PROPOSED DALY UNIT NO. 18

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (01 62A)

Daly, Manitoba

February 28, 2018
Tundra Oil and Gas Partnership

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INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8, 9, 10 and 11, of Ranges 27, 28 & 29 WPM (Figure 1). Within the Daly Oilfield, Bakken reservoirs have been developed with horizontal and vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells on 20 acre spacing have been drilled by Tundra Oil and Gas (Tundra) in parts of the Daly field.

Within the area, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. The following represents an application by Tundra Oil and Gas Partnership (Tundra) to establish Daly Unit No. 18 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 an existing designated 01-62A Bakken-Three Forks A Pool of the Daly Sinclair Oilfield (Figure 3).

CONCLUSIONS

1. The proposed Daly Unit No. 18 will include 7 producing horizontal wells within 28 Legal Subdivisions (LSD) of the Bakken producing reservoir. The project is located north of Daly Unit No. 8 and northeast of Daly Unit No. 10 (Figure 1).

2. Total Original Oil in Place (OOIP) in the project area has been calculated to be **788** e^3m^3 (4,958 Mbbl) for an average of 28 net e^3m^3 OOIP per 40 acre LSD based on a 0.5 md cutoff for the Middle Bakken & Lyleton 'B'.

3. Cumulative production to the end of November 2017 from the 7 wells within the proposed Daly Unit No. 18 project area was **34.3** e^3m^3 (215.8 Mbbl) of oil and **74.6** e^3m^3 (469.0 Mbbl) of water, representing a **4.3%** Recovery Factor (RF) of the calculated gross OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Daly Unit No. 18 project area is estimated to be **52.5** e^3m^3 (330.5 Mbbl), with **18.2** e^3m^3 (114.5 Mbbl) remaining as of the end of November 2017.

5. Ultimate oil recovery of the proposed Daly Unit No. 18 gross OOIP, under the current Primary production method, is forecasted to be **6.7%**.

6. Figure 4 shows the production from the Daly Unit No. 18 area peaked during November 2014 at 35.6 m^3 of oil per day (OPD). As of November 2017, production was 5.6 m^3 OPD, 15.7 m^3 of water per day (WPD) and a 73.7% watercut (WCUT).

7. In November 2014, production averaged 5.09 m^3 OPD per well in Daly Unit No. 18. As of November 2017, average per well production has declined to 0.80 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **25%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Daly Unit No. 18 has been estimated to be **76.1** e^3m^3. An incremental **23.6** e^3m^3 of proved oil reserves 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 Daly Unit No. 18 is estimated to be **9.7%**.

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

11. Proposed future horizontal openhole produce first injectors, with multi-stage hydraulic fractures, will be drilled between existing horizontal producing wells (Figure 5) within the proposed Daly Unit No. 18, to complete waterflood patterns with effective 200m horizontal to horizontal spacing. One existing cemented liner producer will be converted to an injector to complete the north-south 200m pattern.

DISCUSSION

The proposed Daly Unit No. 18 project area is located in Township 10 & Township 11, Range 28 W1 of the Daly Sinclair Oil Field (Figure 1). The proposed Daly Unit No. 18 currently consists of 7 producing horizontal wells within an area covering the N/2 Section 32-010-28W1 and LSDs 4,5,12,13 of Section 2 and Section 03-011-28W1 (Figure 2). A project area well list with recent production statistics is attached as Table 3.

Within the proposed Unit, potential exists for incremental production and reserves from a Waterflood EOR project in the 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 2. The section runs SW to NE through the proposed Unit area. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton B Siltstone and the Torquay Silty Shale. The reservoir units are represented by the Middle Bakken 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 (Daly Unit 8, Daly Unit 10 and Daly Unit 9) as noted on the Offsetting Units Map at Appendix 1.

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 thickness ranges from 3m to 4m (Appendix 4).

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 or red very fine grained siltstone which is generally non-reservoir. The Lyleton B is between 1.5m-3m thick within the proposed unit (Appendix 5).

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.

Structure:

The structure within the proposed unit area dips quite steeply to the NE as the paleo high over the Daly Field begins to drop off (Appendix 3). The total structural drop over the unit area is roughly 23m. This structural change is not expected to negatively impact flood efficiency or 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 and the isopach maps, all reservoir formations, the Middle Bakken, and Lyleton B, are continuous throughout the proposed unit area. Vertical continuity between the reservoir formations is also unbroken within the unit area.

<u>Gross OOIP Estimates</u>

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **788** e^3m^3 (**4,958** Mbbl) using Tundra internally created maps. Maps used were generated from core data from wells available in the greater Sinclair area (Appendix 6).

An average net to gross ratio was calculated for the reservoir using pressure decay profile permeameter data (PDPK) with a cut off of 0.5mD on surrounding cored wells. To determine net pay these ratios are then applied to each formation thickness from isopach maps based on logs. Porosity is calculated in the same way, using an average from surrounding core data after a 0.5mD cutoff.

Tabulated parameters for each LSD from the calculations can be found in Table 4.

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 PVT information taken from the 100/02-17-009-29W1 and 100/13-19-009-28W1 Bakken wells and is thought to be representative of the fluid characteristics in the reservoir.

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

Historical Production

A historical group production history plot for the proposed Daly Unit No. 18 is shown as Figure 4. Oil production commenced from the proposed Unit area in October 2010 and peaked during November 2014 at 35.6 m^3 OPD. As of November 2017, production was 5.6 m^3 OPD, 15.7 m^3 WPD and a 73.7% WCUT.

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

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

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area to **9.7%**. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have the greatest recovery possible by allowing the development of additional drilling and injector conversions over time, in order to maintain reservoir pressure and increase oil production.

Unit Name

Tundra proposes that the official name of the new Unit shall be Daly Unit No. 18.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Daly Unit No. 18.

Unitized Zone

The unitized zone(s) to be waterflooded in Daly Unit No. 18 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 7 horizontal wells to be included in the proposed Daly Unit No. 18 are outlined in Table 3.

Unit Lands

The Daly Unit No. 18 will consist of 28 LSDs as follows:

N/2 of Section 32 of Township 10, Range 28, W1M
LSDs 4, 5, 12, 13 of Section 2 of Township 11, Range 28, W1M
Section 3 of Township 11, Range 28, W1M

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

Tract Factors

The proposed Daly Unit No. 18 will consist of 28 Tracts, based on the 40 acre Legal Sub Divisions (LSD) containing the existing 7 horizontal wells.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 18 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)
- Last twelve (12) months production to date for the LSD as distributed by the LSD specific PA % in the applicable producing horizontal or vertical well.

- Tract Factor by LSD = Fifty percent (50%) of the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP, and fifty percent (50%) of the product of the Last 12 Months Production as a % of total proposed Unit Last 12 Months Production.

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Table 2. Tundra believes that the above given method provides the most equitable assignment of tract participation factors to all mineral owners, given the geological and reservoir risks associated with waterflooding horizontal to horizontal wellbores in the Bakken formation.

Working Interest Owners

Table 1 outlines the working interest % (WI) for each recommended Tract within the proposed Daly Unit No. 18. Tundra Oil and Gas Partnership holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Partnership will have a 100% working interest in the proposed Daly Unit No. 18.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 18 are based on internal engineering assessments. Project area specific reservoir and geological parameters were used to guide the overall Secondary Waterflood recovery factor. Internal reviews included analysis of available open-hole logs, core data, petrophysics, seismic, drilling and completion information, and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed Daly Unit No. 18 OOIP (Table 4).

Pre-Production of New Horizontal Injection Wells

It is likely that four future horizontal injection wells will be drilled between the existing horizontal producing wells and one existing producer will be converted to injection, as shown in Figure 5, completing an effective 20 acre horizontal to horizontal line drive waterflood pattern within Daly Unit No. 18.

Primary production from the existing horizontal producing wells in the proposed Daly Unit No. 18 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. The following conditions have been observed, without injector conditioning, which Tundra believes negatively impact the ultimate total recovery factor of OOIP:

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

As a result, Tundra has chosen to produce these future injectors to condition the reservoir for optimal waterflood.

Ultimately the final candidates for injection conversion will be chosen based on production performance post unit approval. This will result in an effective 20 acre line drive waterflood pattern within Daly Unit No. 18.

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

Reserves Recovery Profiles and Production Forecasts

The primary performance predictions for the proposed Daly Unit No. 18 are based on oil production decline curve analysis, and the secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Based on the geological description, primary production decline rate, and waterflood response in Daly Unit No. 8, the Bakken formation in the project area is believed to be a suitable reservoir for WF EOR operations.

Primary Production Forecast

Cumulative production to the end of November 2017 from the 7 wells within the proposed Daly Unit No. 18 project area was **34.3** e^3m^3 of oil, and **74.6** e^3m^3 of water, representing a **4.3%** Recovery Factor (RF) of the calculated Net OOIP.

Based on decline analysis of the wells currently on production, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be **52.5** e^3m^3, with **18.2** e^3m^3 remaining as of the end November 2017. This represents a recovery factor of **6.7%** of the total OOIP.

The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 6 and 7.

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

The injection wells will be drilled after unit approval has been received. Tundra will produce these future injectors to condition the reservoir for optimal waterflood. Timing for injection conversion will be chosen based on production performance post unit approval.

Criteria for Conversion to Water Injection Well

Four new horizontal injection wells are required for this proposed Unit. They will be placed on production followed by permanent water injection service as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for converting 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 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 Daly Unit No. 18 project to be developed equitably, efficiently, and moves the project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 8 and 9, respectively. Total Secondary EUR for the proposed Daly Unit No. 18 is estimated to be 76.1 e^3m^3 with **41.8** e^3m^3 remaining representing a total secondary recovery factor of **9.7%** for the proposed Unit area. An incremental **23.6** e^3m^3 of oil, or an incremental **3.0%** recovery factor, are forecasted to be recovered under the proposed Unitization.

WATERFLOOD OPERATING STRATEGY

Water Source

Injection water for the proposed Daly Unit No. 18 will be supplied from the Jurassic source water well at 100/02-25-010-29W1 (2-25). Tundra received approval from the Petroleum Branch in March 2013 to use the 2-25 well as a source water well for waterflood operations. Jurassic-sourced water will be pumped from the 2-25 source well to the Daly 12-24-10-29 battery, where it will be filtered and then pumped up to injection system pressure. A diagram of the Daly 12-24 water injection system and new pipeline connection to the project area injection wells is shown as Figure 10.

Produced water is not currently used for any water injection in the Tundra operated Daly Units and there are no current plans to use produced water as a source supply for Daly Unit No. 18. Tundra does not foresee any compatibility issues between the produced and injection waters based on previous compatibility testing performed by a third party, Baker Hughes.

Injection Wells

Five horizontal injection wells are required for this proposed Unit, as shown in Figure 5. One of the planned injection wells is currently producing and plans are in progress to re-configure the well for downhole injection after approval for waterflood has been received. The four other planned injection wells will be drilled and put on production after unit approval. Tundra will produce these future injectors to condition the reservoir for optimal waterflood. Timing for injection conversion will be chosen based on production performance post unit approval. These planned injectors will be openhole horizontals and will be stimulated by multiple hydraulic fracture treatments to obtain suitable injection rates in an openhole completion (Figure 11). 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 well(s) 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:

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

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

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

The proposed Daly Unit No. 18 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate an actual fracture pressure gradient range of 16 to 18 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be lower than these values due to expected reservoir pressure depletion.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Daly Unit No. 18 project area in the Bakken. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection well during the completion of the well and prior to injection or production. Based on a normally pressured reservoir, it is believed the initial reservoir pressure in this area was on average 8,500kPa.

Reservoir Pressure Management During Waterflood

Tundra expects to inject water for a minimum 2 – 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 1.75 within the pattern 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

Daly Unit No. 18 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 Daly Unit No. 18 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling or water breakthrough, or out-of-Unit migration. The monitoring and surveillance will also provide early indicators of any such issues so that waterflood operations may be altered to maximize ultimate secondary reserves recovery from the proposed Daly Unit No. 18.

On Going Reservoir Pressure Surveys

For each proposed 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 Daly Unit No. 18 as per Section 73 of the Drilling and Production Regulation.

Economic Justification

Under the current Primary recovery method, existing wells within the proposed Daly Unit No. 18 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 Daly Unit No. 18 waterflood operation will utilize the Tundra operated well 100/02-25-10-29W1, sourced from the Jurassic, and water plant (WP) facilities located at the Daly 12-24-10-29W1 battery (Figure 10).

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 12. Surface facilities and wellheads will have cathodic protection to prevent corrosion, where required. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set above the Middle Bakken and Three Forks formations, and the annulus between the tubing and casing will be filled with inhibited fluid.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra will notify all mineral rights and surface rights owners of the proposed EOR project and formation of Daly Unit No. 18. Copies of the Notices, and proof of service, to all surface rights owners will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 18 Application.

Daly Unit No. 18 Unitization, and execution of the formal Daly Unit No. 18 Agreement by affected Mineral Owners, is expected during Q1 2018. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 18 Application.

Should the Petroleum Branch have further questions or require more information, please contact Lindsey Snyder at 403.910.1665 or by email at lindsey.snyder@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Lindsey Snyder, Exploitation Engineer, February 28, 2018

Proposed Daly Unit No. 18

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1

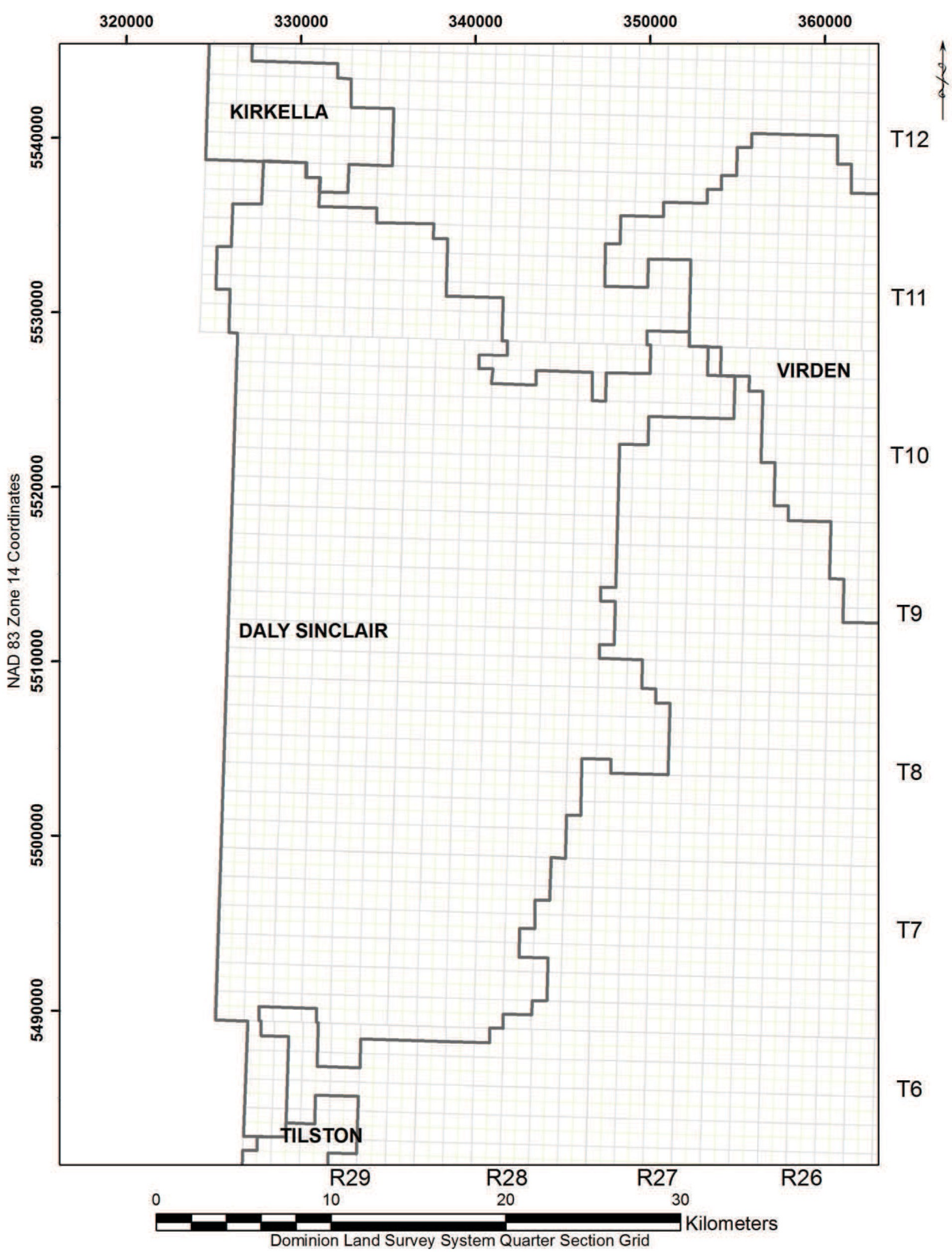
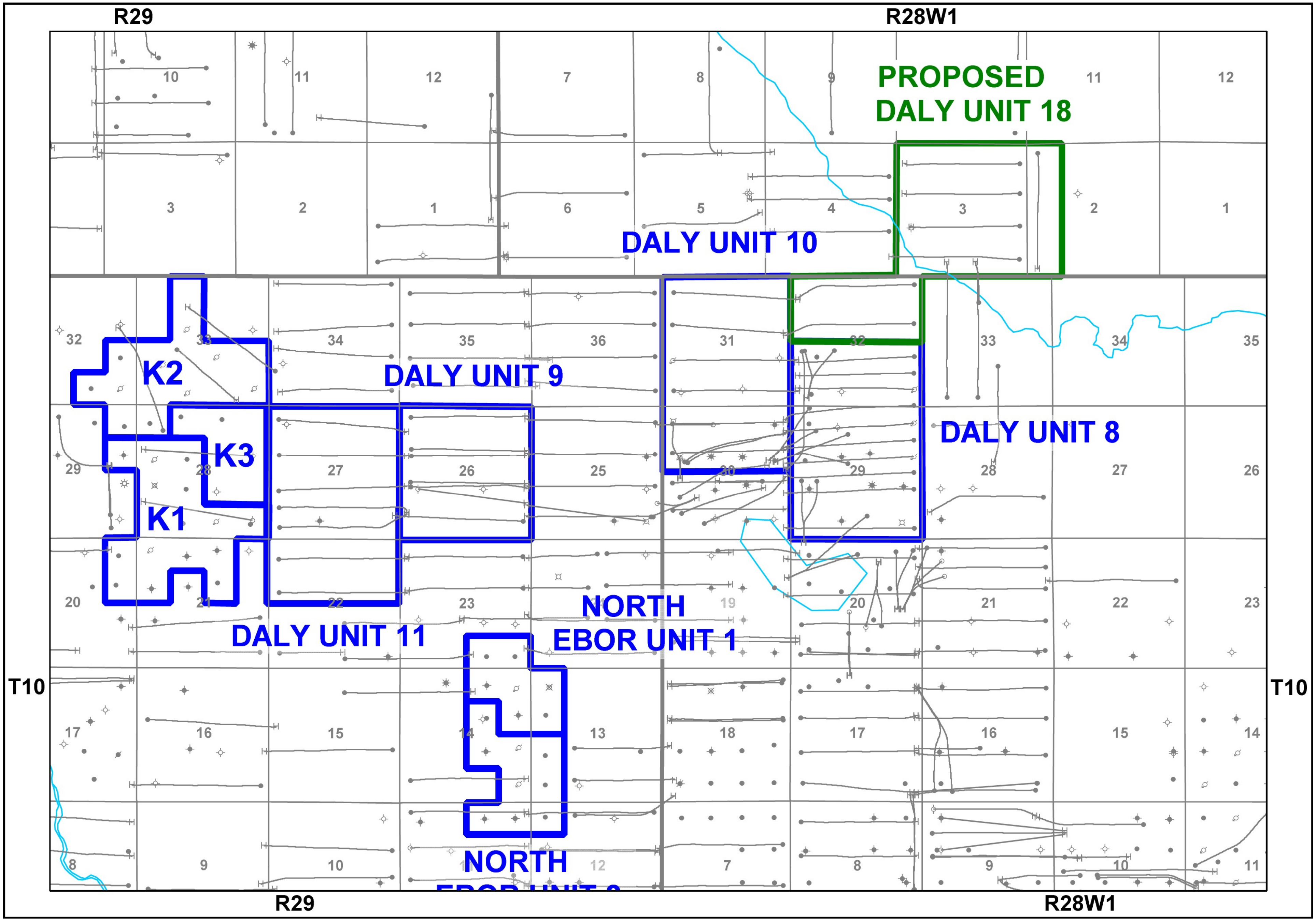


Figure 2 - Daly Sinclair Field (01)

Figure No. 2



SINCLAIR BAKKEN UNITS

Figure No. 3

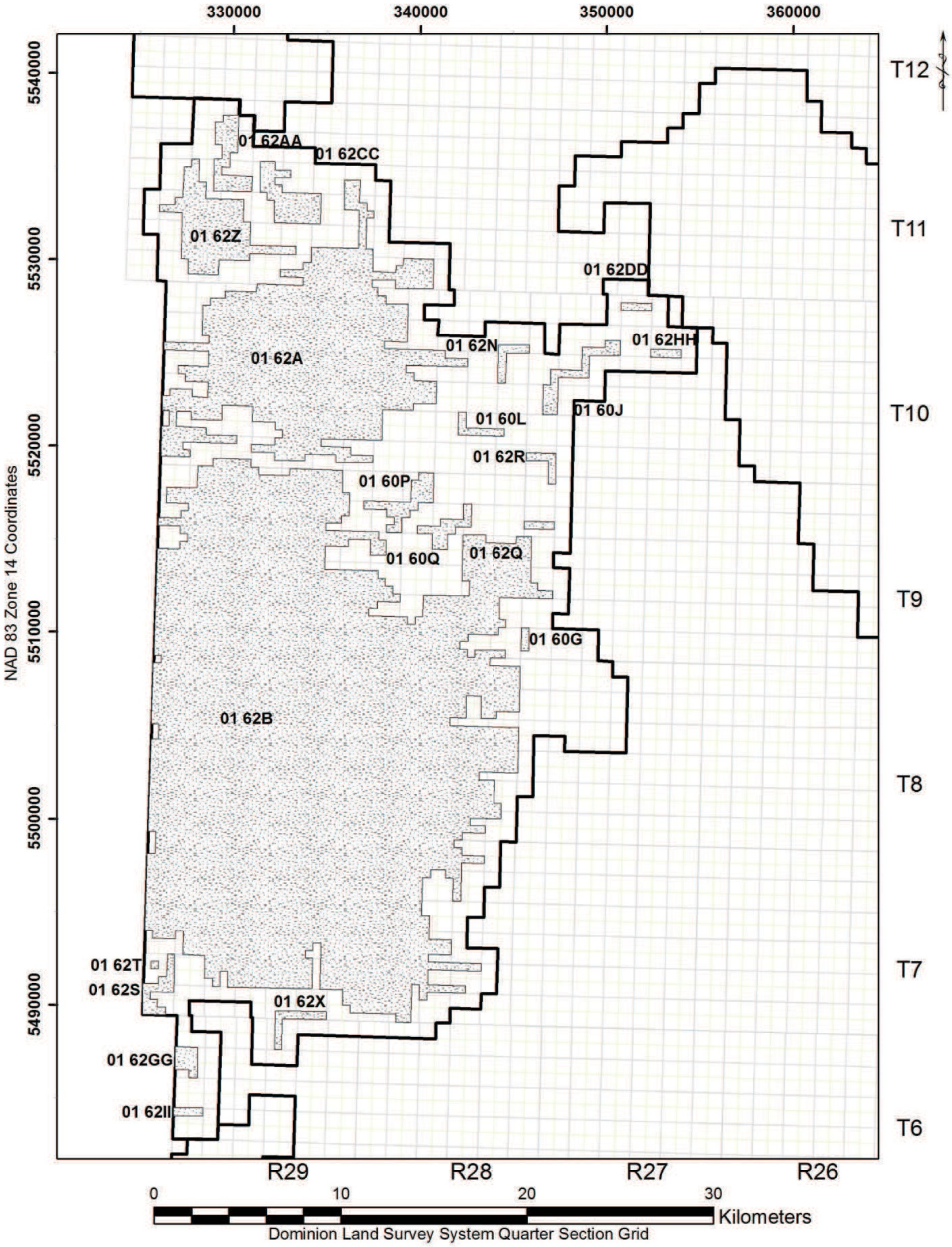


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Figure No. 4

Production Graph

Group:	daly unit 18 well list.lwell	**On Prod:**	2010-10 to 2017-11	**Cum Oil:**	34306.6 m3
# of Wells:	7	**Prod Form:**	BAKKENU; BAKKENM; BAKKEN	**Cum Gas:**	0.0 E3m3
Fluid:	Oil	**Field:**	DALY (MB1)	**Cum Wtr:**	74572.1 m3
Mode:	Producing	**Pool Code:**	MB000162A	**Cum Inj Oil:**	0.0 m3
		Unit Code:		**Cum Inj Gas:**	0.0 E3m3
				Cum Inj Wtr:	0.0 m3

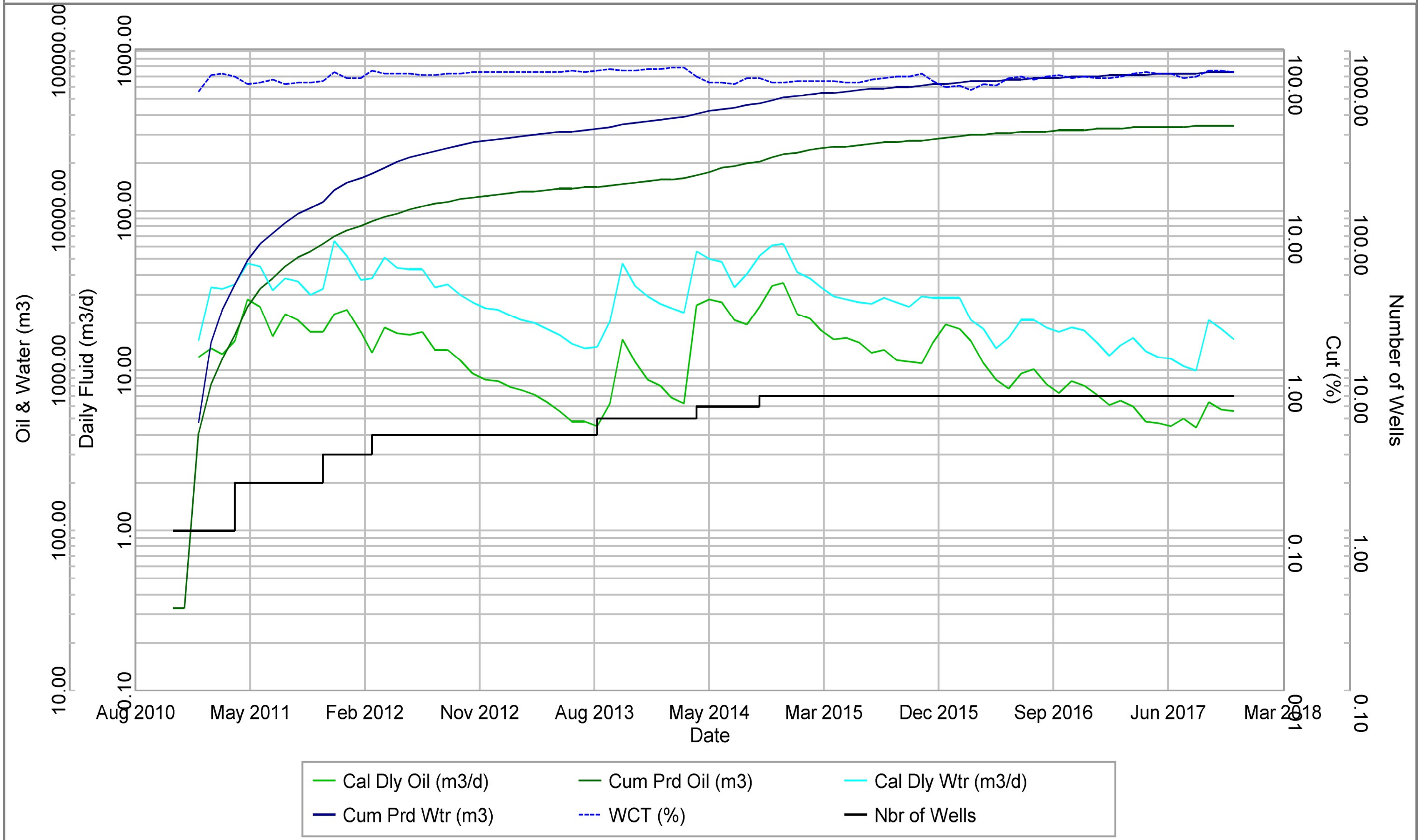
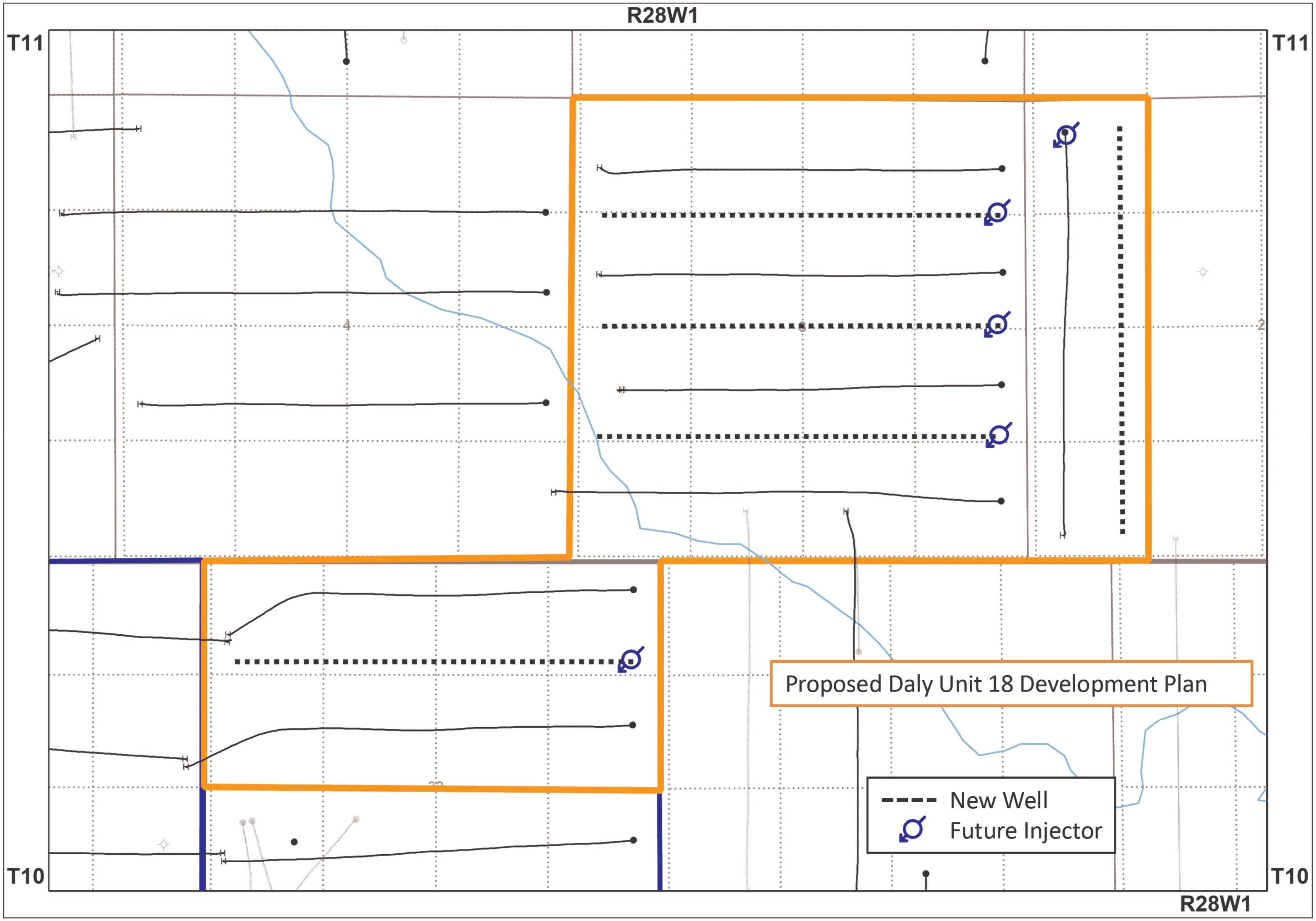


Figure 5.



R28W1
T11
T11
T10
T10
R28W1
Proposed Daly Unit 18 Development Plan
New Well
Future Injector

Figure 6. Primary Production – Rate vs Time

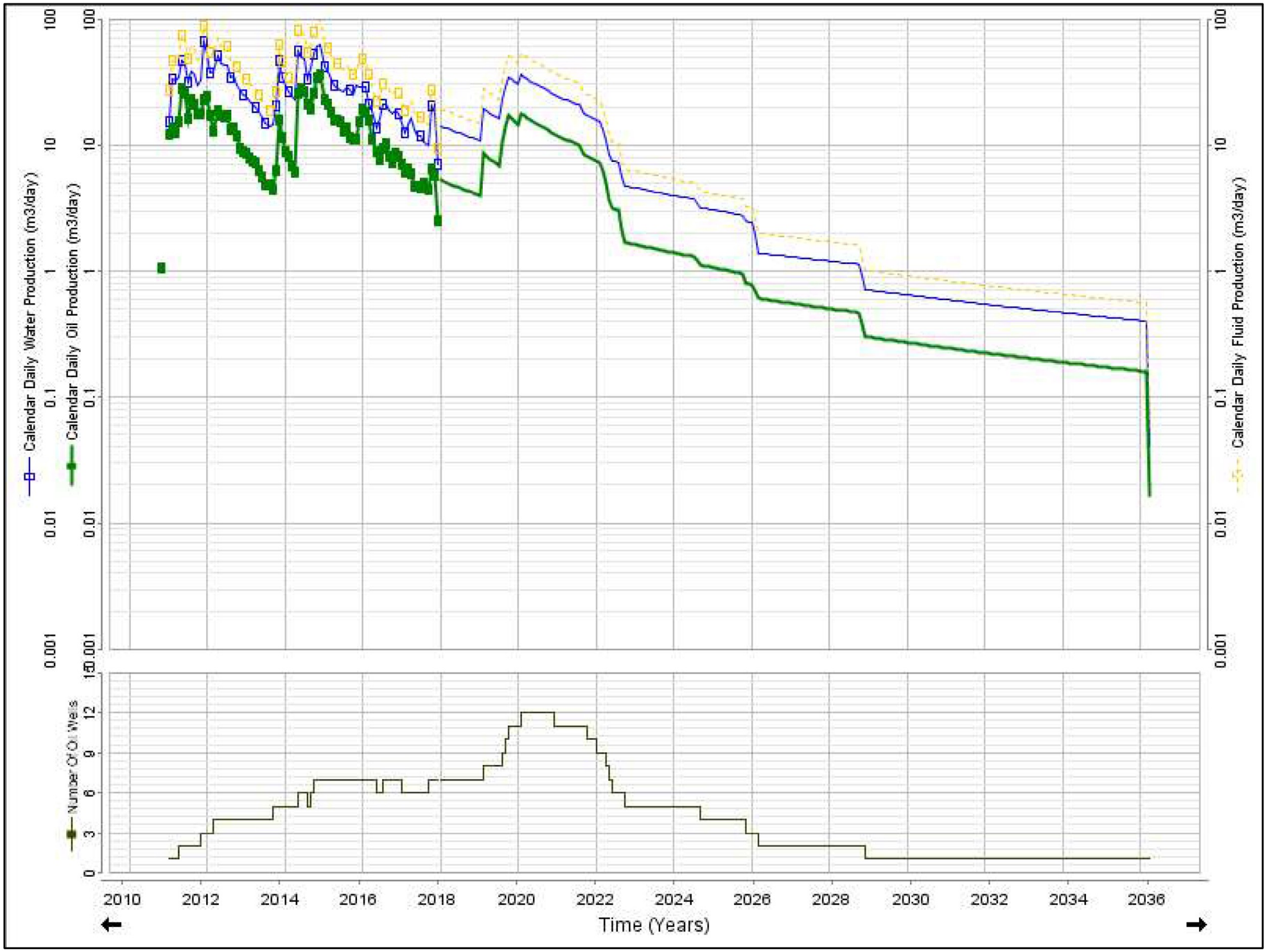


Figure 7. Primary Production – Rate vs Cumulative Production

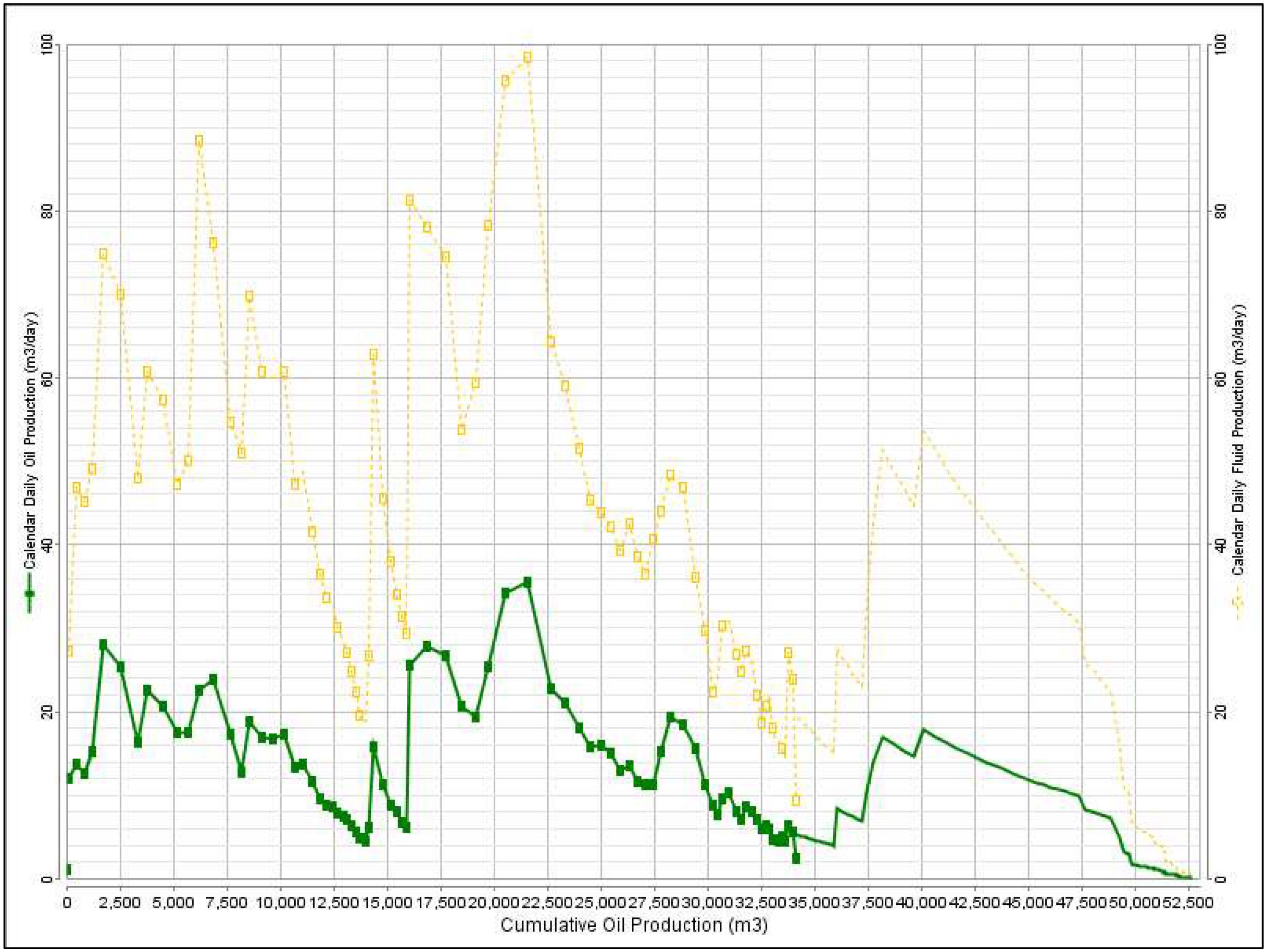


Figure 8. Waterflood Production – Rate vs Time

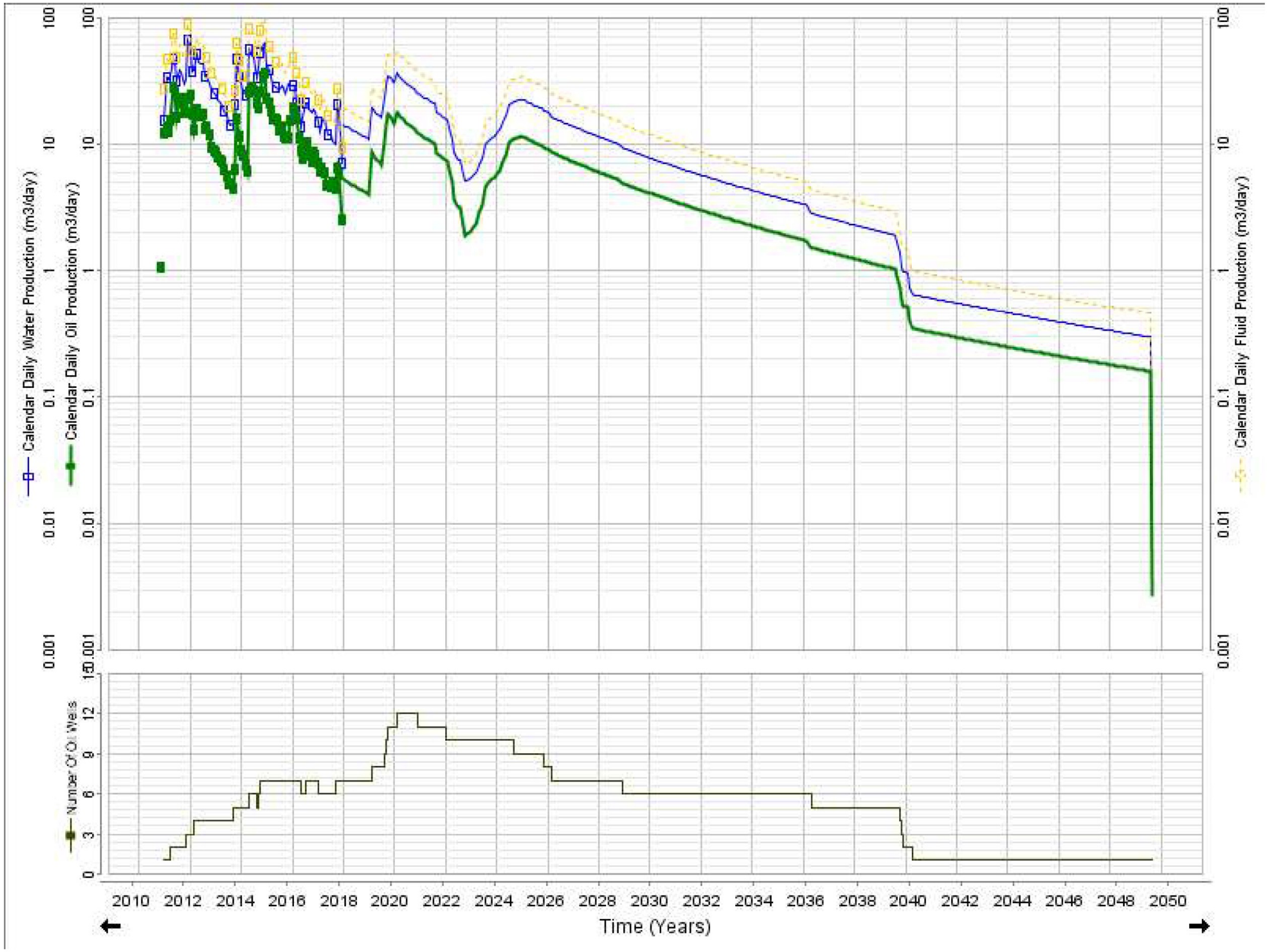
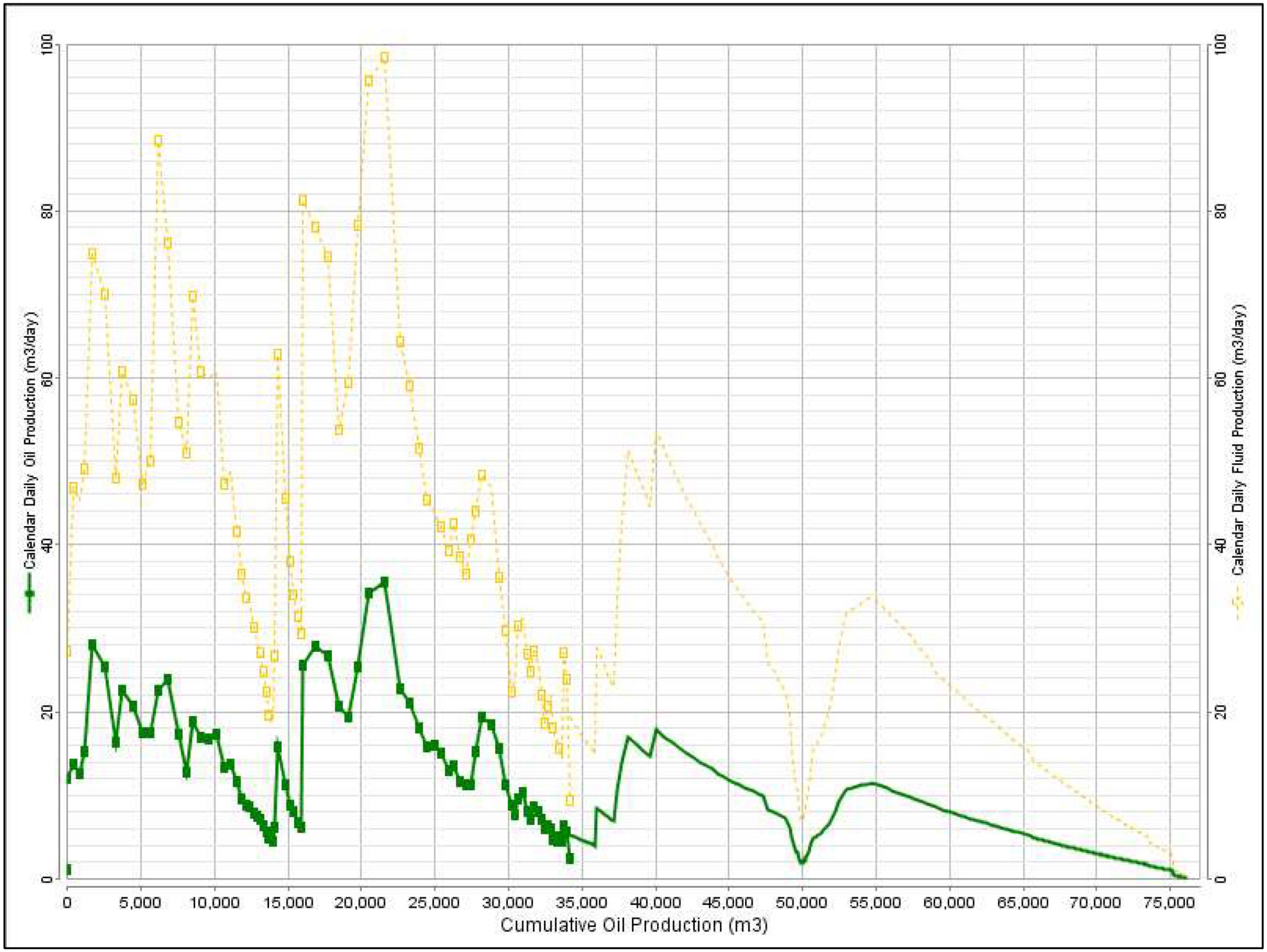
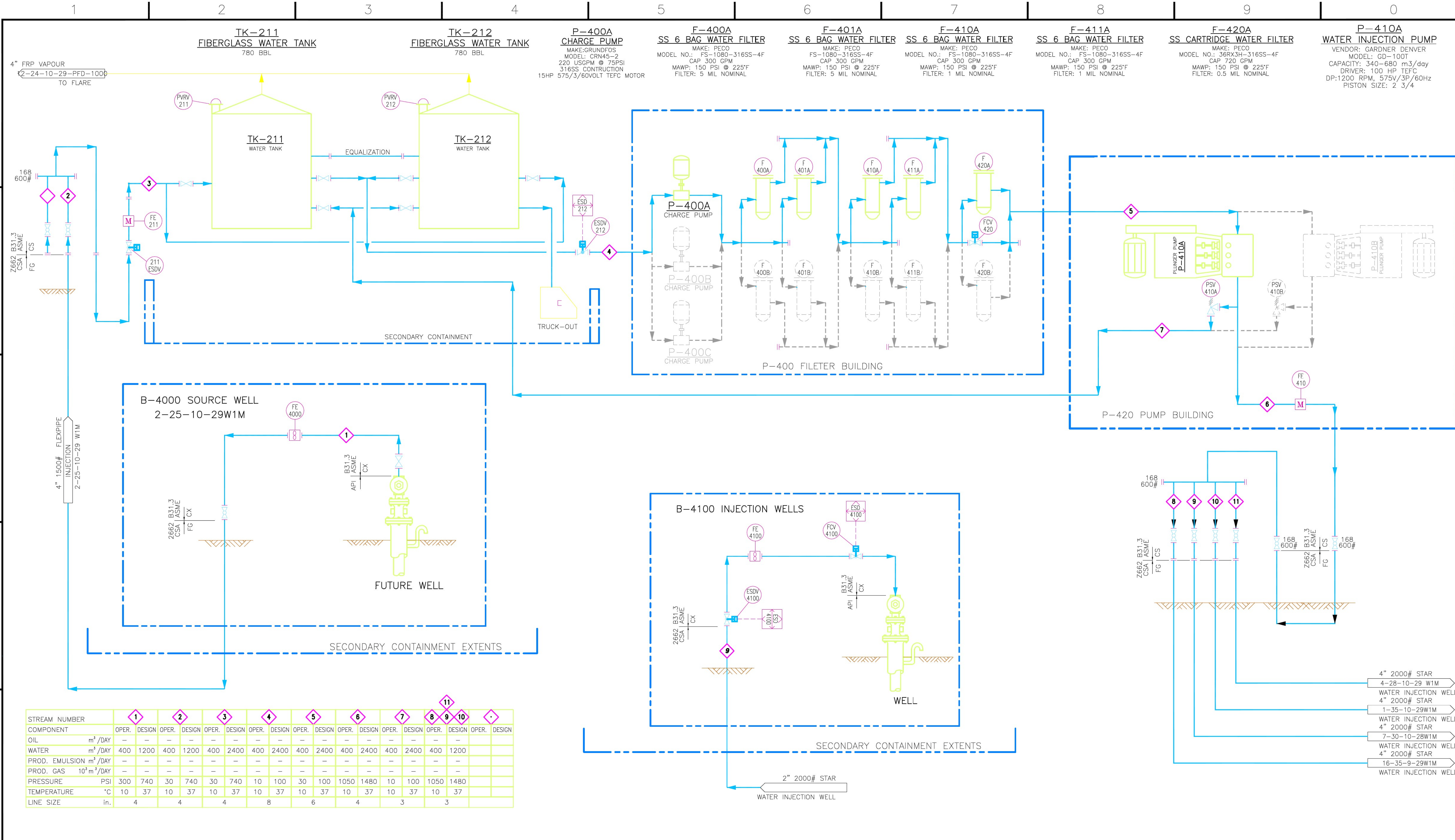


Figure 9. Waterflood Production – Rate vs Cumulative Production





STREAM NUMBER	1		2		3		4		5		6		7		8 9 10 11		·	
COMPONENT	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN
OIL m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
WATER m^3/DAY	400	1200	400	1200	400	2400	400	2400	400	2400	400	2400	400	2400	400	1200		
PROD. EMULSION m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PROD. GAS $10^3 m^3$/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PRESSURE PSI	300	740	30	740	30	740	10	100	30	100	1050	1480	10	100	1050	1480		
TEMPERATURE °C	10	37	10	37	10	37	10	37	10	37	10	37	10	37	10	37		
LINE SIZE in.	4		4		4		8		6		4		3		3			

REV	DESCRIPTION	BY	DATE	CHK	APP
0	ISSUED FOR CONSTRUCTION	JC	30MAY2013	BE	–

REFERENCE DRAWING

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NOTES:

Figure No. 10

TUNDRA OIL & GAS PARTNERSHIP

PROCESS FLOW DIAGRAM
12-24-10-29W1M

PROCESS FLOW DIAGRAM 4 OF 4
INJECTION SYSTEM

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
RM	NTS		12-24-10-29-PFD-1400	0

Tundra Oil And Gas Partnership

Figure No. 11

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	Tundra Daly Unit No. 18 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:

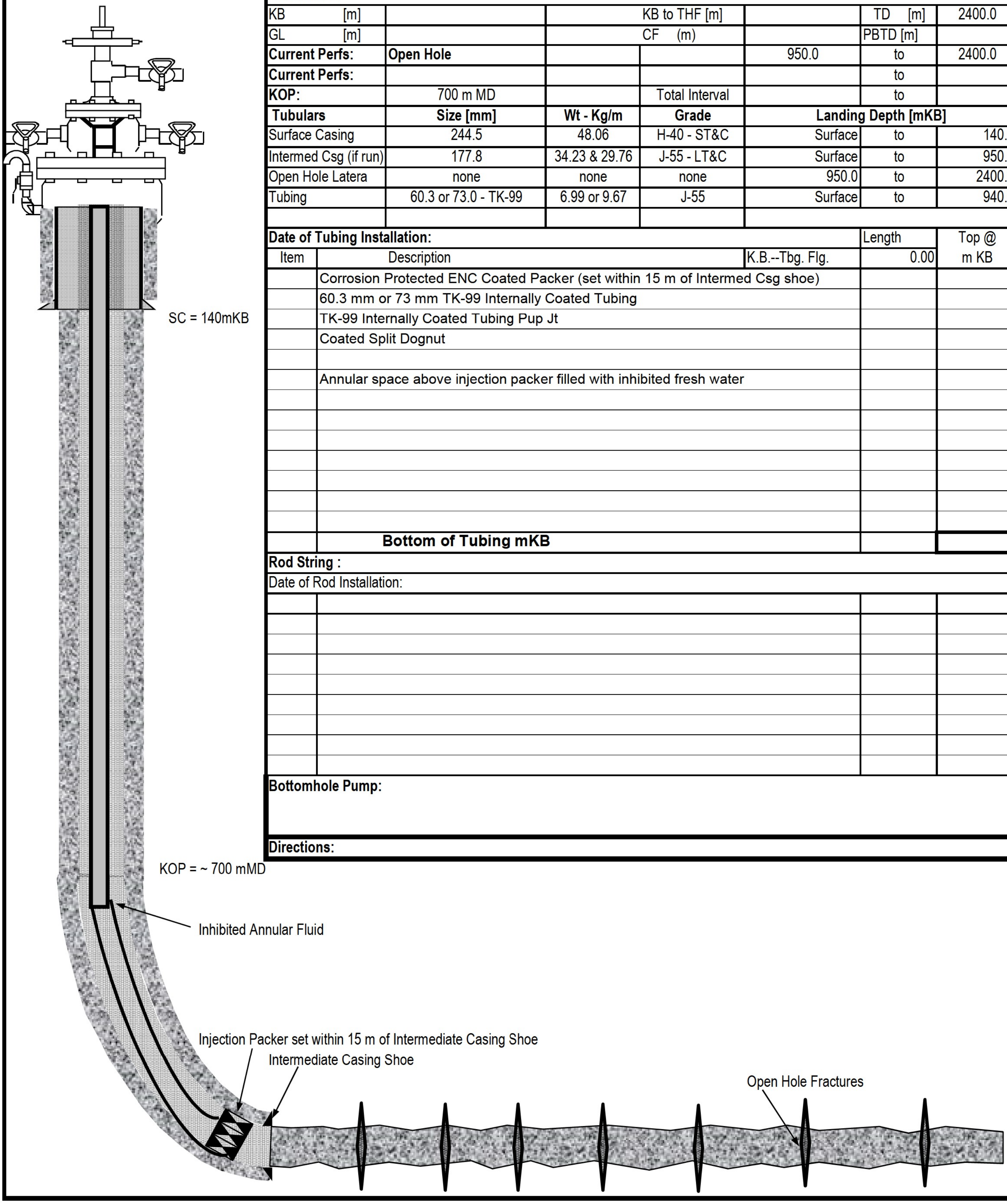


Figure 12 – Corrosion Controls

Source Well

- Located at 02-25-010-29
- Continuous downhole corrosion inhibition
- Downhole scale inhibitor injection
- Corrosion resistant valves and internally coated surface piping
- Biocide injected at source well for entire system

Pipelines

- The water source line will be composite from source well to 12-24-10-29 water plant.
- Injection lines will be a mix of 2000psi high pressure fiberglass and composite pipe.
- Producing lines existing as per original flowline licenses.

Facilities

12-24-10-29 Water Plant

- Plant piping – 600 ANSI stainless steel schedule 80 pipe, fiberglass or internally coated
- Filtration – Stainless steel bodies, PVC piping or stainless steel piping
- Pumping – Ceramic plungers, stainless 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 Wells

- 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
- Scale inhibition (pellets & injected post pump at battery)

Producing Wells

- Downhole corrosion inhibitor, either batch or daily injection, as needed.
- Scale inhibitor treatment daily injection as required for horizontal wells.
- Casing cathodic protection where required.

Proposed Daly Unit No. 18

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR DALY BAKKEN UNIT NO. 18 APPLICATION

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) - CUMULATIVE PRODUCTION TO NOVEMBER 2017

LSD-SEC	Tract	*OOIP (m3)*	*Hz Cum Allocated Prodn (m3)*	*Vertical Cum Oil Prodn (m3)*	*OOIP Minus Cum Oil Prodn (m3)*	*OOIP - Cum Prod Tract Factor (%)*	*Last 12 Mth Alloc Prod*	*% of Last 12 Mth Prodn*	*50% of OOIP - Cum TF + 50% Last 12 Mth Prodn TF*	Tract
09-32	09-32-010-28W1M	28111	1905.3	0.0	26205	3.476094641%	171.8	8.460864049%	5.968479345%	09-32-010-28W1M
10-32	10-32-010-28W1M	27951	2008.6	0.0	25942	3.441190032%	181.1	8.919662420%	6.180426226%	10-32-010-28W1M
11-32	11-32-010-28W1M	27867	2005.3	0.0	25862	3.430509658%	180.8	8.904788135%	6.167648897%	11-32-010-28W1M
12-32	12-32-010-28W1M	28433	1934.3	0.0	26499	3.514996067%	174.4	8.589586892%	6.052291480%	12-32-010-28W1M
13-32	13-32-010-28W1M	29056	974.9	0.0	28081	3.724900615%	87.0	4.287097674%	4.005999144%	13-32-010-28W1M
14-32	14-32-010-28W1M	28594	1593.8	0.0	27000	3.581521667%	142.3	7.008276761%	5.294899214%	14-32-010-28W1M
15-32	15-32-010-28W1M	28451	1597.0	0.0	26854	3.562172235%	142.6	7.022449983%	5.292311109%	15-32-010-28W1M
16-32	16-32-010-28W1M	28507	1523.0	0.0	26984	3.579416301%	136.0	6.696950996%	5.138183649%	16-32-010-28W1M
04-02	04-02-011-28W1M	27391	357.0	0.0	27034	3.586025575%	19.1	0.938666494%	2.262346034%	04-02-011-28W1M
05-02	05-02-011-28W1M	27604	645.3	0.0	26958	3.575956174%	34.5	1.696961938%	2.636459055%	05-02-011-28W1M
12-02	12-02-011-28W1M	27787	644.3	0.0	27142	3.600368862%	34.4	1.694218216%	2.647293539%	12-02-011-28W1M
13-02	13-02-011-28W1M	27944	606.6	0.0	27337	3.626253882%	32.4	1.595094251%	2.610674067%	13-02-011-28W1M
01-03	01-03-011-28W1M	27292	805.1	0.0	26487	3.513444786%	57.6	2.835450915%	3.174447851%	01-03-011-28W1M
02-03	02-03-011-28W1M	27497	843.4	0.0	26654	3.535556736%	60.3	2.970526042%	3.253041389%	02-03-011-28W1M
03-03	03-03-011-28W1M	27548	841.8	0.0	26706	3.542469899%	60.2	2.964728960%	3.253599430%	03-03-011-28W1M
04-03	04-03-011-28W1M	27437	808.5	0.0	26628	3.532174835%	57.8	2.847694397%	3.189934615%	04-03-011-28W1M
05-03	05-03-011-28W1M	28059	460.0	0.0	27599	3.660956191%	15.2	0.749635047%	2.205295619%	05-03-011-28W1M
06-03	06-03-011-28W1M	28026	1678.1	0.0	26348	3.495013710%	55.5	2.734796099%	3.114904905%	06-03-011-28W1M
07-03	07-03-011-28W1M	27922	1681.9	0.0	26240	3.480674509%	55.7	2.740991430%	3.110832970%	07-03-011-28W1M
08-03	08-03-011-28W1M	27617	1610.8	0.0	26006	3.449679092%	53.3	2.625050236%	3.037364664%	08-03-011-28W1M
09-03	09-03-011-28W1M	28073	1821.9	0.0	26251	3.482185390%	46.4	2.285726950%	2.883956170%	09-03-011-28W1M
10-03	10-03-011-28W1M	28370	1898.4	0.0	26472	3.511460439%	48.4	2.381737589%	2.946599014%	10-03-011-28W1M
11-03	11-03-011-28W1M	28558	1903.1	0.0	26655	3.535711633%	48.5	2.387632979%	2.961672306%	11-03-011-28W1M
12-03	12-03-011-28W1M	28757	1089.5	0.0	27668	3.670068509%	27.8	1.366888298%	2.518478404%	12-03-011-28W1M
13-03	13-03-011-28W1M	29191	466.9	0.0	28724	3.810140375%	16.4	0.805577876%	2.307859126%	13-03-011-28W1M
14-03	14-03-011-28W1M	28991	883.8	0.0	28107	3.728367632%	31.0	1.524857565%	2.626612598%	14-03-011-28W1M
15-03	15-03-011-28W1M	28648	889.5	0.0	27759	3.682139624%	31.2	1.534796751%	2.608468188%	15-03-011-28W1M
16-03	16-03-011-28W1M	28500	828.4	0.0	27671	3.670550929%	29.0	1.429291055%	2.549920992%	16-03-011-28W1M
		788183	**34306.6**	**0.0**	**753876**	**100.000000000%**	**2030.4**	**100.000000000%**	**100.000000000%**	

Table 3 - Proposed Daly Unit No. 18 Well List and Status

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Production 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 (%)
100/09-32-010-28W1/0	009851	Horizontal	BAKKEN-THREE FORKS A	BAKKENU	Producing	4/2/2014	Nov-2017	1.8	52.9	7853.5	3.5	104.7	11818.8	66.43
100/16-32-010-28W1/0	009850	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	9/18/2014	Nov-2017	0.9	27.2	5688.7	2.0	60.6	7936.0	69.02
100/13-02-011-28W1/0	009353	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	8/31/2013	Nov-2017	1.0	28.8	2253.2	6.2	185.7	10602.5	86.57
100/01-03-011-28W1/0	007996	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/29/2012	Nov-2017	0.7	21.3	3298.8	0.5	15.1	7332.6	41.48
100/08-03-011-28W1/2	007467	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	10/31/2010	Nov-2017	0.4	10.8	5430.9	1.3	39.7	13561.5	78.61
100/09-03-011-28W1/0	007835	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/26/2011	Nov-2017	0.5	15.1	6712.9	1.1	33.4	13868.5	68.87
100/16-03-011-28W1/0	007997	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	10/31/2011	Nov-2017	0.4	12.2	3068.6	1.1	33.4	9452.2	73.25
										34306.6			**74572.1**	

Table No. 4 - OOIP Calculation

Tract	OOIP (m3)	OOIP (bbls)
09-32-010-28W1M	28,111	176,811
10-32-010-28W1M	27,951	175,806
11-32-010-28W1M	27,867	175,279
12-32-010-28W1M	28,433	178,838
13-32-010-28W1M	29,056	182,757
14-32-010-28W1M	28,594	179,851
15-32-010-28W1M	28,451	178,954
16-32-010-28W1M	28,507	179,306
04-02-011-28W1M	27,391	172,285
05-02-011-28W1M	27,604	173,622
12-02-011-28W1M	27,787	174,773
13-02-011-28W1M	27,944	175,763
01-03-011-28W1M	27,292	171,662
02-03-011-28W1M	27,497	172,952
03-03-011-28W1M	27,548	173,269
04-03-011-28W1M	27,437	172,572
05-03-011-28W1M	28,059	176,486
06-03-011-28W1M	28,026	176,280
07-03-011-28W1M	27,922	175,624
08-03-011-28W1M	27,617	173,706
09-03-011-28W1M	28,073	176,575
10-03-011-28W1M	28,370	178,445
11-03-011-28W1M	28,558	179,624
12-03-011-28W1M	28,757	180,878
13-03-011-28W1M	29,191	183,604
14-03-011-28W1M	28,991	182,348
15-03-011-28W1M	28,648	180,192
16-03-011-28W1M	28,500	179,258
	788,183	**4,957,520**

Table 5 - Daly Unit No. 18: Reservoir and Fluid Properties

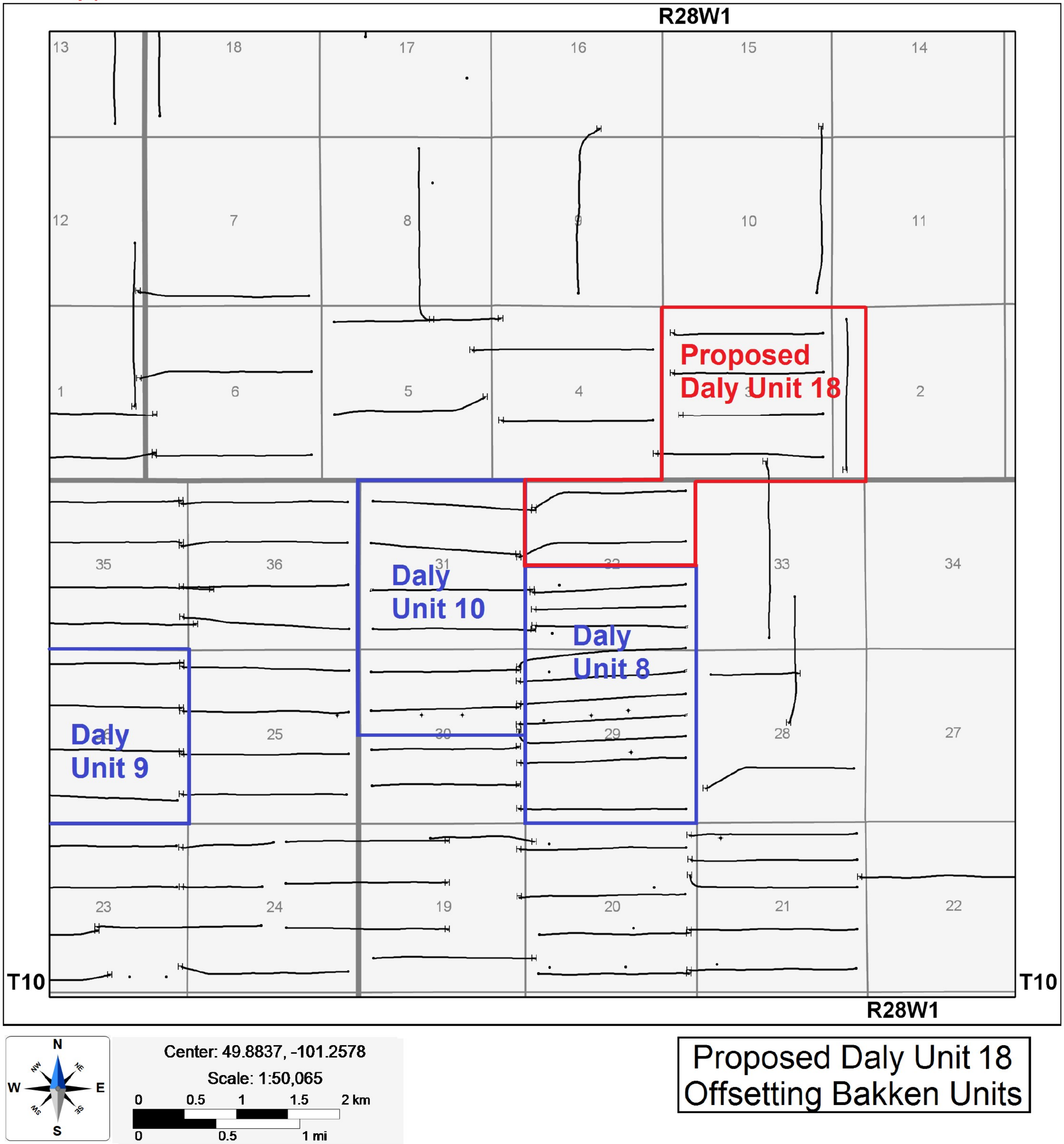
	Units	Bakken	
Depth	m	850	
Initial Reservoir Pressure	kPa	8,200	estimated
Formation Temperature	^{o}C	30	
Saturation Pressure	kPa	1,675	
Fracture Pressure	kPa	14,640	
Solution GOR	m3/m3	5	
Oil Gravity (dead oil)	^{o}API	42	
Bo @ Psat	m3/m3	1.03	
Initial Water Saturation	dec	0.35	
Wettability		neutral	
Average Porosity	%	15.8	
Average Permeability	mD	5	
Water Salinity	mg/L	113,000	

Proposed Daly Unit No. 18

Application for Enhanced Oil Recovery Waterflood Project

LIST OF APPENDICES

Appendix 1



Proposed Daly Unit 18
Offsetting Bakken Units

Appendix 2

A

00/04-32-010-28W1/0

KB: 520.7 m
RR: 1991-10-22
TD: 848.0 m [TVD]
FormTD: TORQUAY
Mode: Comingled
Fluid: Oil
TUNDRA DALY PROV 4-32-10-28
468.3m to next well >

00/05-32-010-28W1/0

KB: 520.9 m
RR: 1999-11-02
TD: 858.0 m [TVD]
FormTD: TORQUAY
Mode: Comingled
Fluid: Oil
TUNDRA DALY PROV. 5-32-10-28
< 468.3m to previous well
2000.1m to next well >

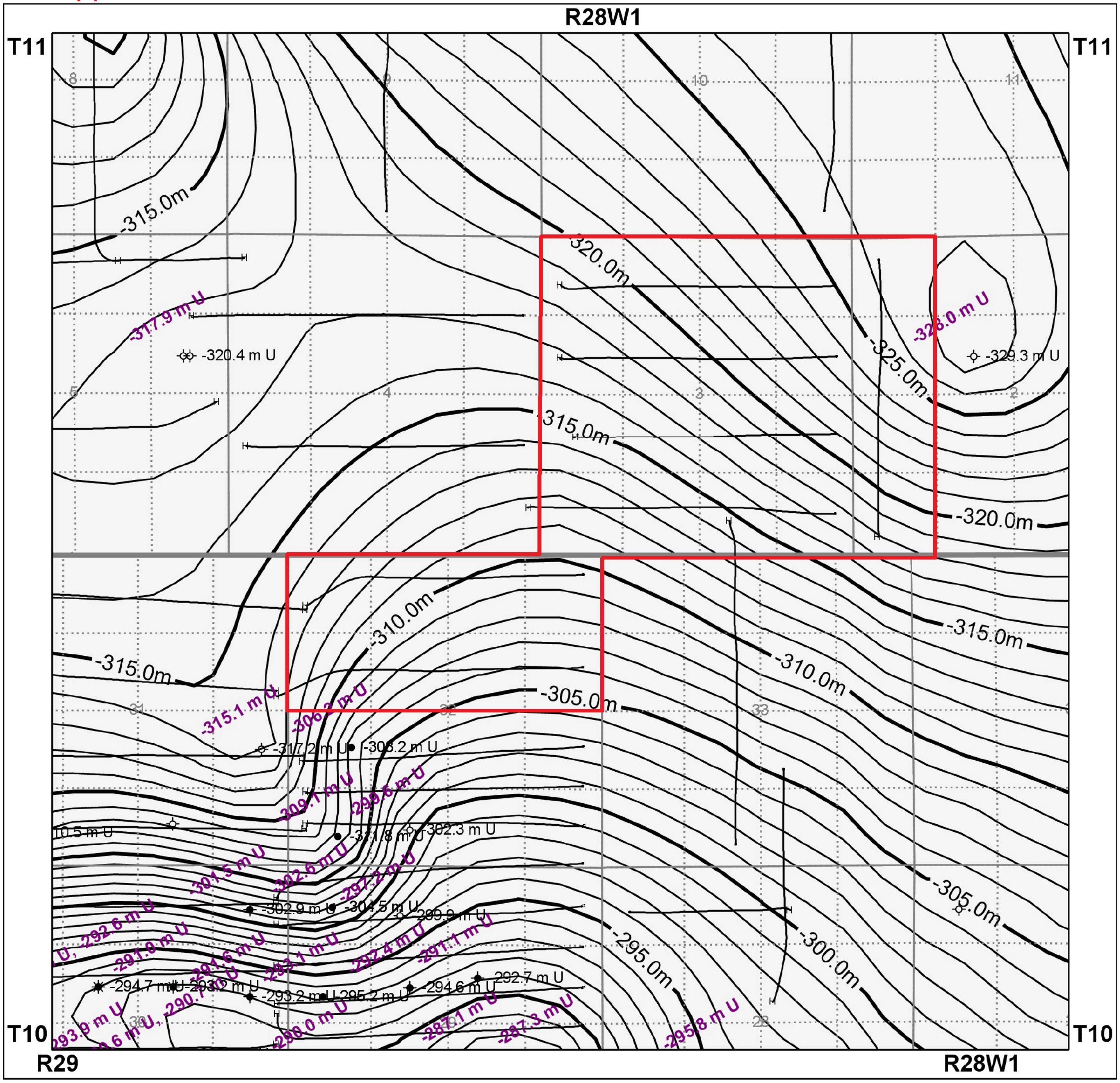
00/05-03-011-28W1/0

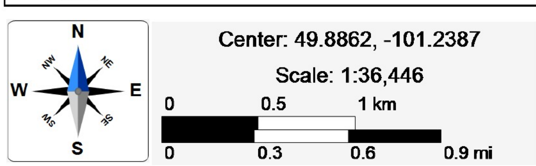
KB: 513.0 m
RR: 2010-09-11
TD: 878.0 m [TVD]
FormTD: BAKKEN
Mode: Abnd
Fluid: N/A
TUNDRA ELKHORN HZNTL 8-3-11-28 (WPM)
< 2000.1m to previous well

A'

Proposed Daly Unit 18
Structural Cross Section
-Southwest to Northeast-
Through Proposed Unit Area

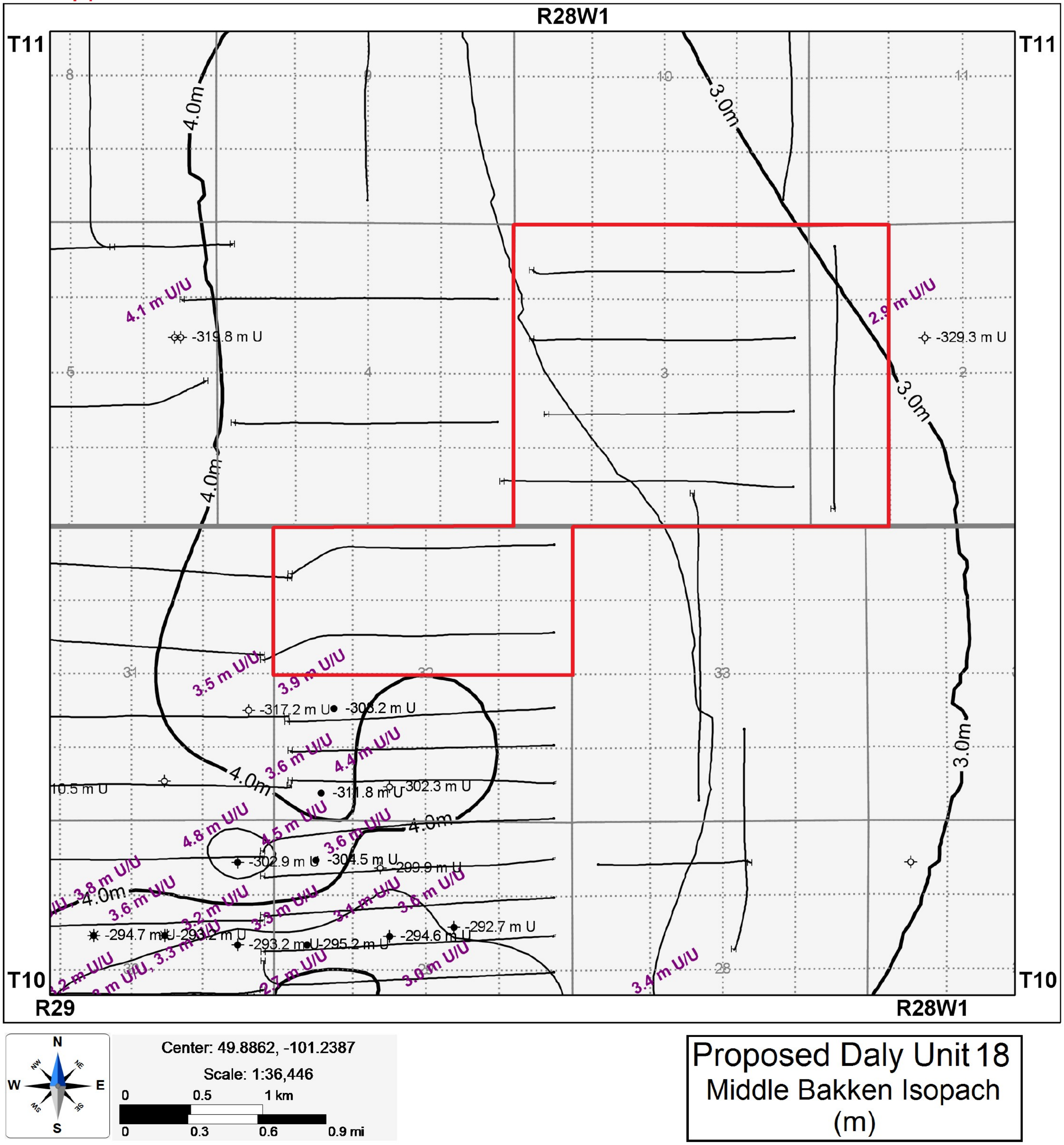
Appendix 3





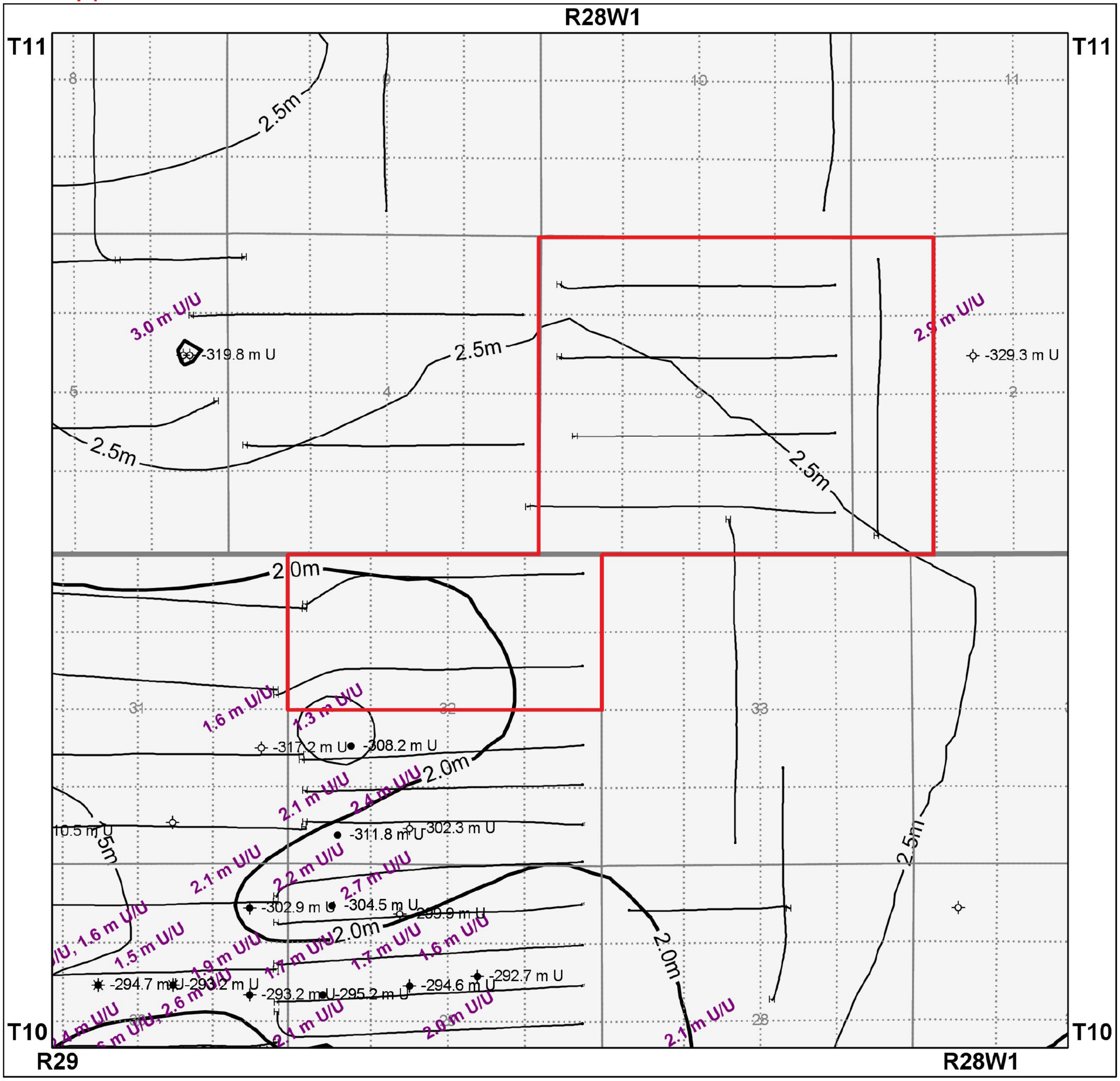
Proposed Daly Unit 18
Upper Bakken Structure
(mSS)

Appendix 4



Proposed Daly Unit 18
Middle Bakken Isopach
(m)

Appendix 5



N
W
E
S

Center: 49.8862, -101.2387

Scale: 1:36,446

0 0.5 1 km

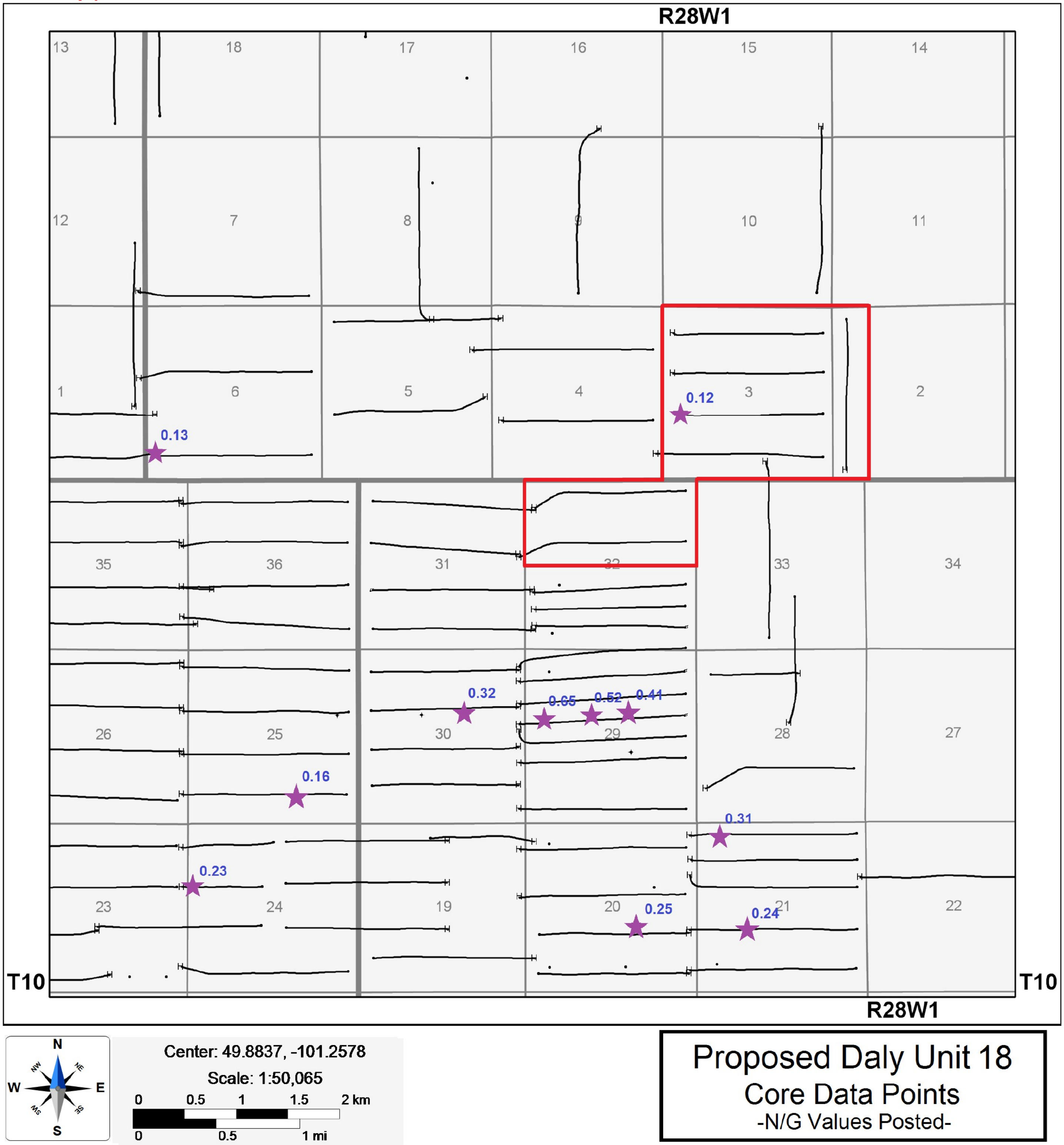
0 0.3 0.6 0.9 mi

Proposed Daly Unit 18

Lyleton B Isopach

(m)

Appendix 6



Proposed Daly Unit 18

Core Data Points

-N/G Values Posted-