February 10, 2014

Subject: **Proposed Unitization of Section 34-008-28W1**
Application for Immiscible Gas Injection Enhanced Oil Recovery Pilot
Middle Bakken/Three Forks Formations
Bakken – Three Forks Pool (01 62B)
Daly Sinclair Field, Manitoba

INTRODUCTION

The Sinclair portion of the Daly Sinclair Oil Field is located in Ranges 28 and 29 W1 in both Townships 7 and 8. Since discovery in 2004, the main oilfield area was developed with vertical wells at 40 acre spacing on Primary Production. Since early 2009, a significant portion of the main oilfield has been Unitized and placed on Secondary Waterflood (WF) Enhanced Oil Recovery (EOR) Production, mainly from the Lyleton A & B members of the Three Forks Formation. Tundra Oil and Gas (Tundra) currently operates and continues to develop many Units in the Sinclair Field as shown in Appendix 1.

Since August 2008 Tundra Oil and Gas (Tundra) has been operating an EOR pilot project injecting carbon dioxide (CO_2) in the South East quarter of Section 04-008-29W1 within Sinclair Unit No. 1. This pilot area was approved for conversion to a Water Alternating Gas (WAG) EOR project in May 2012, and started in August 1, 2013.

The purpose of this Immiscible Gas Injection Pilot Enhanced Oil Recovery Application is to install gas injection at two horizontal injectors in Section 34-008-28W1 and evaluate over a five year period whether water alternating gas (WAG) injection will result in improved oil recovery where waterflooding and miscible gas flooding has been deemed uneconomic due to poor reservoir quality.

The proposed project area falls within the existing designated 01-62B Bakken-Three Forks Pool of the Daly Sinclair Oilfield as shown in Appendix 2.

SUMMARY

1. The proposed Ewart Unit No. 5 will include 4 existing producing wells within Section 34-008-28W1 of the Middle Bakken/Three Forks producing reservoir. The project is located east of the existing Ewart Unit No. 2 (Appendix 1).
2. Total Net Original Oil in Place (OOIP) in the project area has been calculated to be 2,780 thousand barrels (Mbbl) for an average of 174 net Mbbl OOIP per 40 acre LSD.
3. Appendix 17 shows the production from the proposed area which peaked in December 2009 at 268 bbl of oil per day (OPD). As of November 2013, production was 38 bbl OPD, 62 bbl of water per day (WPD) and a 62% watercut.
4. Cumulative production to the end of November 2013 from the 4 wells within the proposed Ewart Unit No. 5 project area was 206.5 Mbbl of oil, and 292.8 Mbbl of water, representing a 7.4% Recovery Factor (RF) of the Net OOIP.

5. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Ewart Unit No. 5 project area has been calculated to be 256 Mbbl, with 49.5 Mbbl remaining as of the end of November 2013.
6. Ultimate oil recovery of the proposed Ewart Unit No. 5, under the current Primary Production method, is forecasted to be 9.2% of OOIP.
7. In December 2009, production averaged 268 bbl OPD per well. As of November 2013, average per well production has declined to 9.6 bbl OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 28.6% in the project area.
8. Based on a study conducted by Coho Consulting Ltd. (Coho) identifying optimal immiscible gas floods criteria, this section is deemed to be a suitable area for an N_2 gas flood.
9. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WAG EOR for the proposed Ewart Unit No. 5 has been calculated to be 379 Mbbl, with 176 Mbbl remaining. An incremental 123 Mbbl of proved oil reserves, or 4.4%, are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.
10. Total RF under Secondary WAG in the proposed Ewart Unit No. 5 is estimated to be 13.6%.
11. The existing horizontal 08-34-008-28 producer well will be converted to an injector, a new injection well will be drilled between existing horizontal producing wells, as shown in Appendix 22, within the proposed Ewart Unit No. 5, to trial a 40 acre and a 20 acre N_2 WAG flood.

GEOLOGY

STRATIGRAPHY

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section attached as Appendix 3. The section runs W to NE approximately through the mid-point of the proposed unit. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton 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/Lyleton B reservoirs. The reservoir units in the proposed unit are a continuation of the Bakken / Lyleton producing reservoirs that have been applied for just west of the proposed unit (26-8-29W1, 29-8-28W1 and Sinclair Unit 5 please see Appendix 4).

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 is 3 - 4 m thick (Appendix 5).

The Lyleton B reservoir consists of buff to tan very fine grained siltstone (occasionally very fine siltstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. The Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones are interbedded with dark grey-green very fine grained siltstone which is generally non-reservoir. The Lyleton B is approximately 2 - 4 m thick within the proposed unit; thinning from west to east and ultimately pinching out about a mile east of the proposed unit (Appendix 6).

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

STRUCTURE

Structure contour maps are provided for the top of each major unit (Appendices 7 through 9). The structure within the proposed unit area generally consists of a gentle dip to the SW. Structural variations in the area are interpreted as being caused by dissolution of the underlying Prairie Evaporites. Structural variations cause by dissolution are common in the Sinclair Field but do not appear to represent continuous barriers to lateral fluid flow within the reservoir as they do not appear to interrupt the lateral continuity of the reservoir beds (see cross section Appendix 3).

No direct evidence of natural faulting is noted from either proprietary seismic data or well/production data in the vicinity of the proposed unit area.

RESERVOIR CONTINUITY

Lateral continuity of the reservoir units is an essential requirement of a successful immiscible gas flooding and as demonstrated by the cross section (Appendix 3) and the isopach maps, the lateral continuity of the reservoir within the proposed unit is very good. Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir is also good as there is no evidence of an intervening aquitard between these units. In fact it can be difficult even in core to pick the unconformity surface between these units.

RESERVOIR QUALITY

Porosity (Phi-h in por*m) and permeability (k-h in mD*m) maps for the two reservoir units are provided (Appendices 10 through 13). These maps are generated using core data and are generated as follows. First the core is divided into the reservoir units present. This data is then subject to a permeability cutoff (0.5 md cutoff in the MBKKN and Lyleton B) permeability and intervals that meet or exceed the criteria are multiplied by the interval thickness and then summed to get the total value for the Phi-h or k-h for that particular reservoir unit.

As can be noted from the Phi-h and k-h maps the bulk of the reservoir in the proposed unit is contained in the Middle Bakken section. Maps of Phi-h and k-h for the Middle Bakken are included as Appendices 10 and 11 and Lyleton B maps as Appendices 12 and 13.

FLUID CONTACTS

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

OOIP ESTIMATES

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be 442 E3m3 (2780 MSTB) using Tundra internally created maps. Appendix 14 lists the qualifications of the Tundra Geologists who produced these maps. Maps used were generated from core data from 316 wells available in the Sinclair area (Appendix 15).

Net pay for each cored well is calculated using a 0.5 md permeability cut off from core. Representative intervals that had a measured permeability greater than 0.5 md were considered pay. The weighted average porosity (phi) of all pay intervals for each formation was calculated for each cored well. The height of pay (h) was derived by summing the heights of each representative sample that met the 0.5 md permeability cut off. For each cored well, OOIP for each producing formation was calculated based on 40 acre area using the following formula:

$$OOIP = \frac{Area * Net\ Pay * \ Porosity * (1 - Water\ Saturation)}{Initial\ Formation\ Volume\ Factor\ of\ Oil}$$

or

$$OOIP(m3) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * \frac{10{,}000m2}{ha}$$

or

$$OOIP(Mbbl) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * 3.28084\frac{ft}{m} * 7{,}758.367\frac{bbl}{acre * ft} * \frac{1Mbbl}{1{,}000bbl}$$

where

OOIP = Original Oil in Place by LSD (Mbbl, or m3)
A = Area (40acres, or 16.187 hectares, per LSD)
h * Ø = Net Pay * Porosity, or Phi * h (ft, or m)
Bo = Formation Volume Factor of Oil (stb/rb, or sm3/rm3)
Sw = Water Saturation (decimal)

The initial oil formation volume factor was adopted from a PVT taken from the 3-3-8-29 Sinclair Bakken well, thought to be representative of the fluid characteristics in the reservoir.

The OOIP values for all cored wells were contoured using Golden Software's "Surfer 9" program using a 500 m grid node spacing. OOIP values for each LSD were calculated off the associated Surfer 9 grid by determining the values at the center of each LSD. Tabulated parameters for each LSD from the calculations can be found in Appendix 16.

OOIP were calculated by Tundra geologists whose qualifications are referenced in Appendix 14.

HISTORICAL PRODUCTION

Lifetime production for the existing 4 horizontal Bakken wells is shown in Appendix 17. 00/01-34-008-28W1 was the first horizontal well on production in the Section and started producing in July 2008. As of November 2013 this Section has produced 32.8 e^3m^3 of oil and 46.5 e^3m^3 of water, representing a 7.4% RF of the OOIP.

From peak production in December 2009 to date, oil production is declining at an annual rate of 26% under the current primary production method.

UNITIZATION

Unitization and implementation of a WAG EOR project is forecasted to increase overall recovery of OOIP from the proposed project area.

UNIT NAME

Tundra proposes that the official name of the new Unit shall be Ewart Unit No. 5.

UNIT OPERATOR

Tundra Oil and Gas Partnership will be the operator of record for Ewart Unit No. 5.

UNITIZED ZONE

The Unitized zone(s) to be waterflooded in Ewart Unit No. 5 will be the Middle Bakken and Three Forks formations.

UNIT WELLS

The 4 wells to be included in the proposed Ewart Unit No. 5 are outlined in Appendix 18.

UNIT LANDS

Ewart Unit No. 5 will consist of 16 LSDs in Section 34 of Township 8, Range 28 W1M. The lands included in the 40 acre tracts are outlined in Appendix 19.

TRACT FACTORS

The proposed Unit will consist of 16 Tracts based on the 40 acre LSD's containing the existing 4 horizontal producing wells.

The Tract Factor contribution for each of the LSD's within the proposed unit was calculated as follows:

- Gross OOIP by LSD, minus cumulative production to date for the LSD as distributed by the LSD specific Production Allocation (PA) % in the applicable producing horizontal or vertical well (to yield Remaining Gross OOIP)
- Tract Factor by LSD = the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Appendix 20.

WORKING INTEREST OWNERS

Appendix 19 outlines the working interest (WI) for each recommended Tract within the proposed Ewart Unit No. 5. Tundra Oil and Gas Partnership holds a 100.0% WI ownership in the proposed Tracts.

GAS INJECTION EOR DEVELOPMENT

The sustained waterflood development in the Sinclair oil field in recent years has left few areas where the oil is economically recoverable under traditional waterflood schemes due to low permeability of reservoir. Gas injection is one possible EOR scheme that can potentially be used to improve the ultimate recovery of these reservoirs. These gas injection schemes can be broadly divided into two categories: *miscible* and *immiscible*. In miscible gas injection, the injected gas forms a single homogeneous phase with the oil. The resulting fluid has lower viscosity, reduced interfacial tension and improved mobility ratio. While immiscible gas injection does not form a single phase with the oil it still has the benefit of improved pressure maintenance and sweep efficiency within the reservoir.

Tundra has been operating a miscible gas (CO_2) injection pilot in the south east quarter of Section 04-008-29W1 since August 2008. As of August 2013 this pilot was converted to WAG. While the theoretical benefits of miscible EOR are greater than for immiscible EOR, the operating costs are also greater. At current price structure, the cost of CO_2 renders commercial expansion uneconomic.

Tundra plans to use N_2 for its immiscible gas as it is readily available in the atmosphere, and even with the initial setup cost of the N_2 generator will cost less to operate per barrel then CO_2 injection. N_2 has the additional benefit of not being a greenhouse gas and is environmentally safe and will not need additional facilities to recapture the produced gases. Due to the nature of our reservoir, greater pressure support can potentially be achieved via gas injection rather than water injection due to its favorable mobility ratio to oil.

TECHNICAL STUDIES

Tundra enlisted the services of Coho Consulting Ltd (Coho) to evaluate the feasibility of immiscible gas injection in this area. In 2012, Coho conducted a pre-screening evaluation to determine the proper reservoir parameters required to successfully deploy an immiscible gas pilot. In 2013, Coho conducted an Exodus simulation model in an effort to quantify the impact of immiscible gas injection in section 34-008-28W1. It was determined that economic quantities of incremental oil could be recovered as a result of gas flooding. The results are presented in Appendix 21.

DEVELOPMENT

Tundra plans to drill one additional injector and convert an existing producer as soon as possible so that the first phase of the WAG scheme can begin in the summer of 2014.

This pilot project would test two different production patterns within the same section as show in Appendix 22. One pattern would test 40 acre spacing while the other would test 20 acre spacing.

The 40 acre spacing pattern would be achieved by converting the existing 08-34-008-28 producer into an injector. This injector would in turn support the production from 00/01-34-008-28 and 00/09-34-008-28.

A new openhole horizontal injector will be drilled in between 09-34-008-28 and 16-34-008-34 to create the 20 acre pattern.

PRE-PRODUCTION OF NEW HORIZONTAL INJECTION WELLS

Primary production from the original horizontal producing wells in the proposed Ewart Unit No. 5 has declined significantly from peak rate indicating a need for secondary pressure support. However, through the process of developing similar waterfloods, Tundra has measured a significant variation in reservoir pressure depletion by the existing primary producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations, and has a negative impact on the ultimate total recovery factor of OOIP.

Considering the expected reservoir pressures and reservoir lithology described, Tundra believes an initial period of producing the new horizontal well prior to placing it on water injection is essential.

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

RESERVES RECOVERY PROFILES AND PRODUCTION FORECASTS

The primary waterflood performance predictions for the proposed Ewart Unit No. 5 are based on oil production decline curve analysis. The secondary immiscible WAG performance predictions for the proposed Ewart Unit No. 5 are based on results obtained from an Exodus simulation model (Black oil simulator), provided by Coho. The geological model that was integrated in the simulation was derived using the tops from the vertical wells and the available core data in the area (Appendix 21).

CRITERIA FOR CONVERSION TO WATER INJECTION WELL

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

- Measured reservoir pressures at start of and/or through primary production
- Fluid production rates and any changes in decline rate
- Any observed production interference effects with adjacent vertical and horizontal wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

This allows for the proposed Ewart Unit No. 5 project to be developed equitably, efficiently, and moves the project to the best condition for the start of WAG 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 in conjunction with the Exodus simulation model prepared by Coho, as well as the actual response observed to date in the Sinclair CO_2 Pilot waterflood.

Under primary production Section 34-008-28W1 is expected to produce 256 Mbbl. A 9.2% overall RF of calculated OOIP. Rate vs. time and rate vs. cumulative production plots can be found in Appendices 25 and 26.

The proposed Ewart Unit No. 5 Secondary WAG oil production forecast over time is plotted in Appendix 23. Ultimate recoverable oil in the proposed Ewart Unit No. 5 project under WAG is estimated to be 379 Mbbl (Appendix 24), resulting in a 13.6% overall RF of calculated Net OOIP, or an additional 4.4% RF over primary production.

ESTIMATED FRACTURE PRESSURE

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

OPERATING STRATEGY

N_2 SOURCE

The N_2 for this pilot will be generated on site through an N_2 PSA Generator. In general transporting liquid nitrogen is much more difficult than CO_2 due to its low boiling point temperature. This unit filters the N_2 from the atmosphere and compresses and stores it on site. The specifications for the N_2 generator are given in Appendix 27. This is a significantly more cost effective method of delivering gas injection when compared to Tundra's existing CO_2 pilot.

WATER SOURCE

The injection water for the proposed Ewart Unit No. 5 will be supplied from the existing Sinclair Units source and injection water system. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-7-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Sinclair Units Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Sinclair water injection system and new pipeline connection to the proposed Ewart Unit No. 5 project area injection wells is shown in Appendices 28 to 30.

Produced water is not currently used for any water injection in the Tundra operated Sinclair Units and there are no current plans to use produced water as a source supply for Ewart Unit No. 5.

Since all producing Middle Bakken/Three Forks wells in the Daly Sinclair areas, whether vertical or horizontal, have been hydraulically fractured, produced waters from these wells are inherently a mixture of Three Forks and Bakken native sources. This mixture of produced waters has been extensively tested for compatibility with 102/16-32 source Lodgepole water, by a highly qualified third party, prior to implementation by Tundra in Sinclair Unit 1. All potential mixture ratios between the two waters, under a range of temperatures, have been simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors has also been conducted and minimum inhibition concentration requirements for the source water volume determined. At present, continuous scale inhibitor application is maintained into the source water stream out of the Sinclair injection water facility. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Appendix 31.

INJECTION WELLS

The new future injection well will be drilled, cleaned out, and configured downhole for injection as an openhole injector as shown in Appendix 32. The existing well at 08-34 will be configured for injection as shown in Appendix 33.

The new water injection wells will be placed on injection after the pre-production period and approval to inject. Wellhead injection pressures will be maintained below the least value of either:

- the area specific known and calculated fracture gradient, or
- the licensed surface injection Maximum Allowable Pressure (MOP)

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

All new water injection wells are surface equipped with injection volume metering and rate/pressure control (Appendix 30). 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 Ewart Unit No. 5 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure. The N_2 injection rate is forecasted to be 2 -5 e3m3/d. The N_2 generator has a limit of 5 e3m3/d.

RESERVOIR PRESSURE

No recent or representative initial pressure surveys are currently available for the vertical producing wells within the proposed Ewart Unit No. 5 project area in the Bakken formation. The extremely long shut-in and build-up times required to obtain any possible representative surveys from the producing wells are economically prohibitive. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection wells during the completion of the well and prior to injection or production.

RESERVOIR PRESSURE MANAGEMENT DURING WAG

Tundra expects to alternate N_2 and water injection every 3-6 months to optimize the flood front and minimize the gas channeling and breakthroughs. Initial monthly Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 3.00 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

Ewart Unit No. 5 EOR response and WAG 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 Ewart Unit No. 5 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 Ewart Unit No. 5.

ECONOMIC LIMITS

Under the current Primary recovery method, existing wells within the proposed Ewart Unit No. 5 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.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of this proposed EOR project and formation of Ewart Unit No. 5. Copies of the notices and proof of service, to all surface and mineral rights owners will be forwarded to the Petroleum Branch when available to complete the Ewart Unit No. 5 Application.

Ewart Unit No. 5 Unitization, and execution of the formal Ewart Unit No. 5 Agreement by affected Mineral Owners, is expected during Q4. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Ewart Unit No. 5 Application.

Please contact Rob Prefontaine with any questions regarding this application.

TUNDRA OIL & GAS PARTNERSHIP

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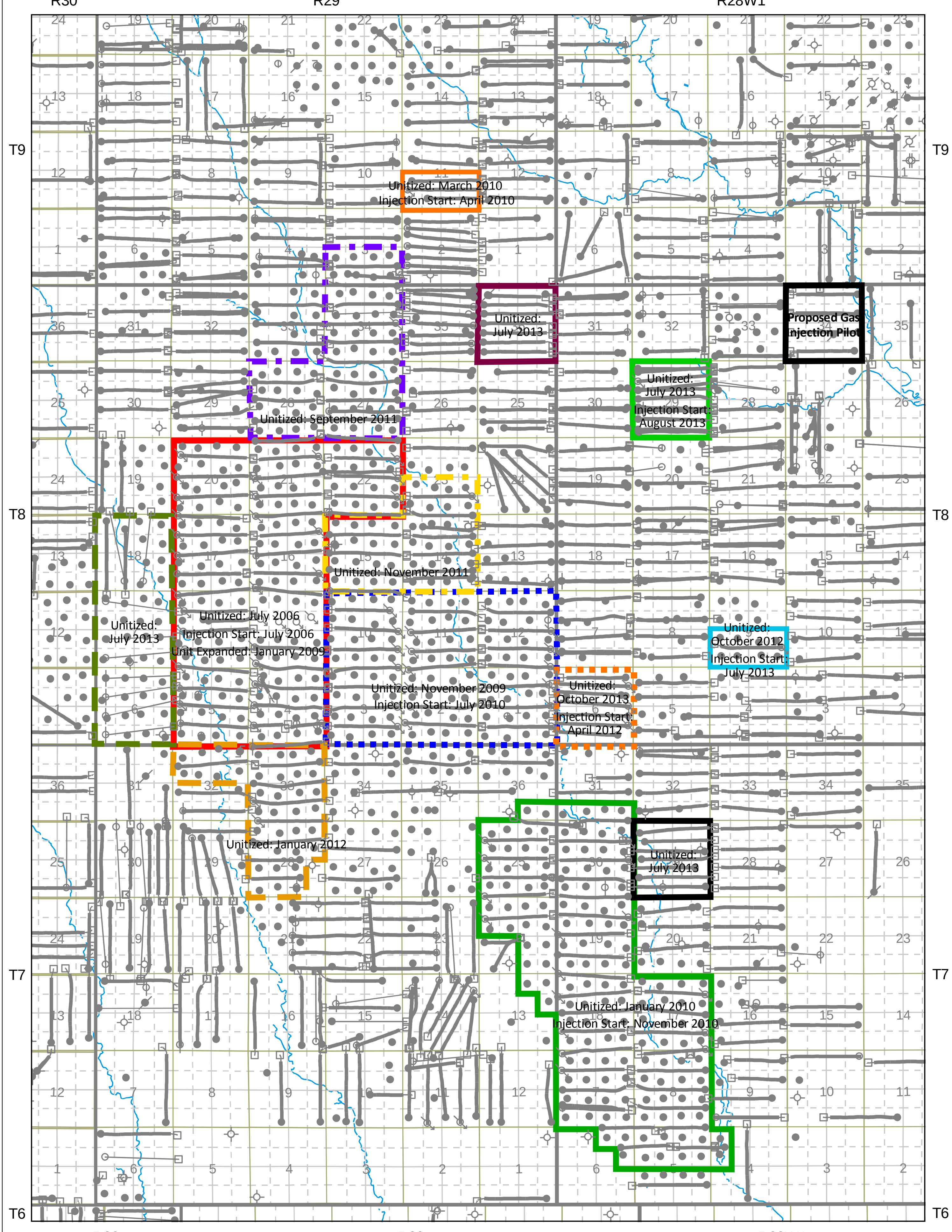
LIST OF ATTACHMENTS

APPENDIX 1: SINCLAIR UNITS MAP



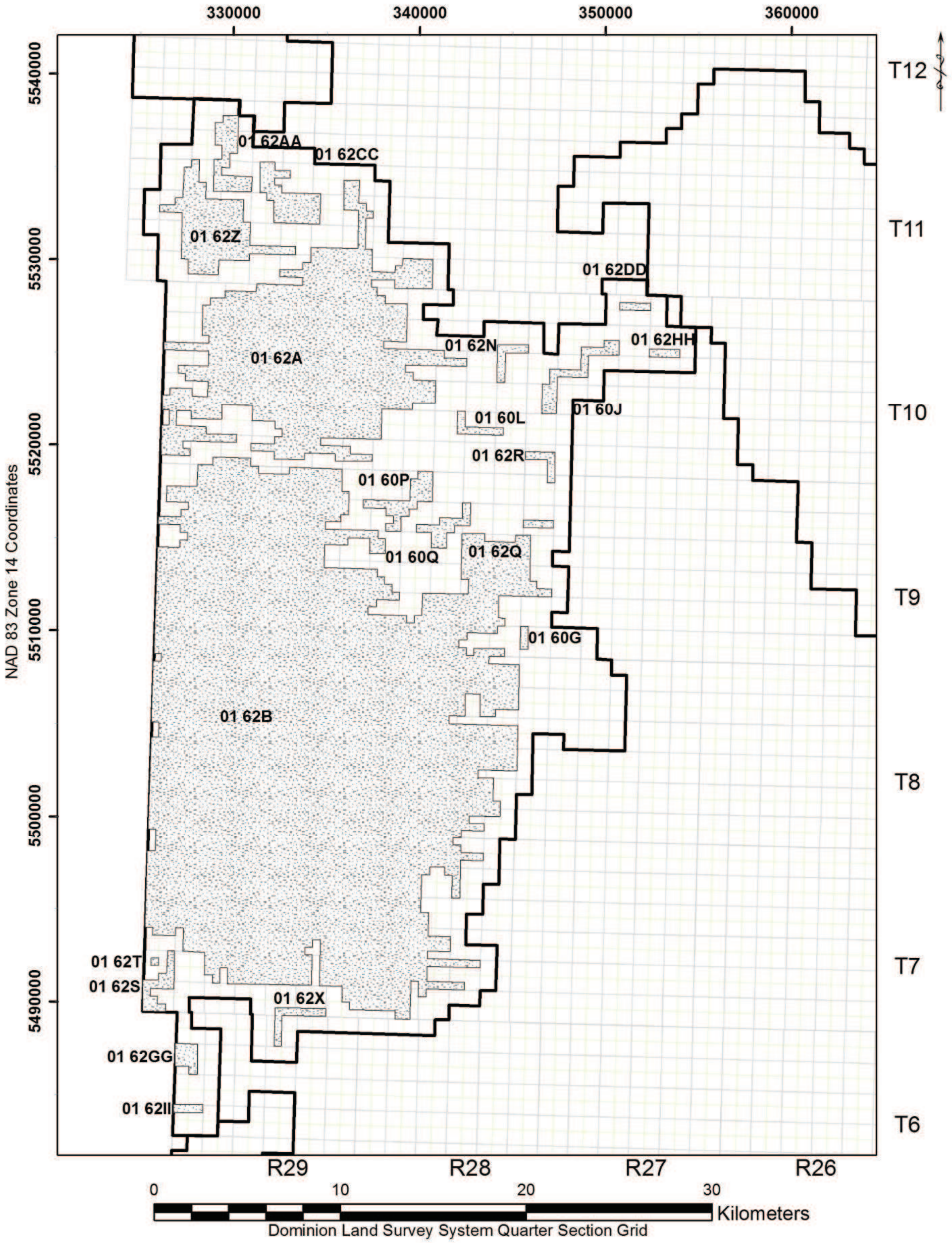
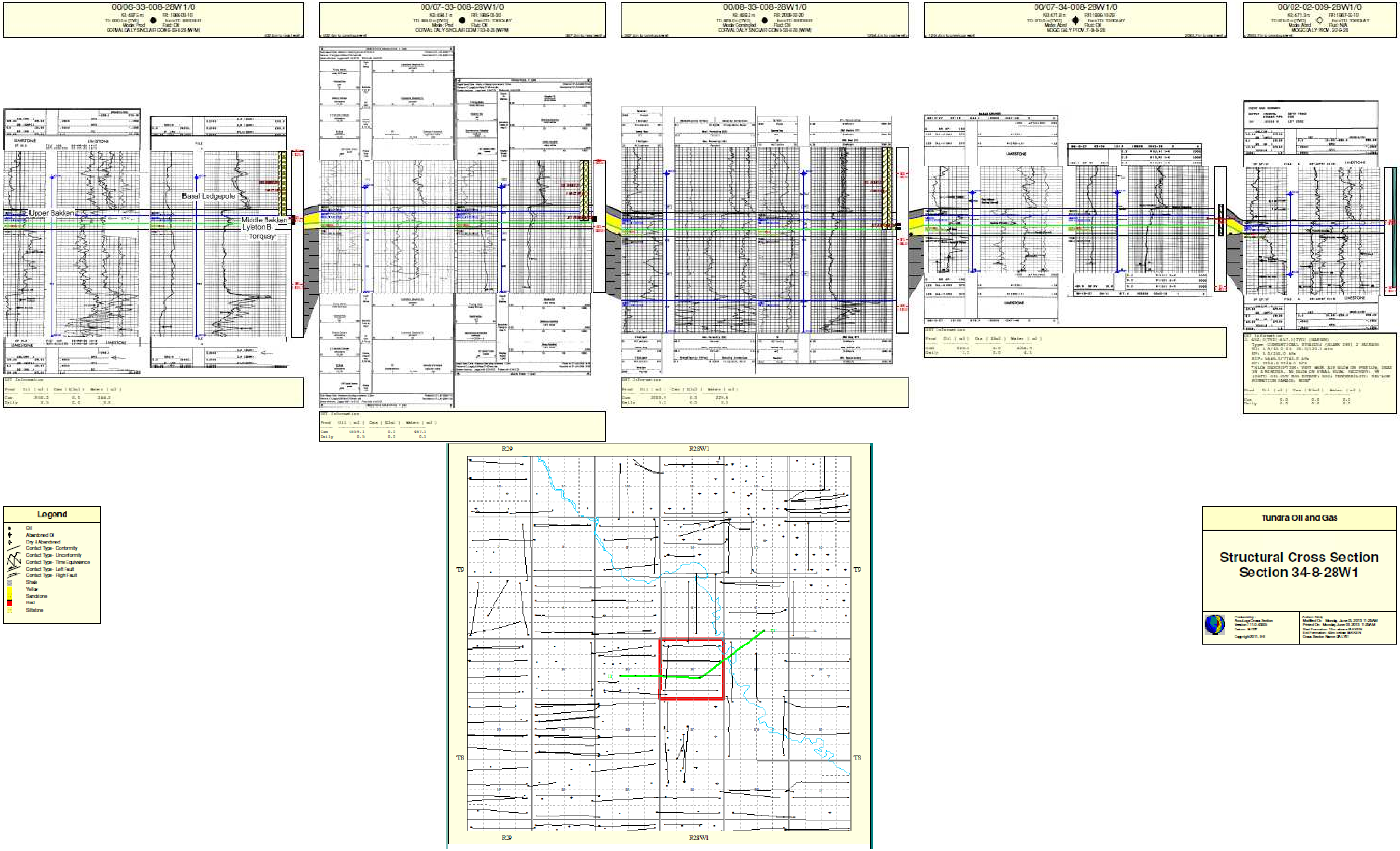


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)



00/06-33-008-28W1/0
00/07-33-008-28W1/0
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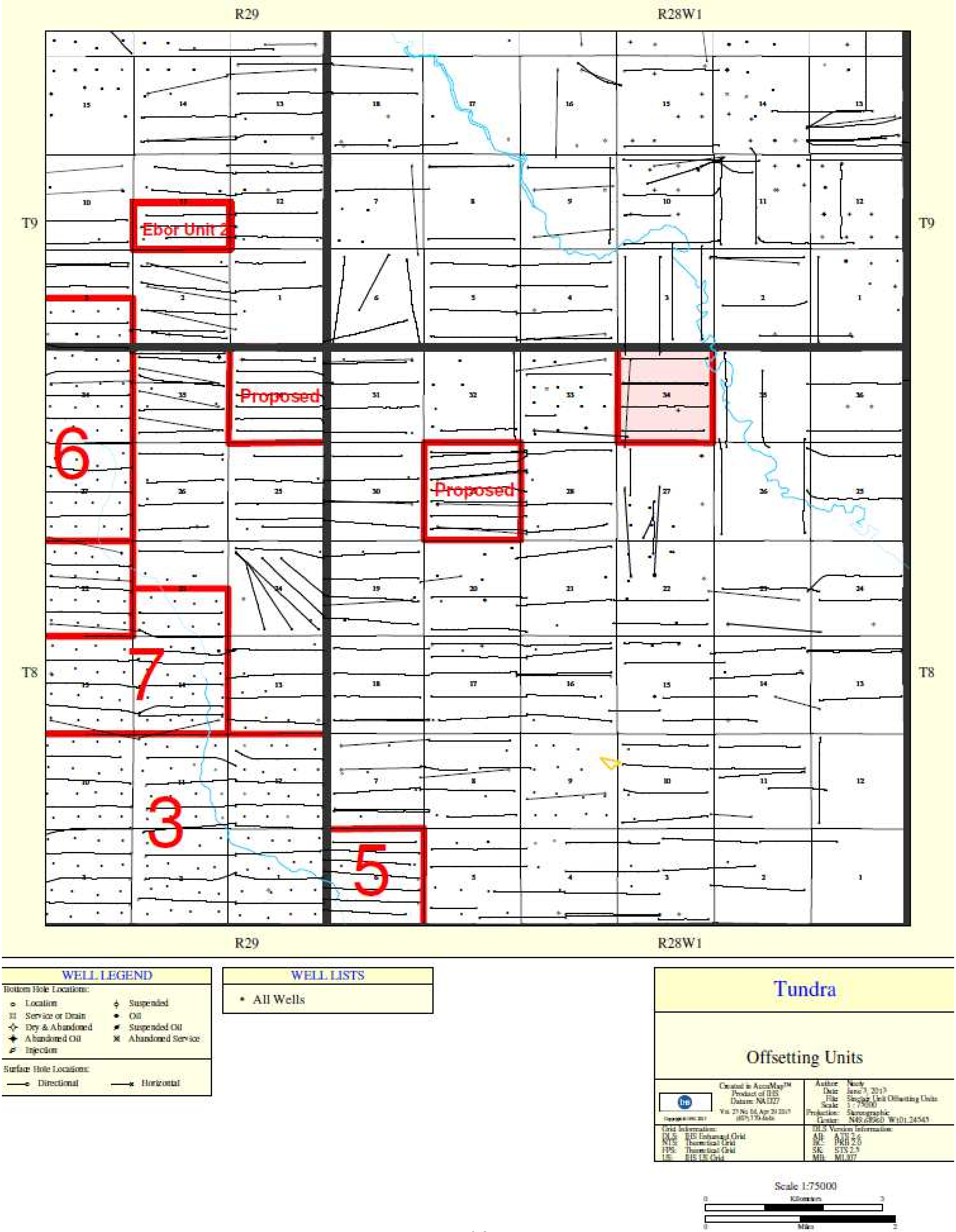
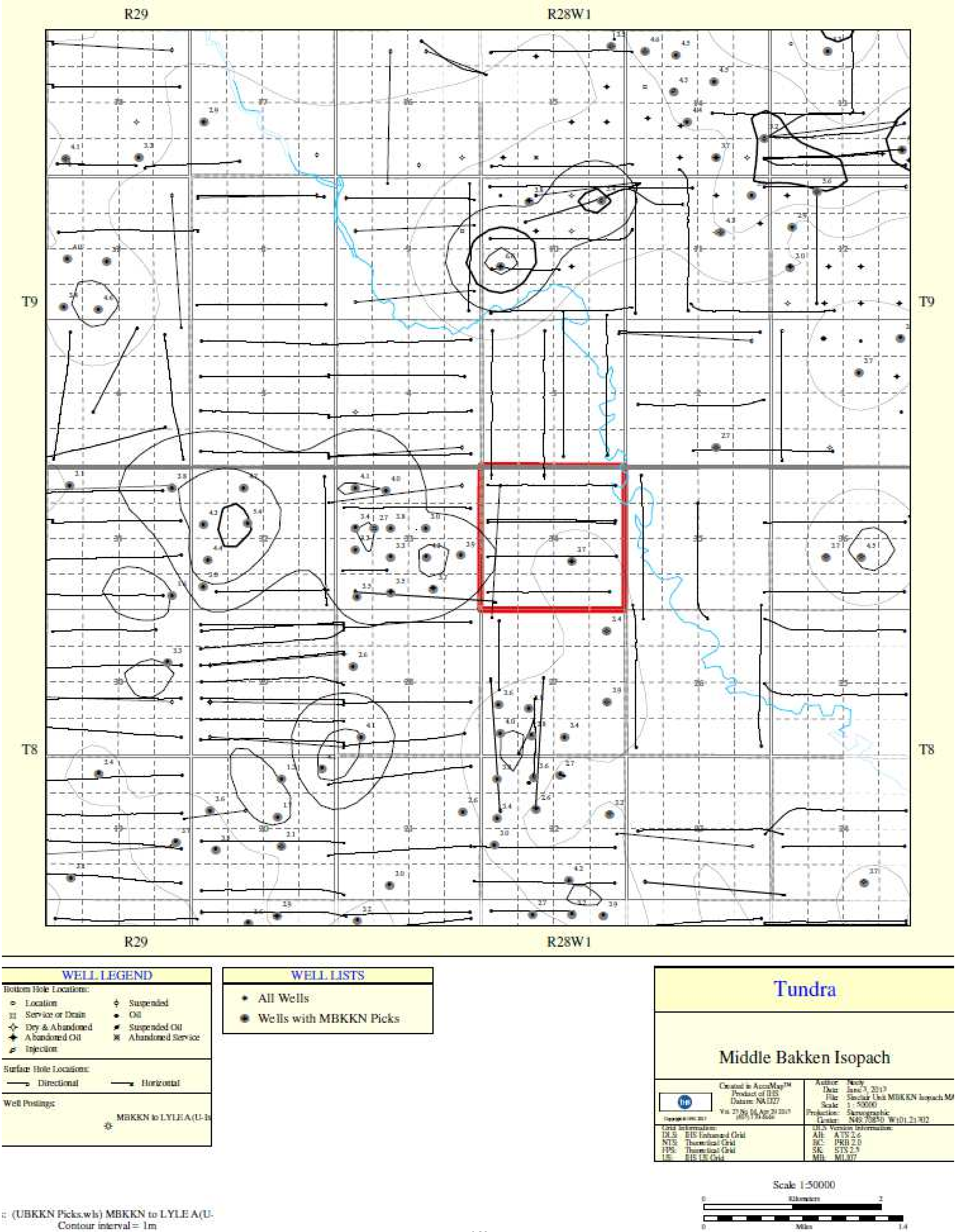
00/02-02-009-28W1/0
Basal Lodgepole
Upper Bakken
Middle Bakken
Lyleton B
Torquay
Legend
Oil
Abandoned Oil
Dry & Abandoned
Contact Type - Conformity
Contact Type - Unconformity
Contact Type - Time Equivalence
Contact Type - Left Fault
Contact Type - Right Fault
Shale
Yellow
Sandstone
Red
Siltstone
R29
R28W1
T9
T8
Tundra Oil and Gas
Structural Cross Section
Section 34-8-28W1

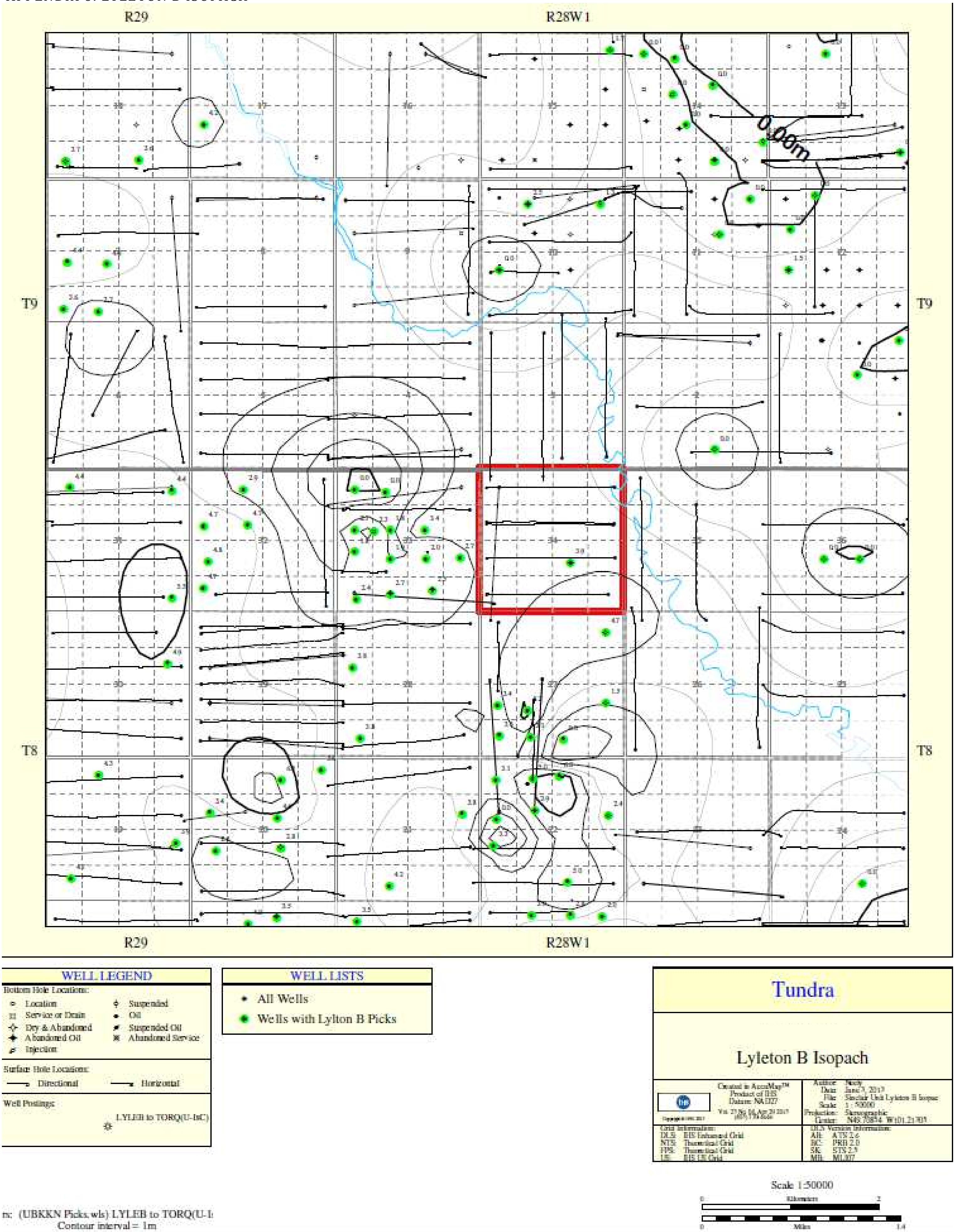
APPENDIX 4: OFFSETTING UNIT MAP



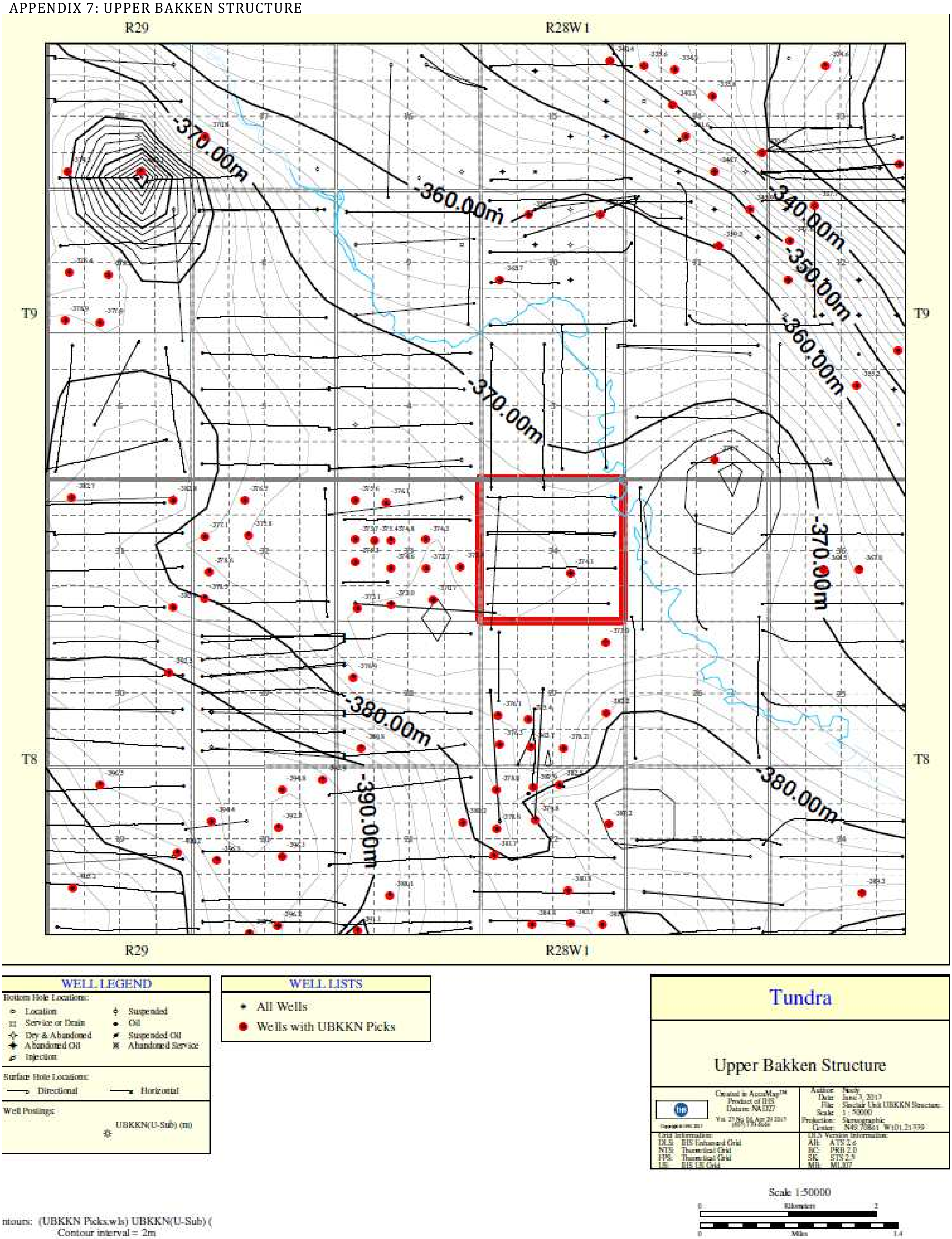
APPENDIX 5: MIDDLE BAKKEN ISOPACH



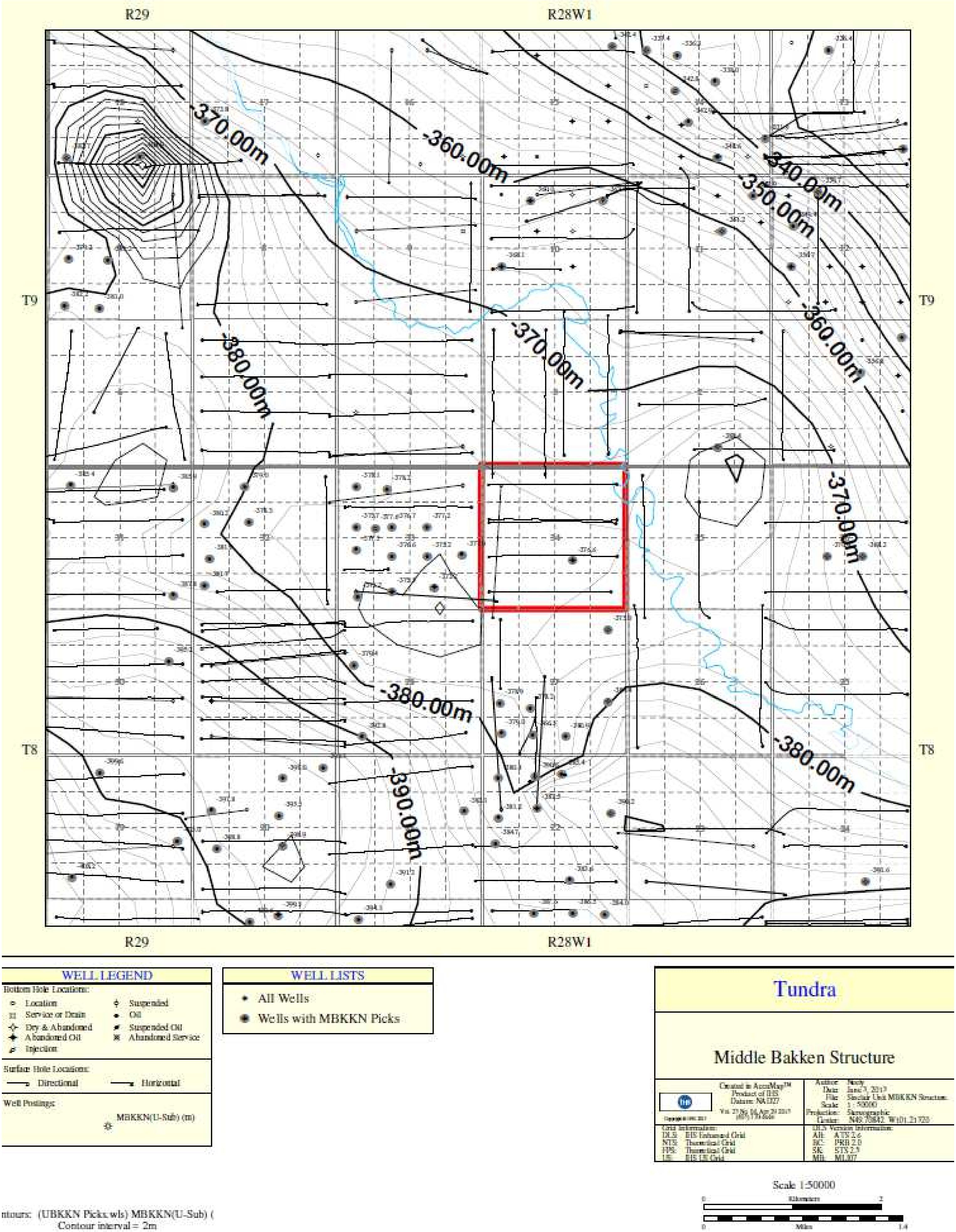
APPENDIX 6: LYLETON B ISOPACH



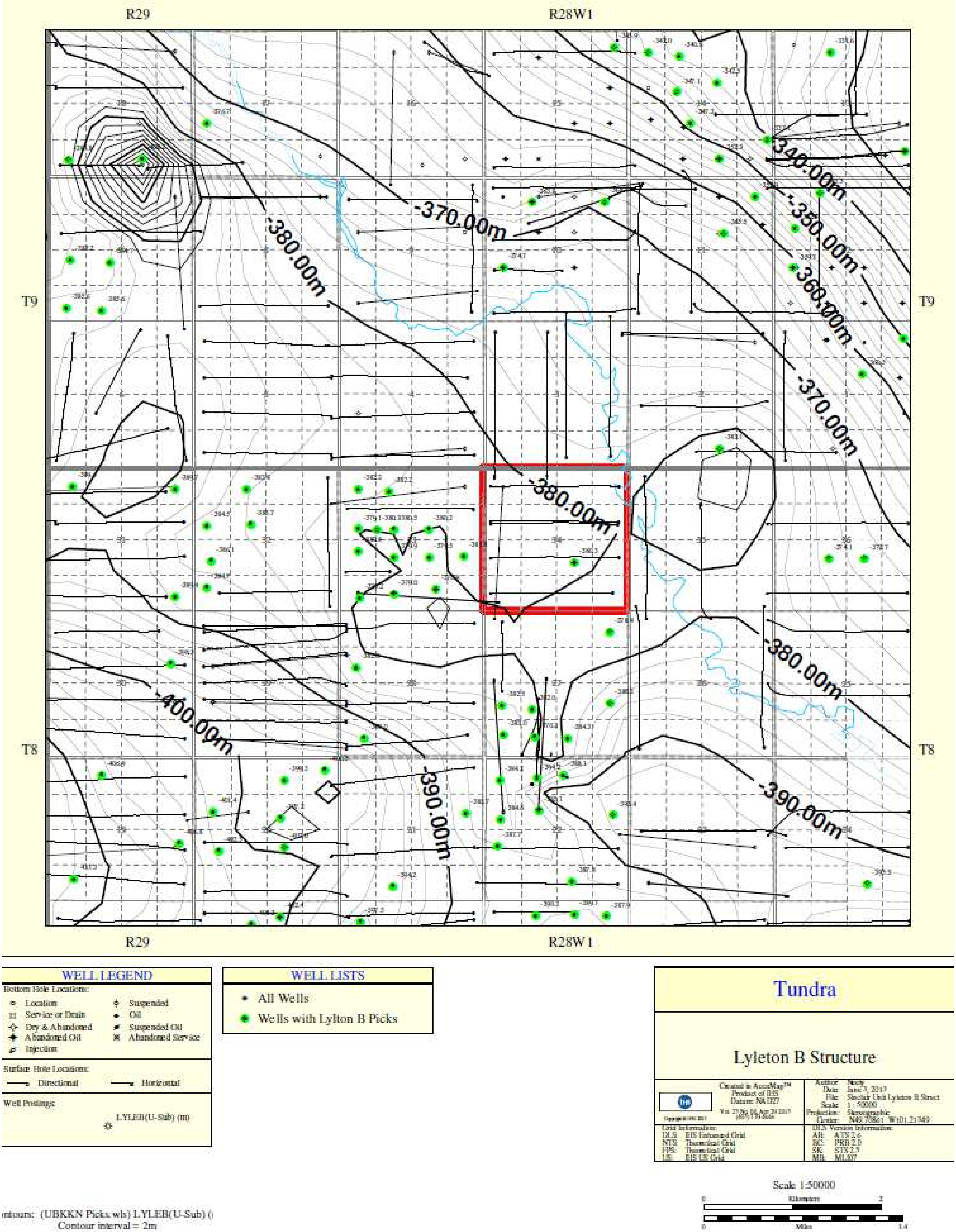
APPENDIX 7: UPPER BAKKEN STRUCTURE



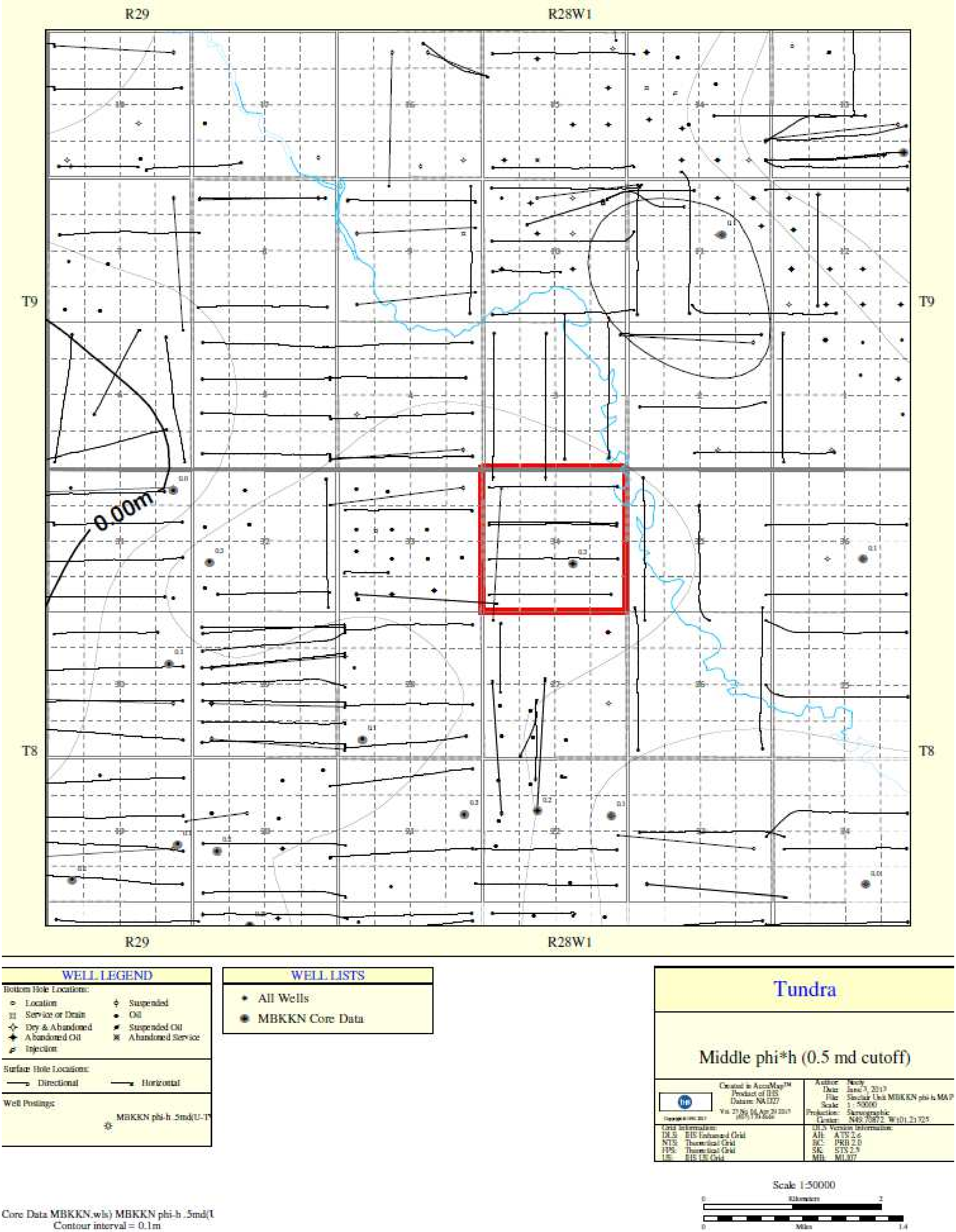
APPENDIX 8: MIDDLE BAKKEN STRUCTURE



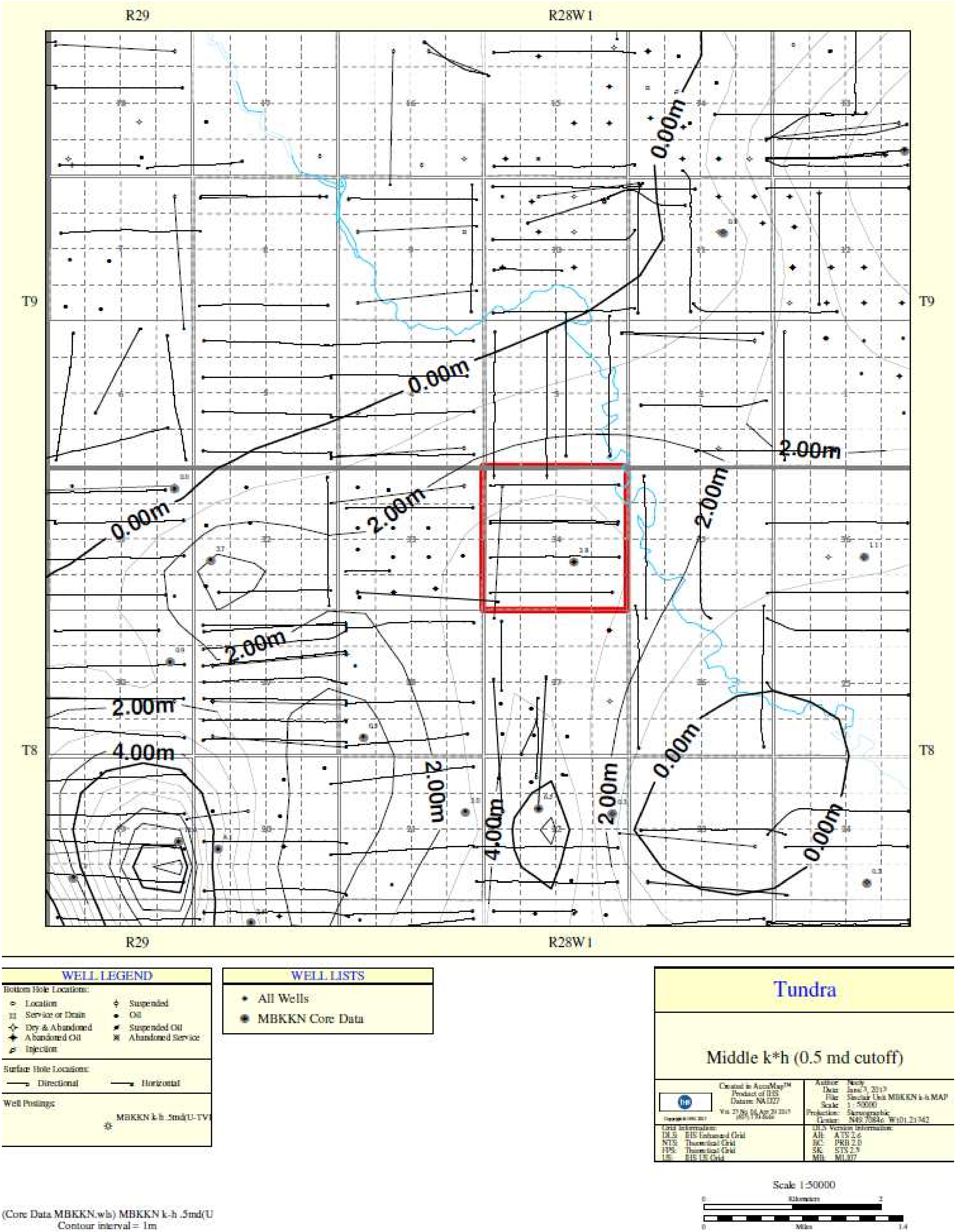
APPENDIX 9: LYLETON B STRUCTURE



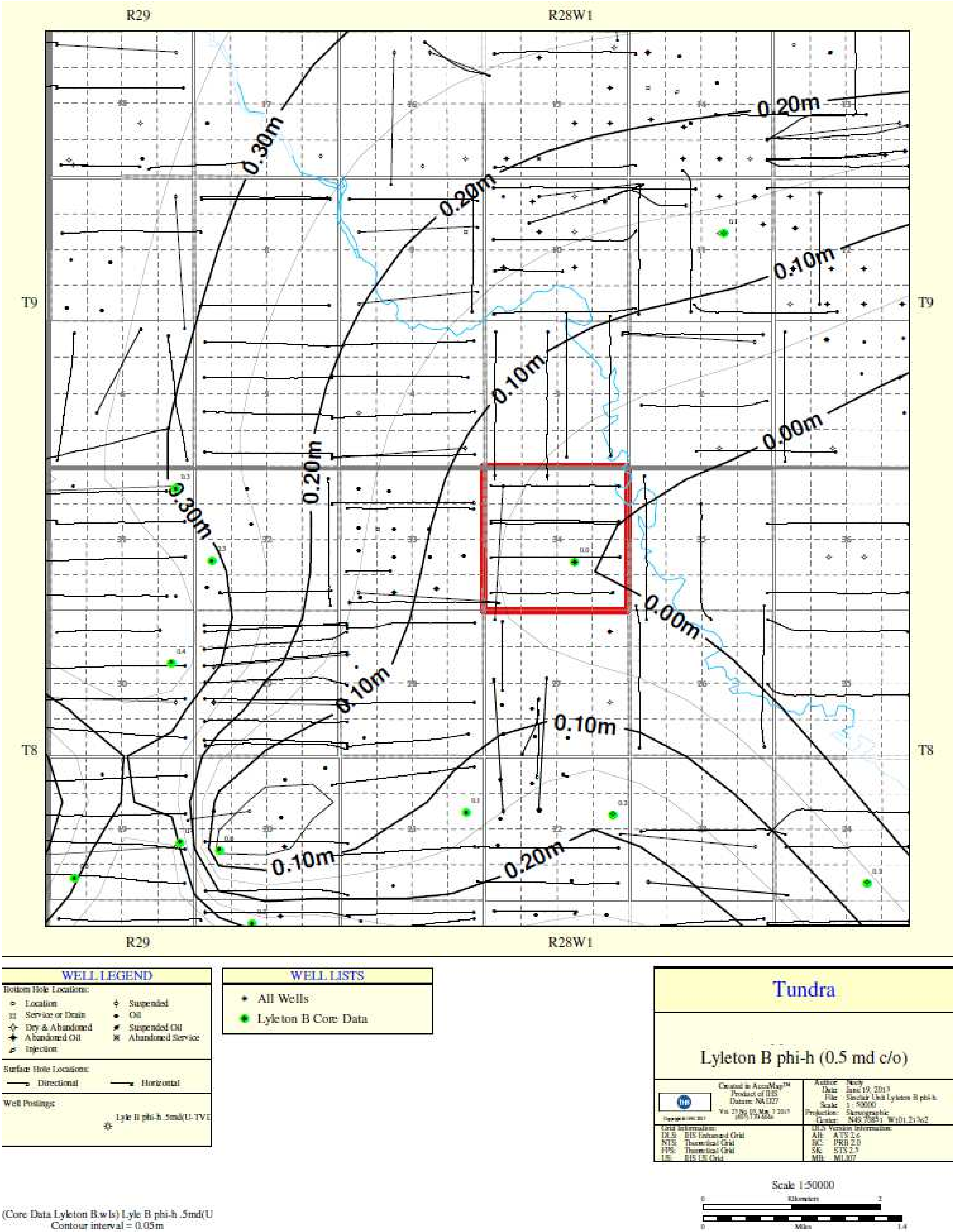
APPENDIX 10: MIDDLE BAKKEN PHI-H



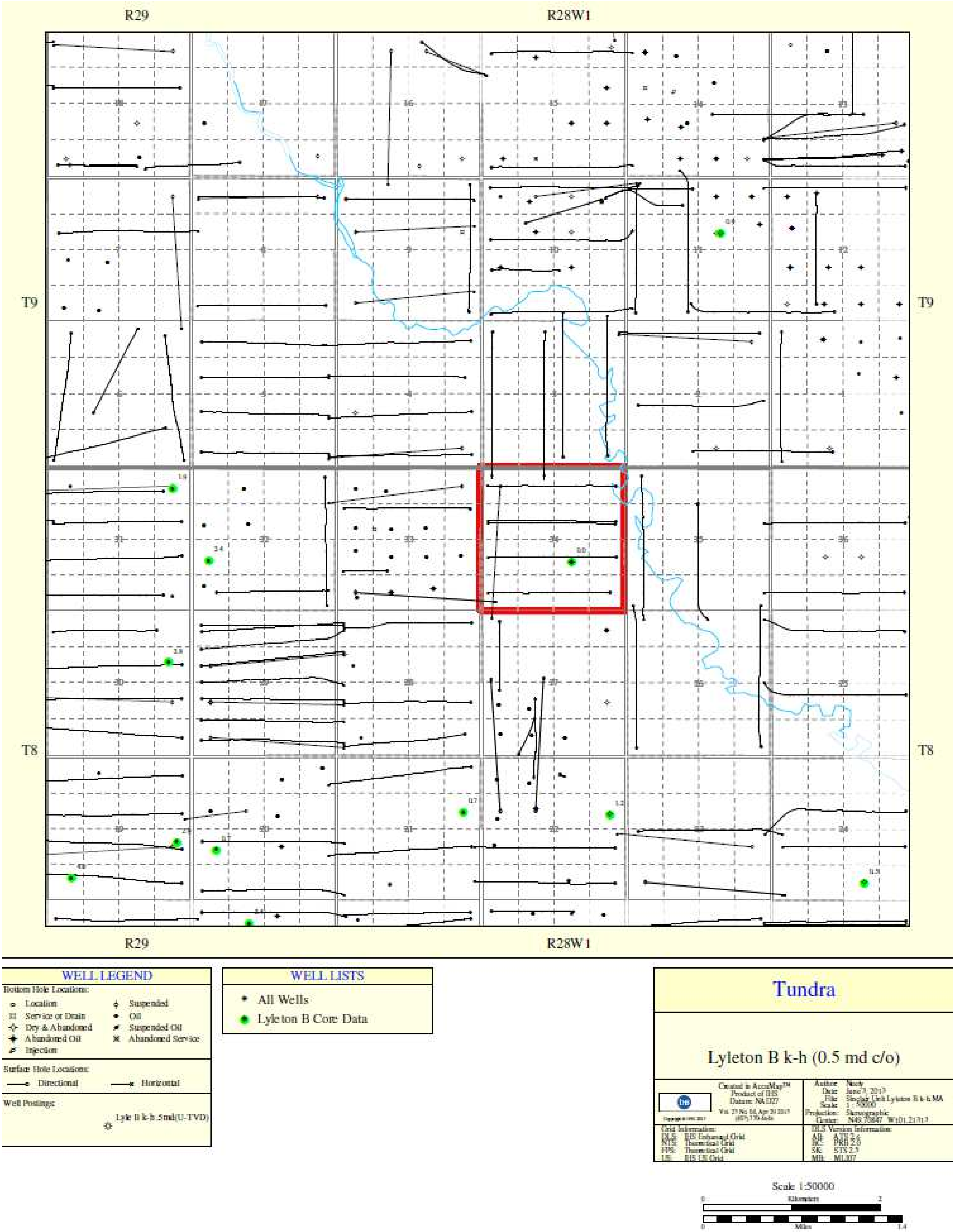
APPENDIX 11: MIDDLE BAKKEN K-H



APPENDIX 12: LYLETON B PHI-H



APPENDIX 13: LYLETON B K-H



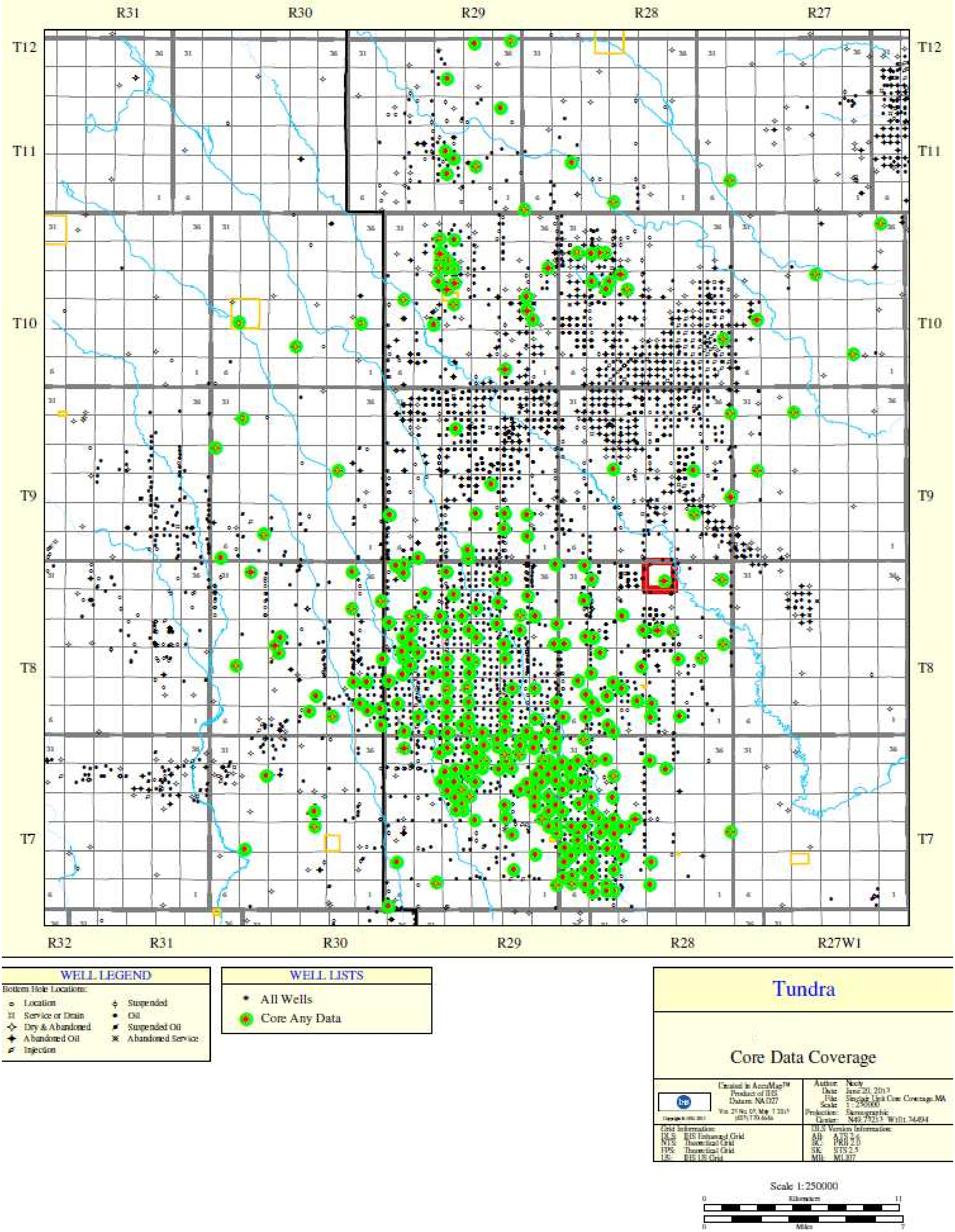
QUALIFICATIONS FOR ORIGINAL OIL IN PLACE (OOIP) CALCULATIONS

OOIP for Proposed Ewart Unit 5 were calculated by Tundra Geologist Todd Neely, using a dataset originally compiled by Barry Larson.

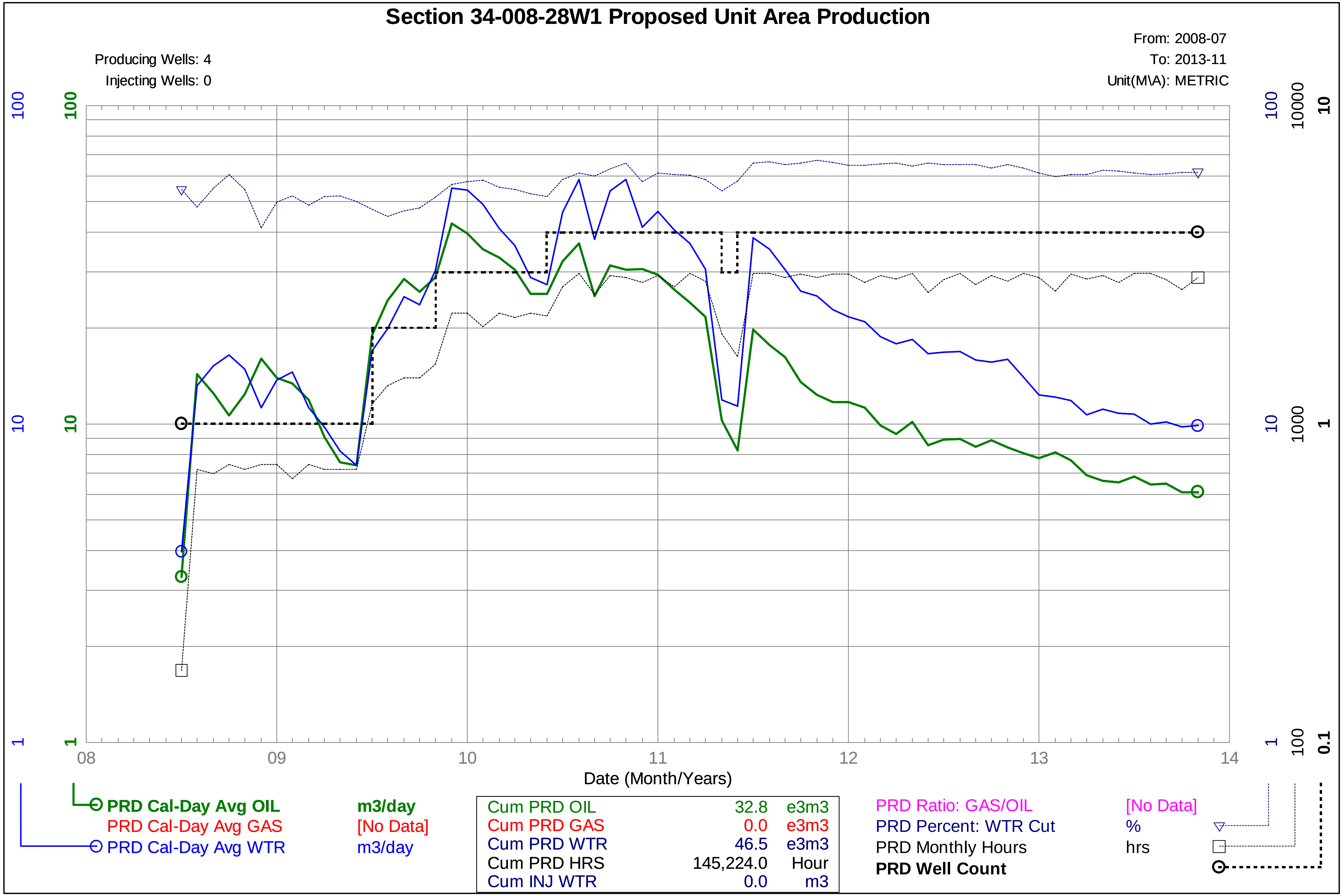
Barry holds a BSc. in geology from the University of Saskatchewan, and has 35 years of industry experience, 19 of which are in the Williston Basin.

Todd Neely holds a BSc. in geology from the University of Manitoba, and has 15 years of industry experience, 4 of which are in the Williston Basin.

APPENDIX 15: CORE DATA COVERAGE



UWI	MBKKN	MBKKN	MBKKN	MBKKN	Lyleton B	Lyleton B	Lyleton B	Lyleton B	Total	Total
	Phi-h	Sw	Bo	Calc OOIP	Phi-h	Sw	Bo	Calc OOIP	Calc OOIP	Calc OOIP
	(m)	(dec)	(m3/m3)	(m3)	(m)	(dec)	(m3/m3)	(m3)	(m3)	(stb)
01-34-008-28W1M	0.199	0.45	1.018	17385.280	0.118	0.45	1.018	10355.405	27740.68586	174483.6433
02-34-008-28W1M	0.181	0.45	1.018	15818.086	0.128	0.45	1.018	11232.261	27050.34671	170141.5413
03-34-008-28W1M	0.154	0.45	1.018	13444.154	0.144	0.45	1.018	12612.944	26057.09815	163894.1965
04-34-008-28W1M	0.132	0.45	1.018	11527.986	0.159	0.45	1.018	13894.072	25422.05726	159899.9099
05-34-008-28W1M	0.137	0.45	1.018	11960.849	0.174	0.45	1.018	15173.992	27134.84005	170672.9883
06-34-008-28W1M	0.152	0.45	1.018	13314.119	0.151	0.45	1.018	13213.027	26527.14536	166850.7042
07-34-008-28W1M	0.175	0.45	1.018	15264.079	0.129	0.45	1.018	11319.430	26583.50957	167205.2243
08-34-008-28W1M	0.190	0.45	1.018	16648.193	0.114	0.45	1.018	9948.478	26596.67041	167288.0035
09-34-008-28W1M	0.195	0.45	1.018	17027.670	0.108	0.45	1.018	9407.058	26434.72819	166269.4177
10-34-008-28W1M	0.182	0.45	1.018	15912.858	0.129	0.45	1.018	11301.940	27214.79826	171175.9103
11-34-008-28W1M	0.168	0.45	1.018	14696.636	0.154	0.45	1.018	13491.605	28188.24059	177298.6776
12-34-008-28W1M	0.158	0.45	1.018	13841.101	0.183	0.45	1.018	15977.902	29819.00302	187555.8634
13-34-008-28W1M	0.177	0.45	1.018	15473.595	0.193	0.45	1.018	16892.477	32366.07134	203576.4392
14-34-008-28W1M	0.182	0.45	1.018	15949.517	0.160	0.45	1.018	13971.796	29921.31308	188199.3742
15-34-008-28W1M	0.192	0.45	1.018	16829.866	0.130	0.45	1.018	11396.027	28225.89295	177535.5037
16-34-008-28W1M	0.205	0.45	1.018	17904.060	0.101	0.45	1.018	8845.465	26749.52533	168249.4319
Total									**442031.9261**	**2780296.829**


Section 34-008-28W1 Proposed Unit Area Production
From: 2008-07
To: 2013-11
Unit(M\A): METRIC
Producing Wells: 4
Injecting Wells: 0
08
09
10
11
12
13
14
Date (Month/Years)
PRD Cal-Day Avg OIL m3/day
PRD Cal-Day Avg GAS [No Data]
PRD Cal-Day Avg WTR m3/day
Cum PRD OIL 32.8 e3m3
Cum PRD GAS 0.0 e3m3
Cum PRD WTR 46.5 e3m3
Cum PRD HRS 145,224.0 Hour
Cum INJ WTR 0.0 m3
PRD Ratio: GAS/OIL [No Data]
PRD Percent: WTR Cut %
PRD Monthly Hours hrs
PRD Well Count

Unique Well ID	Current Operator Name	On Date	Date	PRD Monthly HRS hrs	PRD Calndr-Day Avg OIL m3	PRD Calndr-Day Avg WTR m3	PRD Monthly OIL m3	PRD Monthly WTR m3	PRD Cumulative OIL m3	PRD Cumulative WTR m3	PRD Percent: WTR Cut %
00/01-34-008-28W1/0	Tundra O&G Prtnshp	2008-07	2013-11	720	0.9	1.5	27.6	45	7713.6	9025.2	62
00/08-34-008-28W1/0	Tundra O&G Prtnshp	2010-06	2013-11	720	2.3	4.7	70.4	142.3	7413.7	16343.5	66.9
00/09-34-008-28W1/0	Tundra O&G Prtnshp	2009-07	2013-11	720	0.9	0.9	28.3	27.6	10588.5	9502	49.4
00/16-34-008-28W1/0	Tundra O&G Prtnshp	2009-11	2013-11	720	1.9	2.7	57	81.2	7105.4	11676.4	58.8

Working Interest				Royalty Interest		
Tract No.	Land Description	Owner	Share (%)	Owner	Share (%)	Tract Participation
1	01-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.346087793%
2	02-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.052600993%
3	03-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.809689491%
4	04-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.876178086%
5	05-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.354914597%
6	06-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.963098232%
7	07-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.978683821%
8	08-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.000922900%
9	09-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.770583320%
10	10-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	5.921880643%
11	11-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.159892916%
12	12-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.845986446%
13	13-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	7.624972862%
14	14-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.819870775%
15	15-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.405556090%
16	16-34-008-28W1M	Tundra Oil & Gas Partnership	100%	Her Majesty the Queen in Right of the Province Of Manitoba	100%	6.069081035%
						100.000000000%

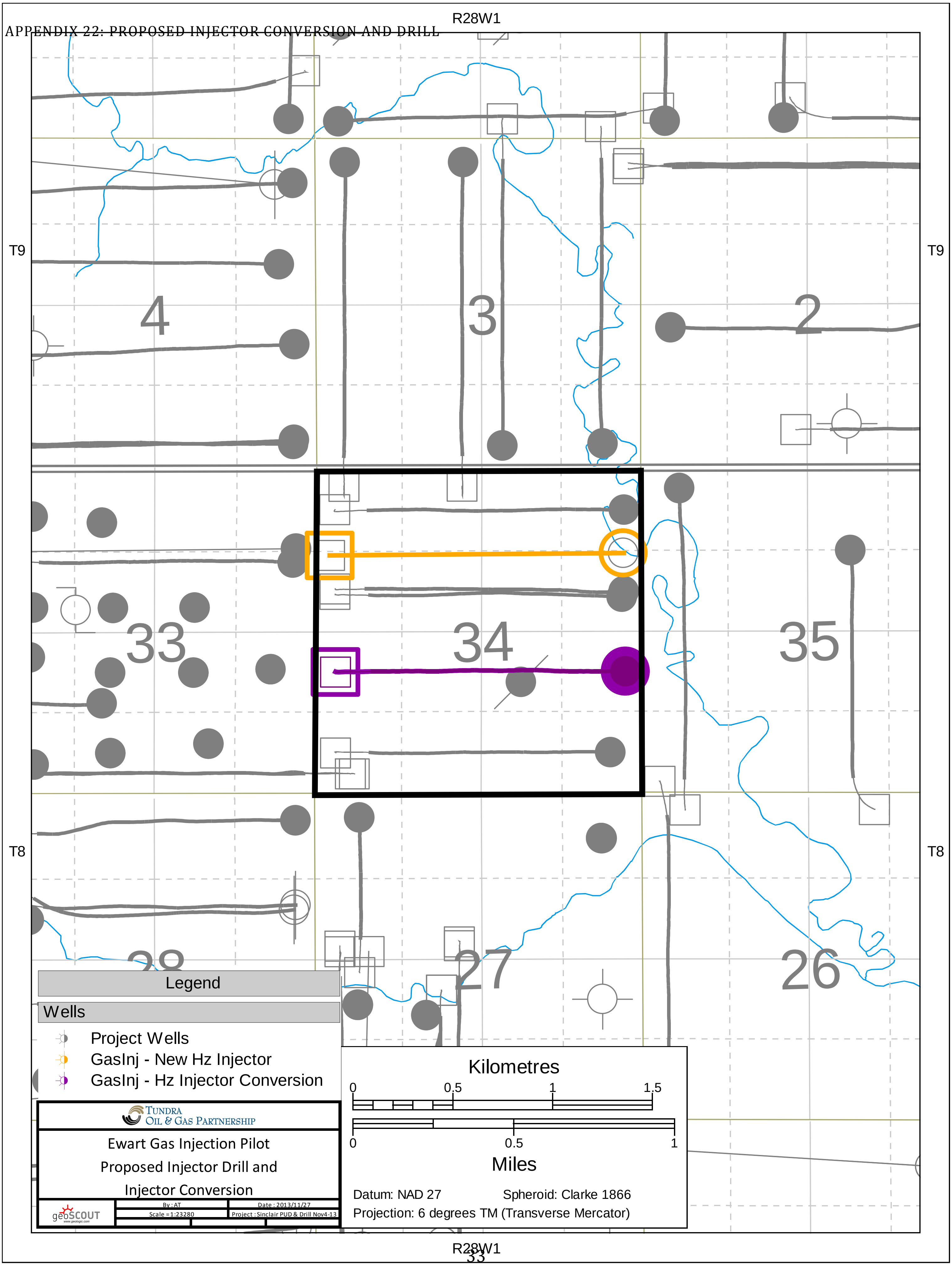
LSD	Total Calc OOIP (m3)	Producing Well (s)	Cumulative Well Production to November 2013	LSD Production Allocation (%)	LSD Allocated Production (m3)	OOIP-Production (m3)	OOIP-Production Tract Factor
01-34-008-28W1M	27740.68586	00/01-34-008-28W1/0	7713.600000000	22.970%	1771.8139200	25968.87194	0.063460878
02-34-008-28W1M	27050.34671	00/01-34-008-28W1/0	7713.600000000	29.590%	2282.4542400	24767.89247	0.060526010
03-34-008-28W1M	26057.09815	00/01-34-008-28W1/0	7713.600000000	29.600%	2283.2256000	23773.87255	0.058096895
04-34-008-28W1M	25422.05726	00/01-34-008-28W1/0	7713.600000000	17.840%	1376.1062400	24045.95102	0.058761781
05-34-008-28W1M	27134.84005	00/08-34-008-28W1/0	7413.700000000	15.240%	1129.8478800	26004.99217	0.063549146
06-34-008-28W1M	26527.14536	00/08-34-008-28W1/0	7413.700000000	28.670%	2125.5077900	24401.63757	0.059630982
07-34-008-28W1M	26583.50957	00/08-34-008-28W1/0	7413.700000000	28.570%	2118.0940900	24465.41548	0.059786838
08-34-008-28W1M	26596.67041	00/08-34-008-28W1/0	7413.700000000	27.520%	2040.2502400	24556.42017	0.060009229
09-34-008-28W1M	26434.72819	00/09-34-008-28W1/0	10588.500000000	26.641%	2820.8822850	23613.84591	0.057705833
10-34-008-28W1M	27214.79826	00/09-34-008-28W1/0	10588.500000000	28.161%	2981.8274850	24232.97078	0.059218806
11-34-008-28W1M	28188.24059	00/09-34-008-28W1/0	10588.500000000	28.156%	2981.2980600	25206.94253	0.061598929
12-34-008-28W1M	29819.00302	00/09-34-008-28W1/0	10588.500000000	17.042%	1804.4921700	28014.51085	0.068459864
13-34-008-28W1M	32366.07134	00/16-34-008-28W1/0	7105.400000000	16.380%	1163.8645200	31202.20682	0.076249729
14-34-008-28W1M	29921.31308	00/16-34-008-28W1/0	7105.400000000	28.340%	2013.6703600	27907.64272	0.068198708
15-34-008-28W1M	28225.89295	00/16-34-008-28W1/0	7105.400000000	28.340%	2013.6703600	26212.22259	0.064055561
16-34-008-28W1M	26749.52533	00/16-34-008-28W1/0	7105.400000000	26.940%	1914.1947600	24835.33057	0.060690810
Total	442031.9261		131284.800000000		32821.2000000	409210.7261	1.000000000

Exodus Simulation Immiscible Gas Injection Pilot Area

Coho Consulting Ltd

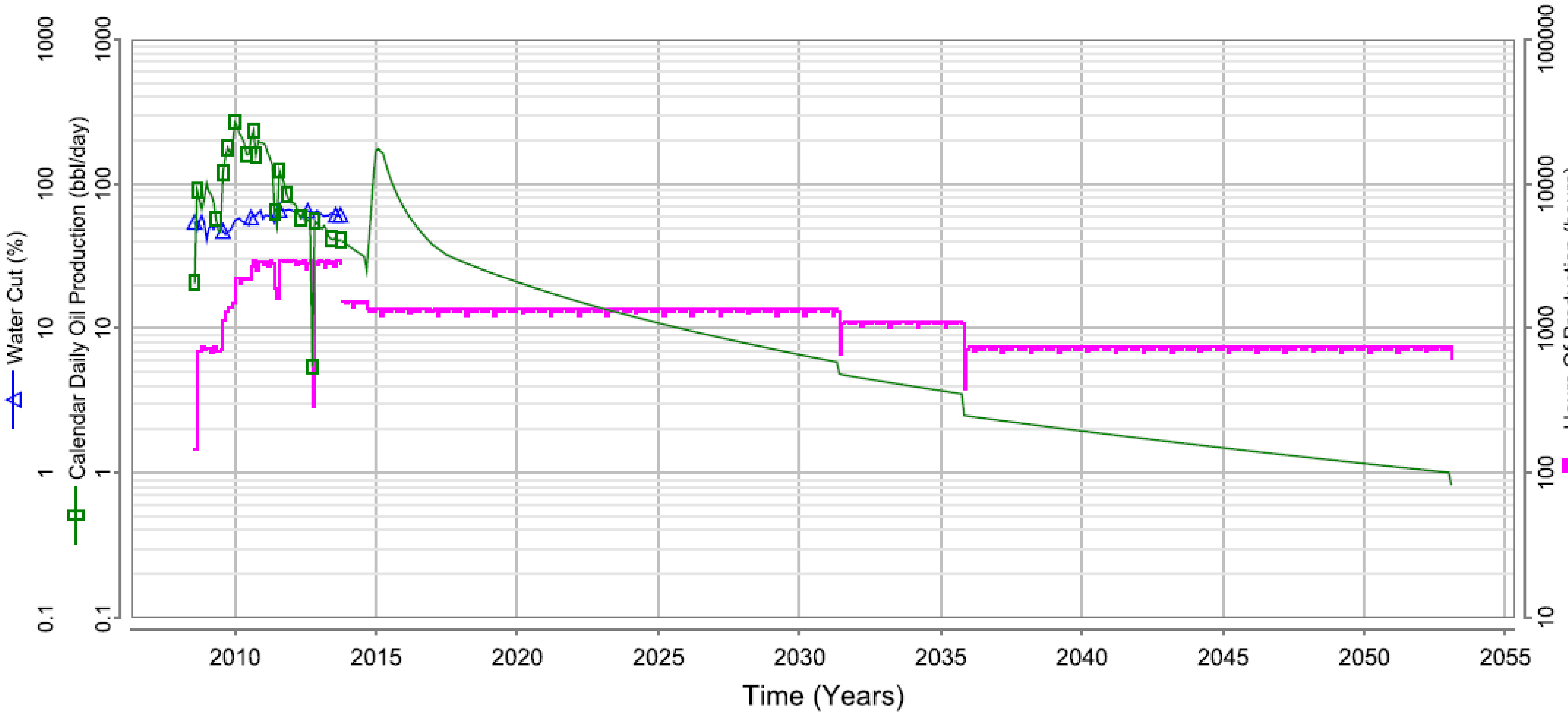
For Tundra Oil and Gas

July 2013


R28W1
T9
T9
4
3
2
33
34
35
T8
T8
28
27
26
Legend
Wells
Project Wells
GasInj - New Hz Injector
GasInj - Hz Injector Conversion
TUNDRA OIL & GAS PARTNERSHIP
Ewart Gas Injection Pilot
Proposed Injector Drill and Injector Conversion
By : AT
Date : 2013/11/27
Scale = 1:23280
Project : Sinclair PUD & Drill Nov4-13
geoSCOUT
Kilometres
0
0.5
1
1.5
0
0.5
1
Miles
Datum: NAD 27
Spheroid: Clarke 1866
Projection: 6 degrees TM (Transverse Mercator)
R28W1

CONSOLIDATED PRODUCTION AND FORECAST

Effective January 01, 2013
Selection: Current selection from current workbench list
Type:
Category: S1

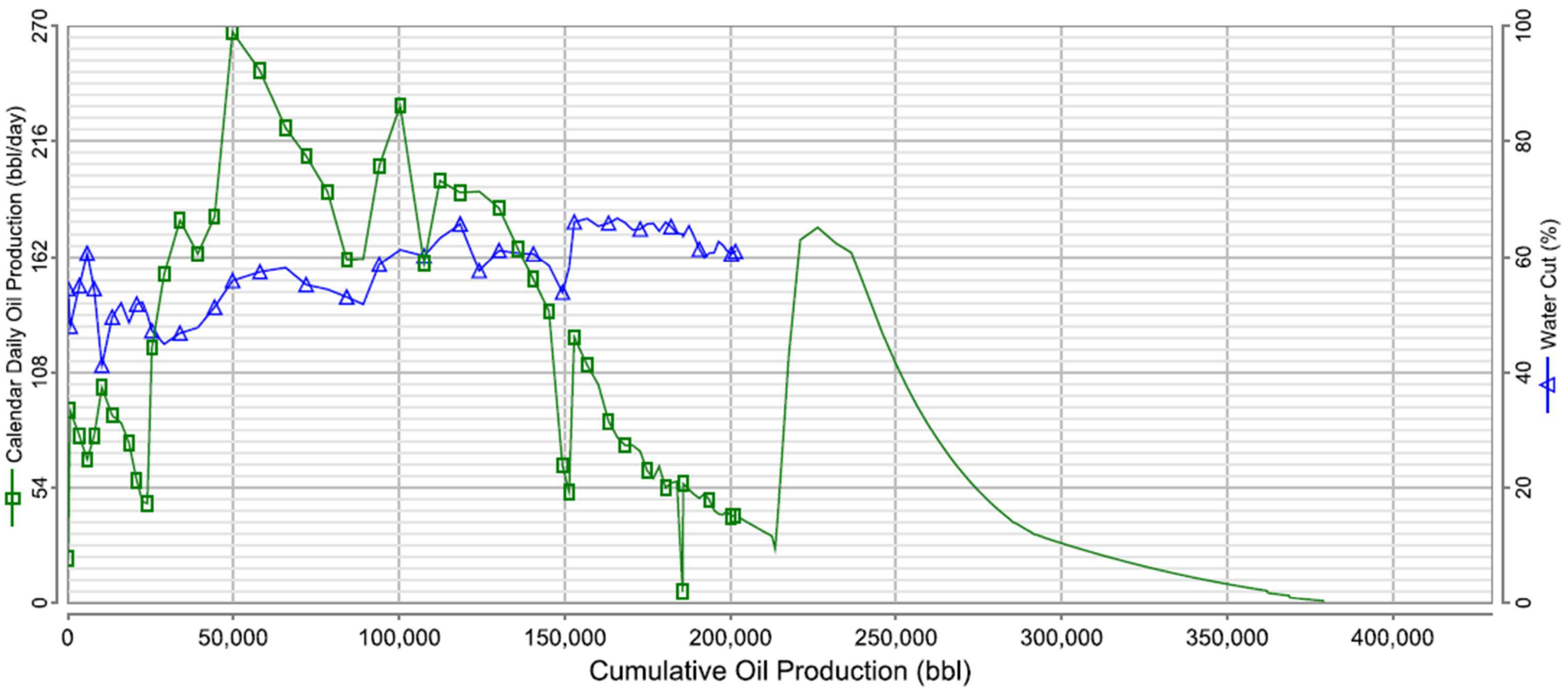


Cum Oil	(bbl)	201,538	Cum Gas	(Mcf)	0	Cum Water	(bbl)	283,657	Cum Cond (bbl)	0

Forecast Start		2013/10/01	Calculation Type			Est. Cum Prod	(bbl)	191,891	Decline Exponent	
Forecast End		2053/01/31	OVIP	(bbl)		Remaining	(bbl)	187,171	Intial Decline (%/yr)	98.7
Initial Rate	(bbl/day)	76.7	Recovery Factor			Surface Loss			Life Index	16.19
Final Rate	(bbl/day)	1.0	Ult. Recoverable	(bbl)	379,062	Total Sales	(Mcf)		Half Life (years)	3.27

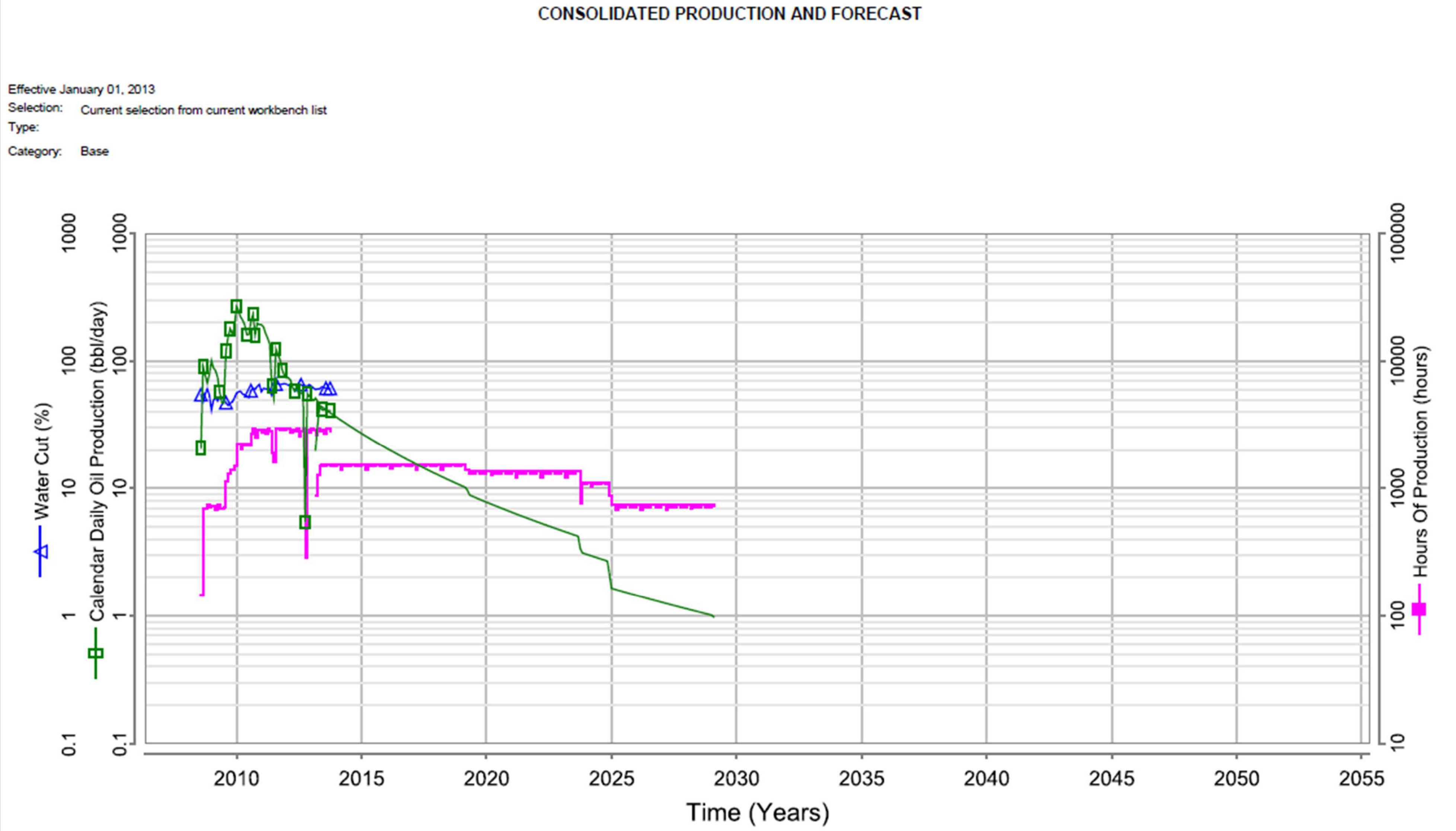
CONSOLIDATED PRODUCTION AND FORECAST

Effective January 01, 2013
Selection: Current selection from current workbench list
Type:
Category: S1



Cum Oil	(bbl)	201,538	Cum Gas	(Mcf)	0	Cum Water	(bbl)	283,657	Cum Cond	(bbl)	0

Forecast Start		2013/10/01	Calculation Type			Est. Cum Prod	(bbl)	191,891	Decline Exponent	
Forecast End		2053/01/31	OVIP	(bbl)		Remaining	(bbl)	187,171	Intial Decline (%/yr)	98.7
Initial Rate	(bbl/day)	76.7	Recovery Factor			Surface Loss			Life Index	16.19
Final Rate	(bbl/day)	1.0	Ult. Recoverable	(bbl)	379,062	Total Sales	(Mcf)		Half Life (years)	3.27

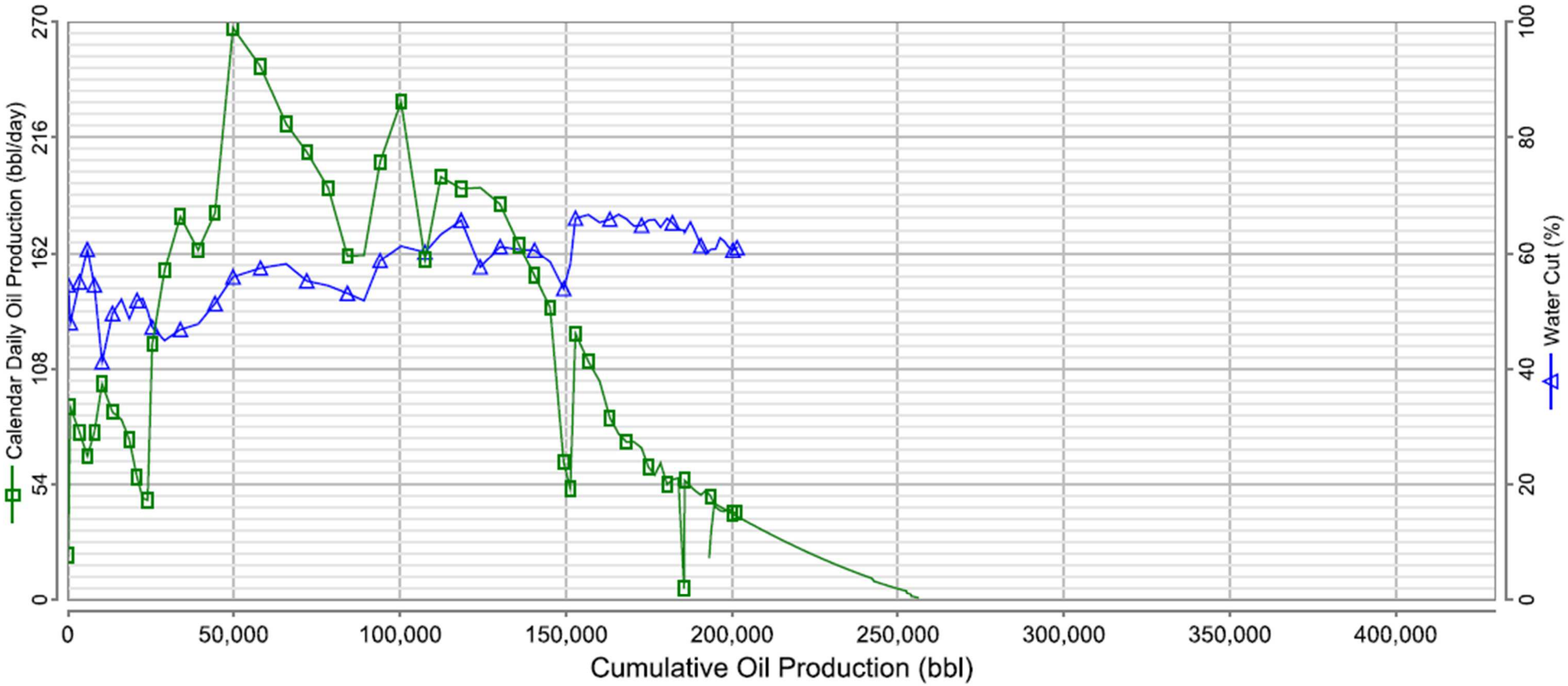


Cum Oil	(bbl)	201,538	Cum Gas	(Mcf)	0	Cum Water	(bbl)	283,657	Cum Cond	(bbl)	0

Forecast Start		2013/02/01	Calculation Type			Est. Cum Prod	(bbl)	191,661	Decline Exponent	
Forecast End		2029/01/31	OVIP	(bbl)		Remaining	(bbl)	64,362	Intial Decline (%/yr)	96.7
Initial Rate	(bbl/day)	30.7	Recovery Factor			Surface Loss			Life Index	5.07
Final Rate	(bbl/day)	1.0	Ult. Recoverable	(bbl)	256,022	Total Sales	(Mcf)		Half Life (years)	2.75

CONSOLIDATED PRODUCTION AND FORECAST

Effective January 01, 2013
Selection: Current selection from current workbench list
Type:
Category: Base



Cum Oil	(bbl)	201,538	Cum Gas	(Mcf)	0	Cum Water	(bbl)	283,657	Cum Cond (bbl)	0
Forecast Start		2013/02/01	Calculation Type			Est. Cum Prod	(bbl)	191,661	Decline Exponent	
Forecast End		2029/01/31	OVIP	(bbl)		Remaining	(bbl)	64,362	Intial Decline (%/yr)	96.7
Initial Rate	(bbl/day)	30.7	Recovery Factor			Surface Loss			Life Index	5.07
Final Rate	(bbl/day)	1.0	Ult. Recoverable	(bbl)	256,022	Total Sales	(Mcf)		Half Life (years)	2.75

South-Tek Systems, LLC

Date: 11/15/2013

Designers and Manufacturers of Nitrogen Gas Generators Quote # N2 GEN®650S_PSA

Reference: N2 GEN® 650S PSA Generator; 99% Purity; requiring 7500 SCFH

NITROGEN GENERATION SYSTEM Specifications and Dimensions

STS Model N2 GEN® 650S PSA Nitrogen Generator

Produces up to a total of 9236 SCFH each at a purity of 99%; 12067 scfh @98%; 14356 scfh @97%
ASME, CRN on pressure vessels
Electrics: 120Volts/60Hz/1 Phase
Dimensions each system: 68"w x 64"l x 144"h
Weight each system: 9000 lbs.
Air Requirement each system: 483 SCFM compressed feed air at 100 PSIG
Outlet Pressure: 60 PSIG

1550 Gallon Nitrogen Storage Tank(s)

Dimensions each tank: 54" x 174"h
Weight each tank: 2,560 lbs.

Nitrogen Booster Package

150 -190 scfm @ 1160 psig,1800 RPM
Electrics: 575 Volts/60Hz/3 phase
Motor HP rating: 100 HP
Dimensions: 42"w x 75"l x 43"h (block and motor; full skid TBD)
Weight: 2,750 lbs.
(See attached Data Sheet for additional information)

Complete Air Cooled Rotary Screw Air Compressor Package

Produces up to a total of 536 SCFM compressed air each, at 125 PSIG
125 HP Motor each
Electrics: 575Volts/60Hz/3 phase
TEFC Enclosure
Dimensions each: 103"l x 51"w x 80"h
Weight each: 5200 lbs

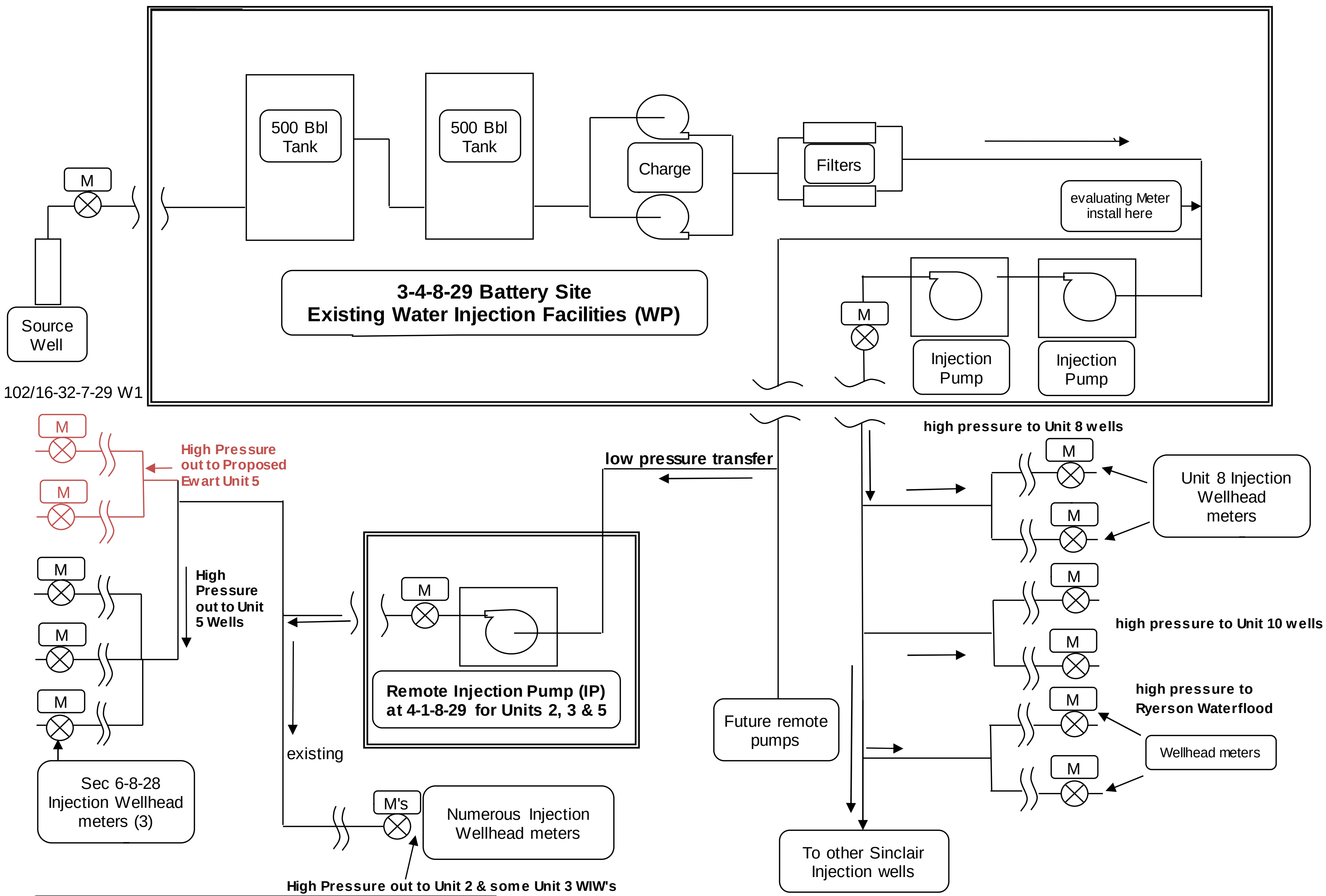
400 Gallon Nitrogen Storage Tank(s)

Dimensions each tank: 20" x 347"h
Weight each tank: TBD

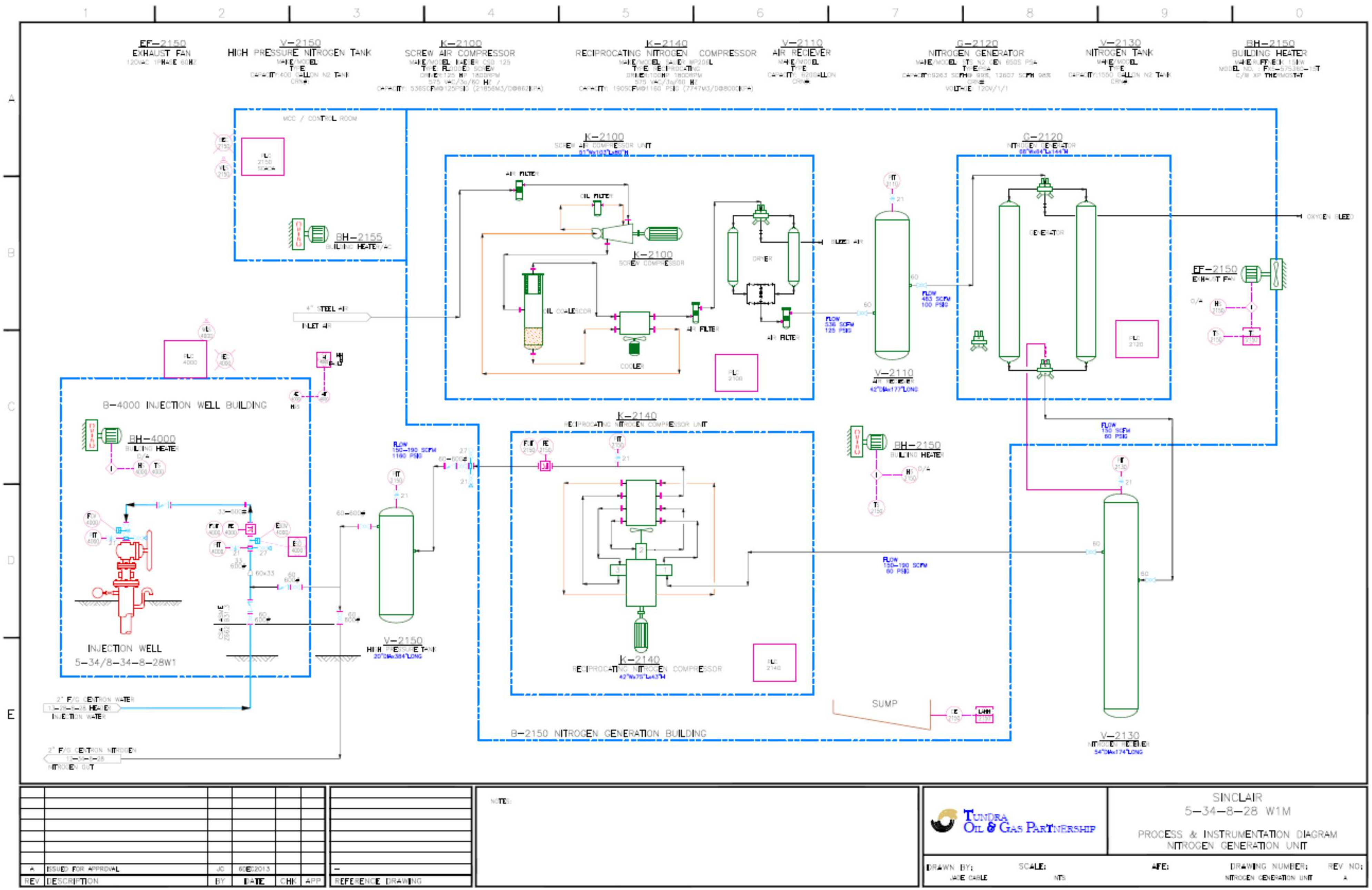
N2 GEN® 450S
Similar to quoted
Model

Information in this proposal is for quoting purposes only. All specifications and dimensions are subject to verification at time of Engineering approval ARO. Installation and Operations Manuals from original equipment suppliers supercede any information contained in this quote.

Sinclair Water Injection System

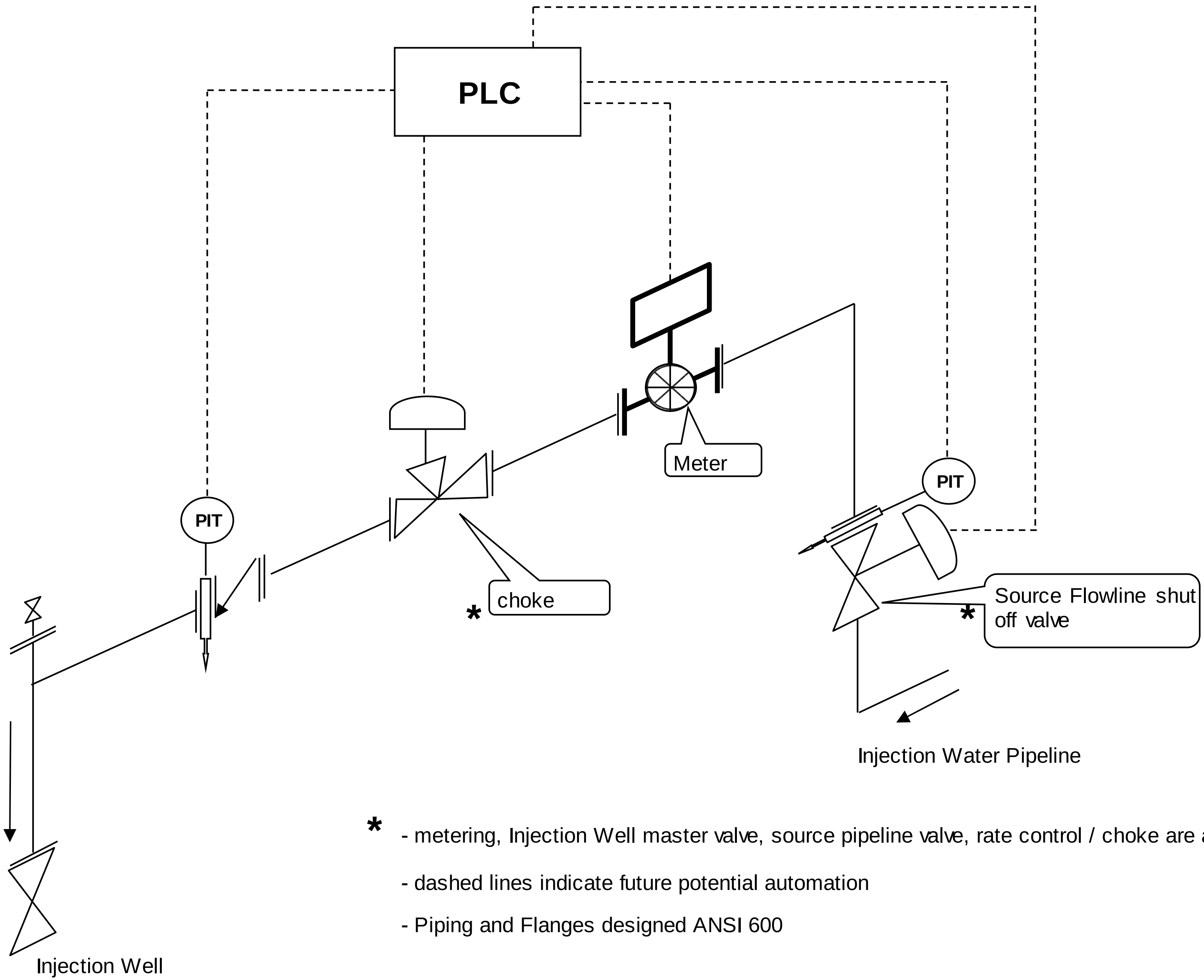


The 2 injection pumps at 3-4 and the injection pump at 4-1 are all tied into the injection distribution system so water can go where it is needed.


EF-2150
EXHAUST FAN
V-2150
HIGH PRESSURE NITROGEN TANK
K-2100
SCREW AIR COMPRESSOR
K-2140
RECIPROCATING NITROGEN COMPRESSOR
V-2110
AIR RECIEVER
G-2120
NITROGEN GENERATOR
V-2130
NITROGEN TANK
BH-2150
BUILDING HEATER
MCC / CONTROL ROOM
BH-2155
K-2100
K-2100
SCREW COMPRESSOR
AIR FILTER
OIL FILTER
DRYER
AIR FILTER
AIR FILTER
COOLER
4" STEEL AIR
INLET AIR
V-2110
G-2120
GENERATOR
OXYGEN BLEED
EF-2150
BH-2150
B-4000 INJECTION WELL BUILDING
BH-4000
INJECTION WELL
5-34/8-34-8-28W1
K-2140
K-2140
RECIPROCATING NITROGEN COMPRESSOR
V-2150
HIGH PRESSURE TANK
SUMP
B-2150 NITROGEN GENERATION BUILDING
V-2130
NOTES:
TUNDRA OIL & GAS PARTNERSHIP
SINCLAIR
5-34-8-28 W1M
PROCESS & INSTRUMENTATION DIAGRAM
NITROGEN GENERATION UNIT
REFERENCE DRAWING
ISSUED FOR APPROVAL
REV DESCRIPTION BY DATE CHK APP
DRAWN BY:
SCALE:
AFE:
DRAWING NUMBER:
REV NO:
NITROGEN GENERATION UNIT

Proposed N2 WAG

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

EOR WATER ALTERNATING GAS PROJECT

PLANNED CORROSION CONTROL PROGRAM **

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

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

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

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

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

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

** subject to final design and engineering

Tundra Oil And Gas Partnership

OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

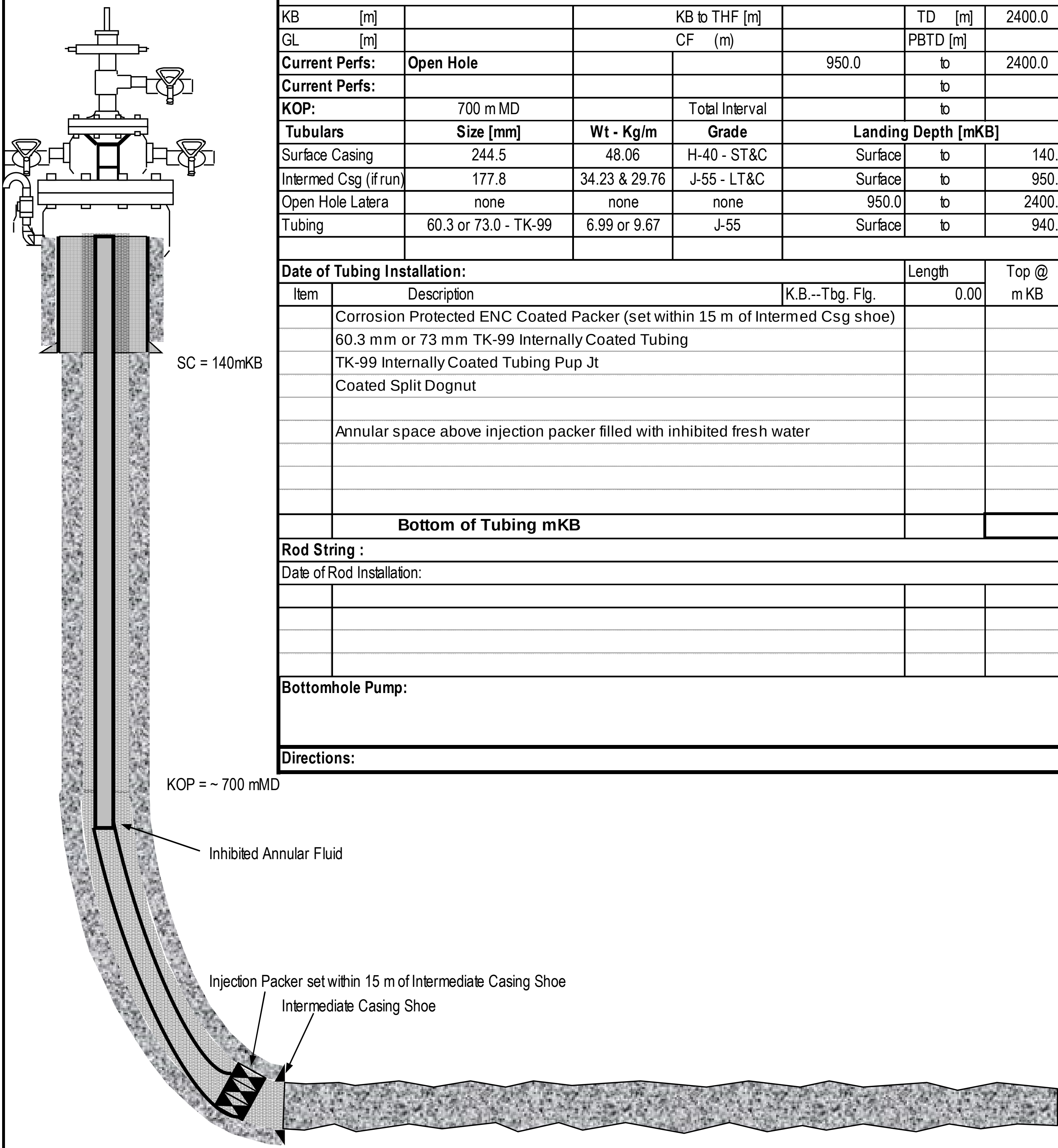
WELL NAME:	**Tundra Ewart Unit 5 HZNTL Open Hole WIW**				**WELL LICENCE:**	
Prepared by	WRJ	(average depths)		Date:	2012	
Elevations :						
KB [m]		KB to THF [m]			TD [m]	2400.0
GL [m]		CF (m)			PBTD [m]	
Current Perfs:	**Open Hole**			950.0	to	2400.0
Current Perfs:					to	
KOP:	700 m MD		Total Interval		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:



APPENDIX 33: DOWNHOLE WIW WELLBORE SCHEMATIC – CEMENTED LINER

Tundra Oil And Gas Partnership

TYPICAL CEMENTED LINER WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	**Tundra Ewart Unit 5 HZNTL Cemented Liner WIW**			**WELL LICENCE:**		
Prepared by	WRJ	(average depths)		Date:	2012	
Elevations :						
KB [m]		KB to THF [m]			TD [m]	2400.0
GL [m]		CF (m)			PBTD [m]	
Current Perfs:	**Cemented Casing / Liner**			950.0	to	2400.0
Current Perfs:					to	
KOP:	700 m MD		Total Interval		to	
Tubulars	**Size [mm]**	**Wt - Kg/m**	**Grade**	**Landing Depth [mKB]**		
Surface Casing	244.5	48.06	H-40 - ST&C	Surface	to	140.0
Intermed Csg (if run)	177.8	34.23 & 29.76	J-55 - LT&C	Surface	to	950.0
Production Liner	114.3	17.26	L-80	Surf or from Intermed Csg to		2400.0
Tubing	60.3 or 73.0 - TK-99	6.99 or 9.67	J-55	Surface	to	940.0

Date of Tubing Installation:			Length	Top @
Item	Description	K.B.--Tbg. Flg.	0.00	m KB
	Corrosion Protected ENC Coated Packer (set inside 114.3 mm Casing / Liner)			
	60.3 mm or 73 mm TK-99 Internally Coated Tubing			
	TK-99 Internally Coated Tubing Pup Jt			
	Coated Split Dognut			
	Annular space above injection packer filled with inhibited fresh water			
	Bottom of Tubing mKB			

Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions: