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Comparison of CSS and SAGD Performance in the Clearwater Formation at Cold Lake

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Abstract

Data are available for four SAGD projects and two CSS projects operating in the Clearwater formation at Cold Lake. This paper uses these data to compare the energy efficiency and recovery performance of SAGD and CSS.

For the conditions outlined in this paper, field data demonstrate that:

1. *Bitumen recovery using SAGD is generally uneconomic in the Clearwater formation.*
2. *Bitumen recovery using CSS in the Clearwater formation:*
   - *Produces as much as 50% or more bitumen/m^3 external gas consumed than SAGD; and*
   - *Will result in significantly higher overall bitumen recoveries (as a percentage of OBIP) than SAGD.*

These observations are consistent with industry experience in non-Clearwater SAGD and CSS operations.

In addition, operating and design data for commercial SAGD and CSS projects is used to demonstrate that:

1. *Due to differences in steam quality, SOR is not an appropriate indicator of energy efficiency. Energy efficiency comparisons are more appropriately based on the quantity of external gas required to produce 1-m^3 of bitumen.*
2. *To convert SOR data to an external gas requirement, the following conversion factors are proposed:*
   - *1-m^3 wet (80% quality) steam requires approximately 60-m^3 gas.*
   - *1-m^3 dry (100% quality) steam requires approximately 75-m^3 gas.*
3. *The use of project specific EBIP, versus OBIP, in calculating recovery makes meaningful comparisons difficult.*

Background

Clearwater Reservoir Description. The Cretaceous Clearwater formation in Cold Lake contains high quality bitumen pay that has been shown to be economically recoverable using thermal recovery processes. Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) have been applied to varying degrees in this regard.

The Clearwater sands are thick and unconsolidated, with gross thickness up to 70-m. The formation top at Cold Lake is nominally 400 to 450-m TVD. Cumulative net pay (≥8-wt% bitumen) is typically between 10 and 40-m and porosities range from 30 to 35%. Bitumen saturation averages 10.5% by weight, or about 65% of pore volume. The bitumen is very viscous, about 100 to 200 Pa·s at ambient reservoir temperature of 13 °C.

Most Clearwater net pay sections consist of alternating layers of higher and lower energy depositional units. Figure 1 contains photos of two 2.25-m sections of high quality resource. In higher energy depositional units, the mud components are typically localized in clast zones. The clasts will cause only minor reductions in vertical permeability.

In lower energy depositional units, muds are typically deposited in thin laminae. While individual lamina can have limited areal extent, when taken as a unit, they can cause major reductions in vertical permeability as a result of the tortuous path steam and bitumen must follow.

Thus, while bitumen content of the resource in the higher and lower energy depositional units is comparable, the type of mudstone bedform can have a significant effect on the performance of gravity drainage.

SAGD Process Description. Imperial Oil developed and patented the SAGD recovery process.[1] As shown in Figure 2, SAGD requires two wellbores. One wellbore continuously injects steam and a second one continuously produces mobilized bitumen and condensed steam. Horizontal wells are used to enhance reservoir access and thus well productivity.

Because SAGD relies on gravity drainage to recover bitumen, it is preferable to place the wells in, and drain bitumen from, higher energy depositional units.

In reservoirs that contain bitumen, the typical strategy is to drill the injector and producer nominally 5-m apart. To establish communication between injectors and producers, several start-up strategies have been developed.[2,3,4,5]

Typically, these strategies facilitate thermal communication between the injector and producer within three months.

Operating practices are available to minimize potential for excessive steam coning at the producers, while at the same time not adversely affecting the production of bitumen.[6]

CSS Process Description. The CSS process involves a single well with three stages and can use vertical (shown in Figure 3), deviated, and horizontal wells. In Stage 1, steam is injected at formation parting, or fracture pressure to heat the bitumen. In Stage 2, the wells are shut-in to soak. In Stage 3, the wells are put on production. During a typical cycle, 10% of the calendar days are for steam injection, 10% are for soak, and 80% are for production operations.

Strategies to manage orderly steaming and production operations for commercial developments have been developed.[7,8]

The CSS recovery process takes advantage of a variety of recovery mechanisms, including formation recompaction, solution gas drive, fluid expansion, condensate's sensible heat and gravity drainage, whose relative importance changes with cycle.[9,10,11] As CSS utilizes multiple mechanisms to recover bitumen, it is more tolerant than SAGD to variations in resource quality.

Defining the Economic Limit for Thermal Recovery Processes

Economics ultimately determine the extent of bitumen recovery achievable with thermal recovery technologies. In this section, industry SAGD and CSS projects are used to develop a consistent basis for comparing the economic limit of the SAGD and CSS processes.

Industry SAGD Projects. Figure 4 summarizes project name, location, and operator for the majority of the SAGD pilots and commercial projects that are operating, under construction or under review by regulators in Alberta (Alberta Energy and Utilities Board, or AEUB) and Saskatchewan (Saskatchewan Energy and Mines, or SEM).

Of the project locations shown:

- Eleven are in Athabasca (McMurray Formation),
- Five are in Saskatchewan (Grand Rapids Formation),
- One is in Peace River (Bluesky Formation), and
- Four are in Cold Lake (4 - Clearwater Formation, 1- Grand Rapids Formation. Note - Wolf Lake has operated SAGD in both the Clearwater and Grand Rapids (Lloydminster)).

SAGD recovers bitumen by using latent heat available in the steam. The sensible heat of condensate injected into the reservoir has no value to the recovery process, as the condensate drains directly from the injector to the underlying producer. For this reason, SAGD projects generate steam at 80% quality using once-through steam generators and then separate the vapor from the condensate. Recovery of a portion of the condensate's sensible heat occurs at the central plant, while the dry steam is sent to wells in the field.

A common measure of thermal efficiency of the SAGD process is Steam Oil Ratio (SOR) - the ratio between the volume of steam injected and the volume of bitumen ultimately recovered. There is also an economic limit SOR - above which the value of the bitumen recovered fails to provide adequate return for the capital investment and operating expense incurred in generating the steam to extract an incremental m^3 of bitumen.

Figure 5 shows the economic limit SOR, plotted against horizontal permeability, for a number of commercial SAGD projects.[a] These data are derived from information provided in conjunction with regulatory submissions for the various projects. More specifically, the individual data provided are based on:

1. A specific value (Surmont) or midpoint of a range (MacKay) identified by the operator in their application; or
2. The mid-point of a range (Firebag) included in a response to a specific question from the AEUB; or
3. The SOR identified for the last year of SAGD operation (Burnt Lake and Hilda Lake) in the project application.

From Figure 5, it would appear that the average economic limit SOR for the projects examined is about 4, and it appears to be independent of reservoir permeability.

While SOR is a common measure of the efficiency of steam-based recovery processes, comparisons based on SOR implicitly assume that the quantity of external gas burned (process and utility steam generation, fired heaters, etc) per m^3 steam used in the field to recover bitumen are the same for all projects. To test this assumption, Figure 6 shows the external gas required by the commercial SAGD projects per m^3 of high-pressure steam generated for use in the field.[a] Only projects without cogeneration facilities have been included. While there is some scatter, SAGD projects typically require 77-m^3 of gas per m^3 of dry steam sent to the field.[b]

Combining the economic limit SOR and the gas required per m^3 of steam, suggests an economic limit for gas consumption of 300-m^3gas/m^3 bitumen recovered.[c]

Industry CSS Projects. Currently there are three commercial CSS projects in Alberta. Two are in Cold Lake (CNRL Primrose and Imperial Oil Cold Lake) and one is in Peace River (Shell). While expansion plans are in place at all three, only one is a grassroots CSS project without power cogeneration: Imperial Oil's Nabiye Project.[d] Data provided in the regulatory application for this project provides a basis for establishing the economic limit gas consumption for CSS, much in the same way as was determined above for SAGD.[12,e]

CSS operations typically send wet steam (vapor and condensate) to the field. The steam quality at the exit of the steam

a The data used in Figures 5, 6 and 18, as well as the source documents for each project are summarized in Appendix A.

b Considering only data for Clearwater SAGD projects (BlackRock Orion and CNRL Burnt Lake), a similar result (75-m^3 external gas/m^3 steam) is obtained.

c (77-m^3 gas/m^3 dry steam)(4-m^3 dry steam/m^3 bitumen), rounded.

d Other recent commercial CSS operation expansions include Imperial Oil Mahkeses (CLPP 11-13), CNRL Wolf Lake and Primrose Expansion Project and Shell.

e Data for Nabiye and their sources are included in Appendix A.

generators is 75 to 80%, but as a result of surface line heat losses, the steam quality at the wellhead is reduced to 65 to 70%. Unlike SAGD, where the sensible heat of any condensate injected has no value in the recovery process, the heat from injected condensate does enhance recovery in CSS operations. As a result, CSS SOR is typically indicated on a wet steam basis. Over the first 20-years of operation, wet steam SOR for Nabiye is predicted to average 3.3.[e]

Using data for the last CSS cycle in the Nabiye application, the economic limit SOR is 5. The material balance provided in the Nabiye application has a requirement of 59-m^3 external gas per m^3 wet steam sent to the field.

Combining the economic limit SOR and the gas required per m^3 of steam, the economic limit gas consumed per m^3 bitumen cut-off for CSS is calculated to be 300-m^3/m^3 - similar to that calculated for SAGD.[f]

Economic Limit Definition. While SAGD and CSS use different steam qualities to recover bitumen and consume different quantities of gas per m^3 steam sent to the field, the information supplied in project regulatory applications suggest that SAGD and CSS have a similar economic limit in terms of gas consumption per m^3 bitumen recovered.

For the purposes of this paper, *the assumption is that when the quantity of gas required to produce one m^3 of bitumen exceeds 300-m^3 the economic limit has been reached.*[g]

Implicit in this definition is the need for the cumulative external gas requirement to be significantly less than 300-m^3/m^3 bitumen at some point in the project life. *If this does not occur, the initial project investment would not be economic as the bitumen revenue would not be sufficient to recover the project's capital and operating costs. As a result, there would be no commercially economic bitumen production.*

For projects that inject dry steam, SOR data are converted to an external gas requirement using 75-m^3 gas/m^3 dry steam. For projects that inject wet steam, a conversion factor of 60-m^3 gas/m^3 wet steam is used.[h]

In-situ Recovery Energy Efficiencies

Cold Lake In-situ Projects. There are currently a number of in-situ recovery projects in the Cold Lake Area (Figure 7). The two smallest operations, BlackRock Hilda Lake and CNRL Burnt Lake are Clearwater SAGD pilots. The two largest operations, Imperial Oil Cold Lake and CNRL Primrose are Clearwater CSS projects. The fifth operation is CNRL Wolf Lake, with SAGD in the Lower Grand Rapids and CSS in the Clearwater. An assessment of the performance of each project relative to economic recovery criteria follows.

f (59-m^3 gas/m^3 wet steam)(5-m^3 wet steam/m^3 bitumen), rounded.

g As fuel and water treatment costs are two major expenses for SAGD and CSS, a similar gas consumption cut-off is expected. Even so, there is sufficient data presented to allow the reader to confirm the robustness of the analysis using their choice of economic limit gas consumptions.

h CNRL has presented cumulative SOR data for Burnt Lake twice.[16,17] Once on a dry steam basis and once on an 80% quality steam basis. The implied dry to wet steam SOR conversion factor was: wet steam SOR = dry steam SOR/0.8. This conversion factor is consistent with the ratio of the gas requirements needed to generate 1-m^3 of wet and dry steam in the current analysis.

Wolf Lake SAGD. In Oct. 1993, Amoco started operation of the first dual horizontal well SAGD configuration in the Clearwater at Wolf Lake.[i] This well pair has 825-m long liners. The injector and producer liner diameters are 219-mm and 178-mm, respectively.

Inspection of open-hole logs and core indicate the wells are placed in resource with very poor vertical continuity.

Amoco predicted a requirement for 300-m^3 gas/m^3 bitumen produced and an ultimate recovery of >40%. During the first three years of operation, Amoco predicted the well pair would produce 90,000-m^3 of bitumen.[13]

As shown in Figure 8, the SAGD operation ran from Oct. 1993 to June 1996. The well pair required 1,060-m^3 gas/m^3 bitumen recovered (dry steam SOR of 14.1) and recovered 5,200-m^3 of bitumen.

In July 1996 Amoco converted the pilot to CSS operation. As shown in Figure 8, during the CSS operation the gas consumption declined to 160-m^3/m^3 bitumen recovered.

Relative to the economic recovery criteria proposed in this paper, there was no economic recovery with SAGD in the Clearwater formation at Wolf Lake. However, the subsequent conversion of this pilot to CSS has resulted in economic recovery being achieved.

Burnt Lake SAGD. In Dec. 1996, Suncor started operation of the Burnt Lake SAGD project. The project consists of three well pairs, each with injector and producer liner diameters of 244-mm and 178-mm, respectively. Two of the well pairs have liner lengths of 1,000-m, while the wells in the third pair have liner lengths of approximately 700-m. In 2000, CNRL acquired the Burnt Lake operation from Suncor.

Inspection of open-hole logs and core confirm that the horizontal wells are in resource comparable to Figure 1.

For the first five years of operation, the three well pairs were predicted to produce 225-m^3/d (reduced from Suncor's 250-m^3/d to compensate for shorter length of one well pair) and require 180-m^3 gas/m^3 bitumen recovered (dry steam SOR of 2.4).[14]

Figure 9 contains the Burnt Lake performance data. While the well pairs were granted pilot status, they were included in a commercial project approval. Their combined monthly production is available in an AEUB publication.[15]

The pilot status for the wells does not expire until Sep. 2002, so steam injection data is not currently available. Nonetheless it is possible to back-calculate an estimate of the steam injection volumes by tracking the monthly water disposal volumes because there is no water recycle at this pilot. The method for converting the water disposal volume to steam

i Imperial Oil's Horizontal Well Pilot 1 that started operation in 1979 utilized a vertical injector and a horizontal production well.

requires a single cumulative SOR data point and a corresponding cumulative bitumen production volume[16,17,j]

During the first five years (Jan. 1997 to Dec. 2001), the average bitumen production rate was 210-m^3/d. This is within 10% of forecast. It is estimated that the pilot required 300-m^3 gas/m^3 bitumen recovered (dry steam SOR of 4), 65% more than originally predicted.

The reduction in gas required per m^3 bitumen between 1999 and 2000 is the result of a reduction in steam injection allowing the steam chamber pressure to decline. The improvement was not sustainable as evidenced by the leveling off in cumulative gas consumption per m^3 bitumen recovered in late-2000.

It is noteworthy that coincident with this change in steaming strategy, Suncor received permission from the AEUB to inject a small quantity (5 to 10-m^3/d) of diluent with the steam at one of the SAGD well pairs.[18] The diluent injection approval was for only one year and the approval was not renewed. In August 2001, CNRL received AEUB approval to inject methane with the steam.[19] It is not apparent that either test has materially impacted bitumen production. Hence no impact is assumed in the current analysis.

The cumulative gas consumption is at the economic limit of 300-m3/m3 bitumen recovered. On a go-forward basis *where past capital expenditures are ignored*, SAGD performance is marginal relative to the minimum economic limit used in this study. As mentioned previously, if a project's cumulative external gas requirement is never significantly less than 300-m^3/m^3 bitumen recovered, it is unlikely that the initial project investment would be made as the bitumen revenue would not be sufficient to recover the project's capital and operating costs.

Relative to the economic recovery criteria proposed in this paper, there was no economic recovery with SAGD at Burnt Lake.

Hilda Lake SAGD. In Sep. 1997, BlackRock (previously Discovery West) started operation of the Hilda Lake SAGD project. The project initially consisted of one well pair, with injector and producer liner diameters of 219-mm and 178-mm, respectively. The liner lengths are approximately 950-m.

Inspection of open-hole logs and core confirm that the horizontal wells are in resource comparable to Figure 1.

In the original pilot application[20] BlackRock identified an external gas consumption requirement of 190-m^3/m^3 bitumen (dry steam SOR of 2.5) and a bitumen production target of 140-m^3/d. Over the first 5 years of operation, the well pair was to produce 235,000-m^3 of bitumen.[k]

In 1999, BlackRock filed a pilot expansion application.[21] BlackRock predicted that during the first 5 years of operation, a SAGD well pair would average 65-m^3/d bitumen, require 225-m^3 gas/m^3 bitumen recovered (dry steam SOR of 3) and produce 120,000-m^3 of bitumen. These represented a 50% reduction in well productivity and a 20% increase in gas consumption.

Figure 10 shows the performance of well pair #1. Steam rates were reduced 30 to 40% in mid-1999. As a result, the cumulative gas consumption decreased from 290 to 260-m^3/m^3 bitumen recovered in 2000. Since that time cumulative gas requirements have slowly increased. In the first quarter of 2002, the monthly gas consumption was 380-m^3/m^3 bitumen recovered.

For the conditions outlined in this paper, well pair #1 was *economic until Dec. 2001*. A detailed analysis of well pair #1 performance is presented elsewhere.[22]

Hilda Lake well pair #3 uses 178-mm diameter liners that are approximately 950-m in length.[l] Figure 11 contains the performance data for well pair #3. While still early, these data suggest that the well pair is not performing as well as well pair #1, with gas consumption well above 300-m^3/m^3 bitumen recovered. For the conditions outlined in this paper, there has been no economic recovery from this well pair to date.

Primrose SAGD. In July 1998, Amoco started a single SAGD well pair at Primrose. The well pair used 178-mm diameter liners that are 600-m in length. As shown in Figure 12, the SAGD operation ran from July 1998 to Nov. 2000, with blowdown continuing until May 2001. The well pair required 405-m^3 of gas/m^3 bitumen recovered (dry steam SOR of 5.4) and recovered 25,000-m^3 of bitumen.

In May 2001 it appears that CNRL converted the pilot to CSS operation. As shown in Figure 12, during the CSS operation the gas consumption declined to 160-m^3/m^3 bitumen recovered.

Relative to the economic recovery criteria proposed in this paper, there was no economic recovery with SAGD at Primrose. However, the subsequent conversion of this pilot to CSS has resulted in economic recovery being achieved.

Cold Lake CSS. Phases 1 and 2 of the Imperial Oil Cold Lake Production Phases (CLPP) project started steaming operations in 1985. The CLPP project expanded in 1985 (Phases 3 and 4), 1986 (Phases 5 and 6), 1988 (Phases 7 to 10), and 2002 (Phases 11 to 13 (Mahkeses)). The CLPPs use deviated wells and reservoir fracture pressure steam injection.

As shown in Figure 13, the cumulative gas requirement has remained quite consistent at 185-m^3/m^3 bitumen recovered. This is well within the economic limit for gas consumption proposed in this paper.[m,n]

Through the end of 2001, the CLPPs have produced 78 million m^3 of bitumen.

j CNRL has presented cumulative SOR data for Burnt Lake. The disposal water volume multiplier required to match the cumulative SOR is 0.739.

k Actual liner length is 950-m versus 1000-m planned. The production rate and volume targets were reduced to compensate.

l Well pair #2 was not drilled.

m The cumulative gas requirements shown for CSS were calculated using the well level monthly steam and bitumen production data. No attempt was made to match future oil production with current steam injection.

n Leming and May were excluded due to testing of non-CSS processes.

Primrose CSS. Amoco started CSS steaming operations at Primrose in February 1995. As originally envisioned, the Primrose project used horizontal wells and slightly below fracture pressure steam injection as a precursor to a line-drive steam flood.[23] To enhance initial steam injectivity, the horizontal wells produced on primary for a period of up to six months.[o]

In 1999, CNRL acquired Primrose and Wolf Lake from Amoco. In 2000, CNRL received approval to convert a portion of the CSS operation to fracture pressure steam injection. The objective was to see if fracture pressure operation could improve steam injectivity, bitumen production rates, and project economics.[24]

In 2001, CNRL received approval to use fracture-pressure steam injection in approximately one third of the operation. CNRL identified wells converted to fracture pressure CSS in 2000 had achieved higher steam injection rates and two to three fold increases in bitumen production rates.[25]

In 2002, CNRL received approval to convert the remainder of the wells to fracture pressure steam injection.[17] In a supplementary information filing, CNRL identified that operating CSS at pressures below fracture pressure was not economic when existing infrastructure costs were considered. Thus sub-fracture steam injection would not be considered for future project expansions.[26]

As shown in Figure 14, the cumulative gas requirement has remained constant at 195-m^3/m^3 bitumen recovered.

Through the end of 2001, Primrose has produced nearly 8 million m^3 of bitumen using CSS.

Clearwater Energy Efficiencies. Figure 15 summarizes cumulative gas consumption data for Burnt Lake, Hilda Lake, and Primrose SAGD and Cold Lake and Primrose CSS projects.[p] Time zero is defined as the first month of steam injection.

In all cases, after an initial period of somewhat higher gas consumption at the onset of thermal recovery operations, cumulative gas consumption declines. It is noteworthy that the average gas consumption over time for CSS recovery is much lower than for SAGD operations, and well within the suggested economic limit. Gas consumption for in-situ recovery of bitumen in the Clearwater formation at Cold Lake using the SAGD process are estimated to be 50% (or more) above that required for CSS operations, and in most cases gas consumption is also above the suggested economic limit. The one exception would appear to be the Hilda Lake well pair #1, which appears to have operated economically for a period of about four years.

o Bitumen produced before the start of steaming operations was excluded when calculating the cumulative performance for Primrose. In addition, wells involved in non-CSS operations (i.e. SAGD, Combined Drive Drainage (CDD), Single Well CDD, Mixed Well Steam Drive Drainage, cold flow) were not included.

p Wolf Lake SAGD was not included in this comparison as its resource quality is significantly poorer than for the other projects.

Supporting Data. At Peace River, Shell's project contained 12 SAGD well pairs and 15 Soak Radial (a CSS recovery process Shell has optimized for the Bluesky formation) wells at the end of 2001.[27] Of the 12 SAGD well pairs, two (Pairs 1 and 2) were over thick bottom water[28], and five used an innovative dual horizontal lateral design (SAGD IP wells 8 to 12).[29] Because these seven well pairs have performed poorer than SAGD well pairs 3 to 7, they will not be included in
this assessment.

As shown in Figure 16 the cumulative gas requirement of SAGD well pairs 3 to 7 is double that required with the first three Soak Radial wells.[q] These data confirm the Clearwater analyses results.

Dover Phase B is located in the McMurray formation and contains the first three commercial length SAGD well pairs operated in Canada.[30] As shown by the data in Figure 17:

1. SAGD in the McMurray produces 50% more bitumen per m^3 of gas consumed than SAGD in the Clearwater. This result is consistent with the McMurray having both a higher bitumen content and permeability than the Clearwater (Figure 18[a]).
2. CSS in the Clearwater and SAGD in the McMurray produce comparable quantities of bitumen per m^3 gas consumed. This result suggests that the additional recovery mechanisms available using CSS in the Clearwater offset the benefit of higher bitumen content and permeability in the McMurray formation.

These observations also explain why the vast majority of proposed SAGD developments are targeting reservoir in the Athabasca.

Recovery Performance

There is no consistent approach used by industry to define "bitumen in place" and therefore recovery factor for in-situ projects. A common resource recovery definition to facilitate a comparison of Clearwater formation SAGD and CSS recovery factors is proposed.

Bitumen in Place. Imperial Oil calculates the "original bitumen in place", or OBIP, based on the quantity of bitumen present in the gross reservoir thickness with a bitumen content ≥ 6 wt%. No other criterion is applied.

Others define an "exploitable bitumen in place", or EBIP. Factors used to estimate EBIP can include:

- A need for vertical continuity (based on assessing the type of shale present or facies) and how much of the well spacing impermeable shale is thought to extend across; and/or
- A requirement for the resource to be above the planned depth of the SAGD or CSS producer; and/or
- An exclusion (or inclusion) of an allowance for recovery beyond the ends of the horizontal well liner.

Although in some cases EBIP can equal OBIP, in most cases the EBIP will typically represent only a portion of OBIP.

q Shell injects dry steam at both the SAGD and Soak Radial wells.

For example, the OBIP of the principal development area of the Petro-Canada MacKay River project is in excess of 100 million m^3.[31] The EBIP for SAGD and the expected recovery are 52 million m^3 and 37 million m^3, respectively. *While the project is predicted to recover 71% of the EBIP, this translates to less than 37% of the OBIP.*

For this paper, the recovery factors for SAGD and CSS will be estimated based on OBIP, as defined above.

Pattern Area. For this paper, the pattern area for SAGD is the width of the well spacing times the horizontal well liner length plus an allowance for depletion of the reservoir beyond both ends of the liner that is half the width of the well spacing. For CSS, the pattern area will be 3.2-hA, (8-acres). This is the well spacing Imperial Oil has adopted for recent developments.

Recovery Prediction. For this paper, SAGD recovery is based on field data and CSS performance predictions are based on data published by Imperial Oil for offset resource.

Imperial Oil's predictions are based on empirical models developed and validated through the statistical analysis of 20 years of historical field data.

SAGD and CSS OBIP Recovery Performance

Burnt Lake, Primrose and Wolf Lake. For the economic criteria suggested in this paper, bitumen recovery based on SAGD performance at Burnt Lake, Primrose and Wolf Lake is uneconomic. Using data contained in Imperial Oil's Nabiye and Mahihkan North regulatory application, OBIP recoveries with CSS are estimated to be 18% at Primrose (adjacent to Mahihkan North) and 19% at Burnt Lake (adjacent to Nabiye).[12] No CSS recovery estimate is available for Wolf Lake.

Hilda Lake. As identified previously, BlackRock well pair #1 reached the economic gas consumption limit at the end of 2001. For the conditions outlined in this paper, the economic recovery is 105,000 m^3 of bitumen and the OBIP of the well spacing is 756,000 m^3.[r] SAGD recovered 14% of the estimated OBIP.

The Hilda Lake pilot is located adjacent to Imperial Oil's Mahkeses project. Using data published for the Mahkeses project, the CSS recovery factor for the Hilda Lake pilot is estimated to be 23% of OBIP, or 60% higher than achieved with SAGD.[32]

Conclusions

Clearwater Formation. Operating data from four SAGD projects and two CSS projects demonstrate that for the criteria suggested in this paper:

1. Bitumen recovery using SAGD is generally uneconomic in the Clearwater formation.
2. Bitumen recovery using CSS in the Clearwater formation:
   - Produces as much as 50% or more bitumen/m^3 gas than SAGD; and
   - Will result in significantly higher overall bitumen recoveries (as a percentage of OBIP) than SAGD.

SAGD and CSS Comparisons. Operating and design data for commercial SAGD and CSS projects demonstrate that:

1. Due to differences in steam quality, SOR is not an appropriate indicator of energy efficiency. Energy efficiency comparisons are more appropriately based on the quantity of external gas required to produce 1-m^3 of bitumen.
2. To convert SOR data to an external gas requirement, the following conversion factors are proposed:
   - 1-m^3 wet (80% quality) steam requires approximately 60-m^3 gas.
   - 1-m^3 dry (100% quality) steam requires approximately 75-m^3 gas.
3. The use of project specific EBIP, versus OBIP, in calculating recovery makes meaningful comparisons difficult.

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Nomenclature

AEUB	Alberta Energy and Utilities Board.
CLPP	Cold Lake Production Phases.
CNRL	Canadian Natural Resources Limited.
CSS	Cyclic Steam Stimulation.
CWE	Cold Water Equivalent volume.
EBIP	Exploitable Bitumen in Place.
hA	Hectacre (10,000-m^2).
JACOS	Japan Canada Oil Sands Limited.
MPa	Pressure, Megapascals
OBIP	Original Bitumen in Place.
$P_{Chamber}$	Steam chamber pressure
$P_{Reservoir}$	Initial reservoir pressure
Pa·s	Viscosity, Pascal seconds.
Quality	Weight percent steam that is vapor.
SAGD	Steam Assisted Gravity Drainage.
SEM	Saskatchewan Energy and Mines.
SOR	Steam Oil Ratio (m^3 steam/m^3 oil).
TVD	True vertical depth.

Conversion Factors

Cubic meter (m^3)	= 6.29 barrels
	= 35.315 standard cubic feet
Hectacre (hA)	= 2.47 acres
Meter (m)	= 3.28 feet
Millimeter (mm)	= 0.0394 inches
MPa	= 145 pounds per square inch
Pa·s	= 1,000 centipoise.

r The drainage pattern is 10.5 hA, based on a well pair length of 950-m, 100-m allowance for end effects and a pattern width of 100-m. Using BlackRock contoured OBIP plots, the Clearwater OBIP is 72,000 m^3/hA (756,000 m^3/spacing).[20]

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24 CNRL: AEUB Application 1056392, "Wolf Lake and Primrose Oil Sands Projects - Year 2000 Development Plan", Jan. 2000.
25 CNRL: AEUB Application 1076081, "Wolf Lake and Primrose Oil Sands Projects - Year 2001 Development Plan", Oct 2000.
26 CNRL: AEUB Application 1078240, "CNRL PAW Project - Supplementary Information", July 2001.
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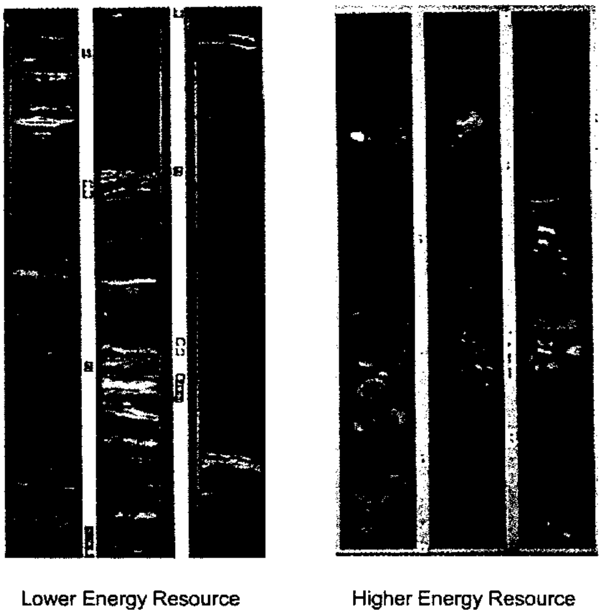

Figure 1: Clearwater "Clean Sand" Core Samples

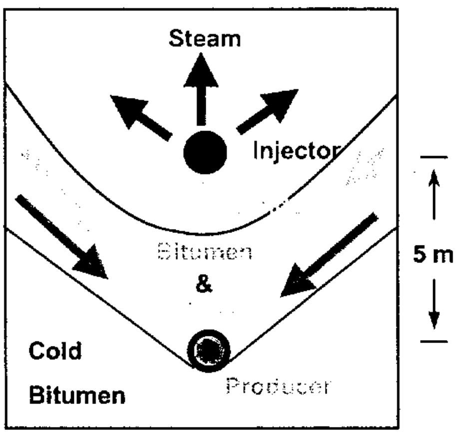

Figure 2: SAGD Well Pair Configuration

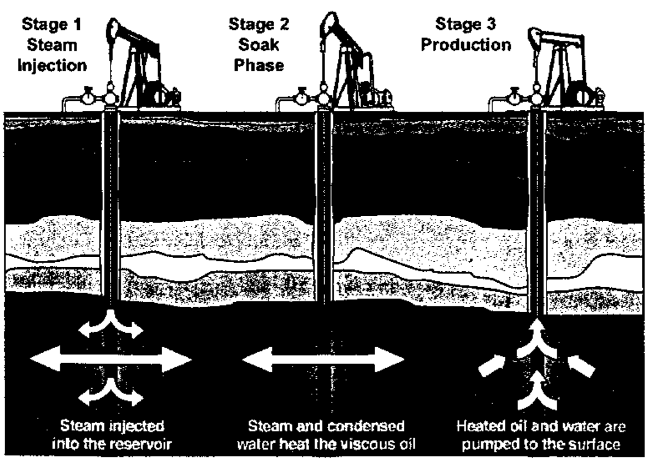

Figure 3: Stages of the CSS Process

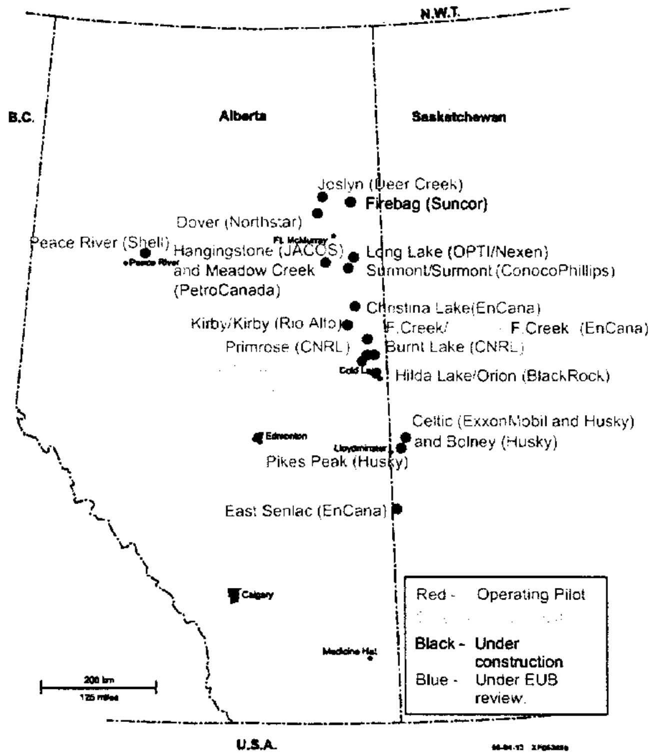

Figure 4: SAGD Project Status and Locations

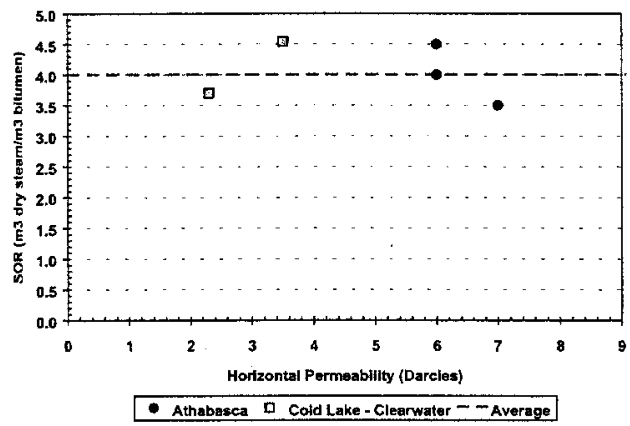

Figure 5: SAGD Project Economic Limit Dry Steam to Field SORs

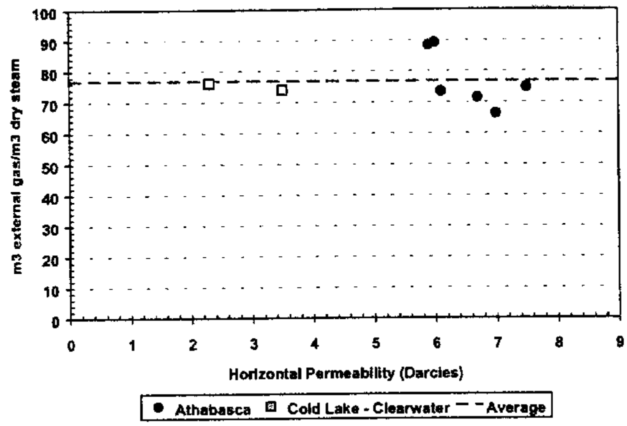

Figure 6: SAGD Project External Gas/m3 Steam to Field Demand

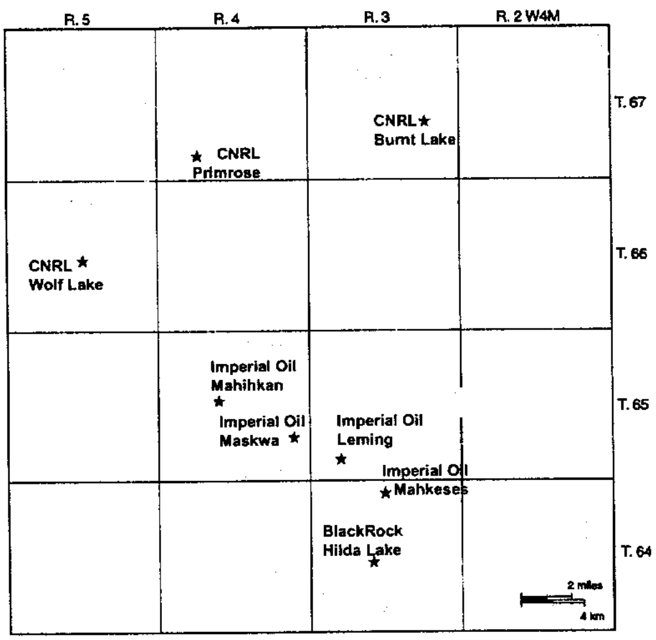

Figure 7: Location of Cold Lake In-situ Projects

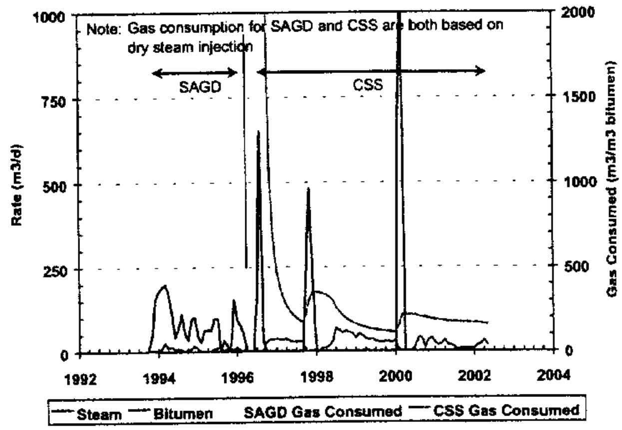

Figure 8: Wolf Lake SAGD (and Conversion to CSS)

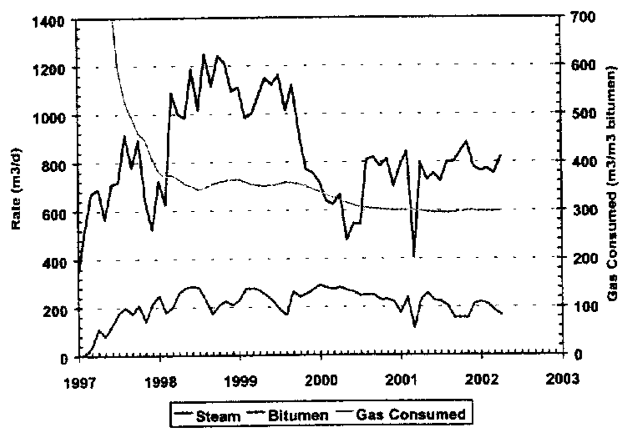

Figure 9: Burnt Lake SAGD Performance

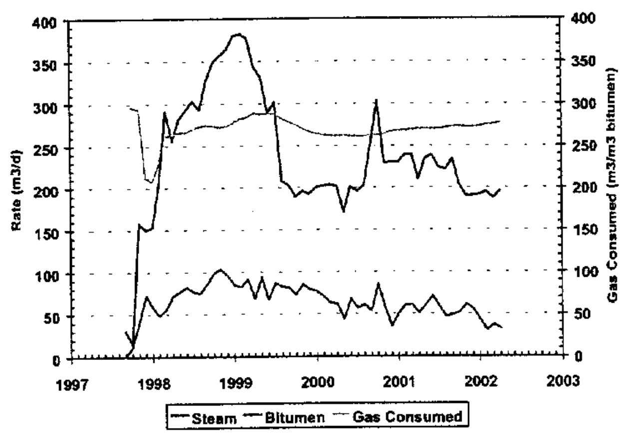

Figure 10: Hilda Lake SAGD #1 Performance

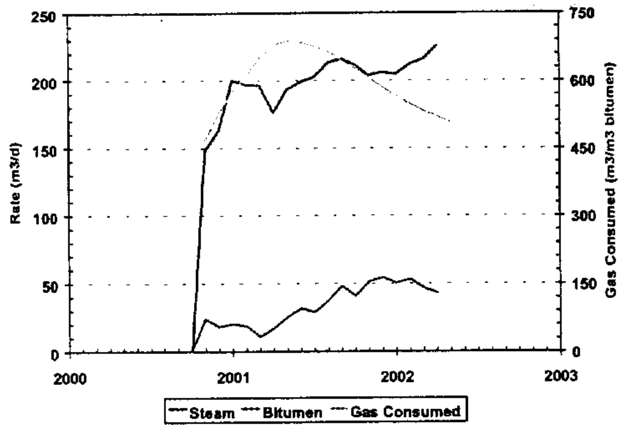

Figure 11: Hilda Lake SAGD #3 Performance

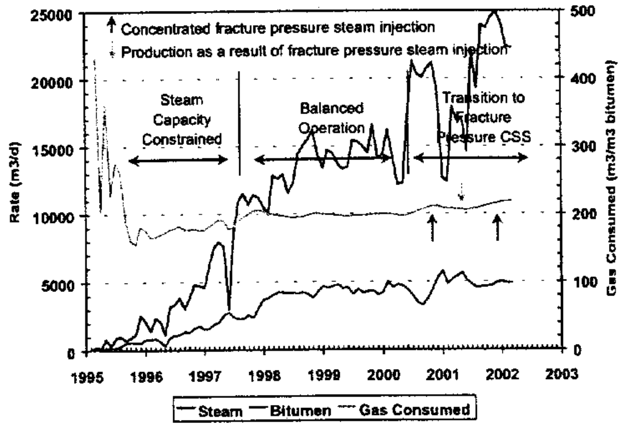

Figure 14: Primrose CSS Cumulative Gas Consumption

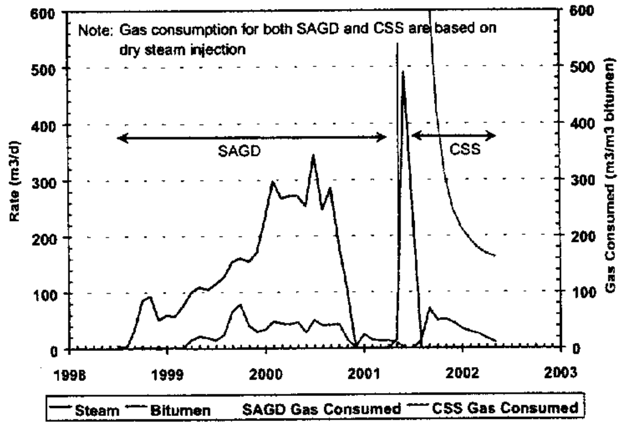

Figure 12: Primrose SAGD (and Conversion to CSS)

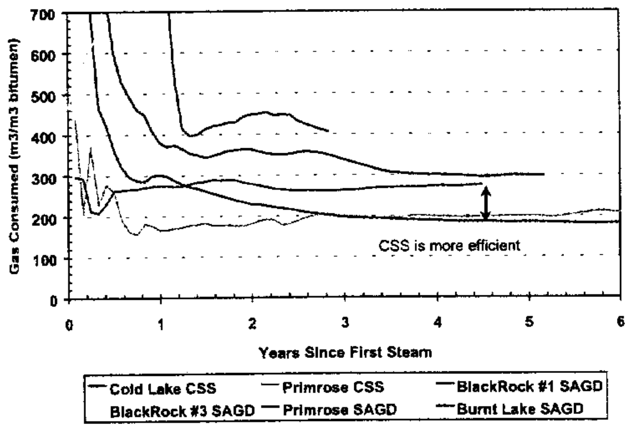

Figure 15: SAGD and CSS Cumulative Gas Consumption #1

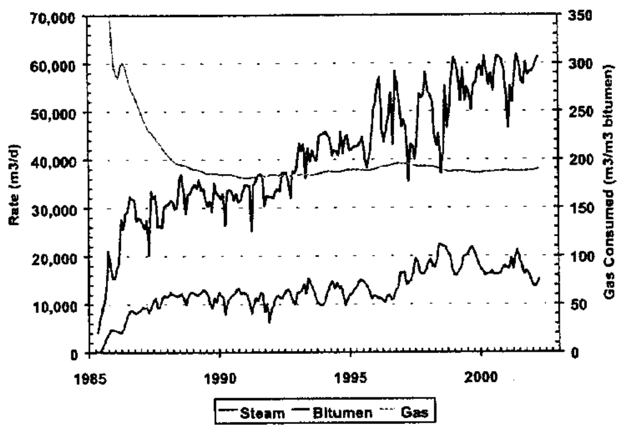

Figure 13: Cold Lake CSS Cumulative Gas Consumption

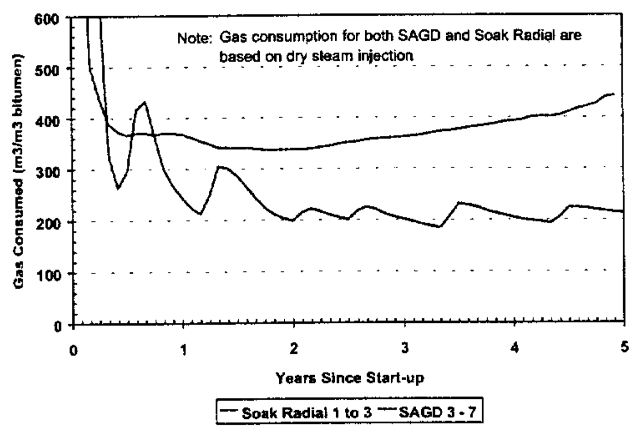

Figure 16: Peace River Soak Radial and SAGD Cumulative Gas Consumption

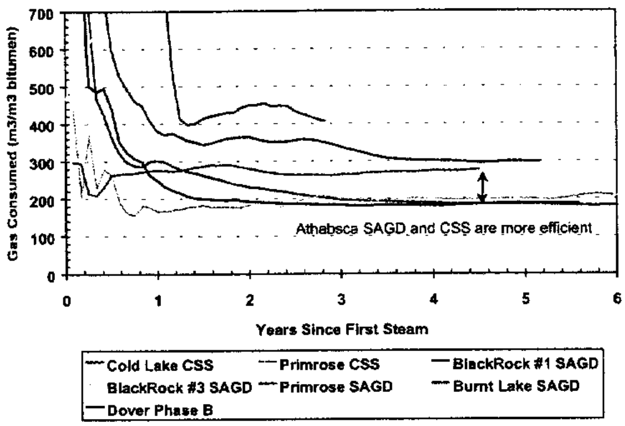

Figure 17: CSS and SAGD Cumulative Gas Consumption #2

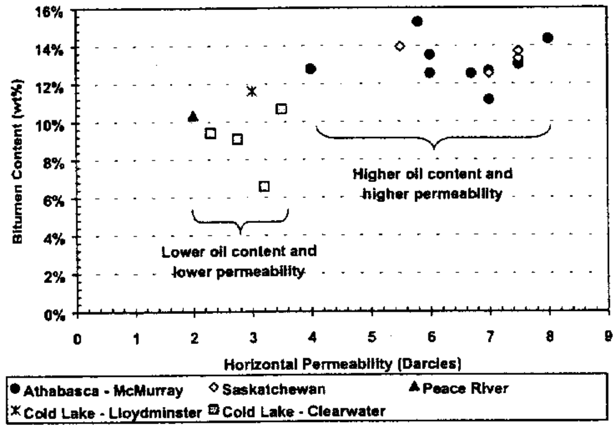

Figure 18: SAGD Project Wt% Bitumen - Permeability Crossplot

Appendix A: Energy Efficiency and Reservoir Data and Sources

Table 1: Commercial Project External Gas Requirement Data

SAGD Project	Operator	Steam to Field m3/d	Quality	External Gas m3/d	Gas to Steam to Field Ratio m3 gas/m3 100% quality steam	Reference
Burnt Lake - Phase 2	CNRL	5,650	100%	430,000	76.1	14. Figure 5.0.2.
Christina - Phase 2	EnCana	7,180	100%	528,000	73.5	33. Q50 Fig 2.
Firebag - Phase 1	Suncor	11,100	100%	736,600	66.4	34. Figure B6.2.
Foster Creek - Phase 2	EnCana	20,330	100%	1,520,514	74.8	35. PFD-05-002 & PFD-07-001.
Hilda Lake	BlackRock	9,540	100%	706,000	74.0	36. Figure 2-26.
MacKay	Petro-Canada	11,528	100%	1,019,300	88.4	31. Figure 9.1.
Kirby	Rio Alto	11,525	100%	824,000	71.5	37. Figure B-58.
Surmont - Phase 1	ConocoPhillips	9,938	100%	887,017	89.3	38 Figure 7-9.
					Average: 76.7	

CSS Project	Operator	Steam to Field m3/d	Quality	External Gas m3/d	Gas to Steam to Field Ratio m3 gas/m3 80% quality steam	Reference
Nabiye	Imperial Oil	18,550	80%	1,098,000	59.2	12. Pg 7-23.

Table 2: SAGD Project Reservoir Data

Geologic Zone	Project	Operator	So	ϕ	wt% Bit	kH (D)	Recovery	Steady State SOR	Cut-off SOR	References and Pages
McMurray	Christina	EnCana	0.80	0.35	13.5	6	65%	1.5		33. Q50 Fig 2.; 39. Page 19.
	Dover	Devon Canada	0.80	0.335	12.8	4				30. Page 2.
	Firebag	Suncor	0.84	0.32	12.7	7	51%	2	3.5	[illegible] Pages B-29 and B-66.; 40. Pages 5-19 and 5-23.
	Foster Creek	EnCana	0.80	0.34	13.0	7.5	70%	2.5		41.Page 3-2.; 42. Page 3.
	Hangingstone	JACOS	0.826	0.375	15.2	5.8	65%	3		43. Page 21.; 44. Pages 24 and 61.
	Kirby	Rio Alto	0.80	0.33	12.5	6.7	47%	2.4		37. Pages B3-5, B6-1 and B8-2.
	Long Lake	OPTI Canada	0.85	0.35	14.4	8	50%	2.5		45. Pages B1-15 and B1-18.
	MacKay	Petro-Canada	0.80	0.33	12.5	6	72%	3.3	4.5	[illegible] Pages 3-2 and 3-3.; 46. Page 1.
	Meadow Creek	Petro-Canada	0.80	0.30	11.1	7	65%	2.6		47. Page 2-10 (Prospect A); 48.
	Surmont	ConocoPhillips	0.80	0.35	13.5	6	45%	2.5	4	38. Pages 2-8, 4-4 and 6-2.
Dina/Cummings	Senlac	EnCana	0.85	0.33	13.3	7.5	65%	1.9		49. Pages 288 and 290.
Sparky	Celtic	ExxonMobil Canada	0.80	0.33	12.5	7	60%			50. Page 6.
Waseca	Pikes Peak	Husky	0.875	0.33	13.7	7.5	50%			51. Pages 6 and 8.
Colony	Bolney	Husky	0.89	0.33	13.9	5.5				52. Page 1-11.
Bluesky	Peace River	Shell Canada	0.81	0.28	10.4	2	55%	3.6		27. Page 7.; 53. Figure 7, P50 properties.
Lloydminster	Wolf Lake	CNRL	0.74	0.33	11.6	3	60%			16. Page B2-6.; 54. Page 15.
Clearwater	Burnt Lake	CNRL	0.65	0.31	9.4	2.3	60%	2.8	3.7	[illegible] Page 282.; 14. Table 1 and Figure 3.2.1.
	Hilda Lake	BlackRock	0.61	0.36	10.7	3.5	50%	3	4.5	21. Table 5.1.; 55. Page 2-1 and 2-30.
	Primrose	CNRL	0.58	0.33	9.1	2.8	54%			16. Page B2-1.; 25. Page 3-8.
	Wolf Lake	CNRL	0.42	0.33	6.6	3.2	40%	3.6	—	13. Page 6.; 16. Page B2-5.
		Averages:					57%	2.7	4.0	

Notes:
1. Wt% Bitumen = (So * ϕ)/(2.65 * (1-ϕ) + 1.0 * ϕ) * 100. Where: 2.65 = density of reservoir rock (gram/cm^3) and 1.0 is the density of the bitumen and water.
2. All SORs based on high-pressure dry steam to field.
3. Values shown are either the specific value or the mid-point of the range quoted in the reference.
4. References 1-33 are located at end of main paper

Additional References for Appendix A

33 PanCanadian: AEUB Application 1023589, "Christina Lake Thermal Project - Supplemental Information":, Sep. 1998.

34 Suncor: AEUB Application 1065224, "Firebag In Situ Oil Sands Project Application", May 2000

35 AEC: AEUB Application 1252809, "Foster Creek Commercial Project - Phase II and III", Dec. 2001.

36 BlackRock: AEUB Application 1241564, "Orion EOR Project", Jul. 2001.

37 RioAlto: AEUB Application 1261126, "Application for the Rio Alto Kirby Project", Apr. 2002.

38 Gulf Canada: AEUB Application 1090197, "Surmont In-situ Oil Sands Project", Mar. 2001.

39 PanCanadian: AEUB Application 1023589, "Christina Lake Thermal Project", Mar. 1998.

40 Suncor: AEUB Application 1065224, "Firebag In Situ Oil Sands Project Application - Supplemental Information", Sep. 2000.

41 AEC: AEUB Application 1039535, "Foster Creek In Situ Oil Sands Project", Mar. 1999.

42 AEC: AEUB Application 1039535, "Foster Creek In Situ Oil Sands Project - Supplemental Information", Nov. 1999.

43 JACOS: AEUB Application 1017621, "Hangingstone Steam Assisted Gravity Drainage Demonstration Project", Dec. 1997.

44 JACOS: AEUB Application 1038027, "Phase 2 of the Hangingstone Steam Assisted Gravity Drainage Demonstration Project", Feb. 1999.

45 OPTI Canada: AEUB Application 1080609, "Long Lake Project", Dec. 2000.

46 Mattison, B.W., King, B., Knight, J. and Slevinsky, B.: "Petro-Canada's MacKay River In-situ Oil Sands Project: Current Scope and Status", 047-1, presented at the CSPG Rock the Foundation Convention, Calgary Alberta, June 18-22, 2001.

47 Petro-Canada: AEUB Application 1250512, "Meadow Creek SAGD Project", Nov. 2001.

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49 Edmunds, N.R. and Suggett, J.C.: "Design of a Commercial SAGD Heavy Oil Project", SPE 30277, presented at the International Heavy Oil Symposium, Calgary, Alberta, Jun 19-21, 1995.

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51 Husky Oil: SEM Application, "Steam Injection Project Expansion", Apr. 1999.

52 Marathon Canada: "Heavy Oil Divestment Information Package prepared by Waterous", May 2001.

53 Shell Canada: AEUB Application 1026733, "Approval for Termination of the Peace River Expansion Project", Jun. 1998.

54 CNRL: AEUB Application 1076081, "Wolf Lake and Primrose Oil Sands Projects - Year 2001 Development Plan - Supplemental Information", Jan. 2001.

55 BlackRock: AEUB Application 1241564, "Orion EOR Project", Jul. 2001.

b) Please refer to Figure 5.25b which depicts the data in Figure 5.25a (revised from B3.1 to include steam injection and instantaneous SOR) on a cumulative basis.

c) The upper limit to the instantaneous SOR that Suncor considers to be economic for the Firebag Project scheme is between 3.0 and 4.0 m^3/m^3. This SOR limit is highly sensitive to the forecasted natural gas price. The limit is reached between 12 and 13 years of operation, as shown in Figure 5.25a. The SOR begins to increase rapidly at this point because the oil production rate begins to decrease as the ultimate recovery is approached, as shown in Figure 5.25b.

d) The cumulative SOR of 2.0 is based on the results of Suncor's numerical simulation. Suncor believes that the cumulative SOR for the Firebag Project should be lower than the SOR for a thinner reservoir such as UTF or MacKay River. In a thick reservoir, cumulative heat losses to the overburden are less than for a thin reservoir. Reduced heat loss per barrel of bitumen recovered results in a more efficient SAGD process and a lower SOR. Should the SOR at the Firebag Project prove to be higher than simulated, the bitumen production rate will be lower than forecast. For clarity, 280,000 bpd (CWE) injected steam results in production of 140,000 bpd bitumen at a SOR of 2.0 but only 112,000 bpd bitumen at a SOR of 2.5.

Connective Shale/Geophysical Program/Well Spacing

Question 5.26

Suncor indicates that the well spacing will be determined after the interpretation of the 1999/2000 seismic surveys (*Volume 1, Section B3.2.1, p. B-27*).

a) Provide a figure to illustrate the location of individual seismic lines that comprise this work.

b) Describe pertinent details of this geophysical program (what were expected and actual results). Does the geophysical program provide the resolution necessary to define the internal geologic units that were identified?

c) Is further work on the design of Stage 1, waiting on the interpretation of Suncor's seismic program results? If so, when will this work be completed?

Response:

Optimum well spacing is a function of net pay thickeness. To maximize recovery per well pair, horizontal wells would be spaced further apart in thicker reservoir. Based on an average net pay thickness in the Stage 1 area of 37 m, Suncor has concluded that the optimum well spacing is 160 m.

At the time of application, Suncor expected that the 1999/2000 seismic surveys would provide enough definition of reservoir structure to estimate the net pay, and therefore provide a basis for definition of well spacing over a larger portion of the lease. However, interpretation of the 3-D seismic survey in the Stage 1 area has not provided the expected results. Therefore, above the base of the reservoir, which is defined locally by the Beaverhill Lake structure or the top of the Lower McMurray continental sediments deposited in lows on the Beaverhill Lake. The injector will be drilled approximately five metres above the producer. The pre-heat phase will last from one to three months with steam being injected down the tubing to the toe of the well and circulated back up the casing to the wellhead. The maximum pressure is expected to be 1750 kPaa, which is below the calculated overburden stress pressure of 2100 kPaa at the top of the reservoir. The Dover Project injects at a similar pressure-to-overburden-stress-pressure ratio and to date there has been no evidence of formation fracture. The planned steam rate is 100 m^3/day per well-pair and the production wells will be operated at a slightly lower pressure than the injection wells to promote communication between the wells.

After the pre-heat phase, the wells will be put on normal SAGD operation with approximately 80% of the steam injected down the injector casing and 20% down the tubing. The steam injection rate will be increased gradually until a target reservoir operating pressure of 1750 kPa is attained. The production wells will be converted to normal SAGD operation and flow will be induced by gas lift. The wells are expected to flow to surface thereafter, however the flow rate will be regulated at surface to ensure a sub-cool of several degrees.

The base operational design indicates that well-pairs will be operated until their instantaneous steam-oil ratios (SOR) reach a value of four to five m^3 of steam injected per m^3 of bitumen produced, based on economic indications. At that time, steam injection will stop and a non-condensable gas may be injected to maintain reservoir pressure and to reduce steam migration between active and inactive steam chambers. Alternative non-condensable gas sources are currently being investigated for the project.

Injection of a non-condensable gas is an unproved aspect of a field-wide application of SAGD technology but numerical simulation suggests it will work. This concept is being tried at the Dover Project and Petro-Canada has full access to this information. If this form of pressure maintenance is unsuccessful, a buffer zone of undeveloped bitumen may need to be left around inactive, low pressure, steam chambers to isolate them from the active, high pressure steam chambers.

Development of the MacKay River reservoir will likely begin in Section 04-093-12 W4M with four pads and 24 well-pairs. It is expected that a total of 24 pads with three to eight well-pairs each will be required to develop the known reserves while reducing the overall surface impact to a minimum. The distance between well-pairs is nominally 100 metres, although spacings as short as 80 metres may be used in parts of the reservoir where the bitumen zone is thinner, and individual wells may be up to 700 metres long.

3.2 Observation Wells

Some observation wells will be included in the initial development of the MacKay River Project. It is planned that six temperature and pressure observation wells will be drilled in and around one pad of wells to monitor steam chamber growth in and around the pad.

6 Recovery Process

6.1 Bitumen Recovery

The steam assisted gravity drainage (SAGD) process utilizes two parallel horizontal wells: a production well and a steam injection well located about 5 m above it. During the startup phase, steam is circulated in both wells for approximately three months. This process heats the oil sands between the wells until the bitumen is mobilized and pressure communication is established between the wells. Once this occurs, the steam is injected only into the injection well to allow a steam chamber to grow vertically and laterally initiating the process of gravity drainage of heated bitumen to the production well (Figure 1-1).

The steam injection rate is increased until the desired reservoir operating pressure is achieved. It is then adjusted to maintain the desired pressure. The operating pressure would typically start at a higher pressure to accelerate bitumen rates and then decline with time to make use of stored heat in the reservoir. The injection pressures will not exceed the formation fracture pressure, which varies with the depth of the top of the reservoir but is generally not expected to exceed 4000 kPa. As the bitumen is heated, its viscosity is reduced from over 1,000,000 mPa·s to less than 20 mPa·s enabling it to flow toward the lower production well. The flow-rate of the production well is controlled so that the bottomhole temperature of the produced fluids is a few degrees Celsius below the saturated steam temperature at the operating pressure. This temperature differential is referred to as 'subcool.' This steam trap control allows the steam chamber to cone down, but not into the producer.

Once a group of steam chambers have been fully exploited, formation pressure should be maintained, so as not to reduce the bitumen recovery in adjacent areas. After the bitumen has been recovered, water from the bitumen-free phase of the McMurray Formation will be injected into the depleted chambers to reinstate pre-extraction reservoir pressures (Section 9.3).

6.2 Recovery Efficiency

Numerical simulation of the SAGD process to predict the resource recovery is based on the geological information and interpretation, and pilot operations.

Gulf plans to develop a variety of reservoir models during project development. Existing reservoir models for a wellpair with 30 m reservoir gross thickness show potential recoveries over 70 percent of the original bitumen in place (OBIP) at an instantaneous dry steam-oil ratio (SOR) cut-off of 4.0 by the end of a well life. These results are consistent with those achieved at the Dover UTF (underground test facility) and indicate residual bitumen content in steamed chambers is very low (i.e., high sweep efficiency). A typical forecast for a wellpair located in an area without thief zones is shown in Figure 6-1.

The forecast is based on a numerical thermal simulation model (Exotherm©) set with the following input parameters:

- Well Length 700 m
- Well Pair Spacing 100 m