°C	
Saturation Pressure		2034 kPa	Bubble Point
GOR		6-10 m^3/m^3	Gas-Oil Ratio
API Oil Gravity		36-38	
Swi (fraction)		0.4	Intial Water Saturation
Produced Water Sp. Gr.		1.11	
Produced Water pH		7.1-7.3	
Produced Water TDS (mg/L)		150,000-156,000	
Wettability		Moderately oil-wet	
Average Air Permeability	Middle Bakken	2	Wt. Average Core Data
	Lyleton A	1.9	(kmax>0.5 mD)
	Lyleton B	1.3	
Average Porosity (Fraction)	Middle Bakken	0.16	Wt. Average Core Data
	Lyleton A	0.14	(kmax>0.5 mD)
	Lyleton B	0.17	

Wt Average from all MBKKN/Lyleton Cores in the proposed Sinclair Unit 17 boundary and immediate area