February 18, 2010

Manitoba Science, Technology, Energy and Mines
Petroleum Branch
Box 1359, 227 King Street W
Virden, Manitoba
R0M 2C0

Attention: Ms. Jennifer Abel, P. Eng
Chief Petroleum Engineer

Dear Ms. Abel:

RE: Proposed Ebor Unit No. 2
Unitization and Waterflood Enhanced Oil Recovery (EOR) Application

Thank you for confirming receipt and preliminary review of the proposed Ebor No. 2 Unitization and Waterflood EOR Application submitted by Tundra Oil and Gas (Tundra).

As requested by your letter of February 11, Tundra hereby submits the following additional information to supplement the original Application;

Mineral and Surface Ownership Notifications

Names and addresses of mineral owners in the project area, and within 0.5 km area, are contained within the attached Appendix 11.

A listing of surface owners, and copy of the Notice advising the surface owners of the proposed EOR project are also attached as Appendix 11.

Estimated Fracture Pressure

Completion data from the 3 existing producing wells within the project area indicate an actual fracture pressure gradient range of 20.5 to 21.2 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal (hz) injection well will be somewhat lower than these values due to expected reservoir pressure depletion.

Water Injection Facilities

The injection water for the proposed project will be supplied from the existing Sinclair Water Injection system which also supplies Sinclair Unit No 1. The attached Figure 14 outlines the process flow of water supply, treatment, measurement, as well as rated maximum working pressures. High quality injection water will be transferred to the proposed Ebor Unit No 2 project by pipelines as shown by Figure 11 in the original application. Attached also is Figure 15 which describes the new proposed 102 / 4-11-9-29 W1 project injection well surface piping, equipment, and design pressure.

Injection Water Compatibility

The same high quality Lodgepole sourced injection water currently used for Sinclair Unit No 1 will also be used in the proposed Ebor project. Tundra does not foresee any compatibility issues between the produced and injection waters based on the rigorous testing already conducted and quoted in the EOR application submissions for Sinclair Units 2 and 3.

Since all producing wells in the Sinclair and Ebor areas, whether vertical or horizontal, have been hydraulically fractured, produced waters from these wells are inherently a mixture of Three Forks and Bakken native sources. It was this mixture of produced waters that was extensively tested for compatibility with same source Lodgepole water by a highly qualified 3rd party prior to implementation by Tundra in Sinclair Unit 1. All potential mixture ratios between the two waters, under a range of temperatures, have been simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors has also been conducted and minimum inhibition concentration requirements for the source water volume determined. At present, continuous scale inhibitor application is maintained into the source water stream out of the Sinclair injection water facility. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program. Injection well rates vs time plots are routinely monitored for evidence of any injection restriction due to scaling and Tundra sees no operational problems with the system design at this time.

Unit Agreement

A copy of the proposed Ebor No 2 Unit Agreement is attached as Appendix 12.

Geological Reports (Appendices 2 – 7)

Revised Appendices 2 – 7 with requested changes are attached.

APEGM Geological Qualification

Tundra Oil and Gas is currently a member in good standing of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA), and has been since 2003. APPEGA members are recognized by The Association of Professional Engineers and Geoscientists of Manitoba (APEGM) as an equivalent certification. Tundra is currently pursuing formal Company recognition by APEGM as an APEGGA member.

Geological Information Calculations Description (Appendices 2 – 7)

A complete discussion outlining the calculation methods for all geological information presented in Appendices 2 – 7 is attached as Appendix 13.

Original Oil in Place (OOIP) Estimates

The OOIP values for the proposed Ebor Unit 2 were determined internally by Tundra's Calgary based Senior Professional Geologist, Barry W Larson.

A detailed description of the OOIP calculation methodology is also included in Appendix 13.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Ebor 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. If no production rate response to waterflooding is realized, existing producers will effectively become uneconomic as described under the Primary production scenario.

Assuming Unitization and EOR project approvals are received by the date proposed, Tundra plans to operate the project throughout 2010 and expects to observe an actual project production response for comparison to numerical simulation model predictions. Tundra has no intention of prematurely abandoning the Ebor project without adequate observation or evaluation and will provide a future operating prognosis as part of the 2010 Annual Progress report.

Analogy to Sinclair Unit No 1

The unconventional nature of the reservoir in the project area, as outlined by the rock and fluid properties listed in Table 1 of the original application, presents a unique challenge to forecasting oil production rate and potential reserves recovery under EOR. Such uncertainties are best addressed by locating another analogous reservoir or EOR project response upon which to base such predictions. Since there are no direct EOR project analogies available to aid generating of an expected EOR production response forecast out of the proposed Ebor Unit 2, an inference of response potential was derived by looking south to that of Sinclair Unit No 1.

The original application does not state that Sinclair Unit No 1 Waterflood reservoir and geological parameters are analogous to the proposed Ebor Unit 2 project. It does however state the EOR production response observed from Sinclair reservoir rock parameters was used to infer what a reduced or "de-rated" Ebor EOR response may be, given the lower quality reservoir in Ebor. This was deemed valid given similar well completion methods, and no other real or technically sound available alternatives.

The attached Table 4 summarizes reservoir rock parameters previously provided to the Branch for the original Sinclair Unit No 1 EOR application. Of note is the significantly higher measured air permeability in Sinclair Unit 1 compared to the much lower average measured air permeability, and variance of permeability, in the Ebor project area. These inherent differences were used to generate the significantly lower reported primary and secondary Ebor production rates and recovery factor forecasts vs those provided for Sinclair Unit No 1.

Injection Well Hydraulic Fracture Design

Tundra has extensive experience with horizontal fracturing in the area surrounding the proposed Ebor project. To prevent or minimize the potential for out of zone fracture growth, and thereby limit the potential for out-of-zone injection, all fracture operations are rigorously programmed and executed as follows;

- the number of, and specific placement of each fracture stage is pre-programmed on all injection well horizontal sections to offset adjacent pattern producing wells
- all fracture stages are designed and programmed to place small sand tonnages at very low treatment pumping rates
- all fracture jobs are entirely supervised by experienced Tundra representatives
- for each fracture stage, isolation packer running procedures, tool setting pressures, and tools function, are monitored and supervised on-site
- fracture job quality control procedures are programmed and reviewed for each stage
- on-site quality control tests are carried out before all jobs including; cleaned for purpose fluid tanks condition, optimum fluid temperature, gel times and tendencies, gel viscosity
- all fracture operational parameters are monitored live from job beginning to end including all chemical additive rates and loadings, pumping rate, sand loadings, and treating pressures, to ensure they remain within design and program parameters
- job pressures and tool function are also monitored for any evidence of isolation packer failure on each stage

Post fracturing, the horizontal injection well will be left open hole to eliminate any potential tools or liner corrosion issues and allow for future access to the lateral section if required.

Reservoir Pressure at (4-12) 102 / 4-11-9-29 W1 (Lic # 7213)

A reservoir pressure from the proposed injection well 102 / 4-11-9-29 W1 (surface 4-12) cannot be supplied now as well operations have not yet progressed to the point where it can be measured and recovered. A measured and interpreted reservoir pressure obtained from the subject well, prior to water injection, will be reported within a 2010 Annual Progress Report for Ebor Unit No 2 as per Section 73 of the Drilling and Production Regulation.

Tracer Information

The drilling fluid was traced with Tritium only in the 102 / 4-12-9-29 W1 vertical well bore section of License # 7213. This was attempted as a means to potentially measure Initial Water Saturation (Swi) from reservoir core analysis for comparison to the Swi values determined by conventional methods utilizing electric wireline log data.

The Tritium tracer and was in no way programmed or related to determining any fracture characteristics or fracture orientation. The vertical wellbore section of 102 / 4-12-9-29 W1 was programmed to be abandoned and never hydraulically fractured.

Tritium tracer has not been programmed within any part of drilling or completion of the 102 / 4-11-9-29 W1 (Lic # 7213) horizontal injection wellbore. In addition, no operations are planned to map the orientation of any hydraulic fracture stages in the subject injection well proposed for Ebor Unit No 2. Tundra has investigated and concluded that the area geology, TVD, and necessary hydraulic fracture design preclude the use of currently available fracture mapping technologies. Tundra currently believes hydraulically induced fractures propagate, from the east / west drilled horizontal injection wells, in a direction perpendicular to the least principle regional stress.

Reservoir Simulation

As stated in the original application, a numerical reservoir simulation model for the project area is expected to be capable of predictive production forecasts for comparison against actual production in the project by the end of Q3 2010. At minimum, this information will be reported within a 2010 Annual Progress Report for Ebor Unit No 2 as per Section 73 of the Drilling and Production Regulation.

If you have any questions or require further discussion, please contact William (Bill) Jenkins at 403-513-1018 or Anna Koscianski, Area Exploitation Engineer, at 403-513-1022.

Yours truly,

TUNDRA OIL & GAS PARTNERSHIP

for Alex Solberg, P. Eng
Vice President, Exploitation and Reservoir Engineering

enclosures

Proposed Ebor Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project

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Sinclair Water Injection System

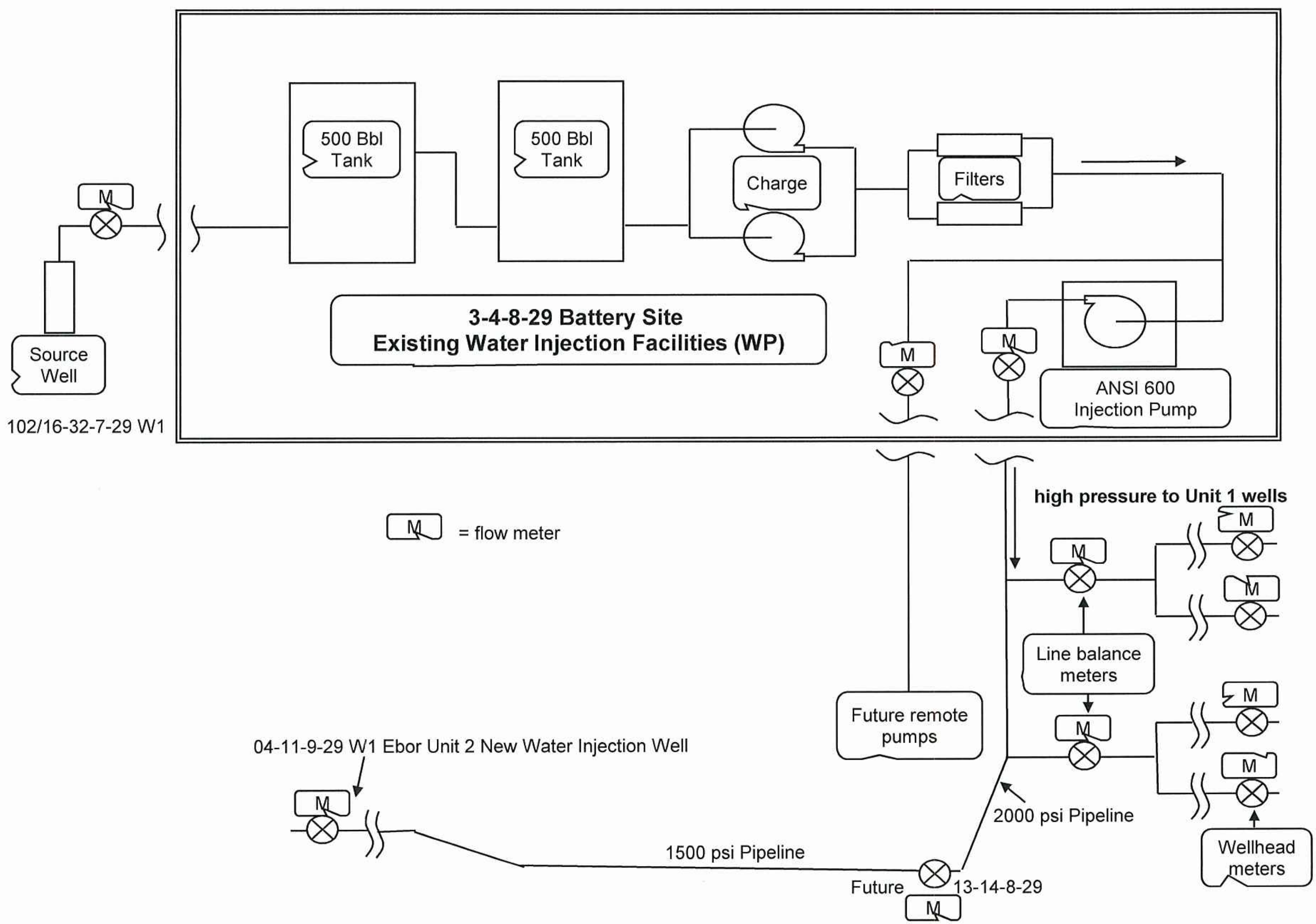
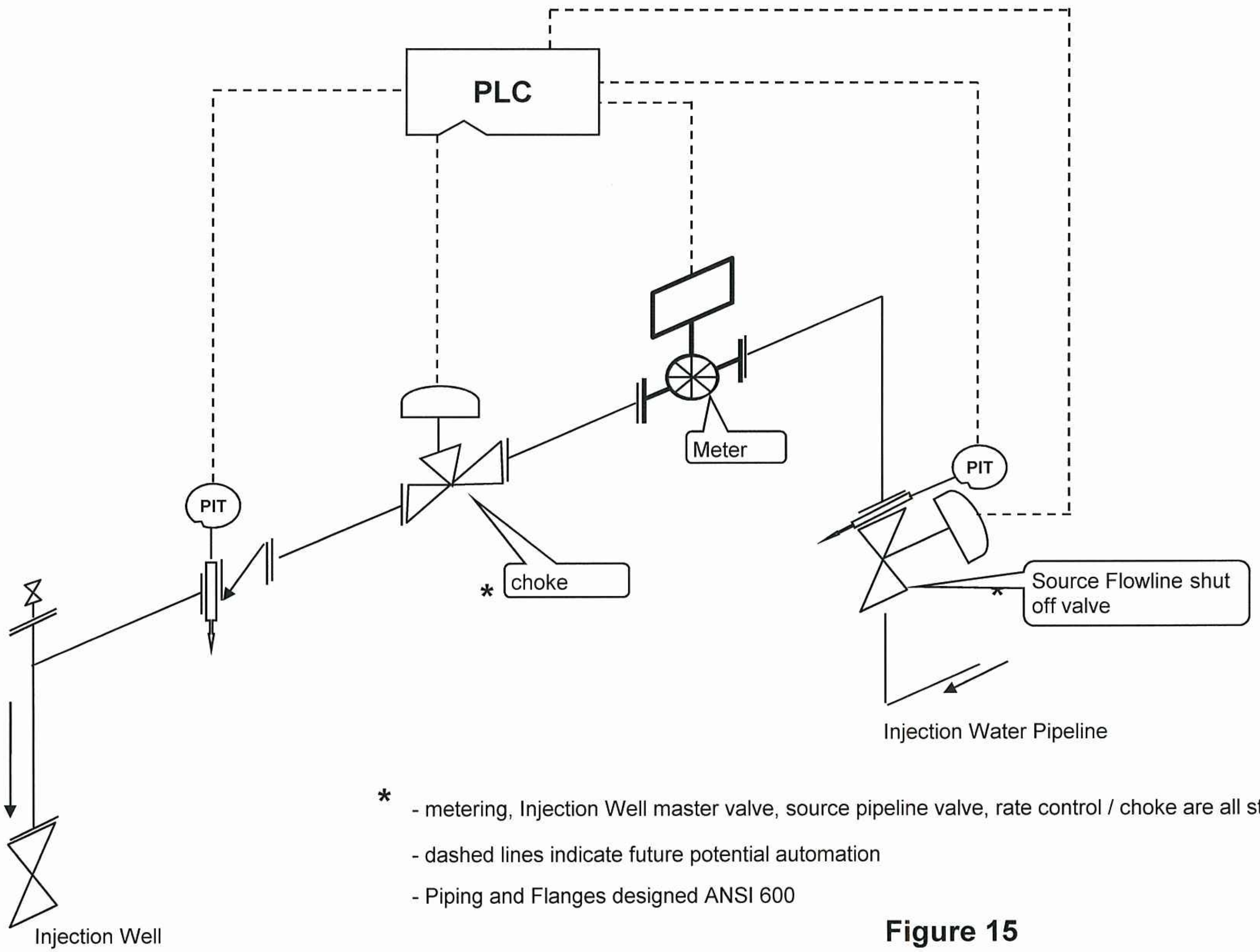


Figure 14

Ebor Unit No. 2

Proposed Injection Well Surface Piping P&ID



* - metering, Injection Well master valve, source pipeline valve, rate control / choke are all standard

- dashed lines indicate future potential automation

- Piping and Flanges designed ANSI 600

Figure 15

Proposed Ebor Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project

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- Estimated Ultimate Recovery (EUR) Primary Reserves Forecast
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- OOIP Recovery Factors; Primary and Secondary Forecasts

Table 3 — Proposed Ebor Unit 2 Well List

Table 4 — Original Sinclair Unit No 1 Reservoir Rock Parameters

Table 4

Sinclair Unit No 1 - Sections 4 & 9

THREE FORKS FORMATION ROCK & FLUID PARAMETERS

Formation Pressure	10.3 MPa	Initial Average Reservoir Pressure
Formation Temperature	40 C	
Saturation Pressure	2,034 Kpa	Bubble Point
GOR	5.6 m3/m3	Gas Oil Ratio
Oil Viscosity	1.59 cP	
Soi (fraction)	0.726	Initial Oil Saturation
Swi (fraction)	0.274	Initial Water Daturation
Sor (fraction)	0.293	Residual Oil Saturation
Swirr (fraction)	0.236	Irreducible Water Saturation
Wettability	Moderately oil-wet	
Average Air Permeability	11.5 mD	From Core Data
koi	3.2 mD	Initial Permeability to oil
kwf	0.67 mD	Final Permeability to water
Average Porosity (fraction)	0.17	Core Derived Average Porosity
Micropores <1 micron	34.60%	Pore Size Distribution of Total
Mesopores 1 - 3 microns	36.70%	Pore Size Distribution of Total
Macrpores > 3 microns	28.70%	Pore Size Distribution of Total