PROPOSED DALY UNIT NO. 8

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (01 62A)

Daly, Manitoba

June 20th, 2014
Tundra Oil and Gas Partnership

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INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8-11 Ranges 27-29 WPM (Figure 1). Within the Daly oilfield, most Bakken reservoirs have been developed with vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells have recently been drilled by Tundra Oil and Gas (Tundra) in 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. 8 (Sec 29, S/2 32-10-28W1) and implement a Secondary Waterflood EOR scheme within the Three Forks and Middle Bakken formations as outlined on Figure 2.

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

SUMMARY

1. The proposed Daly Unit No. 8 will include 14 producing wells (4 verticals and 10 horizontals) within 24 Legal Sub Divisions (LSD's) of the Middle Bakken/Three Forks producing reservoir. The project is located east of Kola Unit No. 1 and Kola Unit No. 2 and northeast of North Ebor Unit No. 1 and North Ebor Unit No. 2 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Daly Unit No. 8 has been calculated to be **696.7** 10^3m^3 for an average of **29.0** net E^3m^3 OOIP per 40 acre LSD using petro-physical values for the average Middle Bakken porosity and net pay > = 12% limestone porosity and Sw < = 60%. .

3. Cumulative production to the end of March 2014 from the 14 producing and 3 abandoned wells within the proposed Daly Unit No. 8 project area was 49.3 E^3m^3 of oil, and 138.9 E^3m^3 of water, representing a **7.1%** Recovery Factor (RF) of the OOIP.

4. Estimated Ultimate Recovery (EUR) of current wells with Primary Proved Producing oil reserves in the proposed Daly Unit No. 8 project area is estimated to be **70.7** E^3m^3, with **21.4** E^3m^3 remaining as of the end of March 2014.

5. Ultimate oil recovery of the proposed Daly Unit No. 8 OOIP, under the current Primary Production method, is forecasted to be **10.1%**.

6. Figure 4 shows the production from the proposed Daly Unit No. 8 peaked in October 2011 at 60.0 m^3 of oil per day (OPD). As of March 2014, production was 23.8 m^3 OPD, 114.2 m^3 of water per day (WPD) and 76.4% watercut.

7. In October 2011, production averaged 6.7 m^3 OPD per well in Daly Unit No. 8. As of March 2014, average per well production has declined to 1.7 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **40.9%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Daly Unit No. 8 has been calculated to be **100.4** E^3m^3, with **51.0** E^3m^3 remaining. An incremental **29.6** E^3m^3 of proved oil reserves, or **4.3%**, are forecasted to be recovered under the proposed Unitization and Secondary EOR production versus the existing Primary Production method.

9. Total RF under Secondary WF in the proposed Daly Unit No. 8 is estimated to be **14.4%**. Primary accounts for **10.1%** and secondary for **4.3**%.

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

11. All five (5) future horizontal injectors, with multi-stage hydraulic fractures, have been drilled (Figure 5) within the proposed Daly Unit No. 8, to complete waterflood patterns with effective 20 acre spacing for 4 patterns and one 40 acre spacing for one-half pattern.

TECHNICAL DISCUSSION

The proposed Daly Unit No. 8 project area is located in Township 10, Range 28 W1 of the Daly Sinclair oil field. The proposed Daly Unit No. 8 currently consists of 4 producing vertical wells and 10 producing horizontal wells within an area covering Section 29, S/2 Section 32-10-28W1 (Figure 2). A project area well list complete with recent production statistics is attached as Table 3.

Within the proposed unit, potential exists 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 of Daly Unit 8 is shown on the stratigraphic cross section A – A' attached as Appendix 2. The cross section runs from northwest to southeast across the proposed unit. The producing sequence from youngest to oldest is: the Upper Bakken Shale, the Middle Bakken fine grained sandstone/siltstone, the Lyleton 'B' siltstone, and the Lyleton 'C' silty shale. This sequence is unconformably overlain by the Mississippian Lodgepole Formation and is unconformably underlain by the Devonian Birdbear Formation.

Within the sequence, the Mississippian Middle Bakken unconformably overlies the Devonian Three Forks Group (the Lyleton 'B' and Lyleton 'C') and the Three Forks group thins towards the east.

The main productive zone is considered to be the Middle Bakken, however there may be a small contribution to the total OOIP by the underlying Lyleton 'B'. Whatever pay there is in the upper Lyleton 'B' is marginal and thin and therefore has not been mapped or included in this application.

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained siltstone to sandstone (often tan colored when oil stained). It can be divided into two units – the upper Middle Bakken and the lower Middle Bakken. The upper Middle Bakken is about 0.5 – 1m thick in the Unit 8 area and is mainly considered non-reservoir. It is composed of heavily bioturbated grey siltstone with small brachiopod shells and the occasional crinoid and coral fragments. Pyrite nodules are common. The environmental interpretation of the upper Middle Bakken is an offshore transition/lower shoreface.

The lower Middle Bakken consists of finely laminated grey and tan colored siltstone and fine grained sandstone interbeds with occasional bioturbation. Where there is a higher sand content, bioturbation is rare. Inclined heterolithic stratification is common. The environmental interpretation of the lower Middle Bakken is of a tidal bar. This is the main reservoir unit of the Middle Bakken and ranges from 0.2 to 3 meters thick in Daly Unit 8 (Appendix 4).

The upper Lyleton B reservoir unit is at the top and is composed of ripple – cross laminated dolo- siltstones increasingly interbedded with tight greenish/grey dolomitic shales with depth. The upper Lyleton B is interpreted to have been deposited in a brackish bay type environment. This unit is very thin to non-existent in Daly Unit 8.

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

Structure:

Appendix 3 is a top Middle Bakken Subsea Structure map. The unit is partially on the peak of the 'Daly high', the structurally highest portion of the Daly oil pool. The peak of the structure is in the southeast quarter of section 29 and then drops to the northwest, the east, and to the southwest (in the regional dip direction). There is about 25m elevation change between the crest of the Daly high at 7-29-10-28W1 and the structural low in southwest 32-10-28W1.

Reservoir Continuity:

Cross section A – A' (Appendix 2) and the Middle Bakken Net Pay map (Appendix 4) demonstrate that there is likely fairly good lateral reservoir continuity in the Middle Bakken formation. Vertical reservoir continuity within the Middle Bakken and the underlying Lyleton is likely very poor to non-existent due to the heterolithic depositional environment and the multiple thin shale interbeds. This is also seen in the low 'Kvert' values of the analyzed core in the area (Appendix 8).

Reservoir Quality:

Only 3 of the wells within the unit have core analysis in the Middle Bakken formation (10-29, 11-29 and 12-29-10-28W1) but they have high Kmax.h values (14.3, 36.9, and 61.9 mD.m respectively) indicating that the lower Middle Bakken has good reservoir in the area (Appendix 6). It is not worth generating a KH map of the area as there are only the 3 data points within the unit.

The good reservoir interpretation is also supported with the relatively high average porosity values seen in Appendix 5: Middle Bakken Average porosity – where the limestone porosity values range from 14.5 to 19% throughout the proposed unit.

Fluid Contacts:

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

OOIP Estimates:

OOIP was calculated by Tundra Geologist Jennifer Tremblay. Jennifer holds a BSc honors in Geology from the University of Calgary and has 13 years oil industry experience; 6.5 of which working in the Williston Basin. Each vertical well within the unit was petrophysically analyzed by Gille Montsion, incorporating existing conventional core analysis data. Gille has 20 years of experience as a Sr. Petrophysicist with

Canadian Hunter, ConocoPhillips, and Nexen. Gille does all his advanced petrophysics with Tundra's Geolog license and brings consistency to our evaluations.

Total volumetric OOIP for the Middle Bakken within the proposed Daly Unit 8 has been calculated to be **696.7** 10^3m^3 using Tundra internally created maps. OOIP was estimated using petrophysical values for the average Middle Bakken porosity and net pay > = 12% limestone porosity and Sw < = 60%. Refer to Appendices 7 and 8.

The petrophysically defined net pay and phi.h values were then hand contoured in Geoscout by Jennifer Tremblay and OOIP was calculated on a LSD by LSD basis honoring the well values when present or the interpolated value by mapping if there was no vertical well in the LSD.

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. 8 is shown as Figure 4. Oil production commenced from the proposed Unit area in February 1986 and peaked during October 2011 at 60.0 m^3 OPD. As of March 2014, production was 23.8 m^3 OPD, 114.2 m^3 of water per day (WPD) and 76.4% watercut.

Oil production is currently declining at an annual rate of approximately **40.9%** 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 current development by **4.3%**. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have the greatest recovery possible by allowing the development of additional drilling and injector conversions over time, in order to maintain reservoir pressure and increase oil production.

Unit Name

Tundra proposes that the official name of the new Unit covering Section 29, S/2 Section 32-10-28W1 shall be Daly Unit No. 8.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Daly Unit No. 8.

Unitized Zone

The Unitized zone(s) to be waterflooded in Daly Unit No. 8 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 4 vertical and 10 horizontal wells to be included in the proposed Daly Unit No. 8 are outlined in Table 3.

Unit Lands

The Daly Unit No. 8 will consist of 24 LSD's as follows:

LSD's 1-16 of Section 29 of Township 10, Range 28, W1M
LSD's 1-8 of Section 32 of Township 10, Range 28, W1M

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

Tract Factors

The proposed Daly Unit No. 8 will consist of 24 tracts based on the 40 acre LSD's containing the existing 4 vertical and 10 horizontal producing wells.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 8 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

Unit tract factor calculations for all individual LSD's based on the above methodology are outlined within Table 2.

Working Interest Owners

Table 1 outlines the working interest (WI) for each individual tract within the proposed Daly Unit No. 8, and Tundra Oil and Gas Partnership holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Partnership will have a 100% WI in the proposed Daly Unit No. 8.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 8 are based on internal engineering assessments. Internal reviews included analysis of available open-hole logs; core data; petro-physics; seismic; drilling information; completion information; and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed Daly Unit No. 8 OOIP (Table 4).

Unitizing the proposed Daly Unit No. 8 will provide an equitable means of maximizing ultimate oil recovery in the project area.

Horizontal Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Daly Unit No. 8 has declined significantly from peak rate indicating a need for secondary pressure support. Tundra drilled infill producers in 2012 to understand reservoir depletion and reservoir heterogeneity in this area. The new producers have been on production since that time and have shown some interference affects with the old producers in the area.

All five (5) future horizontal injection wells were drilled in 2011 as shown in Figure 5. The waterflood will consist of a half 40 acre line drive waterflood pattern and four (4) 20 acre line drive waterflood patterns within Daly Unit No. 8. This is being done to understand the most effective waterflood response spacing that will result in the best ultimate recovery in the future development of this area.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Daly Unit No. 8 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.

Based on the geological description, primary production decline rate, and waterflood response in Kola Units 1 & 2 and North Ebor Units 1 & 2, the Bakken formation in the project area is believed to be a suitable reservoir for WF EOR operations.

Primary Production Forecast

Cumulative production in the Daly Unit No. 8 project area, to the end of March 2014, was 49.3 E^3m^3 of oil, and 138.9 E^3m^3 of water for a recovery factor **7.1%** 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 **70.7** E^3m^3, with **21.4** E^3m^3 remaining as of the end March 2014. This represents a recovery factor of **10.1%** of the total OOIP.

Primary production plots of the expected production decline and forecasted oil rate v. time and rate v. cumulative oil production are shown in Figures 7 and 8, respectively.

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 Daly Unit No. 8, while maximizing reservoir knowledge (Table 7).

Criteria for Conversion to Water Injection Well

Five (5) horizontal injection wells are required for this proposed Unit. They will be placed on permanent water injection service as shown in Figure 5. No existing vertical producer wells within the proposed Daly Unit No. 8 project are planned for conversion to water injection, as oil production response is better with horizontal injectors than with vertical injectors.

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

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

The above schedule allows for the proposed Daly Unit No. 8 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

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

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 9 and 10, respectively. Total Secondary EUR for the proposed Daly Unit No. 8 is estimated to be **100.4** E^3m^3 with **51.0** E^3m^3 remaining representing a total secondary recovery factor of **14.4%** for the proposed Unit area. An incremental **29.6** E^3m^3 of oil, or incremental **4.3%** recovery factor, are forecasted to be recovered under the proposed Unitization.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate a fracture pressure gradient of 16.0 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

Injection water for the proposed Daly Unit No. 8 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.

Tundra does not foresee any compatibility issues between the produced and injection waters based on previous compatibility testing performed by a third party, Nalco Champion.

Injection Wells

All five (5) future water injection wells for the proposed Daly Unit No. 8 have been drilled, are currently producing and plans are in progress to re-configure four (4) of the wells for downhole injection as soon as approval for waterflood has been received. The one remaining injector will be converted in 2015. The horizontal injection wells have been stimulated by multiple hydraulic fracture treatments to obtain suitable injection rates in a cemented liner completion (Figure 13). 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 approval to inject has been received from the Petroleum Branch. 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. 8 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

The estimated reservoir pressure for the proposed Daly Unit No. 8 is in the range of 4,000 – 7,000 kPa. Pressures measured in the newly drilled wells are detailed in Table 6. All measured pressures are within the Middle Bakken zone and corrected to a common datum of -450 mSS for comparison with other units in the area.

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 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

Daly Unit No. 8 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. 8 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. 8.

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. 8 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Daly Unit No. 8 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. 8 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 11).

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Appendix 9. All surface facilities and wellheads will have cathodic protection to prevent corrosion. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set above the Middle Bakken and Three Forks formations, and the annulus between the tubing and casing will be filled with inhibited fluid.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra will notify all mineral rights and surface rights owners of this proposed EOR project and formation of Daly Unit No. 8. 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. 8 Application.

Daly Unit No. 8 Unitization, and execution of the formal Daly Unit No. 8 Agreement by affected Mineral Owners, is expected before the end of Q1 2014. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 8 Application.

Should the Petroleum Branch have further questions or require more information, please contact Raj Sharma at 403.767.1237 or by email at raj.sharma@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Raj Sharma, P. Eng. June 20th, 2014

Proposed Daly Unit No. 8

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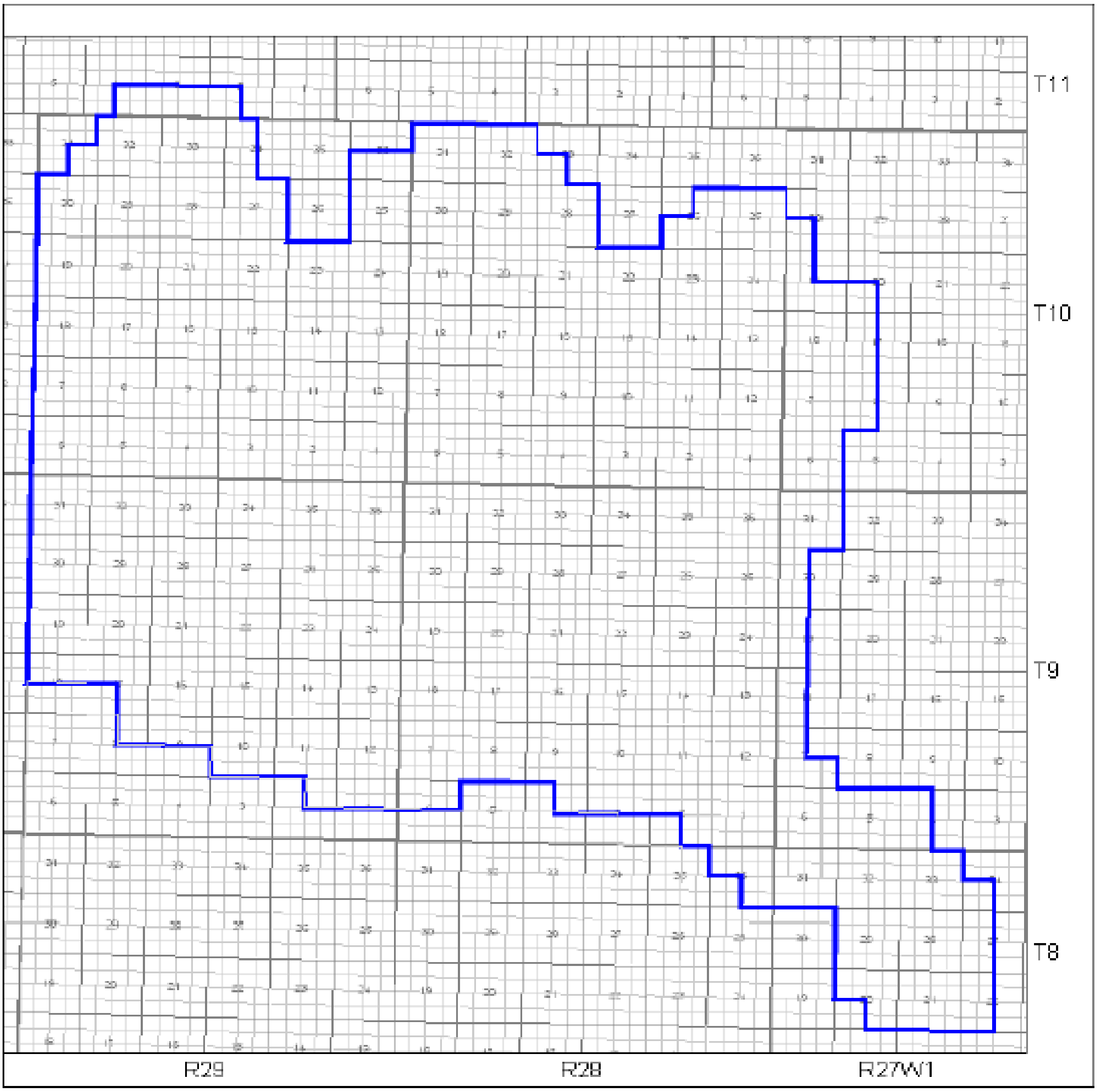
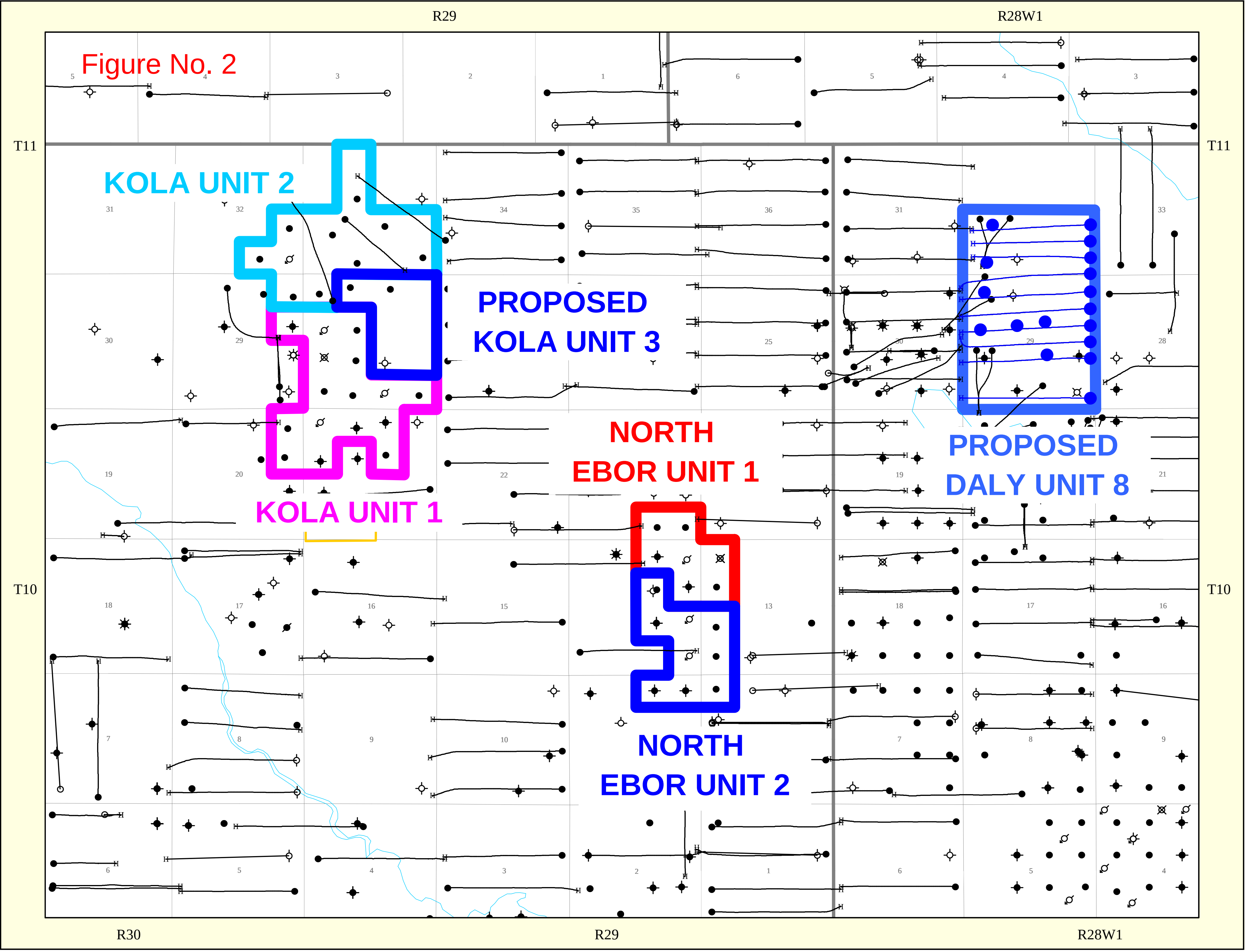


Daly Field

Daly Field Boundary

Source: Manitoba Petroleum Branch Designated Fields and Pools – 2009

Figure 1



File: Daly Unit No. 8.MAP Datum: NAD27 Projection: Stereographic Center: N49.84970 W101.31739 Created in AccuMap™, a product of IHS

Figure No. 3

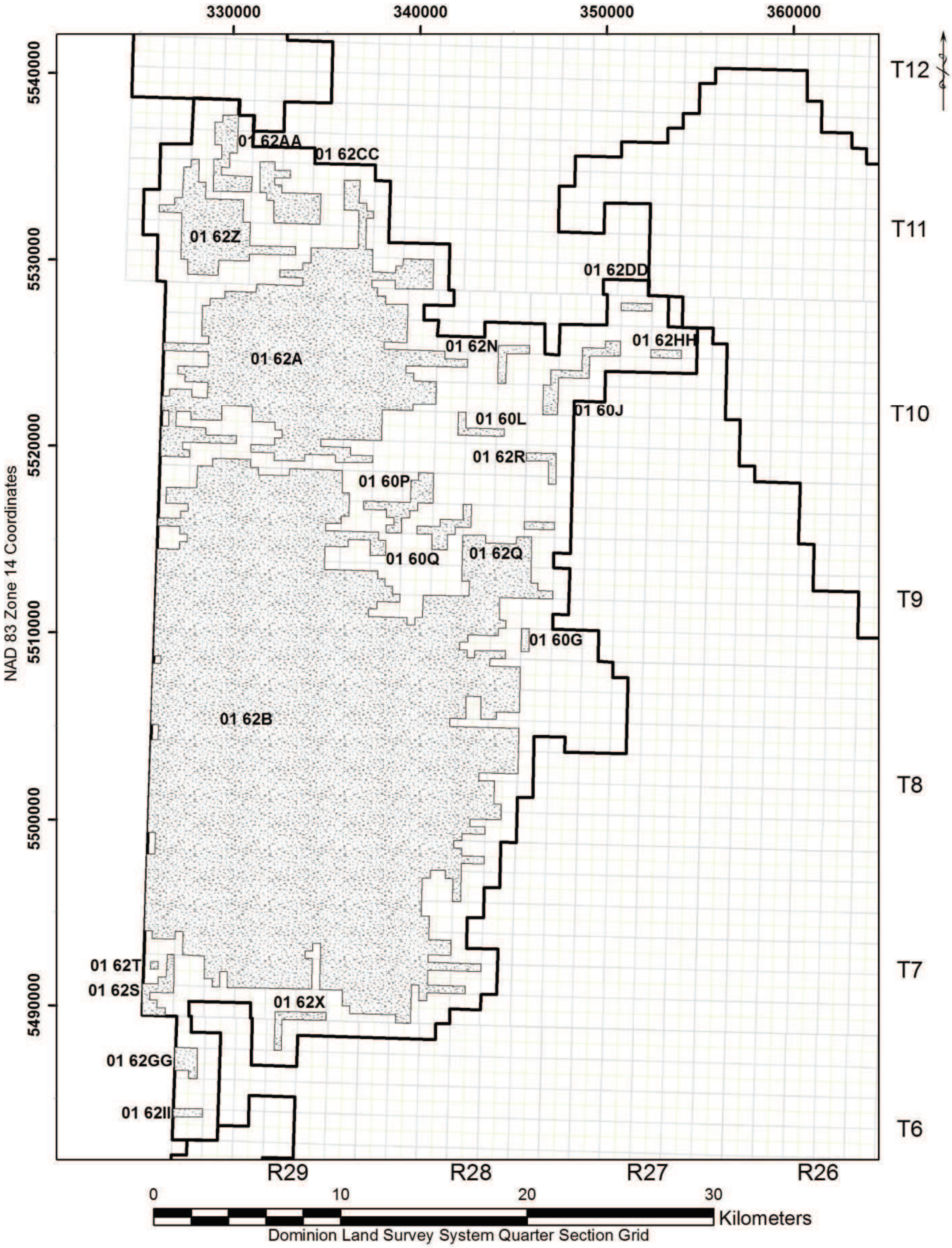
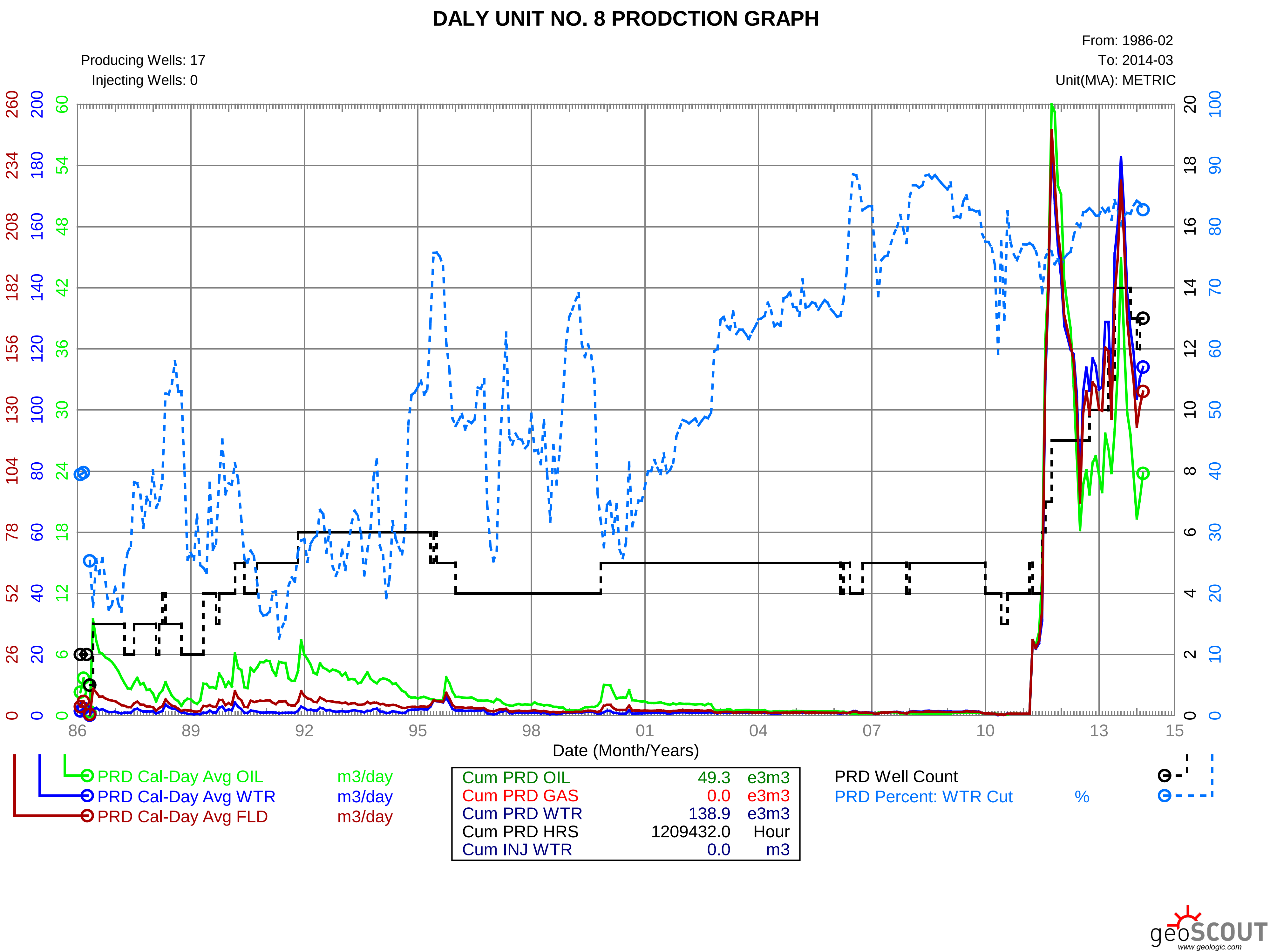


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Figure No. 4


DALY UNIT NO. 8 PRODCTION GRAPH
From: 1986-02
To: 2014-03
Unit(M\A): METRIC
Producing Wells: 17
Injecting Wells: 0
0 26 52 78 104 130 156 182 208 234 260
0 20 40 60 80 100 120 140 160 180 200
0 6 12 18 24 30 36 42 48 54 60
0 2 4 6 8 10 12 14 16 18 20
0 10 20 30 40 50 60 70 80 90 100
86 89 92 95 98 01 04 07 10 13 15
Date (Month/Years)
PRD Cal-Day Avg OIL m3/day
PRD Cal-Day Avg WTR m3/day
PRD Cal-Day Avg FLD m3/day
Cum PRD OIL 49.3 e3m3
Cum PRD GAS 0.0 e3m3
Cum PRD WTR 138.9 e3m3
Cum PRD HRS 1209432.0 Hour
Cum INJ WTR 0.0 m3
PRD Well Count
PRD Percent: WTR Cut %
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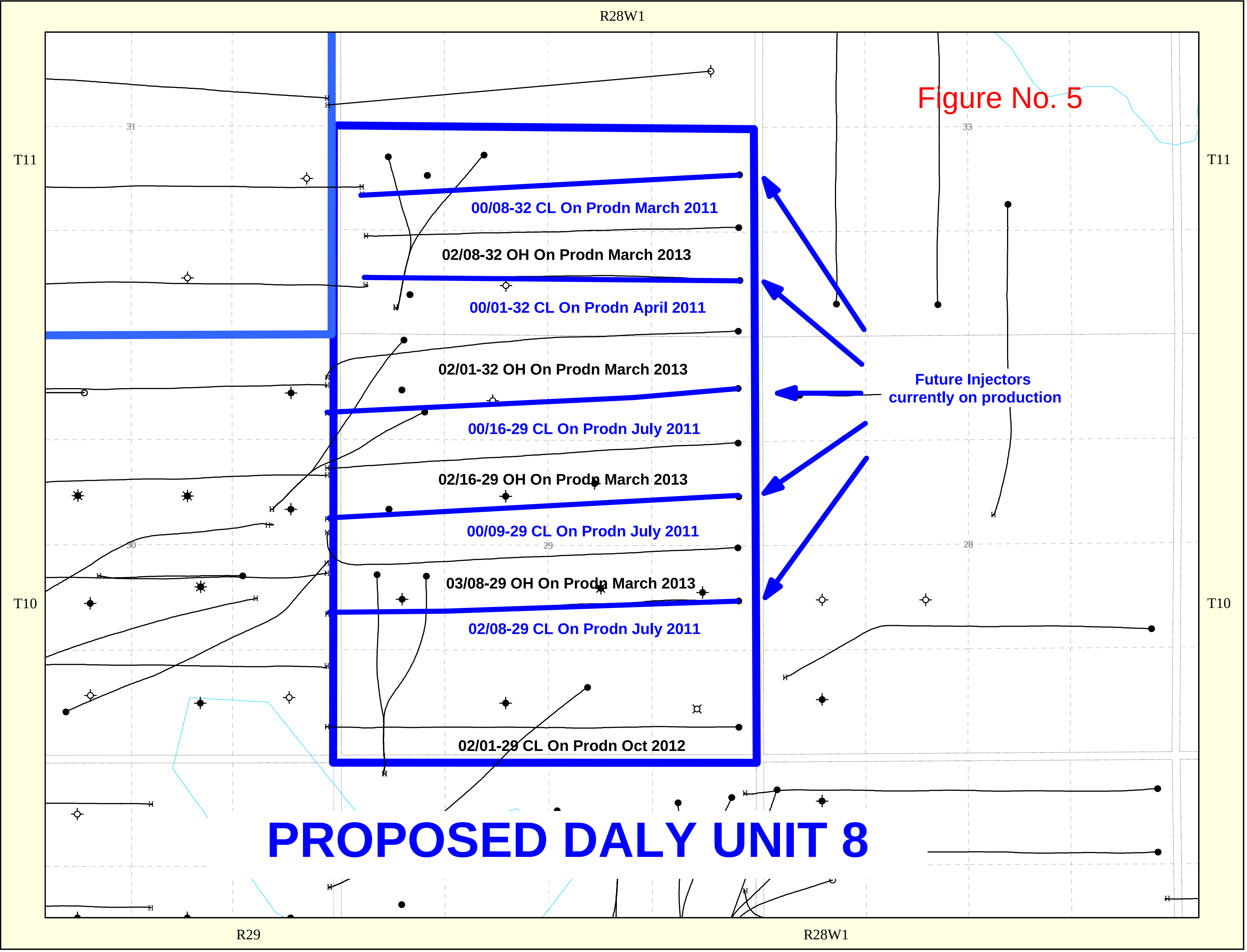
www.geologic.com



File: Daly Unit No. 8 Proposed Injec Datum: NAD27 Projection: Stereographic Center: N49.86708 W101.24312 Created in AccuMap™, a product of IHS

Well Information as of 4/16/2014 - Group Well Report

Figure No. 6

Production Graph

# of Wells:	16	**Prod Zone:**	BAKKEN; TORQUAY	**On Prod:**	2004-12 to 2014-02
		Field:	DALY (1)	**Cum Oil:**	145249.5 m3
Fluid:	Oil; Water Injection	**Pool Code:**	62B	**Cum Gas:**	0.0 E3m3
Mode:	Producing; Injection	**Unit Code:**	162B01	**Cum Wtr:**	22626.7 m3

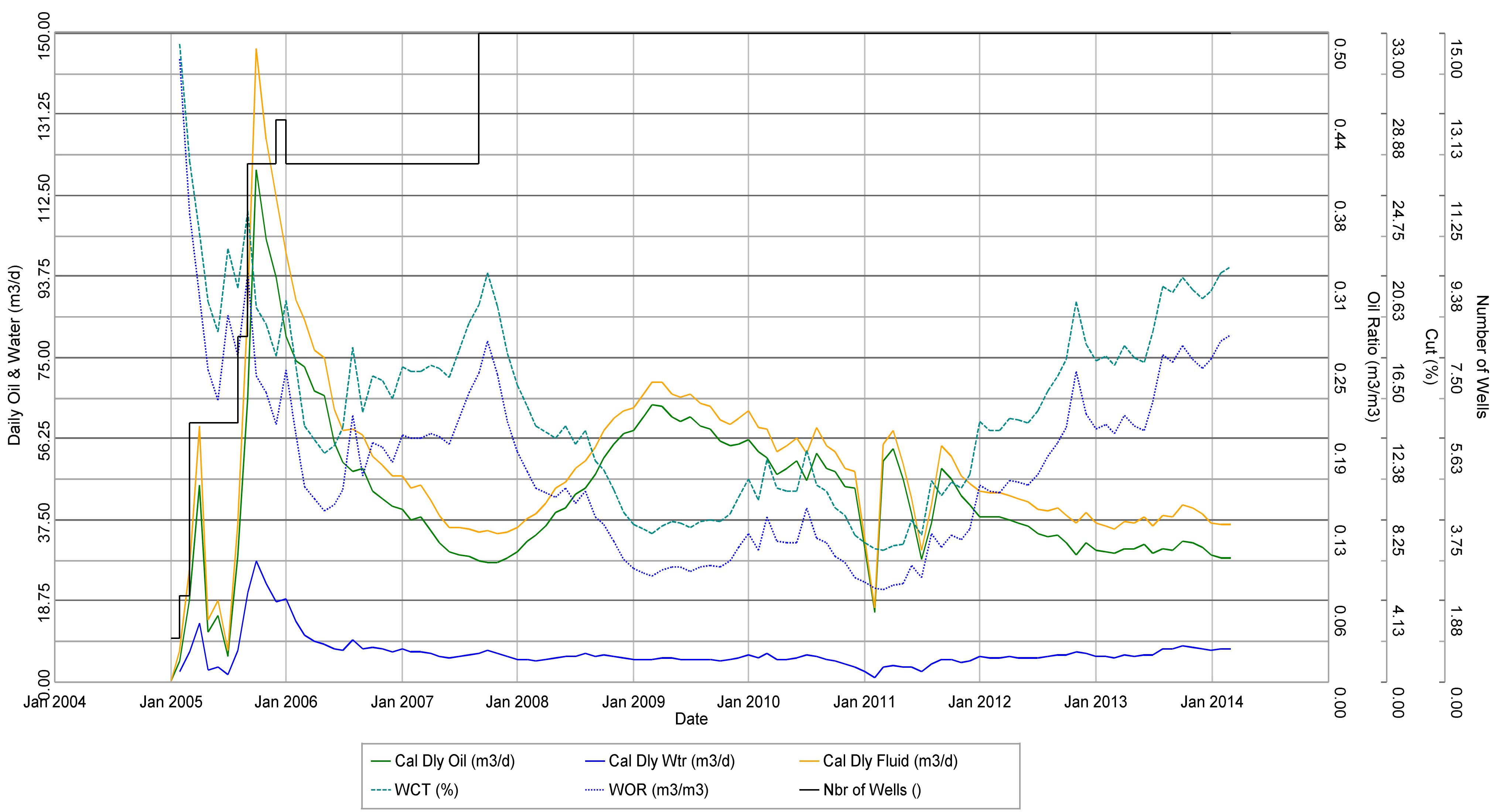
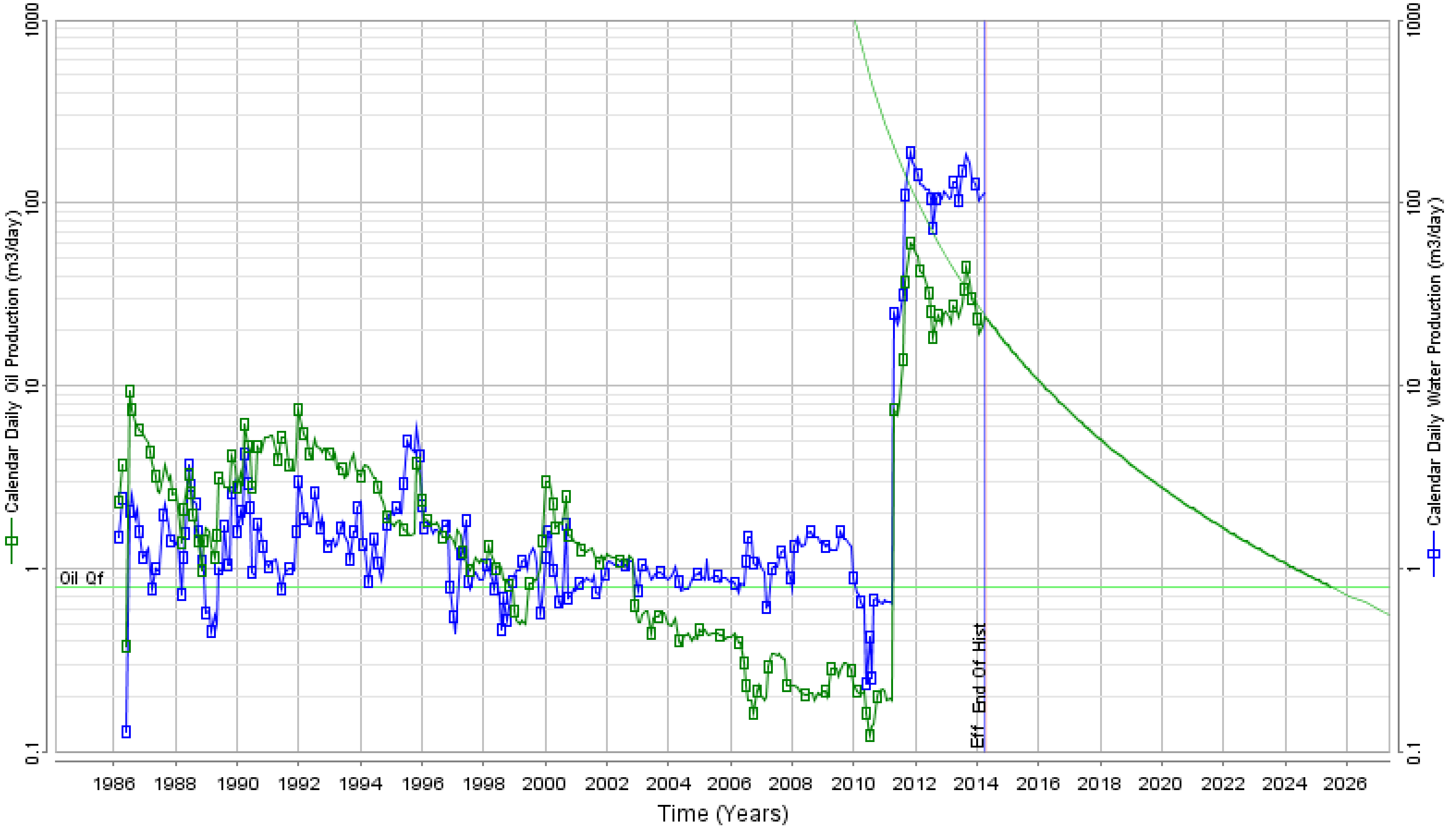


Figure No. 7

Province:	Manitoba
Field:	n/a
Pool:	n/a
Unit:	
Status:	n/a
Operator:	n/a

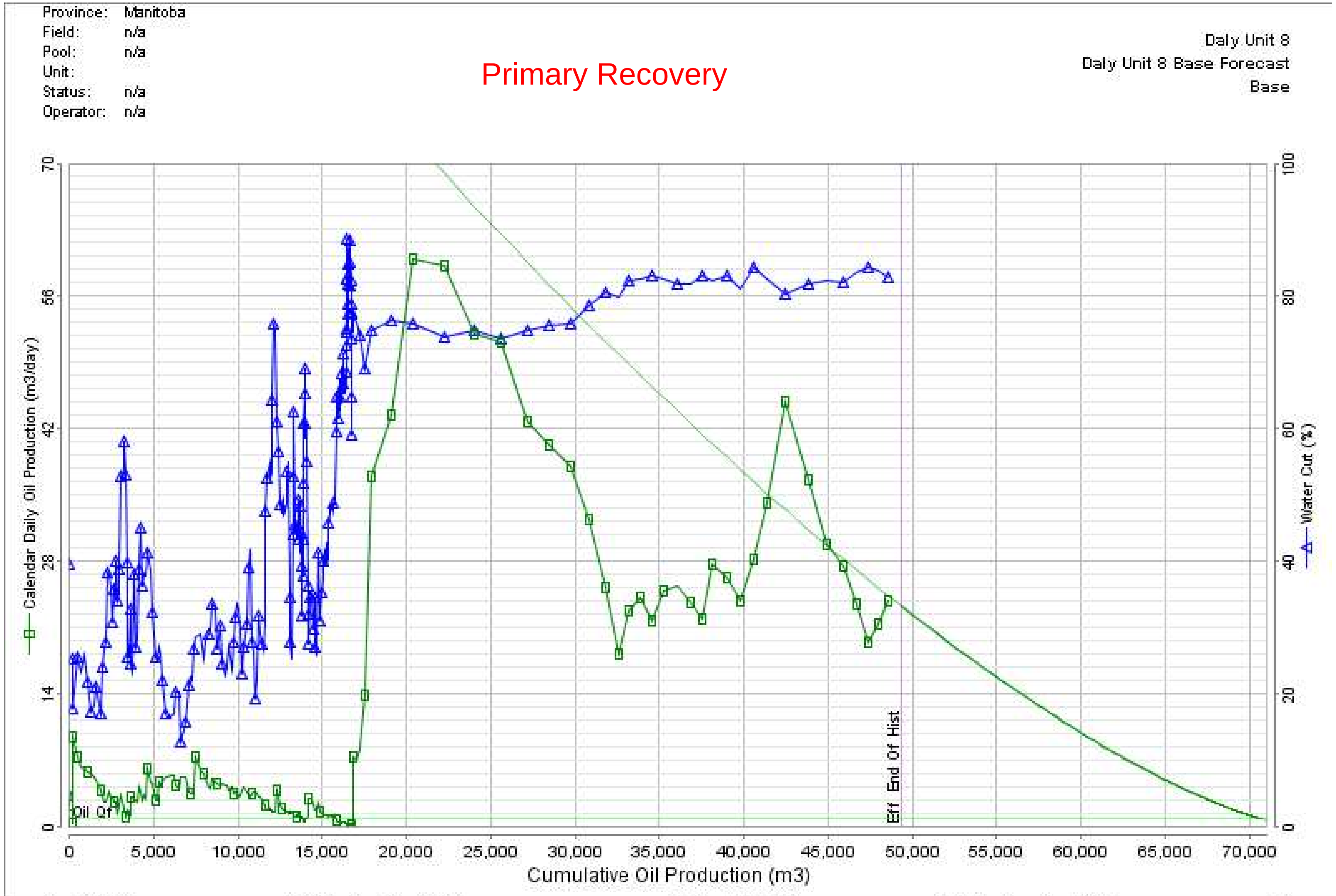
Primary Recovery

Daly Unit 8
Daly Unit 8 Base Forecast
Base



Cum Oil(m3):	49,336	Cum Gas(E3m3):	0	Cum Water(m3):	138,931	Cum Cond(m3):	0
Forecast Start:	04/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	49,336	Decline Exponent:	0.300
Forecast End:	06/20/2025	OVIP (m3):	0	Remaining (m3):	21,378	Initial Decline (%/yr):	40.9
Initial Rate (m3):	23.8	Recovery Factor:	0.000				
Final Rate (m3):	0.8	Ult. Recoverable (m3):	70,715				

Figure No. 8



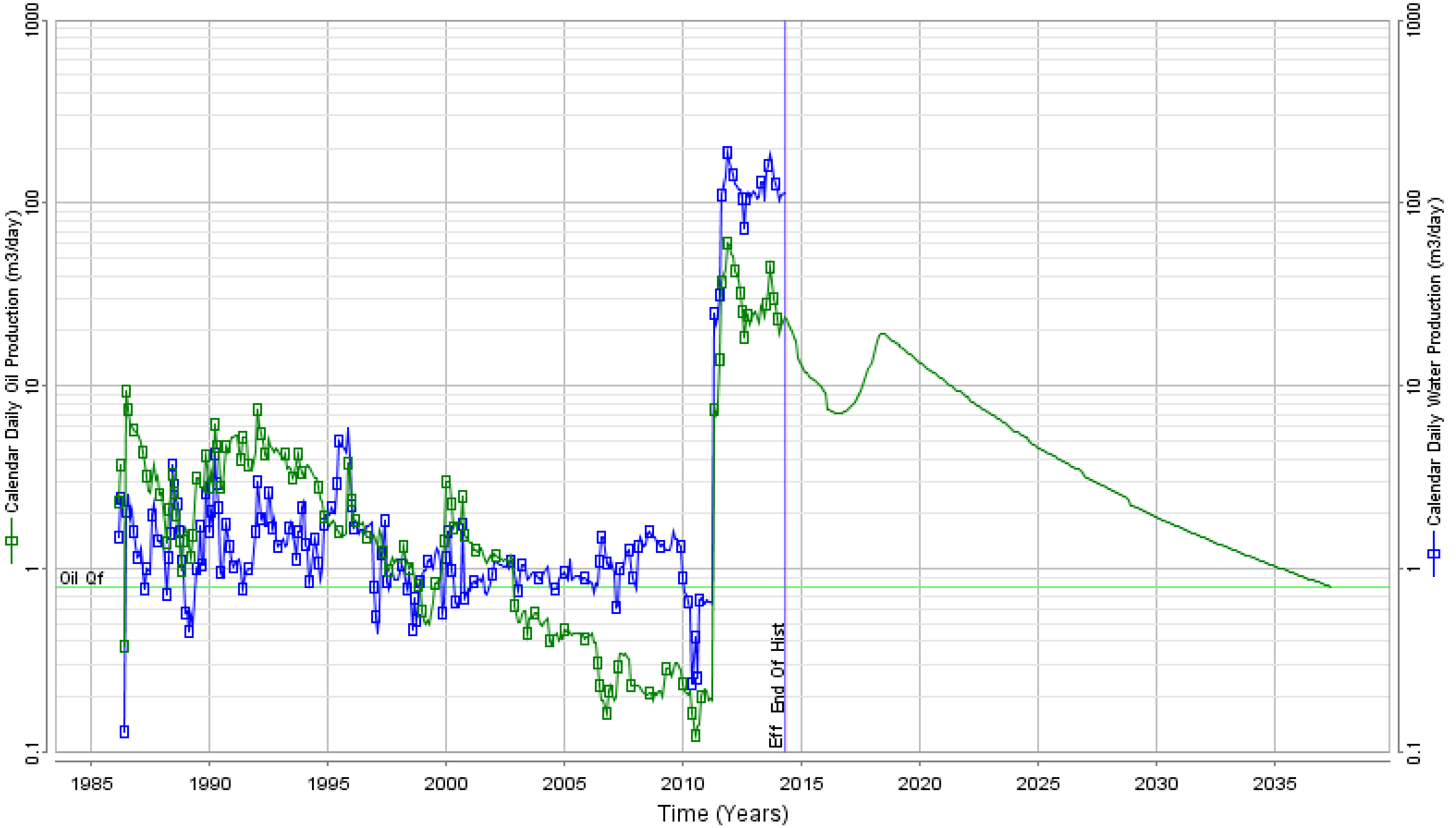
Cum Oil(m3):	49,336	Cum Gas(E3m3):	0	Cum Water(m3):	138,931	Cum Cond(m3):	0
Forecast Start:	04/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	49,336	Decline Exponent:	0.300
Forecast End:	06/20/2025	OVIP (m3):	0	Remaining (m3):	21,378	Initial Decline (%/yr):	40.9
Initial Rate (m3):	23.8	Recovery Factor:	0.000				
Final Rate (m3):	0.8	Ult. Recoverable (m3):	70,715				

Figure No. 9

Province: Manitoba
Field: multi zone (2)
Pool: multi zone (2)
Unit: multi zone (18)
Status: n/a
Operator: Tundra O&G Prtnshp

Primary + Secondary Recovery

Daly Unit 8
Daly Unit 8 WF Forecast
Base + Growth 1



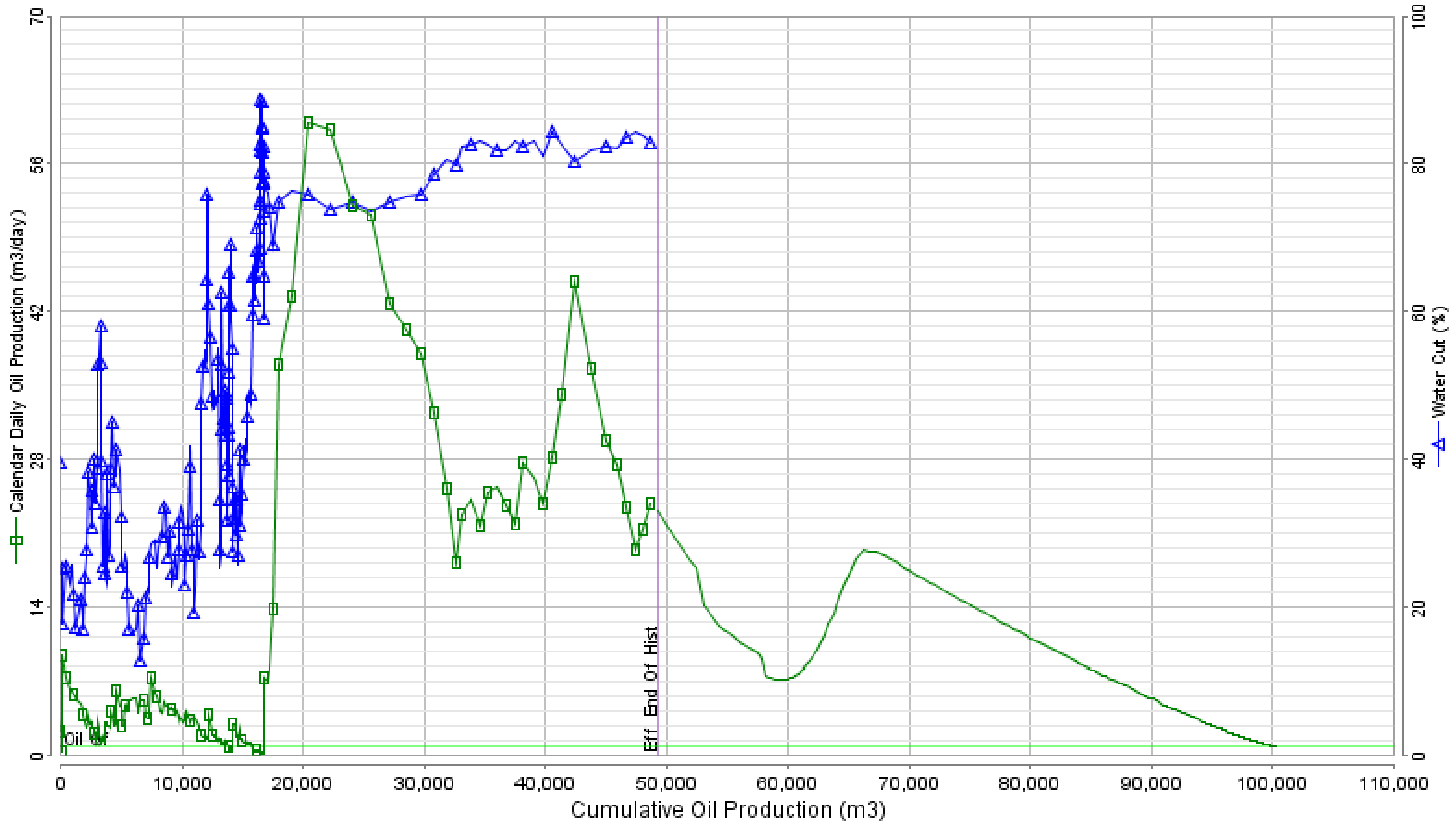
Cum Oil(m3):	49,336	Cum Gas(E3m3):	0	Cum Water(m3):	138,931	Cum Cond(m3):	0
Forecast Start:	04/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	49,336	Decline Exponent:	0.000
Forecast End:	04/30/2037	OVIP (m3):	0	Remaining (m3):	51,014	Initial Decline (%/yr):	0.0
Initial Rate (m3):	23.0	Recovery Factor:	0.000				
Final Rate (m3):	0.8	Ult. Recoverable (m3):	100,350				

Figure No. 10

Province:	Manitoba		
Field:	multi zone (2)		
Pool:	multi zone (2)		
Unit:	multi zone (18)		
Status:	n/a		
Operator:	Tundra O&G Prtnshp		

Daly Unit 8
Daly Unit 8 WF Forecast
Base + Growth 1

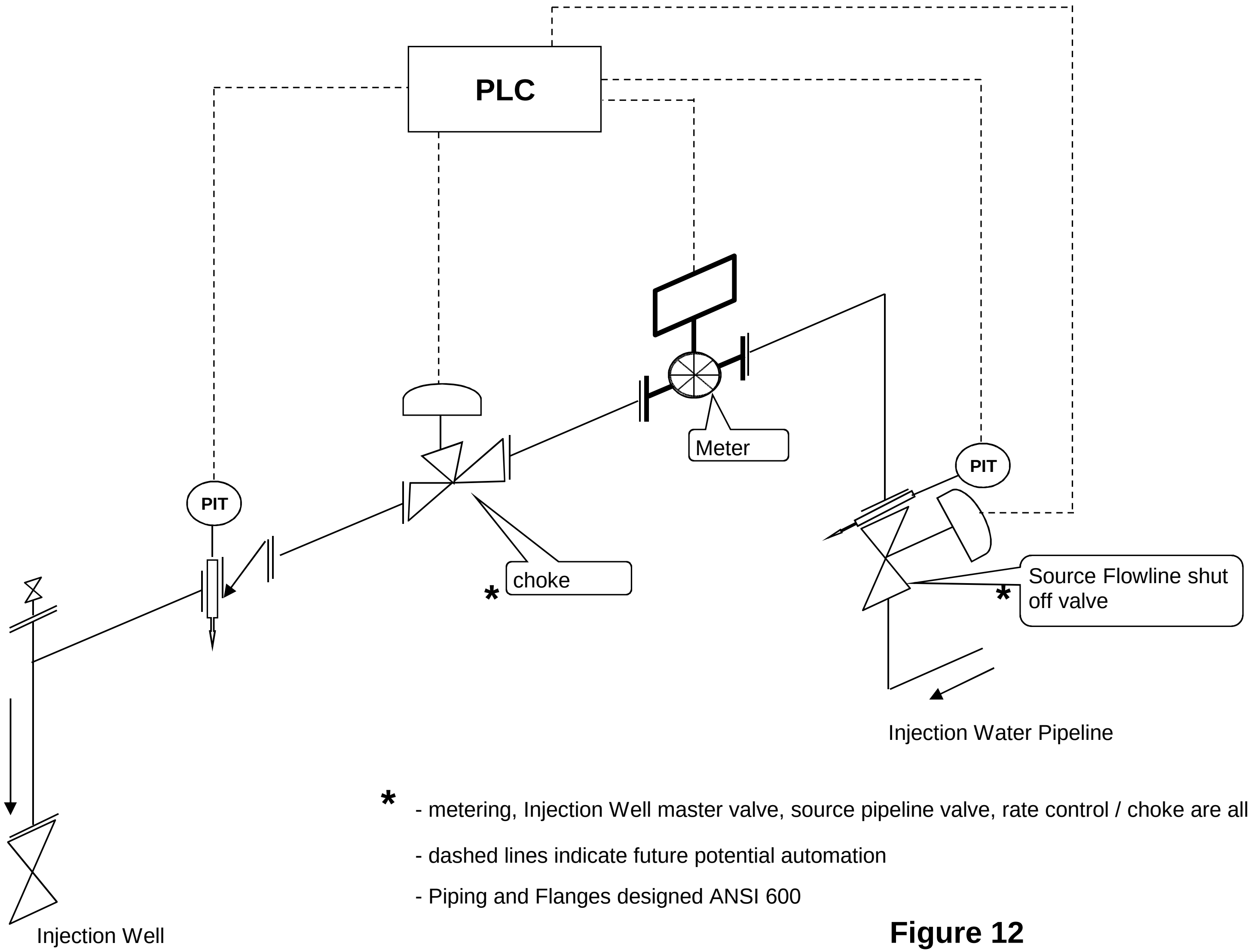
Primary + Secondary Recovery



Cum Oil(m3):	49,336	Cum Gas(E3m3):	0	Cum Water(m3):	138,931	Cum Cond(m3):	0
Forecast Start:	04/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	49,336	Decline Exponent:	0.000
Forecast End:	04/30/2037	OVIP (m3):	0	Remaining (m3):	51,014	Initial Decline (%/yr):	0.0
Initial Rate (m3):	23.0	Recovery Factor:	0.000				
Final Rate (m3):	0.8	Ult. Recoverable (m3):	100,350				

Daly Unit No. 8

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

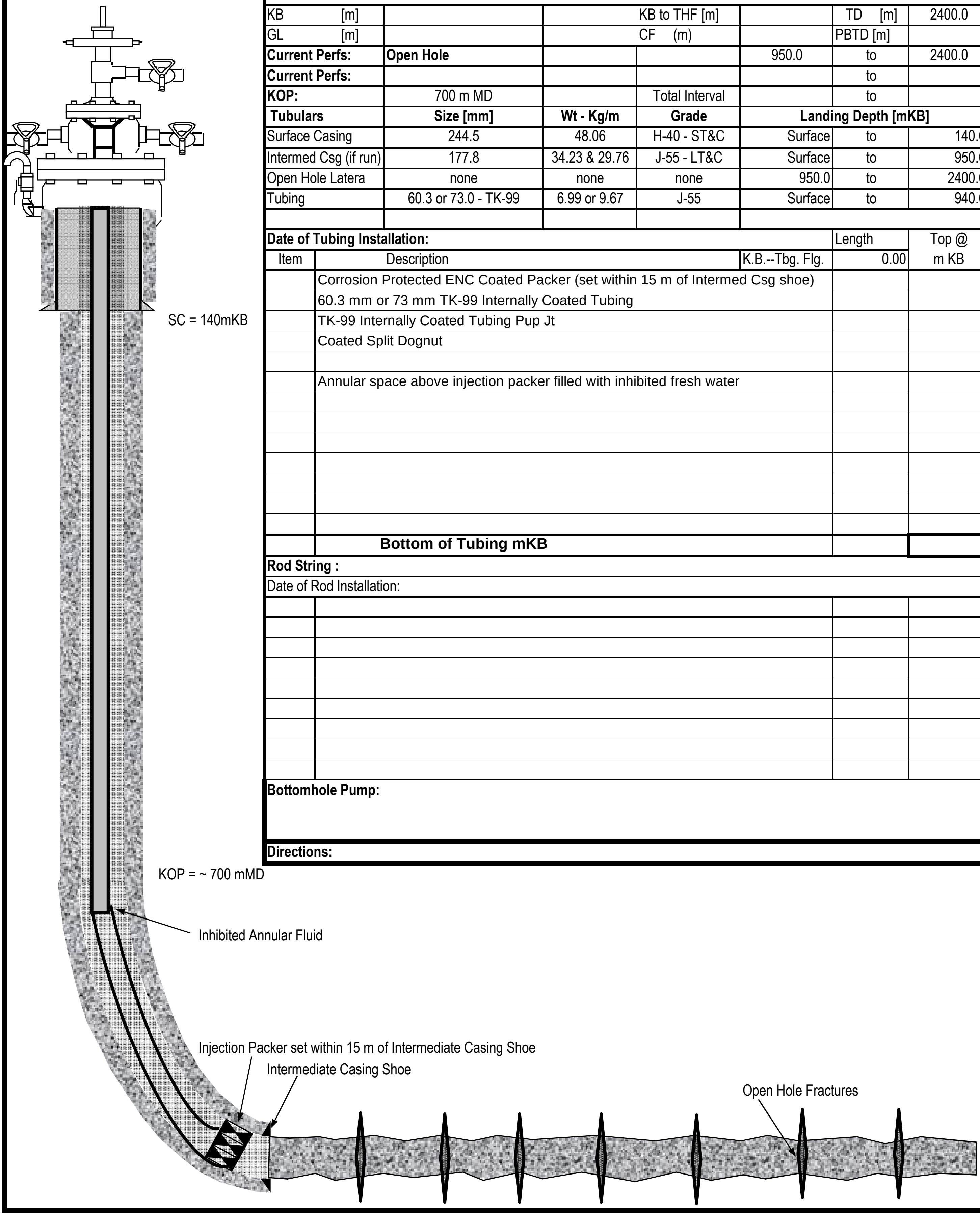
- Piping and Flanges designed ANSI 600

Figure 12

Tundra Oil And Gas Partnership

Figure No. 13

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME:	Tundra Daly Unit No. 8 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

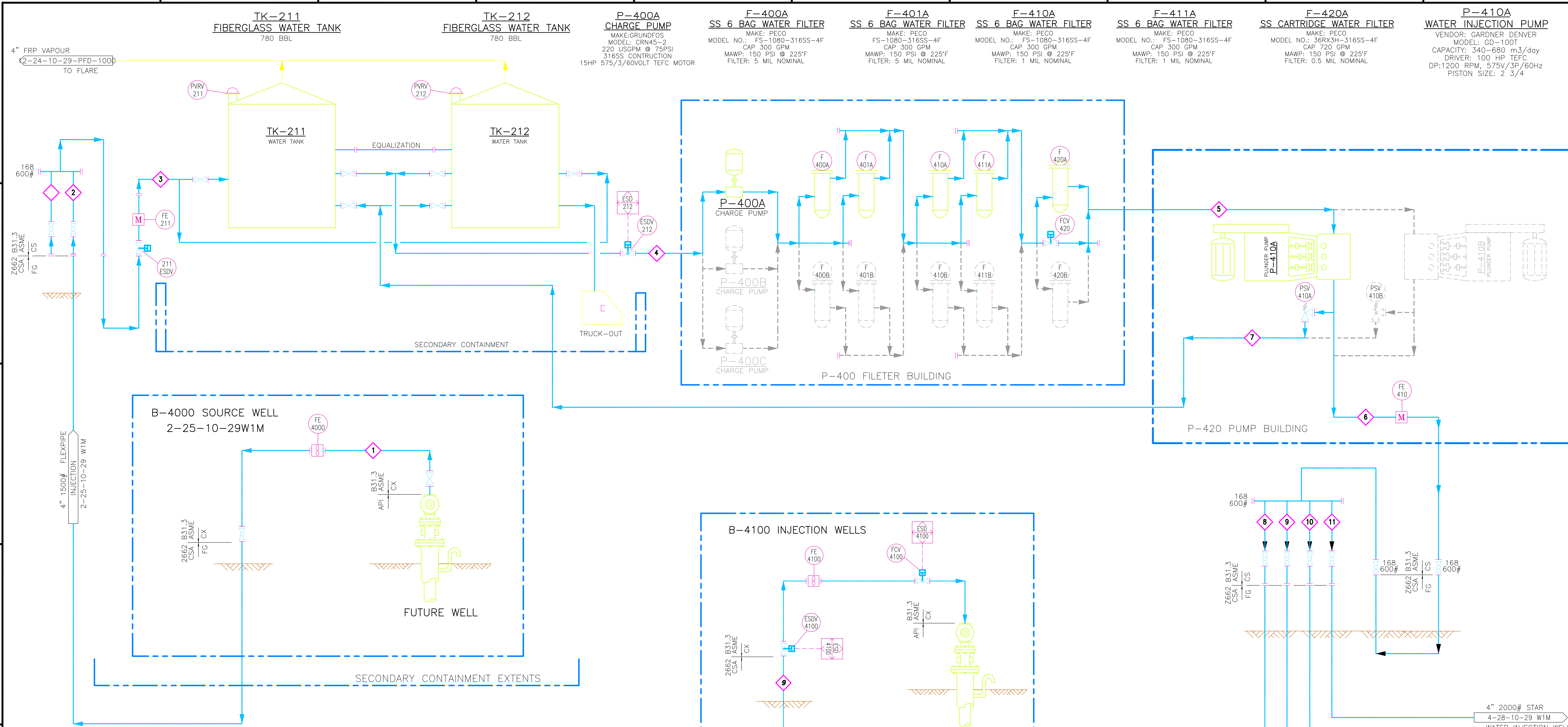
Date of Tubing Installation:			Length	Top @
Item	Description	K.B.--Tbg. Flg.	0.00	m KB
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)			
	60.3 mm or 73 mm TK-99 Internally Coated Tubing			
	TK-99 Internally Coated Tubing Pup Jt			
	Coated Split Dognut			
	Annular space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

Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions:



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
–

NOTES:

Figure No. 11

TUNDRA OIL & GAS PARTNERSHIP

PROCESS FLOW DIAGRAM
12-24-10-29W1M

PROCESS FLOW DIAGRAM 4 OF 4
INJECTION SYSTEM

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

TABLE NO. 1: TRACT PARTICIPATION FOR PROPOSED DALY UNIT NO. 8

	Working Interest			Royalty Interest		Tract Participation (%)
Tract No.	Land Description	Owner	Share (%)	Owner	Share (%)	
1	01-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	6.483835864
2	02-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	7.253560993
3	03-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	6.626047440
4	04-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	6.630203562
5	05-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	6.452705198
6	06-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	6.570682947
7	07-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	3.508422211
8	08-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	3.378895548
9	09-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	3.309280684
10	10-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	4.613899854
11	11-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	5.872531020
12	12-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	5.914911032
13	13-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	4.109780193
14	14-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	4.591299237
15	15-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	4.153530008
16	16-29-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	3.351650844
17	01-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	2.830883031
18	02-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	3.120848990
19	03-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	0.988224882
20	04-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	1.748571306
21	05-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	2.438728789
22	06-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	1.864299799
23	07-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	2.128466385
24	08-32-010-28W1M	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA	100%	2.058740183
						100.000000000

TABLE No. 2: TRACT FACTOR CALCULATIONS

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) LESS CUMULATIVE OIL PRODUCED METHOD

PROPOSED DALY UNIT NO. 8							
LSD-SEC	**TWP-RGE**	***UWI***	***OOIP (m3)***	***Hz Cum Prodn March 2014 (m3)***	***Vertical Cum Oil Prodn March 2014 (m3)***	***OOIP Minus Cum Oil Prodn (m3)***	***Tract Factor (%)***
01-29	010-28W1	100/01-29-010-28W1/0	42617	642	0	41975	6.483835864
02-29	010-28W1	100/02-29-010-28W1/0	47631	672	0	46958	7.253560993
03-29	010-28W1	100/03-29-010-28W1/0	43568	672	0	42896	6.626047440
04-29	010-28W1	100/04-29-010-28W1/0	43568	645	0	42923	6.630203562
05-29	010-28W1	100/05-29-010-28W1/0	42790	1016	0	41774	6.452705198
06-29	010-28W1	100/06-29-010-28W1/0	43568	1030	0	42538	6.570682947
07-29	010-28W1	100/07-29-010-28W1/0	26772	992	3067	22713	3.508422211
08-29	010-28W1	100/08-29-010-28W1/0	22778	904	0	21874	3.378895548
09-29	010-28W1	100/09-29-010-28W1/0	22778	1354	0	21424	3.309280684
10-29	010-28W1	100/10-29-010-28W1/0	33765	1435	2460	29870	4.613899854
11-29	010-28W1	100/11-29-010-28W1/0	40413	1441	953	38018	5.872531020
12-29	010-28W1	100/12-29-010-28W1/0	44121	1324	4505	38292	5.914911032
13-29	010-28W1	100/13-29-010-28W1/0	30861	1749	2506	26606	4.109780193
14-29	010-28W1	100/14-29-010-28W1/0	31613	1889	0	29723	4.591299237
15-29	010-28W1	100/15-29-010-28W1/0	28786	1897	0	26889	4.153530008
16-29	010-28W1	100/16-29-010-28W1/0	23513	1815	0	21698	3.351650844
01-32	010-28W1	100/01-32-010-28W1/0	20098	1772	0	18327	2.830883031
02-32	010-28W1	100/02-32-010-28W1/0	22043	1839	0	20204	3.120848990
03-32	010-28W1	100/03-32-010-28W1/0	8212	1815	0	6398	0.988224882
04-32	010-28W1	100/04-32-010-28W1/0	15128	968	2840	11320	1.748571306
05-32	010-28W1	100/05-32-010-28W1/0	17669	1007	874	15788	2.438728789
06-32	010-28W1	100/06-32-010-28W1/0	13831	1762	0	12069	1.864299799
07-32	010-28W1	100/07-32-010-28W1/0	15560	1781	0	13779	2.128466385
08-32	010-28W1	100/08-32-010-28W1/0	15041	1713	0	13328	2.058740183
TOTAL			**696721**	**32131**	**17205**	**647385**	**100.000000000**

Table 3: Daly Unit 8 Well List

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Prod Date	Prod Date	Cal Dly Oil (m3/d)	Monthly Oil (m3)	Cum Prd Oil (m3)	Cal Dly Water (m3/d)	Monthly Water (m3)	Cum Prd Water (m3)	WCT (%)	
102/01-29-010-28W1/0	008578	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	10/1/2012	2014-03	2.5	77.2	2630.3	14.7	454.3	9312.6	85.5	
102/08-29-010-28W1/0	007893	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	7/1/2011	2014-03	1	30.7	2763.9	15.3	473.3	35986.9	93.9	
103/08-29-010-28W1/0	009210	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	4/1/2013	2014-03	5.3	164.9	1752.7	21.8	675.5	7391.6	80.4	
100/09-29-010-28W1/0	007894	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	7/1/2011	2014-03	0.4	12.4	4010.6	0.9	29.4	19577.3	70.3	
100/12-29-010-28W1/0	003869	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Comingled	6/1/1986	2014-03	0	0	4505.2	0	0.6	2305.8	100	
100/13-29-010-28W1/0	004167	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Comingled	3/1/1990	2013-10	0	0.1	2505.8	0.1	2.1	2747.5	95.5	0
100/16-29-010-28W1/0	007854	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	7/1/2011	2014-03	1.2	37.2	6171.9	3.9	121.1	9174.6	76.5	
102/16-29-010-28W1/0	009191	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	6/1/2013	2014-03	4	123.6	1413.9	23.4	725.6	8425.3	85.4	
100/01-32-010-28W1/0	007855	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	4/1/2011	2014-03	0.9	27.8	5239.9	1.6	49	14867.7	63.8	
102/01-32-010-28W1/0	009220	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	6/1/2013	2014-03	3.9	121.8	1290.2	26.4	819.3	8724.8	87.1	
100/04-32-010-28W1/0	004299	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Comingled	11/1/1991	2014-03	0.3	8.7	2839.5	0.1	3.3	1824.6	27.5	
100/05-32-010-28W1/2	004848	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Comingled	11/1/1999	2014-03	0	0.3	874.3	0.1	2	662.7	87	
100/08-32-010-28W1/0	007829	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/1/2011	2014-03	2.7	83.4	5724.3	2.5	78.4	11053.7	48.5	
102/08-32-010-28W1/0	009192	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	3/1/2013	2014-03	1.6	49	1133.7	3.4	104.4	2062	68.1	

These wells are abandoned and will not be included in Daly Unit 8

100/07-29-010-28W1/0	003782	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/1/1986	Dec/2009	0.0	0.6	3067.2	0.1	4.5	3116.0	88.2
100/10-29-010-28W1/0	003845	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/1/1986	Dec/1995	0.1	2.5	2459.9	0.1	3.5	1373.4	58.3
100/11-29-010-28W1/0	003930	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	7/1/1987	Jun/1995	0.1	2.7	953.2	0.3	8.4	324.9	75.7
										49336.5			**138931.4**	

Table 4: Daly Unit 8 OOIP Calculations

M Bkkn OOIP Calculation **OOIP = {A*h*phi (1-Sw)}/Boi** **1m3 = 6.28981 bbl**

LSD	Section	Twp	Rge	Avg.Por	h	Area	Sw est	1-Sw	Area*h*phi*(1-Sw)	Boi	OOIP	OOIP	OOIP	Formations Present	Formation Completed	Comments
				%	m	m2	%				m3	barrels	MSTB	(Lyl B, Lyl A, M Bkkn)	(Lyl B, Lyl A, M Bkkn)	
1	29	10	28	0.17	2.9	160000	0.45	0.55	43384	1.018	**42617**	268052	**268.05**	M Bkkn		
2	29	10	28	0.19	2.9	160000	0.45	0.55	48488	1.018	**47631**	299588	**299.59**	M Bkkn		
3	29	10	28	0.18	2.8	160000	0.45	0.55	44352	1.018	**43568**	274033	**274.03**	M Bkkn		
4	29	10	28	0.18	2.8	160000	0.45	0.55	44352	1.018	**43568**	274033	**274.03**	M Bkkn		
5	29	10	28	0.165	3	160000	0.45	0.55	43560	1.018	**42790**	269140	**269.14**	M Bkkn		
6	29	10	28	0.18	2.8	160000	0.45	0.55	44352	1.018	**43568**	274033	**274.03**	M Bkkn		
7	29	10	28	0.163	1.9	160000	0.45	0.55	27253.6	1.018	**26772**	168389	**168.39**	M Bkkn	M Bkkn	
8	29	10	28	0.155	1.7	160000	0.45	0.55	23188	1.018	**22778**	143269	**143.27**	M Bkkn		
9	29	10	28	0.155	1.7	160000	0.45	0.55	23188	1.018	**22778**	143269	**143.27**	M Bkkn		
10	29	10	28	0.186	2.1	160000	0.45	0.55	34372.8	1.018	**33765**	212376	**212.38**	M Bkkn	M Bkkn	
11	29	10	28	0.187	2.5	160000	0.45	0.55	41140	1.018	**40413**	254187	**254.19**	M Bkkn	M Bkkn	
12	29	10	28	0.176	2.9	160000	0.45	0.55	44915.2	1.018	**44121**	277513	**277.51**	M Bkkn	M Bkkn	
13	29	10	28	0.17	2.1	160000	0.45	0.55	31416	1.018	**30861**	194107	**194.11**	M Bkkn	M Bkkn	
14	29	10	28	0.159	2.3	160000	0.45	0.55	32181.6	1.018	**31613**	198837	**198.84**	M Bkkn		
15	29	10	28	0.185	1.8	160000	0.45	0.55	29304	1.018	**28786**	181058	**181.06**	M Bkkn		
16	29	10	28	0.16	1.7	160000	0.45	0.55	23936	1.018	**23513**	147891	**147.89**	M Bkkn		
1	32	10	28	0.155	1.5	160000	0.45	0.55	20460	1.018	**20098**	126414	**126.41**	M Bkkn		
2	32	10	28	0.17	1.5	160000	0.45	0.55	22440	1.018	**22043**	138648	**138.65**	M Bkkn		
3	32	10	28	0.19	0.5	160000	0.45	0.55	8360	1.018	**8212**	51653	**51.65**	M Bkkn		
4	32	10	28	0.175	1	160000	0.45	0.55	15400	1.018	**15128**	95150	**95.15**	M Bkkn	M Bkkn	
5	32	10	28	0.146	1.4	160000	0.45	0.55	17987.2	1.018	**17669**	111136	**111.14**	M Bkkn	M Bkkn	
6	32	10	28	0.16	1	160000	0.45	0.55	14080	1.018	**13831**	86995	**86.99**	M Bkkn		
7	32	10	28	0.15	1.2	160000	0.45	0.55	15840	1.018	**15560**	97869	**97.87**	M Bkkn		
8	32	10	28	0.145	1.2	160000	0.45	0.55	15312	1.018	**15041**	94607	**94.61**	M Bkkn		
											696721	4382245	**4382.25**			

Table 5 - Daly Unit No. 8: Reservoir and Fluid Properties

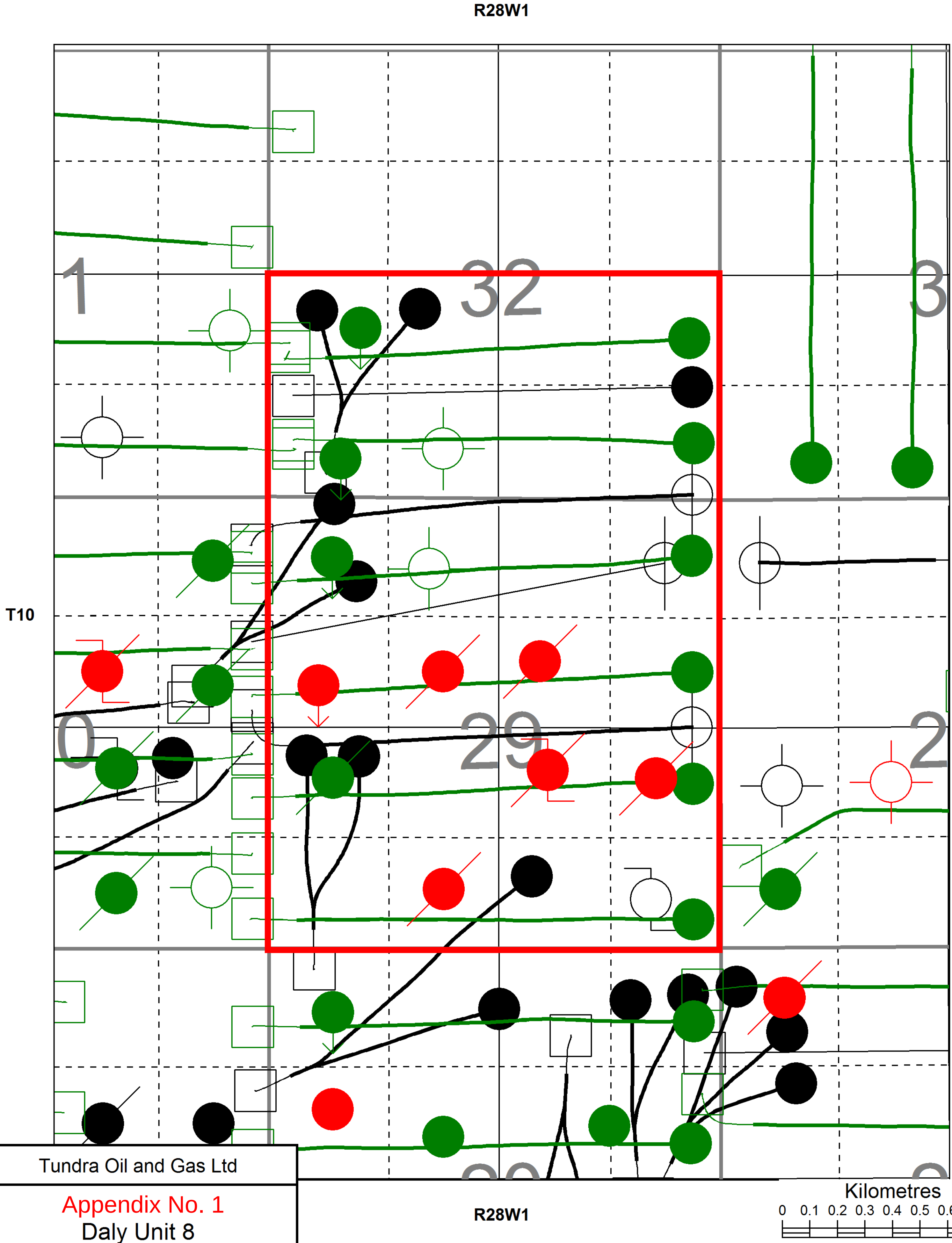
	Units	Bakken
Depth	m	825
Initial Reservoir Pressure	kPa	8,200
Formation Temperature	^{o}C	30
Saturation Pressure	kPa	1,675
Fracture Pressure	kPa	14,500
Solution GOR	m3/m3	5
Oil Gravity (dead oil)	^{o}API	42
Bo @ Psat	m3/m3	1.03
Initial Water Saturation	dec	0.45
Wettability		neutral
Average Porosity	%	16.3
Average Permeability	mD	30
Water Salinity	mg/L	113,000

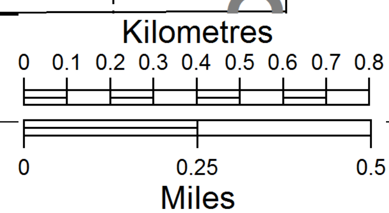
Table 6: Daly Unit No. 8 - Pressure Summary

Location	Test Date	Final Pressure (kPaa)	MPP (mTVD)	KB	Datum Depth	Gradient	Pressure @ -450 masl
103/08-29-010-28W1/00	Feb 2nd - 22nd, 2013	5526.5	819.58	519.94	-450	8.25	6767
102/16-29-010-28W1/00	Jan 28th - Feb 11th, 2013	4229.8	818.2	519.32	-450	8.25	5476
102/01-32-010-28W1/00	Feb 9th - 23rd, 2013	5702.0	825.94	520.12	-450	8.25	6891
102/08-32-010-28W1/00	Jan 18th - 29th, 2013	3905.8	825.07	520.67	-450	8.25	5107

Table No. 7: Daly Unit No. 8 Project Schedule

Timing	Injector Conversions
Q3 2014	
Q4 2014	4
Q1 2015	
Q2 2015	
Q3 2015	
Q4 2015	1
Q1 2016	





Tundra Oil and Gas Ltd

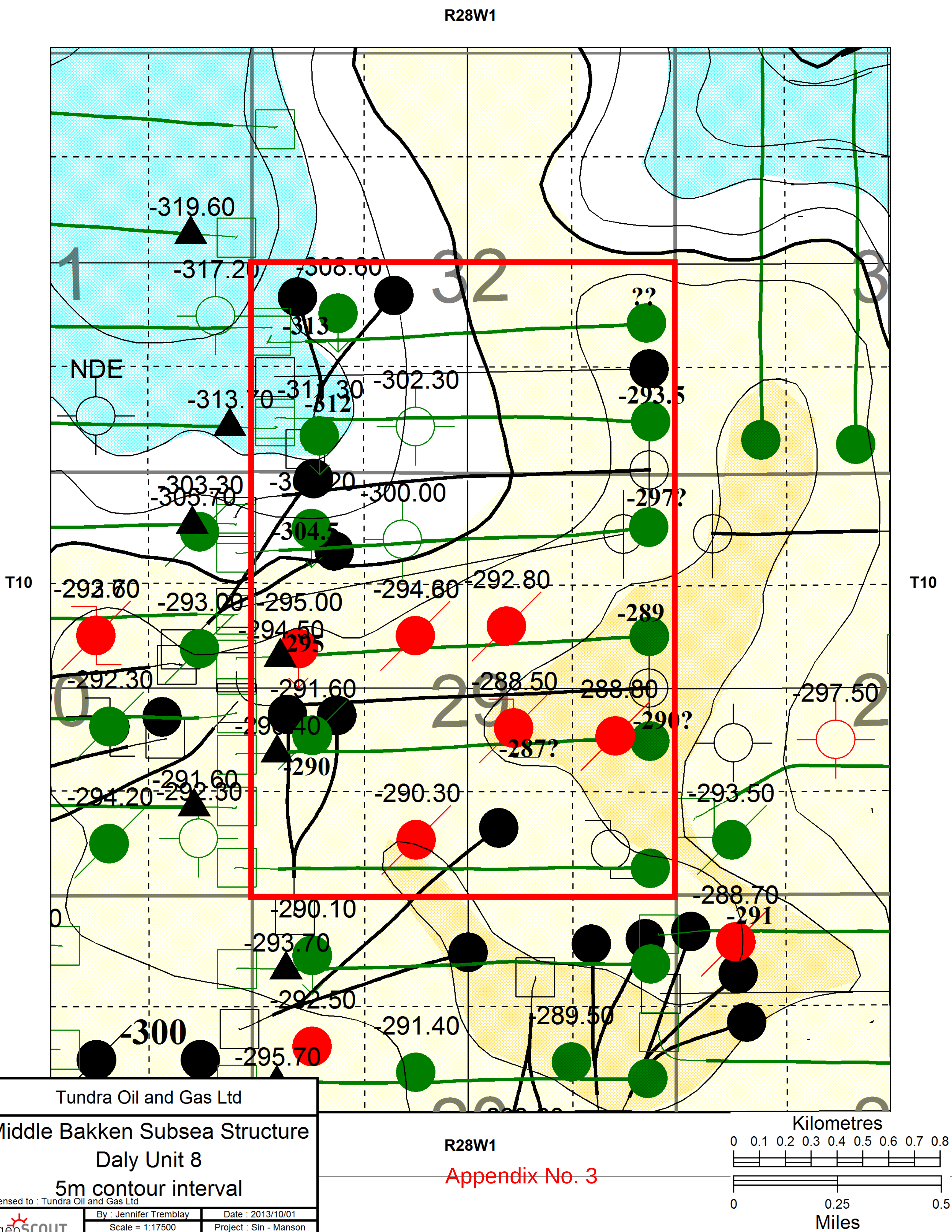
Appendix No. 1

Daly Unit 8

Licensed to : Tundra Oil and Gas Ltd

By : Jennifer Tremblay	Date : 2013/10/01
Scale = 1:17500	Project : Sin - Manson

geoSCOUT www.geologic.com



Tundra Oil and Gas Ltd

Middle Bakken Subsea Structure
Daly Unit 8
5m contour interval

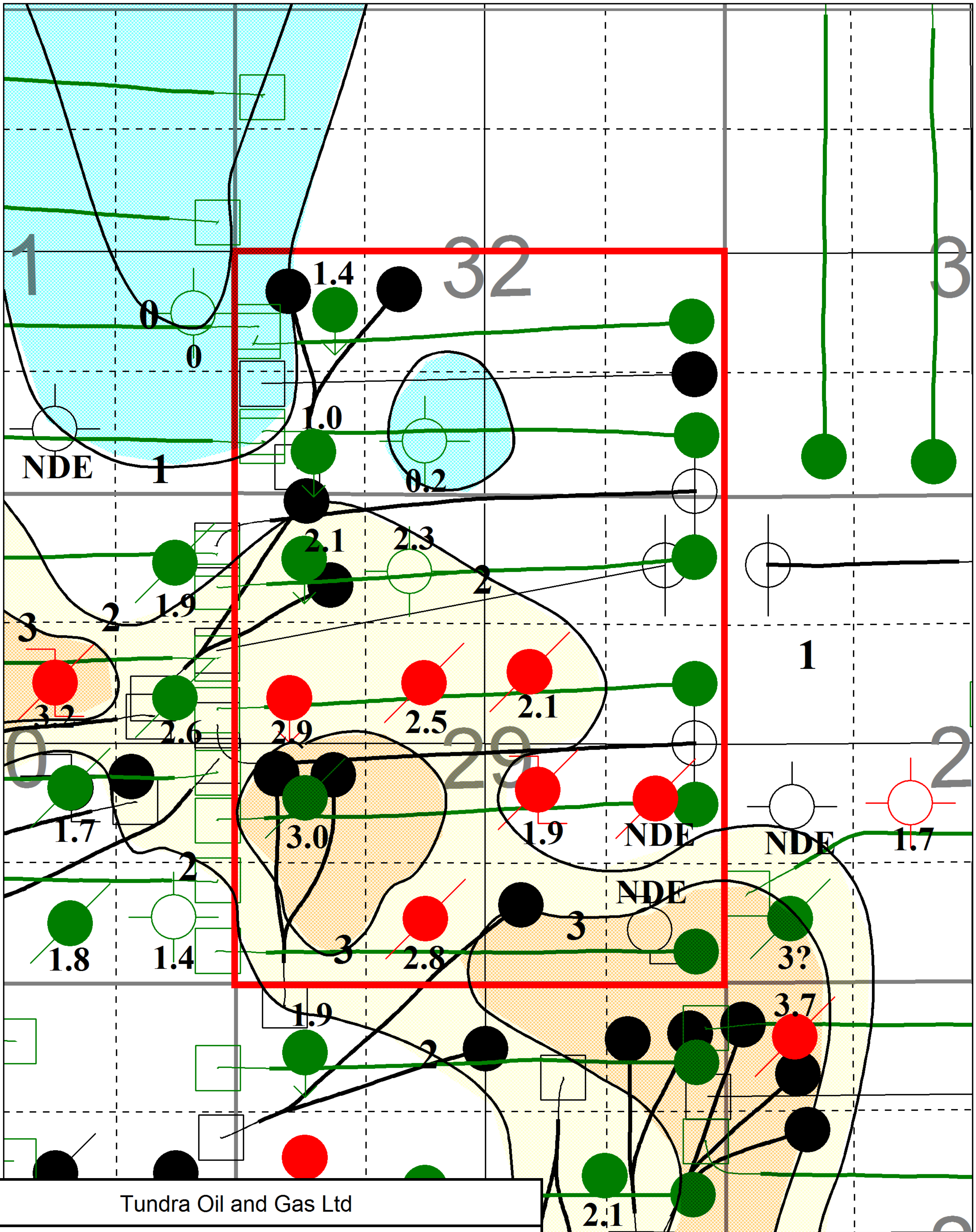
Licensed to : Tundra Oil and Gas Ltd

geoSCOUT	By : Jennifer Tremblay	Date : 2013/10/01
	Scale = 1:17500	Project : Sin - Manson

Appendix No. 3

R28W1

T10



T10

Tundra Oil and Gas Ltd

Middle Bakken Net Pay (petrophysically defined)

LS porosity >=12%; Sw <= 60%

1m contour interval

Licensed to : Tundra Oil and Gas Ltd

geoSCOUT www.geologic.com	By : Jennifer Tremblay	Date : 2013/10/01
	Scale = 1:17500	Project : Sin - Manson

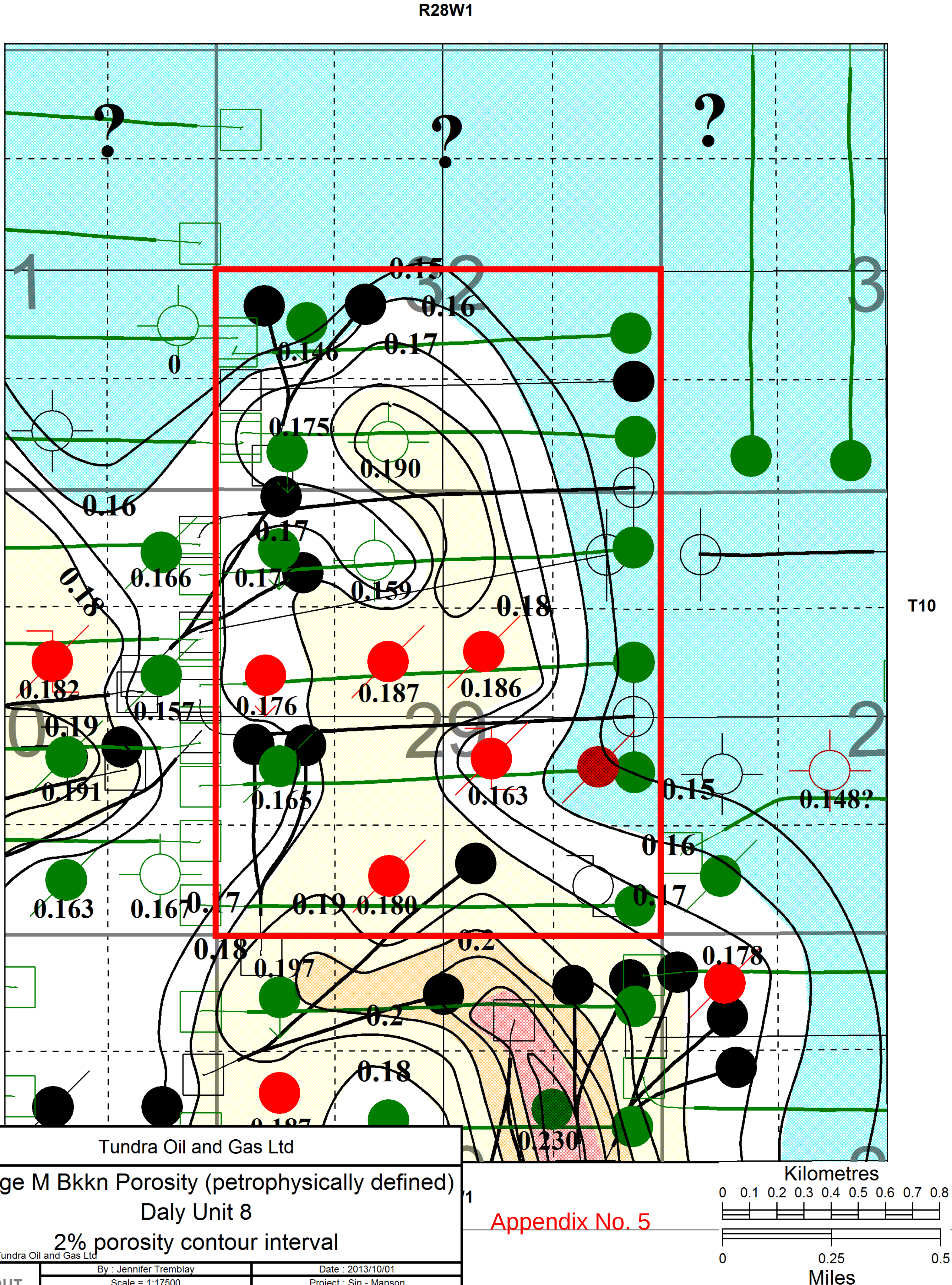
Appendix No. 4

Kilometres

0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8

0 0.25 0.5

Miles



Tundra Oil and Gas Ltd

Average M Bkkn Porosity (petrophysically defined)

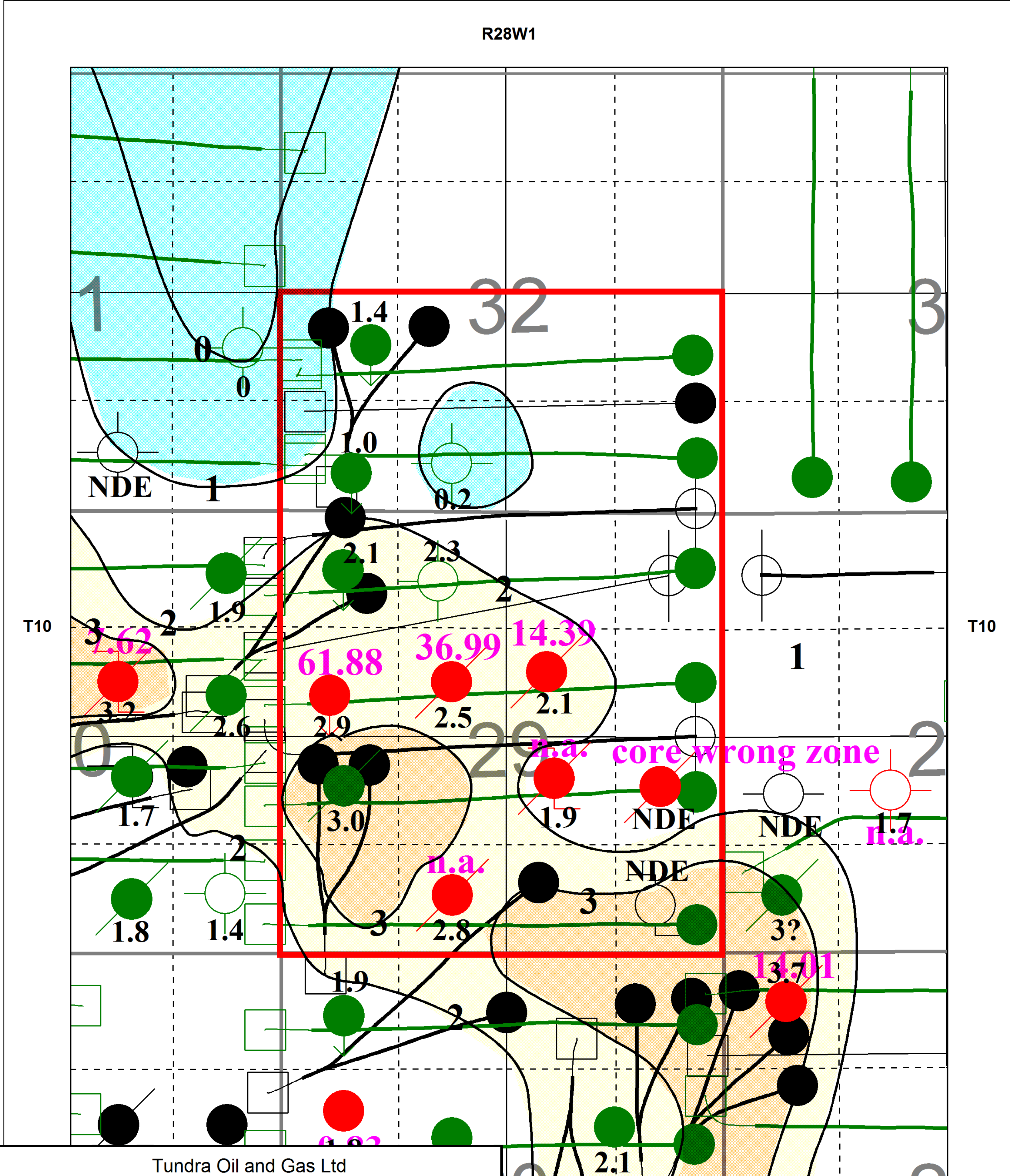
Daly Unit 8

2% porosity contour interval

Licensed to : Tundra Oil and Gas Ltd

geoSCOUT	By : Jennifer Tremblay	Date : 2013/10/01
	Scale = 1:17500	Project : Sin - Manson

Appendix No. 5



Tundra Oil and Gas Ltd

Core Kmax.h (pink) and Middle Bakken Net Pay

Daly Unit 8

Red wells - have been cored in the Bakken

Appendix No. 6

Licensed to : Tundra Oil and Gas Ltd

By : Jennifer Tremblay	Date : 2013/10/01
Scale = 1:17500	Project : Sin - Manson

geoSCOUT

Appendix 7: Petrophysical Analysis Daly Unit 8 - 24wells

Interpreter: Gille Montsion (Aug 23, 2013)

(cutoffs)				(> = 12%)	(< = 60%)
WELL	**ZONE**	**Net_Pay**	**Vsh_Avg**	**Phie_Avg**	**Swe_Avg**
-	-	m	v/v	v/v	v/v
100013001028W100	BakkenM	1.4	0.16	0.167	0.535
100023001028W100	BakkenM	1.8	0.09	0.163	0.462
100032901028W100	BakkenM	2.8	0.02	0.180	0.524
100033201028W100	BakkenM	0.2	0.00	0.190	0.576
100043201028W100	BakkenM	1	0.00	0.175	0.541
100052901028W100	BakkenM	3	0.10	0.165	0.519
100053201028W100	BakkenM	1.4	0.14	0.146	0.562
100062101028W100	BakkenM	1	0.14	0.153	0.568
100072901028W100	BakkenM	1.9	0.04	0.163	0.483
100073001028W100	BakkenM	1.7	0.03	0.191	0.467
100083101028W100	BakkenM	0			
100093001028W100	BakkenM	2.6	0.11	0.157	0.488
100102001028W100	BakkenM	2.1	0.00	0.230	0.529
100102901028W100	BakkenM	2.1	0.00	0.186	0.542
100103001028W100	BakkenM	3.2	0.00	0.182	0.528
100112001028W100	BakkenM	1.7	0.10	0.166	0.534
100112901028W100	BakkenM	2.5	0.00	0.187	0.535
100122001028W100	BakkenM	1.8	0.00	0.187	0.537
100122901028W100	BakkenM	2.9	0.05	0.176	0.536
100132001028W100	BakkenM	1.9	0.00	0.197	0.475
100132101028W100	BakkenM	3.7	0.00	0.178	0.541
100132901028W100	BakkenM	2.1	0.00	0.176	0.517
100142901028W100	BakkenM	2.3	0.13	0.159	0.489
100163001028W100	BakkenM	1.9	0.00	0.166	0.581

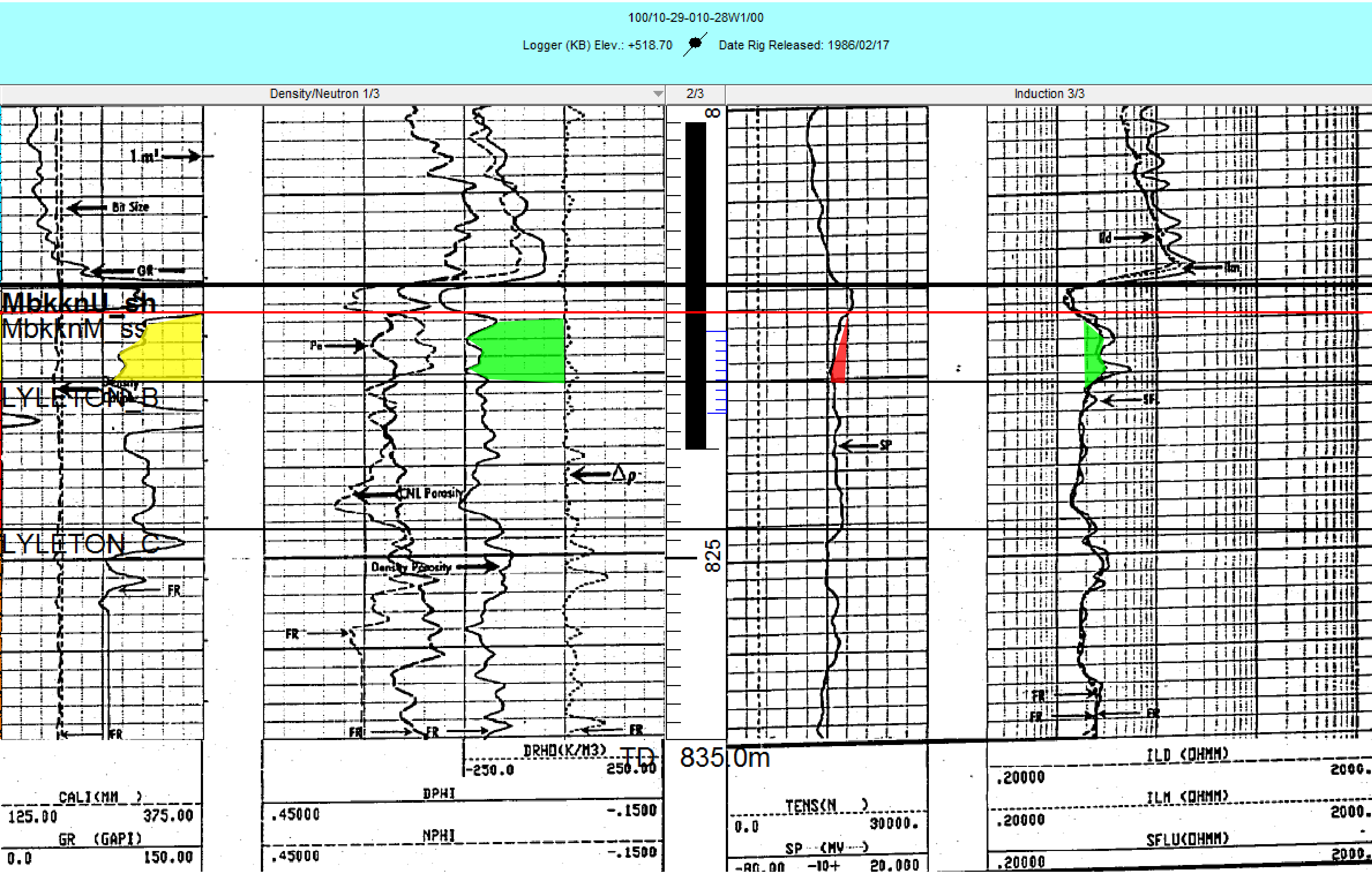
Appendix No. 8

Daly Unit 8 Cored wells

Bakken Core analysis and Cross plots

10-29-10-28W1

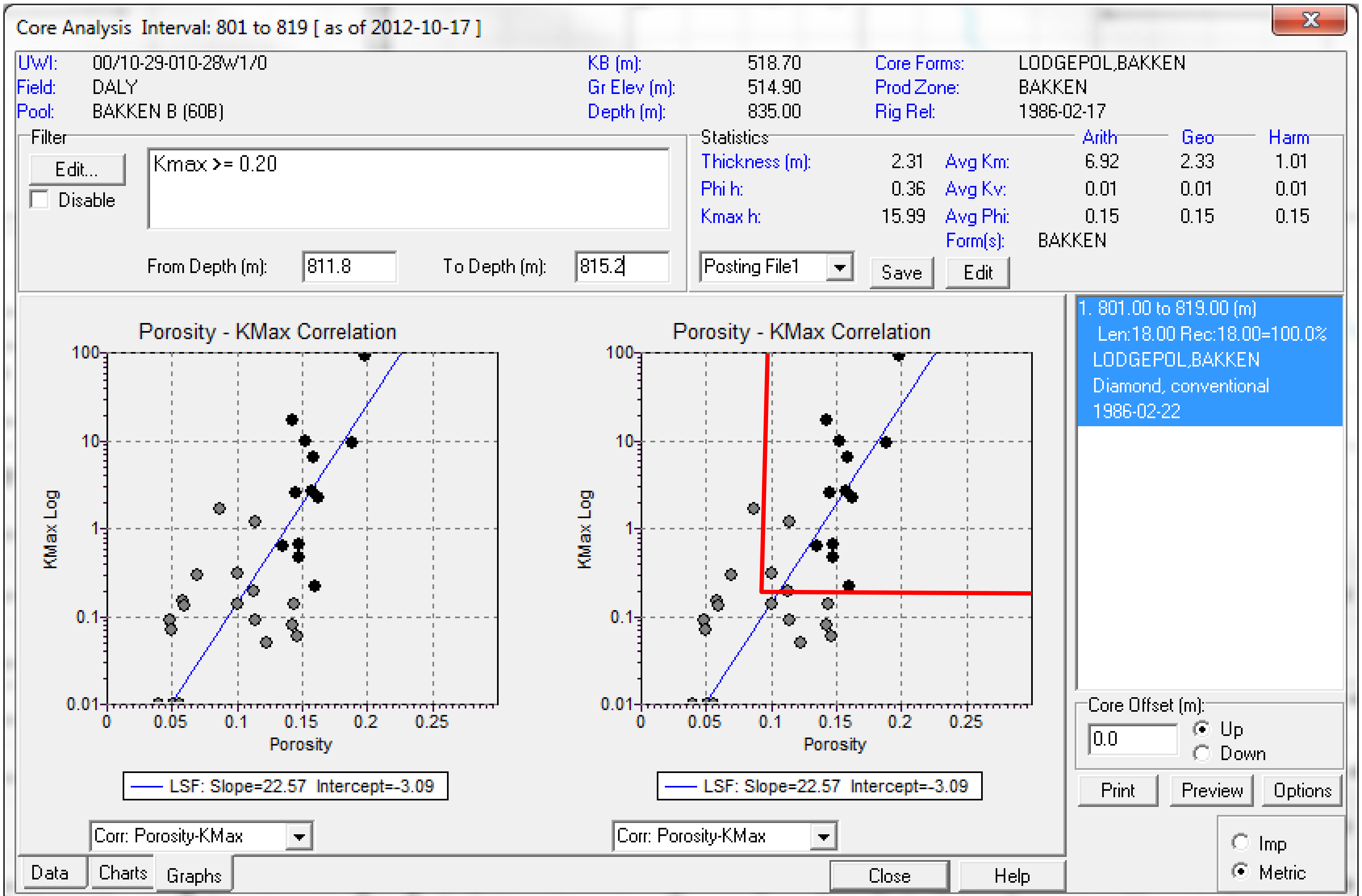
- KH 15.99 after 0.2 mD cutoff



10-29 Core Data

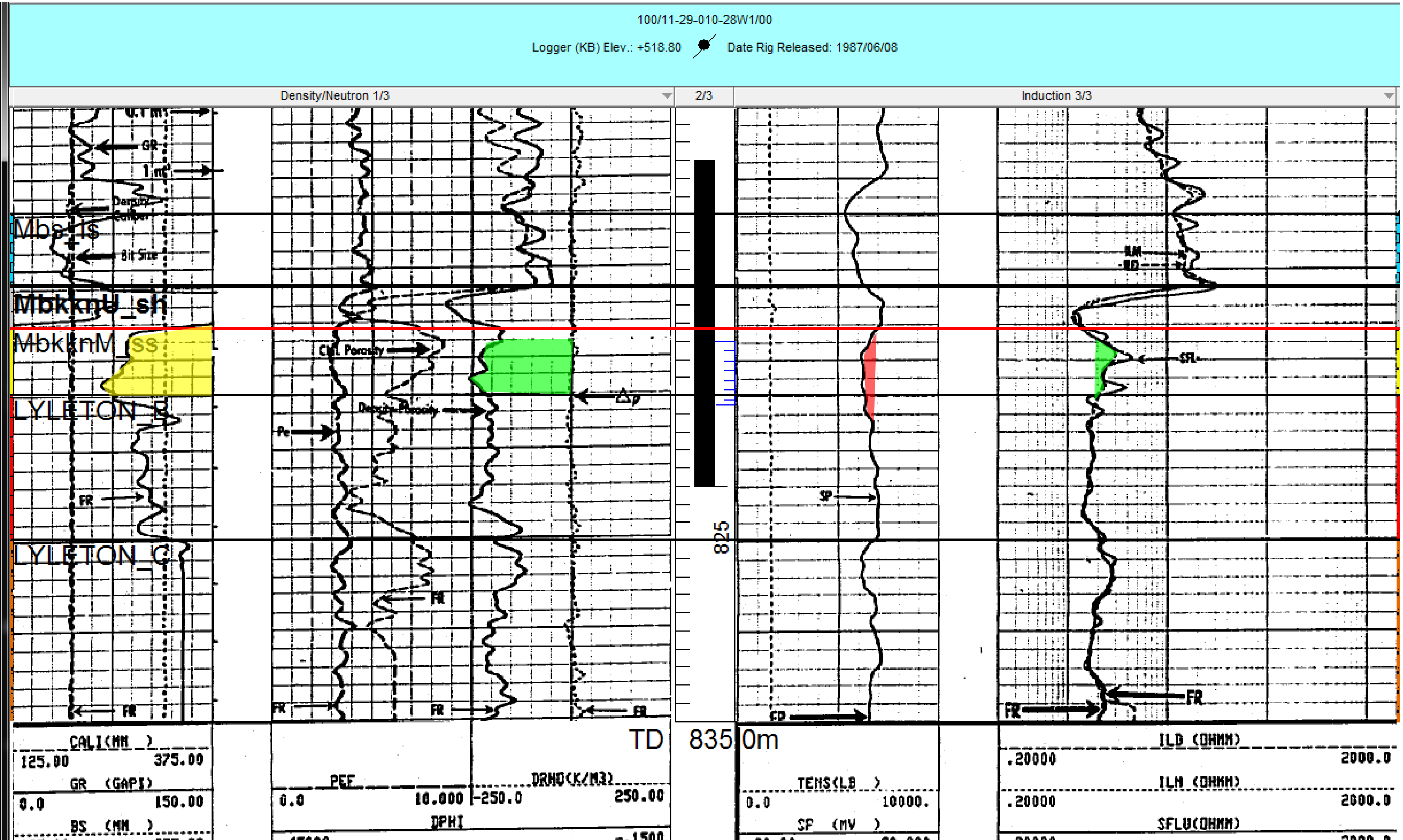
System - Core Analysis							M Bkkn	Lyl A	Lyl B					
UWI	Sample Upper Depth (m)	Sample Lower Depth (m)	Sample Thickness (m)	Sample Upper Formation	Sample Lower Formation	KMax (mD)	Kmax.H	Kmax.H	K maxh	K90 (mD)	KVert (mD)	Porosity	Residual Sat Oil Ratio	Residual Sat Water Ratio
100/10-29-010-28W1/0	809.18	809.64	0.46	LODGEPOL	LODGEPOL	0.01				0.01	0.01	0.051		0.593
100/10-29-010-28W1/0	809.64	812.35	2.71	Upper Bakken Shale	Middle Bakken									
100/10-29-010-28W1/0	812.35	812.42	0.07	Middle Bakken	Middle Bakken	6.36	0.45					0.159	0.283	0.125
100/10-29-010-28W1/0	812.42	812.66	0.24	Middle Bakken	Middle Bakken	0.05	0.01			0.03	0.01	0.123	0.073	0.550
100/10-29-010-28W1/0	812.66	812.76	0.10	Middle Bakken	Middle Bakken	0.47	0.05			0.29	0.06	0.147	0.136	0.561
100/10-29-010-28W1/0	812.76	812.83	0.07	Middle Bakken	Middle Bakken	93.60	6.55					0.198	0.372	0.122
100/10-29-010-28W1/0	812.83	813.17	0.34	Middle Bakken	Middle Bakken	2.25	0.77			2.25	0.01	0.162	0.089	0.630
100/10-29-010-28W1/0	813.17	813.34	0.17	Middle Bakken	Middle Bakken	0.66	0.11			0.64	0.01	0.147	0.068	0.601
100/10-29-010-28W1/0	813.34	813.54	0.20	Middle Bakken	Middle Bakken	0.14	0.03			0.10	0.01	0.144	0.081	0.487
100/10-29-010-28W1/0	813.54	813.82	0.28	Middle Bakken	Middle Bakken	0.62	0.17			0.49	0.01	0.135	0.066	0.538
100/10-29-010-28W1/0	813.82	814.10	0.28	Middle Bakken	Middle Bakken	0.09	0.03			0.05	0.01	0.114		0.702
100/10-29-010-28W1/0	814.10	814.23	0.13	Middle Bakken	Middle Bakken	0.19	0.02			0.15	0.01	0.113	0.133	0.527
100/10-29-010-28W1/0	814.23	814.55	0.32	Middle Bakken	Middle Bakken	2.53	0.81			1.92	0.01	0.145	0.154	0.432
100/10-29-010-28W1/0	814.55	814.72	0.17	Middle Bakken	Middle Bakken	16.90	2.87					0.142	0.214	0.117
100/10-29-010-28W1/0	814.72	814.97	0.25	Middle Bakken	Middle Bakken	9.89	2.47			5.81	0.02	0.152	0.078	0.774
100/10-29-010-28W1/0	814.97	815.18	0.21	Middle Bakken	Middle Bakken	0.22	0.05			0.15	0.01	0.160	0.097	0.544
100/10-29-010-28W1/0	815.18	815.39	0.21	Lyleton B	Lyleton B	2.65			0.56	1.26	0.01	0.158	0.193	0.460
100/10-29-010-28W1/0	815.39	815.53	0.14	Lyleton B	Lyleton B				0.00					
100/10-29-010-28W1/0	815.53	815.58	0.05	Lyleton B	Lyleton B	9.45			0.47			0.188	0.094	0.484
100/10-29-010-28W1/0	815.58	815.78	0.20	Lyleton B	Lyleton B				0.00					
100/10-29-010-28W1/0	815.78	815.85	0.07	Lyleton B	Lyleton B	9.45			0.66			0.188	0.094	0.484
100/10-29-010-28W1/0	815.85	816.07	0.22	Lyleton B	Lyleton B				0.00					
100/10-29-010-28W1/0	816.07	816.32	0.25	Lyleton B	Lyleton B	0.08			0.02	0.07	0.01	0.143	0.113	0.561
100/10-29-010-28W1/0	816.32	816.50	0.18	Lyleton B	Lyleton B	0.06			0.01	0.05	0.01	0.146	0.169	0.411
100/10-29-010-28W1/0	816.50	819.00	2.50	Lyleton B	Lyleton B									
M Bkkn							14.39					0.146		

10-29 Phi vs Kmax Crossplot



11-29-10-28W1

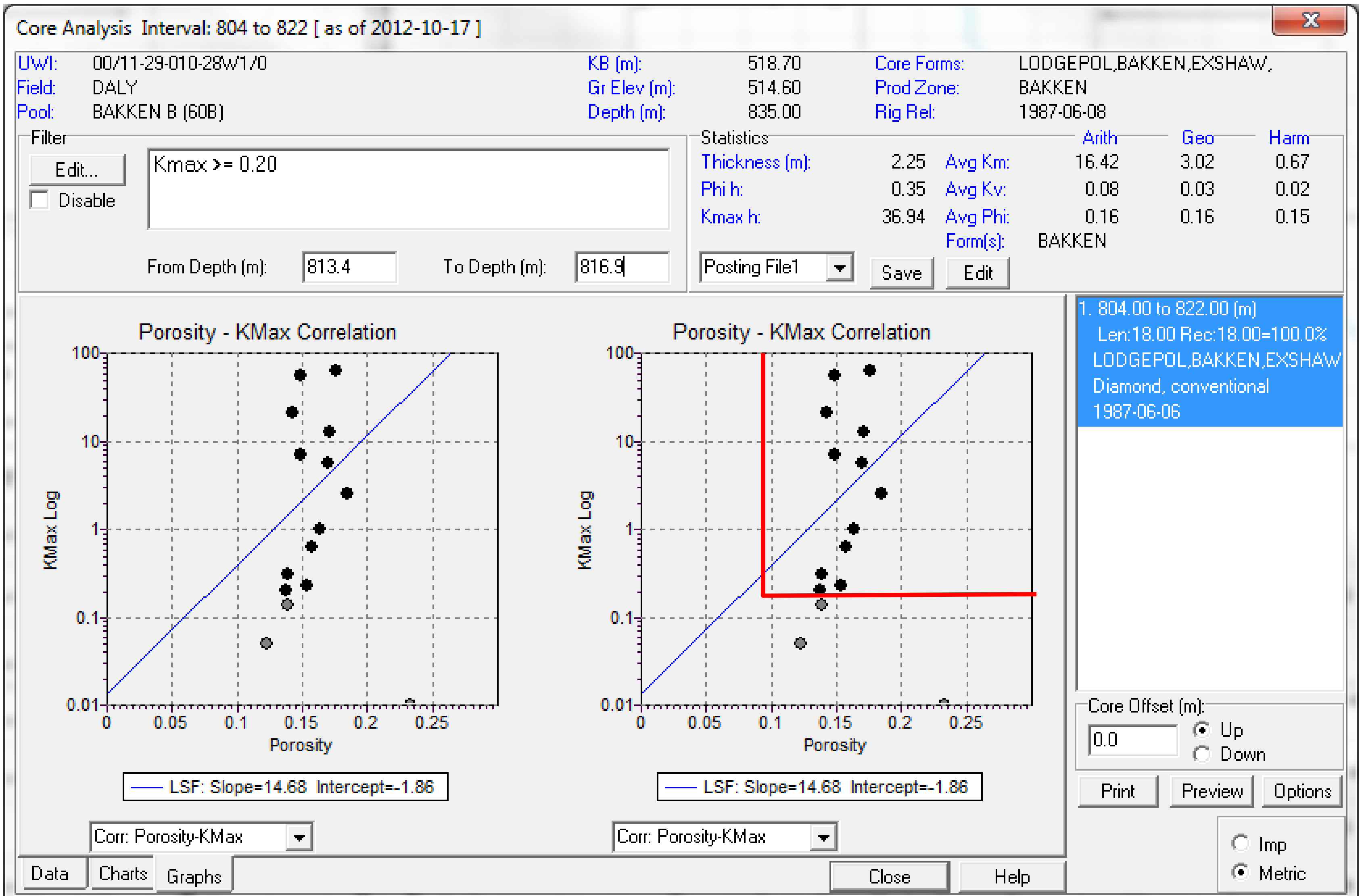
- Kh 36.98 before 2 mD cutoff;
- KH 36.94 after 2mD cutoff



11-29 Core Data

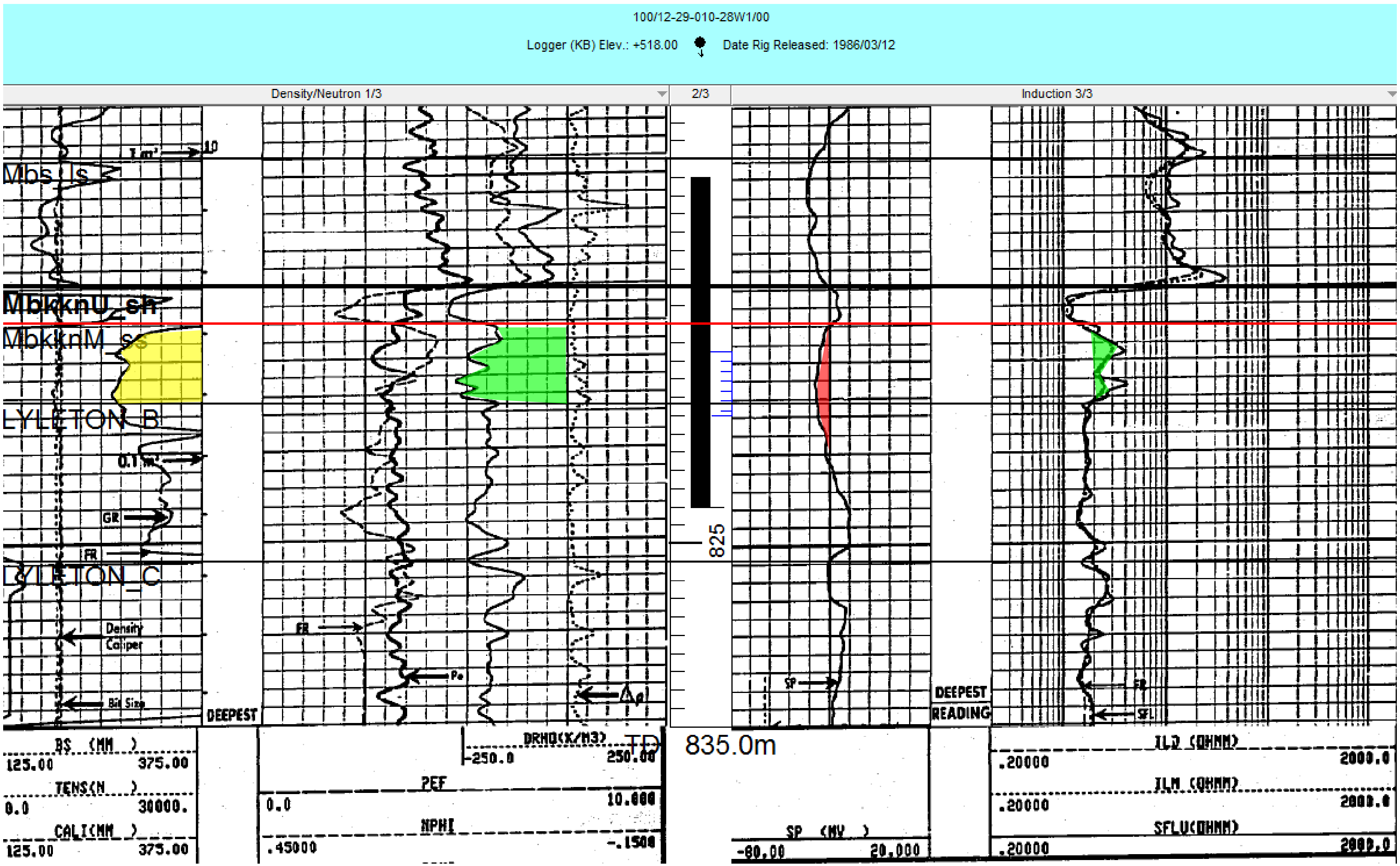
System - Core Analysis							M Bkkn	Lyl A	Lyl B					
UWI	Sample Upper Depth (m)	Sample Lower Depth (m)	Sample Thickness (m)	Sample Upper Formation	Sample Lower Formation	KMax (mD)	Kmax.H	Kmax.H	K maxh	K90 (mD)	KVert (mD)	Porosity	Residual Sat Oil Ratio	Residual Sat Water Ratio
100/11-29-010-28W1/0	804.00	810.44	6.44	LODGEPOL	LODGEPOL									
100/11-29-010-28W1/0	810.44	812.09	1.65	LODGEPOL	Upper Bakken Shale									
100/11-29-010-28W1/0	812.09	813.40	1.31	Upper Bakken Shale	Middle Bakken									
100/11-29-010-28W1/0	813.40	813.57	0.17	Middle Bakken	Middle Bakken	0.05	0.01					0.123	0.137	0.717
100/11-29-010-28W1/0	813.57	813.69	0.12	Middle Bakken	Middle Bakken	6.93	0.83			6.56	0.34	0.149	0.138	0.721
100/11-29-010-28W1/0	813.69	813.87	0.18	Middle Bakken	Middle Bakken	21.21	3.82			6.36	0.12	0.143	0.089	0.548
100/11-29-010-28W1/0	813.87	814.17	0.30	Middle Bakken	Middle Bakken	55.68	16.70			49.82	0.15	0.149	0.065	0.703
100/11-29-010-28W1/0	814.17	814.27	0.10	Middle Bakken	Middle Bakken	1.02	0.10					0.164	0.176	0.512
100/11-29-010-28W1/0	814.27	814.57	0.30	Middle Bakken	Middle Bakken	0.14	0.04			0.10	0.01	0.139	0.144	0.652
100/11-29-010-28W1/0	814.57	814.70	0.13	Middle Bakken	Middle Bakken	0.20	0.03					0.137	0.055	0.499
100/11-29-010-28W1/0	814.70	815.15	0.45	Middle Bakken	Middle Bakken	0.31	0.14			0.24	0.01	0.139	0.060	0.820
100/11-29-010-28W1/0	815.15	815.25	0.10	Middle Bakken	Middle Bakken	5.62	0.56					0.170	0.143	0.354
100/11-29-010-28W1/0	815.25	815.38	0.13	Middle Bakken	Middle Bakken	12.41	1.61					0.171	0.225	0.324
100/11-29-010-28W1/0	815.38	815.58	0.20	Middle Bakken	Middle Bakken	62.01	12.40			34.59	0.01	0.176	0.141	0.544
100/11-29-010-28W1/0	815.58	815.78	0.20	Middle Bakken	Middle Bakken	2.49	0.50					0.185	0.179	0.358
100/11-29-010-28W1/0	815.78	816.18	0.40	Middle Bakken	Middle Bakken		0.00							
100/11-29-010-28W1/0	816.18	816.24	0.06	Middle Bakken	Middle Bakken	2.53	0.15					0.185	0.051	0.405
100/11-29-010-28W1/0	816.24	816.43	0.19	Middle Bakken	Middle Bakken		0.00							
100/11-29-010-28W1/0	816.43	816.60	0.17	Middle Bakken	Middle Bakken		0.00					0.233	0.057	0.321
100/11-29-010-28W1/0	816.60	816.80	0.20	Middle Bakken	Middle Bakken	0.23	0.05			0.01	0.01	0.154	0.270	0.378
100/11-29-010-28W1/0	816.80	816.88	0.08	Middle Bakken	Middle Bakken	0.63	0.05					0.158	0.102	0.341
100/11-29-010-28W1/0	816.88	822.00	5.12	Lyleton B	Lyleton B									
M Bkkn Kh							36.99					0.161		

11-29 Phi vs Kmax crossplot



12-29-10-28W1

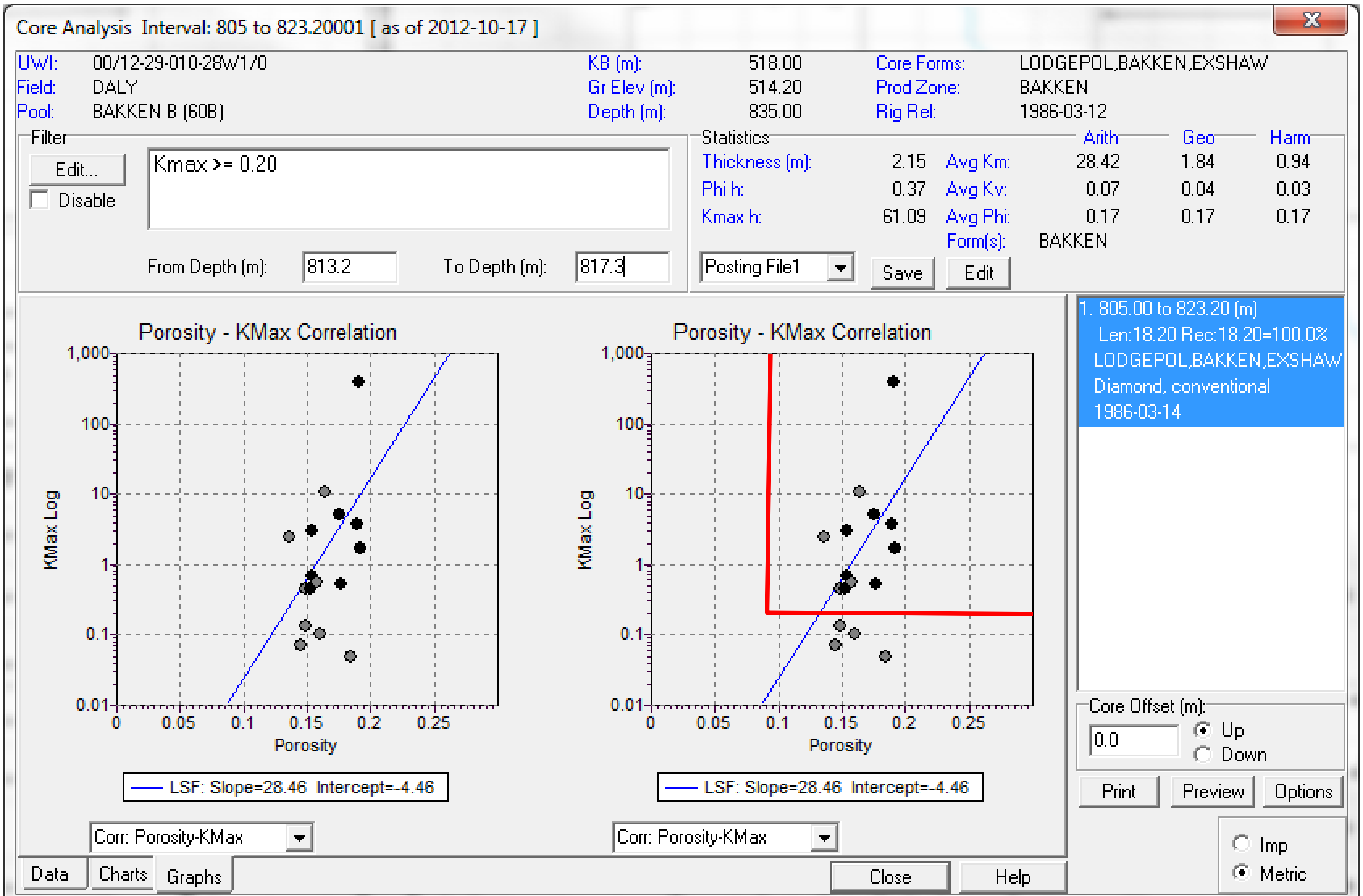
- KH 61.88 before 2mD cutoff
- KH 61.09 after 2mD cutoff



12-29 Core Data

ystem - Core Analysis							M Bkkn	Lyl A	Lyl B					
UWI	Sample Upper Depth (m)	Sample Lower Depth (m)	Sample Thickness (m)	Sample Upper Formation	Sample Lower Formation	KMax (mD)	Kmax.H	Kmax.H	K maxh	K90 (mD)	KVert (mD)	Porosity	Residual Sat Oil Ratio	Residual Sat Water Ratio
00/12-29-010-28W1/2	805.00	812.28	7.28	LODGEPOL	Upper Bakken Shale									
00/12-29-010-28W1/2	812.28	812.33	0.05	Upper Bakken Shale	Upper Bakken Shale	10.70						0.164	0.125	0.228
00/12-29-010-28W1/2	812.33	812.54	0.21	Upper Bakken Shale	Upper Bakken Shale									
00/12-29-010-28W1/2	812.54	812.57	0.03	Upper Bakken Shale	Upper Bakken Shale	10.70						0.164		
00/12-29-010-28W1/2	812.57	812.71	0.14	Upper Bakken Shale	Upper Bakken Shale	0.44				0.28	0.01	0.149	0.053	0.404
00/12-29-010-28W1/2	812.71	812.95	0.24	Upper Bakken Shale	Middle Bakken	2.49	0.60			2.46	0.77	0.136	0.172	0.314
00/12-29-010-28W1/2	812.95	813.13	0.18	Middle Bakken	Middle Bakken	0.54	0.10			0.46	0.01	0.157	0.097	0.492
00/12-29-010-28W1/2	813.13	813.41	0.28	Middle Bakken	Middle Bakken	0.70	0.20			0.63	0.20	0.154	0.105	0.483
00/12-29-010-28W1/2	813.41	813.66	0.25	Middle Bakken	Middle Bakken	0.07	0.02			0.06	0.01	0.145	0.069	0.487
00/12-29-010-28W1/2	813.66	814.08	0.42	Middle Bakken	Middle Bakken	0.45	0.19			0.42	0.02	0.152	0.053	0.641
00/12-29-010-28W1/2	814.08	814.32	0.24	Middle Bakken	Middle Bakken	0.13	0.03			0.11	0.01	0.149	0.050	0.617
00/12-29-010-28W1/2	814.32	814.55	0.23	Middle Bakken	Middle Bakken	3.06	0.70			2.63	0.06	0.154	0.125	0.450
00/12-29-010-28W1/2	814.55	814.70	0.15	Middle Bakken	Middle Bakken	5.15	0.77					0.176	0.151	0.373
00/12-29-010-28W1/2	814.70	814.85	0.15	Middle Bakken	Middle Bakken	383.00	57.46					0.191	0.191	0.207
00/12-29-010-28W1/2	814.85	815.00	0.15	Middle Bakken	Middle Bakken	0.10	0.02			0.05	0.01	0.160	0.054	0.641
00/12-29-010-28W1/2	815.00	815.29	0.29	Middle Bakken	Middle Bakken	3.68	1.07			2.52	0.07	0.190	0.155	0.411
00/12-29-010-28W1/2	815.29	815.61	0.32	Middle Bakken	Middle Bakken	1.69	0.54			1.40	0.01	0.192	0.131	0.383
00/12-29-010-28W1/2	815.61	816.15	0.54	Middle Bakken	Middle Bakken	0.05	0.03			0.04	0.01	0.184		0.677
00/12-29-010-28W1/2	816.15	816.46	0.31	Middle Bakken	Middle Bakken	0.53	0.16			0.48	0.06	0.177		0.696
00/12-29-010-28W1/2	816.46	823.20	6.74	Lyleton B	Lyleton B									
1 Bkkn KH							61.88					0.164		

12-29 Phi vs Kmax Crossplot



Appendix 9 – Corrosion Controls

Injection Wells

- Corrosion inhibitor in the annulus between tubing and casing.
- Surface freeze protection of annular fluids near surface.
- Corrosion-resistant valves on wellhead and flowline.
- Corrosion-resistant flowline equipment.
- Installation of cathodic protection to protect casing.
- Scale inhibitor protection as needed.
- Bacteria control chemical treatments when needed.
- Water injector packer will be coated for corrosion resistance.

Producing Wells

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

Pipelines

- The water source line will be Flexcord 2000# pipe.
- Injection lines will be a mix of Flexpipe 601 pipe and Centron 2000# pipe.
- Producing lines existing as per original flowline licenses.
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Facilities

12-24-10-29 Water Plant

- Plant piping – internally coated, fiberglass or stainless steel.
- Filtration – stainless steel.
- Pumps – ceramic plungers, stainless steel disc valves.
- Tanks – fiberglass with stainless steel valves.