PROPOSED WHITEWATER UNIT NO. 2

Application for Enhanced Oil Recovery Waterflood Project

Lodgepole Formation

Lodgepole Whitewater Lake Member Pool (06 52B)

Whitewater Field (MB06), Manitoba

April 20th, 2020
Tundra Oil and Gas Limited

INTRODUCTION

Whitewater Unit No. 1, located in Township 3 Range 21 west of the prime meridian, first produced in March 1954 (Figure 1). The main production target in the unit was the Lodgepole Whitewater Lake A pool. Injection commenced in the unit in January 1973 and was terminated in 1985.

For the lands southeast of Whitewater Unit No. 1, potential exists for incremental production and reserves from a Waterflood EOR project in the Lodgepole Whitewater Lake oil reservoirs. The following represents an application by Tundra Oil and Gas Partnership (Tundra) to establish Whitewater Unit No. 2 (LSDs 2-16 of Section 2-003-21W1, LSDs 1-3, 6-10, 15-16 of Section 3-003-21W1 and LSDs 1-4 of Section 11-003-21W1) and implement a Secondary Waterflood EOR scheme within the Lodgepole Whitewater Lake formation as outlined on Figure 2.

The proposed project area falls within the existing designated 06-52B Lodgepole Whitewater Lake B Pool of the Whitewater Oilfield (Figure 3).

SUMMARY

1. The proposed Whitewater Unit No. 2 will include 28 vertical and 6 horizontal wells (2 dual-leg), within 29 Legal Sub Divisions (LSD) of the Lodgepole Whitewater Lake producing reservoir. The project is located southeast of Whitewater Unit No. 1 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Whitewater Unit No. 2 has been calculated to be **1,305.3** e^3m^3 (8,210.3 Mbbl) for an average of **45.0** net e^3m^3 (283.1 Mbbl) OOIP per 40 acre LSD.

3. Cumulative production to the end of January 2020 from the 34 wells within the proposed Whitewater Unit No. 2 project area was **253.6** e^3m^3 (1,595.8 Mbbl) of oil, and **3,703.0** e^3m^3 (23,302.5 Mbbl) of water, representing a **19.4%** Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Whitewater Unit No. 2 project area has been calculated to be **366.2** e^3m^3 (2,304.6 Mbbl), with **112.6** e^3m^3 (708.8 Mbbl) remaining as of the end of January. These estimates include six future horizontal wells, scheduled to start production through 2021 and 2022. They are expected to add **47.6** e^3m3 (300.0 Mbbl) of Primary reserves.

5. Ultimate oil recovery of the proposed Whitewater Unit No. 2 OOIP, under the current Primary Production method, is forecasted to be **28.1%**.

6. Figure 4 shows the production from the Whitewater Unit No. 2 peaked in February 1986 at 58.75 m^3 (OPD). As of December 2019, production was 12.51 m^3 OPD, 261.34 m^3 of water per day (WPD) and a 95.4% watercut.

7. In February 1986, production averaged 3.26 m^3 OPD per well in Whitewater Unit No. 2. As of January 2020, average per well production has declined to 1.12 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **19.4%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Whitewater Unit No. 2 has been calculated to be **421.1** e^3m^3 (2,650.1 Mbbl), with **167.5** e^3m^3 (1,054.2 Mbbl) remaining. An incremental **54.9** e^3m^3 (345.4 Mbbl) of proved oil reserves, or **4.2%**, 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 Whitewater Unit No. 2 is estimated to be **32.3%**.

10. Based on waterflood response in Whitewater Unit No. 1, and in other fields within the Lodgepole formation, the Lodgepole Whitewater Lake Formation in the proposed project area is believed to be a suitable reservoir for WF EOR operations.

11. Existing horizontal wells will be converted to injection wells (Figure 5) within the proposed Whitewater Unit No. 2, to complete waterflood patterns with effective 20 to 40 acre spacing, similar to that of Whitewater Unit No. 1.

DISCUSSION

The proposed Whitewater Unit No. 2 project area is located within Township 3, Range 21 W1 of the Whitewater oilfield. The proposed Whitewater Unit No. 2 currently consists of 28 vertical and 6 horizontal wells (2 dual-leg) within an area covering 29 LSDs (Figure 2). A project area well list complete with recent production statistics is attached as Table 3.

Tundra believes that the waterflood response in Whitewater Unit No. 1 demonstrates potential for incremental production and reserves from a WF EOR project in the subject Lodgepole Whitewater Lake oil reservoirs in the proposed Whitewater Unit No. 2.

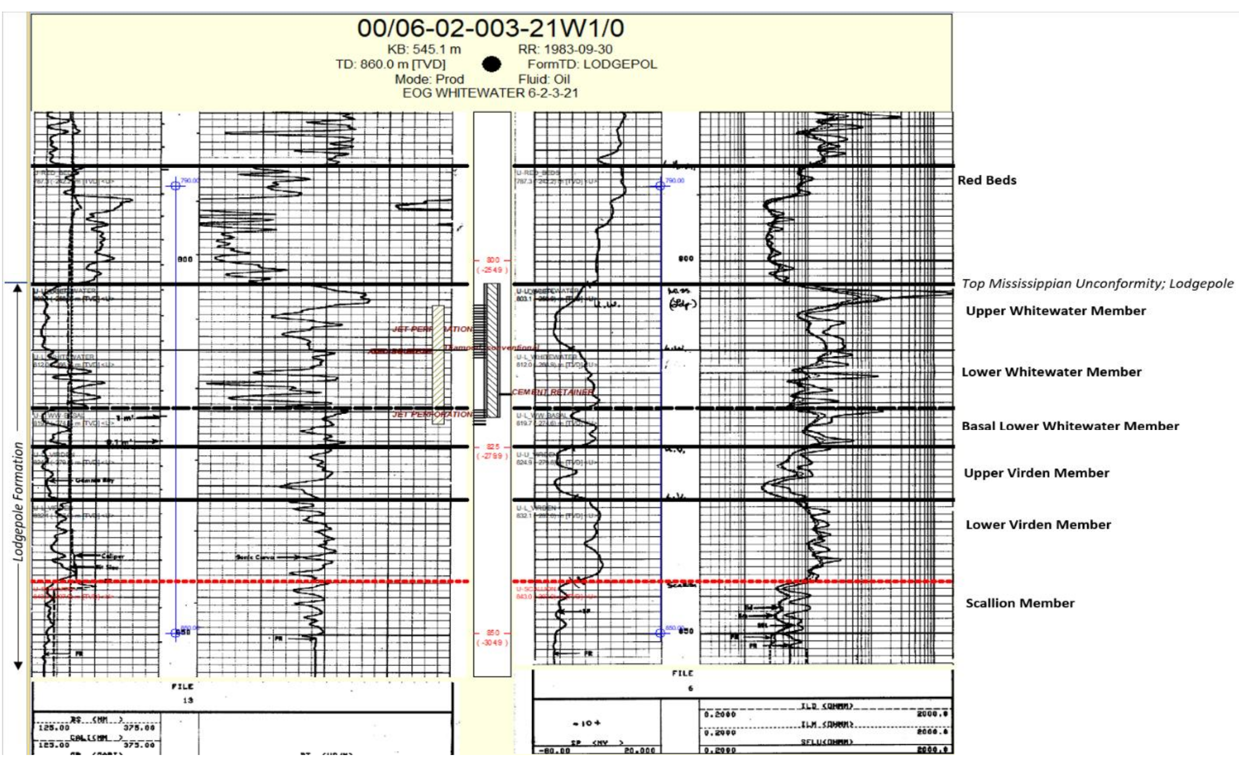
Geology

Stratigraphy

The main producing zones of the proposed Whitewater Unit No. 2 (Unit 2 boundary shown in Appendix 1) are, from youngest to oldest, the Upper Whitewater, Lower Whitewater, and Basal Lower Whitewater Members of the Mississippian Lodgepole Formation.

The Lodgepole Formation in the Whitewater area is capped by the top Mississippian Unconformity, which is an angular unconformity that quickly truncates the Lodgepole strata towards the northeast. Appendix 2: Schematic Diagram of the Whitewater Field, and Appendix 4: Geological Cross Section A – A' demonstrates how the top Mississippian Unconformity truncates the underlying Lodgepole.

Please refer to Type Log 100/06-02-003-21W1 below. The Upper Whitewater Member is locally unconformably overlain by the Jurassic Red Beds, also known as the Lower Watrous Formation.



The Upper Whitewater Member conformably overlies the Lower Whitewater Member, which in turn overlies the Basal Lower Whitewater Member. The Basal Lower Whitewater Member overlies the Upper Virden Member, which is underlain by the Lower Virden and finally the Scallion Members. The entire Lodgepole package is conformably underlain by the Mississippian Bakken Formation.

The Upper Whitewater Member will be the primary target of the waterflood, however the Lower and Basal Lower Whitewater Members are included because they have been completed in many of the vertical wells within the unit. The Upper Virden and Scallion Members will not be included in Whitewater Unit No. 2 and are considered hydrodynamically separate.

Sedimentology

The Upper Whitewater Member in the Whitewater pool is the most prolific oil reservoir of all the Lodgepole Members in the area. It consists of mixed oolitic and bioclastic lime packstones to grainstones that are variably crystallized and dissolved. The colour ranges from tan to dark brown, depending on the degree of oil staining. Anhydrite blebs are common

The upper 1-3m of the Upper Whitewater is locally altered by subaerial exposure along the top Mississippian Unconformity surface and is often referred to as the 'cap'. The cap is composed of abundant light grey anhydrite and recrystallized dolomite and is tight and considered non reservoir. The cap, along with the rapid northeastward erosion of the strata along the top Mississippian Unconformity provides an up dip stratigraphic trap for the reservoir units of the Whitewater Pool.

The Lower Whitewater Member is separated from the Upper Whitewater Member by a thin, ~0.2m lens of reddish purple to grey argillaceous lime mudstone. It can sometimes be obscured in core due to masking by the oil stain, however is apparent while horizontally drilling from the Upper Whitewater to the Lower Whitewater because there is an increase in gamma and it is a difficult barrier to break through. On vertical well logs, the argillaceous bed is identified by a slight indent on the gamma, SP, and resistivity curves.

The upper 2 – 4m of the Lower Whitewater are composed of 2 tan to medium brown limestone bioclastic packstone to grainstone lenses separated by 0.5 – 1m tight argillaceous lime mudstones. They are considered poor to fair reservoir. These bioclastic lenses are underlain by 4-5m reddish maroon argillaceous lime mudstones to wackestones with the occasional grainstone lens (which do not appear to be laterally extensive). The argillaceous lime mudstones create the bottom seal for the Lower Whitewater Member.

Locally the Lower Whitewater can be very productive, however it appears to produce higher amounts of water. Some of the wells in the unit have core where vertical fractures are observed in the Lower Whitewater reservoir, however they do not appear to extend into the underlying argillaceous lime mudstones and wackestones, or into the Basal Lower Whitewater. Local DST results and production tests support that the fractures rarely penetrate between the members if at all.

The top of the Basal Lower Whitewater Member is a 1-2m thick, tan to medium brown coloured oolitic grainstone. The grainstone grades downwards into a pale green, grey, and /or reddish maroon mudstone which creates a vertical permeability barrier with the underlying Upper Virden Member.

The Upper Virden Member locally consists of 2 layers of tan to dark coloured variably leached crinoidal bioclastic packstone to grainstone, separated by thin beds of light grey coloured wackestone.

The Lower Virden Member is about 11 – 12 m of argillaceous mottled red – purple – grey limestone and is non reservoir rock. It provides a laterally extensive thick barrier between the overlying Upper Virden and underlying Scallion Members.

The Scallion Member is comprised of clean, non-argillaceous, white to medium grey to pinkish cherty limestones with finely crystalline to chalky texture. It is characterized with abundant microporosity and is easily seen on logs by a prominent thick SP kick.

Structure

The Lodgepole Formation dips regionally towards the southwest at an average rate of 6 meters per kilometer. Appendix 6 is a Top Whitewater Member Subsea Structure map over Unit 2. The structure dips towards the west – southwest to -271 m subsea at the western edge of the Unit and is highest at the 16-2-3-21W1 vertical well (-255.2 m subsea). The Upper Whitewater thins rapidly towards the subcrop edge is just north and east of the 16-2-3-21W1 (The Upper Whitewater Subcrop edge is the purple line on Appendix 6).

Reservoir Continuity

Appendix 5 shows the Upper Whitewater Member Net Hydrocarbon Pay. The pay ranges from 0 to 5.1m, with the thickest pay trending southwest to northeast in a 1-2 LSD wide band from roughly 10-33-2-21W1 (inferred from seismic and trends in Upper Whitewater thickness), up towards 15-2-3-21W1, and jutting out 2 LSDs to the west to 13-2-3-21W1 (based on well control and seismic). The Upper Whitewater thins rapidly to zero at its subcrop edge towards the north and east from the thick pay due to rapid erosion by the top Mississippian Unconformity. The Upper Whitewater pay also thins to 0 to the west from 9 and 16-3-3-21 to 10 and 15-3-3-21W1 due to erosion by the top Mississippian Unconformity and the resulting alteration of the thinned zone.

There is some evidence of compartmentalization within the Upper Whitewater Member – either from cap alteration occluding all permeability and porosity within the Upper Whitewater (as evidenced by 16-33-2-21W1) in some areas of the pool or perhaps by depositional separation of grainstone shoals. The 6-2-3-21W1 and 10-2-3-21W1 vertical wells have very low water cuts and low pressures, while wells in the same zone in other parts of the pool have higher pressures and higher water cuts. The presence of completions in the underlying Lower Whitewater and Basal Lower Whitewater in other vertical wells, as well as bad cement jobs and pressurized acid squeezes adds enough uncertainty that a map of where the compartmentalization occurs would be inaccurate.

Reservoir Quality

Reservoir quality within the Upper Whitewater Member is quite heterogeneous. This is due in part by the alteration that extends down from the top Mississippian unconformity (degrading the permeability and porosity), in part due to depositional differences that happen rapidly between the active shoal and stable platform within the Upper Whitewater, differences in dissolution of the grains and matrix, and the thickness of the Upper Whitewater due to erosion from the top Mississippian unconformity.

Appendix 7 is an Upper Whitewater Member Kmax.h or Capacity map. It is derived from summing the {max core permeability multiplied by corresponding interval thickness}. The highest permeability in the Upper Whitewater Member is found at 2-3-3-21W1 (819.8 mD.m), followed by 6-2-3-21W1 (360.4 mD.m) followed by 13-2-3-21W1 (275.4 mD.m). The map is computer contoured with an interval of 50mD.m. 0 mD.m points were put in where the Upper Whitewater Member gets very thin near the subcrop edge to complete the map.

Appendix 8 is an Upper Whitewater Average Core Porosity map (values from wireline logs were added to the vertical wells where there was no core analysis in the Upper Whitewater). Porosity ranges from 4 to 16.5%, along the same southwest to northeast trend that the net pay was the thickest in the Upper Whitewater. Once again the map was computer contoured by Accumap, however 0% porosity values were added along the Upper Whitewater subcrop edge for completeness.

Fluid Contacts

An oil water contact (owc) for the Upper Whitewater, Lower Whitewater, Basal Lower Whitewater, and Upper Virden members is estimated at -278 m subsea structure. The owc was determined based on DST recoveries, oil staining on core, and production from each zone in the area. The oil water contact of the Upper Whitewater is mapped based on vertical well logs, contacts within horizontal wells, and integration with seismic just west of the unit boundary, near the border of Sections 3 and 4-3-21W1.

Gross OOIP Estimates

The total volumetric OOIP for the Upper Whitewater Member within the proposed Whitewater Unit No. 2 has been calculated to be 1305.3 e^3m^3 (8,210.3 Mbbl) (Table 4).

The OOIP was calculated LSD by LSD interpolating between vertical wells using Archie's equation:

$\boxed{\text{OOIP = [Ah phi(1-Swi)/Boi]}}$ where,

OOIP = Original Oil in Place
A = Reservoir Area (m2)
h = Reservoir Thickness (m)
phi = Reservoir Porosity
Swi = Connate Water Saturation – estimated to be 0.15 to 0.38 in the area
Boi = Initial Formation Volume Factor – assumed to be 1.003 in the area

Net pay cut – offs for the Upper Whitewater Member were as follows: Limestone Porosity greater than 7%; SP response; oil staining in core; oily recovery on DST or commercial oil production from the zone.

Currently only the Upper Whitewater Member will be waterflooded because the underlying Lower Whitewater and Basal Lower Whitewater Members appear to have sufficient water drive for maximum oil recovery.

Historical Production

A historical group production history plot for the proposed Whitewater Unit No. 2 is shown as Figure 4. Oil production commenced from the proposed Unit area in May 1982 and peaked in February 1986 at 58.75 m^3 OPD. As of January 2020, production was 17.98 m^3 OPD, 263.35 m^3 WPD and a 93.6% watercut.

From peak production in February 1986 to date, oil production is declining at an annual rate of approximately **19.4%** under the current Primary Production method.

The remainder of the field's production and decline rates indicate the need for pressure restoration and maintenance. Waterflooding is deemed to be the most efficient means of secondary recovery to introduce energy back into the system and 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.

Unit Name

Tundra proposes that the official name of the new Unit shall be Whitewater Unit No. 2.

Unit Operator

Tundra Oil and Gas Limited (Tundra) will be the Operator of record for Whitewater Unit No. 2.

Unitized Zone

The Unitized zone(s) to be waterflooded in Whitewater Unit No. 2 will be the Lodgepole Whitewater Lake formation.

Unit Wells

The 28 vertical and 6 horizontal wells (2 dual-leg) to be included in the proposed Whitewater Unit No. 2 are outlined in Table 3.

Unit Lands

Whitewater Unit No. 2 will consist of 29 LSDs as follows:

LSDs 2-16 of Section 2 of Township 3, Range 21, W1M
LSDs 1-3, 6-10, 15-16 of Section 3 of Township 3, Range 21, W1M
LSDs 1-4 of Section 11 of Township 3, Range 21, W1M

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

Tract Factors

The proposed Whitewater Unit No. 2 will consist of 29 Tracts based on the 40 acre LSDs containing the existing 28 vertical and 6 horizontal wells (2 dual-leg).

The Tract Factor contribution for each of the LSD's within the proposed Whitewater Unit No. 2 was calculated as follows:

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

Tract Factor calculations for all individual LSDs based on the above methodology are outlined within Table 2.

Working Interest Owners

Table 1 outlines the working interest (WI) for each recommended Tract within the proposed Whitewater Unit No. 2. Tundra Oil and Gas Limited holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Limited will have a 100% WI in the proposed Whitewater Unit No. 2.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Whitewater Unit No. 2 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 Whitewater Unit No. 2 OOIP (Table 4).

Pre-Production of New Horizontal Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Whitewater Unit No. 2 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 formations with similar permeability, and has a negative impact on the ultimate total recovery factor of OOIP.

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

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

Reserves Recovery Profiles and Production Forecasts

The primary performance predictions for the proposed Whitewater Unit No. 2 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.

Primary Production Forecast

Cumulative production in the Whitewater Unit No. 2 project area, to the end of January 2020 from 14 wells, was **253.6** e^3m^3 of oil and **3,703.0** e^3m^3 of water for a recovery factor of **19.4%** of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Whitewater Unit No. 2 has been estimated to be **366.2** e^3m^3, or a **28.1**% Recovery Factor (RF) of OOIP. Remaining Producing Primary Reserves has been estimated to be **112.6** e^3m^3 to the end of January 2020. These estimates include reserves 6 future horizontal producers, which are expected to add 47.6 e^3m^3 (300.0 Mbbl) of Primary reserves.

The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 7 and 8.

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

Tundra will devise an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Whitewater Unit No. 2, while maximizing reservoir knowledge. This schedule is usually based on the economics of converting wells to injection.

Criteria for Conversion to Water Injection Well

Four (4) water injection wells are required for this proposed unit as shown in Figure 5, which will result in an effective 20 - 40 acre line drive waterflood pattern within Whitewater Unit No. 2.

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

The above schedule allows for the proposed Whitewater Unit No. 2 project to be developed equitably, efficiently, and moves to project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast

The proposed project oil production profile under Secondary Waterflood has been developed based on the response observed to date in the Whitewater Unit No. 1 Waterflood (Figure 6). The ultimate secondary recovery forecast for the proposed Unit is also based on performance from other waterfloods in the Upper Virden and Scallion members within the same Lodgepole formation. Although these members are not directly analogous to the Whitewater member, they provide a fair expectation of waterflood performance due to some similar characteristics they have to the reservoir in the proposed Unit.

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production vs. cumulative oil are plotted in Figures 9 and 10, respectively. Total Secondary EUR for the proposed Whitewater Unit No. 2 is estimated to be **421.1** e^3m^3 with **167.5** e^3m^3 remaining, representing a total secondary recovery factor of **32.3 %** for the proposed Unit area. An incremental **54.9** e^3m^3 of oil, or an incremental **4.2%** recovery factor, are forecasted to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method.

Estimated Fracture Pressure

Completion data from the producing wells within the project area indicate an actual fracture pressure gradient range of 18.0 to 21.0 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be somewhat lower than these values due to expected reservoir pressure depletion.

WATERFLOOD OPERATING STRATEGY

Water Source

Injection water for the proposed Whitewater Unit No. 2 will likely be supplied from the currently abandoned well at 102/11-02-003-21W1. Tundra will request approval from the Petroleum Branch to convert this well as a source water well for waterflood operations. Mannville water from this well will be redistributed to the injection system. A wellhead filtration system at each injection site will be installed to filter the source water. A diagram of the Whitewater 02/11-02 injection system and pipeline connection to the project area injection wells is shown as Figure 13.

Tundra does not foresee any injectivity issues when using Mannville source water for the waterflood operations in the proposed Whitewater Unit No. 2

Currently all produced waters are inherently a mixture of Upper and Lower Whitewater native sources. This mixture of produced waters will be extensively tested for compatibility with 102/11-32 source Mannville water, by a highly qualified third party. All potential mixture ratios between the two waters, under a range of temperatures, will be simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors will also be conducted and minimum inhibition concentration requirements for the source water volume determined. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program in Tundra's waterflood operations.

Injection Wells

Two out of the four water injection wells for the proposed Whitewater Unit No. 2 have been drilled, are currently producing and plans are in progress to re-configure the wells for downhole injection upon waterflood approval. Figure 11. The horizontal injection wells have been completed as open hole, and not fractured. This prevents any undesired communication between the Upper Whitewater and other zones that may carry high amounts of water.

The new water injection wells will be placed on injection after 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 fair understanding of area fracture gradients. A management program will be utilized to set and routinely review injection target rates and pressures vs. surface MOP and the known area formation fracture pressures.

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

The proposed Whitewater Unit No. 2 horizontal water injection well rate is forecasted to average **30 – 50** m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

The initial reservoir pressure for wells drilled in the Lodgepole Whitewater Lake formation in the proposed Whitewater Unit No. 2 is shown in Figure 12. The estimated reservoir pressure for the proposed unit area is in the range of 4000 - 6500 kPa, depending on the level of depletion.

Reservoir Pressure Management during Waterflood

Tundra expects it will take 2-4 years to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial monthly Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 2.00 within the patterns during the fill up period. This will ensure that the injected water has optimal sweep and no early water breakthrough is caused. 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

Whitewater Unit No. 2 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring vs target
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern VRR
- Potential use of chemical tracers to track water injector/producer responses
- Use of some or all of: Water Oil Ratio (WOR) trends, Log WOR vs Cum Oil, Hydrocarbon Pore Volumes Injected, Conformance Plots

The above surveillance methods will provide an ever-increasing understanding of reservoir performance and provide data to continually control and optimize the Whitewater Unit No. 2 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 Whitewater Unit No. 2.

On Going Reservoir Pressure Surveys

Any pressures taken during the operation of the proposed unit will be reported within the Annual Progress Reports for Whitewater Unit No. 2 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Whitewater Unit No. 2 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 Whitewater Unit No. 2 waterflood operation will utilize the Tundra operated water source well 102/11-02-003-21W1/2. This well will be equipped with a submersible pump which has the dual role of pumping Mannville water from 102/11-02 and acting as an injection supply pump for the injection wells in the area.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 13. All surface facilities and wellheads will have cathodic protection to prevent corrosion. All injection flowlines will be fiberglass construction to eliminate corrosion risks.

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 Whitewater Unit No. 2. 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 Whitewater Unit No. 2 Application.

Whitewater Unit No. 2 Unitization, and execution of the formal Whitewater Unit No. 2 Agreement by affected Mineral Owners, is expected during Q2 2020. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Whitewater Unit No. 2 Application.

Should the Petroleum Branch have further questions or require more information, please contact Angel Duran at 403.910.1673 or by email at angel.duran@tundraoilandgas.com.

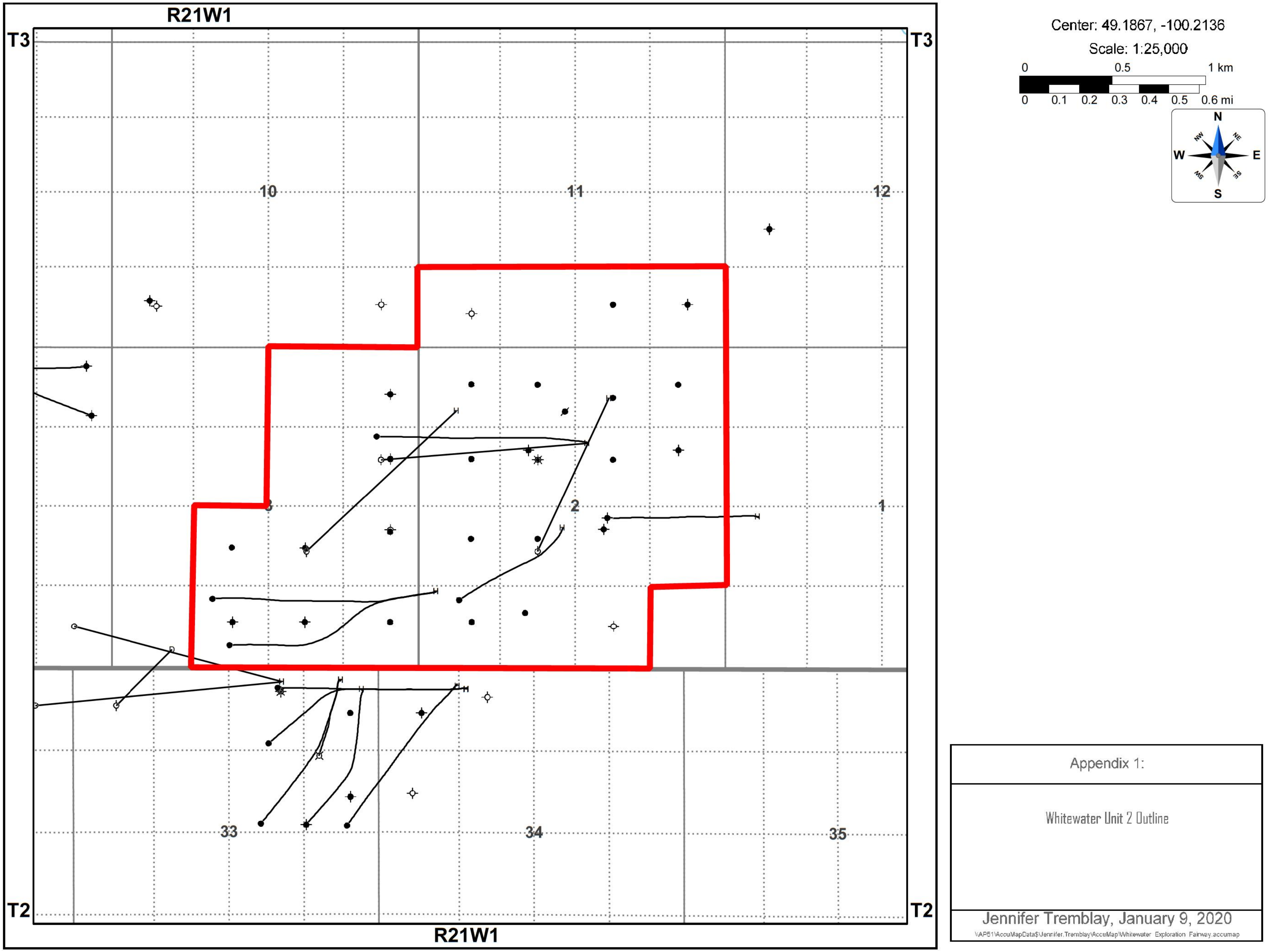
TUNDRA OIL & GAS LIMITED

Original Signed by Angel Duran, April 20th, 2020, in Calgary, AB

Proposed Whitewater Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project

LIST OF APPENDICES



Appendix 1:

Whitewater Unit 2 Outline

Jennifer Tremblay, January 9, 2020

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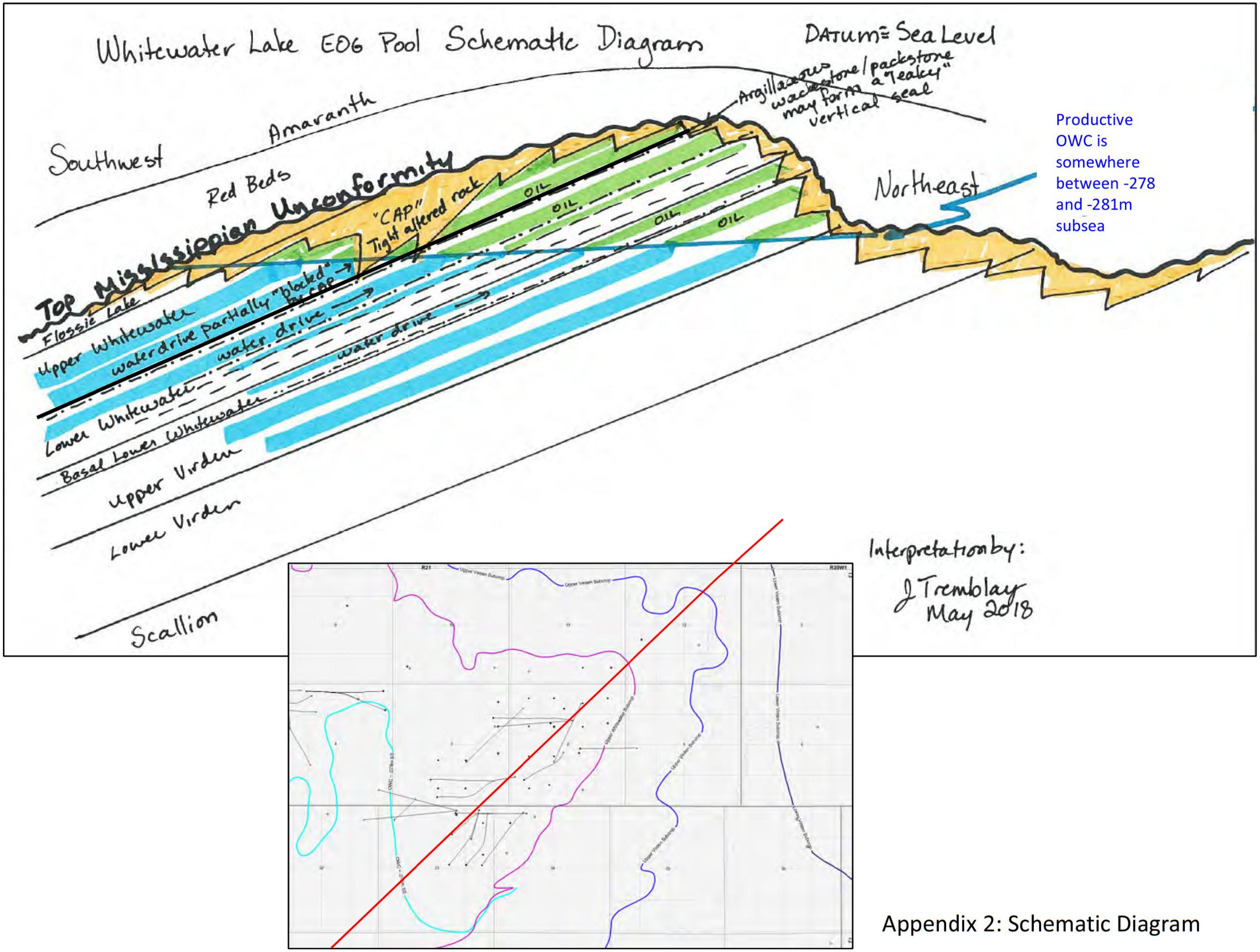
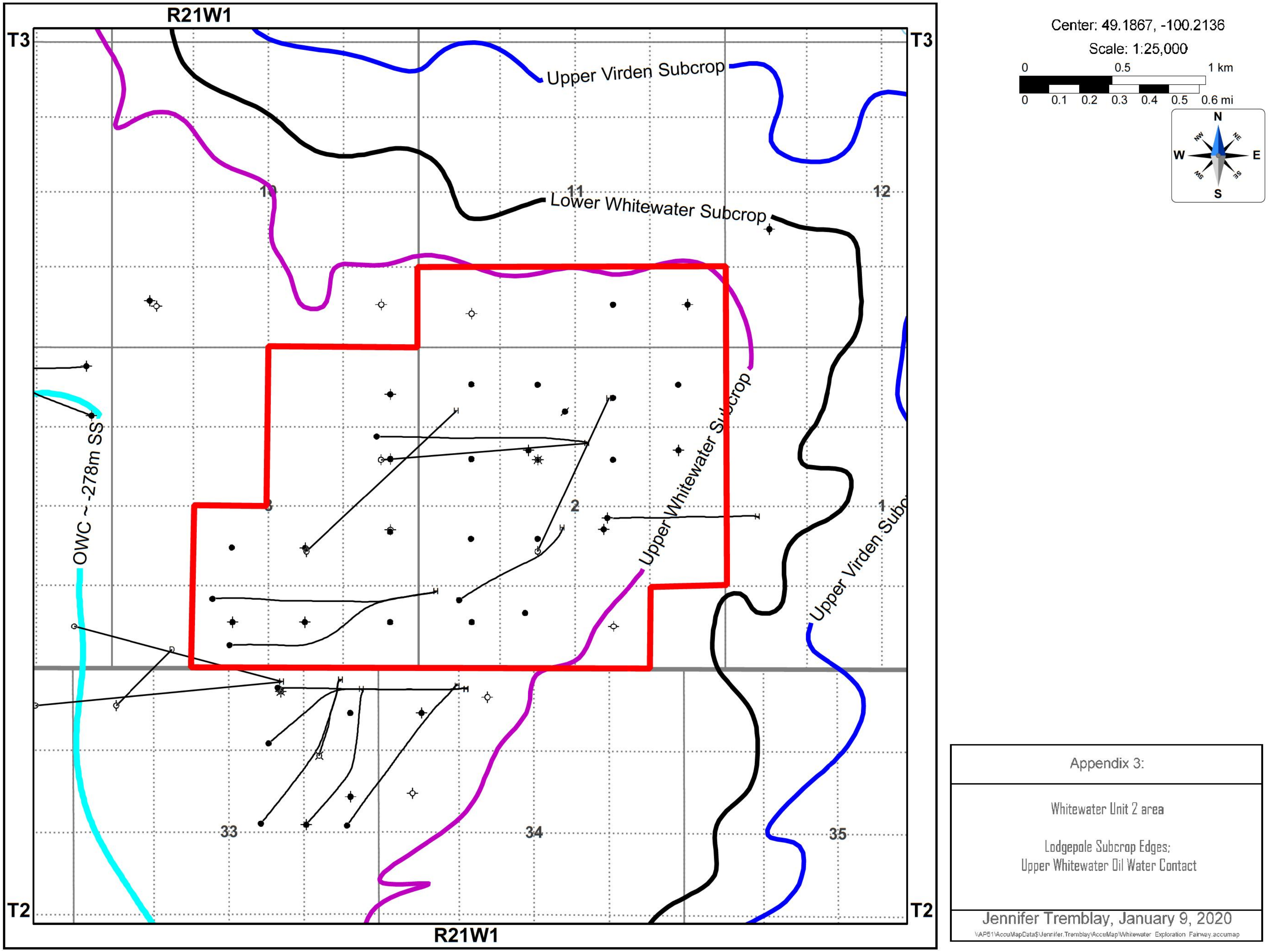
Appendix 1:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07



Appendix 2: Schematic Diagram



Appendix 3:

Whitewater Unit 2 area

Lodgepole Subcrop Edges;
Upper Whitewater Oil Water Contact

Jennifer Tremblay, January 9, 2020

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Appendix 3:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

00/06-03-003-21W1/0

KB: 542.7 m RR: 1988-03-13
TD: 860.0 m [TVD] ● FormTD: LODGEPOL
Mode: Prod Fluid: Oil
EOG WHITEWATER 6-3-3-21
941.3m to next well >

00/01-03-003-21W1/0

KB: 547.3 m RR: 1986-01-15
TD: 860.5 m [TVD] ● FormTD: LODGEPOL
Mode: Prod Fluid: Oil
EOG WHITEWATER 1-3-3-21
< 941.3m to previous well
907.2m to next well >

00/06-02-003-21W1/0

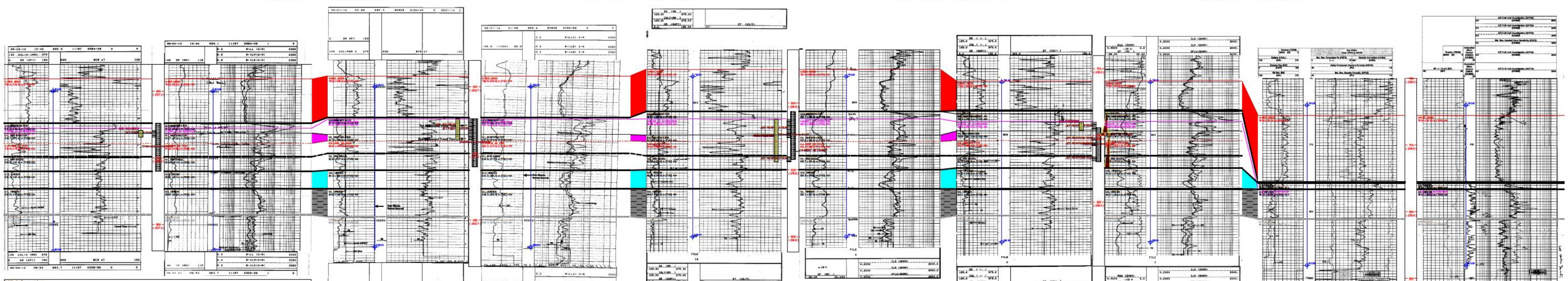
KB: 545.1 m RR: 1983-09-30
TD: 860.0 m [TVD] ● FormTD: LODGEPOL
Mode: Prod Fluid: Oil
EOG WHITEWATER 6-2-3-21
< 907.2m to previous well
1121.6m to next well >

00/16-02-003-21W1/0

KB: 536.7 m RR: 1982-03-20
TD: 845.0 m [TVD] ● FormTD: LODGEPOL
Mode: Prod Fluid: Oil
EOG WHITEWATER 16-2-3-21
< 1121.6m to previous well
1500.2m to next well >

00/07-12-003-21W1/0

KB: 522.0 m RR: 1997-05-19
TD: 825.0 m [TVD] ◇ FormTD: LODGEPOL
Mode: Abnd Fluid: N/A
EOG WHITEWATER 7-12-3-21
< 1500.2m to previous well



00/06-03-003-21W1/0 — DST Information

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	9855.6	0.0	318850.2
Daily	0.9	0.0	28.8

00/01-03-003-21W1/0 — DST Information

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	16306.0	0.0	85236.7
Daily	1.4	0.0	7.2

00/06-02-003-21W1/0 — DST Information

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	25194.7	0.0	1629.5
Daily	2.0	0.0	0.1

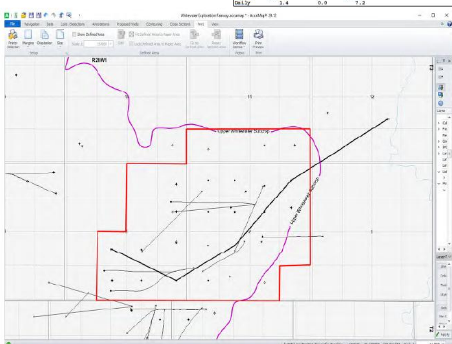
00/16-02-003-21W1/0 — DST Information

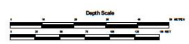
1. 796.0[TVD]-800.0[TVD] (LODGEPOL)
   Type: CONVENTIONAL STRADDLE (BLANK OFF)
   VO: 8.0/85.0 SI: 61.0/170.0 min
   FP: 679.0/705.0 kPa
   SIP: 7362.0/7246.0 kPa
   HP: 9679.0/9607.0 kPa
   "BLOW DESCRIPTION: VERY WEAK AIR BLOW ON PREFLOW. WEAK AIR BLOW DECREASING TO VERY WEAK AIR BLOW AFTER 60 MINUTES ON FINAL FLOW. RECOVERY: 40M (131FT) WATER CUT MUD PMAX: 7615.45KPA; PERMEABILITY: AVERAGE FORMATION DAMAGE: POSSIBLE"
2. 791.0[TVD]-799.0[TVD] (LODGEPOL)
   Type: DUAL CONVENTIONAL STRADDLE (BLANK OFF) 4 PACKERS
   VO: 8.0/90.0 SI: 55.0/164.0 min
   FP: 604.0/565.0 kPa
   SIP: 7351.0/7194.0 kPa
   HP: 9197.0/9197.0 kPa
   "BLOW DESCRIPTION: WEAK AIR BLOW THROUGHOUT PREFLOW. WEAK AIR BLOW OR 45 MINUTES ON FINAL FLOW, DECREASING VERY WEAK. RECOVERY: 36M (118FT) WATER CUT MUD PMAX: 7622.8KPA; PERMEABILITY: REL-LOW FORMATION DAMAGE: NONE"
3. 798.0[TVD]-812.0[TVD] (LODGEPOL)
   Type: DUAL CONVENTIONAL STRADDLE (BLANK OFF) 4 PACKERS
   VO: 5.0/83.0 SI: 63.0/183.0 min
   FP: 0.0/2350.0 kPa
   SIP: 7483.0/7525.0 kPa
   HP: 9457.0/9407.0 kPa
   "BLOW DESCRIPTION: FAINT TO STRONG BLOW ON PREFLOW. FAIR BLOW, INCREASING TO STRONG AFTER 10 MINUTES ON FINAL FLOW, STEADY THROUGHOUT. RECOVERY: 171M (561FT) MUD CUT GAS CUT OIL RECOVERY: 96M (315FT) GAS CUT OIL PMAX: 7531.5KPA; PERMEABILITY: REL-HIGH FORMATION DAMAGE: POSSIBLE"

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	10990.6	0.0	156591.6
Daily	0.8	0.0	12.1

00/07-12-003-21W1/0 — DST Information

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	0.0	0.0	0.0
Daily	0.0	0.0	0.0





Legend

- ● Oil
- ◇ Dry & Abandoned
- Contact Type - Conformity
- Contact Type - Unconformity
- Contact Type - Time Equivalence
- Contact Type - Left Fault
- Contact Type - Right Fault
- Yellow
- Red
- Purple
- Light Blue
- Shale

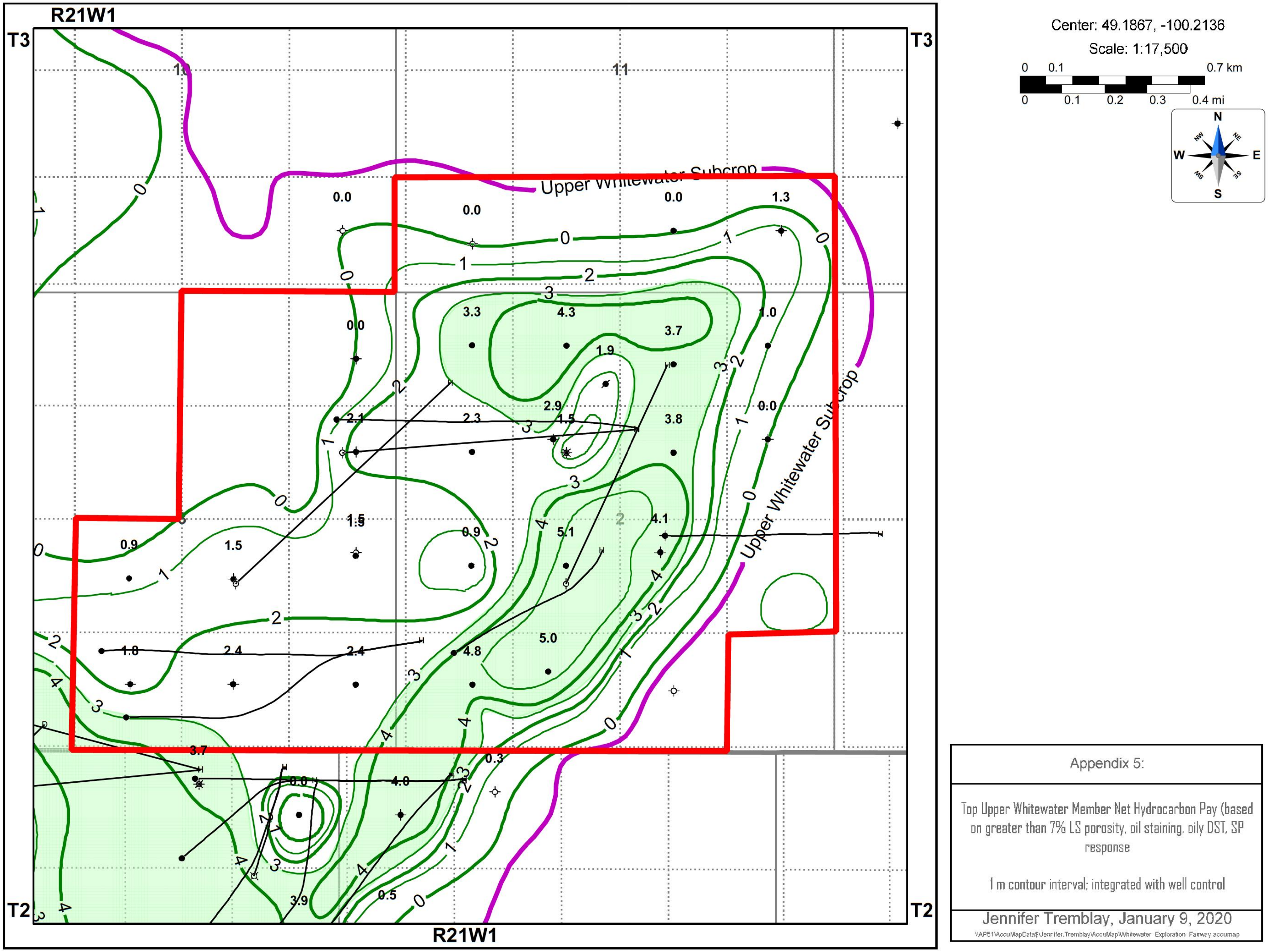
Appendix 4

Whitewater Unit 2

Cross Section A - A'
Datum: Lower Virden

Produced by:
AccuLogs
Version 9.2.5.238744
Datum: NAD27

Author: Jennifer Tremblay
Modified On: Tuesday, January 14, 2020 02:34PM
Printed On: Tuesday, January 14, 2020 02:34PM
Start Formation: 5m. above U-RED_BEDS
End Formation: 5m. below Total Depth
Cross Section Name: WHITEWATERII.XSC



Appendix 5:

Top Upper Whitewater Member Net Hydrocarbon Pay (based on greater than 7% LS porosity, oil staining, oily DST, SP response

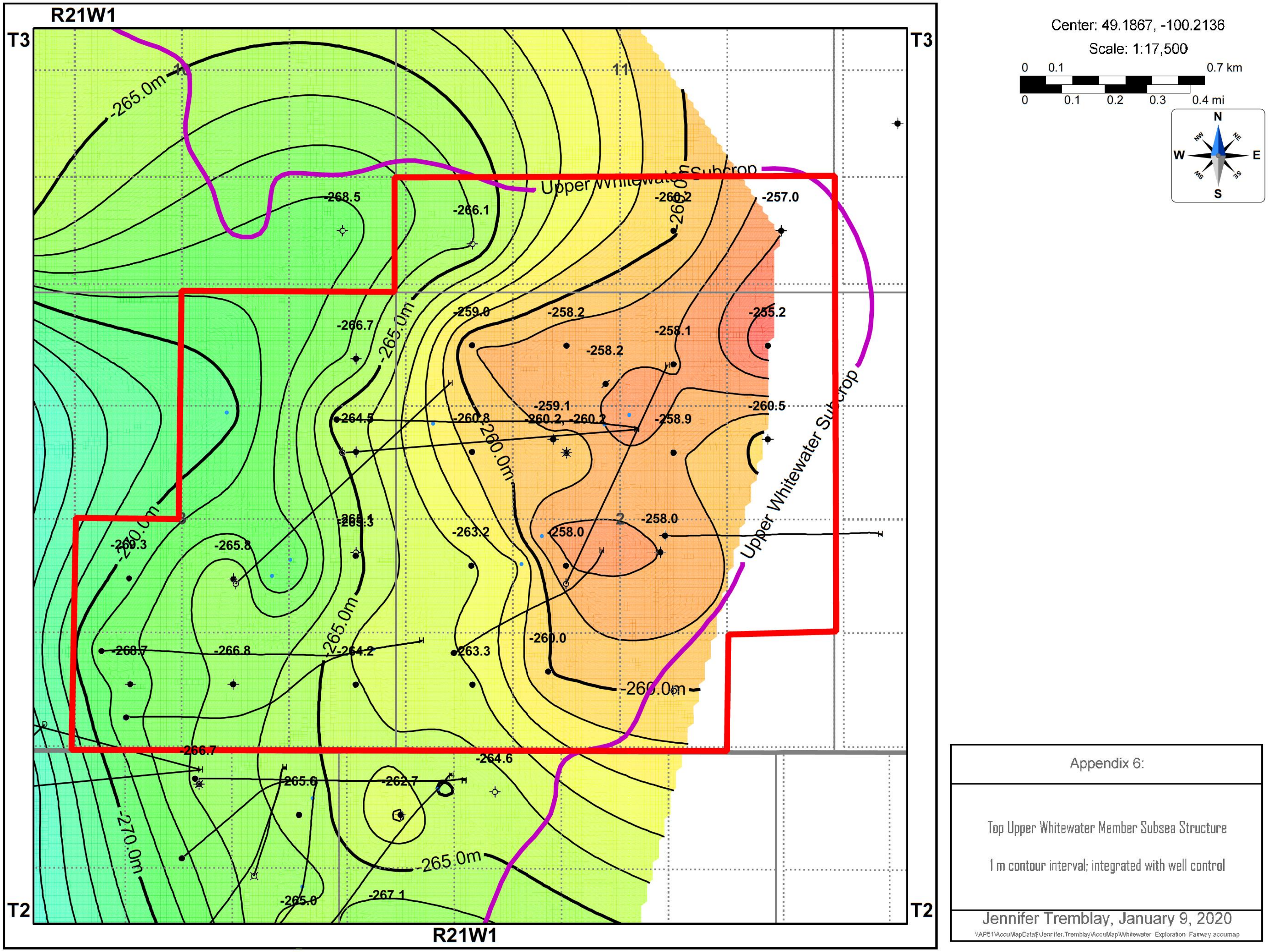
1 m contour interval; integrated with well control

Jennifer Tremblay, January 9, 2020

\\AP51\AccuMapData$\Jennifer.Tremblay\AccuMap\Whitewater_Exploration_Fairway.accumap

Appendix 5:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07



Appendix 6:

Top Upper Whitewater Member Subsea Structure

1 m contour interval; integrated with well control

Jennifer Tremblay, January 9, 2020

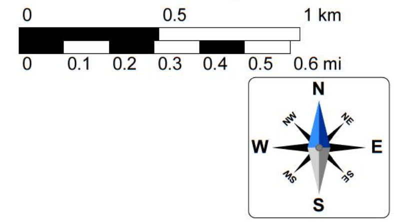
\\AP51\AccuMapData$\Jennifer.Tremblay\AccuMap\Whitewater_Exploration_Fairway.accumap

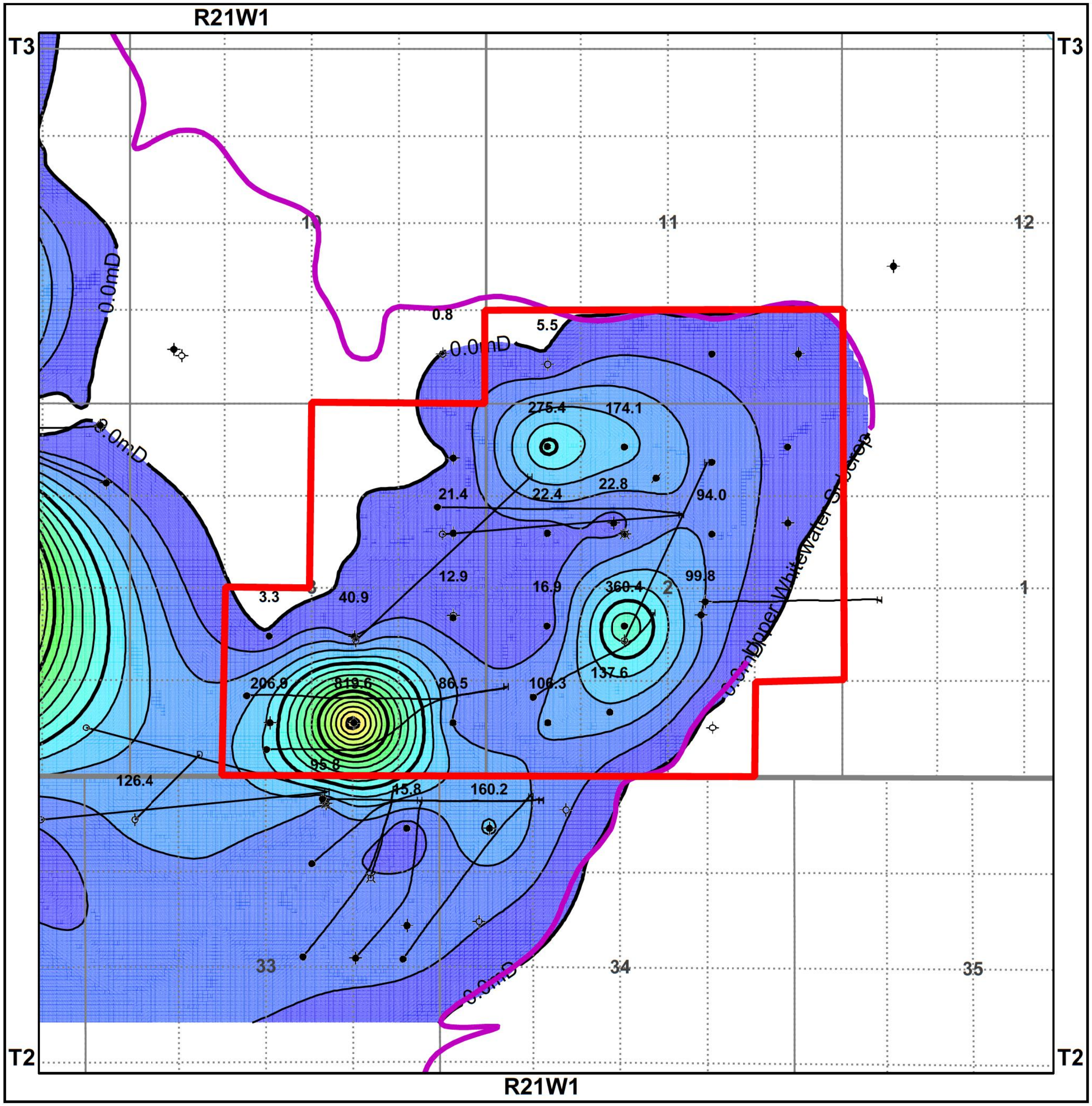
Appendix 6:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Center: 49.1867, -100.2136

Scale: 1:25,000





Appendix 7:

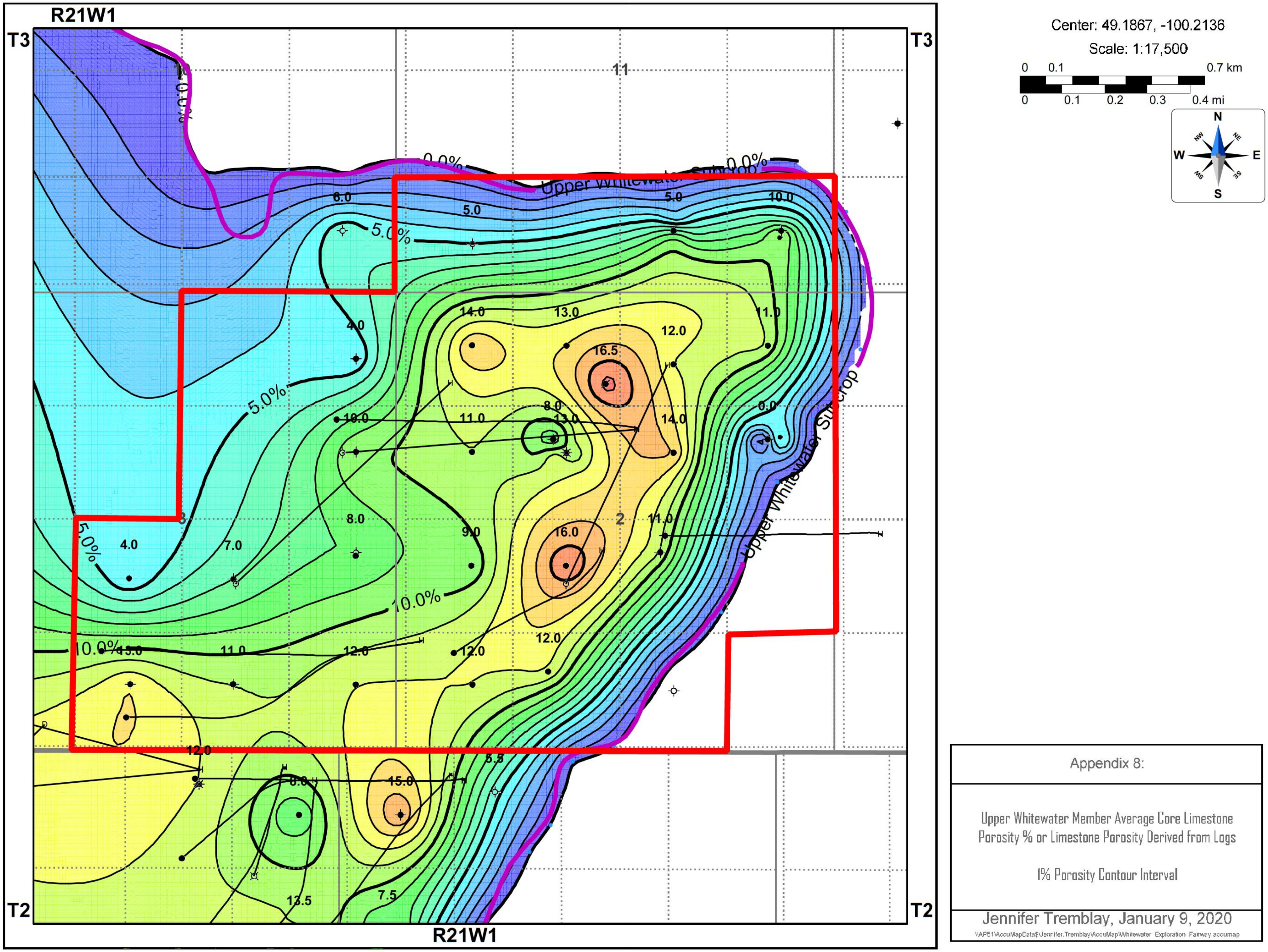
Upper Whiteweater Member Kmax.h (mD.m) or Capacity
Derived from core analysis
50 mD.m contour interval

Jennifer Tremblay, January 9, 2020

\\AP51\AccuMapData$\Jennifer.Tremblay\AccuMap\Whitewater Exploration Fairway.accumap

Appendix 7:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07



Appendix 8:

Upper Whitewater Member Average Core Limestone Porosity % or Limestone Porosity Derived from Logs

1% Porosity Contour Interval

Jennifer Tremblay, January 9, 2020

\\AP51\AccuMapData$\Jennifer.Tremblay\AccuMap\Whitewater Exploration Fairway.accumap

Appendix 8:

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Proposed Whitewater Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure No. 1

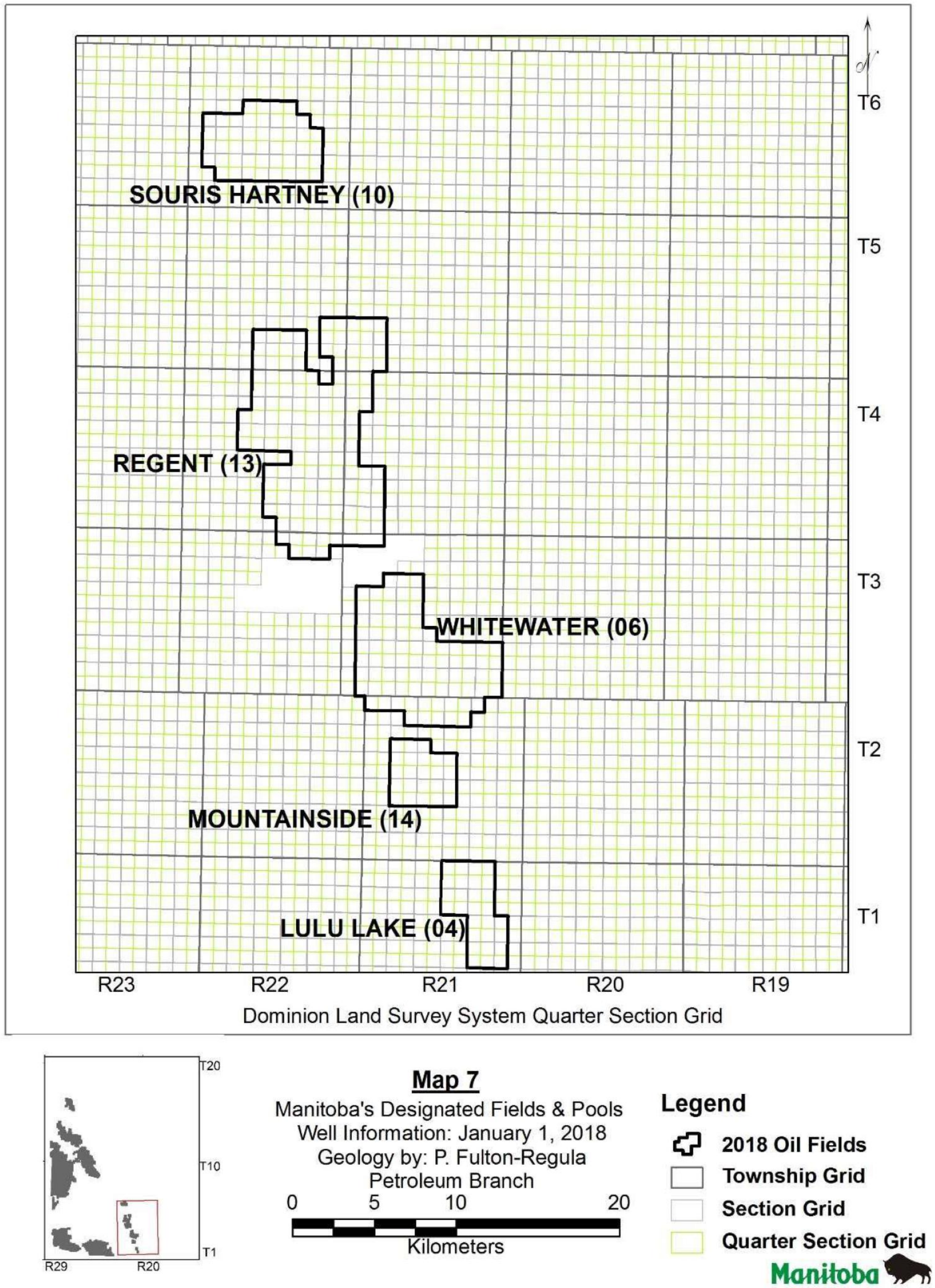
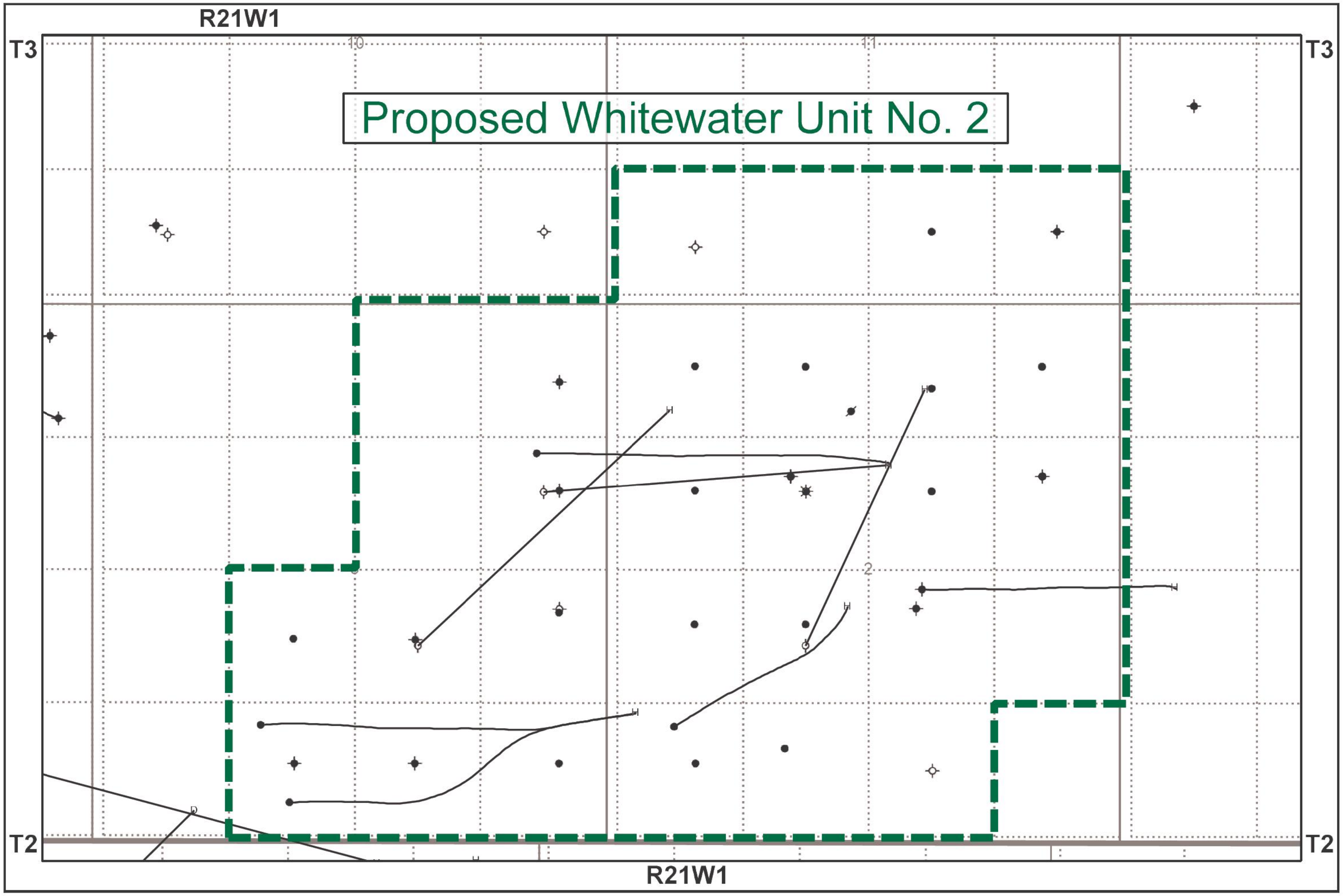


Figure 9: *Map 7; Souris Hartney, Regent, Whitewater, Mountainside & Lulu Lake fields.*

Figure No. 2



Map Title

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Figure No. 3

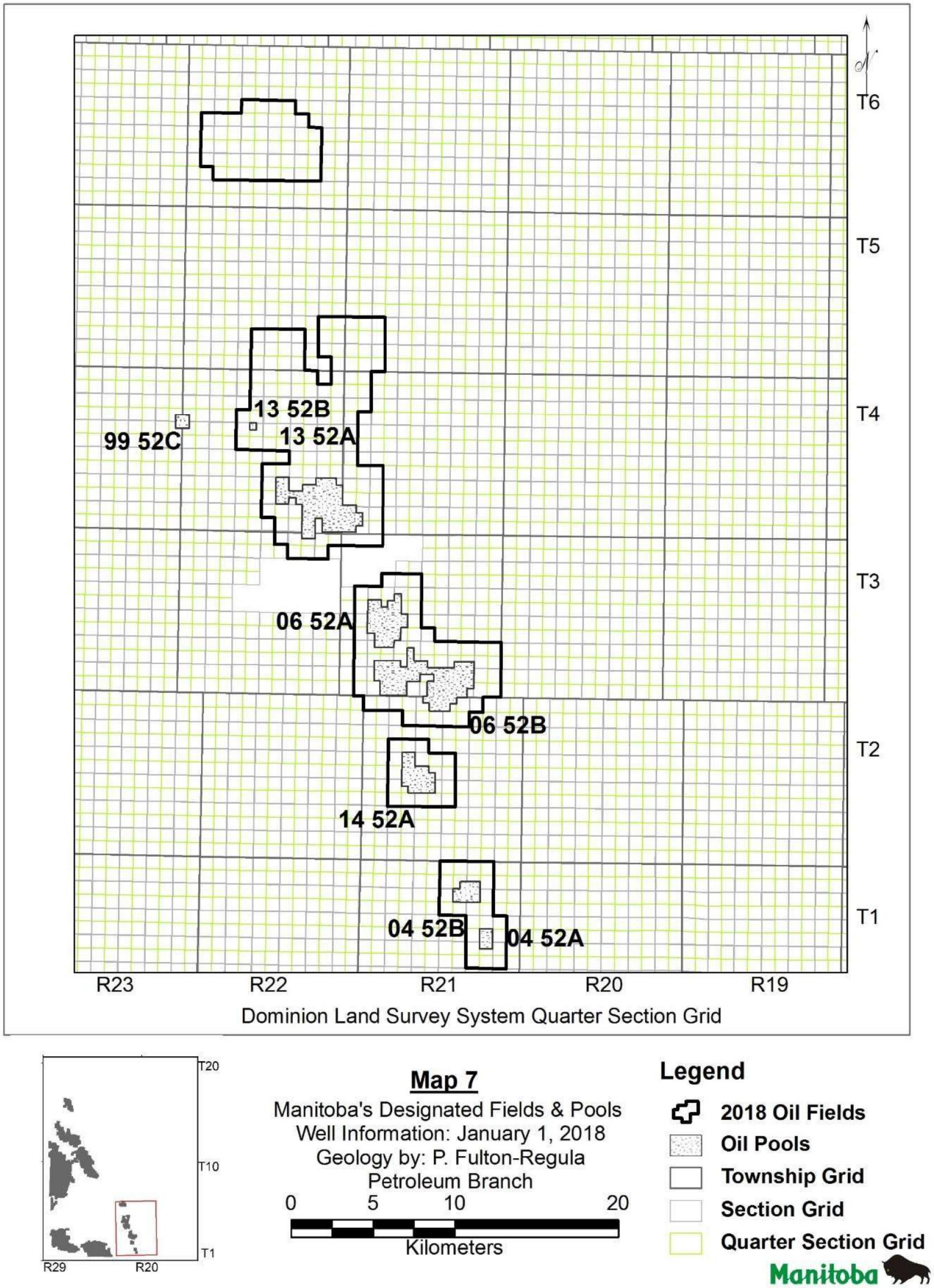


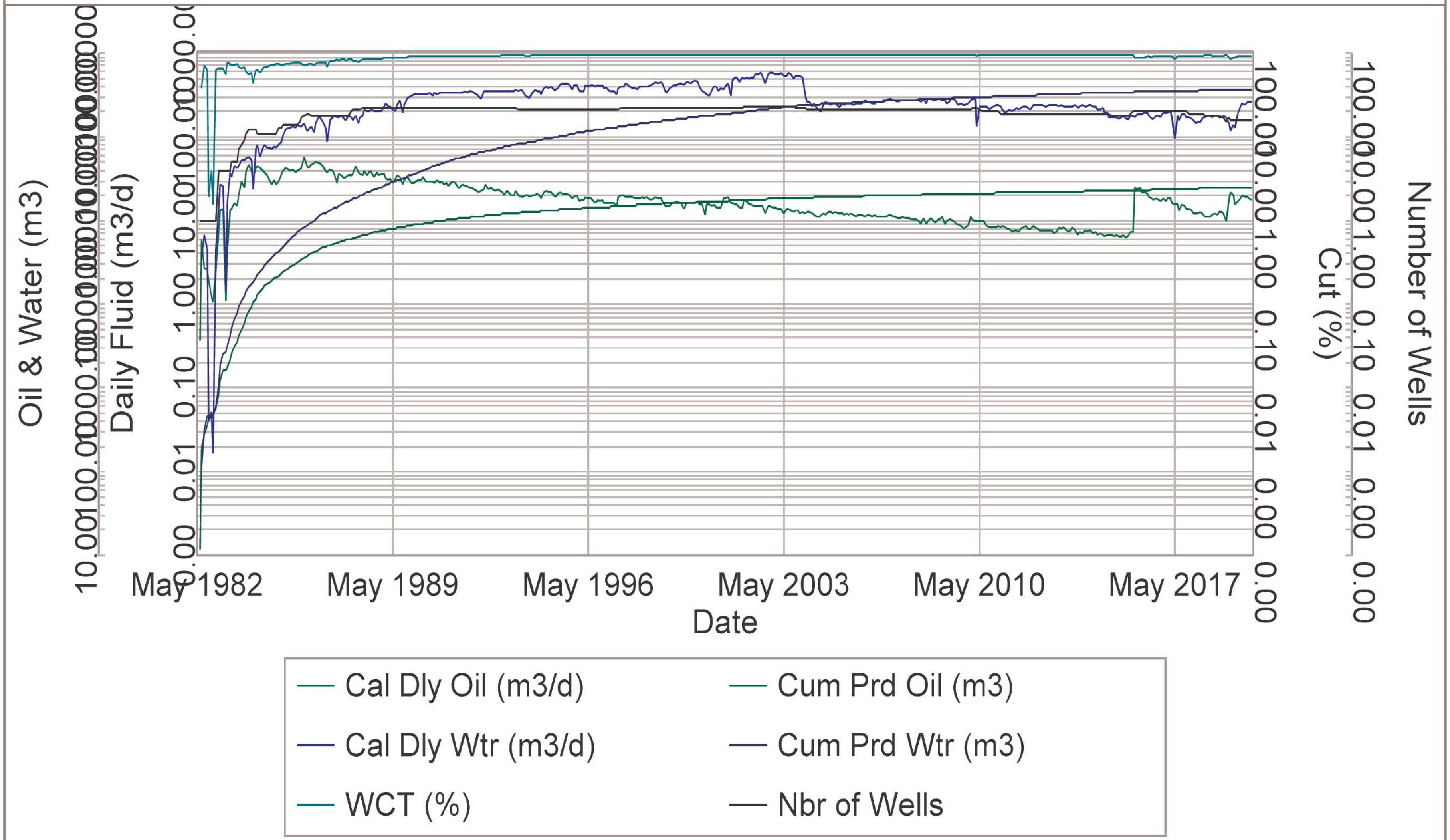
Figure 41: *Map 7; Lodgepole Formation Whitewater Lake Member pools (52).*

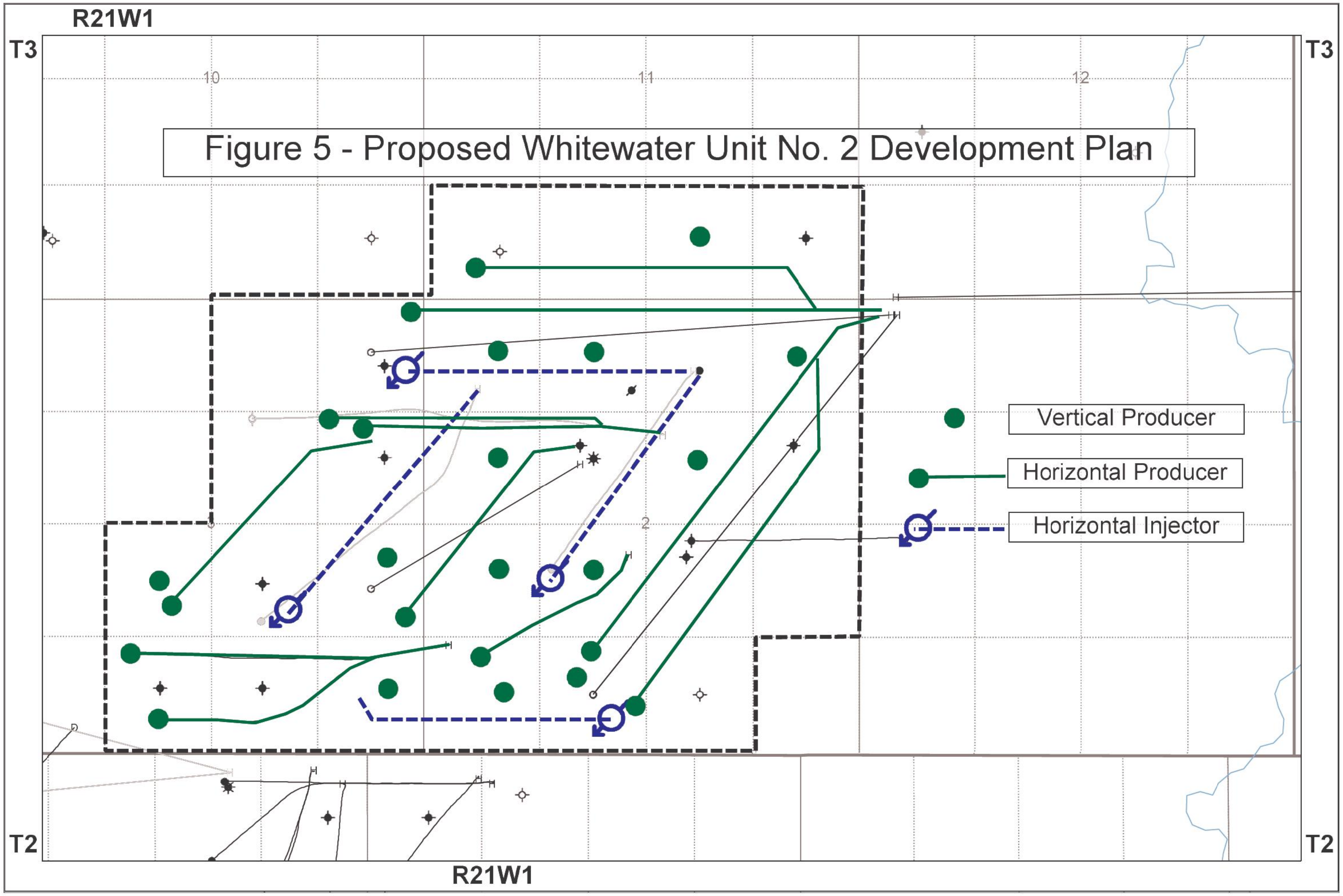
Well Information as of 2020-03-20 - Group Well Report

Figure No. 4

Production Graph

Group:	whitewater unit no. 2.lwell	On Prod:	1982-05 to 2020-01	Cum Oil:	253595.3 m3
# of Wells:	36	Prod Form:	LODGEPOL	Cum Gas:	0.0 E3m3
Fluid:	Oil	Field:	WHITEWATER (MB6)	Cum Wtr:	3702989.4 m3
Mode:	Abandoned; Producing; Abandoned Zone; Suspended; Drilled & Cased	Pool Code:	MB000652B	Cum Inj Oil:	0.0 m3
		Unit Code:		Cum Inj Gas:	0.0 E3m3
				Cum Inj Wtr:	0.0 m3





Map Title

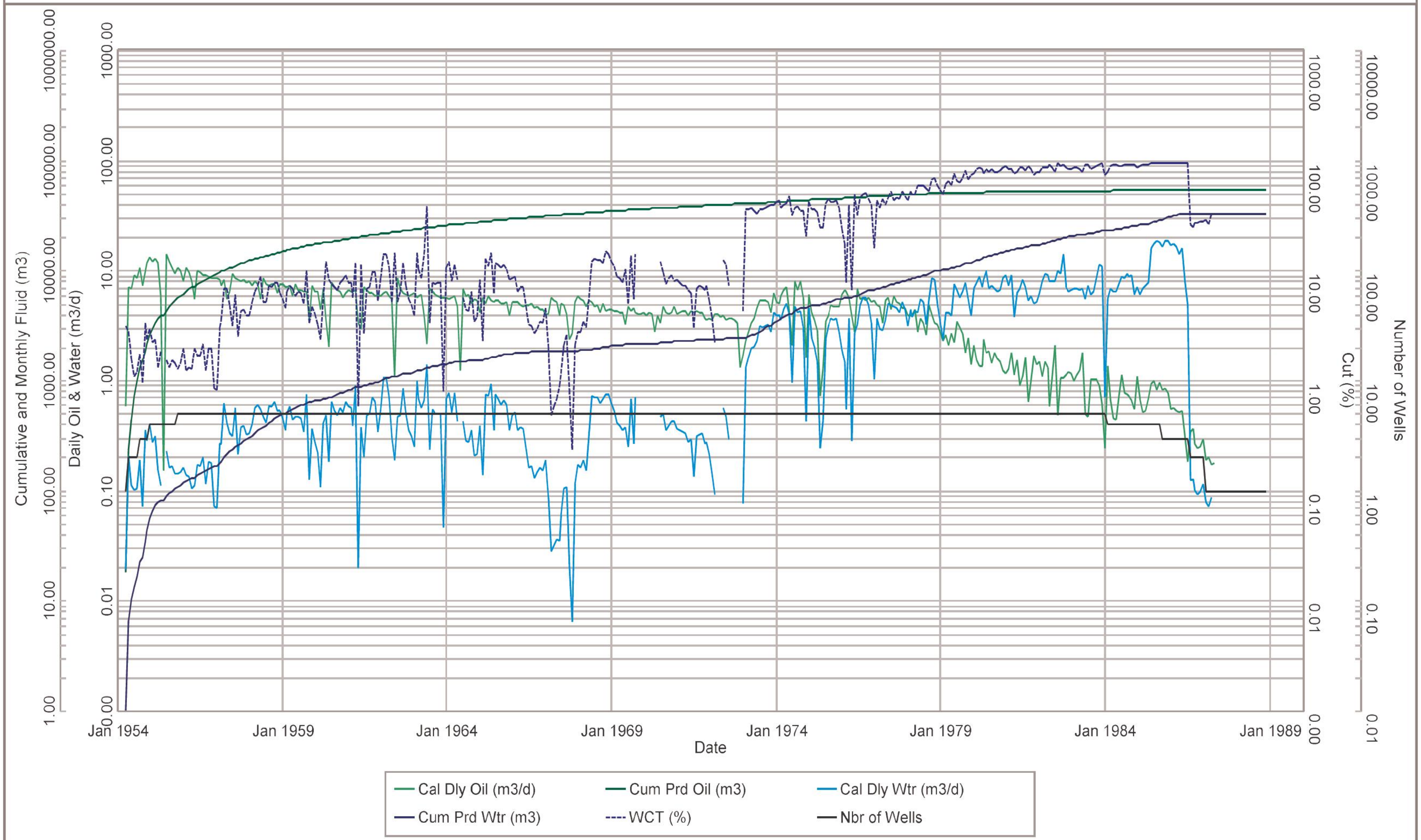
Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Well Information as of 3/2/2020 - Group Well Report

Figure No. 6

Production Graph

Group:	whitewater unit no. 1 well list.lwell	On Prod:	1954-03 to 1988-11	Cum Oil:	54483.5 m3
# of Wells:	5	Prod Form:	LODGEPOL	Cum Gas:	0.0 E3m3
Fluid:	Oil; Water Injection	Field:	WHITEWATER (MB6)	Cum Wtr:	33646.9 m3
Mode:	Abandoned	Pool Code:	MB000652A	Cum Inj Oil:	0.0 m3
		Unit Code:	652A1	Cum Inj Gas:	0.0 E3m3
				Cum Inj Wtr:	186329.0 m3



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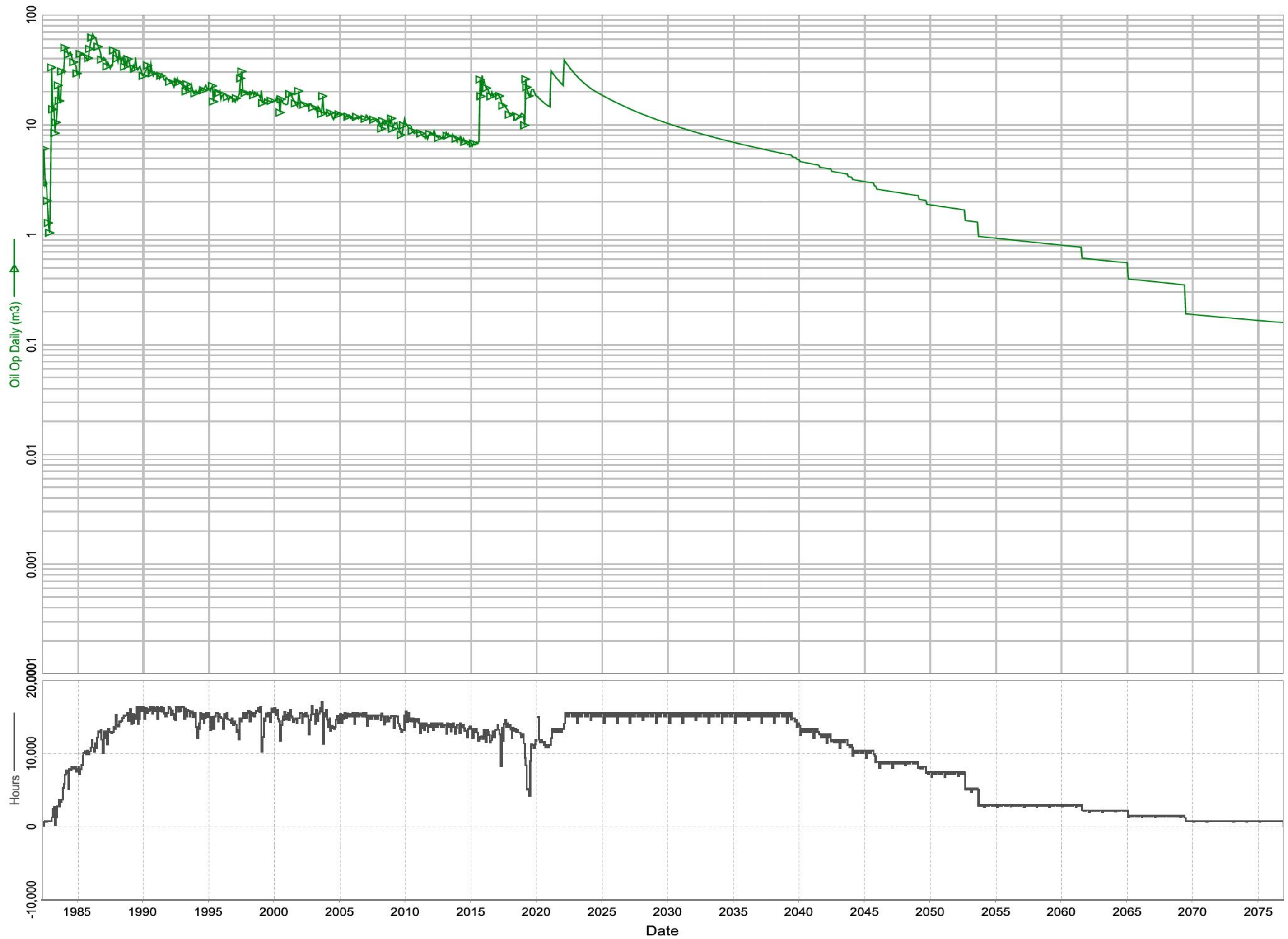
Tundra Oil and Gas
PRIMARY VOLUME FORECAST REPORT
Evaluation WB List

Figure No. 7

Effective February 01, 2020



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (m3)	253,595
	Rem Rec (m3)	112,644
	Ult Rec (m3)	366,239
Gas	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
Water	Cum (m3)	3,702,989
	Rem Rec (m3)	0
	Ult Rec (m3)	3,702,989
Field	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
NGL	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0

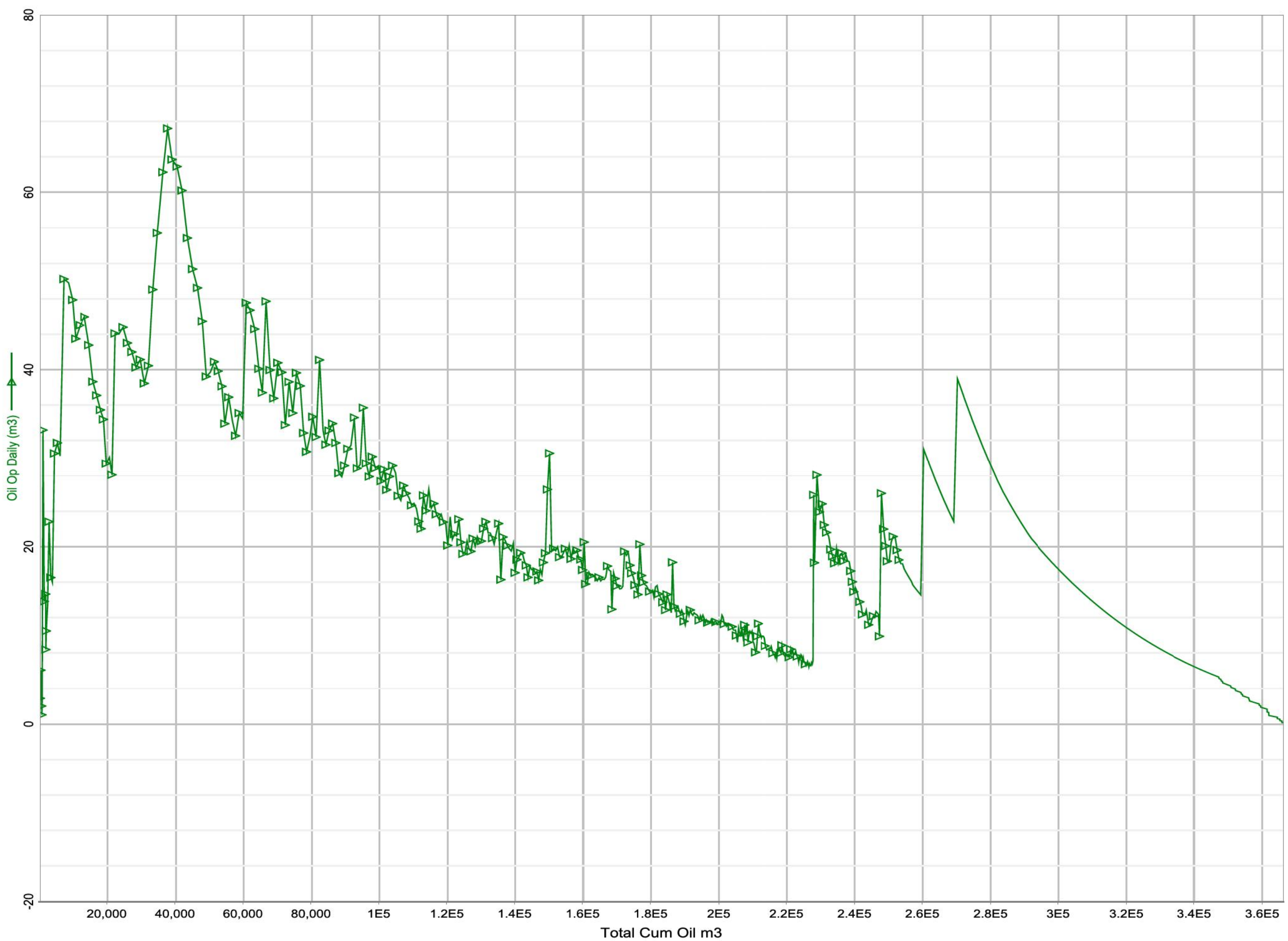
Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2020/02/01
Forecast End	2076/12/01
Presentation	Default Private
Initial Rate (m3)	18.08
Final Rate (m3)	0.16
Ult Rec (m3)	366,239.14
Cum (m3)	253,595.29
Rem Rec (m3)	112,643.85
Res Life (yrs)	56.83
RLI Full Year (yrs)	3.05
Res Half Life (yrs)	44.91

Report Time: Thu, 16 Apr 2020 17:50
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic12 Version: 2019.5

Tundra Oil and Gas
PRIMARY VOLUME FORECAST REPORT
Evaluation WB List

Figure No. 8

Effective February 01, 2020



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (m3)	253,595
	Rem Rec (m3)	112,644
	Ult Rec (m3)	366,239
Gas	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
Water	Cum (m3)	3,702,989
	Rem Rec (m3)	0
	Ult Rec (m3)	3,702,989
Field	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
NGL	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0

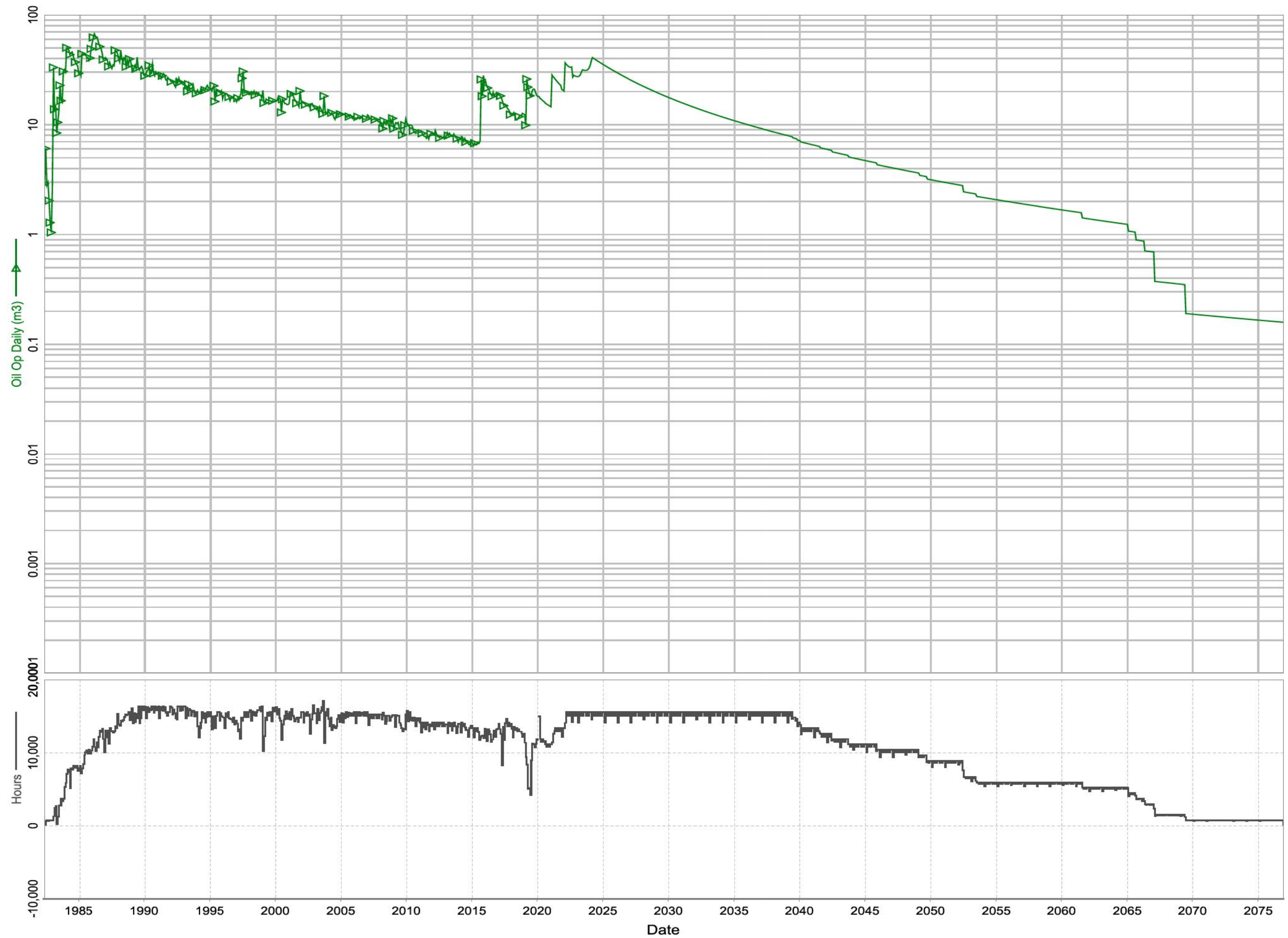
Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2020/02/01
Forecast End	2076/12/01
Presentation	Default Private
Initial Rate (m3)	18.08
Final Rate (m3)	0.16
Ult Rec (m3)	366,239.14
Cum (m3)	253,595.29
Rem Rec (m3)	112,643.85
Res Life (yrs)	56.83
RLI Full Year (yrs)	3.05
Res Half Life (yrs)	44.91

Report Time: Thu, 16 Apr 2020 17:50
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic12 Version: 2019.5

Tundra Oil and Gas
PRIMARY + SECONDARY VOLUME FORECAST REPORT
Evaluation WB List

Figure No. 9

Effective February 01, 2020



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base + Growth 1
Aggregation	Sum
Normalization	None

Volume Summary

Oil	Cum (m3)	253,595
	Rem Rec (m3)	167,531
	Ult Rec (m3)	421,126
Gas	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
Water	Cum (m3)	3,702,989
	Rem Rec (m3)	0
	Ult Rec (m3)	3,702,989
Field	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
NGL	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0

Forecast and Indicators @ Eff Date

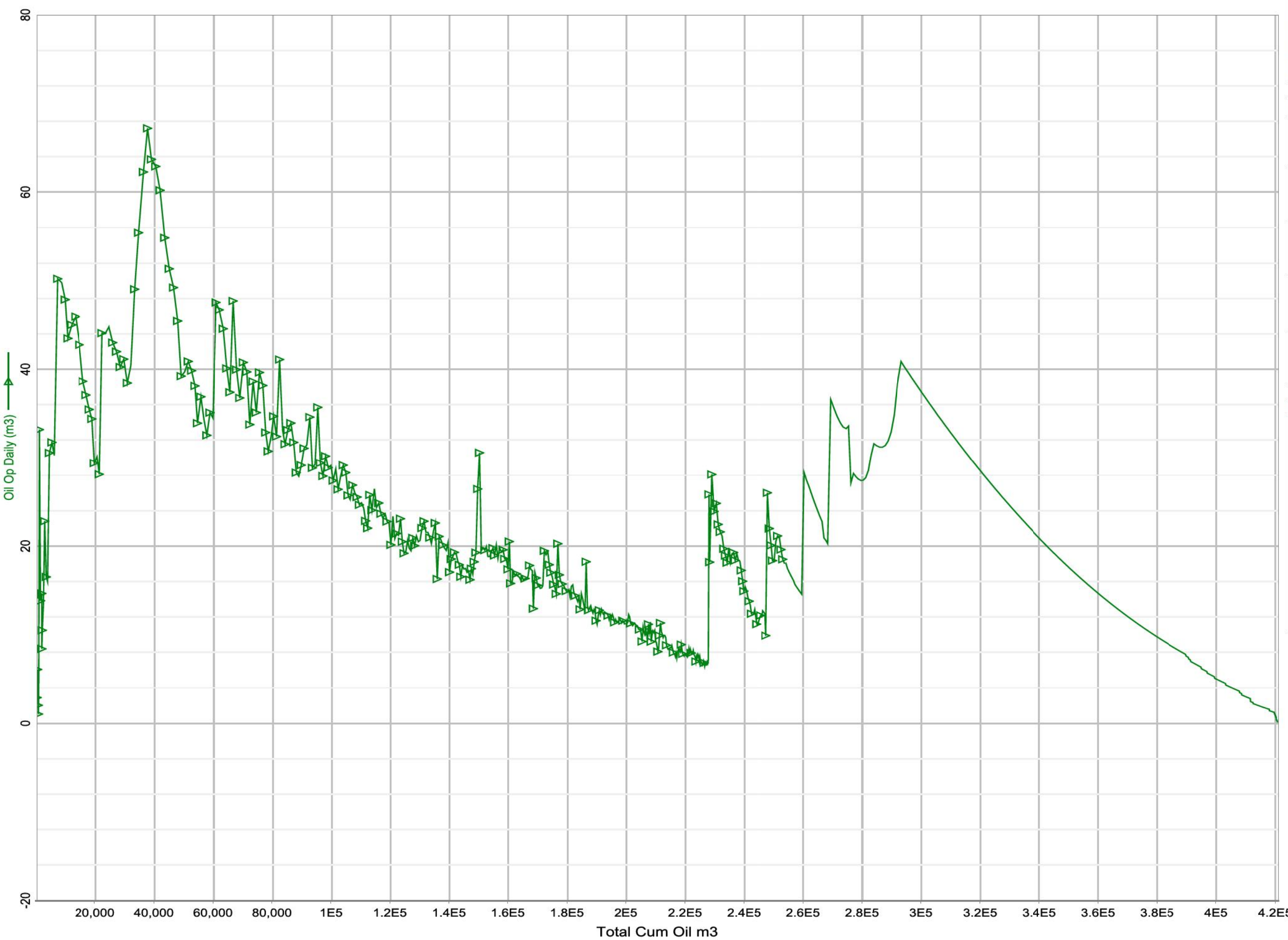
Product	Oil
Forecast Start	2020/02/01
Forecast End	2076/12/01
Presentation	Default Private
Initial Rate (m3)	18.08
Final Rate (m3)	0.16
Ult Rec (m3)	421,126.15
Cum (m3)	253,595.29
Rem Rec (m3)	167,530.86
Res Life (yrs)	56.83
RLI Full Year (yrs)	4.54
Res Half Life (yrs)	46.00

Report Time: Thu, 16 Apr 2020 17:46
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic12 Version: 2019.5

Tundra Oil and Gas
PRIMARY + SECONDARY VOLUME FORECAST REPORT
Evaluation WB List

Figure No. 10

Effective February 01, 2020



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base + Growth 1
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (m3)	253,595
	Rem Rec (m3)	167,531
	Ult Rec (m3)	421,126
Gas	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
Water	Cum (m3)	3,702,989
	Rem Rec (m3)	0
	Ult Rec (m3)	3,702,989
Field	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0
NGL	Cum (m3)	0
	Rem Rec (m3)	0
	Ult Rec (m3)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2020/02/01
Forecast End	2076/12/01
Presentation	Default Private
Initial Rate (m3)	18.08
Final Rate (m3)	0.16
Ult Rec (m3)	421,126.15
Cum (m3)	253,595.29
Rem Rec (m3)	167,530.86
Res Life (yrs)	56.83
RLI Full Year (yrs)	4.54
Res Half Life (yrs)	46.00

Report Time: Thu, 16 Apr 2020 17:46
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic12 Version: 2019.5

Tundra Oil And Gas Partnership

Figure No. 11

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	**Tundra Whitewater Unit 2 HZNTL Open Hole WIW**			**WELL LICENCE:**		
Prepared by	BH	(average depths)		Date:	2019	
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	925.0
Open Hole Lateral	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	915.0

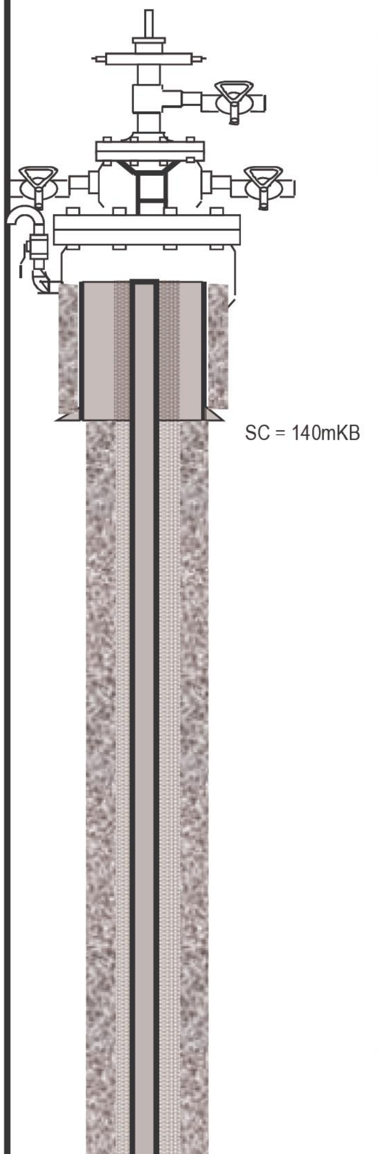
Date of Tubing Installation:			Length	Top @
Item	Description	K.B.--Tbg. Flg.	0.00	m KB
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)			
	60.3 mm or 73 mm TK-99 Internally Coated Tubing			
	TK-99 Internally Coated Tubing Pup Jt			
	Coated Split Dognut			
	Annular space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

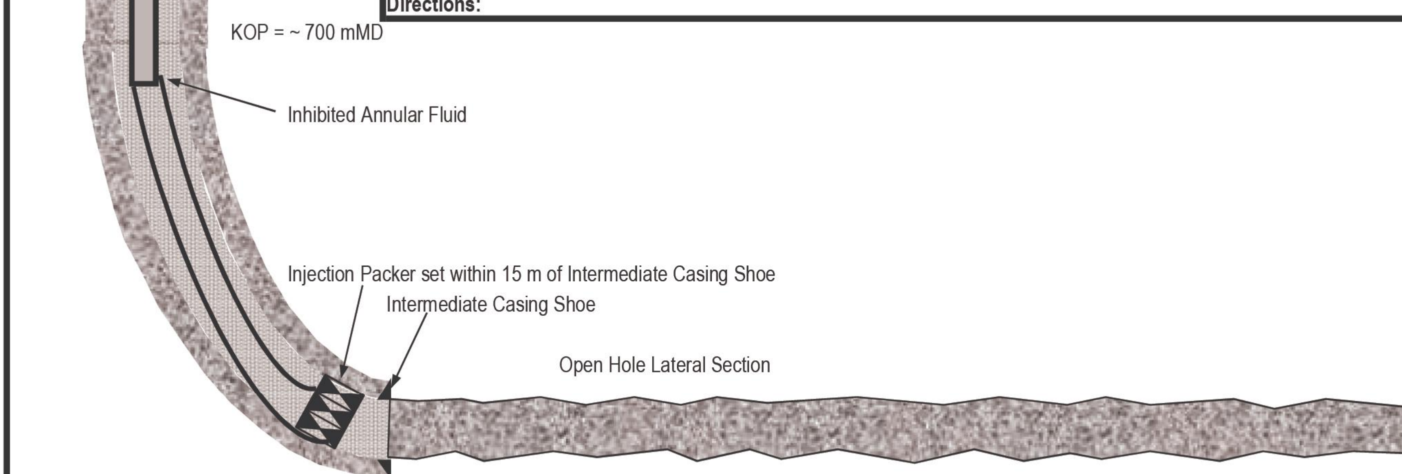
Rod String :

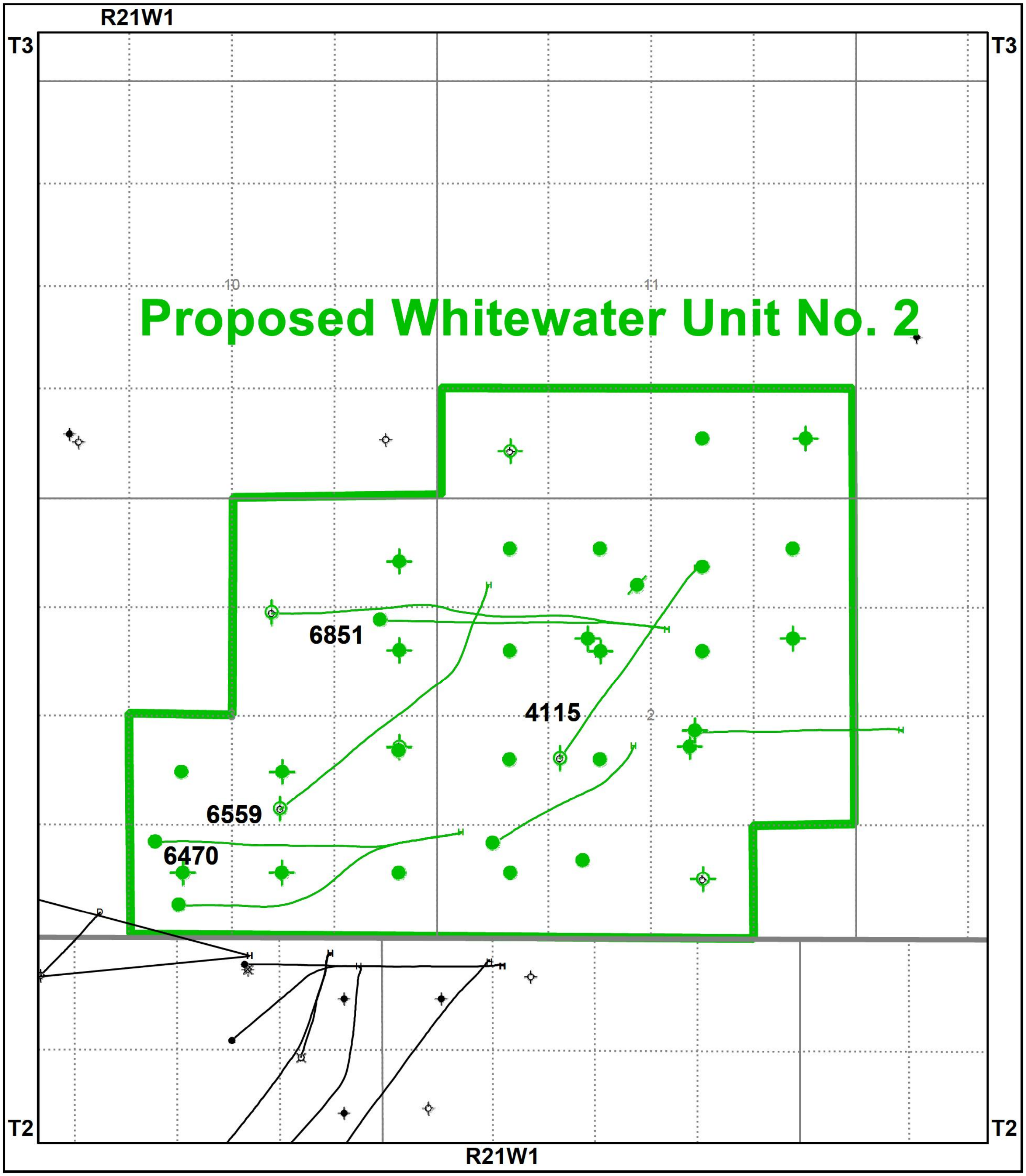
Date of Rod Installation:

Bottomhole Pump:

Directions:

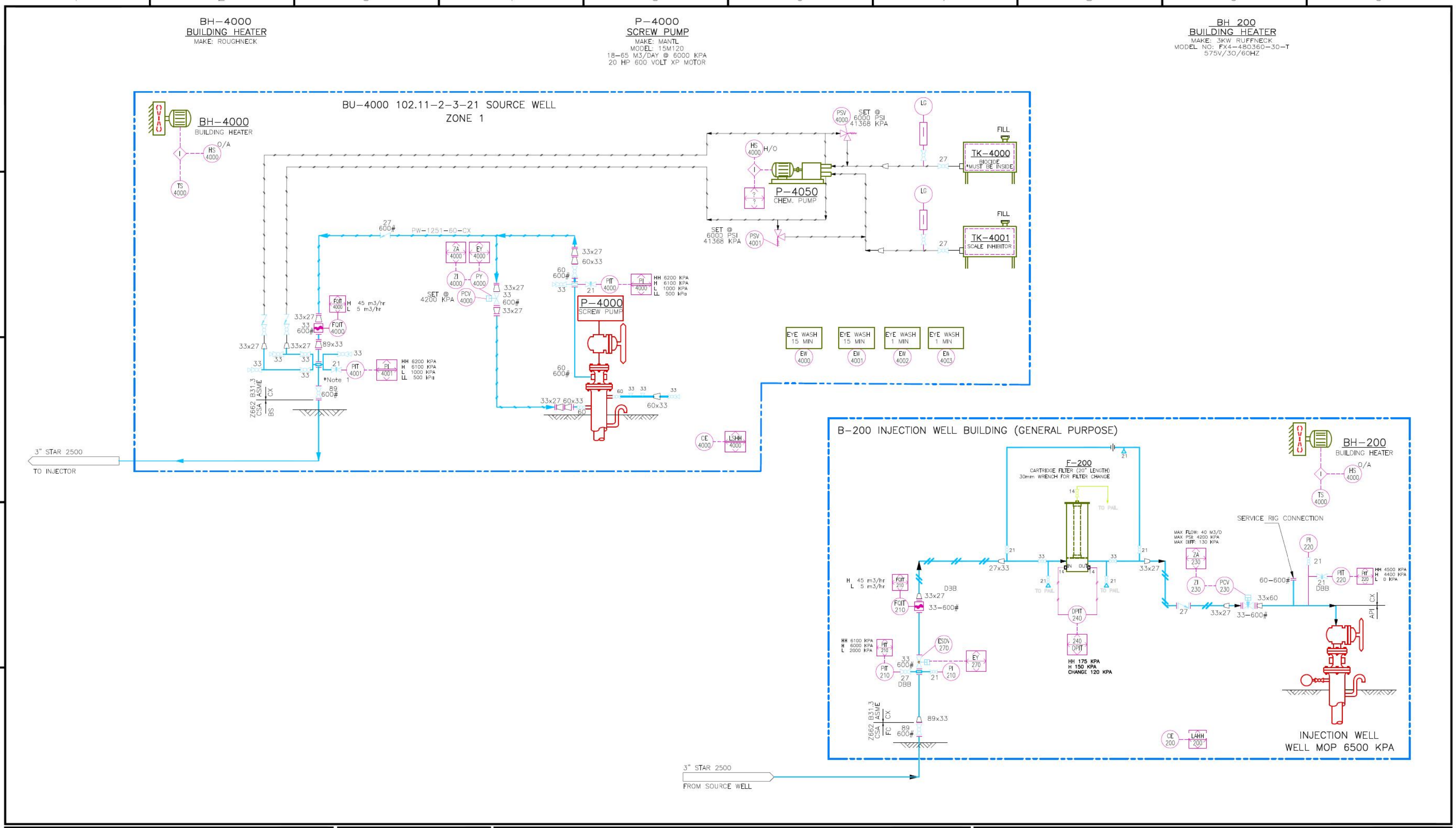






Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Figure No. 12
Initial Reservoir Pressures
Sharon Baker, January 21, 2020
\\AP51\AccuMapData$\Sharon.Baker\AccuMap\Whitewater.accumap



NOTES:
1: Blind with 4x 1" tap

Figure No. 13

REV	DESCRIPTION	BY	DATE	CHK	APP
A	ISSUED FOR REVIEW	LF	2020APR09		

REFERENCE DRAWING
-

TUNDRA OIL & GAS PARTNERSHIP

WHITEWATER
UNIT 2

PROCESS FLOW DIAGRAM
SOURCE/INJECTION WELLS

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
LF	NTS	TBA	11-02-003-21-PFD	0

Proposed Whitewater Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR PROPOSED WHITEWATER UNIT NO. 2

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

Tract No.	LSD-SEC	UWI	*OOIP (m3)*	*Hz Cum Prodn (m3)*	*Vertical Cum Prodn (m3)*	*OOIP Minus Cum Oil Prodn (m3)*	*Tract Factor (%)*
1	02-02	02-02-003-21W1	15,810	0.0	0.0	15,810	1.503194800%
2	03-02	03-02-003-21W1	55,725	2,082.9	11,685.3	41,957	3.989285393%
3	04-02	04-02-003-21W1	68,361	2,082.9	10,531.8	55,747	5.300428249%
4	05-02	05-02-003-21W1	52,450	2,191.7	7,067.9	43,190	4.106561058%
5	06-02	06-02-003-21W1	128,777	2,797.0	25,456.6	100,523	9.557777981%
6	07-02	07-02-003-21W1	64,031	0.7	6,194.5	57,835	5.499021616%
7	08-02	08-02-003-21W1	10,706	0.7	0.0	10,706	1.017890107%
8	09-02	09-02-003-21W1	14,803	0.0	7,789.6	7,014	0.666867280%
9	10-02	10-02-003-21W1	88,472	310.1	17,449.3	70,712	6.723365203%
10	11-02	11-02-003-21W1	44,343	1,922.5	140.7	42,280	4.020003632%
11	12-02	12-02-003-21W1	71,446	1,337.0	14,289.1	55,820	5.307361245%
12	13-02	13-02-003-21W1	74,734	83.0	10,714.0	63,937	6.079122966%
13	14-02	14-02-003-21W1	67,414	74.3	17,574.4	49,765	4.731692781%
14	15-02	15-02-003-21W1	78,589	59.8	8,783.1	69,746	6.631503594%
15	16-02	16-02-003-21W1	46,343	0.0	11,030.4	35,313	3.357561540%
16	01-03	01-03-003-21W1	40,009	2,449.1	16,326.7	21,233	2.018876190%
17	02-03	02-03-003-21W1	41,399	4,478.7	10,034.2	26,886	2.556321497%
18	03-03	03-03-003-21W1	52,827	3,568.6	2,766.9	46,491	4.420413866%
19	06-03	06-03-003-21W1	26,339	21.1	9,918.2	16,400	1.559337220%
20	07-03	07-03-003-21W1	41,006	141.4	7,075.0	33,790	3.212736211%
21	08-03	08-03-003-21W1	38,766	199.4	11,346.7	27,220	2.588074297%
22	09-03	09-03-003-21W1	62,355	1,065.5	10,039.5	51,250	4.872858297%
23	10-03	10-03-003-21W1	32,826	0.0	0.0	32,826	3.121124601%
24	15-03	15-03-003-21W1	4,571	0.0	0.0	4,571	0.434602278%
25	16-03	16-03-003-21W1	17,756	83.2	3,004.5	14,668	1.394646380%
26	01-11	01-11-003-21W1	16,899	0.0	3,592.1	13,307	1.265204680%
27	02-11	02-11-003-21W1	21,982	0.0	5,835.7	16,146	1.535159696%
28	03-11	03-11-003-21W1	16,396	0.0	0.0	16,396	1.558975058%
29	04-11	04-11-003-21W1	10,202	0.0	0.0	10,202	0.970032284%
			1,305,335	**24,949.1**	**228,646.2**	**1,051,740**	**100.000000000%**

Table No. 3 - Whitewater Unit No. 2 Well List

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 (%)
100/02-02-003-21W1/0	000854	Vertical			Abandoned	N/A								
100/03-02-003-21W1/0	003235	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	2/8/1984	Jan-2020	0.43	13.30	11685.30	2.75	85.10	14769.90	86.48
100/04-02-003-21W1/0	003724	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	12/14/1985	Mar-2019	0.05	1.60	10531.80	6.25	193.60	100262.10	99.18
102/04-02-003-21W1/0	004708	Horizontal	LODGEPOLE WL B	LODGEPOL	Producing	6/22/1997	Apr-2018	0.11	3.30	8331.40	3.98	119.40	61663.80	97.31
100/05-02-003-21W1/0	003232	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	1/31/1984	Jan-2019	0.02	0.50	7067.90	0.10	3.00	218315.30	85.71
100/06-02-003-21W1/0	003136	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	10/15/1983	Jan-2020	2.20	68.20	25456.60	0.98	30.40	1744.40	30.83
102/06-02-003-21W1/0	011143	Horizontal			Drilled & Cased	N/A	Jan-2020	3.76	116.50	2004.00	0.87	27.10	359.90	18.87
100/07-02-003-21W1/0	003502	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned	3/21/1985	Jan-2004	0.17	5.20	6194.50	33.61	1041.90	265654.50	99.50
102/07-02-003-21W1/0	007138	Horizontal	LODGEPOLE WL B	LODGEPOL	Abandoned	1/27/2010	Mar-2010		0.00	1.30	0.20	6.30	1017.60	100.00
100/09-02-003-21W1/2	003516	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned Zone	5/19/1985	Dec-2010	0.15	4.50	7789.60	0.34	10.50	143554.50	70.00
100/10-02-003-21W1/0	002936	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	7/23/1983	Jan-2020	0.69	21.50	17449.30	0.15	4.50	6057.10	17.31
100/11-02-003-21W1/0	003137	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned	10/30/1983	May-1984	0.01	0.40	82.00	0.91	28.20	40.30	98.60
102/11-02-003-21W1/0	003725	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned	1/30/1986	Apr-1986	0.44	13.30	58.70	0.08	2.30	8.80	14.74
100/12-02-003-21W1/0	003206	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	12/31/1983	Jan-2020	0.31	9.70	14289.10	11.76	364.50	232862.10	97.41
100/13-02-003-21W1/0	003217	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	1/13/1984	Jan-2020	0.60	18.50	10714.00	0.25	7.70	23736.00	29.39
100/14-02-003-21W1/0	003168	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	11/11/1983	Jan-2020	0.97	30.10	13577.70	4.04	125.30	76002.80	80.63
102/14-02-003-21W1/0	005003	Vertical	LODGEPOLE WL B	LODGEPOL	Suspended	11/11/2001	Dec-2014	0.14	4.40	3996.70	9.37	290.50	146442.20	98.51
100/15-02-003-21W1/0	002935	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	1/26/1983	Jan-2020	0.24	7.30	8783.10	27.17	842.40	351572.60	99.14
100/16-02-003-21W1/0	002754	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	5/28/1982	Jan-2020	0.33	10.20	11030.40	0.21	6.60	156619.20	39.29
100/01-03-003-21W1/0	003794	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	2/9/1986	Jan-2020	0.17	5.30	16326.70	11.52	357.20	86684.70	98.54
100/02-03-003-21W1/0	003972	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned Zone	10/25/1987	Apr-2010	0.02	0.60	10034.20	1.73	52.00	199397.30	98.86
100/03-03-003-21W1/0	003973	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned Zone	10/27/1987	Oct-2018	0.01	0.20	2766.90	0.27	8.50	137005.10	97.70
102/03-03-003-21W1/0	010310	Horizontal	LODGEPOLE WL B	LODGEPOL	Producing	10/31/2015	Jan-2020	4.16	128.90	10497.60	17.31	536.60	20999.40	80.63
102/03-03-003-21W1/2	010310	Horizontal	LODGEPOLE WL B		Producing	N/A								
100/06-03-003-21W1/0	004059	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	3/31/1988	Jan-2020	0.52	16.20	9918.20	28.62	887.10	322322.20	98.21
100/07-03-003-21W1/0	004009	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned Zone	11/28/1987	Jan-2019	0.02	0.50	7075.00	0.12	3.70	69177.70	88.10
102/07-03-003-21W1/0	011065	Horizontal			Drilled & Cased	N/A	Jan-2020	1.84	56.90	541.30	3.38	104.70	5534.80	64.79
100/08-03-003-21W1/0	003767	Vertical			Abandoned	N/A								
102/08-03-003-21W1/0	003844	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	3/17/1986	Jan-2020	0.35	10.70	11346.70	38.66	1198.50	381469.20	99.12
100/09-03-003-21W1/0	003507	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned Zone	3/24/1985	Sep-2017	0.05	1.40	10039.50	3.74	112.30	197384.20	98.77
102/09-03-003-21W1/0	010311	Horizontal	LODGEPOLE WL B	LODGEPOL	Producing	9/30/2015	Jan-2020	0.61	19.00	3573.50	97.02	3007.50	30889.00	99.37
102/09-03-003-21W1/2	010311	Horizontal			Drilled & Cased	N/A								
100/16-03-003-21W1/0	003793	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned	1/27/1986	Sep-1993	0.26	7.70	3004.50	7.96	238.80	20829.50	96.88
100/01-11-003-21W1/0	002933	Vertical	LODGEPOLE WL B	LODGEPOL	Abandoned	1/19/1983	Aug-2003	0.20	6.20	3592.10	19.16	594.10	145669.00	98.97
100/02-11-003-21W1/0	002938	Vertical	LODGEPOLE WL B	LODGEPOL	Producing	1/28/1983	Jan-2020	0.81	25.20	5835.70	18.67	578.80	284944.20	95.83
100/04-11-003-21W1/0	003976	Vertical			Abandoned	N/A								
										253595.3			**3702989.4**	

TABLE NO. 4: OOIP Calculation

LSD	OOIP(m3)	OOIP(bbls)
02-02-03-21W1	15,810	99,440
03-02-03-21W1	55,725	350,500
04-02-03-21W1	68,361	429,980
05-02-03-21W1	52,450	329,900
06-02-03-21W1	128,777	809,980
07-02-03-21W1	64,031	402,740
08-02-03-21W1	10,706	67,340
09-02-03-21W1	14,803	93,110
10-02-03-21W1	88,472	556,470
11-02-03-21W1	44,343	278,910
12-02-03-21W1	71,446	449,380
13-02-03-21W1	74,734	470,060
14-02-03-21W1	67,414	424,020
15-02-03-21W1	78,589	494,310
16-02-03-21W1	46,343	291,490
01-03-03-21W1	40,009	251,650
02-03-03-21W1	41,399	260,390
03-03-03-21W1	52,827	332,270
06-03-03-21W1	26,339	165,670
07-03-03-21W1	41,006	257,920
08-03-03-21W1	38,766	243,830
09-03-03-21W1	62,355	392,200
10-03-03-21W1	32,826	206,470
15-03-03-21W1	4,571	28,750
16-03-03-21W1	17,756	111,680
01-11-03-21W1	16,899	106,290
02-11-03-21W1	21,982	138,260
03-11-03-21W1	16,396	103,130
04-11-03-21W1	10,202	64,170
Total/Average	**1,305,335**	**8,210,310**