PROPOSED NORTH EBOR UNIT NO. 3

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (01 62A)

Daly, Manitoba

February 28, 2021
Tundra Oil and Gas Limited

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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, Bakken reservoirs have been developed with horizontal and vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells on 20 acre spacing have been drilled by Tundra Oil and Gas Limited (Tundra) in parts of the Daly field.

Within the area, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. ***The following represents an application by Tundra Oil and Gas Limited (Tundra) to rescind the current North Ebor Unit No. 1 and North Ebor Unit No. 2 boundaries and waterflood orders and establish North Ebor Unit No. 3 (N/2 Sec 10, N/2 Sec 11, N/2 Sec 13, Sec 14, LSDs 1-12, 15-16 Sec 15, SE/4 Sec 22, Sec 23, LSDs 1-6, 11-14 Sec 24-010-29W1)*** and implement a Secondary Waterflood EOR scheme within the Three Forks and Middle Bakken formations as outlined on Figure 2.

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

CONCLUSIONS

1. The proposed North Ebor Unit No. 3 will include 13 horizontal wells and 14 vertical wells within 84 Legal Subdivisions (LSD) of the Bakken producing reservoir. The project is located south of Daly Units 9, 11 & 19 (Figure 2).

2. Total Original Oil in Place (OOIP) in the project area has been calculated to be **3,251** e^3m^3 (20,447 Mbbl) for an average of 38.7 net e^3m^3 OOIP per 40 acre LSD based on a 0.5 md cutoff for the Middle Bakken & Lyleton 'B'.

3. Cumulative production to the end of November 2020 from the 27 wells within the proposed North Ebor Unit No. 3 project area was **161.6** e^3m^3 (1,016.4 Mbbl) of oil and **344.3** e^3m^3 (2,165.6 Mbbl) of water, representing an **5.0%** Recovery Factor (RF) of the calculated gross OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed North Ebor Unit No. 3 project area is estimated to be **291.9** e^3m^3 (1,835.9 Mbbl), with **130.3** e^3m^3 (819.5 Mbbl) remaining as of the end of November 2020.

5. Ultimate oil recovery of the proposed North Ebor Unit No. 3 gross OOIP, under the current Primary production method, is forecasted to be **8.9%**.

6. Figure 4 shows the production from the North Ebor Unit No. 3 area peaked during March 2013 at 87.6 m^3 of oil per day (OPD). As of November 2020, production was 11.0 m^3 OPD, 52.3 m^3 of water per day (WPD) and an 82.6% watercut (WCUT).

7. In March 2013, production averaged 5.47 m^3 OPD per well in North Ebor Unit No. 3. As of November 2020, average per well production has declined to 0.85 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **16%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed North Ebor Unit No. 3 has been estimated to be **466.6** e^3m^3. An incremental **174.8** e^3m^3 of proved oil reserves are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

9. Total RF under Secondary WF in the proposed North Ebor Unit No. 3 is estimated to be **14.3%**.

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

11. Primary 400m development will be completed with cemented liner, multi-stage hydraulically fractured, horizontal producing wells. Future horizontal openhole produce first injectors, with multi-stage hydraulic fractures, will be drilled between existing horizontal producing wells within the proposed North Ebor Unit No. 3, to complete waterflood patterns with effective 200m horizontal to horizontal spacing (Figure 5).

DISCUSSION

The proposed North Ebor Unit No. 3 project area is located in Township 10 Range 29 W1 of the Daly Sinclair Oil Field (Figure 1). The proposed North Ebor Unit No. 3 currently consists of 13 horizontal wells and 14 vertical wells within an area covering 84 LSDs (Figure 2). A project area well list with recent production statistics is attached as Table 3.

Within the proposed Unit, potential exists for incremental production and reserves from a Waterflood EOR project in the Bakken and/or Three Forks oil reservoirs.

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross-section attached as Appendix 2. The section runs south to north through the proposed Unit area. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton B Siltstone and the Torquay Silty Shale. The reservoir units are represented by the Middle Bakken and Lyleton B Siltstones. The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken and Lyleton reservoirs. The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved adjacent to the proposed unit (Daly Unit 11, Daly Unit 9, Daly Unit 19 and Pending Daly Unit 21) as noted on the Offsetting Units Map at Appendix 1.

Sedimentology:

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

The Lyleton B reservoir consists of buff to tan fine grained siltstone (occasionally very fine siltstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. The Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones are interbedded with dark grey-green or red very fine grained siltstone which is generally non-reservoir. The Reservoir package, consisting of Middle Bakken and Lyleton B, isopach ranges between 6.1m to 8.2m thick within the proposed unit (Appendix 4).

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

Structure:

The structure within the proposed unit area is consistent with the regional SW dip (Appendix 3). The total structural drop over the unit area is roughly 35m. This structural change is not expected to negatively impact flood efficiency or interrupt the lateral continuity of the reservoir beds (see cross-section Appendix 1).

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood. As demonstrated by the cross section and the isopach maps, all reservoir formations, the Middle Bakken, and Lyleton B, are continuous throughout the proposed unit area. Vertical continuity between the reservoir formations is also unbroken within the unit area.

Fluid Contacts:

There is no oil/water contacts proximal to the proposed unit area.

Gross OOIP Estimates

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **3,251** e^3m^3 (20,447 Mbbl) using Tundra internally created maps. Maps used were generated from core data from wells available in the greater Sinclair area (Appendix 5).

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

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

OOIP values were calculated using the following volumetric equation:

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

or

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

or

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

where

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

The initial oil formation volume factor was adopted from PVT information taken from the 100/02-17-009-29W1 and 100/13-19-009-28W1 Bakken wells and is thought to be representative of the fluid characteristics in the reservoir.

Historical Production

A historical group production history plot for the proposed North Ebor Unit No. 3 is shown as Figure 4. Oil production commenced from the proposed Unit area in June 1986 and peaked during March 2013 at 87.6 m^3 OPD. As of November 2020, production was 11.0 m^3 OPD, 52.3 m^3 WPD and an 82.6% WCT.

Oil production is currently declining at an average annual rate of approximately **16%** under the current Primary Production method.

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

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area to **14.3%**. 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 shall be North Ebor Unit No. 3.

Unit Operator

Tundra Oil and Gas Limited (Tundra) will be the Operator of record for North Ebor Unit No. 3.

Unitized Zone

The unitized zone(s) to be waterflooded in North Ebor Unit No. 3 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 13 horizontal producing wells and 14 vertical producing wells to be included in the proposed North Ebor Unit No. 3 are outlined in Table 3.

Unit Lands

The North Ebor Unit No. 3 will consist of 84 LSDs as follows:

N/2 Section 10 of Township 10, Range 29, W1M
N/2 Section 11 of Township 10, Range 29, W1M
N/2 Section 13 of Township 10, Range 29, W1M
Section 14 of Township 10, Range 29, W1M
LSDs 1-12, 15-16 Section 15 of Township 10, Range 29, W1M
SE/4 Section 22 of Township 10, Range 29, W1M
Section 23 of Township 10, Range 29, W1M
LSDs 1-6, 11-14 Section 24 of Township 10, Range 29, W1M

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

Tract Factors

The proposed North Ebor Unit No. 3 will consist of 84 Tracts, based on the 40 acre Legal Sub Divisions (LSD) containing the existing 13 horizontal wells and 14 vertical wells.

The Tract Factor contribution for each of the LSD's within the proposed North Ebor Unit No. 3 was calculated as follows:

- Gross OOIP by LSD, minus cumulative production to date for the LSD as distributed by the LSD specific Production Allocation (PA) % in the applicable producing horizontal or vertical well (to yield Remaining Gross OOIP)
- Last twelve (12) months production to date for the LSD as distributed by the LSD specific PA % in the applicable producing horizontal or vertical well.
- Tract Factor by LSD = Fifty percent (50%) of the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP, and fifty percent (50%) of the product of the Last 12 Months Production as a % of total proposed Unit Last 12 Months Production.

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

Working Interest Owners

Table 1 outlines the working interest % (WI) for each recommended Tract within the proposed North Ebor Unit No. 3. Tundra Oil and Gas Limited holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Limited will have a 100% working interest in the proposed North Ebor Unit No. 3.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed North Ebor Unit No. 3 are based on internal engineering assessments. Project area specific reservoir and geological parameters were used to guide the overall Secondary Waterflood recovery factor. Internal reviews included analysis of available open-hole logs, core data, petrophysics, seismic, drilling and completion information, and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed North Ebor Unit No. 3 OOIP (Table 4).

Pre-Production of New Horizontal Injection Wells

It is likely that future horizontal injection wells will be drilled between the existing horizontal producing wells, as shown in Figure 5, completing an effective 20 acre horizontal to horizontal line drive waterflood pattern within North Ebor Unit No. 3.

Primary production from the existing horizontal producing wells in the proposed North Ebor Unit No. 3 has declined significantly from peak rate indicating a need for secondary pressure support. Through the process of developing similar waterfloods, Tundra has measured a significant variation in reservoir pressure depletion by the existing primary producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations and has a negative impact on the ultimate total recovery factor of OOIP.

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

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

Reserves Recovery Profiles and Production Forecasts

The primary performance predictions for the proposed North Ebor Unit No. 3 are based on oil production decline curve analysis, and the secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

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

Primary Production Forecast

Cumulative production to the end of November 2020 from the 13 horizontal wells and 14 vertical wells within the proposed North Ebor Unit No. 3 project area was **161.6** e^3m^3 of oil, and **344.3** e^3m^3 of water, representing an **5.0%** Recovery Factor (RF) of the calculated Net OOIP.

Based on decline analysis of the wells currently on production, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be **291.9** e^3m^3, with **130.3** e^3m^3 remaining as of the end November 2020. This represents a recovery factor of **8.9%** of the total OOIP.

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

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

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

Criteria for Conversion to Water Injection Well

17 water injection wells are required for the proposed North Ebor Unit No. 3 as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for converting from primary production to water injection service.

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

The above schedule allows for the proposed North Ebor Unit No. 3 project to be developed equitably, efficiently, and moves the project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 8 and 9, respectively. Total Secondary EUR for the proposed North Ebor Unit No. 3 is estimated to be **466.6** e^3m^3 with **305.0** e^3m^3 remaining representing a total secondary recovery factor of **14.3%** for the proposed Unit area. An incremental **174.8** e^3m^3 of oil, or an incremental **5.4%** recovery factor, are forecasted to be recovered under the proposed Unitization.

WATERFLOOD OPERATING STRATEGY

Water Source

Injection water for the proposed North Ebor Unit No. 3 will be supplied from the Jurassic source water well at 100/02-25-010-29W1 (2-25). Tundra received approval from the Petroleum Branch in March 2013 to use the 2-25 well as a source water well for waterflood operations. Jurassic-sourced water will be pumped from the 2-25 source well to the Daly 12-24-10-29 battery, where it will be filtered and then pumped up to injection system pressure. A diagram of the Daly 12-24 water injection system and new pipeline connection to the project area injection wells is shown as Figure 10.

Produced water is not currently used for any water injection in the Tundra operated Daly Units and there are no current plans to use produced water as a source supply for North Ebor Unit No. 3. Tundra does not foresee any compatibility issues between the produced and injection waters based on previous compatibility testing performed by a third party, Baker Hughes.

Injection Wells

The water injection wells for the proposed North Ebor Unit No. 3 will be producing wells configured downhole for injection as shown in Figure 11. The horizontal injection wells have been stimulated by multiple hydraulic fracture treatments to obtain suitable injection. Tundra has extensive experience with horizontal fracturing in the area, and all jobs are rigorously programmed and monitored during execution. This helps ensure optimum placement of each fracture stage to prevent, or minimize, the potential for out-of-zone fracture growth and thereby limit the potential for future out-of-zone injection.

The water injection well(s) will be placed on injection after approval to inject. Wellhead injection pressures will be maintained below the least value of either:

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

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

All new water injection wells will be surface equipped with injection volume metering and rate/pressure programmable logic control (PLC). An operating procedure for monitoring water injection volumes and meter balancing will also be utilized to monitor the entire system measurement and integrity on a daily basis. The proposed North Ebor Unit No. 3 horizontal water injection well rate is forecasted to average 10 – 30 m^3 WPD, based on expected reservoir permeability and pressure.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate an actual fracture pressure gradient range of 16 to 18 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be lower than these values due to expected reservoir pressure depletion. North Ebor Unit No. 1 and North Ebor Unit No. 2

Waterfloods were approved for a maximum wellhead injection pressure of 7.0 MPa at which water may be injected.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed North Ebor Unit No. 3 project area in the Bakken. 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. Based on a normally pressured reservoir, it is believed the initial reservoir pressure in this area was on average 8,400 kPa.

Reservoir Pressure Management During Waterflood

Tundra expects to inject water for a minimum 2 – 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 1.75 within the pattern during the fill up period. As the cumulative VRR approaches 1, target reservoir operating pressure for waterflood operations will be 75 – 90 % of original reservoir pressure.

Waterflood Surveillance and Optimization

North Ebor Unit No. 3 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 increased understanding of reservoir performance and provide data to continually control and optimize the North Ebor Unit No. 3 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 North Ebor Unit No. 3.

Economic Justification

Under the current Primary recovery method, existing wells within the proposed North Ebor Unit No. 3 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 North Ebor Unit No. 3 waterflood operation will utilize the Tundra operated well 100/02-25-10-29W1, sourced from the Jurassic, and water plant (WP) facilities located at the Daly 12-24-10-29W1 battery (Figure 10).

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

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra will notify all mineral rights and surface rights owners of the proposed EOR project and formation of North Ebor Unit No. 3. 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 North Ebor Unit No. 3 Application.

North Ebor Unit No. 3 Unitization, and execution of the formal North Ebor Unit No. 3 Agreement by affected Mineral Owners, is expected during Q2 2021. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the North Ebor Unit No. 3 Application.

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

TUNDRA OIL & GAS LIMITED

Original Signed by Lindsey Snyder, P.Eng., February 28, 2021

Proposed North Ebor Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

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TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR NORTH EBOR UNIT NO. 3

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) - CUMULATIVE PRODUCTION TO NOV 2020

LS-SE	Tract	OOIP (m3)	HZ Wells Alloc Prod (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	OOIP - Cum Tract Factor	Last 12 Mth Alloc Hz Prod	Last 12 Mth Vert Prod	% of Last 12 Mth Prod	50% of OOIP - Cum TF + 50% Last 12 Mth Prodn TF	Tract
09-10	09-10-10-29W1	40,768	1,261.4	0.0	1,261.4	39,506	1.278332393%	37.0	0.0	0.833630485%	1.055981439%	09-10-10-29W1
10-10	10-10-10-29W1	40,602	1,320.9	0.0	1,320.9	39,281	1.271061240%	38.7	0.0	0.872974629%	1.072017935%	10-10-10-29W1
11-10	11-10-10-29W1	41,160	1,319.3	0.0	1,319.3	39,841	1.289153475%	38.7	0.0	0.871941241%	1.080547358%	11-10-10-29W1
12-10	12-10-10-29W1	41,707	1,214.9	0.0	1,214.9	40,492	1.310236350%	35.6	0.0	0.802958210%	1.056597280%	12-10-10-29W1
13-10	13-10-10-29W1	41,106	0.0	0.0	0.0	41,106	1.330099893%	0.0	0.0	0.000000000%	0.665049947%	13-10-10-29W1
14-10	14-10-10-29W1	40,560	0.0	0.0	0.0	40,560	1.312416298%	0.0	0.0	0.000000000%	0.656208149%	14-10-10-29W1
15-10	15-10-10-29W1	39,968	0.0	0.0	0.0	39,968	1.293285974%	0.0	0.0	0.000000000%	0.646642987%	15-10-10-29W1
16-10	16-10-10-29W1	39,582	0.0	0.0	0.0	39,582	1.280772265%	0.0	0.0	0.000000000%	0.640386133%	16-10-10-29W1
09-11	09-11-10-29W1	33,531	241.2	0.0	241.2	33,290	1.077180690%	31.8	0.0	0.717454303%	0.897317496%	09-11-10-29W1
10-11	10-11-10-29W1	35,841	421.2	0.0	421.2	35,420	1.146106428%	55.5	0.0	1.252795224%	1.199450826%	10-11-10-29W1
11-11	11-11-10-29W1	41,004	429.7	0.0	429.7	40,574	1.312892662%	56.7	0.0	1.278170277%	1.295531469%	11-11-10-29W1
12-11	12-11-10-29W1	41,088	411.8	0.0	411.8	40,676	1.316197764%	54.3	0.0	1.224911452%	1.270554608%	12-11-10-29W1
13-11	13-11-10-29W1	39,647	0.0	0.0	0.0	39,647	1.282887249%	0.0	0.0	0.000000000%	0.641443625%	13-11-10-29W1
14-11	14-11-10-29W1	38,452	0.0	0.0	0.0	38,452	1.244205563%	0.0	0.0	0.000000000%	0.622102782%	14-11-10-29W1
15-11	15-11-10-29W1	35,255	0.0	2211.2	2,211.2	33,044	1.069226197%	0.0	0.0	0.000000000%	0.534613099%	15-11-10-29W1
16-11	16-11-10-29W1	35,651	0.0	5672.4	5,672.4	29,978	0.970030436%	0.0	0	0.000000000%	0.485015218%	16-11-10-29W1
09-13	09-13-10-29W1	37,837	0.0	0.0	0.0	37,837	1.224306042%	0.0	0.0	0.000000000%	0.612153021%	09-13-10-29W1
10-13	10-13-10-29W1	38,400	0.0	0.0	0.0	38,400	1.242545434%	0.0	0.0	0.000000000%	0.621272717%	10-13-10-29W1
11-13	11-13-10-29W1	38,932	0.0	0.0	0.0	38,932	1.259759496%	0.0	0.0	0.000000000%	0.629879748%	11-13-10-29W1
12-13	12-13-10-29W1	38,403	0.0	7966.5	7,966.5	30,436	0.984841553%	0.0	0.0	0.000000000%	0.492420777%	12-13-10-29W1
13-13	13-13-10-29W1	39,004	0.0	2962.3	2,962.3	36,042	1.166227134%	0.0	0.0	0.000000000%	0.583113567%	13-13-10-29W1
14-13	14-13-10-29W1	39,534	0.0	0.0	0.0	39,534	1.279235189%	0.0	0.0	0.000000000%	0.639617595%	14-13-10-29W1
15-13	15-13-10-29W1	39,527	0.0	0.0	0.0	39,527	1.278991393%	0.0	0.0	0.000000000%	0.639495697%	15-13-10-29W1
16-13	16-13-10-29W1	38,962	0.0	0.0	0.0	38,962	1.260728759%	0.0	0.0	0.000000000%	0.630364380%	16-13-10-29W1
01-14	01-14-10-29W1	34,089	0.0	2386.9	2,386.9	31,703	1.025822109%	0.0	0.0	0.000000000%	0.512911055%	01-14-10-29W1
02-14	02-14-10-29W1	34,553	0.0	0.0	0.0	34,553	1.118042598%	0.0	0.0	0.000000000%	0.559021299%	02-14-10-29W1
03-14	03-14-10-29W1	36,441	0.0	0.0	0.0	36,441	1.179146287%	0.0	0.0	0.000000000%	0.589573143%	03-14-10-29W1
04-14	04-14-10-29W1	37,539	0.0	0.0	0.0	37,539	1.214680144%	0.0	0.0	0.000000000%	0.607340072%	04-14-10-29W1
05-14	05-14-10-29W1	36,265	0.0	0.0	0.0	36,265	1.173457419%	0.0	0.0	0.000000000%	0.586728710%	05-14-10-29W1
06-14	06-14-10-29W1	35,172	0.0	0.0	0.0	35,172	1.138084874%	0.0	0.0	0.000000000%	0.569042437%	06-14-10-29W1
07-14	07-14-10-29W1	34,082	0.0	1417.6	1,417.6	32,665	1.056952324%	0.0	0.0	0.000000000%	0.528476162%	07-14-10-29W1
08-14	08-14-10-29W1	36,870	0.0	2080.2	2,080.2	34,790	1.125715338%	0.0	0.0	0.000000000%	0.562857669%	08-14-10-29W1
09-14	09-14-10-29W1	37,509	0.0	5866.6	5,866.6	31,642	1.023862133%	0.0	0.0	0.000000000%	0.511931067%	09-14-10-29W1
10-14	10-14-10-29W1	38,008	0.0	6434.1	6,434.1	31,574	1.021656348%	0.0	0.0	0.000000000%	0.510828174%	10-14-10-29W1
11-14	11-14-10-29W1	35,613	0.0	0.0	0.0	35,613	1.152350435%	0.0	0.0	0.000000000%	0.576175218%	11-14-10-29W1
12-14	12-14-10-29W1	35,023	0.0	0.0	0.0	35,023	1.133261216%	0.0	0.0	0.000000000%	0.566630608%	12-14-10-29W1
13-14	13-14-10-29W1	34,313	2,348.8	0.0	2,348.8	31,964	1.034290524%	86.2	0.0	1.944821933%	1.489556228%	13-14-10-29W1
14-14	14-14-10-29W1	34,354	2,033.3	0.0	2,033.3	32,321	1.045840353%	74.6	0.0	1.683566303%	1.364703328%	14-14-10-29W1
15-14	15-14-10-29W1	35,909	0.0	5529.4	5,529.4	30,380	0.983012966%	0.0	0.0	0.000000000%	0.491506483%	15-14-10-29W1
16-14	16-14-10-29W1	40,853	0.0	2888.1	2,888.1	37,965	1.228461171%	0.0	0.0	0.000000000%	0.614230585%	16-14-10-29W1
01-15	01-15-10-29W1	38,094	0.0	0.0	0.0	38,094	1.232632674%	0.0	0.0	0.000000000%	0.616316337%	01-15-10-29W1
02-15	02-15-10-29W1	38,748	0.0	0.0	0.0	38,748	1.253803220%	0.0	0.0	0.000000000%	0.626901610%	02-15-10-29W1
03-15	03-15-10-29W1	39,995	0.0	0.0	0.0	39,995	1.294161068%	0.0	0.0	0.000000000%	0.647080534%	03-15-10-29W1
04-15	04-15-10-29W1	41,042	0.0	0.0	0.0	41,042	1.328016333%	0.0	0.0	0.000000000%	0.664008167%	04-15-10-29W1
05-15	05-15-10-29W1	39,940	1,356.7	0.0	1,356.7	38,583	1.248469769%	15.6	0.0	0.352107340%	0.800288555%	05-15-10-29W1
06-15	06-15-10-29W1	38,892	1,612.9	0.0	1,612.9	37,280	1.206285578%	18.6	0.0	0.418584697%	0.812435138%	06-15-10-29W1
07-15	07-15-10-29W1	37,682	1,613.5	0.0	1,613.5	36,069	1.167110292%	18.6	0.0	0.418743734%	0.792927013%	07-15-10-29W1
08-15	08-15-10-29W1	36,486	1,544.8	0.0	1,544.8	34,942	1.130629707%	17.8	0.0	0.400931619%	0.765780663%	08-15-10-29W1
09-15	09-15-10-29W1	35,385	1,166.6	0.0	1,166.6	34,219	1.107239177%	323.8	0.0	7.304238362%	4.205738769%	09-15-10-29W1
10-15	10-15-10-29W1	37,592	1,253.5	0.0	1,253.5	36,338	1.175825582%	347.9	0.0	7.848399285%	4.512112434%	10-15-10-29W1

LS-SE	Tract	OOIP (m3)	HZ Wells Alloc Prod (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	OOIP - Cum Tract Factor	Last 12 Mth Alloc Hz Prod	Last 12 Mth Vert Prod	% of Last 12 Mth Prod	50% of OOIP - Cum TF + 50% Last 12 Mth Prodn TF	Tract
11-15	11-15-10-29W1	38,218	1,252.1	0.0	1,252.1	36,966	1.196129092%	347.5	0.0	7.839489885%	4.517809488%	11-15-10-29W1
12-15	12-15-10-29W1	39,340	732.4	0.0	732.4	38,608	1.249266239%	203.3	0.0	4.585519774%	2.917393006%	12-15-10-29W1
15-15	15-15-10-29W1	35,982	2,085.3	0.0	2,085.3	33,897	1.096825407%	76.5	0.0	1.726622399%	1.411723903%	15-15-10-29W1
16-15	16-15-10-29W1	34,320	2,346.1	0.0	2,346.1	31,974	1.034604169%	86.1	0.0	1.942632640%	1.488618405%	16-15-10-29W1
01-22	01-22-10-29W1	34,475	1,329.4	515.3	1,844.7	32,630	1.055846253%	85.3	0.0	1.923426313%	1.489636283%	01-22-10-29W1
02-22	02-22-10-29W1	37,208	1,158.7	0.0	1,158.7	36,049	1.166474823%	74.3	0.0	1.676405572%	1.421440197%	02-22-10-29W1
07-22	07-22-10-29W1	41,032	1,553.8	0.0	1,553.8	39,478	1.277435664%	113.8	0.0	2.567405793%	1.922420729%	07-22-10-29W1
08-22	08-22-10-29W1	37,753	1,773.6	0.0	1,773.6	35,979	1.164208958%	129.9	0.0	2.930658738%	2.047433848%	08-22-10-29W1
01-23	01-23-10-29W1	41,482	0.0	16263.3	16,263.3	25,219	0.816020661%	0.0	41.0	0.924894511%	0.870457586%	01-23-10-29W1
02-23	02-23-10-29W1	35,479	0.0	9736.6	9,736.6	25,742	0.832952008%	0.0	55.9	1.261014711%	1.046983359%	02-23-10-29W1
03-23	03-23-10-29W1	33,844	1,136.2	0.0	1,136.2	32,708	1.058357102%	72.9	0.0	1.643951260%	1.351154181%	03-23-10-29W1
04-23	04-23-10-29W1	33,846	1,326.0	0.0	1,326.0	32,520	1.052263281%	85.0	0.0	1.918509714%	1.485386498%	04-23-10-29W1
05-23	05-23-10-29W1	36,073	1,770.3	0.0	1,770.3	34,302	1.109950634%	129.7	0.0	2.925149633%	2.017550134%	05-23-10-29W1
06-23	06-23-10-29W1	36,071	925.7	0.0	925.7	35,146	1.137229809%	67.8	0.0	1.529553108%	1.333391459%	06-23-10-29W1
07-23	07-23-10-29W1	37,161	2,103.5	0.0	2,103.5	35,057	1.134375201%	32.4	0.0	0.730905712%	0.932640456%	07-23-10-29W1
08-23	08-23-10-29W1	43,718	2,430.0	0.0	2,430.0	41,288	1.335988047%	37.4	0.0	0.844331548%	1.090159798%	08-23-10-29W1
09-23	09-23-10-29W1	42,678	2,363.2	0.0	2,363.2	40,315	1.304492117%	39.3	0.0	0.886041522%	1.095266820%	09-23-10-29W1
10-23	10-23-10-29W1	39,944	2,485.6	0.0	2,485.6	37,458	1.212064540%	41.3	0.0	0.931919123%	1.071991831%	10-23-10-29W1
11-23	11-23-10-29W1	39,400	2,483.6	0.0	2,483.6	36,916	1.194530487%	41.3	0.0	0.931158628%	1.062844557%	11-23-10-29W1
12-23	12-23-10-29W1	39,948	1,458.0	0.0	1,458.0	38,489	1.245433744%	24.2	0.0	0.546663361%	0.896048552%	12-23-10-29W1
13-23	13-23-10-29W1	42,735	2,060.3	0.0	2,060.3	40,675	1.316137564%	77.0	0.0	1.736162163%	1.526149864%	13-23-10-29W1
14-23	14-23-10-29W1	42,187	3,693.0	0.0	3,693.0	38,493	1.245563124%	138.0	0.0	3.112070299%	2.178816711%	14-23-10-29W1
15-23	15-23-10-29W1	42,183	3,667.3	0.0	3,667.3	38,516	1.246298091%	137.0	0.0	3.090368205%	2.168333148%	15-23-10-29W1
16-23	16-23-10-29W1	42,182	3,434.2	0.0	3,434.2	38,747	1.253780003%	128.3	0.0	2.893944310%	2.073862157%	16-23-10-29W1
01-24	01-24-10-29W1	40,051	1,589.4	0.0	1,589.4	38,462	1.244538834%	98.9	0.0	2.230796499%	1.737667666%	01-24-10-29W1
02-24	02-24-10-29W1	41,168	1,665.5	0.0	1,665.5	39,502	1.278201891%	103.6	0.0	2.337636773%	1.807919332%	02-24-10-29W1
03-24	03-24-10-29W1	42,830	1,663.6	0.0	1,663.6	41,167	1.332061628%	103.5	0.0	2.334833954%	1.833447791%	03-24-10-29W1
04-24	04-24-10-29W1	44,494	1,472.0	0.0	1,472.0	43,022	1.392108418%	91.6	0.0	2.065953690%	1.729031054%	04-24-10-29W1
05-24	05-24-10-29W1	45,002	2,439.9	0.0	2,439.9	42,563	1.377229671%	37.6	0.0	0.847780286%	1.112504979%	05-24-10-29W1
06-24	06-24-10-29W1	43,888	2,083.3	0.0	2,083.3	41,805	1.352713782%	32.1	0.0	0.723879631%	1.038296707%	06-24-10-29W1
11-24	11-24-10-29W1	43,422	3,614.4	0.0	3,614.4	39,807	1.288078789%	174.6	0.0	3.938523147%	2.613300968%	11-24-10-29W1
12-24	12-24-10-29W1	43,361	3,765.8	0.0	3,765.8	39,595	1.281212837%	181.9	0.0	4.103547417%	2.692380127%	12-24-10-29W1
13-24	13-24-10-29W1	41,676	3,179.7	0.0	3,179.7	38,496	1.245648323%	39.3	0.0	0.885425493%	1.065536908%	13-24-10-29W1
14-24	14-24-10-29W1	41,185	4,333.1	0.0	4,333.1	36,852	1.192449292%	53.5	0.0	1.206595092%	1.199522192%	14-24-10-29W1
		3,251,305	**88,925.6**	**71,930.5**	**160,856.1**	**3,090,449**	**100.000000000%**	**4,336**	**97**	**100.000000000%**	**100.000000000%**	

Table No. 3: Proposed North Ebor Unit No. 3 Well List and Status

UWI	*License Number*	*Type*	*Pool Name*	*Producing Zone*	*Mode*	*On Production Date*	*Prod Date*	*Cal Dly Oil (m3/d)*	*Monthly Oil (m3)*	*Cum Prd Oil (m3)*	*Cal Dly Water (m3/d)*	*Monthly Water (m3)*	*Cum Prd Water (m3)*	*WCT (%)*
100/09-10-010-29W1/0	007725	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/18/2011	Nov-2020	0.76	22.80	5116.50	6.49	194.80	28467.90	89.52
100/12-11-010-29W1/0	010798	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	10/31/2017	Feb-2020	2.63	76.30	1504.00	47.34	1372.80	36275.00	94.73
100/15-11-010-29W1/0	003909	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	12/27/1986	May-1996	0.33	10.20	2211.20	1.54	47.60	5901.00	82.35
100/16-11-010-29W1/2	003770	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	12/4/1989	Aug-2019	0.20	6.10	5672.40	0.48	14.80	12730.50	70.81
100/12-13-010-29W1/0	004060	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/21/1988	Dec-2017	0.17	5.40	7966.50	0.52	16.10	12865.10	74.88
100/13-13-010-29W1/0	004106	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/28/1989	Aug-2009	0.00	0.00	2962.30	0.03	0.80	3802.10	100.00
100/01-14-010-29W1/0	004222	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Injection	9/28/1990	Apr-1994	0.00	0.00	2386.90	0.00	0.00	479.70	0.00
100/07-14-010-29W1/0	003912	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/18/1987	May-1996	0.41	12.70	1417.60	0.15	4.50	729.10	26.16
100/08-14-010-29W1/0	004108	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Injection	3/25/1989	Sep-1991	0.00	0.00	2080.20	0.00	0.00	360.40	0.00
100/09-14-010-29W1/0	004035	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/18/1988	Jan-1994	0.00	0.00	5866.60	0.00	0.00	1462.70	0.00
102/10-14-010-29W1/0	004260	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/31/1991	Feb-2018	0.08	2.10	6434.10	0.65	18.10	12523.70	89.60
100/15-14-010-29W1/0	004036	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	2/24/1988	Mar-1998	0.25	7.70	5529.40	1.26	39.10	4330.40	83.55
100/16-14-010-29W1/0	003927	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Injection	6/30/1987	Jun-1990	0.00	0.00	2888.10	0.00	0.00	318.20	0.00
100/08-15-010-29W1/0	007014	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	8/31/2009	Nov-2020	0.28	8.40	6127.90	2.84	85.20	9875.00	91.03
100/09-15-010-29W1/0	011085	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	12/21/2018	Nov-2020	3.34	100.20	4404.70	9.87	296.10	9503.20	74.72
100/15-15-010-29W1/0	007008	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	8/31/2009	Nov-2020	0.89	26.80	8813.40	1.28	38.30	15038.60	58.83
100/01-22-010-29W1/2	003675	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	5/22/1987	Feb-1990	0.11	3.00	515.30	0.14	4.00	373.50	57.14
100/02-22-010-29W1/0	009632	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	12/24/2013	Nov-2020	0.50	15.00	4950.30	2.01	60.40	14969.40	80.11
100/07-22-010-29W1/0	008508	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/29/2012	Nov-2020	0.73	22.00	6023.40	8.26	247.80	24836.20	91.85
100/01-23-010-29W1/0	003991	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Pumping	10/28/1987	Nov-2020	0.20	6.00	16263.30	0.85	25.40	8414.00	80.89
100/02-23-010-29W1/0	004113	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	6/30/1989	Nov-2020	0.20	6.00	9736.60	1.78	53.30	10513.40	89.88
100/09-23-010-29W1/0	009007	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	12/18/2012	Nov-2020	0.67	20.10	8790.40	5.83	175.00	25838.70	89.70
100/16-23-010-29W1/0	009018	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	1/13/2013	Nov-2020	0.69	20.80	12854.70	3.05	91.40	22015.80	81.46
100/01-24-010-29W1/0	009684	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/28/2014	Nov-2020	1.00	30.00	6390.50	2.54	76.30	17059.40	71.78
100/06-24-010-29W1/0	008487	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/29/2012	Nov-2020	0.62	18.60	9056.70	2.88	86.50	39359.00	82.30
100/11-24-010-29W1/0	009640	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	1/13/2014	Nov-2020	0.90	27.00	7380.20	1.71	51.30	12703.20	65.52
100/14-24-010-29W1/0	008953	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	1/31/2013	Nov-2020	0.23	6.80	8255.10	2.96	88.70	13557.70	92.88
							Total in Nov 2020	11.01		**161598.30**	52.35		**344302.90**	82.62

Table No. 4: Proposed North Ebor Unit No. 3 OOIP Calculation

UWI	Area (m2)	Reservoir Iso (m)	OOIP (m3)	OOIP (bbl)
9-10-10-29W1	162729	7.4	40768	256387
10-10-10-29W1	162070	7.4	40602	255348
11-10-10-29W1	162105	7.5	41160	258855
12-10-10-29W1	162099	7.6	41707	262296
13-10-10-29W1	161893	7.5	41106	258516
14-10-10-29W1	161899	7.4	40560	255079
15-10-10-29W1	161725	7.3	39968	251361
16-10-10-29W1	162384	7.2	39582	248929
9-11-10-29W1	159749	6.2	33531	210876
10-11-10-29W1	160406	6.6	35841	225404
11-11-10-29W1	163673	7.4	41004	257874
12-11-10-29W1	164009	7.4	41088	258404
13-11-10-29W1	164943	7.1	39647	249340
14-11-10-29W1	164607	6.9	38452	241822
15-11-10-29W1	160211	6.5	35255	221719
16-11-10-29W1	159554	6.6	35651	224207
9-13-10-29W1	161974	6.9	37837	237954
10-13-10-29W1	162039	7.0	38400	241499
11-13-10-29W1	161970	7.1	38932	244845
12-13-10-29W1	162048	7.0	38403	241513
13-13-10-29W1	162268	7.1	39004	245296
14-13-10-29W1	162189	7.2	39534	248630
15-13-10-29W1	162158	7.2	39527	248583
16-13-10-29W1	162094	7.1	38962	245033
1-14-10-29W1	159831	6.3	34089	214388
2-14-10-29W1	159471	6.4	34553	217301
3-14-10-29W1	163090	6.6	36441	229177
4-14-10-29W1	163064	6.8	37539	236083
5-14-10-29W1	162304	6.6	36265	228071
6-14-10-29W1	162330	6.4	35172	221196
7-14-10-29W1	159797	6.3	34082	214343
8-14-10-29W1	160157	6.8	36870	231875
9-14-10-29W1	160570	6.9	37509	235891
10-14-10-29W1	160383	7.0	38008	239031
11-14-10-29W1	161836	6.5	35613	223969
12-14-10-29W1	161642	6.4	35023	220259
13-14-10-29W1	160880	6.3	34313	215794
14-14-10-29W1	161074	6.3	34354	216055
15-14-10-29W1	160709	6.6	35909	225831
16-14-10-29W1	160896	7.5	40853	256925
1-15-10-29W1	160746	7.0	38094	239572
2-15-10-29W1	161204	7.1	38748	243687
3-15-10-29W1	161834	7.3	39995	251531
4-15-10-29W1	161639	7.5	41042	258111
5-15-10-29W1	161610	7.3	39940	251183
6-15-10-29W1	161804	7.1	38892	244595
7-15-10-29W1	161314	6.9	37682	236985
8-15-10-29W1	160857	6.7	36486	229463

N/G	0.380
Phi	0.14
Sw	0.3
Boi	1.1

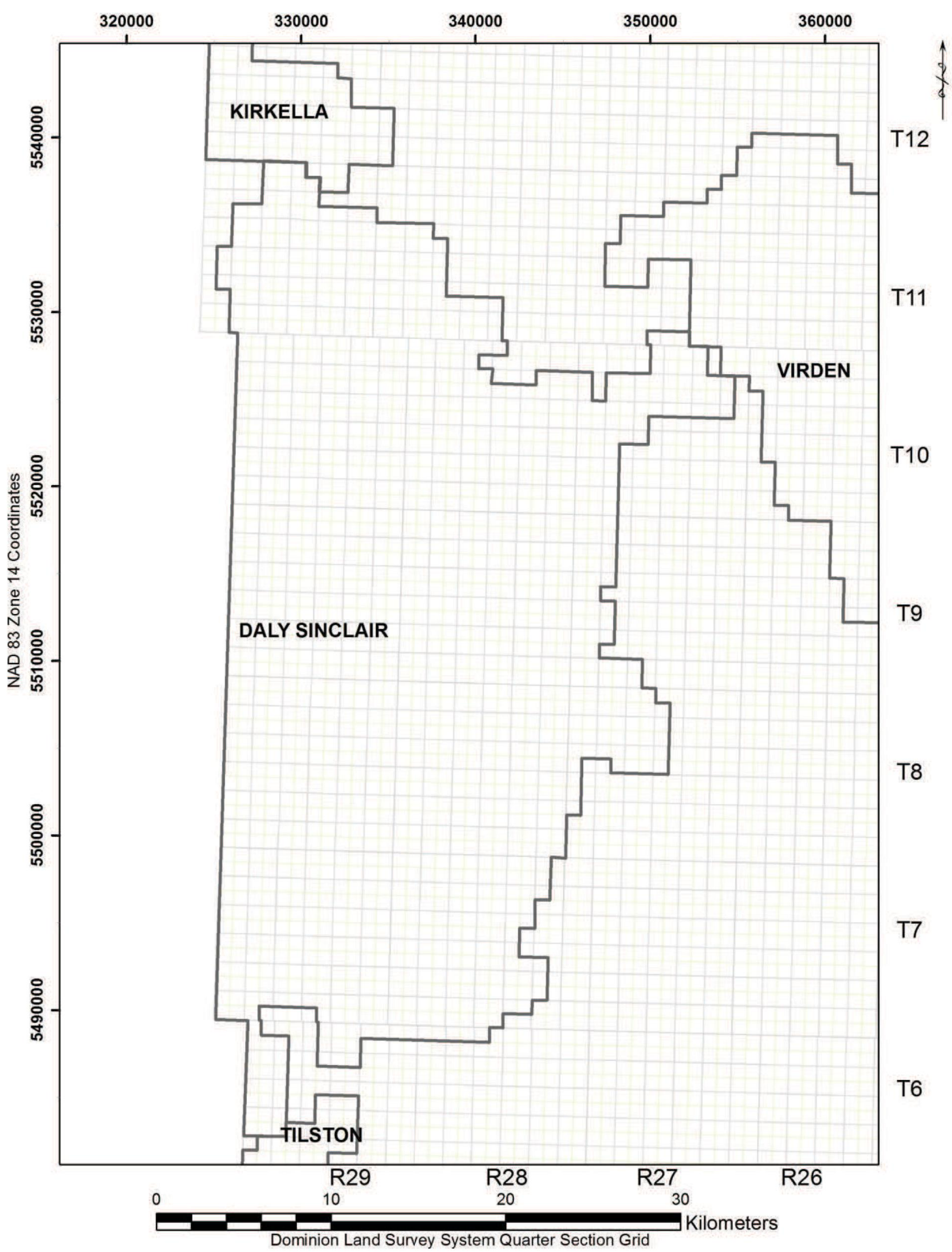
UWI	Area (m2)	Reservoir Iso (m)	OOIP (m3)	OOIP (bbl)
9-15-10-29W1	160802	6.5	35385	222538
10-15-10-29W1	160926	6.9	37592	236415
11-15-10-29W1	161269	7.0	38218	240352
12-15-10-29W1	161394	7.2	39340	247411
15-15-10-29W1	161037	6.6	35982	226291
16-15-10-29W1	160913	6.3	34320	215839
1-22-10-29W1	161640	6.3	34475	216814
2-22-10-29W1	161626	6.8	37208	234001
7-22-10-29W1	161602	7.5	41032	258052
8-22-10-29W1	161616	6.9	37753	237428
1-23-10-29W1	161224	7.6	41482	260880
2-23-10-29W1	161226	6.5	35479	223125
3-23-10-29W1	161241	6.2	33844	212846
4-23-10-29W1	161248	6.2	33846	212855
5-23-10-29W1	161443	6.6	36073	226862
6-23-10-29W1	161436	6.6	36071	226852
7-23-10-29W1	161421	6.8	37161	233704
8-23-10-29W1	161418	8.0	43718	274942
9-23-10-29W1	161619	7.8	42678	268401
10-23-10-29W1	161625	7.3	39944	251207
11-23-10-29W1	161639	7.2	39400	247786
12-23-10-29W1	161640	7.3	39948	251230
13-23-10-29W1	161834	7.8	42735	268759
14-23-10-29W1	161833	7.7	42187	265311
15-23-10-29W1	161821	7.7	42183	265292
16-23-10-29W1	161814	7.7	42182	265280
1-24-10-29W1	162060	7.3	40051	251882
2-24-10-29W1	162136	7.5	41168	258904
3-24-10-29W1	162196	7.8	42830	269359
4-24-10-29W1	162257	8.1	44494	279825
5-24-10-29W1	162108	8.2	45002	283021
6-24-10-29W1	162047	8.0	43888	276013
11-24-10-29W1	162354	7.9	43422	273080
12-24-10-29W1	162127	7.9	43361	272698
13-24-10-29W1	161977	7.6	41676	262100
14-24-10-29W1	162204	7.5	41185	259013
			3251305	20447455

Proposed North Ebor Unit 3

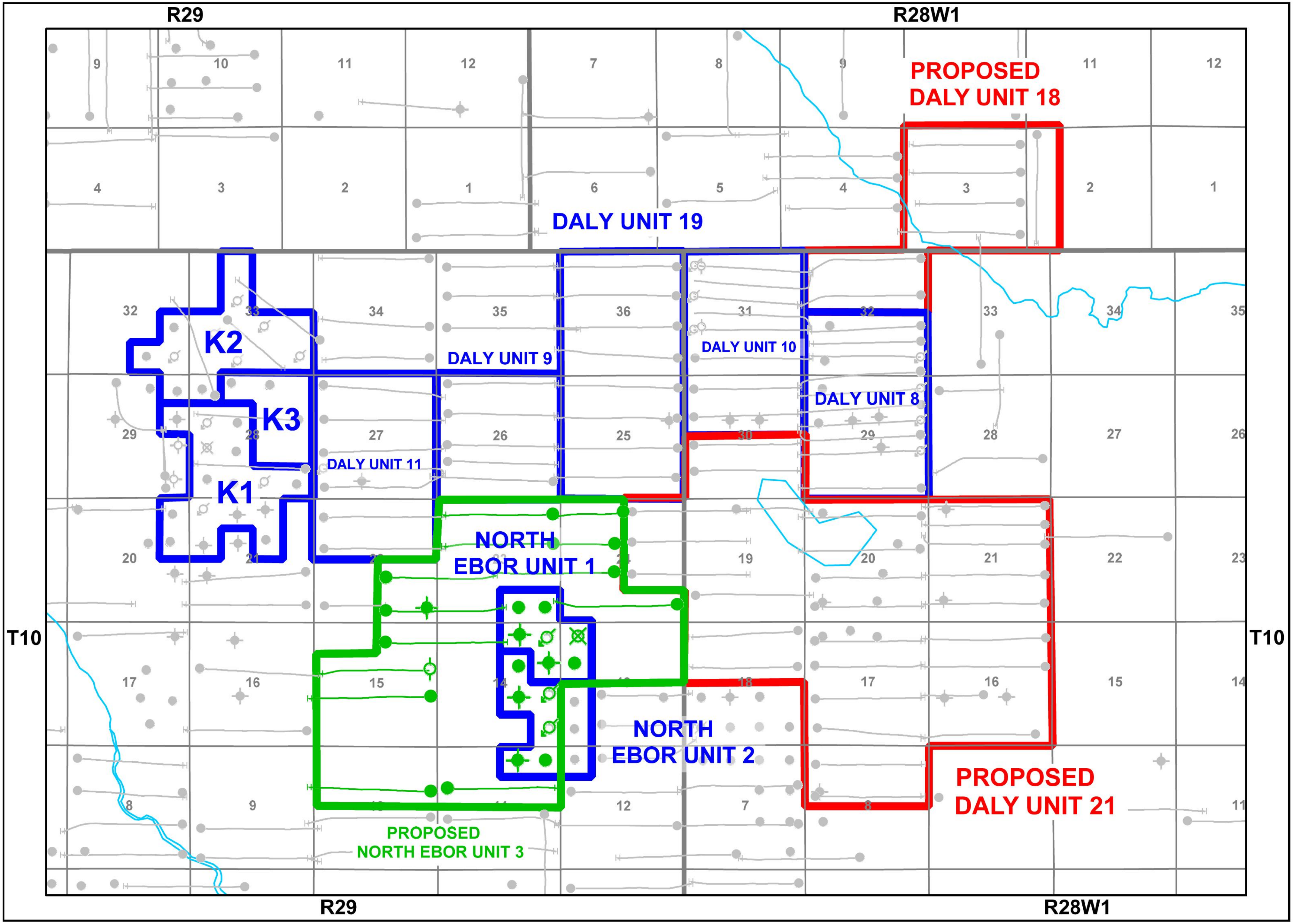
Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1

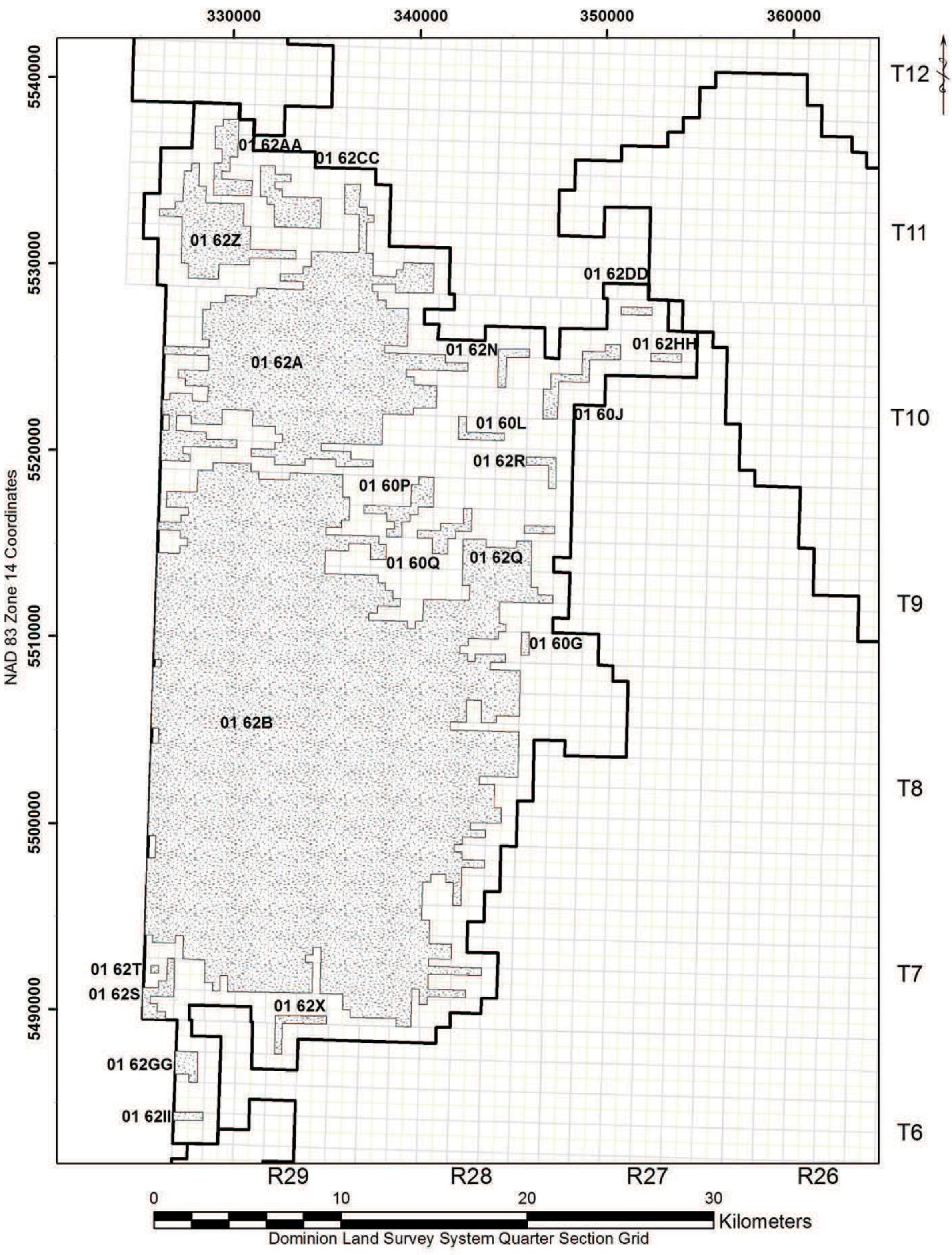


Daly Sinclair Field (01)



SINCLAIR UNITS

Figure No. 3



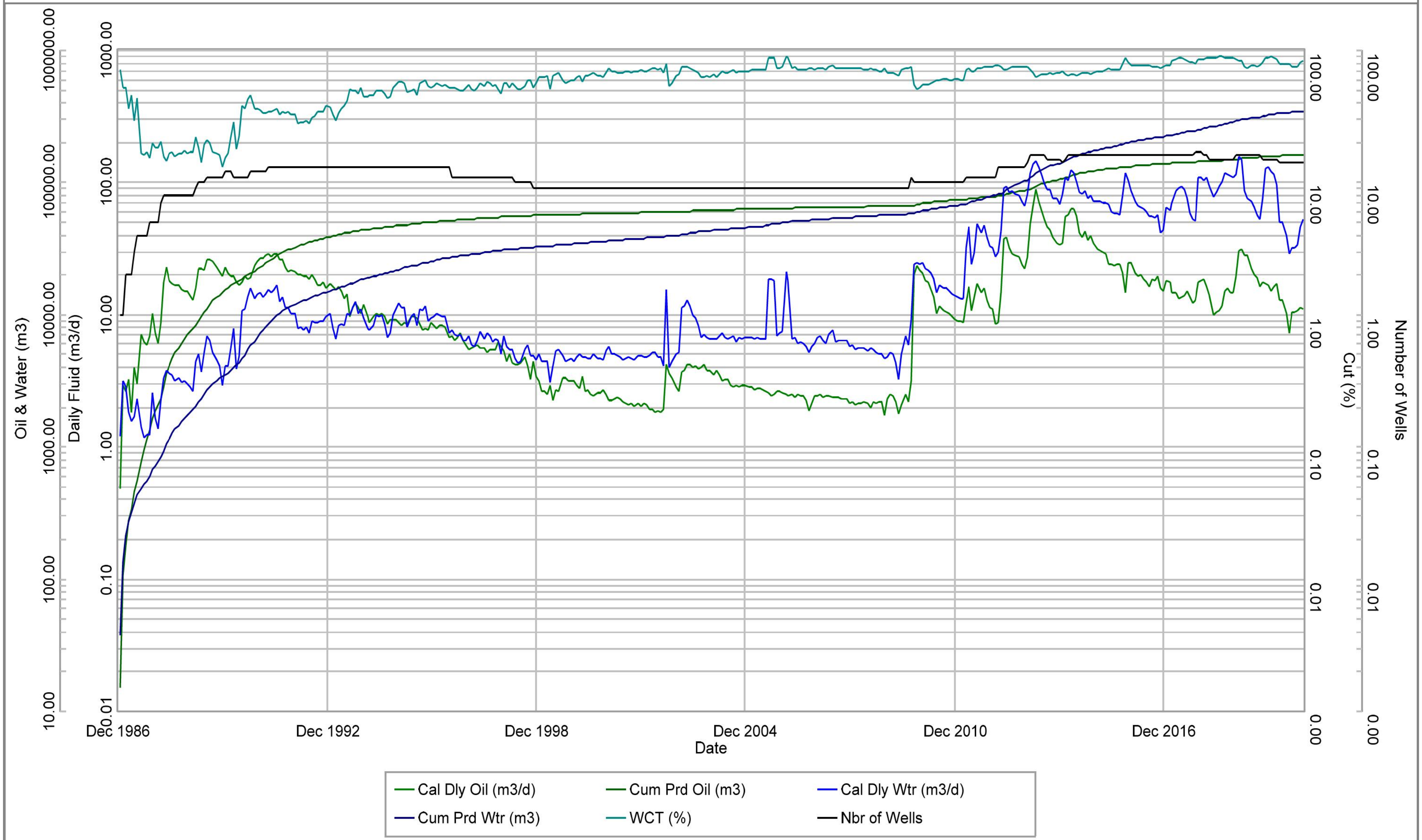
Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Well Information as of 2/8/2021 - Group Well Report

Production Graph

Figure No. 4

Group:	north ebor unit 3 wells.lwell	On Prod:	1986-12 to 2020-11	Cum Oil:	161598.3 m3
# of Wells:	27	Prod Form:	BAKKEN; BAKKENM; BAKKENU	Cum Gas:	0.0 E3m3
Fluid:	Oil; Water Injection; Water	Field:	DALY (MB1)	Cum Wtr:	344302.9 m3
Mode:	Producing; Injection; Pumping; Abandoned	Pool Code:	MB000162A	Cum Inj Oil:	0.0 m3
		Unit Code:	162A1; 162A2-9; 162A2	Cum Inj Gas:	0.0 E3m3
				Cum Inj Wtr:	302571.6 m3



Datum: NAD27

Printed on 3/1/2021 10:54:14 AM

Figure 5.

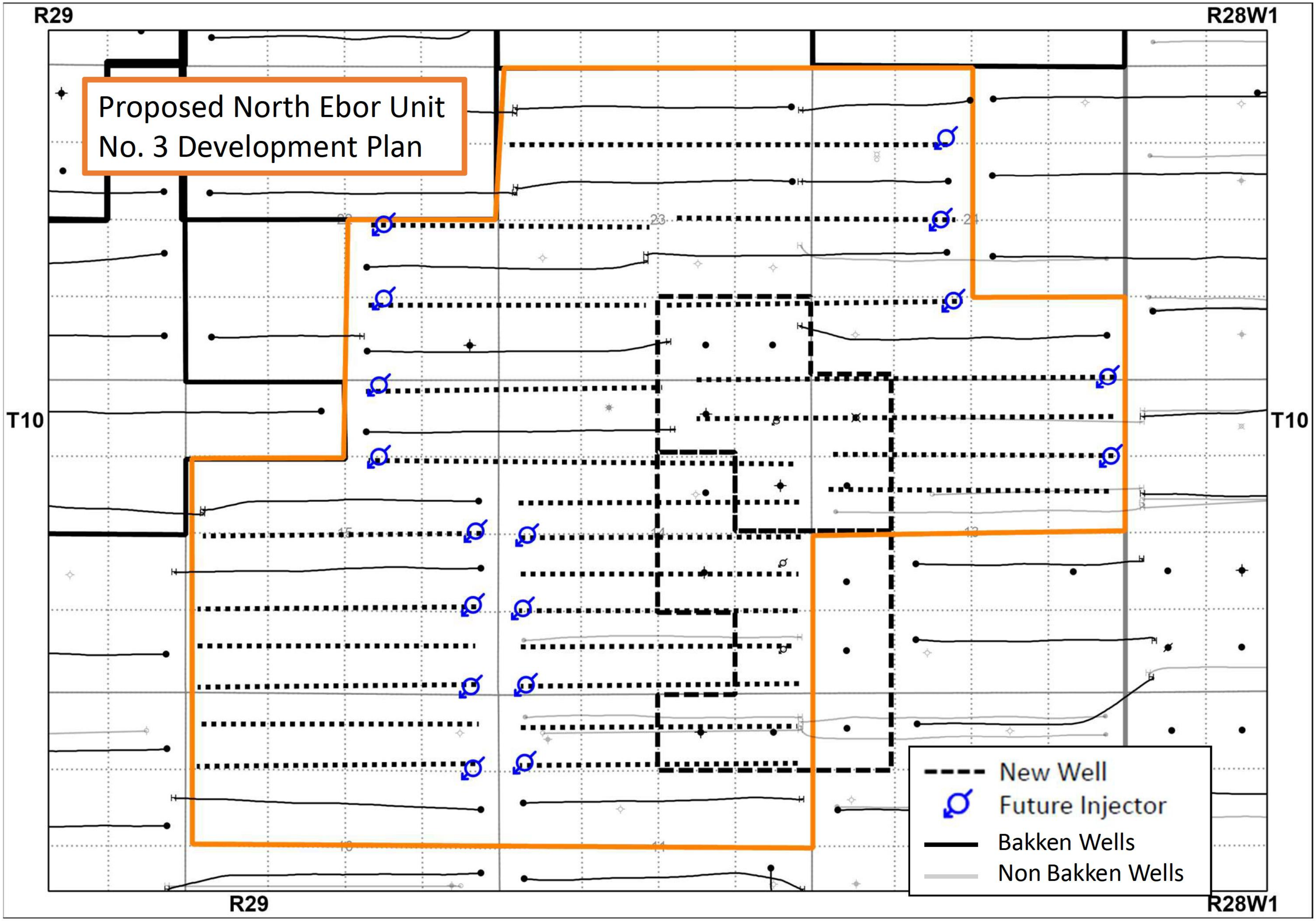
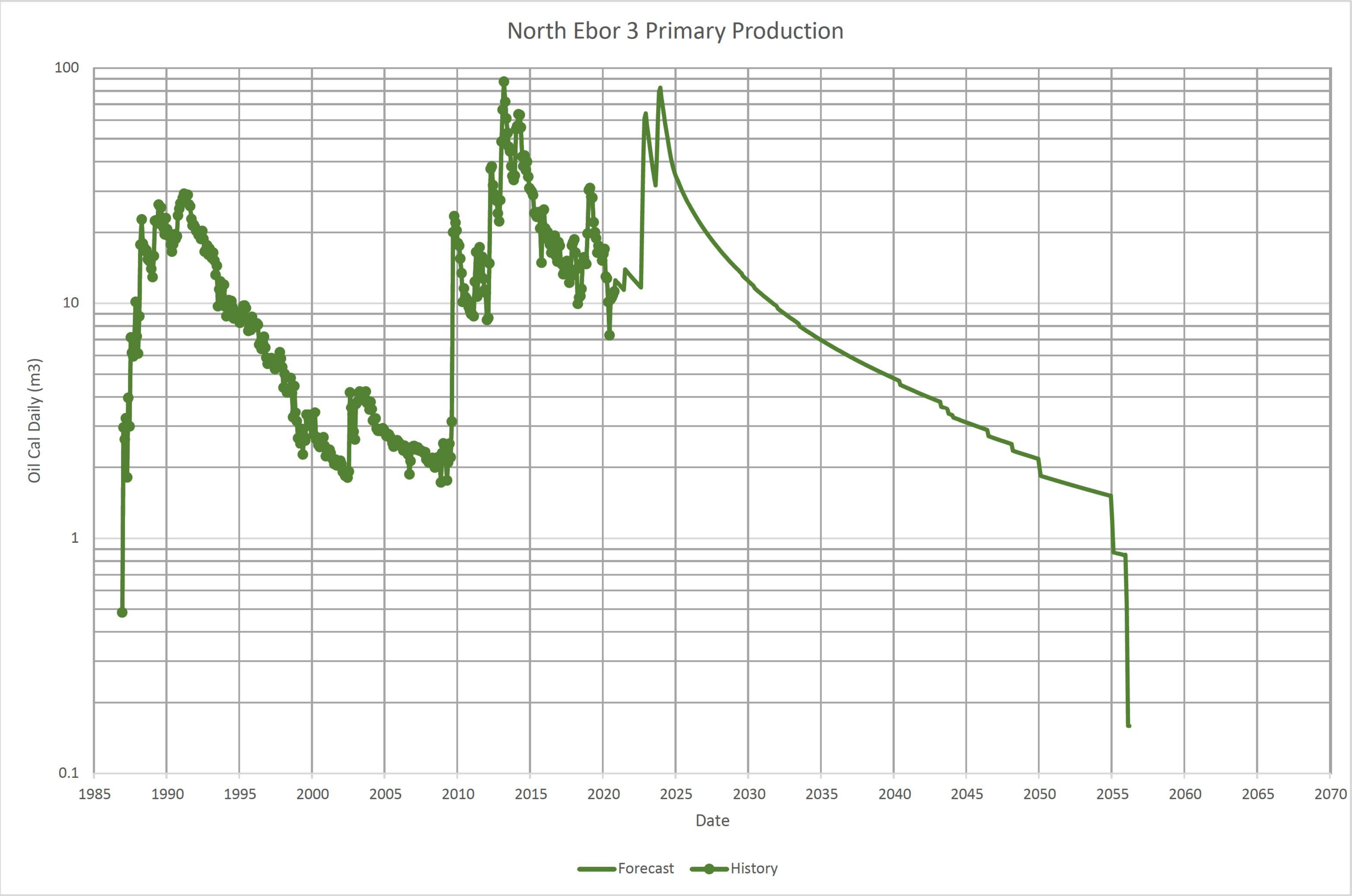
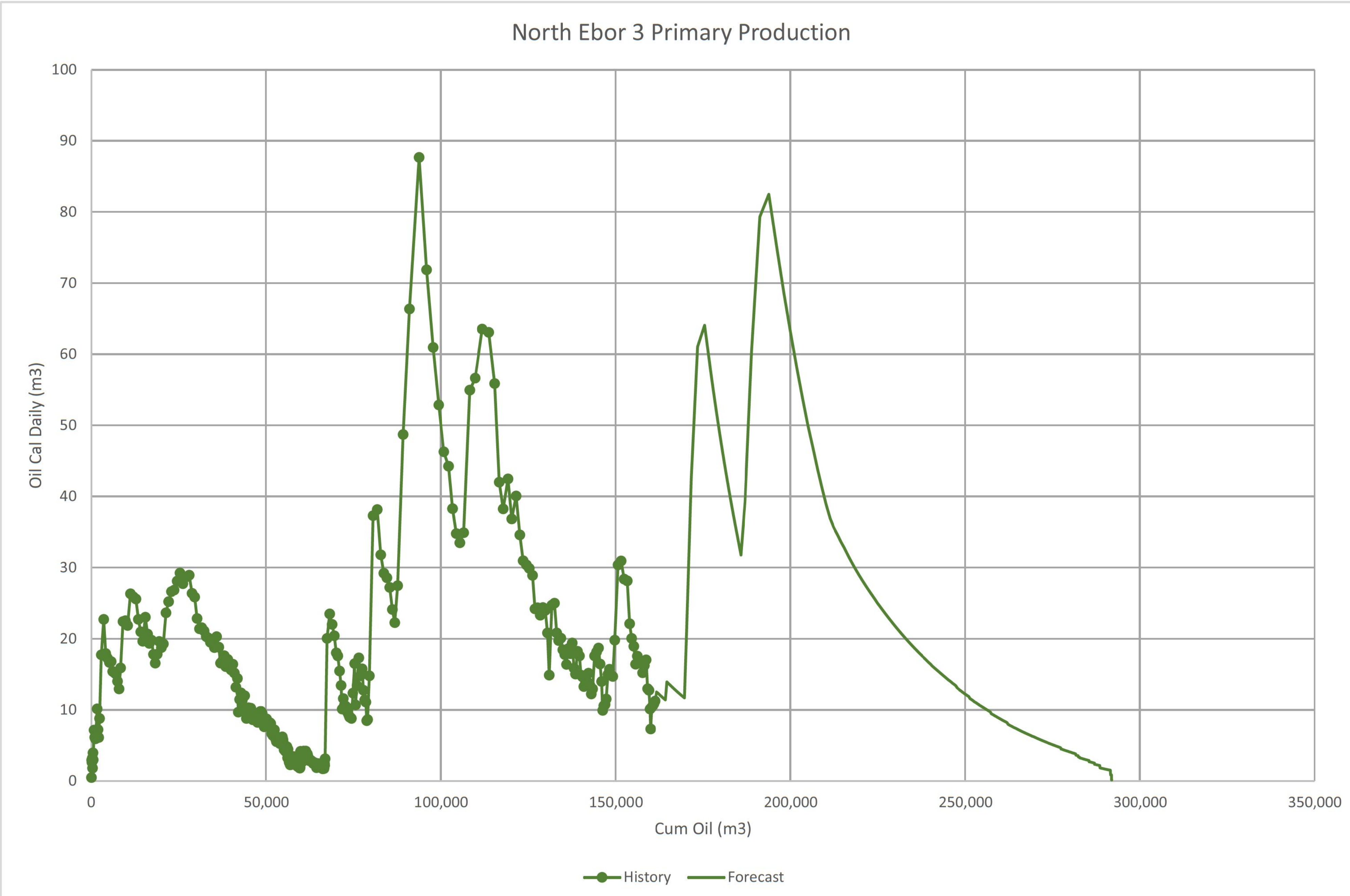

R29
R28W1
Proposed North Ebor Unit
No. 3 Development Plan
T10
T10
R29
R28W1
New Well
Future Injector
Bakken Wells
Non Bakken Wells

Figure No. 6



North Ebor 3 Primary Production
100
10
1
0.1
Oil Cal Daily (m3)
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
2055
2060
2065
2070
Date
Forecast
History

Figure No. 7

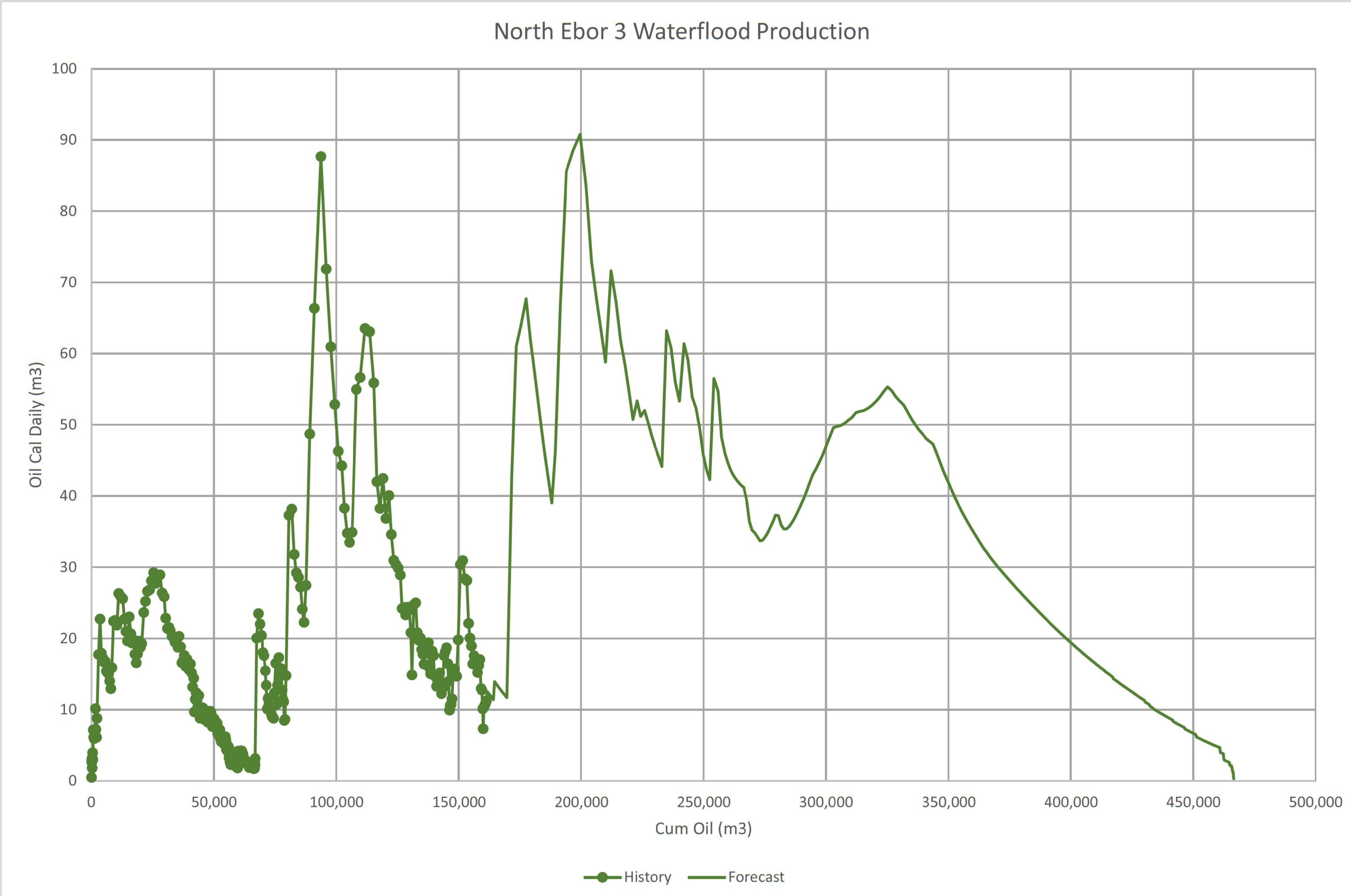


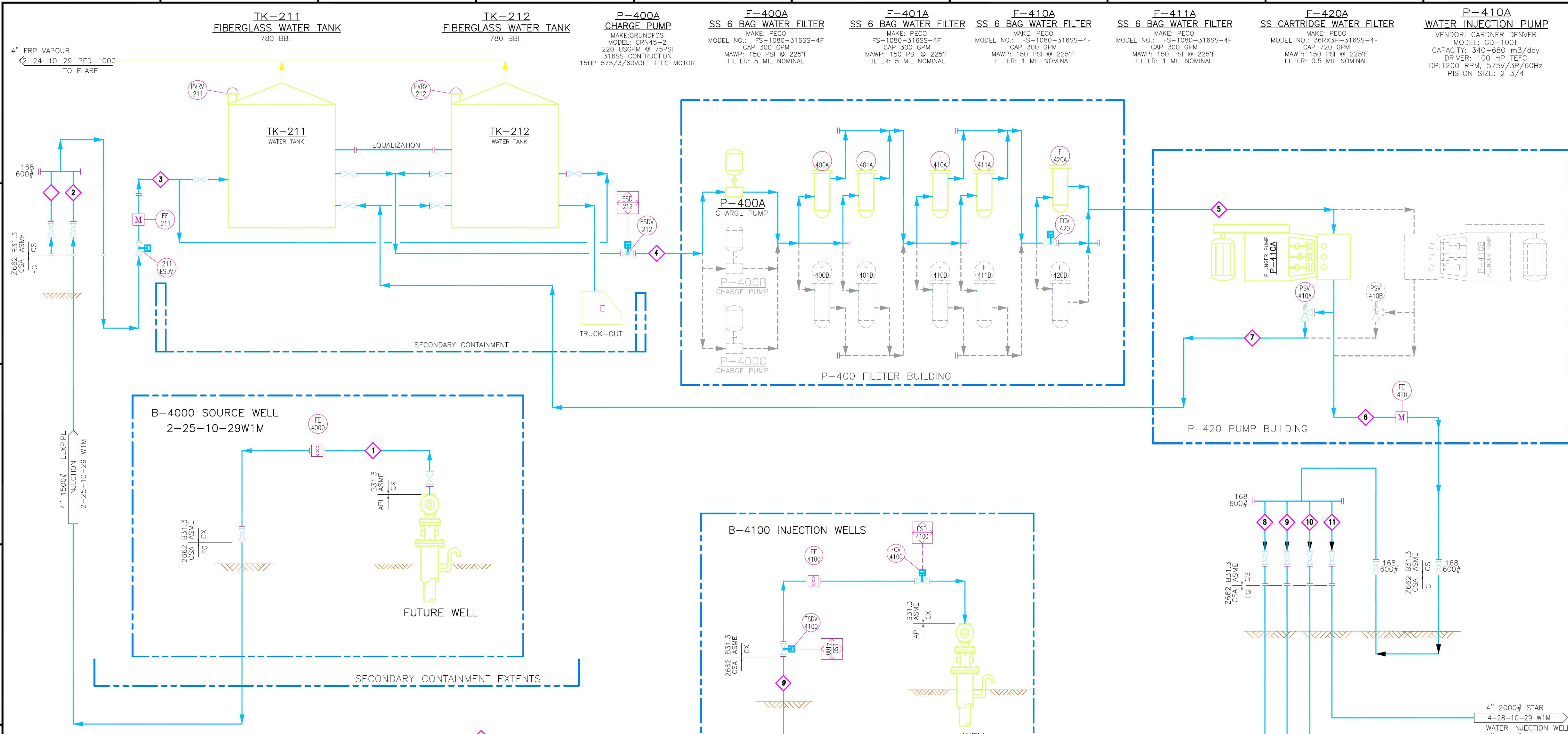
North Ebor 3 Primary Production
Oil Cal Daily (m3)
100
90
80
70
60
50
40
30
20
10
0
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
Cum Oil (m3)
History
Forecast

Figure No. 8

North Ebor 3 Waterflood Production
100
10
1
0.1
Oil Cal Daily (m3)
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
2055
2060
2065
2070
Date
Forecast
History

Figure No. 9


North Ebor 3 Waterflood Production
Oil Cal Daily (m3)
0
10
20
30
40
50
60
70
80
90
100
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
400,000
450,000
500,000
Cum Oil (m3)
History
Forecast



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. 10

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

Figure No. 11

Tundra Oil And Gas Partnership

TYPICAL CEMENTED LINER WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	**Tundra North Ebor Unit 3 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:

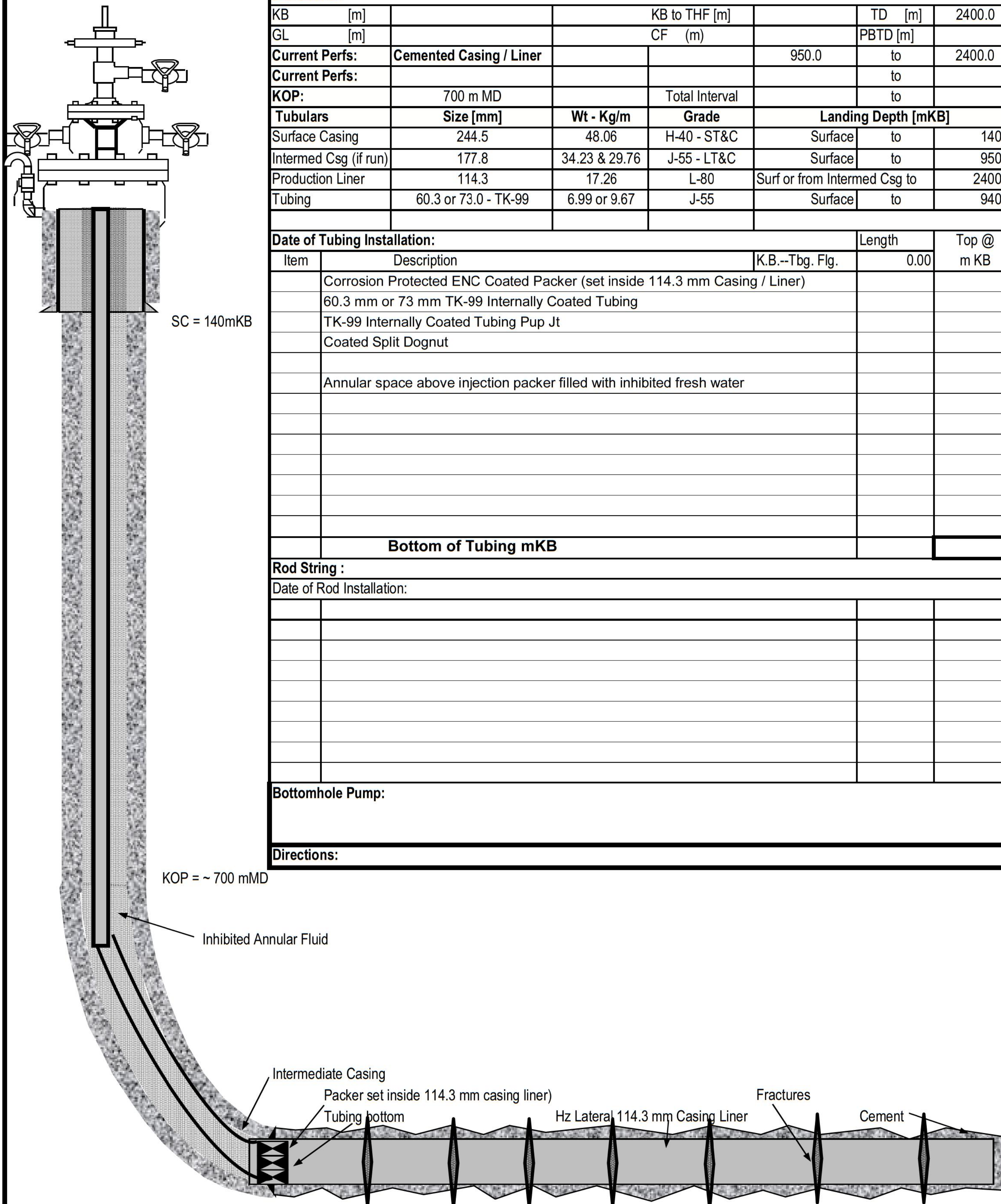


Figure 12 – Corrosion Controls

Source Well

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

Pipelines

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

Facilities

12-24-10-29 Water Plant

- Plant piping – 600 ANSI stainless steel schedule 80 pipe, fiberglass or internally coated
- Filtration – Stainless steel bodies, PVC piping or stainless steel piping
- Pumping – Ceramic plungers, stainless disc valves
- Tanks – Fiberglass shell, corrosion resistant valves

Injection Wellhead / Surface Piping

- Corrosion resistant valves and stainless steel and/or internally coated steel surface piping

Injection Wells

- Casing cathodic protection where required
- Wetted surfaces coated downhole packer
- Corrosion inhibited water in the annulus between tubing / casing
- Internally coated tubing surface to packer
- Surface freeze protection of annular fluid
- Corrosion resistant master valve
- Corrosion resistant pipeline valve
- Scale inhibition (pellets & injected post pump at battery)

Producing Wells

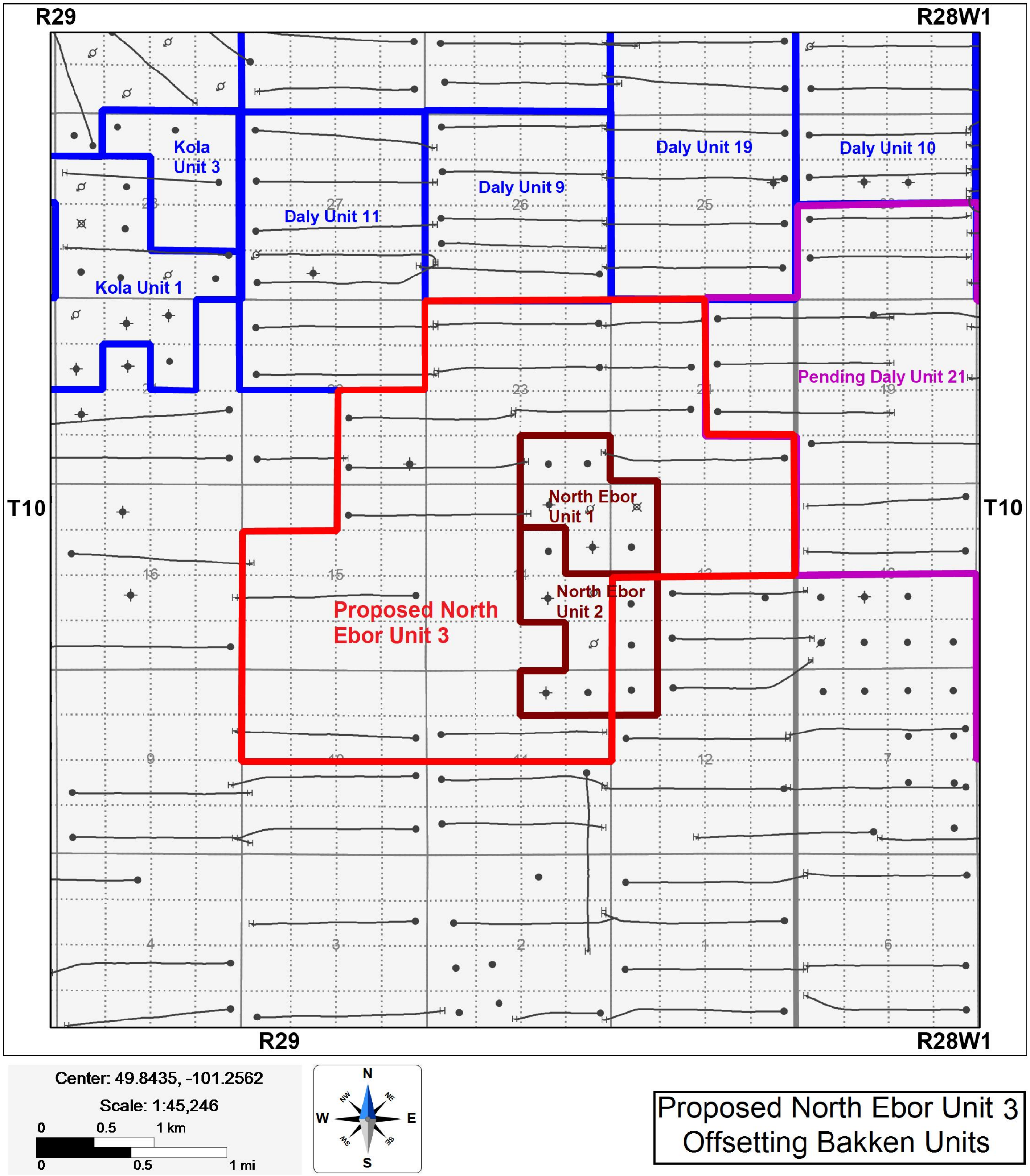
- Downhole corrosion inhibitor, either batch or daily injection, as needed.
- Scale inhibitor treatment daily injection as required for horizontal wells.
- Casing cathodic protection where required.

Proposed North Ebor Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

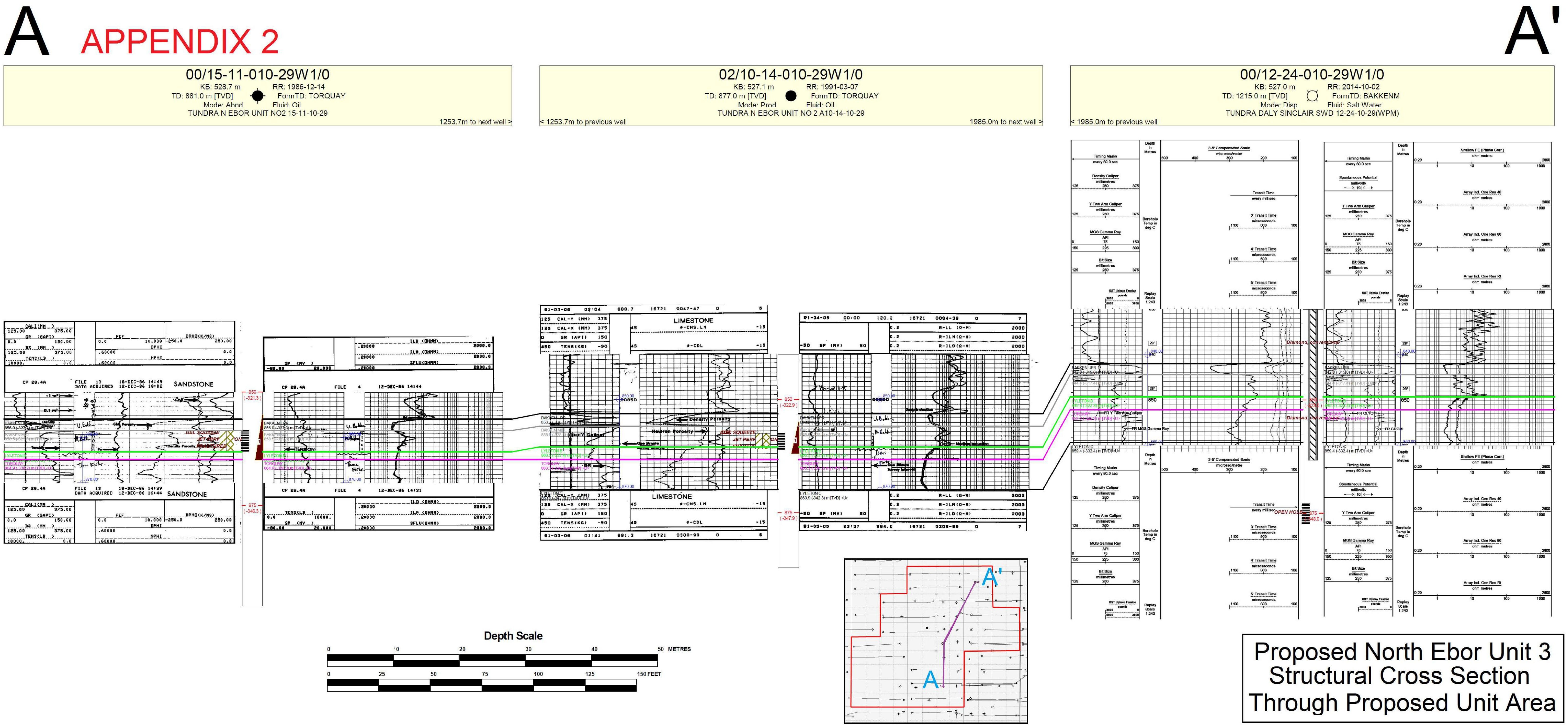
LIST OF APPENDICES

APPENDIX 1



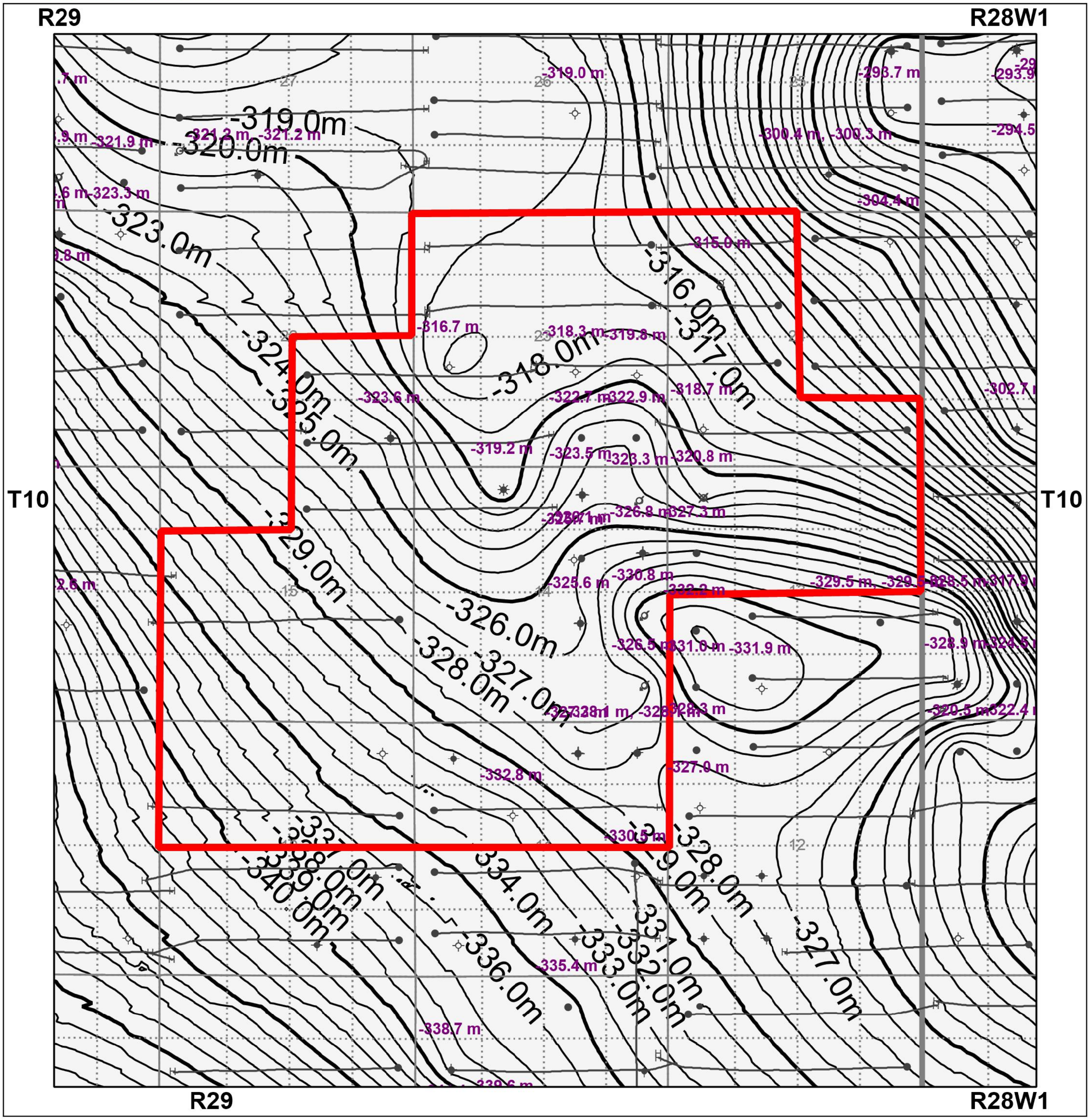
Proposed North Ebor Unit 3
Offsetting Bakken Units

APPENDIX 2



Proposed North Ebor Unit 3 Structural Cross Section Through Proposed Unit Area

APPENDIX 3



Center: 49.8368, -101.3148

Scale: 1:36,722

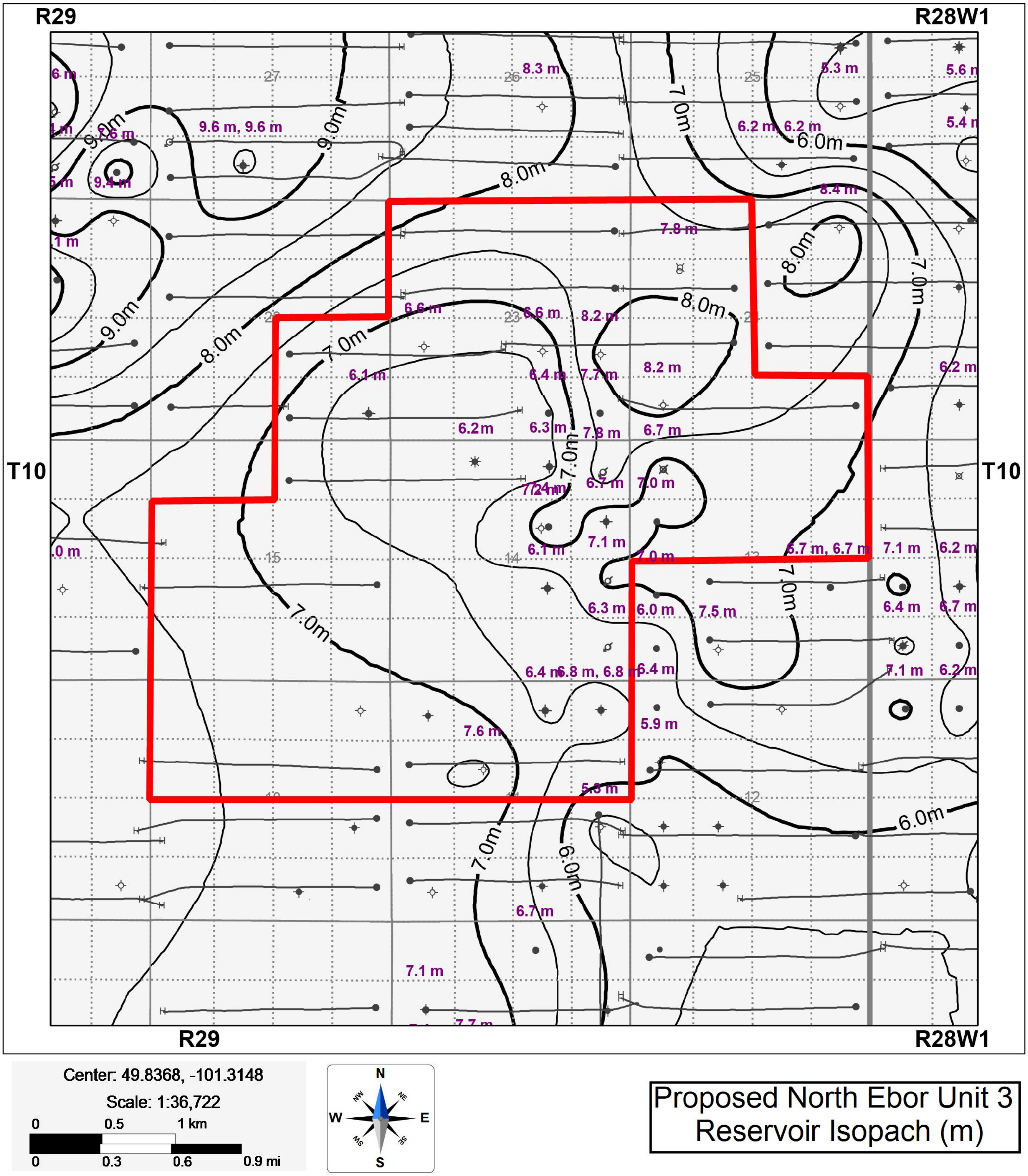
0 0.5 1 km

0 0.3 0.6 0.9 mi

N W E S

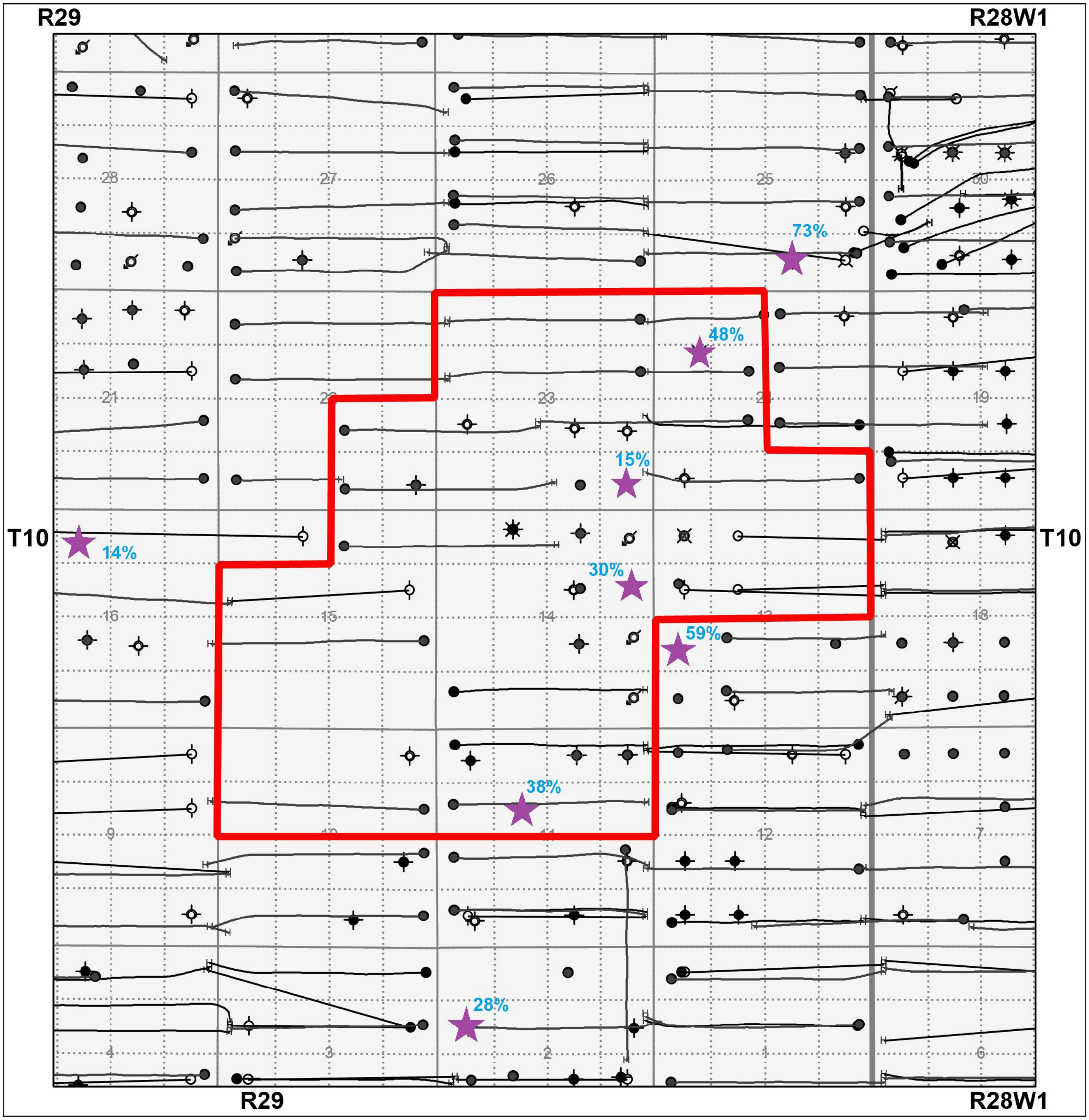
Proposed North Ebor Unit 3
Middle Bakken Structure
(mSS)

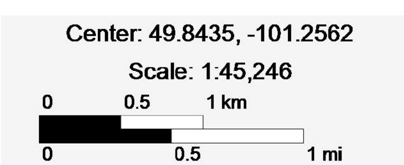
APPENDIX 4

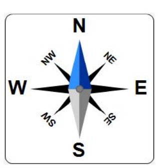


Proposed North Ebor Unit 3
Reservoir Isopach (m)

APPENDIX 5







Proposed North Ebor Unit 3
Routine Core Net to Gros Ratio