

PROPOSED SINCLAIR UNIT NO. 12

Application for Enhanced Oil Recovery Waterflood Project

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

February 7th, 2014
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 and 10 as shown on **Figure 1**.

In the eastern part of the Sinclair field, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. The following represents an application by Tundra to establish Sinclair Unit No. 12 (N/2 Section 5, Sections 7, 8, 16, 17, 18, S/2 Section 20-8-28W1, Section 13-8-29W1) 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 Pool of the Daly Sinclair Oilfield (**Figure 3**).

CONCLUSIONS

1. The proposed Sinclair Unit No. 12 will include 31 horizontal wells and 24 vertical wells, within 112 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located east of Sinclair Unit No. 3 and Sinclair Unit No. 7 (Figure 2).
2. Total Net Original Oil in Place (OOIP) in Sinclair Unit No. 12 has been calculated to be **28,961** thousand barrels (Mbb) for an average of **258.6** net Mbb 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 October 2013 from the 55 wells within the proposed Sinclair Unit No. 12 project area was 1,787.4 Mbb of oil, and 2,572.6 Mbb of water, representing a **6.2%** Recovery Factor (RF) of the Net OOIP.
4. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Sinclair Unit No. 12 project area has been calculated to be **2,489.0** Mbb, with **701.6** Mbb remaining as of the end of October 2013.
5. Ultimate oil recovery of the proposed Sinclair Unit No. 12 OOIP, under the current Primary Production method, is forecasted to be **8.6%**.
6. Figure 4 shows the production from the Sinclair Unit No. 12 which peaked in February 2010 at 1,608 bbl of oil per day (OPD). As of October 2013, production was 558 bbl OPD, 1,304 bbl of water per day (WPD) and a 70.0% watercut.
7. In February 2010, production averaged 37.4 bbl OPD per well in Sinclair Unit No. 12. As of October 2013, average per well production has declined to 11.6 bbl OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **27.6%** in the project area.
8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Sinclair Unit No. 12 has been calculated to be **3,806.0** Mbb, with **2,018.6** Mbb remaining. An incremental **1,316.0** Mbb of proved oil reserves, or **4.5%**, 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. 12 is estimated to be **13.1%**.
10. Based on waterflood response in the adjacent main portion of the Sinclair field, the Three Forks and Middle Bakken Formations in the proposed project area are believed to be suitable reservoirs for WF EOR operations.
11. 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. 12, to complete waterflood patterns with effective 20 acre spacing similar to that of Sinclair Unit No. 5.

DISCUSSION

RESOURCE POTENTIAL IN PROPOSED SINCLAIR UNIT NO. 12

The proposed Sinclair Unit No. 12 project area is located within Township 8, Ranges 28 and 29 W1 of the Daly Sinclair oil field. The proposed Sinclair Unit No. 12 currently consists of 31 horizontal and 24 vertical wells, within an area covering 112 LSDs (Figure 2). This includes the N/2 of Section 5, Sections 7, 8, 16, 17, 18 and the S/2 of Section 20-008-28W1 and Section 13-008-29W1. A project area well list complete with recent production statistics is attached as Table 3.

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

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section attached as Appendix 1. The section runs W to NE approximately through the mid-point of the proposed unit. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton A Siltstone, the Red Shale Marker, Lyleton B Siltstone and the Torquay silty shale. The reservoir units are represented by the Middle Bakken, Lyleton A and Lyleton B Siltstones. The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken/Lyleton B reservoirs. The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved adjacent to the proposed unit (Sinclair Unit 5 and Ewart Unit 3) please see Appendix 2.

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to fine sandstone which may be subdivided on the basis of lithologic characteristics into upper and lower units. The upper portion is very often heavily bioturbated and is generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of well-worn brachiopod, coral and occasional crinoid fragments suggesting deposition in a marginal marine environment. The lower part of the Middle Bakken is generally finely laminated with alternating light and dark laminations with occasional bioturbation. Reservoir quality is highly variable within the Unit area. Within the proposed unit, the Middle Bakken ranges from 2 m on the west side to just over 3 m in the northeast (Appendix 3).

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. < 0.1 md). 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 along the Western edge of the proposed unit (Appendix 4). The Lower Lyleton A pinches out just slightly east of the Upper Lyleton A, and as such, has a greater presence in the proposed unit, but it is limited to the southwest portion (Appendix 5).

The Red Shale Marker can form an aquitard between the overlying Middle Bakken and the underlying Lyleton B reservoir. It consists of brick red dolomitic siltstone which is highly water soluble. The Red Shale Marker is about 3 m thick on the southwest side and pinches out along the northeast side of the proposed unit (Appendix 6). The effectiveness of the Red Shale Marker unit as a permeability barrier is reduced from west to east across the proposed unit area in direct correlation with the reduction in thickness of the Red Shale. As such, over most of the 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 very 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 approximately 3.5 to 4.5 m thick within the proposed unit; thinning from west to east across the proposed unit (Appendix 7).

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

Structure:

Structure contour maps are provided for the top of each major unit (Appendices 8 through 12). The structure within the proposed unit area generally consists of a gentle dip to the SW. 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 reservoir within the proposed unit is very good.

Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir is also good over most of the proposed unit area. The only possible break in vertical continuity between the Middle Bakken and Lyleton B would be on the west from the presence of the Red Shale on the western side of

the proposed unit. The planned injection wells will be completed with multi stage fracture treatments and as such, vertical communication across the 1 to 3 m thick red shale is anticipated.

Where the Red Shale is not present, the vertical continuity between the Middle Bakken and Lyleton B appears to be quite good. There is no evidence that the contact between the two units will reduce flow between the two 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 13 through 20). These maps were generated as follows using core data. 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 Petroleum Consultants, for third party reserve evaluations on Tundra's Sinclair properties. The permeability cutoffs applied are as follows:

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

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

Fluid Contacts:

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

Gross OOIP Estimates

OOIP were calculated by Tundra Geologists Barry Larson and Todd Neely. 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. Todd Neely holds a BSc. in Geology from the University of Manitoba, and has 15 years of industry experience, 4 of which are in the Williston Basin. The dataset used to determine the OOIP values for Unit 12 was originally compiled by Barry Larson. It consists of conventional core analysis of all available core in the Sinclair area. Todd took over Barry's dataset in 2012. Ultimately, OOIP values for Unit 12 were generated by Todd, using Barry's original dataset.

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **4,604 E³m³ (28,961 Mbbl)** using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the Sinclair area (Appendix 21).

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 (ϕ) 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 $\phi \cdot h$ value was calculated for all four productive horizons in all wells with core over each respective formation.

The $\phi \cdot h$ values for all cored wells were contoured using Golden Software's "Surfer 9" program using a 500 m grid node spacing. $\phi \cdot h$ 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. 12 volumetric OOIP estimates on an individual LSD basis by formation. Average OOIP by individual LSD was determined to be **258.6** Mbbbl for Sinclair Unit No. 12.

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. 12 is shown as **Figure 4**. Oil production commenced from the proposed Unit area in July 2004 and peaked during February 2010 at 1,608 bbl OPD. As of October 2013, production was 558 bbl OPD, 1,304 bbl of water per day (WPD) and a 70.0% watercut.

From peak production in February 2010 to date, oil production is declining at an annual rate of approximately **27.6%** under the current Primary Production method.

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

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. 12.

Unit Operator

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

Unitized Zone

The Unitized zone(s) to be waterflooded in the Sinclair Unit No. 12 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 31 horizontal wells and 24 vertical wells to be included in the proposed Sinclair Unit No. 12 are outlined in [Table 3](#).

Unit Lands

The Sinclair Unit No. 12 will consist of 112 LSDs as follows:

North ½ Section 5 of Township 8, Range 28, W1M
Section 7 of Township 8, Range 28, W1M
Section 8 of Township 8, Range 28, W1M
Section 16 of Township 8, Range 28, W1M
Section 17 of Township 8, Range 28, W1M
Section 18 of Township 8, Range 28, W1M
South ½ Section 20 of Township 8, Range 28, W1M
Section 13 of Township 8, Range 29, W1M

The lands included in the 40 acre tracts are outlined in [Table 1](#).

Tract Factors

The proposed Sinclair Unit No. 12 will consist of 112 Tracts based on the 40 acre LSDs containing the existing 31 horizontal and 24 vertical wells.

The Tract Factor contribution for each of the LSD's within the proposed Sinclair Unit No. 12 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. 12. 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. 12.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Sinclair Unit No. 12 Bakken project are based on internal engineering assessments. Project area specific reservoir and geological parameters were utilized and then compared to Sinclair Unit No. 1 parameters, yielding the WF EOR response observed there to date.

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

Pre-Production of New Horizontal Injection Wells

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. 12.

Primary production from the original vertical/horizontal producing wells in the proposed Sinclair Unit No. 12 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 13 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. 12 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. 1 as an analogy because it is developed with a similar waterflood pattern design of a horizontal injector with offsetting vertical producers.

Primary Production Forecast

Cumulative production in the Sinclair Unit No. 12 project area, to the end of October 2013 from 55 wells, was 1,787.4 Mbbl of oil and 2,572.6 Mbbl of water for a recovery factor of **6.2%** of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Sinclair Unit No. 12 has been estimated to be **2,489.0** Mbbl, or an **8.6%** Recovery Factor (RF) of OOIP. Remaining Producing Primary Reserves has been estimated to be **701.6** Mbbl to the end of October 2013. 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. 12, while maximizing reservoir knowledge (**Table 6**).

Criteria for Conversion to Water Injection Well

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

Twenty-three (23) horizontal wells are planned to be drilled for pre-production followed by permanent water injection service as shown in **Figure 5**. No existing vertical wells within the proposed Sinclair Unit No. 12 project are planned for conversion to water injection, as oil production response is better with horizontal injectors than with vertical injectors.

The above schedule allows for the proposed Sinclair Unit No. 12 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 1 Pilot Waterflood (**Figure 6**).

The proposed Sinclair Unit No. 12 Secondary Waterflood oil production forecast over time is plotted on **Figure 8**. Total Proved EOR recoverable reserves in the proposed Sinclair Unit No. 12 project under Secondary WF has been estimated at **3,806.0** Mbbl (**Figure 9**), resulting in a **13.1%** overall RF of calculated Net OOIP.

An incremental **1,316.0** Mbbl of oil reserves is forecasted, based on a recovery factor estimate using Sinclair Units 1-3 analogy, to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method. Incremental Secondary RF is forecasted to be **4.5%** of the calculated OOIP.

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate an actual fracture pressure gradient range of 18.5 to 22.0 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be somewhat lower than these values due to expected reservoir pressure depletion.

WATERFLOOD OPERATING STRATEGY

Water Source

The injection water for the proposed Sinclair Unit No. 12 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. 12 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. 12.

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. 12 will be drilled, cleaned out, and configured downhole for injection as shown in **Figure 10**. 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. 12 horizontal water injection well rate is forecasted to average **10 – 25** m³ WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

A static gradient & pressure buildup test was taken at the 100/11-08-008-28W1 open hole horizontal well in March 2007 ([Appendix 22](#)).

The static gradient was taken at a depth of 930 m TVD with a pressure of **9,194 kPaa**.

The build-up was taken at a depth of 402 m TVD, with a last measured stable pressure of 4,115 kPaa. Using the fluid gradient of 10.4 kPa/m from the static gradient test and converting it to a bottomhole pressure, a MPP pressure of **9,588 kPaa** was calculated.

The majority of the horizontal producers in the proposed Sinclair Unit No. 12 did not start production until 2008 and after. The vertical wells within the proposed unit boundaries started production as early as 2005, however, cumulative production volumes from 2005 – 2007 were relatively small. Therefore, this could be representative of an estimated initial reservoir pressure for the proposed unit area. This is also validated by DST data from the nearby 100/01-07-008-29W1 well drilled in the Sinclair pool which would suggest an initial reservoir pressure of **9,445 KPa** in February 2005 ([Appendix 22](#)).

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. 12 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring 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. 12 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling or water breakthrough, or out-of-Unit migration. The monitoring and surveillance will also provide early indicators of any such issues so that waterflood operations may be altered to maximize ultimate secondary reserves recovery from the proposed Sinclair Unit No. 12.

On Going Reservoir Pressure Surveys

For each openhole horizontal injection well, a measured reservoir pressure will be obtained prior to water injection. These pressures will be reported within the Annual Progress Reports for Sinclair Unit No. 12 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. 12 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. 12 waterflood operation will utilize the existing Tundra operated source well supply and water plant (WP) facilities located at 3-4-8-29 W1M which supplies the existing Sinclair 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. 12. 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. 12 Application.

Sinclair Unit No. 12 Unitization, and execution of the formal Sinclair Unit No. 12 Agreement by affected Mineral Owners, is expected during Q1 2014. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Sinclair Unit No. 12 Application.

Should the Petroleum Branch have further questions or require more information, please contact Ray Lee at 403.767.1247 or by email at ray.lee@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Ray Lee, P. Eng. February 7th, 2014

R30

R29

R28W1

Figure No. 1

T9

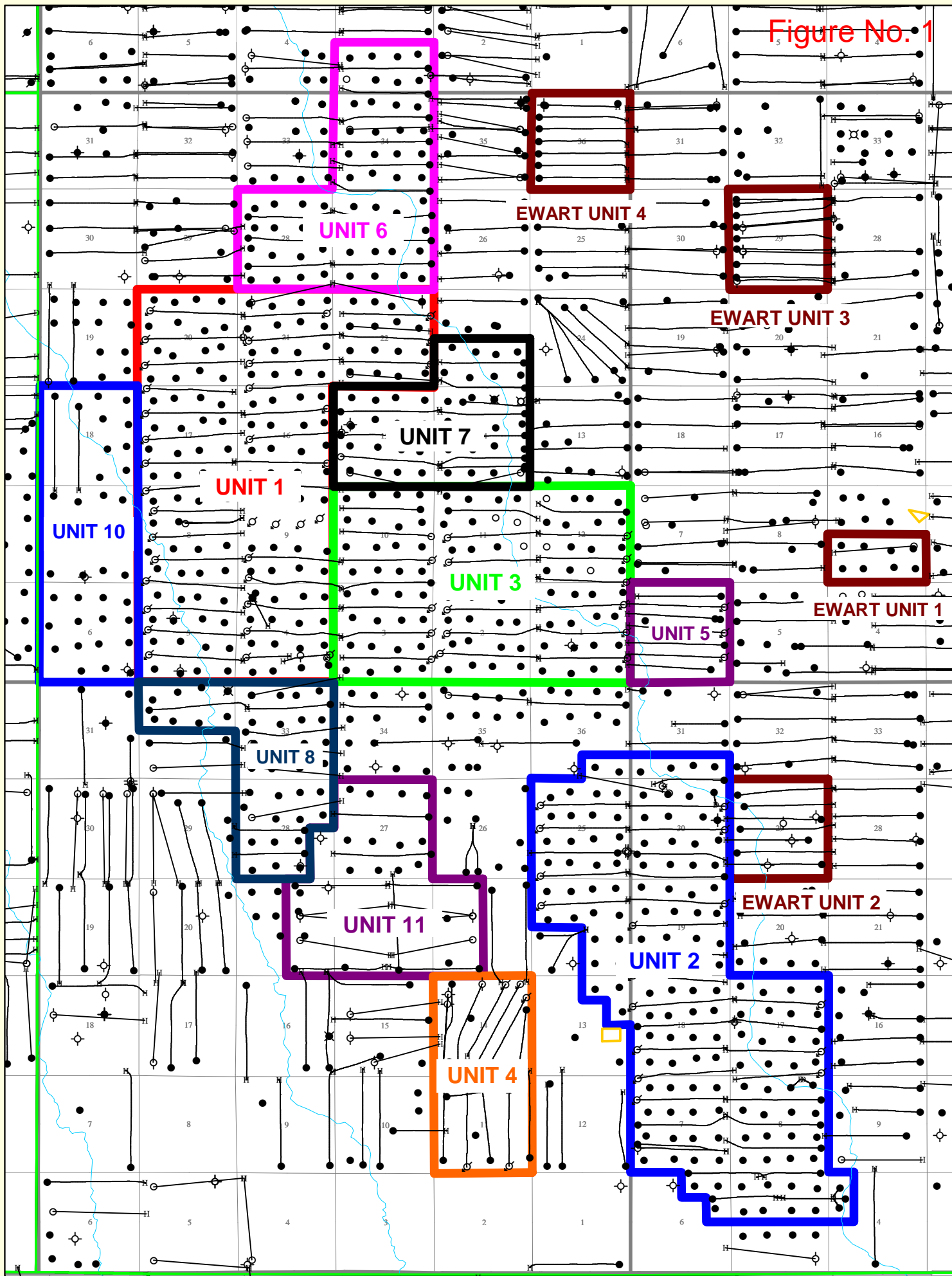
T9

T8

T8

T7

T7



R30

R29

R28W1

R29

R28W1

Figure No. 2

T9

T9

EWART UNIT 4

EWART UNIT 3

Proposed UNIT 12

T7

T8

UNIT 3

UNIT 5

EWART UNIT 1

T8

T7

T7

EWART UNIT 2

R29

R28W1

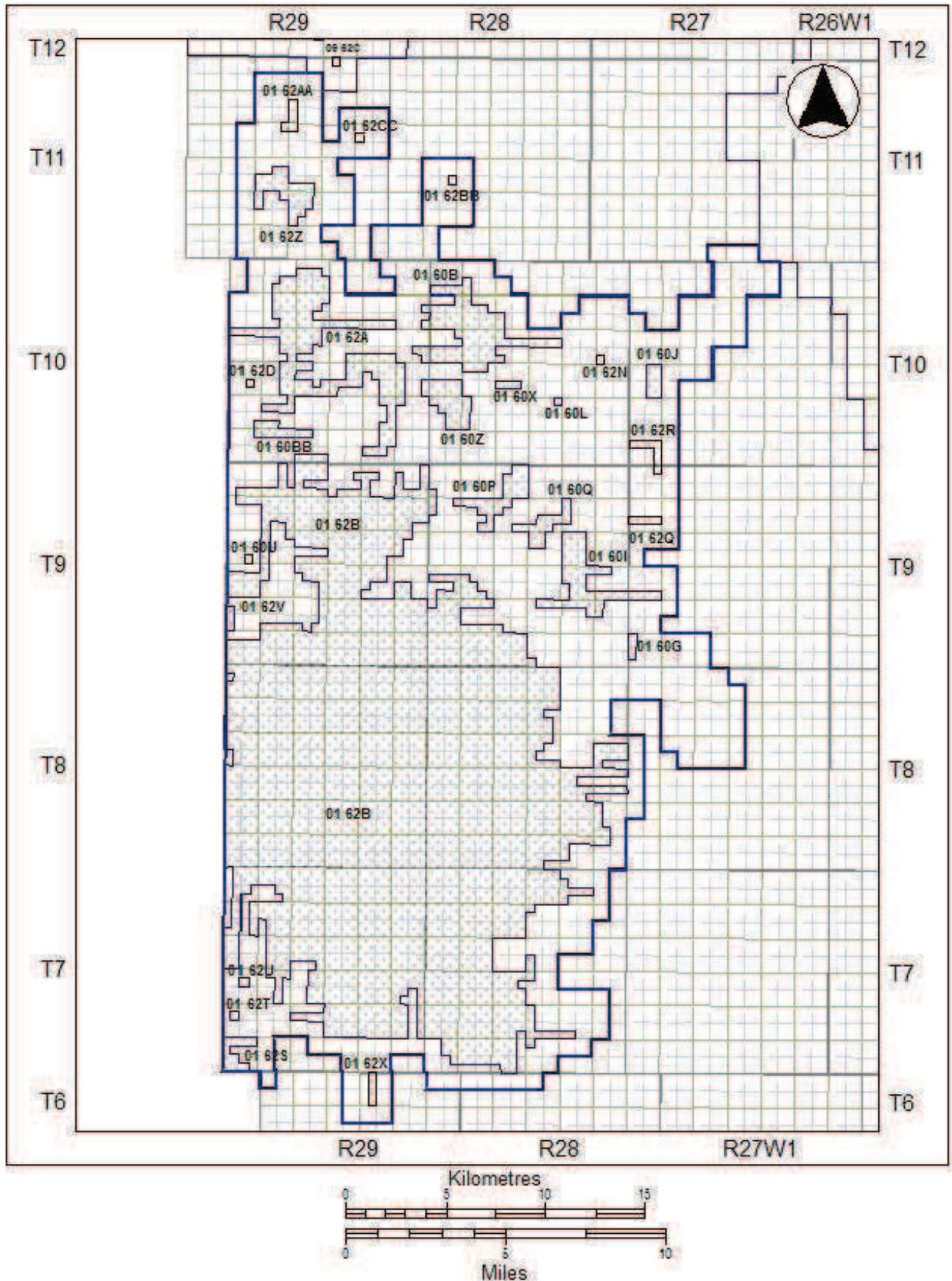


FIGURE 14 - DALY SINCLAIR BAKKEN & BAKKEN-THREE FORKS POOLS (01 60A - 01 60BB & 01 62A – 01 62CC) (Drawn on the DLS System Quarter Section Grid)

Sinclair Unit 12

Production Graph

On Prod: 2004-07 to 2013-10
 Cum Oil: 1787424.8 bbl
 Cum Gas: 0.0 mcf
 Cum Wtr: 2572600.6 bbl

Prod Zone: BAKKEN; TORQUAY
 Field: DALY (1)
 Pool Code: 62B
 Unit Code:

of Wells: 55
 Fluid: Oil
 Mode: Producing; Potential; Standing

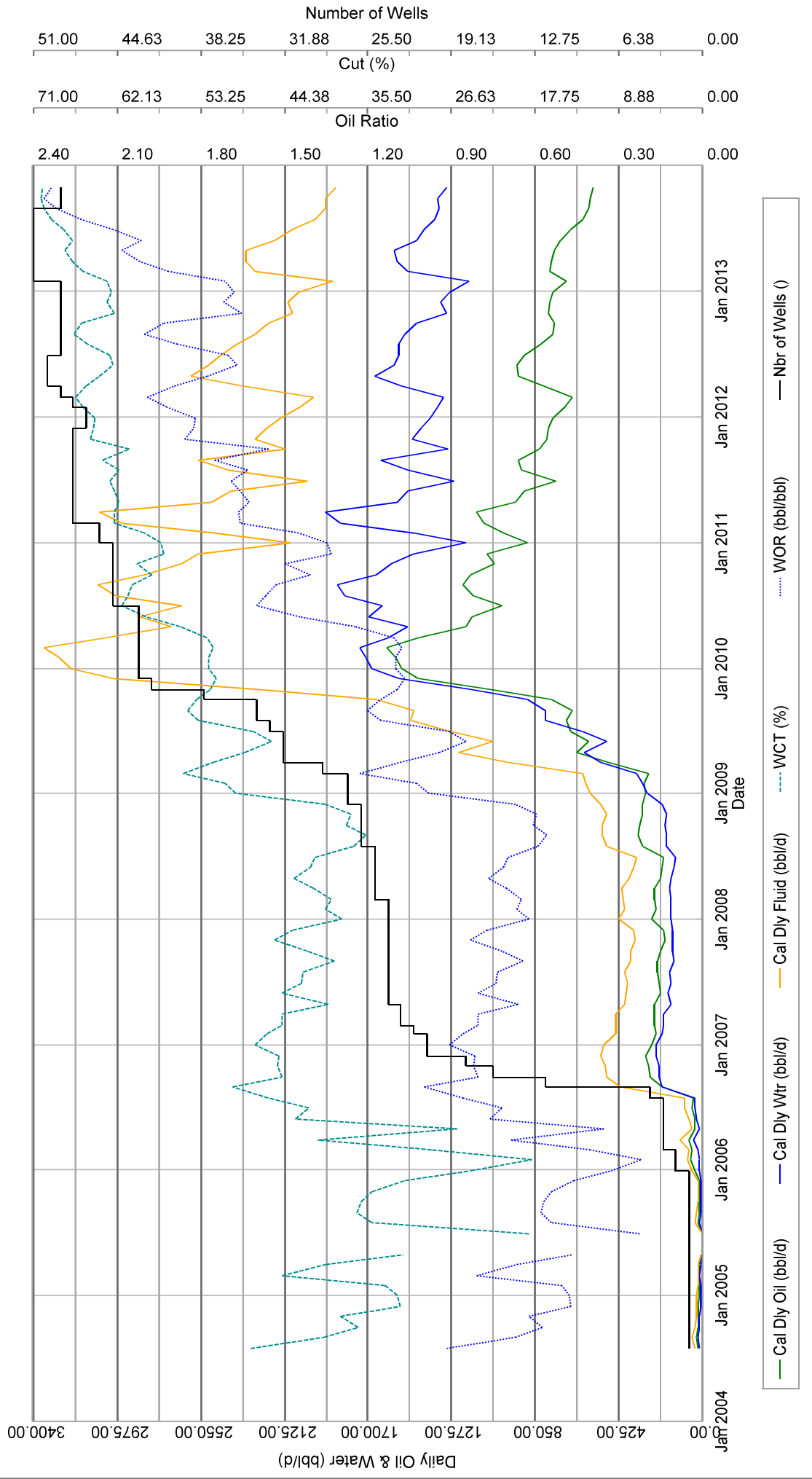
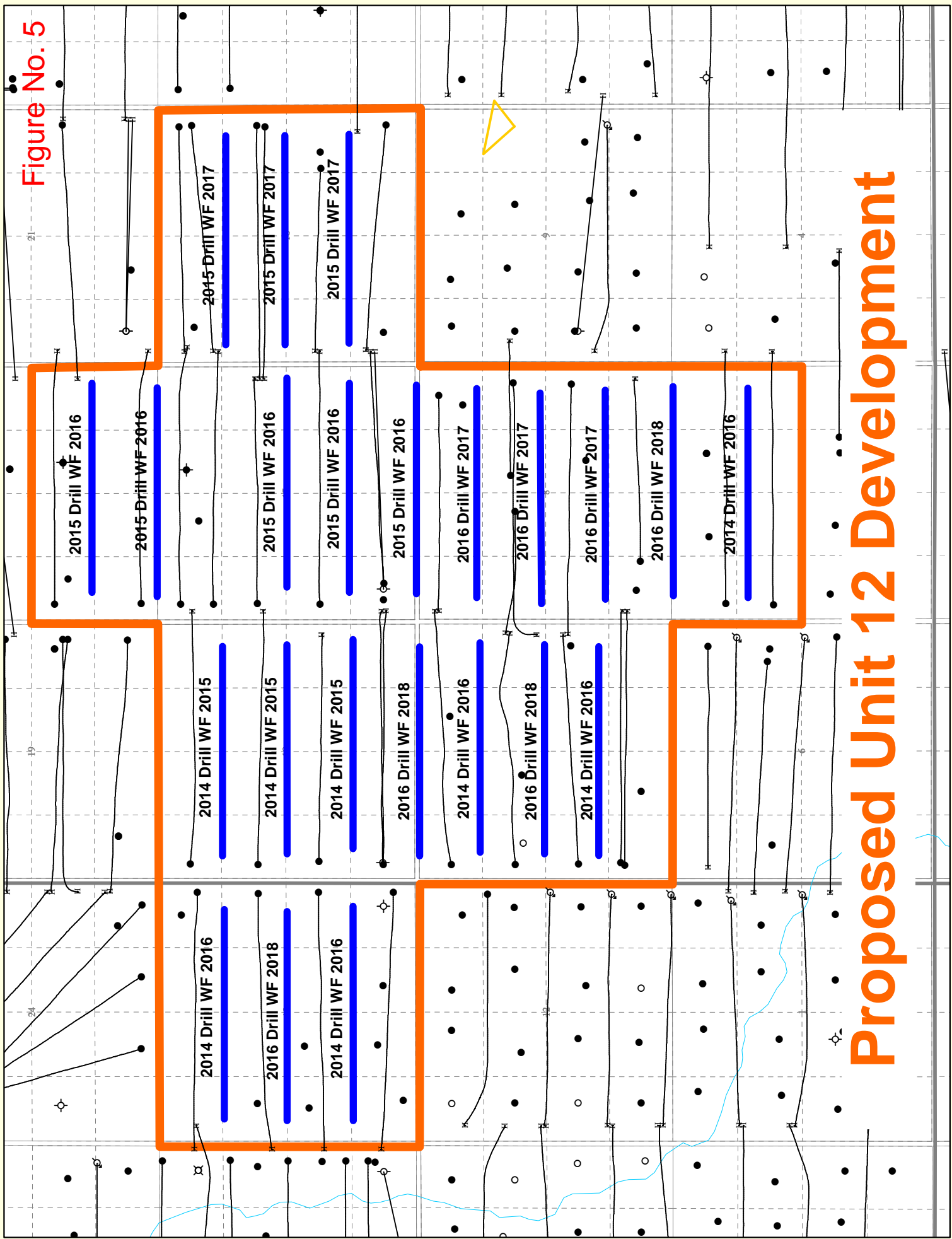


Figure No. 5



Proposed Unit 12 Development

R28W1

R28W1

R29

R29

T8

T8

Sinclair Unit 1 Pilot Waterflood

Figure No. 6

Production Report

of Wells: 16
 Fluid: Oil; Water Injection
 Mode: Producing; Injection

Prod Zone: BAKKEN; TORQUAY
 Field: DALY (1)
 Pool Code: 62B
 Unit Code: 162B01

On Prod: 2004-12 to 2013-10
 Cum Oil: 141701.5 m3
 Cum Gas: 0.0 E3m3
 Cum Wtr: 21722.6 m3

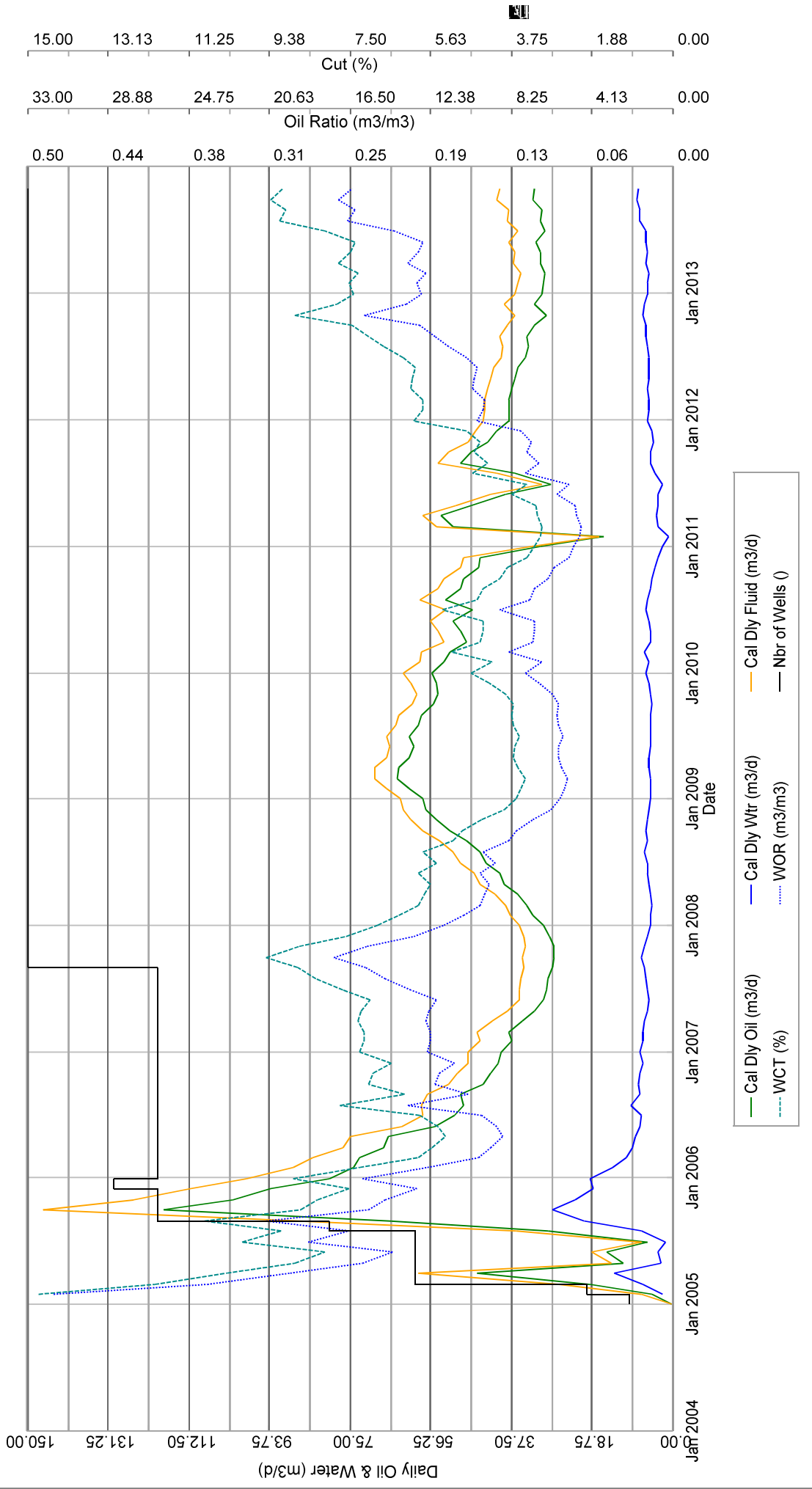


Figure No. 7

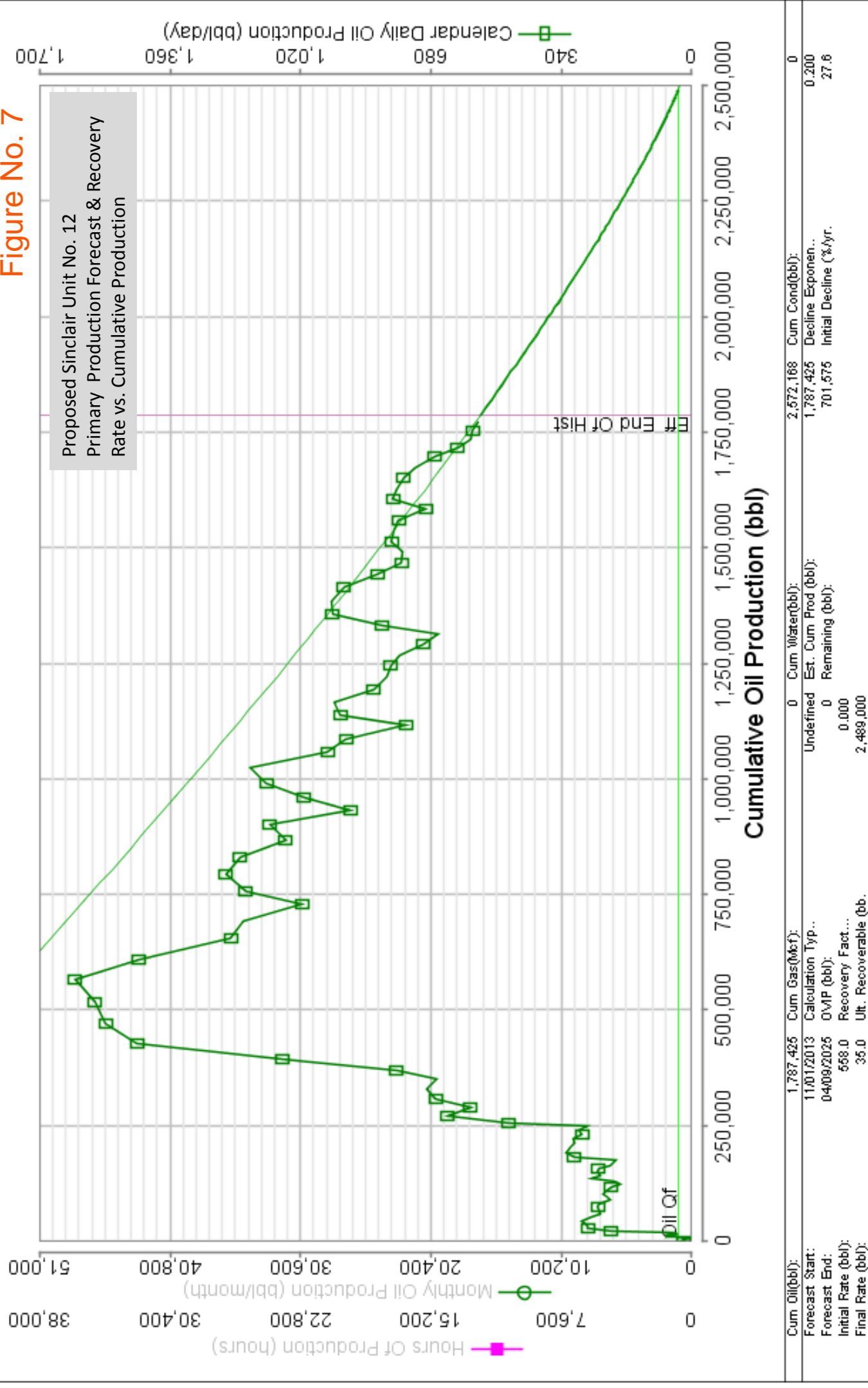
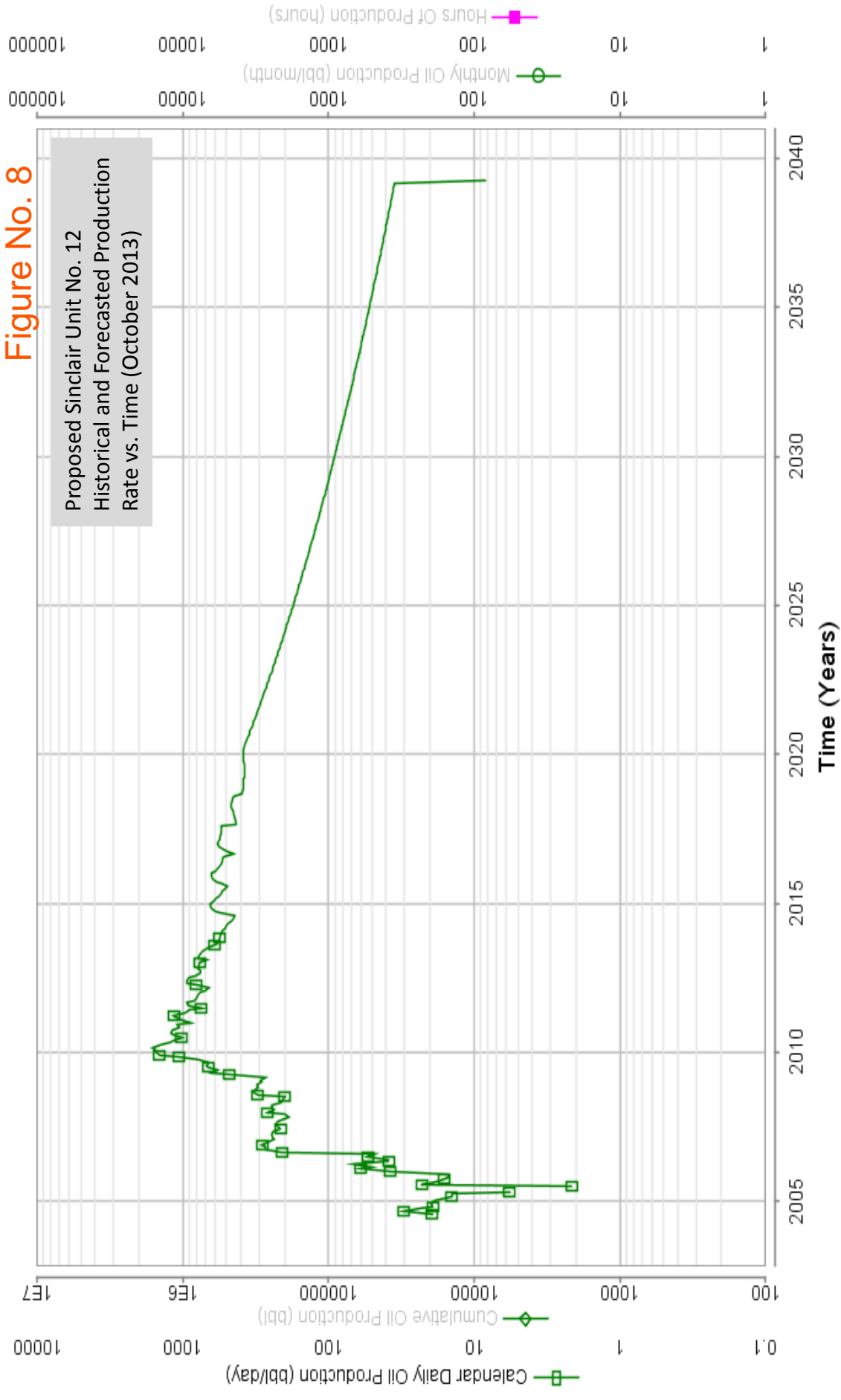


Figure No. 8

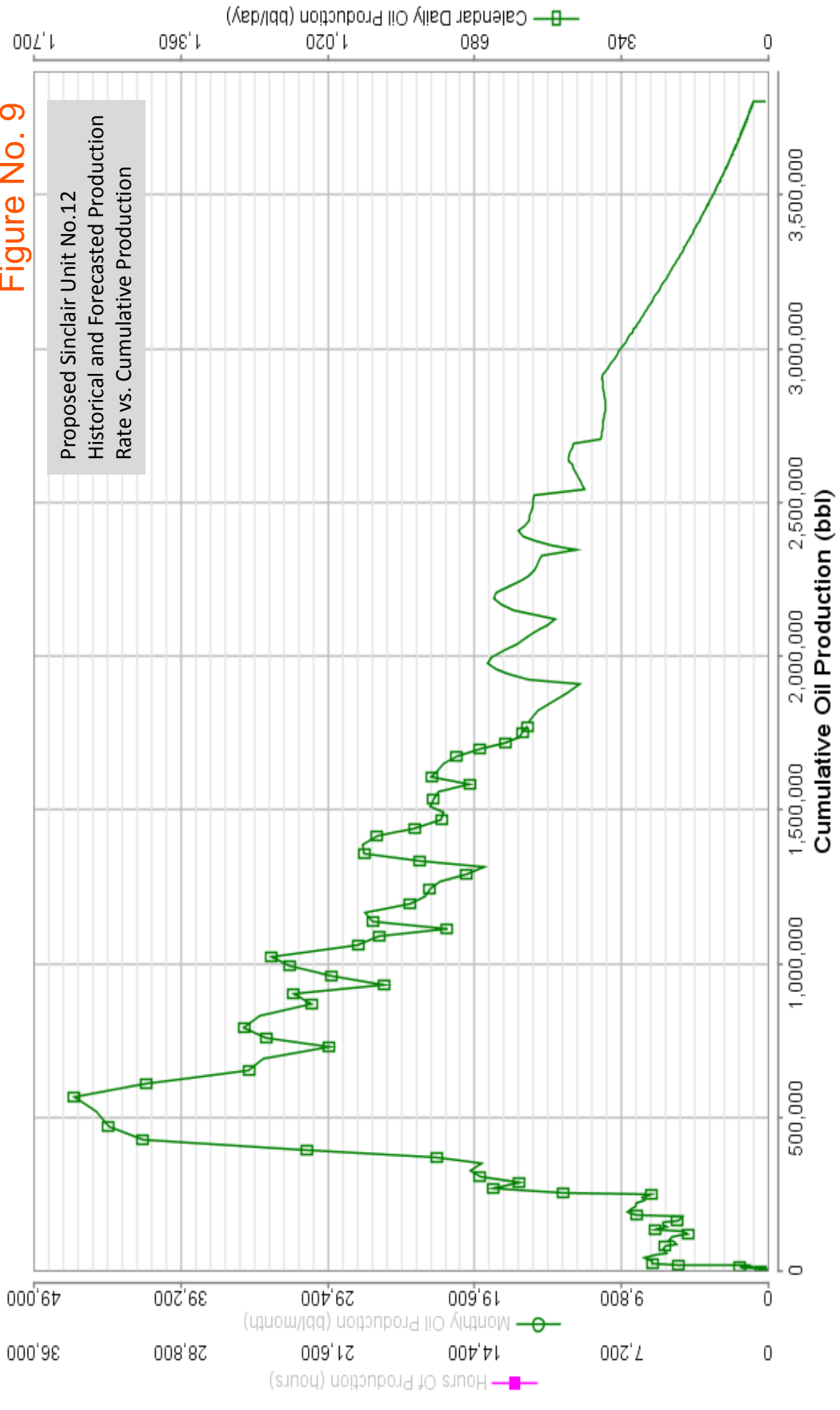
Proposed Sinclair Unit No. 12
 Historical and Forecasted Production
 Rate vs. Time (October 2013)



Cum Oil (bbl)	1,787,425	Cum Gas (Mcf)	0	Cum Water (bbl)	2,531,766	Cum Cond (bbl)	0
Forecast Start	2013/11/01	Calculation Type		Est. Cum Prod	(bbl)	Decline Exponent	
Forecast End	2039/03/31	OVIP	(bbl)	Remaining	(bbl)	Initial Decline (%/Yr)	93.7
Initial Rate (bbl/day)	1,556,751.3	Recovery Factor		Surface Loss	(Mcf)	Life Index	11.78
Final Rate (bbl/day)	98,404.7	Ult. Recoverable (bbl)	3,806,000	Total Sales	(Mcf)	Half Life (years)	5.48

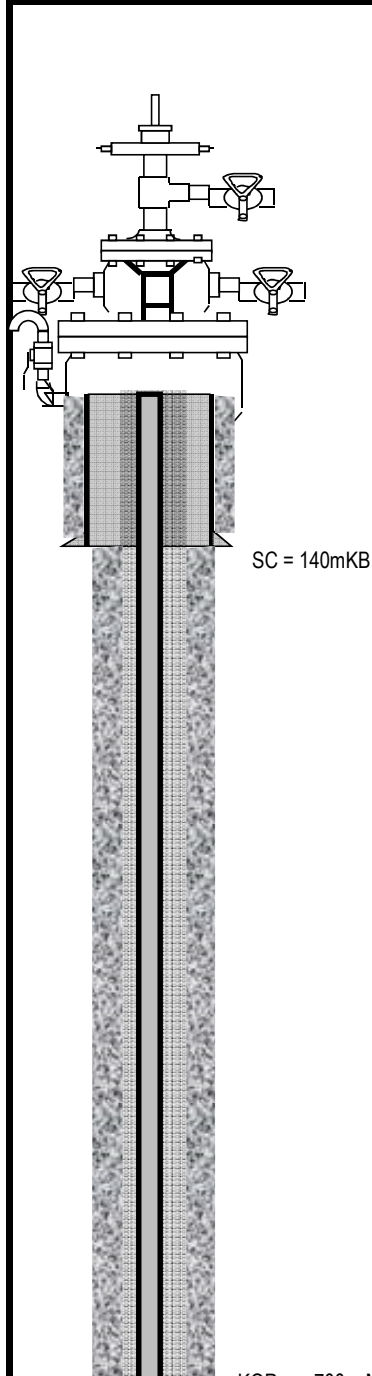
Figure No. 9

Proposed Sinclair Unit No.12
Historical and Forecasted Production
Rate vs. Cumulative Production



Cum Oil (bb)	1,787,425	Cum Gas (Mcf)	0	Cum Water (bb)	2,531,766	Cum Cond (bb)	0
Forecast Start	2013/11/01	Calculation Type		Est. Cum Prod (bb)	1,787,425	Decline Exponent	93.7
Forecast End	2039/03/31	OVIP	(bb)	Remaining (bb)	2,018,575	Initial Decline (%/yr)	11.78
Initial Rate (bb/day)	1,566,751.3	Recovery Factor		Surface Loss		Life Index	5.48
Final Rate (bb/day)	98,404.7	Ult. Recoverable (bb)	3,806,000	Total Sales (Mcf)		Half Life (years)	

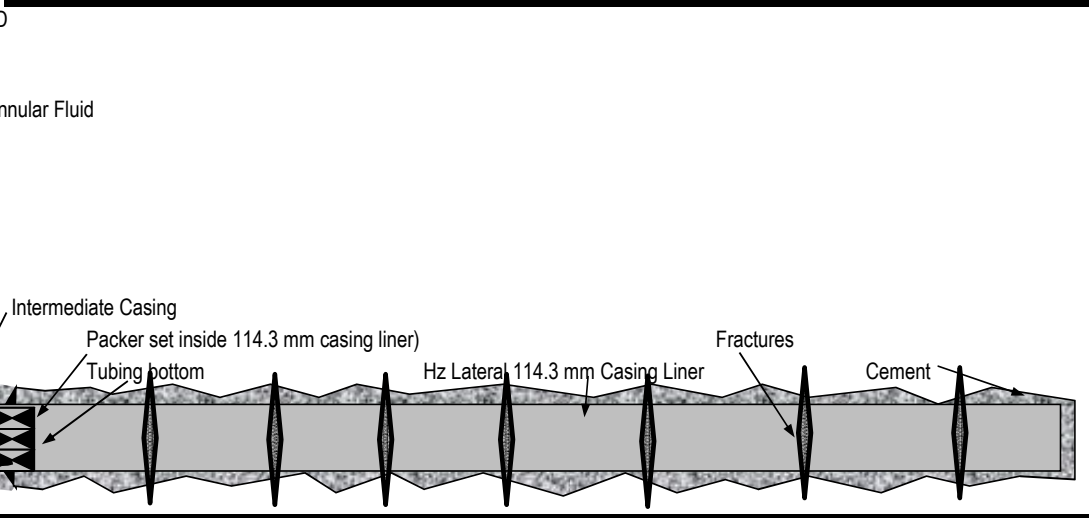
TYPICAL CEMENTED LINER WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



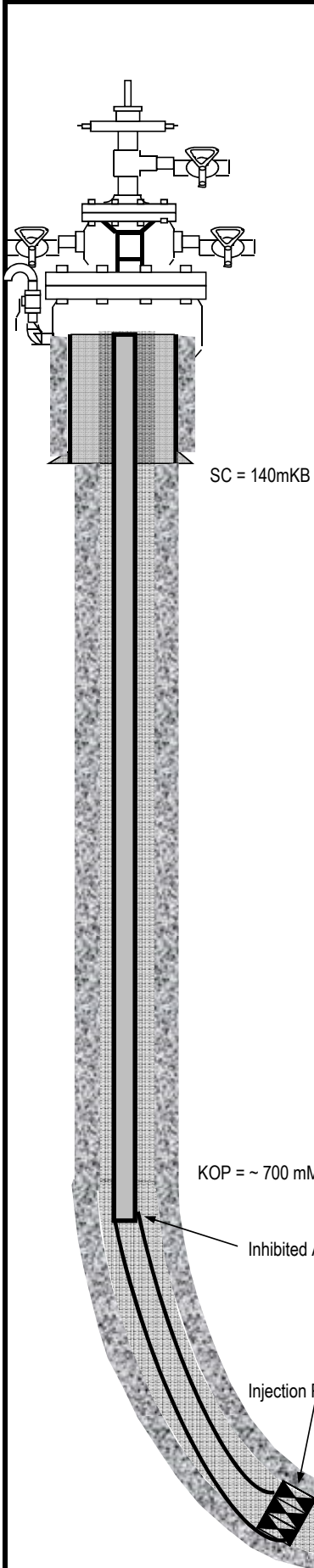
WELL NAME: Tundra Sinclair Unit 12 HZNTL Cemented Liner WIW			WELL LICENCE:		
Prepared by WRJ (average depths)		Date: 2012			
Elevations :					
KB [m]		KB to THF [m]		TD [m]	2400.0
GL [m]		CF (m)		PBTD [m]	
Current Perfs:	Cemented Casing / Liner		950.0	to	2400.0
Current Perfs:				to	
KOP:	700 m MD		Total 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
Production Liner	114.3	17.26	L-80	Surf or from Intermed Csg 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:					
Item	Description	K.B.--Tbg. Flg.	Length	0.00	Top @ m KB
	Corrosion Protected ENC Coated Packer (set inside 114.3 mm Casing / Liner)				
	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:					



KOP = ~ 700 mMD
Inhibited Annular Fluid



TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME: Tundra Sinclair Unit 12 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. Fig.	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:

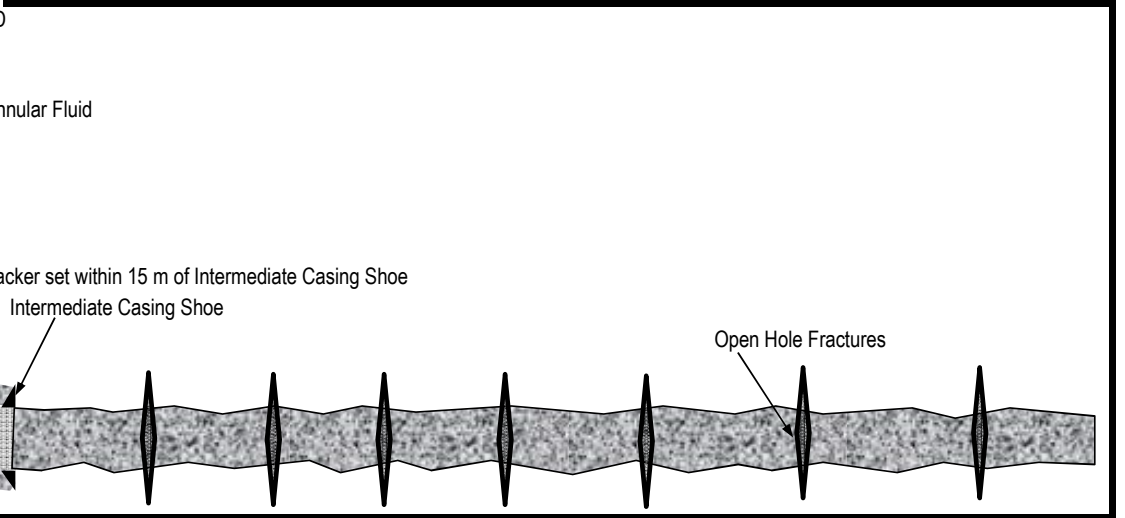


Figure No. 11

Sinclair Water Injection System

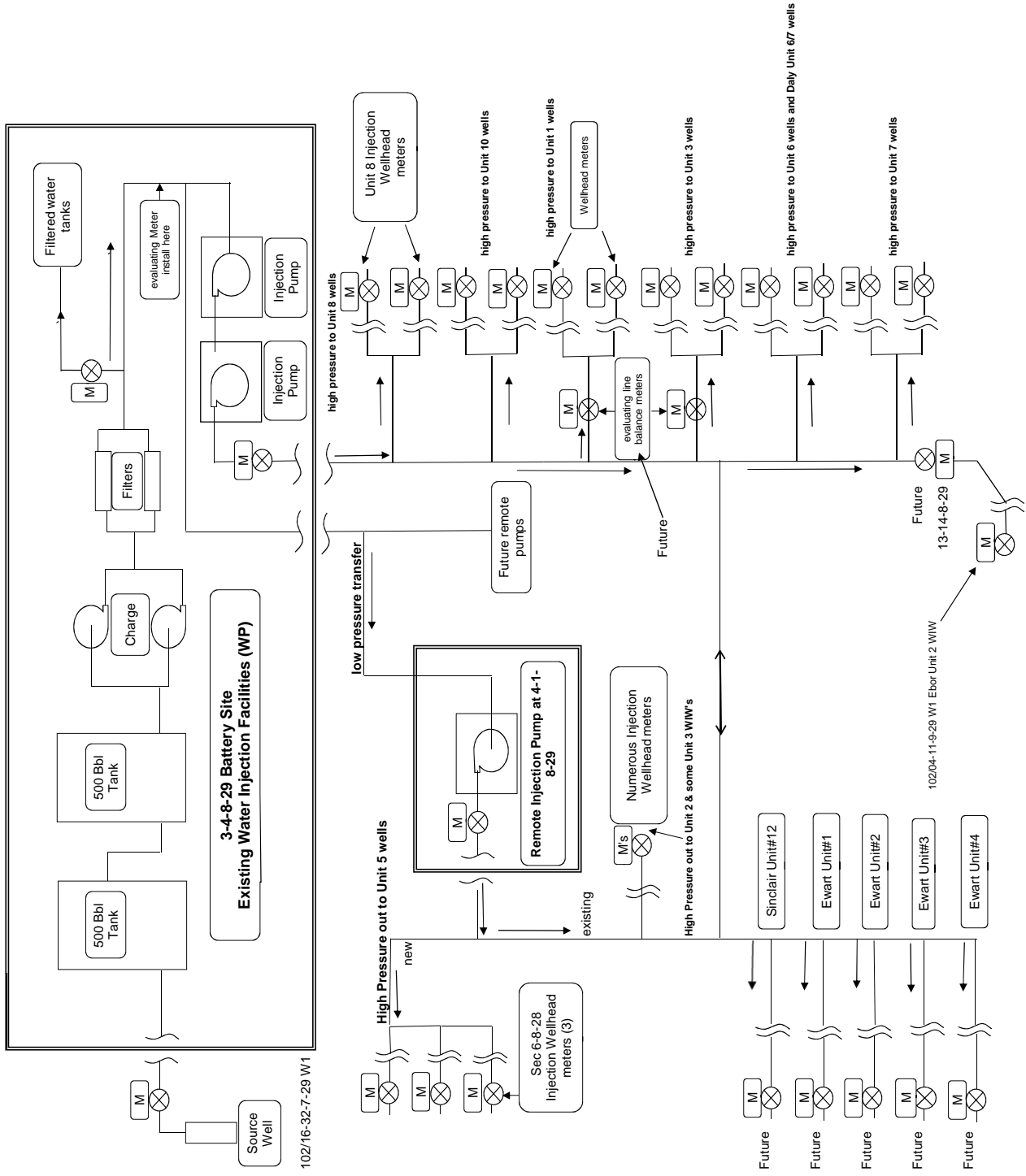
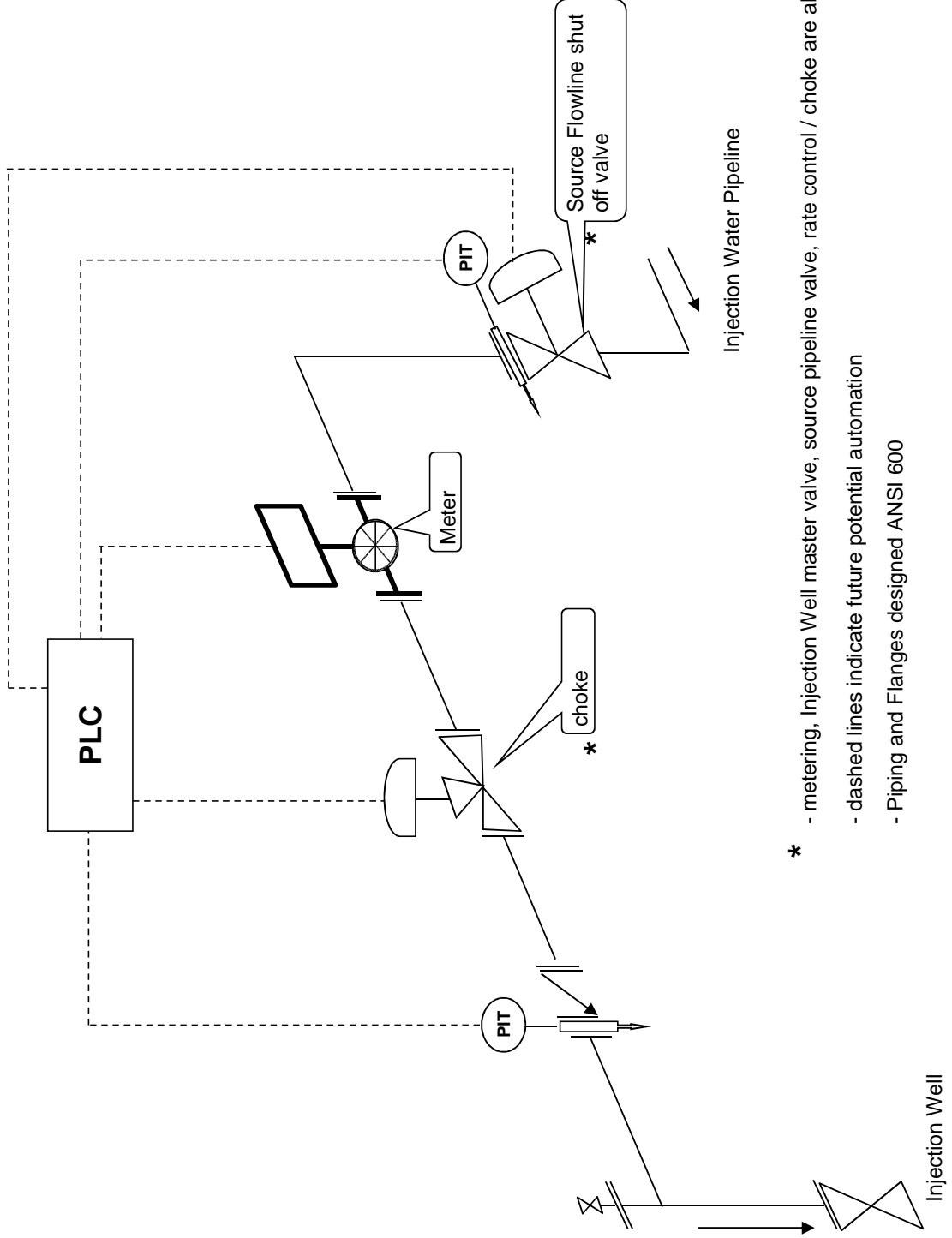


Figure No. 12

Sinclair Unit No. 12

Proposed Injection Well Surface Piping P&ID



- * - metering, Injection Well master valve, source pipeline valve, rate control / choke are all standard
- dashed lines indicate future potential automation
- Piping and Flanges designed ANSI 600

Sinclair Unit No. 12

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

TABLE NO. 1: TRACT PARTICIPATION FOR PROPOSED SINCLAIR UNIT NO. 12

Tract No.	Working Interest			Royalty Interest		Tract Participation
	Land Description	Owner	Share (%)	Owner	Share (%)	
1	09-05-008-28W1M	Tundra Oil & Gas Partnership	100%	5139318 Manitoba Ltd.	100%	0.839791717%
2	10-05-008-28W1M	Tundra Oil & Gas Partnership	100%	5139318 Manitoba Ltd.	100%	0.908440809%
3	11-05-008-28W1M	Tundra Oil & Gas Partnership	100%	101084695 Saskatchewan Ltd. T. Ramsay Incorporated	50% 50%	1.045310257%
4	12-05-008-28W1M	Tundra Oil & Gas Partnership	100%	101084695 Saskatchewan Ltd. T. Ramsay Incorporated	50% 50%	0.976908133%
5	13-05-008-28W1M	Tundra Oil & Gas Partnership	100%	101084695 Saskatchewan Ltd. T. Ramsay Incorporated	50% 50%	0.844759585%
6	14-05-008-28W1M	Tundra Oil & Gas Partnership	100%	101084695 Saskatchewan Ltd. T. Ramsay Incorporated	50% 50%	0.766828765%
7	15-05-008-28W1M	Tundra Oil & Gas Partnership	100%	5139318 Manitoba Ltd.	100%	0.809834070%
8	16-05-008-28W1M	Tundra Oil & Gas Partnership	100%	5139318 Manitoba Ltd.	100%	0.810607952%
9	01-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50.00% 12.50% 12.50% 6.25% 6.25% 12.50%	0.886836586%
10	02-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.958218267%
11	03-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.910215693%
12	04-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.986443565%
13	05-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.636755528%
14	06-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.692366127%
15	07-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.757195656%
16	08-07-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Gregg C. & Kathleen M. Campbell Neil F. Campbell George F. Hawkin Janis D. Hoogstraten Judith St. Clair-Capewell	50% 12.50% 12.50% 6.25% 6.25% 12.50%	0.674637579%

Tract No.	Working Interest			Royalty Interest		Tract Participation
	Land Description	Owner	Share (%)	Owner	Share (%)	
17	09-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Cenovus Energy Inc.	100.00%	0.782043934%
18	10-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Cenovus Energy Inc.	100.00%	0.754268123%
19	11-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Erin E. Bender Bret D. Bender	50.00% 50.00%	0.777334215%
20	12-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Erin E. Bender Bret D. Bender	50.00% 50.00%	0.715021989%
21	13-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Erin E. Bender Bret D. Bender	50.00% 50.00%	0.830178073%
22	14-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Erin E. Bender Bret D. Bender	50.00% 50.00%	0.858265014%
23	15-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Cenovus Energy Inc.	100.00%	0.865680462%
24	16-07-008-28W1M	Tundra Oil & Gas Partnership	100%	Cenovus Energy Inc.	100.00%	0.813289356%
25	01-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd. HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	96.8875% 3.1125%	0.857249226%
26	02-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	0.900214755%
27	03-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	0.910171387%
28	04-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	0.787916323%
29	05-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	0.875645592%
30	06-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	1.029672880%
31	07-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd.	100.00%	0.988426462%
32	08-08-008-28W1M	Tundra Oil & Gas Partnership	100%	74103 Manitoba Ltd. HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	96.8875% 3.1125%	0.974603314%
33	09-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.117141805%
34	10-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.192401634%
35	11-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.076734533%
36	12-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	0.874183967%
37	13-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	0.913591888%
38	14-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.091504578%
39	15-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.230990640%
40	16-08-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership	100.00%	1.135562008%
41	01-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.822002085%
42	02-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.800011459%
43	03-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski University of Manitoba	45.265% 45.265% 9.47%	0.859537254%
44	04-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski	50.00% 50.00%	0.961625903%
45	05-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski University of Manitoba	46.475% 46.475% 7.05%	0.991814636%
46	06-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski University of Manitoba	48.70% 48.70% 2.60%	0.876130066%
47	07-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.824688229%
48	08-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.837196944%
49	09-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.839563788%
50	10-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.830213252%
51	11-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski	50.00% 50.00%	0.866903358%

Tract No.	Working Interest			Royalty Interest		Tract Participation
	Land Description	Owner	Share (%)	Owner	Share (%)	
52	12-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski University of Manitoba	46.75% 46.75% 6.50%	0.923794184%
53	13-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski	50.00% 50.00%	0.819470489%
54	14-16-008-28W1M	Tundra Oil & Gas Partnership	100%	Donald J. Shalanski T. David Shalanski	50.00% 50.00%	0.823591437%
55	15-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.815464130%
56	16-16-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.831983656%
57	01-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	1.139104702%
58	02-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	1.135878302%
59	03-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.992961280%
60	04-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.824817762%
61	05-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	1.015985551%
62	06-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.962654435%
63	07-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	1.034204403%
64	08-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	1.053063249%
65	09-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	0.962076395%
66	10-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	0.956080379%
67	11-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.938512592%
68	12-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.901357020%
69	13-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.876486728%
70	14-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. 5301807 Manitoba Ltd.	50.00% 50.00%	0.827881274%
71	15-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd.	50.00% 50.00%	0.892481773%
72	16-17-008-28W1M	Tundra Oil & Gas Partnership	100%	1093105 Ontario Inc. Purvis Energy Ltd. Missing Royalty Owner	47.2375% 47.2375% 5.525%	0.876545879%
73	01-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Dale Smeltz Ltd. 5651396 Manitoba Ltd. 5704708 Manitoba Ltd.	33.3334% 33.3333% 33.3333%	0.943851560%
74	02-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Dale Smeltz Ltd. 5651396 Manitoba Ltd. 5704708 Manitoba Ltd.	33.3334% 33.3333% 33.3333%	0.942472060%
75	03-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.911785653%
76	04-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.890957054%
77	05-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.792121377%

Tract No.	Working Interest			Royalty Interest		Tract Participation
	Land Description	Owner	Share (%)	Owner	Share (%)	
78	06-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.810171467%
79	07-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Dale Smeltz Ltd. 5651396 Manitoba Ltd. 5704708 Manitoba Ltd.	33.3334% 33.3333% 33.3333%	0.825612593%
80	08-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Dale Smeltz Ltd. 5651396 Manitoba Ltd. 5704708 Manitoba Ltd.	33.3334% 33.3333% 33.3333%	0.860366876%
81	09-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.877293948%
82	10-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.867853117%
83	11-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership Hazel Barkman James R. Gibson	50.00% 25.00% 25.00%	0.859290042%
84	12-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership Hazel Barkman James R. Gibson	50.00% 25.00% 25.00%	0.823994690%
85	13-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership Hazel Barkman James R. Gibson	50.00% 25.00% 25.00%	0.877348381%
86	14-18-008-28W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership Hazel Barkman James R. Gibson	50.00% 25.00% 25.00%	0.914298629%
87	15-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.909151392%
88	16-18-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.890870254%
89	01-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.775753811%
90	02-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.745518259%
91	03-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.713147925%
92	04-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.699513305%
93	05-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.604441773%
94	06-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.621279187%
95	07-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.602424550%
96	08-20-008-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100.00%	0.685024491%
97	01-13-008-29W1M	Tundra Oil & Gas Partnership	100%	5215731 Manitoba Inc. 1268052 Alberta Ltd.	25.00% 75.00%	0.863313771%
98	02-13-008-29W1M	Tundra Oil & Gas Partnership	100%	5215731 Manitoba Inc. 1268052 Alberta Ltd.	25.00% 75.00%	0.808495952%
99	03-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	2.004049203%
100	04-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	2.023369439%

Tract No.	Working Interest			Royalty Interest		Tract Participation
	Land Description	Owner	Share (%)	Owner	Share (%)	
101	05-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	0.812159211%
102	06-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	0.682885641%
103	07-13-008-29W1M	Tundra Oil & Gas Partnership	100%	5215731 Manitoba Inc. 1268052 Alberta Ltd.	25.00% 75.00%	0.731911695%
104	08-13-008-29W1M	Tundra Oil & Gas Partnership	100%	5215731 Manitoba Inc. 1268052 Alberta Ltd.	25.00% 75.00%	0.764137275%
105	09-13-008-29W1M	Tundra Oil & Gas Partnership	100%	Brian J. & Theresa Isaac 1268052 Alberta Ltd.	25.00% 75.00%	0.803933635%
106	10-13-008-29W1M	Tundra Oil & Gas Partnership	100%	Brian J. & Theresa Isaac 1268052 Alberta Ltd.	25.00% 75.00%	0.760289873%
107	11-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	0.734650744%
108	12-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	0.700692658%
109	13-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	1.713433974%
110	14-13-008-29W1M	Tundra Oil & Gas Partnership	100%	E.S.P. 13,5 Ltd.	100.00%	0.704596180%
111	15-13-008-29W1M	Tundra Oil & Gas Partnership	100%	Brian J. & Theresa Isaac 1268052 Alberta Ltd.	25.00% 75.00%	0.728733742%
112	16-13-008-29W1M	Tundra Oil & Gas Partnership	100%	Brian J. & Theresa Isaac 1268052 Alberta Ltd.	25.00% 75.00%	0.747479569%

100.00000000%

LS-SE	Tract	OOIP (m3)	HZ Wells Alloc Prod (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	Tract Factor	Tract
15-17	15-17-008-28W1M	40,423	1,864.5	0.0	1,864.5	38559	0.892481773%	15-17-008-28W1M
16-17	16-17-008-28W1M	39,546	1,676.3	0.0	1,676.3	37870	0.876545879%	16-17-008-28W1M
01-18	01-18-008-28W1M	42,235	1,457.4	0.0	1,457.4	40778	0.943851560%	01-18-008-28W1M
02-18	02-18-008-28W1M	42,289	1,570.4	0.0	1,570.4	40718	0.942472060%	02-18-008-28W1M
03-18	03-18-008-28W1M	40,984	1,591.3	0.0	1,591.3	39393	0.911785653%	03-18-008-28W1M
04-18	04-18-008-28W1M	40,013	1,520.1	0.0	1,520.1	38493	0.890957054%	04-18-008-28W1M
05-18	05-18-008-28W1M	37,108	2,885.8	0.0	2,885.8	34223	0.792121377%	05-18-008-28W1M
06-18	06-18-008-28W1M	38,154	3,151.2	0.0	3,151.2	35003	0.810171467%	06-18-008-28W1M
07-18	07-18-008-28W1M	38,792	3,122.3	0.0	3,122.3	35670	0.825612593%	07-18-008-28W1M
08-18	08-18-008-28W1M	38,965	1,794.0	0.0	1,794.0	37171	0.860366876%	08-18-008-28W1M
09-18	09-18-008-28W1M	40,794	2,892.0	0.0	2,892.0	37902	0.877293948%	09-18-008-28W1M
10-18	10-18-008-28W1M	40,631	3,136.2	0.0	3,136.2	37495	0.867853117%	10-18-008-28W1M
11-18	11-18-008-28W1M	40,136	3,011.5	0.0	3,011.5	37125	0.859290042%	11-18-008-28W1M
12-18	12-18-008-28W1M	38,786	3,186.7	0.0	3,186.7	35600	0.823994690%	12-18-008-28W1M
13-18	13-18-008-28W1M	40,637	2,732.6	0.0	2,732.6	37905	0.877348381%	13-18-008-28W1M
14-18	14-18-008-28W1M	42,369	2,867.8	0.0	2,867.8	39501	0.914298629%	14-18-008-28W1M
15-18	15-18-008-28W1M	42,119	2,840.0	0.0	2,840.0	39279	0.909151392%	15-18-008-28W1M
16-18	16-18-008-28W1M	41,162	2,672.6	0.0	2,672.6	38,489	0.890870254%	16-18-008-28W1M
01-20	01-20-008-28W1M	34,998	1,482.2	0.0	1,482.2	33,516	0.775753811%	01-20-008-28W1M
02-20	02-20-008-28W1M	33,857	1,647.4	0.0	1,647.4	32,209	0.745518259%	02-20-008-28W1M
03-20	03-20-008-28W1M	32,459	1,648.0	0.0	1,648.0	30,811	0.713147925%	03-20-008-28W1M
04-20	04-20-008-28W1M	31,751	1,529.5	0.0	1,529.5	30,222	0.699513305%	04-20-008-28W1M
05-20	05-20-008-28W1M	28,356	1,149.1	1,093.0	2,242.1	26,114	0.604441773%	05-20-008-28W1M
06-20	06-20-008-28W1M	28,075	1,233.2	0.0	1,233.2	26,842	0.621279187%	06-20-008-28W1M
07-20	07-20-008-28W1M	29,018	1,230.8	1,760.6	2,991.4	26,027	0.602424550%	07-20-008-28W1M
08-20	08-20-008-28W1M	30,731	1,135.0	0.0	1,135.0	29,596	0.685024491%	08-20-008-28W1M
01-13	01-13-008-29W1M	38,366	1,067.9	0.0	1,067.9	37,298	0.863313771%	01-13-008-29W1M
02-13	02-13-008-29W1M	37,908	1,123.0	1,855.4	2,978.4	34,930	0.808495952%	02-13-008-29W1M
03-13	03-13-008-29W1M	88,772	1,077.6	1,111.4	2,189.0	86,583	2.004049203%	03-13-008-29W1M
04-13	04-13-008-29W1M	92,333	964.2	3,951.4	4,915.6	87,417	2.023369439%	04-13-008-29W1M
05-13	05-13-008-29W1M	37,780	2,121.2	570.6	2,691.8	35,088	0.812159211%	05-13-008-29W1M
06-13	06-13-008-29W1M	33,033	2,338.6	1,191.4	3,530.0	29,503	0.682885641%	06-13-008-29W1M
07-13	07-13-008-29W1M	34,063	2,441.9	0.0	2,441.9	31,621	0.731911695%	07-13-008-29W1M
08-13	08-13-008-29W1M	35,352	2,338.5	0.0	2,338.5	33,014	0.764137275%	08-13-008-29W1M
09-13	09-13-008-29W1M	36,373	1,640.2	0.0	1,640.2	34,733	0.803933635%	09-13-008-29W1M
10-13	10-13-008-29W1M	34,543	1,695.6	0.0	1,695.6	32,847	0.760289873%	10-13-008-29W1M
11-13	11-13-008-29W1M	33,359	1,619.4	0.0	1,619.4	31,740	0.734650744%	11-13-008-29W1M
12-13	12-13-008-29W1M	32,789	1,538.4	978.4	2,516.8	30,273	0.700692658%	12-13-008-29W1M
13-13	13-13-008-29W1M	76,219	2,192.5	0.0	2,192.5	74,027	1.713433974%	13-13-008-29W1M
14-13	14-13-008-29W1M	32,821	2,379.4	0.0	2,379.4	30,441	0.704596180%	14-13-008-29W1M
15-13	15-13-008-29W1M	33,981	2,496.6	0.0	2,496.6	31,484	0.728733742%	15-13-008-29W1M
16-13	16-13-008-29W1M	36,418	2,382.5	1,741.6	4,124.1	32,294	0.747479569%	16-13-008-29W1M
		4,604,423	230,907.6	53,132.1	284,039.7	4,320,383	100.00000000%	

Table No. 3: Sinclair Unit No. 12 Well List

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Prod Date	Last 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 (%)
00/12-05-008-28W1/0	007050	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	10/1/2009	Oct-2013	1.2	37.7	7357.8	2.1	65.8	7039.2	63.57
00/13-05-008-28W1/0	007285	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	6/1/2010	Oct-2013	1.6	49.5	8909.4	3.1	95.1	7809.3	65.77
00/14-05-008-28W1/0	005946	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	8/1/2006	Oct-2013	0.3	8.9	3249.1	0.2	6.5	1795.8	42.21
00/15-05-008-28W1/2	006117	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	11/1/2006	Oct-2013	0.2	6.4	2186.0	0.1	3.0	1021.9	31.91
00/03-07-008-28W1/0	005939	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2006	Oct-2013	0.1	3.5	1895.9	0.5	15.3	2379.7	81.38
00/04-07-008-28W1/0	006920	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2009	Oct-2013	1.7	54.2	7994.7	1.4	43.2	5157.2	44.35
00/05-07-008-28W1/0	006928	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2009	Oct-2013	2.2	68.8	9682.2	12.7	394.9	21289.6	85.16
00/08-07-008-28W1/0	005940	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	8/1/2006	Oct-2013	0.5	14.9	2588.4	0.5	16.1	3361.1	51.94
00/11-07-008-28W1/0	006119	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	11/1/2006	Oct-2013	0.1	1.6	978.7	0.1	3.0	715.6	65.22
00/12-07-008-28W1/0	005963	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Potential	9/1/2006	Oct-2013	0.1	1.8	1539.9	0.1	4.3	636.8	70.49
02/12-07-008-28W1/0	008974	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	1/1/2013	Oct-2013	7.8	240.6	2639.6	16.1	498.1	5091.3	67.43
00/13-07-008-28W1/0	008963	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	1/1/2013	Oct-2013	8.4	261.1	3833.9	14.4	447.4	5923.9	63.15
00/15-07-008-28W1/0	005947	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	8/1/2006	Oct-2013	0.3	8.5	1380.1	0.3	9.6	1124.5	53.04
00/04-08-008-28W1/0	005941	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	8/1/2006	Oct-2013	0.6	19.4	5397.8	0.3	7.9	2228.6	28.94
02/04-08-008-28W1/0	006665	Horizontal	BAKKEN-THREE FORKS B	TORQUAY	Producing	7/1/2008	Oct-2013	2.2	67.9	11906.5	1.0	30.5	5399.8	31.00
00/07-08-008-28W1/0	006082	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	10/1/2006	Jul-2013	0.1	4.5	2951.4	0.3	8.8	2482.7	66.17
00/08-08-008-28W1/0	006929	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2009	Oct-2013	3.6	111.4	12146.9	2.3	71.2	5931.7	38.99
00/10-08-008-28W1/0	008507	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2012	Oct-2013	3.5	108.1	3647.6	2.5	78.8	3543.6	42.16
00/11-08-008-28W1/0	006286	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	4/1/2007	Oct-2013	1.0	30.8	5516.5	0.9	28.0	3765.5	47.62
00/16-08-008-28W1/0	005292	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	7/1/2004	Oct-2013	0.9	28.0	4819.1	0.6	18.0	2729.3	39.13
02/16-08-008-28W1/0	006797	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2008	Oct-2013	1.8	57.1	5355.8	32.1	995.0	45299.4	94.57
00/01-16-008-28W1/0	006909	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2009	Oct-2013	2.1	66.5	9128.9	2.6	81.5	8365.0	55.07
00/04-16-008-28W1/0	006198	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2007	Oct-2013	0.3	10.2	3001.1	0.2	5.3	923.7	34.19
00/08-16-008-28W1/0	006103	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2006	Oct-2013	0.2	6.3	1428.2	0.4	13.4	2759.5	68.02
02/08-16-008-28W1/0	007053	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	10/1/2009	Oct-2013	2.2	69.1	7936.9	2.9	90.3	9598.2	56.65
00/09-16-008-28W1/0	006910	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2009	Oct-2013	0.2	7.7	8142.8	8.0	248.3	9138.0	96.99
00/13-16-008-28W1/0	006580	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2008	Oct-2013	0.5	14.8	2018.0	0.5	15.1	1838.2	50.50
00/16-16-008-28W1/0	007017	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2009	Oct-2013	2.9	89.7	7112.6	3.4	106.7	9901.4	54.33
00/04-17-008-28W1/0	005942	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	7/1/2006	Oct-2013	0.4	13.7	2071.1	0.1	4.3	1441.0	23.89
02/04-17-008-28W1/0	006902	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2009	Oct-2013	2.3	71.7	8929.7	4.4	137.8	10911.0	65.78
03/04-17-008-28W1/0	009443	Horizontal	N/A	N/A	Standing	N/A								
00/05-17-008-28W1/0	007055	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	10/1/2009	Oct-2013	2.3	71.8	10943.9	2.1	64.6	9470.9	47.36
00/12-17-008-28W1/0	006903	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2009	Oct-2013	2.1	65.7	10116.0	2.3	70.9	9407.3	51.90
00/13-17-008-28W1/0	007018	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2009	Oct-2013	2.1	65.6	8701.5	2.2	67.1	9829.4	50.57
00/14-17-008-28W1/0	005943	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2006	Oct-2013	0.3	9.3	3373.5	0.4	11.7	4078.0	55.71
00/04-18-008-28W1/0	006932	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	6/1/2009	Oct-2013	1.3	41.7	6139.2	20.1	622.7	38371.4	93.72
02/04-18-008-28W1/0	009212	Horizontal	N/A	N/A	Standing	N/A								
00/05-18-008-28W1/0	007286	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	6/1/2010	Oct-2013	3.0	94.0	10953.3	18.3	568.8	39975.0	85.82
00/12-18-008-28W1/0	006935	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	7/1/2009	Oct-2013	2.9	90.9	12226.3	13.9	431.5	28021.8	82.60
00/13-18-008-28W1/0	007069	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	10/1/2009	Oct-2013	1.9	59.9	11113.0	2.1	63.7	9944.5	51.54

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Prod Date	Last 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 (%)
00/04-20-008-28W1/0	007504	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2011	Oct-2013	3.7	116.2	6307.1	4.8	149.4	9101.9	56.25
00/05-20-008-28W1/0	005987	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	9/1/2006	Oct-2011	0.0	0.1	1093.0	0.0	0.1	1113.8	50.00
02/05-20-008-28W1/0	007755	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2011	Oct-2013	3.1	94.8	4748.1	7.2	223.7	9129.7	70.24
00/07-20-008-28W1/2	005794	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2006	May-2012	0.2	6.1	1760.6	0.6	18.1	3783.9	74.79
02/01-13-008-29W1/0	008451	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	2/1/2012	Oct-2013	4.9	151.0	4232.6	6.3	196.7	6869.7	56.57
00/02-13-008-29W1/0	006123	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	1/1/2007	Oct-2013	0.1	2.3	1855.4	0.2	5.5	1907.7	70.51
00/03-13-008-29W1/0	005951	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	8/1/2006	Oct-2013	0.1	4.2	1111.4	0.2	5.5	1691.3	56.70
00/04-13-008-29W1/0	005673	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	12/1/2005	Oct-2013	0.2	6.3	3951.4	0.0	1.0	642.5	13.70
00/05-13-008-29W1/0	005952	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	9/1/2006	Oct-2013	0.1	3.1	570.6	0.2	7.0	758.3	69.31
00/06-13-008-29W1/0	005953	Vertical	BAKKEN-THREE FORKS B	BAKKEN,TORQUAY	Producing	9/1/2006	Jul-2013	0.0	0.7	1191.4	0.0	0.7	954.2	50.00
00/08-13-008-29W1/0	007625	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	12/1/2010	Oct-2013	1.9	59.7	9240.2	2.7	85.1	11031.4	58.77
02/09-13-008-29W1/0	008436	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	1/1/2012	Oct-2013	5.6	172.9	6493.6	6.8	209.5	10091.9	54.79
00/12-13-008-29W1/0	005674	Vertical	BAKKEN-THREE FORKS B	TORQUAY	Producing	8/1/2006	Oct-2013	0.0	0.8	978.4	0.0	1.1	916.9	57.89
00/16-13-008-29W1/0	005959	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	10/1/2006	Oct-2013	0.1	2.1	1741.6	0.1	2.4	892.4	53.33
02/16-13-008-29W1/0	007076	Horizontal	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2009	Oct-2013	3.5	107.6	9451.0	3.2	100.7	11225.6	48.34

284039.7 m3

1787424.8 bbls

05-20-008-28W1M	14,948	0	0	13,408	28,356	0.172494128	0.000000000	0.000000000	0.140426325	0.158869073		0.176022033	
06-20-008-28W1M	15,920	0	0	12,155	28,075	0.176437735	0.000000000	0.000000000	0.127305394	0.152576086		0.171953803	
07-20-008-28W1M	15,611	0	0	13,408	29,018	0.177335261	0.000000000	0.000000000	0.140423433	0.149774499		0.173019746	
08-20-008-28W1M	15,846	0	0	14,885	30,731	0.180530752	0.000000000	0.000000000	0.155895391	0.149103984		0.176451565	
01-13-008-29W1M	6,269	0	4,609	27,488	38,366	0.072488089	0.000000000	0.048275457	0.287883571	0.146930565		0.169551684	
02-13-008-29W1M	7,016	0	4,923	25,970	37,908	0.080791373	0.000000000	0.051554797	0.271991521	0.149437184		0.167945864	
03-13-008-29W1M	7,607	51,135	5,403	24,627	88,772	0.087425496	0.494354197	0.056586869	0.257922770	0.151311650		0.165706455	
04-13-008-29W1M	8,137	54,529	6,026	23,641	92,333	0.093239118	0.527165931	0.063110479	0.247594936	0.152035744	0.164271018	0.163150135	0.163595132
05-13-008-29W1M	9,035	0	5,364	23,381	37,780	0.103578597	0.000000000	0.056175586	0.244876005	0.153680249			0.165523605
06-13-008-29W1M	8,400	0	0	24,633	33,033	0.096007685	0.000000000	0.000000000	0.257990326	0.153104984			0.168155185
07-13-008-29W1M	7,769	0	0	26,294	34,063	0.088565139	0.000000000	0.000000000	0.275381340	0.151337715			0.170974268
08-13-008-29W1M	7,164	0	0	28,188	35,352	0.081949416	0.000000000	0.000000000	0.295219255	0.148754435			0.173322423
09-13-008-29W1M	8,227	0	0	28,146	36,373	0.094443640	0.000000000	0.000000000	0.294781297	0.153324869			0.176997017
10-13-008-29W1M	8,501	0	0	26,042	34,543	0.096160469	0.000000000	0.000000000	0.272746715	0.155281272			0.173973190
11-13-008-29W1M	9,156	0	0	24,203	33,359	0.104423843	0.000000000	0.000000000	0.253486990	0.156424331			0.170828335
12-13-008-29W1M	10,168	0	0	22,621	32,789	0.116371236	0.000000000	0.000000000	0.236919286	0.156566962			0.167673010
13-13-008-29W1M	11,265	39,065	4,437	21,452	76,219	0.128966784	0.377667540	0.046469895	0.224670839	0.159184795		0.168866170	0.168924035
14-13-008-29W1M	9,857	0	0	22,964	32,821	0.112776499	0.000000000	0.000000000	0.240506358	0.159791318			0.172198684
15-13-008-29W1M	8,886	0	0	25,095	33,981	0.100875498	0.000000000	0.000000000	0.262824319	0.159488474			0.175737456
16-13-008-29W1M	8,877	0	0	27,541	36,418	0.104687334	0.000000000	0.000000000	0.288446038	0.157858821			0.179127166

4,604,423

28,961 Mbbi

Table No. 5

Proposed Sinclair Unit No. 12

LYLETON / THREE FORKS FORMATION ROCK & FLUID PARAMETERS

Formation Pressure		9500 kPa	Initial Average Reservoir Pressure
Formation Temperature		31°C	
Saturation Pressure		2,034 Kpa	Bubble Point
GOR		6 - 10 m3/m3	Gas Oil Ratio
API Oil Gravity		40	
Swi (fraction)		0.40	Initial Water Saturation
Produced Water Specific Gravity		1.08	
Produced Water pH		7.1 - 7.3	
Produced Water TDS		125,000	
Wettability		Moderately oil-wet	
Average Air Permeability*	Middle Bakken	5.48 mD	Wt. Average Core Data
	Lyleton Upper A	*	* no data
	Lyleton Lower A	*	* no data
	Lyleton B	2.22 mD	Wt. Average Core Data
Average Porosity (fraction)*	Middle Bakken	0.164	Wt. Average Core Data
	Lyleton Upper A	*	* no data
	Lyleton Lower A	*	* no data
	Lyleton B	0.178	Wt. Average Core Data
* Wt ave from all MBKKN/Lyleton cores in N/ 5, 7, 8, 16, 17, and 18-8-28W1. Plus 13-8-29W1.			

Table 6: Sinclair Unit No. 12 - Development Time Table

Action	July 2014	August 2014	July 2015	August 2015	July 2016	August 2016	August 2017	August 2018	Total
Wells Drilled	8		8		7				23
Wells on Production		8		8		7			23
Wells Converted to Injection				3		10	6	4	23