Review of Thermal Recovery Technologies for the Clearwater and Lower Grand Rapids Formations in the Cold Lake Area in Alberta

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This paper is accepted for the Proceedings of the Canadian International Petroleum Conference (CIPC) 2009, Calgary, Alberta, Canada, 16-18 June 2009. This paper will be considered for publication in Petroleum Society journals. Publication rights are reserved. This is a pre-print and subject to correction.

Abstract
Cyclic Steam Stimulation (CSS) has been a commercial recovery process since the mid 1980’s in the Cold Lake area in northeast Alberta. The current bitumen production is over 220,000 bbl/d using CSS from this area. To achieve desired injectivity in the bitumen saturated reservoir, steam is usually injected at a pressure above or close to the fracture pressure of the formation. A relatively high pressure drawdown is created between the wellbore and formation during the production phase, particularly in the early stage of the production cycle where formation compaction and solution gas drive are the two most important recovery mechanisms. The CSS process has limited application in reservoirs with thick bottom water or in reservoirs with fine grain sands.

The Steam Assisted Gravity Drainage (SAGD) process has been field tested and commercially expanded in the Lower Grand Rapids and Clearwater Formations in the Cold Lake area. In contrast to CSS, SAGD is a continuous steam injection process that relies on "gravity" and requires a minimum pressure drawdown to drive the reservoir fluids to the wellbore. This provides a significant advantage for SAGD as an option for the reservoirs with bottom water, top gas or with formations with fine grain sands. Several SAGD projects are in operation in different types of reservoirs in the Cold Lake and Lloydminster areas; some with thick bottom water zones.

A performance review is conducted based on the available data for various CSS and SAGD projects in the Cold Lake area. The selection criteria between CSS and SAGD technologies for Clearwater and Lower Grand Rapids are discussed. Reservoir modeling results are presented concerning the impact of well placement, reservoir heterogeneity and operating parameters on SAGD performance, based on Osum’s Lower Grand Rapids and Clearwater geology in the Cold Lake area.

Introduction
The Clearwater Formation is the main reservoir focus for thermal commercial development in the Cold Lake area. The
Grand Rapids Formation is a secondary thermal reservoir. To date there is one commercial development in the Lower Grand Rapids Formation in the Cold Lake area. Figure 1 shows a Cold Lake location map where the four major operators are IOL, CNRL, Husky and Shell. Osm Oil Sands Corp. is a relatively new participant in the development of Cold Lake bitumen resources. Its leases are also displayed in Figure 1.

1. Development History in Cold Lake Area

The development of the Clearwater Formation in the Cold Lake area can be divided into the following stages [1]: (1) laboratory testing and research piloting from 1960 to 1970; (2) field demonstration pilot testing from late 1970s to mid 1980s and (3) commercial CSS operations since mid 1980s. IOL and CNRL are the two biggest thermal operators in this area utilizing the CSS process, with a combined total bitumen production of 210,000 bbl/d by the end of 2007 [1, 2].

Pilot testing of SAGD in the Clearwater Formation commenced in the late 1990s at Burnt Lake and Hilda Lake. The Burnt Lake pilot has three well pairs and Hilda Lake has two well pairs [3]. These two pilot projects are still producing today. The first commercial SAGD project in the Clearwater Formation was operated by Husky Oil at Tucker Lake in 2006, with an expected target production of 30,000 bbl/d bitumen. Shell acquired the Hilda Lake lease including the pilot facility from Blackrock Venture Inc., and commenced first steam injection in 2007 for its 10,000 bbl/d SAGD project. These two SAGD projects are still in the early stages of development.

Development of bitumen resources in the Lower Grand Rapids Formation in the Cold Lake area is not as extensive as the Clearwater Formation. The early CSS tests by BP in the Wolf Lake area were uneconomic with a high SOR due to significant sand production and the short duration of the production cycle. Figure 3 shows the location of the CSS test pad at Wolf Lake. BP Amoco tested the first SAGD pair in the Lower Grand Rapids Formation (B10) in Wolf Lake in 1997. With encouraging results from the first SAGD pair, CNRL expanded the SAGD development in the Lower Grand Rapids Formation commencing in 2000 to 20 well pairs which are still operating. The current production is about 5,000 bbl/d.

The typical fluid and reservoir properties for Cold Lake thermal recovery projects are summarized in Table 1. The production from individual thermal projects is given in Table 2. The existing CSS operations in the Cold Lake area have minimum bottom water and localized areas of top gas. However, the two SAGD commercial projects at Husky’s Tucker Lake and Shell’s Orion have direct underlying water zones. The Wolf Lake B10 SAGD in the Lower Grand Rapids Formation has no direct underlying bottom water.

2. Net Pay Definition

The definition of net pay thickness is usually related to the recovery processes. For the Clearwater Formation, CNRL uses >6% bitumen weight to define the net pay for CSS development in the Primrose and Wolf Lake areas [2], with the main reservoir facies containing a minimum amount of Berthierine and <10% mud. For CSS development, a minimum net pay of 7.0 meters is used as a cutoff for the Primrose area and 10.0 meters for the Wolf Lake area. IOL uses >8% bitumen weight to map the exploitable bitumen pay for the CSS recovery process [1].

For the Lower Grand Rapids Formation, CNRL uses a resistivity log cut-off of >20 Ω•m for the SAGD net pay definition and a minimum pay of 10 meters for the Wolf Lake B10 SAGD commercial development [2].

3. Reservoir Performance

The combined total bitumen production from CSS and SAGD in this area was about 220,000 b/d by the end of 2007, 95% of which was from CSS in the Clearwater Formation. Assuming that the Tucker Lake and Orion SAGD projects reach their targeted production in the future, the total production from SAGD projects would still be less than 20% of the total thermal production in the Cold Lake area.

The average daily production and SOR from the individual projects are summarized in Table 2. The average CSOR is 3.3 for IOL’s Cold Lake area and 4.4 for CNRL’s Primrose area and about 6.0 for CNRL’s Wolf Lake area. It can be seen that the difference in CSS performance from different areas is impacted mainly by the quality of the reservoir (see Table 1). The Clearwater Formation, on average, is thicker and richer in bitumen saturation in the Cold Lake area operated by IOL in comparison to those operated by CNRL at Wolf Lake and Primrose.

The first SAGD pair at the Hilda Lake pilot site achieved its expected cumulative SOR of 3.5 over 10 years of operation [3]. CNRL’s Burnt Lake SAGD pilot had a 45% recovery factor at a cumulative SOR of 3.75 by the end of 2007 [2]. Those two pilots are still in operation. A thorough evaluation of SAGD performance in the Clearwater Formation is difficult at this time. Although SAGD has been applied as the commercial process at Husky’s Tucker Lake, the full-life cycle performance for SAGD is yet to be established [5]. The Orion SAGD commercial project operated by Shell is still in the initial ramp-up or steam circulation stage [3].

The comparison of SAGD and CSS performance in the Clearwater Formation should also consider the quality difference for the injected steam. Figure 2 shows the actual CSOR profile and a CSOR with quality converted to 75% for the Burnt Lake SAGD pilot [2]. It can be seen that an actual CSOR of 3.75 for Burnt Lake SAGD pilot is equivalent to a corrected CSOR of 4.5 at 75% quality. Under normal CSS operations, steam generated from the plant (usually at 75 to 80% quality) is all injected into the CSS wells without separation of the condensate from steam.

By the end of 2007, the CNRL’s Wolf Lake B10 SAGD project in the Lower Grand Rapids Formation achieved a cumulative SOR of 4.2 and the performance has continued to improve. The 2007 annual average SOR for the B10 SAGD was 2.8 as compared to a SOR of 3.5 in 2006 [2]. CNRL’s operation at B10 experienced an extensive learning process [6]. With the improvement in slot design size, start-up procedures and lifting technology, the most recent pad (S1A) achieved a cumulative SOR of <3.0 and a peak oil rate of over 100 m³/d per operating well pair.

4. Recovery Process

The major debate on the selection of recovery technology for the Clearwater Formation is focused mainly on the overall energy efficiency and ultimate recovery factor between CSS
and SAGD. Donnelly [4] concluded that SAGD will be the process of choice in the future based on a comparison of Blackrock’s Hilda Lake SAGD and IOL’s Mahkeses CSS performance. In another paper, Scott [7] recommended that CSS should be the preferred process in the Clearwater Formation based on a comparison of fuel consumption for the same amount of bitumen production from CSS and SAGD projects in the Cold Lake area. Jiang and Youck [8] proposed that HPCSS followed by SAGD as another alternative recovery process for the Clearwater Formation. HPCSS is applied as the pre-conditioning phase for a later stage SAGD process. The HPCSS followed by SAGD takes advantage of the low SOR profile from the early cycles of CSS and a high recovery factor from late SAGD. A similar process called Hybrid SAGD was also studied by Coskuner [9] based on a numerical simulation. To date neither has been proven in field application at Cold Lake.

Both CSS and SAGD were tested in the Lower Grand Rapids Formation. Figure 3 shows the location of CNRL’s CSS pad and the Wolf Lake B10 SAGD pads. The CSS test conducted by BP Amoco in the early 1990s achieved a cumulative SOR of 12 over multiple cycles of steaming from this pilot. The major challenge was the significant production of sand which led to a significant number of workovers and short production cycles. The Lower Grand Rapids Formation in the B10 area contains very fine-grained sands, with the average grain size being less than half of the Clearwater Formation sand in the Primrose area [6]. In addition, the Lower Grand Rapids Formation usually contains higher viscosity bitumen and lower solution gas than the Clearwater Formation. This makes the Lower Grand Rapids a less desirable candidate for the CSS process. SAGD has been the only viable commercial thermal recovery technology for the Lower Grand Rapids Formation to date.

5. Well Types and Spacing

Both vertical and horizontal wells have been used successfully in Cold Lake thermal development. The majority of the CSS wells in IOL’s Cold Lake area are vertical wells with well spacing ranging from 2 to 8 acres. The most common well spacing was 4.0 acres. Horizontal wells have mainly been drilled in CNRL’s Primrose CSS operations. The horizontal sections for those wells range from 600 to 1200 meters and the well spacing from 60 to 188 meters. The most common spacing used for horizontal wells is 160 m. IOL has also used horizontal wells in its recent Mahihkan North CSS development [2]. Both IOL and CNRL have infill drilled some of their existing CSS pads with horizontal wells. Infill drilling between existing 160 m spaced horizontal wells at the late cycle stage of CSS at Primrose did not encounter the heated zone [8].

The horizontal wells are completed with slotted or wire-screened liners for sand control. Limited entry perforations are also used to achieve the uniform distribution of steam injection over the entire horizontal section [10]. A comparison for some CSS pads at CNRL’s Wolf Lake operations indicates that there are similar cumulative SORs between horizontal and vertical wells [11]. Therefore, the decision to select the well types for CSS process depends mainly upon the amount of reserves controlled per pad rather than the thermal efficiency. For thin reservoirs such as those in CNRL’s Primrose area, long horizontal wells achieve the largest amount of reserves per well (or per pad) and as such are the most economically viable. In IOL’s operation area where the reservoir is relatively thick, vertical wells have been widely used.

The commercial SAGD projects in Husky’s Tucker Lake and Shell’s Orion use 100 meter lateral spacing between horizontal pairs. The horizontal section ranges from 750 to 1000 meters [3, 5]. The spacing for CNRL’s B10 SAGD project ranges from 90 to 140 meters [2].

6. Injection Pressure and Geo-mechanical Effects

The Clearwater Formation contains relatively high viscous bitumen which has low mobility at original reservoir conditions. The initial injectivity for steam is generally low if the injection pressure is lower than the fracturing pressure of the formation. As a result both CNRL and IOL have selected downhole injection pressures that exceed the fracturing pressure of the formation for their commercial CSS operations in the Cold Lake area.

Mini-frac stress tests from the field are usually used to determine the fracture pressure for steam injection for CSS operations. IOL reported a pressure gradient from 16.7 to 21.3 kPa/m from the tests at the pads in the Mahikeses area [1]. The average pressure gradient in the Cold Lake area is estimated to be approximately 21.0 kPa/m to initialize fracturing in the formation [12].

The change of geo-mechanical properties due to the increased pore pressure by steam injection into the formation can be described by a dilation model proposed by Beattie et al [13]. When the fluid pressure exceeds, or is close to, the fracturing pressure of the formation, reservoir compressibility and porosity are increased significantly. This improves the injectivity of the steam and the productivity of the fluids.

The change of geo-mechanical properties when SAGD is operated at a pressure close to the dilation pressure was studied. The high pressure injection during the initial phase of the SAGD operations is very important to accelerate the ramp-up in production based on the simulation results with a coupled geo-mechanical model [14]. The importance of geo-mechanical effects during the SAGD operations was also observed by Ito [15, 16] in his simulation studies for Hangingstone and UTF Phase B SAGD performance. The modeling results indicated that the geo-mechanical effects improve oil production rates and also alter the shape of the interface of the steam chamber.

Husky reported downhole steam injection pressures from 3000 to 6000 kPa [5] in its Tucker Lake SAGD project. The Burnt Lake SAGD pilot’s initial operating pressure was between 6000 and 9000 KPa; this was later reduced to 3000 to 4000 kPa. The operating pressure has been further reduced since 2002 when downhole pumps were installed and the wells were switched from steam lift to pump lift. The current operating pressure is about 1200 to 1400 kPa [2] which is the lowest SAGD operating pressure in the Clearwater Formation.

7. Impact of Bottom Water or Top Gas

Bottom water and/or top gas zones always present challenges for CSS development in terms of controlling the communication with bottom water or top gas zones. IOL reported about 30 to 40% lower recovery factors in areas with a gas cap from its M & P Trunk pads [1]. IOL also reported that in areas with bottom water, a significant stand-off distance is
required from the water oil contact to the perforation interval. This will also reduce the amount of recoverable bitumen.

In contrast to the CSS process, bottom water and/or top gas has less of an impact on SAGD performance. There are several field examples where SAGD has been applied successfully in producing bitumen from reservoirs with bottom water and/or a gas cap. CNRL’s North Tangleflags SAGD project in Saskatchewan has been operating since 1987 from the Lloydminster Formation which has an extensive bottom water zone and also a gas cap in the central part of the reservoir [17]. Previous primary production and CSS tests all failed due to bottom water coming into the production wells. Husky’s Tucker Lake and Shell’s Orion SAGD project areas also have thick bottom water zones [3, 5].

8. CSS Enhancement and Follow-up Processes

Although CSS has been proven to a robust commercial recovery process for the Clearwater Formation where there is no extensive bottom water or gas cap, the ultimate recovery factor is in the range of 25 to 35% of OOIP. Various processes have been tested in the field to improve the ultimate oil recovery for CSS. Those processes include air injection, solvent injection and also combined drive with gravity drainage. Infill wells have also been tested in the existing CSS operation areas [1, 2]. The following field tests which have been conducted over the last three decades in the Cold Lake area are briefly mentioned:

1. BP tested Air injection in the early 1980s at the Marguerite Lake pilot in Wolf Lake as a follow-up process to CSS [8]. The process is called "Pressure Up and Blow Down (PUBD)", where air or oxygen was injected into vertical CSS wells at a mature stage of CSS operations. Air injection was stopped and the wells were cycled to produce when the reservoir pressure was increased to 6 to 8 MPa with combustion gas. Several cycles were conducted in the pilot area and an incremental 15% was achieved in addition to the 15 to 20% recovery with HPCSS. The PUBD test achieved an equivalent SOR of about 3.6 compared to an SOR of 5 to 6 with HPCSS. The pilot was terminated due to challenges with operations.

2. Amoco tested the Mixed Well Steam Drive and Drainage (MWSDD) process in the late 90’s in the Wolf Lake and Primrose areas as a follow-up process to HPCSS. Horizontal infill wells were drilled between existing vertical wells in the late stage of HP CSS. The process was switched from CSS to a continuous process. Some of the existing vertical wells were converted to continuous injectors and the horizontal wells were continuous producers. The MWSDD process achieved additional recovery but also faced operating challenges and the CSOR (6-8) was relatively high.

3. CNRL tested a solvent injection process at Primrose as a follow-up process to CSS [2]. The solvent was injected in a later stage of the CSS process from a horizontal well pair (BD18) that was originally operated in SAGD mode for several years before it was converted to a CSS operation. Butane was injected in the upper well and bitumen was produced from the lower well. The injected butane was expected to be vaporized in the reservoir due to the high temperature from prior steam injection. A significant improvement in bitumen rates was reported after the solvent injection.

4. IOL tested a process called LASER (Liquid Addition to Steam for Enhanced Recovery of Bitumen) in pad H21 in the Cold Lake area [17, 18] to improve the CSS performance in late cycles. The process involves the addition of liquid diluent to the injected steam to improve bitumen rates and the SOR. The average diluent concentration was 2.4% vol in the injected steam [1] for the first two cycles. The average bitumen uplift was 35% over two cycles and the OSR increased from 0.24 to 0.33. The diluent recovery was 83% from cycle I and 50% from cycle II. It was expected that the remaining diluent in the formation would continue to improve the bitumen recovery in future cycles. IOL expanded the application of the LASER process to include 10 pads in the Mahihkan H-trunk and diluent injection was commenced in Q3 2007.

Geological Description for Taiga Project

Osum's Taiga Project is located on the eastern side of the Cold Lake oil deposit (Figure 1). The main bitumen reservoirs are the Lower Cretaceous Clearwater Formation and the Lower Grand Rapids Formation of the Mannville Group. The Lower Grand Rapids Formation and the Clearwater Formation are comprised of multiple sanding and coarsening-up parasequences, interpreted to have been deposited in a shallowing-up marginal marine to full marine environment. Parasequences range from 5 to 40 meters thick, with the thickest and cleanest parasequence being recorded from the Lower Grand Rapids Formation. The Clearwater Formation preserves three sand-rich zones informally named S1, S2, and S3. These are separated by two mudstone units; the M1, a laterally discontinuous medial mudstone between S1 and S2 (Figure 4), and the M2, an inter-bedded sand and mudstone unit that is in gradational contact between S2 and S3. The type well in Figure 4 shows the stratigraphic relationship of these different units. The vertical permeability of the Clearwater Formation, calculated from core images is represented in the cross section in Figure 5-B. The M1 mudstone is thick with low calculated vertical permeability in the west, and thin with high calculated vertical permeability in the central and eastern parts of the project area.

The Clearwater reservoir contains a gas cap found in the structurally high Clearwater S1 in the southwest portion of the lease (Figure 5). A south-westerly dipping basal water zone combined with the easterly dipping Clearwater structure allows for increased water saturations in the S2 in the eastern portion of the project area. Throughout much of the development area the basal water is within the S3 or the M2 (Figure 5-A).

Reservoir Characterizations and Recovery Technologies

Table 3 summaries the reservoir properties for the Clearwater Formation in the Taiga project area. There are three types of reservoirs based on the vertical distribution of the fluids and mudstone layers (see Figure 5):

Type I:
The reservoir does not have direct underlying bottom water or top gas; the target sands do not contact bottom...
water or separated from bottom water by the M2 mudstone layer;

Type II:
The reservoir has direct underlying bottom water;

Type III:
The reservoir does not have direct underlying bottom water but does have a thin top gas layer. This reservoir type is localized in a small area to the southwest corner of the Taiga Project area.

Three recovery processes will be considered for Taiga project although a wider range of variants is being considered for the ultimate development. The first is HPCSS, as utilized by IOL and CNRL in the area, characterized by above fracture pressure injection. Second is low pressure SAGD where the specific operating pressure will be limited to minimize interference with thief zones and thus will be close to native reservoir pressure. Third is high pressure assisted SAGD which will be operated up to the reservoir dilation pressure but below fracture pressure.

For the type II and III reservoirs, only a low pressure SAGD process will be considered due to the presence of bottom water or top gas. For a type I reservoir, Osum will consider utilizing HPCSS or high pressure assisted SAGD processes depending on the vertical continuity of the sands and specific well pair performance evaluations.

High pressure steam injection (at or close to the fracture pressure of the formation) is necessary for some pads in the type I reservoir area, to break through the M1 mudstone layer or other barriers so that the S1 sand can be accessed with steam injection into the S2 sand. The main advantages of making high pressure steam injection available in the Taiga project are:

- To improve SAGD performance at a pressure close to the dilation pressure of the formation in order to allow the steam to break through the thin mud layers;
- To provide the option to convert SAGD to HPCSS operations if SAGD is underperforming in some part of the reservoir;
- To provide the option to expand the development area into the thinner pay areas (e.g., 7.0 meters) using HPCSS.

The Lower Grand Rapids Formation in the Taiga project contains high porosity and high permeability sands with net pay thicknesses of 12 to 22 meters and an average bitumen saturation of 75%. The low pressure SAGD process will be considered for commercial development due to the presence of bottom water.

**Modeling Studies**

A commercial software package "Exotherm" has been used for the reservoir simulation studies. The geological and reservoir properties in the simulation are based on an up-scaled model from the field-scale geo-statistical modeling using "Petrel". The reservoir simulation model covers a drainage area of 400 x 1000 meters.

**1. Lower Grand Rapids (LGR) Formation**

Figures 6 and 7 show a 3-D distribution of the vertical permeability and oil saturation for a model used for simulation studies. The LGR reservoir is relatively uniform with high vertical permeability and high oil saturation in the pay zone. The properties in the model are representative of the average SAGD pad in the LGR Formation in the Taiga project. The model is divided into 1.0 m grid block size in the vertical dimension and 2.0 m and 50.0 m in the other two dimensions. The model contains five SAGD well pairs, each with a horizontal length of 900 meters and a well spacing of 80 meters.

The base case has all producers and injectors placed above the bottom water (2 to 3 meters above the bottom water). Although the producers are placed in the transition zone in the model, the average oil saturation around the production wells is above 45%. The injection pressure for steam is similar to the original reservoir pressure (2800 kPa assumed at the middle depth of the reservoir) to balance the pressure in the bottom water zone. This is to minimize the coning of bottom water into the steam chamber or steam injection into the bottom water zone. Both the producers and injectors are pre-heated for three months in the model to achieve uniform communication between the injectors and producers. Figure 8 shows the predicted cumulative oil production, water production and steam injection for one average well pair (the average of five pairs). The predicted cumulative oil production vs. monthly average SOR and cumulative SOR is plotted in Figure 9. The average well pair in the LGR Formation is expected to produce 240,000 m³ of bitumen at an SOR of 6.0 as cutoff. This gives a recovery factor of 51% and cumulative SOR of 3.0. Figure 10 shows the predicted oil saturation at 8 years of SAGD operation. The oil saturation above the horizontal producers is low. The oil slumping into the bottom water below the producers is observed for all well pairs (see Figure 10).

For the LGR Formation, the vertical placement of the horizontal wells is the key to SAGD performance due to the presence of bottom water. The modeling with SAGD pair placed at various heights (see Figure 11) was conducted, where pair 1 was placed at 1.0 meter below the oil water contact (OWC) and pair 4 had a couple of horizontal intervals dipping into the bottom water. The remaining three well pairs were placed higher in the model, with pair 3 as the highest in the model. Figure 12 shows the cumulative SOR predicted for the individual well pairs. The two well pairs (1 and 4), where the entire or part of the horizontal sections are placed at 1.0 meter below the OWC in the model, have a much higher SOR during the first 4 years of operation. It is interesting to note that pair 4, which only has a couple of short horizontal intervals placed into the bottom water for the producer, shows the highest cumulative SOR amongst all the well pairs.

The cumulative bitumen production vs. SOR for each well pair is plotted in Figure 13. If an economic SOR of 6.0 is used as the cutoff, the well pairs placed lower produce slightly higher bitumen volumes except for pair 4. It is noticed that the difference in produced bitumen volumes is relatively small between those cases. Therefore, the impact of the vertical placement of SAGD well pairs on the reserves is insignificant in the reservoir with bottom water.

When SAGD is operated in the reservoir with bottom water zones, oil slumping occurs below the producer into the bottom water. This is found in all well pairs regardless of their vertical placement heights. Figure 14 shows the oil saturation profiles at 8 years of SAGD operation. The oil saturation below the SAGD producer is increased for all well pairs. The oil slumping into bottom water below the producer provides the seal for the steam chamber from the bottom water. Without this seal, the well pairs placed into the bottom water (e.g., pair 4) would not be
able to form an independent steam chamber. Figure 15 is the predicted temperature profile at 8 years of SAGD operation. It can be seen that the temperature decreases quickly with the distance downward from the SAGD producer. The slumped bitumen becomes viscous again and immobile when the temperature drops a few meters down from the producer.

Although the simulation results indicate an insignificant impact of the vertical placement of SAGD well pairs on the total bitumen production, the risks for the well pairs placed close to or into the bottom water is much higher than those wells placed higher. The risks include:

- A high SOR during the initial years of SAGD operation which will reduce the economic benefit of the project or make it potentially uneconomic;
- The coning of bottom water from any individual wells at a later stage of production when the steam chambers for all the well pairs have coalesced into a common chamber on the same pad or from the same reservoir. This could result in the failure or difficult operation of entire SAGD pads.

Therefore, it is recommended that the SAGD producers be placed 2.0 to 3.0 meters above the bottom water. If the reservoir has a thick transition zone (>3.0 meters) and the SAGD producers are placed in the transition zone, the minimum oil saturation around the producers should be greater than 50%.

2. Clearwater Formation

The recommendations for well placement and operating strategies for the LGR Formation will serve as a guideline for the type II Clearwater reservoir where the bottom water is in direct contact with the target formation. For the type I reservoir, the operating strategies and performance from CNRL’s Primrose CSS and Burnt Lake SAGD pilot operations can be used as the analogue. To assist with the final decision for the selection of recovery technology for the type I reservoir in the Taiga project, the performance from both CSS and SAGD processes will be studied.

Based on Osum’s studies the most critical geological factor in selecting the best reservoir recovery process for the Type I reservoir is the extent and properties of the M1 mudstone layer. The model used for this study was taken from section 26-65-2W4, where the mudstone layer M1 is relatively continuous at 2-3 meters thick. Figure 16 shows the distribution of vertical permeability in the model, where the mudstone layer M1 has low vertical permeability from 0 to 150 md. This is the most challenging recovery scenario for a Type I reservoir. It should be noted that the mudstone layer M1 becomes minimal or disappears in the central and eastern parts of the Type I reservoir area.

Only the modeling results for SAGD process are presented in this paper. Five SAGD well pairs are included in this model, each with a horizontal length of 900 meters and spacing of 80 meters.

The Figure 17 plot shows the model-predicted SOR vs. cumulative oil production for one average well pair. The initial volume of about 60,000 to 80,000 m³ of bitumen is produced at a relatively low SOR (<4.0), which reflects the drainage from the high quality S2 sand. The subsequent period with the higher SOR of 4 to 5 represents the drainage from the mudstone layer M1 and the S1 sand at the top. The presence of the M1 mudstone layer in the model slows down the rise of the steam chamber into the upper S1 sand. This can also be seen in Figure 18 which provides a temperature profile from a cross section perpendicular to the horizontal wells at 3 years of SAGD operation. The steam chamber spreads along the bottom of M1 where it reaches the top of the S2 sand. There is limited steam chamber growth into M1 at this time due to the low vertical permeability in M1. Although the steam chamber eventually rises into M1 and the upper S1 sand in this model (Figure 19), it will be more costly to produce the bitumen from the S1 sand. Depending on the vertical permeability within M1, the impact of M1 on the overall SAGD performance will be two-fold:

(1.) If M1 is continuous with zero vertical permeability, cumulative SOR is low (<4.0) and the total reserves per well pair is low due to the production from the S2 sand only;
(2.) If M1 is discontinuous or has low vertical permeability to allow the steam flow through to access the upper S1 sand, additional bitumen production from the upper zone (M1 + S1 sand) will be at the expense of a higher SOR (4 to 5). But the total reserves per well pair will be increased significantly due to the long tail production at a relatively high SOR (see Figure 17).

Whether the injected steam has capability to break through the M1 layer or not, its impact on the total SAGD reserves is significant. Therefore, it is important to have high pressure steam available during the SAGD operation when high pressure injection (close to the dilation pressure of the formation) is required to break through the M1 mudstone layer or other barriers such as thin mud beds. The predicted reserves per SAGD pair from this model ranges from 100,000 to 150,000 m³ (37 to 56% recovery factor based on the total thickness of S1 and S2) depending on the accessibility through M1 to the upper S1 sand from the steam chamber below.

A sensitivity run was performed from the same model with the M1 layer replaced by a permeable and bitumen saturated layer. This case represents a relatively thick reservoir (15 to 18 meters on average above the producer) where the M1 mudstone layer has disappeared. This is representative of the reservoir that exists in parts of the Taiga project area. The predicted SAGD performance for this case is shown in Figure 20. The predicted cumulative SOR is 3.6 with total bitumen production of about 170,000 m³ per average well pair. This part of the reservoir will be considered as the phase one development in the Taiga project area.

Development Plan

Three stages of the commercial development were proposed to achieve the target bitumen production of 35,000 b/d from Taiga project area. Phase one is targeted at 10,000 b/d and start-up is targeted for late 2013.

Conclusions

- High pressure CSS is a mature and commercially proven technology for producing bitumen from the Clearwater Formation in the Cold Lake area. The current bitumen production from IOL and CNRL together by the end of 2007 was about 210,000 bbl/d.
The cumulative SOR was 3.3 in the IOL’s Cold Lake area and 4.4 in CNRL’s Primrose area.

- Two SAGD pilots in the Clearwater Formation at Burnt Lake and Hilda Lake have been operating since 1997. Both pilots achieved the expected SAGD performance. The Burnt Lake pilot produced over 45% of OOIP by the end of 2007 at a cumulative SOR of 3.75 (mixed steam quality of 100% for the initial years and 80% afterwards).
- Two commercial SAGD projects in the Clearwater Formation at Husky’s Tucker Lake and Shell’s Orion have bottom water. Both projects are still in the early stage of operation.
- SAGD has been applied successfully in producing bitumen from the Lower Grand Rapids Formation at CNRL’s Wolf Lake area. The average SOR from the B10 SAGD project was 3.7 by the end of 2007 and has continued to improve since then. The latest pad (S1A) has achieved a cumulative SOR of <3.0 and a peak oil rate of over 100 m³/d per well pair.
- Osum’s Taiga project area contains exploitable bitumen in both Lower Grand Rapids and Clearwater Formations.
- Osum’s Lower Grand Rapids reservoir is homogeneous and has a net pay thickness from 10 to 22 meters but with thick bottom water. SAGD will be the main recovery technology.
- The Clearwater Formation in the Taiga project area contains three types of reservoirs: reservoir with no bottom water or top gas (Type I); reservoir with bottom water (Type II) and reservoir with top gas (Type III). High pressure assisted SAGD and HPCSS will be considered for the Type I reservoir. Low pressure SAGD will be considered for Type II and III reservoirs.
- Reservoir simulation based on an up-scaled model from geo-statistical modeling indicates that the LGR Formation is expected to achieve over a 50% recovery factor and a cumulative SOR of 3.0 using the SAGD process.
- The Clearwater Formation is expected to achieve a cumulative SOR ranging from 3.5 to 4.5 and a recovery of 37 to 56% of OOIP from SAGD operations based on the preliminary simulation studies from the Type I reservoir models. The thickness and vertical permeability of the M1 mudstone layer will have a significant impact on the SAGD performance and reserves.
- For the LGR Formation and Type II Clearwater reservoir where bottom water is in direct contact with the target bitumen, the vertical placement of the SAGD wells is the key for the overall performance and operating risk. It is recommended that the SAGD producers should be placed at a minimum of 2 to 3 meters above the bottom water. Where a transition zone exists between the high quality bitumen zone and the bottom water, the producers should be placed in an area where the bitumen saturation is greater than 50% and at a minimum of 2 to 3 meters above the OWC.
- The vertical placement of SAGD well pairs will affect the SOR significantly, particularly during the initial operation. Both the economical and operational risks are high when the SAGD well pairs are placed close to or into the low bitumen saturation zones in the bottom water reservoir.
- It will be necessary in some areas of the Clearwater to operate SAGD at a pressure close to the dilation pressure of the formation in order to enhance the SAGD performance.

Acknowledgements

Permission from Osum Oil Sands Corp. to publish the results from the Taiga project is acknowledged. The statistical modeling and geological interpretation from Shawna Christensen and John Carey of Petrel Robertson Consulting Ltd. is also appreciated.

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7. SCOTT, G. “Comparison of CSS and SAGD Performance in the Clearwater Formation at Cold Lake”, SPE paper 79020-MS, presented at SPE International Thermal Operations and Heavy Oil Symposium and International Horizontal Well Technology Conference, 4-7 November 2002, Calgary, Alberta, Canada
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11. CANADIAN NATURAL RESOURCES LIMITED, 2005 annual performance review to ERCB on Primrose, Wolf Lake, and Burnt Lake
13. BEATTIE, C.J., BOBERG, T.C., and MCNAB, G.S., “Reservoir Simulation of Cyclic Steam Stimulation in the Cold Lake Oil Sands”, SPE 18752
shows a comparison of fuel requirement for the 75% and 100% quality of the injected steam based on 90% thermal efficiencies assumed for boilers and surface heat exchangers. Other assumptions include that the produced water has an average temperature of 150°C at surface and produced water to injected steam volume ratio is 0.9. The water disposed has an average temperature of 60 °C and accounts for 10% of the total condensate volume from the separator.

It can be seen from Figure a.1 that the fuel requirement is not in direct proportional to the steam quality due to the heat recovery from the separated steam condensate. The example shows that additional 15% to 25% fuel gas is required to increase the quality of injected steam from 75% to 100%, depending on the discharge pressure of steam from the boilers and the pressure at the steam separators. For a more fair comparison between the CSS and SAGD performance, the injected entropy required for producing the same amount of bitumen should be used. This requires the evaluation of fuel requirement at the injection pressure and steam quality at the well heads.

Appendix Estimation of Fuel Consumption for Different Quality of Steam

To compare thermal efficiencies between the SAGD and CSS, the total energy consumption for generating one unit volume of steam at the specified pressure should be used to account for the difference in steam quality. The following equations can be used to estimate the energy required for generating 1 m³ CWE steam injected.

\[ \eta_B h_B = \rho_w \left[ h_{inj} + q_c h_c - (q_p h_p + (q_c h_c - q_d h_ds)) \right] 10^{-6} \] \hspace{1cm} (a1)

Where \( h_B \) is the energy of fuel required in the boiler, Gj per m³ of steam (CWE); \( h_{inj} \), \( h_c \), \( h_p \) and \( h_ds \) are the entropies in the injected steam, condensate from the steam separator, produced water and water disposed, kj/kg; \( q_c \), \( q_p \) and \( q_d \) are the volumes of the condensate separated, produced water and water disposed for 1 m³ injected steam; \( \rho_w \) is the density of water; \( \eta_B \) and \( \eta_s \) are the thermal efficiencies for the boilers and the surface heat exchange system. The produced volume \( q_p \) is expressed as the fraction of the injected steam volume and \( q_d \) is expressed as the fraction of the condensate volume from separation.

\[ h_{inj} = H_v - \left( H_I - H_v \right) x_{inj} \] \hspace{1cm} (a2)

\[ q_c = \frac{x_{inj} - x_B}{1 - x_{inj} + x_B} \] \hspace{1cm} (a3)

Where \( H_v \) is the entropy in steam vapor, kj/kg; \( H_I \) is the entropy in liquid, kj/kg; \( x_{inj} \) and \( x_B \) are the steam qualities after steam separator (injected steam) and at boiler points.

The above equation neglects the entropy in the produced oil, which is usually small compared to other terms. Figure a.1
**Table 1, Summary of Reservoir Properties from Thermal Projects in the Cold Lake Area**

<table>
<thead>
<tr>
<th>Project</th>
<th>Operator</th>
<th>Zone</th>
<th>Depth (m)</th>
<th>Avg $\phi$</th>
<th>K ($\mu$m$^2$)</th>
<th>Soi(%)</th>
<th>Net Pay (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Lake</td>
<td>ESSO</td>
<td>Clearwater</td>
<td>400</td>
<td>32</td>
<td>1-4</td>
<td>70</td>
<td>18-70</td>
</tr>
<tr>
<td>Wolf Lake</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>485</td>
<td>33</td>
<td>2.5-4</td>
<td>47-59</td>
<td>10-42</td>
</tr>
<tr>
<td>Primrose</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>500</td>
<td>32</td>
<td>2.9-3.2</td>
<td>41-75</td>
<td>7-29</td>
</tr>
<tr>
<td>Burnt Lake</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>500</td>
<td>32</td>
<td>2-4</td>
<td>65-70</td>
<td>10-30</td>
</tr>
<tr>
<td>Wolf Lake</td>
<td>CNQ</td>
<td>Lower Grand Rapids</td>
<td>400</td>
<td>33</td>
<td>3.2</td>
<td>75</td>
<td>10-14</td>
</tr>
<tr>
<td>Orion</td>
<td>Shell</td>
<td>Clearwater</td>
<td>425</td>
<td>35</td>
<td>3-5</td>
<td>60-64</td>
<td>20-27</td>
</tr>
<tr>
<td>Tucker Lake</td>
<td>Husky</td>
<td>Clearwater</td>
<td>450</td>
<td>33</td>
<td>1-5</td>
<td>55-69</td>
<td>30-60</td>
</tr>
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</table>

**Table 2, Summary of Production Performance from Thermal Projects in the Cold Lake Area**

<table>
<thead>
<tr>
<th>Project</th>
<th>Operator</th>
<th>Zone</th>
<th>Bottom Water (m)</th>
<th>Technology</th>
<th>Commercial since</th>
<th>Well Type</th>
<th>Current Oil Rate (B/d)</th>
<th>Current SOR</th>
<th>Cum. SOR</th>
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<tbody>
<tr>
<td>Cold Lake</td>
<td>ESSO</td>
<td>Clearwater</td>
<td>N/A</td>
<td>CSS</td>
<td>1985</td>
<td>VW &amp; HW</td>
<td>140,000</td>
<td>3.3</td>
<td>3.3</td>
</tr>
<tr>
<td>Wolf Lake</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>N/A</td>
<td>CSS</td>
<td>1984</td>
<td>VW &amp; HW</td>
<td>5,000</td>
<td>-</td>
<td>6.0</td>
</tr>
<tr>
<td>Primrose</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>N/A</td>
<td>CSS</td>
<td>1992</td>
<td>HW</td>
<td>62,000</td>
<td>5.0</td>
<td>4.4</td>
</tr>
<tr>
<td>Burnt Lake</td>
<td>CNQ</td>
<td>Clearwater</td>
<td>N/A</td>
<td>SAGD</td>
<td>Pilot</td>
<td>HW</td>
<td>700</td>
<td>4.9</td>
<td>3.7</td>
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<tr>
<td>Wolf Lake</td>
<td>CNQ</td>
<td>Lower Grand Rapids</td>
<td>0-2</td>
<td>SAGD</td>
<td>2001</td>
<td>HW</td>
<td>5,000</td>
<td>3.7</td>
<td>4.2</td>
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<td>Orion</td>
<td>Shell</td>
<td>Clearwater</td>
<td>0-10</td>
<td>SAGD</td>
<td>2006</td>
<td>HW</td>
<td>2,000</td>
<td>8.0</td>
<td>4.0</td>
</tr>
<tr>
<td>Tucker Lake</td>
<td>Husky</td>
<td>Clearwater</td>
<td>5-20</td>
<td>SAGD</td>
<td>2006</td>
<td>HW</td>
<td>2,500</td>
<td>13.0</td>
<td>-</td>
</tr>
</tbody>
</table>

**Table 3, Summary of Reservoir Properties from Osum's Taiga Project**

<table>
<thead>
<tr>
<th>Zone</th>
<th>Depth (m)</th>
<th>Avg $\phi$</th>
<th>K ($\mu$m$^2$)</th>
<th>Soi(%)</th>
<th>Net Pay (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clearwater</td>
<td>440</td>
<td>32-35</td>
<td>1-4</td>
<td>65-70</td>
<td>10-21</td>
</tr>
<tr>
<td>Lower Grand Rapids</td>
<td>365</td>
<td>33</td>
<td>3-5</td>
<td>75-80</td>
<td>10-22</td>
</tr>
</tbody>
</table>
Figure 1. A) Location Map of the Taiga project area and surrounding oilsand leases. B) Clearwater Formation top structure map showing lease boundary, well locations, type well location (6-26), and cross section location of Figure 5.

Figure 2. Cumulative SOR from Burnt Lake SAGD Pilot

Figure 2. Cumulative SOR from Burnt Lake SAGD Pilot
Figure 3, locations of the CSS pilot and B10 SAGD in Wolf Lake

Figure 4 Type log from the Taiga Project area. Petrophysical logs and Dean Stark saturation and core porosity values from well 1AA/06-26-065-02W4/00. Note the one-meter gas cap at 409-410 m MD and the basal water top at 454 m MD.

Figure 5. Cross section through the Taiga area static model (location in Figure xB). A) Oil saturation. B) Vertical permeability with S1, S2, M1 and M2 highlighted. Note the variation of M1 thickness and permeability laterally.
Figure 6, 3-D Distribution of Vertical Permeability for LGR Base Case Model

Figure 7, 3-D Distribution of Oil Saturation for LGR Base Case Model

Figure 8, Predicted Cumulative Oil, water production and Steam Injection and Recovery Factor from LGR Base Case Model

Figure 9, Predicted SOR and Cumulative Oil Production from LGR Base Case Model
Figure 10. Predicted Oil Saturation at 8 Yrs SAGD Operation from LGR Base Case Model

Figure 11. 3-D Distribution of Oil Saturation for a LGR Model with SAGD Well Pairs Placed at the Different Heights

Figure 12. Predicted Cumulative SOR for Individual SAGD Well Pairs Placed at the Different Heights

Figure 13. Predicted SOR vs. Cumulative Bitumen Production for Individual SAGD Well Pairs Placed at the Different Heights
Figure 14, Predicted Oil Saturation at 8 Years of SAGD Operation for a LGR Model with SAGD Well Pairs Placed at the Different Heights

Figure 15, Predicted Temperature at 8 Years of SAGD Operation for a LGR Model with SAGD Well Pairs Placed at the Different Heights

Figure 16, A Cross-section Showing the Distribution of Vertical Permeability for Base Case Model for Clearwater Water Formation from 26-65-2W4
Figure 17, Predicted SOR vs. Cumulative Bitumen Production from Clearwater Base Case Model

Figure 18, Predicted Temperature at 3 Years of SAGD Operation for Clearwater Based Case Model

Figure 19, Predicted Temperature at 5 Years of SAGD Operation for Clearwater Based Case Model
Figure 20, Predicted SAGD Performance from a Clearwater Model without M1 Layer Barrier

Figure A.1, Predicted Fuel Required for 1 m³ CWE Steam Generation at Two Different Steam Qualities