

December 11, 2007

Manitoba Industry, Trade and Mines  
Petroleum Branch  
1395 Ellice Avenue, Suite 360  
Winnipeg, Manitoba  
R3G 0G3

**Attention: Keith Lowdon**  
**Director**  
**Petroleum Branch**

Dear Keith,

**RE: Sinclair Unit No.1**  
**CO2 Pilot Enhanced Oil Recovery Application**

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Pleased find attached 5 copies of the referenced application to install a CO2 pilot enhanced oil recovery operation in Sinclair Unit No.1. Tundra has completed several engineering studies including PVT work, special core analysis and numerical simulation in support of our application. These are confidential documents which can be made available for review only by Petroleum Branch personnel.

Tundra Oil & Gas Limited would like to have the CO2 pilot oil recovery project in operation by March 1, 2008. To that end, we are prepared to help your department in any way that will facilitate timely approval of our application.

Should you have any questions or prefer further discussion, I can be reached at 934-5853.

Yours truly,

**TUNDRA OIL & GAS LIMITED**

George Czyzewski, P.Eng.  
VP, Engineering

cc : John Fox, P.Eng., Assistant Deputy Minister  
Jennifer Abel, P.Eng., Chief Petroleum Engineer

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**Director**  
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Dear Keith,

**RE: Sinclair Unit No.1**  
**CO2 Pilot Enhanced Oil Recovery Application**

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### **Introduction**

Sinclair Unit No.1 consists currently of Sections 4 & 9 in Township 8 & Range 29 W1M (refer to Figure No.1). Oil production is obtained from the Three Forks formation in the Unit from 28 vertical wells on 20 and 40 acre spacing. Sections 4 & 9 were unitized in July, 2006 to test the effectiveness of waterflood operations in improving oil recovery and maintaining reservoir pressure. Initially only Section 9 was put on waterflood operations to evaluate waterflooding with vertical wells on 40 acre spacing in the North half of Section 9-8-29 W1M. A horizontal injector (5-9-8-29 Hz) was drilled in the South half of Section 9 to similarly test how effective a horizontal injector would be in improving oil recovery. Water injection in the vertical injectors commenced in July, 2006 and in the horizontal injector in August, 2006. Waterflood response has been confirmed in the initial area of application in the Unit. As a result, Tundra drilled 4 additional horizontal injectors in Section 4 to commence waterflood operations in the remaining area of the Unit (Section 4-8-29). Water injection commenced in the 4 new horizontal injectors in September, 2007. During the 1<sup>st</sup> Quarter of 2006 a short single lateral horizontal well was drilled at 8-4-8-29 to evaluate the impact of CO2 injection as a method of improving oil recovery and maintaining reservoir pressure. Initially the 8-4 horizontal injector was put on production and also converted to a horizontal injector to commence waterflood operations in September, 2007. The purpose of this CO2 Pilot Enhanced Oil Recovery Application is to install CO2 injection at the 8-4-8-29 horizontal injector and to evaluate over a five year period whether CO2 will be more attractive in improving oil recovery when compared to secondary recovery with waterflooding. In the final analysis it may be more attractive to go directly to CO2 operations after an initial period of primary oil recovery than to waterflood or going to water alternating gas (WAG) injection scheme. The Unit currently produces 555 barrels of oil a day at a 13% watercut.

## Conclusions

The following conclusions were confirmed based on the recent Sinclair integrated waterflood and CO2 study.

1. The best way to obtain reservoir pressure and fluid composition information is to drill observation well(s) in the Unit. This approach will eliminate long shut-in periods and significant postponement of production which negatively impacts revenue earning. Based on the pressure transient analysis (PTA) work done in the past year in the Unit with the assistance of industry experts, extensive shut-in periods are required to obtain reliable assessment of reservoir parameters. Even with this approach (based on expert analysis) there is no guarantee that there will be a high level of confidence in the data obtained from PTA.
2. Waterflood response has been confirmed in the Unit in Section 9-8-29. Appendix A outlines the Section 9-8-29 individual well production histories. The majority of wells in Section 9 have responded to waterflooding with incremental oil production. Figure No.2 outlines the consolidated production response from the vertical producers in Section 9-8-29 W1M. The highest waterflood response has been noted in vertical oil producers that are offset on either side by injectors.
3. Horizontal injector wells are considered to be a better method of waterflooding the Three Forks formation than with vertical wells. This observation is supported by reviewing actual field performance in Section 9-8-29. The vertical wells offset by the 5-9-8-29 horizontal injector have the highest waterflood response in Section 9.
4. Based on numerical simulation, the existing Unit should be expanded, in order to replace voidage and increase reservoir pressure in the adjacent Sections. This will provide for a more effective waterflood with less leakage and higher oil recovery with waterflooding.
5. The highest oil recovery from the Three Forks formation will be obtained with continuous CO2 injection after an initial period of primary recovery. Waterflooding and WAG recovery schemes will also positively impact oil recovery in the Unit. These conclusions are based on numerical simulation predictions.
6. A CO2 Pilot project is required to test the oil recovery predictions generated by the numerical simulation model before this recovery concept is expanded to other areas of the field. This is the same approach (install waterflood pilot) that was taken in Year 2006 to test how effective waterflood operations would be in the Three Forks formation before giving any consideration to expanding waterflooding to other areas of the Sinclair field..

## **Discussion**

The following items outline the key highlights from our geological and engineering studies that support our position to test a CO<sub>2</sub> Pilot Enhanced Oil Recovery Project in the Unit at this time.

### **1. Geology & Petrophysics**

The Three Forks formation in our application is also referred to as the Lyleton Pool. The Lyleton Pool is located just below the Bakken Shale unconformity and consists of an Upper Lyleton denoted as the 'A' sand and a finely laminated lower member denoted as the 'B' sand, which has poorer reservoir quality. Within the Lyleton 'A' sand there are two distinct layers and are denoted in this study as the Upper 'A' and Lower 'A' and are separated by a tight sand/silt layer.

The Sinclair Lyleton formation lies on the southwestern flank of the Daly high. In this area the Paleozoic strata dip gently to the southwest at about 5 metres / kilometre. The Lyleton reservoir appears to occupy a preservational low as defined by an Upper Bakken to Birdbear isopach. In southwestern Manitoba and the eastern part of Saskatchewan the Lyleton formation unconformably underlines the Middle Bakken Sandstone member of the Bakken formation. The Bakken formation conformably overlies the Torquay Formation and throughout this area the Lyleton formation consists of fine grained silty to very fine grained sandy dolomite with inter-bedded green and red shale.

The data from the cored wells was used to generate the isopachs, porosity thickness ( $\phi h$ ) and permeability thickness ( $kh$ ) mapping. Cutoffs for  $V_{shale}$ , porosity and permeability were 40%, 6% and 0.5 mD, respectively. Wells with full log suites were used to generate formation connate water saturation values.

The geological mapping was reworked based on new data from permeameter measurements resulting in 7 additional layers being added in the Upper Lyleton 'A' layer.

Figures No.3 to No.9 outline the updated geological mapping that was used in the numerical simulation model to generate the various production forecasts.

### **2. Laboratory Studies**

Laboratory studies of the reservoir fluids were done to provide input data that is required for the numerical simulation model. The numerical simulator is an electronic geological model of the reservoir capturing both the reservoir fluids and rock mechanics. The numerical simulator is initially calibrated to actual field performance data. Once the numerical simulation model has been calibrated, forecasts can be generated for various oil recovery and exploitation scenarios.

The laboratory testing included compositional analysis of the reservoir fluids, PVT analysis, live core restoration with determination of relative permeability of the oil / water flow in the reservoir, swelling tests on the oil in the reservoir and slim tube tests to determine the impact of CO<sub>2</sub> injection on reduction of interfacial tension (IFT) between the oil and water in the reservoir. All of this laboratory derived data was used to history match the equation of state generated by the numerical simulator to actual laboratory data. The equation of state essentially defines the mathematical relationship between volume, pressure, and temperature for all states of matter (reservoir fluids and gases).

#### **a. PVT Analysis**

The PVT analysis is used to determine the bubble point or saturation pressure of the solution gas in the oil. The bubble point pressure was determined for the solution gas in the oil to be 2,123 kPaa (2005 test) using the differential liberation testing method. More recently in 2007 the bubble point pressure was determined to be 1,920 kPaa from slim tube testing methods. The discrepancy is quite likely attributable to the fact that there was a compositional difference between the two samples tested. For the purposes of this study, the equation of state model was matched to the Year 2007 bubble point pressure of 1,920 kPaa. The GOR was determined to be 6.4 sm<sup>3</sup>/sm<sup>3</sup>. The formation volume factor was determined to be 1.026 sm<sup>3</sup>/sm<sup>3</sup>. The viscosity of the oil was determined to be 1.597 cp with a residual oil gravity of 42.6 API. The liberated gas gravity averaged 0.88. Appendix D outlines the compositional analysis of the Lyleton formation reservoir fluids.

#### **b. Relative Permeability**

The relative permeability profile for the Lyleton formation is outlined in Figure No.10. This distribution indicates that the Lyleton reservoir has low capacity for water injection and it will become progressively more difficult to inject into this reservoir as voidage is replaced. This condition is attributable to the high interfacial tension between the oil and water reservoir fluids. In summary the initial Swi = 29%, residual Sor = 31%. Formation water permeability at residual oil saturation is 0.21 mD. Reservoir fluid permeability at Swi = 1.2 md. Oil recovery = 56.6% of oil-in-place based on core flooding with water (most optimistic scenario derived in laboratory).

### **c. Swelling Tests**

Swelling tests are done to determine the minimum miscibility pressure required for a specific concentration of CO<sub>2</sub> to become miscible with the reservoir fluids. As the CO<sub>2</sub> becomes miscible with the reservoir fluids, the oil begins to swell and this process reduces the viscosity of the oil with a concurrent reduction in the IFT between the oil and water in the reservoir. Figure No.11 outlines the amount of CO<sub>2</sub> that will be either miscible with the reservoir fluids (single phase system) and the amount of CO<sub>2</sub> that will be in a two phase system (gas and fluid). Therefore, for the addition of slugs consisting of 100% CO<sub>2</sub> with pressures at or above the blue line in Figure No.11, the CO<sub>2</sub> will be miscible with the oil and present as a single phase in the reservoir. For pressures below the blue line using the 80% CO<sub>2</sub> slug size 80% of the CO<sub>2</sub> will be miscible with the oil and 20% of the CO<sub>2</sub> will be present as free gas in the reservoir. Figure No.11 is suggested as an operating guideline to illustrate the operating pressure that must be obtained in the reservoir to ensure complete miscibility with the reservoir fluids.

### **d. Slim Tube Test**

Slim tube tests are done to determine the minimum miscibility pressure that must be maintained in the reservoir to obtain the maximum reduction of IFT. Figure No.12 illustrates that a minimum miscibility pressure of 9.75 MPaa (1,414 psia) is required in the Lyleton reservoir to achieve the maximum benefit from the CO<sub>2</sub> flood in reducing IFT. This pressure of 9.75 MPaa is the pressure that would provide first contact miscibility in the reservoir (ideal situation). It is more likely that a multi – contact environment will exist in the reservoir rather than just first contact miscibility. The consideration here is that as the CO<sub>2</sub> moves through the reservoir it will encounter various pressure regimes and eventually become miscible with the oil.

### **e. Summary of CO<sub>2</sub> Coreflood Recovery Scenarios**

Figure No.13 summarizes all the laboratory derived recovery scenarios by flooding the Lyleton reservoir with CO<sub>2</sub>. The curves labeled Secondary with reservoir pressures ranging from 600 psi to 1,500 psi provide the fastest oil recovery. This represents oil recovery with minimal waterflooding and going directly after primary recovery to CO<sub>2</sub> flooding. Basically after injecting one pore volume of voidage replacement, you will recover 60% of the oil-in-place with this reservoir exploitation strategy.

The next exploitation strategy if you want to reduce CO<sub>2</sub> procurement costs is to implement the tertiary option. The tertiary option has three operating pressures which include reservoir pressures ranging from 600 psi to 1,000 psi. The exploitation strategy here is to waterflood after primary recovery to 3 pore volumes. After 3 pore volumes of reservoir fluid replacement has been achieved, start CO<sub>2</sub> flooding. The reservoir is flooded with CO<sub>2</sub> until 5 pore volumes of fluid replacement has been achieved. After 5 pore volumes of reservoir fluid replacement, waterflood operations are again implemented and continued until 8 pore volumes in total have been injected into the Lyleton. This will result in about 80% of the oil-in-place being recovered. However, if you consider the time value of money in the analysis the economics will clearly indicate that after 20 years of production (Pore Volume > 3.0) there is very little value being generated from this project.

The lowest cost option is outlined in Figure No.13 is the Tertiary 800 psi WAG recovery option. With this exploitation strategy we would initially core flood with CO<sub>2</sub> for the first 0.7 Pore Volume. This would be followed by waterflooding until a total of 5.2 Pore Volumes of reservoir voidage replacement had been achieved. After that CO<sub>2</sub> operations would again be implemented for an additional 0.5 Pore Volume. Waterflood operations would again be commissioned for the balance of the field's producing life.

Economic evaluation of the 3 exploitation strategies would have to be under taken to identify the most attractive reservoir exploitation strategy. In our opinion the exploitation program that can recover the reserves in the shortest time period at a competitive cost will provide the best economics.

### **3. Numerical Simulation Study**

The numerical simulation model was constructed in 2005 to provide a reliable method of evaluating various reservoir exploitation strategies. The initial numerical simulation study ("Sinclair Lyleton 'A' Pool Waterflood Feasibility Study, May 2005") was completed by Exploitation Technologies Inc (ETI) to investigate the potential for waterflooding the Lyleton 'A' sands. In October, 2006 the initial study was updated since it was based on only 19 wells in Sections 4 & 9-8-29. The October, 2006 update was based on numerous wells drilled on 40 acre spacing after the initial study. The October, 2006 update also investigated the final water injection pattern in Section 9-8-29. The November, 2007 update to the October, 2006 study was conducted to evaluate the feasibility of using CO<sub>2</sub> as an enhanced oil recovery option. The November, 2007 study also included an update to the geological model to capture new data from recent drilling and an update to the production and injection histories in the pool. All three studies have been placed on a CD-ROM.

The November, 2007 update investigated a total of 7 cases which are summarized as follows:

**i) Case 1: Section 4 ( Waterflood)**

This is a waterflood case including the injectors in Section 9 plus installation of 5 new horizontal injectors in Section 4-8-29 with waterflooding commencing in September, 2007. In Case 1, it was assumed that offset sections continued under primary production. The model was run from initial conditions until the Year 2045. Ultimate oil recovery was forecasted by the numerical simulator to be 2.575 MMBOE or 34.4% of oil-in-place (refer to Table No.1).

**ii) Case 2: Section 4 (Waterflood) and Offset Waterflood**

This case is similar to Case 1 except that pressure maintenance has been added through waterflood operations to the 7 Sections (3, 5, 8, 10, 15, 16, and 17-8-29) surrounding Sections 4 & 9-8-29 in the LSD's immediately offsetting Sections 4 & 9-8-29. The impact of adding pressure maintenance in the offsetting sections clearly indicates that ultimate oil recovery will increase to 3.265 MMBOE or to 43.6 % of oil-in-place in Section 4-8-29 (refer to Table No.1). Pressure maintenance in the offsetting sections will be critical in increasing the reservoir pressure and containing the waterflood in Sections 4 & 9. Therefore, the provision of offset pressure maintenance corresponds directly to an increase in production rate and incremental oil recovery in Sections 4 & 9-8-29.

**iii) Case 3: Section 4 CO2 Flooding**

This case takes into consideration that offsetting sections are on pressure maintenance through waterflood operations.

This case is based on the consideration that CO<sub>2</sub> is used as an alternate option to waterflooding as a secondary recovery scheme. In Case 3, Section 9 continued under waterflood operations with its current 5 injectors. In Case 3, Section 4 commenced waterflood operations in September, 2007 and injection was switched to CO<sub>2</sub> in April, 2008 and the forecast period continued until 2045. Flooding with CO<sub>2</sub> resulted in the highest oil recovery based on the 5 cases that were investigated with the numerical simulator. The response time to CO<sub>2</sub> injection is forecasted by the numerical simulator to be 1 year. After one year of CO<sub>2</sub> injection, the oil rate will begin to rise steadily and peak in 2012. The delay in the production response is due to the fact that the CO<sub>2</sub> must first re-pressurize the reservoir to about 9,700 kPaa. The CO<sub>2</sub> becomes miscible with the oil at 9,700 kPaa, which results in the oil rate increasing significantly and contributing to incremental oil recovery. The numerical simulator forecasts an oil recovery of 4.55 MMBOE or a recovery factor of 63% of oil-in-place with continuous CO<sub>2</sub> injection.

iv) **Case 4: Section 4 with WAG until 2014**

Case 4 is based on the consideration that there is pressure maintenance installed in the offset sections. Initially the 5 horizontal injectors in Section 4 were placed on waterflood in September, 2007, switched to CO<sub>2</sub> injection in April, 2008, and converted back to waterflood in 2014 and continued waterflood operations until Year 2045. Case 4 resulted in an ultimate oil recovery of 3.5 MMBOE or 48% of oil-in-place. This case clearly indicates the negative impact of a WAG recovery scheme in this reservoir. This observation is supported by the consideration that the oil rate begins to decline immediately after the CO<sub>2</sub> injection is converted to water injection. The significant decline in oil production is directly attributable to water injection being unable to maintain reservoir pressure due to the high IFT in this pool.

v) **Case 5: Section 4 with WAG until 2025**

The only difference between Case 4 and Case 5 is that CO<sub>2</sub> injection in Case 5 is extended for an additional 11 years until Year 2025. In 2025 the horizontal injectors are converted back to water injection and waterflood operations are continued until Year 2045. The WAG recovery scheme again negatively impacts the benefits of the CO<sub>2</sub> flood, since pressure maintenance is not sustained with water injection. The oil rate again begins to decline significantly once the horizontal injectors are converted over to water injection. Case 5 results in an ultimate oil recovery of 3.9 MMBOE or 54% of oil-in-place.

vi) **Case 6: Simulation of Pilot Cases**

Two simulation cases were run to predict the recovery of a pilot project where the HZ08-04-8-29 horizontal injector was converted from water injection to CO<sub>2</sub> injection in April, 2008. In Case 6a (CO<sub>2</sub> flood) CO<sub>2</sub> injection commenced in April, 2008 and was left on CO<sub>2</sub> injection after April, 2009. In Case 6b (WAG) CO<sub>2</sub> injection commenced in April, 2008 and was converted back to water injection a year later. Both cases were forecasted to Year 2045. The oil production rate in the CO<sub>2</sub> flooding option (Case 6a) indicated a 3 fold increase in the oil rate when compared to the WAG scheme (Case 6b). These two pilot cases are directionally similar to the full section (Cases 1 to 5) numerical simulation predictions. Pilot Case 6a (CO<sub>2</sub> Flood) indicated an ultimate oil recovery of 47% of oil-in-place whereas Pilot Case 6b (WAG) predicted an ultimate oil recovery of 43% of oil-in-place.

## **vii) Summary of Numerical Simulation Cases**

The numerical simulation oil recovery predictions clearly indicate that the highest oil recovery will be achieved with straight CO<sub>2</sub> injection. Higher oil recovery is achieved with CO<sub>2</sub> injection because as the CO<sub>2</sub> becomes miscible with the oil it swells the oil and reduces the viscosity of the oil. The reduction in viscosity of the oil results in a decrease in the IFT, which contributes to incremental oil recovery by releasing the oil that is trapped in the reservoir either by phase trapping (high local gas saturation) or oil that has been bypassed by the waterflood front. Table No.1 summarizes the oil recovery predictions generated by the numerical simulation model. Although waterflooding does not result in ultimate recoveries as high as with CO<sub>2</sub> flooding, there is still good benefit provided with water injection. The initial stage of waterflooding will as a minimum increase the reservoir pressure and minimize the likelihood of premature break through of CO<sub>2</sub> in the offset producers.

## **4. Production Forecasts and Recovery Predictions**

The production forecasts and recovery predictions generated by the numerical simulation model for Section 4-8-29 provide a comparison of the performance of the five full section recovery Cases previously outlined under Section 3 of this report with respect to oil rate, cumulative oil production, recovery factor, and re-pressurization of the reservoir. The performance of the five recovery Cases is summarized as follows:

- Figure No.14: Oil Rate Prediction Comparison
- Figure No.15: Cumulative Oil Prediction Comparison
- Figure No.16: Recovery Factor Prediction Comparison
- Figure No.17: Reservoir Re-pressurization Prediction Comparison

The production forecasts for the Pilot area and using only the Hz8-4-8-29 injector to evaluate CO<sub>2</sub> flooding and the WAG recovery scheme are summarized as follows:

- Figure No.18a: CO<sub>2</sub> Pilot flooding after April, 2008 and continued to 2045 (Wells 1-4, 2-4, 3-4 and 4-4)
- Figure No. 18b: CO<sub>2</sub> Pilot flooding after April, 2008 and continued to 2045 (Wells 5-4, 6-4, 7-4 and 8-4)
- Figure No.19a: Impact of WAG, CO<sub>2</sub> flood from April, 2008 until April, 2009 and then covert back to waterflood operations (Wells 1-4, 2-4, 3-4 and 4-4)
- Figure No. 19b: Impact of WAG, CO<sub>2</sub> flood from April, 2008 until April, 2009 and then convert back to waterflood operations (Wells 5-4, 6-4, 7-4 and 8-4).

Appendix E outlines the numerical production forecasts for the five Waterflood and Enhanced Oil Recovery Cases that were investigated.

## **5. Volumetrics and Current Oil Recovery**

The original oil-in-place determined from the history match with the numerical simulator for Section 4 is 7.5 MMBOE. The original oil-in-place for Section 9-8-29 is 8.3 MMBOE. Current oil recovery in Section 4 as of November 30, 2007 is 394,638 BOE or 5.3% of oil-in-place. Current oil recovery in Section 9 as of November 30, 2007 was 421,711 BOE or 5.1% of oil-in-place.

## **6. Working Interest Owners**

In Sinclair Unit No.1 Tundra Oil & Gas Limited is the only working interest owner at this time. In terms of mineral rights, Section 4-8-29 is Crown with Section 9-8-29 being freehold mineral rights.

## **7. Capital Costs**

Table No. 2 outlines the historical expenditures to position the Firm to under take CO2 pilot enhanced oil recovery operations in Section 4-8-29. Total costs to November 30, 2007 are \$1,723,562. Remaining capital costs to commence CO2 injection are estimated at 1.3 MM\$. Table No.3 outlines the remaining capital costs to commence CO2 injection in horizontal injector 8-4-8-29 Hz. Total capital required to test the feasibility of CO2 flooding is estimated at 5 MM\$ (includes drilling 2 observation wells).

## **8. Operating Costs**

### **i) Manpower Costs**

Since this is a critical project for Tundra, additional manpower will be required to ensure that we are making decisions on the best data available from the CO2 Pilot before it is expanded to the rest of the field that would benefit from this type of enhanced oil recovery. The following additional costs are envisioned:

- 1 – Senior Reservoir Engineer (dedicated to Sinclair only): \$100,000 / year
- 1 – Senior Production Engineer (dedicated to Sinclair only), \$100,000 / year
- 1 – Operator to look after Sections 4 and 9-8-29 wells only: \$50,000 / year

- Total manpower costs of \$250,000 / year are estimated at this time with a total cost of \$1,250,000 over the next five years to test the feasibility of CO2 flooding.

ii) **CO2 Sources and Procurement Costs**

Tundra is currently in the process of negotiating a CO2 supply contract to have liquid CO2 trucked from the Koch Fertilizer Plant by Praxair. The supplier will guarantee 15 tonnes / day at a landed cost = \$118 / tonne. Total cost would be about 3.5 MM\$ over the 5 year test period (inflation factor = 2% / year).

**9. Government Incentives**

In order for Tundra to proceed with this project, there must be equivalent government incentives in Manitoba as are currently available in other jurisdictions such as Saskatchewan. Potential incentives would include the following:

- Oil royalty holiday in Section 4 be extended for additional 5 years; this royalty holiday would start when the current waterflood incentive holiday period has expired.
- No GST to be paid on CO2 from either Koch Plant or Husky Plant
- That all findings from the CO2 Pilot enhanced oil recovery project be kept confidential for a period of 5 years.

**10. Green Strategy**

In order to facilitate a green, prosperous, growing Manitoba, we need to develop partnerships between industry and government that will result in a win – win for both industry and the environment. This would include for example constructing a CO2 compression and high pressure pipeline transportation system connecting several sources for the CO2 and the oil fields in south western Manitoba that would benefit from enhanced recovery with CO2 injection. The CO2 will be injected into the oil reservoir displacing the oil and the CO2 will be left behind for long term sequestration in the reservoir. As CO2 is produced with the oil it would be recompressed and re-injected back into the oil reservoir, thereby making Manitoba a producer of green oil. The key phrases are that sustainable resource extraction can occur with CO2 re-injection and through sequestration the environment wins because there is minimal CO2 going back into the atmosphere.

## **11. Waterflood Development**

Tundra is currently testing in Sections 4 and 9 three different waterflood oil recovery strategies. This includes 40 acre spacing vertical well waterflood in the north half of Section 9-8-29. In the south half of Section 9 we are testing 20 acre waterflooding with a horizontal injector. In Section 4-8-29 we are testing 20 acre waterflooding using the vertical wells as producers and drilling 4 horizontal injectors per section, since our current evaluation programs indicate that this is best method to maximize oil recovery using either water or CO<sub>2</sub> as the displacing fluid in the oil reservoir. We envision that the majority of the lands in Township 8 Range 29 are amenable to waterflood recovery. Similarly a good proportion of the lands in Township 7 Range 29 are also suitable for waterflood recovery. We also believe based on preliminary technical evaluations that Township 7 Range 28 may also have lands that can be waterflooded.

## **12. Unit Enlargement**

Tundra will be submitting an application to enlarge the current Sinclair Unit No.1 to include an additional 10 Sections. These new Sections will include Sections 3, 5, 8, 10, 15, 16, 17, 20, 21, and 22-8-29. All of these lands offer good incremental oil recovery potential with waterflooding. We expect to submit the Unit Enlargement application for regulatory approval by the end of December, 2007.

Yours truly,

**TUNDRA OIL & GAS LIMITED**

George Czyzewski, P.Eng.  
VP, Engineering