PETROLEUM SOCIETY
CANADIAN INSTITUTE OF MINING, METALLURGY & PETROLEUM

PAPER 2004-031

CANADIAN INTERNATIONAL
PETROLEUM CONFERENCE

The False Lucre of Low-Pressure SAGD

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This paper is to be presented at the Petroleum Society's 5th Canadian International Petroleum Conference (55th Annual Technical Meeting), Calgary, Alberta, Canada, June 8 – 10, 2004. Discussion of this paper is invited and may be presented at the meeting if filed in writing with the technical program chairman prior to the conclusion of the meeting. This paper and any discussion filed will be considered for publication in Petroleum Society journals. Publication rights are reserved. This is a pre-print and subject to correction.

Abstract

The current trend in the planned application of the SAGD process is towards low-pressure steam injection. The intention is to be more thermally efficient, since steam at lower pressures has a greater proportion of its heat in the form of latent heat, as opposed to the specific heat ("sensible heat") invested in heating water to the boiling point. Latent heat is the predominant source of heat released to the cold reservoir, which then warms up to the steam temperature thus mobilizing the bitumen; therefore, it is essential that the SAGD process be thermally efficient for optimal economic viability.

However, the more rigorous examination of the SAGD process presented here, inclusive of surface processes, reveals that there is no thermal benefit in operating at lower pressures. In addition, the process will be hindered by low-pressure injection due to the higher viscosities and the inhibited dilation of the unconsolidated sandstone reservoir. This paper demonstrates that a complete analysis of the SAGD process favours operation at high pressures, and that the yet-unproven operation of SAGD at low pressures will be less effective.

Introduction

Steam-assisted gravity drainage (SAGD) has been successfully applied to the *in situ* thermal recovery of bitumen beginning with the AOSTRA Underground Test Facility's Phase A laboratory-scale pilot project (1987-1991) and the subsequent commercial-scale pilot[1], Phase B (1991-present). Since then, a large number of commercial projects have emulated their success.

At present, the current trend in operating philosophy is towards low-pressure SAGD, LPSAGD. This is based on the fact that at lower pressures, the physical properties of steam are markedly different, with a larger percentage of latent heat.

Attractiveness of Low-Pressure SAGD

SAGD Process

In the SAGD process, most of the heat transferred to the cold oilsands formation is by the condensation of steam onto the periphery of the steam chamber. The latent heat released from the steam is transferred to the colder formation mainly by conduction; therefore, the predominant flow of condensed steam (i.e. hot water) and mobilized hot bitumen is perpendicular to the direction of conductive heat flow.

Note that the injection of less than 100% quality steam is counterproductive, as the injected liquid water fraction simply falls from the injector well to the producer well under gravitational forces within the isobaric steam chamber. This adds to the water handling costs while contributing nothing to the release of energy to the formation, and therefore nothing to the recovery of bitumen.

Steam Properties

The energy required to convert a given mass of liquid water to steam at constant pressure can be split into the sensible heat and the latent heat. The sensible heat is the energy consumed in raising the temperature of the water from an initial source temperature to the steam temperature; the latent heat is the energy consumed as that hot water undergoes the phase change as it is boiled into steam. It is this latent heat that provides the predominant source of heat for the SAGD process.

Relative to the conditions at a datum temperature, e.g. source groundwater at 10°C, the amount of heat in steam will vary, depending upon the steam pressure. Equally as important, the relative proportions of latent heat to the total heat will vary with pressure, with steam at lower pressures having a higher proportion of latent heat. This is shown in **Figures 1a and 1b**. Steam quality is the proportion of water converted to steam.

Figure 1a Temperature-Enthalpy Schematic for Steam

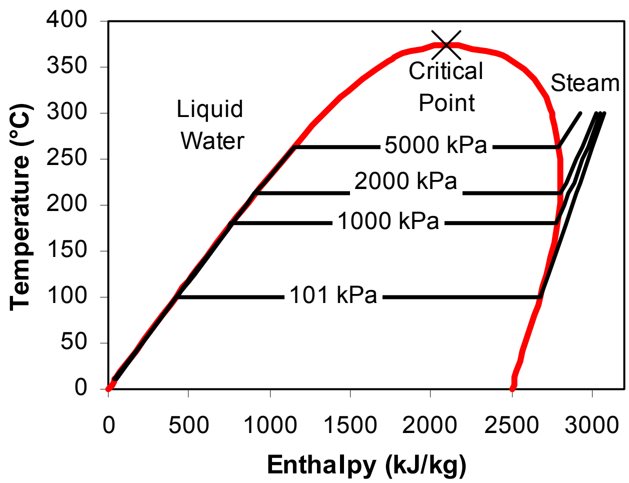
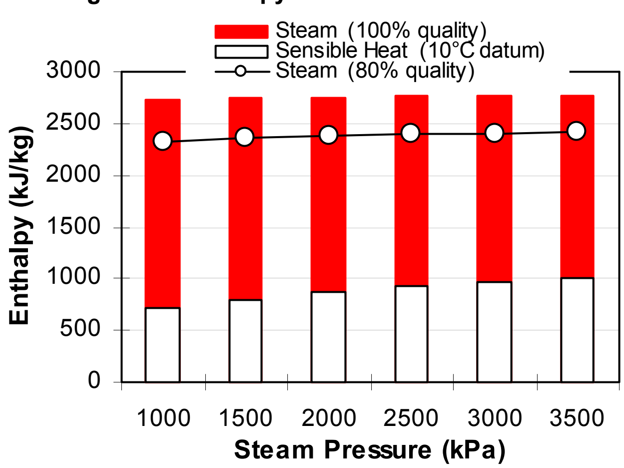


Figure 1b Enthalpy of Steam vs. Pressure



While the enthalpy of steam over the pressure range 1000 – 3500 kPa is relatively uniform (**Fig. 1b**) it is obvious that, at lower pressures, the proportion of heat as latent heat is higher. Since the latent heat is the dominant form of heat transfer to the formation, one can see one attraction of low-pressure injection.

SAGD and Steam Injection Pressure

The current planning philosophy of a number of SAGD operators in the selection of a SAGD operating pressure is towards low pressures. This sea-change in approach may be largely attributed to the paper by Edmunds and Chhina (2001)[2]. The authors conducted four reservoir simulations of the SAGD process assuming constant permeabilities of 3.5D and 7D, and reservoir thicknesses of 10m and 25m. Several simplifying assumptions were made to quantify factors not simulated. These authors presented the results of their thermal reservoir simulation study and economic analysis, and concluded that SAGD economics are more sensitive to the steam/oil ratio (SOR) than the oil rate, and that low injection pressures are favoured because of their low temperatures and low steam consumption, which indicated that pressures as low as 400 kPa were optimal.

Thermal Accounting: SOR vs. Net Energy

The current practice of using the SOR as the economic indicator for SAGD performance is flawed as it only considers the energy injected. An improved metre would be the energy consumed, which requires a fair examination of the energy injected and the energy recovered.

Historically, the SOR has been a fair indicator of the efficacy of steam recovery processes. Before SAGD, the two successful steam recovery processes were steamfloods and cyclic steam stimulation (CSS). In steamflooding, steam is continuously injected into one well while warm water and oil are produced from another well. All of the latent heat and much of the sensible heat have been lost to the formation, at least until steam breakthrough to the producer. In CSS, steam is injected into one well for a period (~month) then the well is shut-in for the "soak" period. Afterwards, that same well is put on production for three or four months, producing hot water and oil at progressively cooler temperatures until the lower production rates warrant another injection cycle. Similarly, all of the steam and much of the latent heat is again lost. As such, the SOR is a good first-order indicator of energy consumption, although improvements can be realized with more rigorous analyses.

In contrast, SAGD produces fluids continuously at constant rates and temperatures just below the steam saturation temperature. This set of conditions makes SAGD ideally suited for heat recovery from the produced fluids. This energy can be recovered, and is currently being recovered, by SAGD operators. This recovered heat must be included in a realistic fashion in any rational thermo-economic analysis of SAGD.

Heat Recovery and Heat Exchangers

Heat exchangers provide the primary method of heat recovery from the produced fluids at steam injection thermal recovery projects. They are a well-known technology with proven performance characteristics.

Heat exchangers are classified according to their flow arrangement and construction, with the most effective design consisting of two concentric pipes with counterflow, as shown schematically in **Figure 2**. Hot fluids flow through one pipe, while cold fluid flows through the other pipe in the opposite direction. The exchange of heat occurs as the two fluids flow past each other. Other flow arrangements exist, but are less efficient. However, some efficiency is sometimes foregone in order to optimize the design of the heat exchanger in terms of other design criteria, such as volume, dimensions, differential thermal expansion, flow constriction, and maintenance. Shell-and-tube exchangers with one shell pass and one tube pass through multiple tubes utilize counterflow.

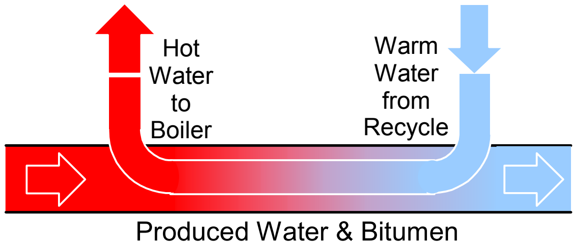


Figure 2 Counterflow Heat Exchanger

Heat Exchanger Effectiveness

The effectiveness of a heat exchanger[3] is the ratio of its heat transfer rate to the maximum possible heat transfer rate and this is largely a function of the surface area of the exchanger, A, the ability of the exchanger to transfer heat for a given temperature difference, U, and the heat capacity rates of the hot and cold fluids (Appendix A). For this study, it was assumed that the produced fluids were commingled. However, separation at high temperatures before any heat transfer is also possible.

Using the injection pressures and resultant SORs provided by Edmunds and Chhina (2001)[2] for their 25m x 7D case, an analysis was done to examine the potential for heat recovery from the produced fluids. Their assumption was that 10% of the injected heat would be recovered. However, this assumption will be shown to unfairly penalize high-pressure operation where the fluid rates and temperatures are higher, and therefore where proportionally more heat is recoverable.

Figure 3 Counterflow Effectiveness

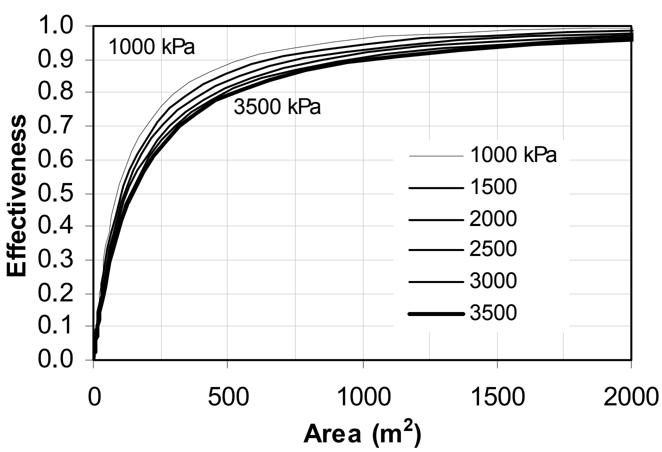
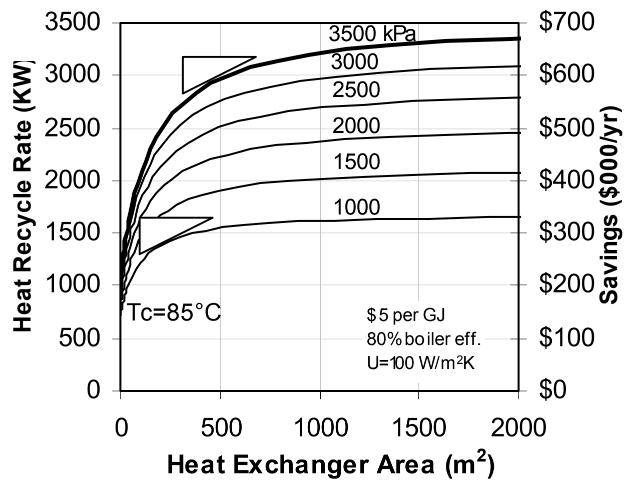


Figure 3 shows the effectiveness of a counterflow heat exchanger, assuming a conservative overall heat transfer coefficient of U=100 W/m^2·K (17.6 BTU/ft^2·h·F) and a CDOR (calendar day oil rate) of 100m^3/d. Curves are plotted at the heat capacity ratios, C_r corresponding to the SORs at the six operating pressures from 1000 to 3500 kPa. The x-axis is the surface area; therefore, these curves include the effect of the minimum heat capacity rate, C_{min}, for each pressure. Heat transfer at lower pressures appears more effective because the heat capacity ratio at lower SORs is more disproportionate than at high values of SOR.

However, the amount of heat available for recovery is much lower at low pressures, and this is clearly seen in **Figure 4**. The rate of heat recycle is plotted against the heat exchanger area, using the previous assumptions. All the curves intersect the y-axis at a point representing a water recycle outlet temperature of 85°C. Relative to a make-up water temperature of 10°C, this is a continual savings in energy required to heat the recycled water to the boiling point, T_{sat}. All other heat recovery is from the heat exchanger.

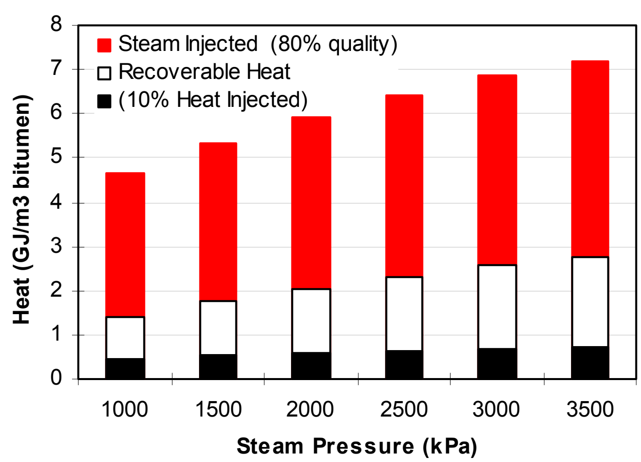
Figure 4 Value of Recovered Heat (CDOR=100m^3/d)



The higher rates of energy recovery at higher operating pressures are a direct result of their higher operating temperatures and total fluid production rates. Note that at higher operating pressures, it is advantageous to have a larger surface area since the hot and cold flow rates are both higher, and their ratio, Cr, is closer to unity and therefore require a larger area for the same level of effectiveness (viz. **Fig. 3**).

The dual vertical scale allows for a quick cost analysis of the heat recycle system. Using a constant price of $5 per GJ for the natural gas firing the boilers, at a boiler efficiency of 80%, the heat recovered can be converted to cost savings. These are based on a CDOR of 100m^3/d, and are therefore scalable to expected production rates. Savings of over $650K per annum are predicted for the highest operating pressure of 3500kPa.

Figure 5 Net Energy

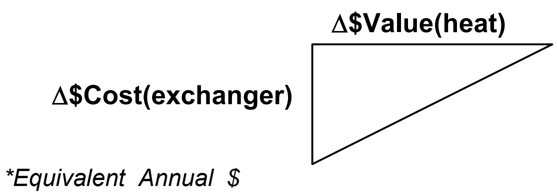


The effect of SAGD heat recovery, as a function of operating pressure, is shown in **Figure 5**. The steam heat injected at each operating pressure is plotted, as is the heat recoverable assuming a heat exchanger area of 1000m^2 (**Figure 4**). Higher heat recoveries are obtainable with larger areas or larger heat transfer coefficients, U. For comparison, the assumption of heat recovery being 10% of the injected heat is shown, and it is shown to be biased against high-pressure SAGD. With reasonable heat recovery, this thermal analysis demonstrates that, from a thermo-economic standpoint only, the SAGD process is almost pressure-independent.

Heat Exchanger Optimization

The optimal size of a heat exchange system will be one where the marginal cost of increasing the size of the heat exchanger equals the incremental benefit of the heat recovered. This requires realistic estimates of the exchanger effectiveness and the value of any heat recovered. For conceptual simplicity, this ratio can be expressed graphically as a triangle (**Figure 6**):

Figure 6 Marginal Cost and Benefit of Incremental Heat Exchanger Area



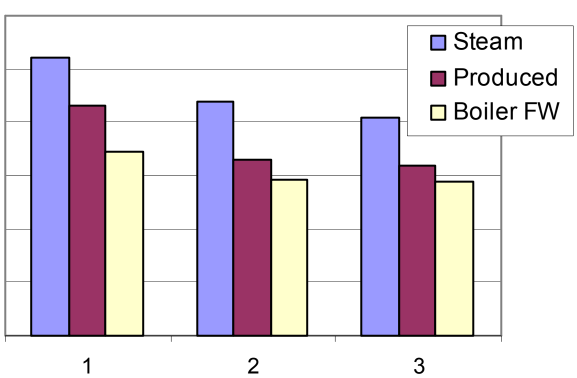
When these costs and benefits are expressed in terms comparable to those in **Figure 4**, the optimal heat exchanger size is obtained when the tangent of the curves in **Figure 4** matches the slope of the hypotenuse in **Figure 6**. This is shown by the two triangles on **Figure 4**, for the cases of high and low pressure. As the price of fuel gas increases, so does the value of the recovered heat and the triangle becomes flatter, increasing the optimal heat exchanger area. Conversely, an increase in the cost of heat exchangers will shift the optimal point towards smaller sizes.

The analysis in **Figure 5** has been done assuming a uniform heat exchanger size of 1000m^2. However, it is certain that the optimal size of a high-pressure heat exchanger will be larger since there is still considerable energy left in the produced fluids. This is shown schematically in **Figure 4**, where the triangle for high-pressure operation is to the right of the identical triangle at low pressure. As such, the net energies reported in **Figure 5** are slightly biased in favour of low-pressure operation. A more complete analysis should include a rigorous examination of heat exchanger costs and performance specifications. However, that is outside the scope of this paper.

Heat Recovery and Field Data

Field data of heat recovery was solicited from operating companies, and the results are shown in **Figure 7**.

Figure 7 Temperatures of Injected Steam, Produced Fluids, and Boiler Feedwater (5°C datum)



This figure shows the temperatures of the injected steam, produced fluids, and boiler feedwater for two SAGD projects and one CSS project. The baseline datum is 5°C, representing the temperature of make-up water. It is clear that the heat recovery systems are fairly effective, with boiler feedwater temperatures at 80% of the produced fluid temperatures. A fourth project was not shown as it was in its startup phase.

These field data support the assertion that the heat recovered can be considerable. Since this heat replaces fuel gas energy, it has equal value and must be included in any economic analysis in a realistic manner. Once that is done, there is no thermal benefit to LPSAGD.

SAGD Economics

The ultimate goal of all SAGD practitioners is to maximize benefit to our companies. It was the original objective of maximizing benefit that resulted in the pursuit of a lower SOR, because reducing the quantity of steam injected would certainly reduce costs, and that would increase benefits. However, the SOR is only one part of a complex equation and it cannot be used in isolation.

It should be obvious that the use of the SOR as the economic indicator of the merit of any SAGD project is wrong because the SOR only examines the heat injected without giving any value for the heat recovered. A better measure of the economic viability of a SAGD project would be the net energy required to recover bitumen. However, even this is not the best measure, since it is only indicative of the operating costs and does not address the capital expenditures.

Any sensible economic analysis of a SAGD project's viability must examine the interaction of all aspects of the process. This examination should quantify each and every cost and benefit, their interdependencies, and their variations with time, scale, and operating pressure. Furthermore, reasonable values must be assigned to each of these parameters, with these values varying with time. Finally, a present value analysis should be done in order to bring all parameters into a common frame of reference in which to make fair and valid comparisons. Any assumptions made in this process should be explicit, so that they can be easily reassessed. Only when this is done can we truly optimize the SAGD process.

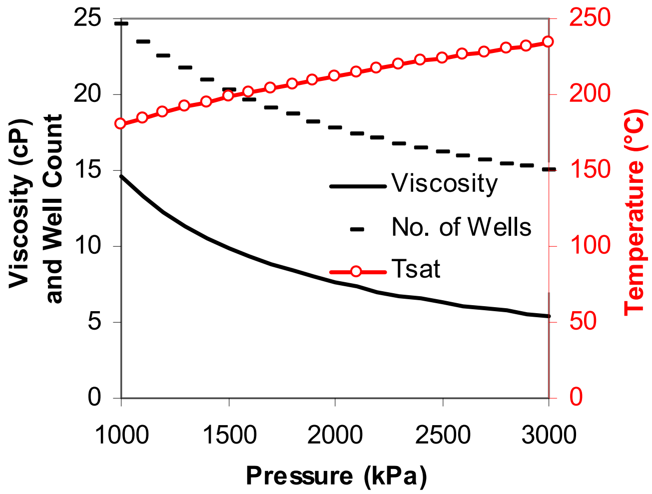
CAPEX Dependence on SAGD Pressure

One of the major drawbacks of LPSAGD is the associated drop in temperature. Since the viscosity of bitumen is exponentially proportional to temperature, and the production rate is proportional to (viscosity)$^{-0.5}$, then the production rate is strongly dependent upon temperature.[4]

This is shown graphically in **Figure 8** in which three curves are plotted against the steam pressure: the saturated steam temperature, a typical Athabasca viscosity, and its inverse square-root, indicating the relative number of wells required for a given CDOR at pseudo-steady state conditions.

The reduction in temperature with LPSAGD has two effects on a SAGD project. Firstly, it increases the number of wellpairs required to maintain a specified CDOR. At CAD$3million per wellpair, this is a considerable capital expenditure (CAPEX) required at the onset of a project. This could increase the CAPEX beyond the hurdle cost set internally, it increases the exposure to risk on a single project, it makes the project less attractive to potential partners, and it ties up capital that might be better spent elsewhere. These wells will also be on production for a long time, which is a commitment to continuing their operation for the longer life of these wells.

Figure 8 Temperature, Viscosity, and Well Count vs. Operating Pressure



The second drawback is that with the low production rates, these wells will reach their economic limit at lower recoverable reserves. While the abandonment rates will likely be lower than for HPSAGD, the recovered reserves will also be lower. One solution is to reduce the wellpair spacing. However, if the wellpair spacing is reduced from 100m to 75m, that would result in 33% more wells being drilled. Even a reduction from 100m to 90m would result in 11% more wellpairs, at $3million per wellpair.

In contrast, high-pressure operation is at higher temperatures with lower viscosities. Production rates are higher therefore fewer wellpairs are required. Well lifespans are shorter, allowing more flexibility on the placement and number of subsequent wellpairs. CAPEX is deferred to the future, since wells are only drilled when required.

Artificial Lift

A major benefit of HPSAGD is that production fluids flow to surface under reservoir pressure. As long as pressure differential between the steam chamber pressure and the wellhead pressure is greater than the hydrostatic head of the production fluids, they will flow to surface without requiring artificial lift. In contrast, LPSAGD requires a lift system to raise the fluids to surface. Options include gas lift, E-lift, and electrical submersible pumps (ESP). All require additional CAPEX and OPEX, and the ESPs have to be replaced every 18-24 months. In some configurations, the additional tubing may require larger casing and therefore higher drilling costs.

Water Handling, Heat Exchange, and Piping

Without question, the higher SOR associated with HPSAGD requires larger volumes of water. Significantly larger volumes of produced water must be recycled. Larger heat exchangers are required in order to optimize the heat recovery; however, this is offset by the value of the heat. All piping and vessels must be more robust, in order to operate at the higher pressures.

Heat Loss

Although operating temperatures are lower with LPSAGD, the length of time that each wellpair operates is considerably longer than for a HPSAGD wellpair. With LPSAGD, the longer operating life and the larger number of wells supersedes the effect of reduced heat loss at the lower temperature. As a result, heat losses may be higher for a LPSAGD project at an equivalent CDOR.

Present Value: a Rational Approach

SAGD projects are large, complex, and cost hundreds of millions of dollars. An objective, rational approach to assessing the economics of initiating, operating, and expanding these projects is the only means of identifying the component quantities, and their costs and benefits.

For each choice of operating strategy (e.g.: LPSAGD vs. HPSAGD) every component of SAGD operation, be it a cost or a benefit, has to be quantified over the life of the project. This will inevitably include projections and estimates, with variations in these quantities over time. Corresponding unit values or unit costs for each of these components must also be quantified, and these too may vary with time. As examples:

- Costs: CAPEX (e.g.: surface facilities, heat exchangers, wellpairs, lift system), OPEX (e.g.: natural gas, electrical power, workovers), royalties, taxes, …
- Benefits: bitumen (including bitumen/crude differential), produced gas, recovered heat, utility heat, power cogeneration, total recoverable reserves, …

Given the temporal profiles of quantities and their respective values, a profile of cash flow can be calculated for each component. Next, a present value analysis can be done, which will discount these to their present day equivalent. Sensitivity analyses of the present values to the discount rate are the norm.

This facilitates the decision-making process, as it couches all costs and benefits in a common frame of reference so that valid comparisons can be made. This methodology does not differentiate between CAPEX and OPEX; however, CAPEX costs will certainly be prominent, especially if the selected discount rate is high. Notably, the bitumen production profile must also be discounted to the present in this analysis.

For larger companies, the optimal choice of operating strategy may be the one with the largest net present value (NPV):

$$NPV = \sum_{i=1}^{m} PV_{Benefits}\left(C_{(t)}^{i} Q_{(t)}^{i}\right) - \sum_{j=1}^{n} PV_{Costs}\left(C_{(t)}^{j} Q_{(t)}^{j}\right) \quad \text{.......(1)}$$

where $C_{(t)}$ is the unit cost, varying with time, of the quantity $Q_{(t)}$, which also varies with time for each component, denoted by the superscript. Alternatively, the optimal choice may be the rate of return, which will still require the present values of the costs and benefits. A levellized cost presentation may provide some insight into the sensitivity of individual components to changes in the bitumen price.

Other companies may have different criteria, such as minimizing the CAPEX, ensuring a ceiling on the outward cash flow, or setting a minimum bitumen rate.

With this approach to SAGD economics, the relative benefits of LPSAGD vs. HPSAGD become more apparent. High CAPEX such as wells, treating facilities, artificial lift, and heat exchangers are included explicitly. The reservoir's response to low or high pressure operation are forecast in the production profiles, SORs, enthalpy profiles, and recovered heat and included in this analysis. Intuitively, this is an improved approach to assessing the value of differing operating strategies as compared to the simplistic approach of using the SOR, which only gives an indication of the steam injected. Once this analytical tool is created, it becomes a powerful means of optimizing the SAGD process to maximize benefit.

The analysis by Birrell, et al. (2003)[5] of a mature SAGD steam chamber included the effect of the expected seasonal fluctuation in the price differential between crude oil and bitumen, which rises in the winter, and falls in the summer paving season.

They predicted that by using the mature steam chambers for production storage by throttling production in winter when prices were low, and flushing production in the summer when prices were higher, that the benefit could be increased by CAD$0.92/bbl. This economic optimization is not the same as the optimization of the SAGD physical process, since drowning a production well is inefficient in terms of maximizing production. However, our objective is to maximize benefit: this is a case in point where an economic analysis, that included variations in quantities and values, led to a more profitable operating strategy. Similarly, the operating pressure could be cycled, with an increase in steam injection and gas consumption in the summer months, and a reduced rate of steam injection in the winter when gas prices are predictably higher.

Mitigating this approach would be the seasonal fluctuations in steam and fluid rates, which would add cost to facilities. However, these effects would be included in a complete present value analysis.

The Geomechanics of SAGD

The entire debate on high pressure vs. low pressure SAGD has been almost completely devoid of any discussion of geomechanics. This reflects a lack of understanding of geomechanics, rather than being an indication of its significance. Predictions of reservoir performance by reservoir engineers presume that the permeability of the oilsand reservoir is fixed and is independent of operating pressure. This is unlikely to be true for operations at low pressures, because the beneficial enhancement of porosity and permeability with shearing is maximized at high pressures. Without geomechanical enhancement of the reservoir, permeabilities may be as low as 10% of expected values, resulting in production rates being a third of expectations. The economics of most SAGD projects could not afford this.

The geomechanical effects of steam injection on an oilsand reservoir can be substantial, and should be substantial if the geomechanical aspects of the SAGD process are to be optimized. However, a full appreciation of the effects of geomechanics demands an examination of the properties of the formation. Since many of these properties are derived from core tests, a review of core and core tests is required.

Core Disturbance

In no other area of petroleum engineering is the core cut at one porosity and tested at a much higher porosity, with the results directly applied to reservoir conditions. The increase in porosity associated with core disturbance has a profound effect on the resultant porosity, saturations, absolute permeability, and fluid mobility. A full appreciation of the effects of geomechanics cannot be had without understanding of the effects of core disturbance first.

Oilsand core disturbance is due to the unconsolidated structure of the deposit. These sands are dense interlocked sediments of near-uniform grainsize.[6] The only difference between these unconsolidated formations and indurated sandstones is their lack of cementation.

The strength of these oilsands is highly dependent upon the confining stress applied to them. If an isotropic confining stress is maintained, thus preserving the interlocking structure developed over geologic time, the oilsands have strength characteristics far greater than if that same specimen were broken up and reconstituted at overburden stresses.

While the bitumen in the core pore space is immobile, it is often saturated at reservoir pressure and temperature. Once the pressure is relieved, gas will nucleate and expand. Since the bitumen is immobile, and the gas phase is non-continuous, the growing gas bubbles force the pores to expand. The oilsand core slowly blows itself apart. This results in permanent and irrecoverable disruption of the sand structure.

Coring

In the past, oilsands were cored with conventional drillrigs, with one or two stands (9 to 18 m) per core run. Trip times were considerable, as the entire drillstring had to be retrieved to obtain the core. More commonly, wireline rigs are now being used, with triple-tube coring. These have the advantage of allowing faster retrieval of the core, and because the drillstring is not tripped, shorter core runs of 2 to 3m are practical. These shorter core runs puts less vertical load on the core, since the core is self-supporting within the inner core tube, particularly once the core barrel is extracted from the well.

The faster recovery time allows the core to be returned to surface in as short a time as possible. This is critical, since gas bubble nucleation and growth is a time-dependent phenomenon. If the core can be frozen before gas bubbles form, the freezing temperatures will minimize disturbance. Freezing temperatures must be sufficiently low to prevent gas exsolution, not just to freeze the pore water. If adequate freezing is not done in time, the bubbles will grow, causing the core to expand in dimension until it completely fills the core tube. Since the gas will continue to expand, the core expansion will be axial, resulting in core extrusion from the core tube.[7] For this reason, core recoveries of more than 100% have been reported. Others use slotted inner core tubes to allow the gas to escape. However, this does not eliminate the disturbance as the core expands to fill the inner core tube. Using "zero clearance" [8] (1.27mm clearance) inner core tubes is highly recommended, as this minimizes the capacity of the core to expand and fill the core tube. The potential for higher frictional resistance to the core entering the core tube is minimized with the shorter, faster wireline core runs.

Specimen Preparation

By the time core has arrived at the physico-chemical laboratory for analysis, the majority of core has expanded to fill the core tube. For conventional core, this means an expansion from 89 to 95 mm, which is a 15% increase in bulk volume, negating any longitudinal expansion. Next, the tube is sawed lengthwise, dividing the specimen into two unequal parts and removing any confining stress in the process. Lastly, the core is semi-thawed to permit a sharpened tube to be forced into the exposed side of the core to obtain a cylindrical specimen, although the option of nitrogen coring is available. This specimen is then extruded out into a flexible sleeve for permeability and porosity testing. The specimen disturbance by this point is considerable, and there are numerous reports of the ubiquitous discrepancy between core and log porosities.

In contrast, oilsand for geomechanical testing is cored with zero-clearance core tubes. The core is frozen with dry ice to ensure that the core fluid is kept undersaturated at atmospheric pressure. Once the core arrives at the geomechanics laboratory, it is stored at temperatures down to –40°C. Sample preparation is done in a cold room at –20°C by technicians in parkas in order to preserve the structural integrity of the core.[9] Specimens are placed in a lathe and machined to the testing diameter; the ends are sawed and trimmed to create a cylinder. Several times during this procedure, each specimen is sealed and immersed in a cold bath to ensure that it is kept sufficiently frozen. Without such meticulous care, even some core at –20°C has been observed to exsolve gas. Each specimen is mounted in a triaxial testing frame under overburden pressure before thawing is allowed. The improvement in core quality justifies this procedure, but only if the core arrives at the laboratory with minimal disturbance.

Quantifying Core Disturbance

Dusseault and van Domselaar (1982) quantified core disturbance with their "Index of Disturbance", defined as the percentage increase from the initial porosity, ϕ_0, to the current porosity, ϕ :

$$I_D = \frac{\phi - \phi_0}{\phi_0} \qquad (2)$$

As an example, oilsands cored from a formation with a porosity of 30% but with a current porosity of 36% would have an I_D = 20%, which is not uncommon. Any core with I_D > 10% was generally accepted to be of little use for geomechanical strength testing; its effect on permeability is equally as profound. While reapplying the *in situ* confining stress can reduce core porosity by reseating grains, any grain rotation will be permanent, and the core's mechanical and hydraulic properties cannot be restored.

The practice of routinely reporting the index of disturbance for all specimens is highly recommended in order to quantify core quality.

Core Disturbance and Absolute Permeability

The best laboratory results for the absolute permeability of undisturbed Athabasca oilsand were obtained from block samples of McMurray Formation outcrop in an area uninvaded by bitumen[10,11]. Subsequent coring was done under controlled laboratory conditions, and using this bitumen-free sample precluded gas exsolution. These specimens were tested under triaxial loading conditions, in which a confining pressure is applied to the cylindrical specimen as the vertical load is increased. As each specimen was loaded to failure, the permeability was measured in the direction of loading. Specimens were cored vertically and horizontally.

Touhidi-Baghini[10] found that the increase in permeability could be related to the volumetric strain in a semi-logarithmic relationship:

$$\ln\frac{k}{k_0} = C_{\phi_o}\varepsilon_v \qquad (3)$$

where k is the current absolute permeability, k_0 is the original absolute permeability, $C_{\phi o}$ is a proportionality constant dependent upon initial porosity, and ε_v is the volumetric strain. This relationship can also be re-stated as **Equation 4** in terms of the initial porosity and B, a proportionality constant.

$$\ln\frac{k}{k_0} = \frac{B}{\phi_0}\varepsilon_v \qquad (4)$$

The relationship is inversely proportional to the initial porosity, signifying that volumetric strains will have more of an effect on the core with the lower porosity. It can also be re-written in terms of porosity as:

$$\ln\frac{k}{k_0} = \frac{B}{\phi_0}\frac{\phi - \phi_0}{1-\phi} \qquad (5)$$

If the log porosity is assumed to be the undisturbed porosity, then the measured core permeability can be back-corrected to their *in situ* value with:

$$\ln\frac{k_{core}}{k_{\log}} = \frac{B}{1-\phi_{core}}\frac{\phi_{core} - \phi_{\log}}{\phi_{\log}} \qquad (6)$$

This becomes a useful tool for estimating the permeability enhancement associated with disturbance. Touhidi-Baghini and Scott (1998)[11] found $C_{\phi o}$=17.48 for vertical Athabasca specimens and $C_{\phi o}$=9.07 for horizontal specimens; alternatively, B=5 for vertical specimens and B=2 for horizontal specimens, although site-specific values obtained from low-disturbance core would be preferred. Note that the equation was rearranged to obtain I_D as one parameter.

Figure 9 Absolute Permeability of Undisturbed Athabasca Oilsand

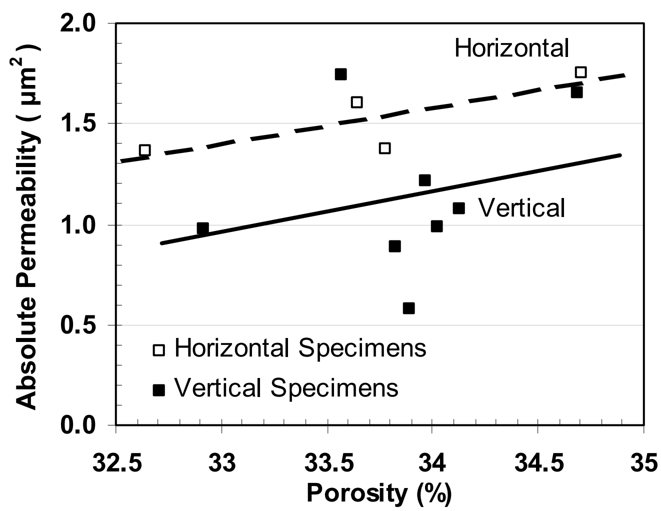


Figure 10 Predicted Absolute Permeability resulting from Disturbance

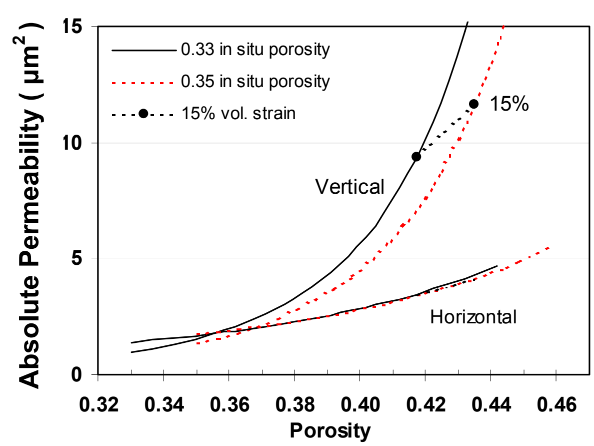


Figure 9 shows the initial permeabilities of these undisturbed specimens, where there is a slight increase in

permeability with porosity. On average, the vertical permeability is just over 1 Darcy while the horizontal permeability is just over 1.5 Darcy. This is a marked difference from the typical physico-chemical laboratory results that are in the order of 10 Darcy. (1 μm^2 = 1.01325 Darcy)

The cause of the discrepancy is the high degree of specimen disturbance in conventional tests because the core has arrived with excessive expansion, and due to the specimen preparation. The specimens from **Figure 9** will exhibit similar behaviour if they are disturbed. Using **Equation 6**, the increase in permeability can be predicted. **Figure 10** shows the predicted increases in horizontal and vertical permeability with increasing disturbance for two initial porosities of 33% and 35%. Note that the vertical permeabilities fall within the range of 10 Darcy for a 15% volumetric strain, which corresponds to the typical condition of conventional core upon arrival at the laboratory.

The salient points are that the undisturbed *in situ* permeability is much lower than indicated by conventional laboratory tests, and that disturbed permeabilities, either from conventional tests or from geomechanical tests that result in disturbance, are 5 to 10 times larger. The fact that history matches of existing SAGD projects require permeabilities in the range of 5-10 D is indicative that this is the effective permeability in the reservoir, under current SAGD operating pressures, which are generally high. SAGD operation at lower pressures will strengthen the oilsand's frictional strength and reduce shearing and its associated dilation and enhancement of porosity and permeability. Lower oil rates should be expected.

Core Disturbance and Fluid Mobility

The increase in porosity results in an influx of fluid to occupy the induced voidage. At colder temperatures, the bitumen is effectively a solid and is immobile. Gas exsolution is similarly retarded, particularly if the SAGD process is increasing the ambient pressures which then makes the bitumen undersaturated. At colder temperatures, water is the only mobile fluid.

Oldakowski (1994)[12] conducted geomechanical triaxial tests on high-quality Athabasca oilsands core at the 8°C reservoir temperature. Increases in porosity, due to the shear-induced dilation of the core, resulted in increases in water saturation and the commensurate increase in effective fluid mobility by three orders of magnitude (viz. Chalaturnyk and Li, 2001)[13].

The implications for SAGD are significant. If the reservoir ahead of the steam chamber can increase in porosity, the pressure front will progress ahead of the steam chamber and permit the gravity drainage of the heated bitumen. Furthermore, the increase in fluid pressure reduces the effective stresses in the rock, which promotes further shearing, dilation, and increased porosity.

Application to SAGD

The initial stress state in the oilsands is a function of the geological history of the reservoir. The weight of the overburden applies the vertical load. The horizontal stresses are due to a combination of the elastic response of the formation to the overburden, and their subsequent increase by mountain-building tectonics. As such, in many reservoirs the highest stress is one of the principal horizontal stresses, with the other principal horizontal stress often being comparable to the vertical stress. Lastly, many reservoirs are below the hydrostatic pressure due to lateral drainage within more transmissible formations.

The injection of pressurized steam reduces the effective stresses on the oilsands, i.e. the portion of the total stresses borne by the rock matrix, as opposed to the fluid pressure. This unloads the reservoir matrix, which then expands vertically in response, as measured in cold oilsands ahead of the steam chamber (O'Rourke, et al., 1994)[14]. The resultant volumetric strain is small (0.25% for UTF Phase B) but the additional porosity created gradually fills with water originating in the steam chamber; this creates a finite demand for several thousand cubic metres of water per wellpair at the onset of steaming. Significantly, the additional water saturation increases the total mobility and pressure communication ahead of the steam chamber. The Dover UTF project reported the pressure front arriving 5 – 12m ahead of expectations within the cold oilsand (Aherne and Birrell, 2002)[15].

For a frictional material like oilsand, the injection of high-pressure steam reduces the confining stress on the sand grains. If a differential stress is applied to the oilsand, as is naturally in place with the varying vertical and horizontal stress, it makes it easier for the individual grains to slide over one another, rotate, and displace. The net result of this shearing is dilation: an increase in the porosity. With higher injection pressures, the effective stresses are lower, the oilsand has less strength, and the shearing and dilation are more prominent. Along with the dilation comes the increase in fluid mobility and absolute permeability, as discussed. However, shearing and enhancement is not uniform within the reservoir; instead, it occurs along induced shear planes, which then become transmissibility conduits for mobile fluids. Field evidence of discrete thermal intrusions ahead of the steam chamber supports this (Ito, et al., 2000)[16]. The Dover UTF project also reported significant heat convection in the cold reservoir (Birrell, 2001)[17].

Note that from a facilities and reservoir engineering standpoint, pressures are an absolute. For geomechanics, pressures are relative, being either "high" or "low", depending upon the depth: 4000 kPa would be high at a depth of 200m, but low at a depth of 400m. This difference in terminology is central to an understanding of the geomechanical effects of injection pressures.

The sharp thermal front ahead of the steam chamber also imposes differential thermal stresses on the oilsand, in the order of 1000 kPa.[18] Depending on the orientation of the steam chamber boundary with respect to the *in situ* stresses, this can either help or hinder shearing by adding to or diminishing the differential stresses due to the original rock stresses. In general, it tends to increase the anisotropic growth of the chamber.

Lastly, the growth of the steam chambers themselves will alter the original stress field. Steam chambers pushing upwards and outwards will increase the horizontal stresses and reduce the vertical stresses in the cold oilsand between wellpairs (Chalaturnyk, 1996)[19]. This thermal jacking will accentuate differential stresses, which will encourage shearing and the lateral growth of the chambers, culminating in steam chamber coalescence.

Once shearing and dilation have occurred, the beneficial effects of enhanced porosity and permeability will be permanent. Reducing the steam chamber pressure during blowdown will have little effect on the induced permeability.

Field Evidence of LPSAGD Geomechanics

Field evidence of SAGD operating at low pressures is scarce, largely because the continuous operation of SAGD at low pressures remains unproven. However, there are indications that reservoir performance at low pressures will be less successful than at high pressures (pressure being relative to depth).

Shell Peace River

Shell Canada's SAGD process in the Peace River oilsands (Hamm and Ong, 1995)[20] was less successful than anticipated, with reported SORs ranging from 5 to 10. The SAGD process was attempted twice, with some wells in bottom water and some not, with no difference in performance. After switching to a cyclic steam stimulation (CSS), first trying a "soak radial" approach, then a multi-lateral side reach ("haybob") well layout, they achieved an acceptable SOR. In explanation, Shell stated that they "forgot the lesson of pressure-enhanced vertical conformance"[21]. The SAGD injection pressure was 2700 kPa, identical to that of UTF Phase A; however, the UTF wells were at 155-160m depth whereas the Peace River wells were at 600m depth. The UTF wells were operated within 700 kPa of the fracture pressure, whereas the Peace River wells were several MPa below theirs. It was highly perceptive of Shell to be cognisant of the "pressure-enhanced vertical conformance", which is strongly indicative of a lack of reservoir permeability enhancement due to injection pressures too low for that depth.

In contrast, the injection pressures for the CSS process were approximately 11,000 kPa, which is at or near the fracture pressure at that depth. Clearly, the higher injection pressure had a beneficial effect on growth.

JACOS Hangingstone

A poignant example of the effects of operating pressure on SAGD performance is documented by Ito, et al. (2004)[22]. The operating pressures currently used are intentionally high, explicitly to achieve geomechanical enhancement within the reservoir, with injection pressures, Pinj, at 4800 – 5300 kPa at a well depth of 300m depth. However, with additional wells coming on production, steam capacity was diverted to them, which resulted in a drop in Pinj to 4600 kPa. The growth of the steam chamber was inhibited as a result, with no vertical growth observed. Once additional steam capacity was added, the steam chamber growth resumed.

The cause of the inhibition could not be correlated with any geological feature, and was attributed to diminished effective permeability due to poor counter-current flow. However, their back-calculated effective "thermal conductivity" of 2.9 W/m·°C while the chamber was growing is in stark contrast to the values of 0.87 – 1.16 W/m·°C back-calculated when the chamber was stagnant. In comparison, controlled laboratory values from Chalaturnyk (1996)[19] were 1.5 W/m·°C at 225°C. It would appear that the higher value includes a component of convective heat transfer, which indicates that the higher Pinj is accelerating the growth of the steam chamber. The authors also specifically recognize the benefit of geomechanical effects in their reservoir.

An Argument for Low-Pressure SAGD

LPSAGD is the only option where the steam chamber is in communication with a thief zone at low pressures. Mobile fluids in a geological unit at a lower pressure, which is in communication with a steam chamber, will necessarily be displaced by steam from the steam chamber. Since the thief zone is colder, steam will continue to condense within it until either the entire thief zone is heated and pressured to steam chamber conditions, or the steam chamber pressure falls and is balanced with the pressure in the thief zone. If the thief zone is extensive, the thermal costs of continuing at a pressure above balance are uneconomic.

High pressure operation is a possibility until the steam chamber comes into close proximity to the thief zone. This would maximize the geomechanical benefits within the limitations imposed by the thief zone, and accelerate steam chamber growth at early times.

Where there is a high probability of communication with a thief zone, or where the impermeable barrier between the steam chamber and thief zone is inadequate, it is preferable to maintain a potential thief zone at as high a pressure as possible in order to allow the greatest flexibility in options for the recovery of the bitumen. Furthermore, should the thief zone be water-bearing, there is the possibility of that water gravity-draining into the steam chamber, even at balanced pressure. This would quench the steam chamber and impose a high thermal load on the process. Lowering the pressure in the thief zone may precipitate the influx of water from a downleg source.

Lastly, bottom water may prevent operation above balance to prevent the egress of heated bitumen and production water. Unless the thief zone can be isolated, or the fluid losses are acceptable, balanced pressure operation is likely the only option.

Conclusions

An objective thermo-economic analysis of the SAGD process must include a realistic value of the heat recovered from the produced fluids. Once that is done, there is essentially no thermo-economic benefit obtained by operating at lower pressures, since higher pressures provide larger volumes of produced fluids at higher temperatures, and therefore more economically recoverable heat.

By including the value of the recovered heat, the economics of all SAGD projects are improved: a considerable savings in operating costs is identified, as this heat will displace projections of natural gas consumption for steam generation. This benefit will be larger for projects operating at higher pressures. Facilities engineers are already recovering much of this heat, so it is unlikely that there will be any immediate increases in revenue. However, recognizing the importance and value of heat recovered from the produced fluids does identify a specific area for optimization and incremental benefits in future. In addition, since the recovered heat reduces the considerable OPEX expense of steam generation, thinner reservoirs become more economically viable: estimates of economically recoverable reserves will increase.

The steam-oil ratio, SOR, is only a measure of the heat injected, and neglects all of the heat produced. As such, it is an incomplete indicator of the true thermal balance of any SAGD operation, and should not be used as the metre by which the thermo-economics of SAGD are evaluated. While the SOR retains its usefulness for evaluating the physical processes within the reservoir and for mass balance calculations, as an economic indicator it is misleading and heavily biased. Using the SOR as the economic indicator will necessarily result in the false conclusion that low-pressure SAGD is thermo-economically optimal. LPSAGD, therefore, is the right answer to the wrong question: "how do we reduce the amount of steam needed to produce bitumen?".

A better question would be: "how do we reduce the energy required to produce bitumen?". As such, the appropriate indicator would be the net energy required to produce bitumen. This must include the heat recovered from the produced fluids, including the efficiencies of the various components associated with heat generation, transportation, and recovery.

However, the energy balance still does not encompass all the differences between low and high pressure SAGD since CAPEX costs are excluded. As an example, LPSAGD operation will require more wells operating from the onset for a target project production rate, and a denser well spacing to access the recoverable reserves within an economic timeframe. Heat exchangers, water handling, and lift systems are also highly dependent upon operating pressure. These considerable costs must be included in any comparison.

The best question becomes: "how do we maximize the benefit to our companies?". This is a subjective question, but to answer it requires an analysis of the present values of every cost and benefit. For most operators, the net present value will be the determining criterion, although other constraints may dominate instead, such as threshold capital costs or minimum production profiles. Importantly, the value of the bitumen being produced must also be discounted to the present day. It was found that, for SAGD operation, the physical optimum was not necessarily the economic optimum.

Lastly, the geomechanics of SAGD dictate that the permeabilities and performance anticipated by reservoir engineers can only be achieved when operating at high pressures; high pressures being relative, which increase with depth. As an approximate guide, when injection pressures are within 500 kPa of the fracture pressure, full geomechanical enhancement should occur: the shearing and dilation of the oilsands, with the associated increases in porosity, absolute permeability, and fluid mobility. At lower pressures these enhancements will either not occur or be inhibited; operating at as high a pressure as possible will maximize benefits. As such, injection pressures should start high and decline with the rise in the steam chamber.

Without geomechanical enhancement, interwell start-up and the subsequent steam chamber growth will be much slower: oil rates will be lower and much less economical. The spectre of impermeable barriers and baffles are real at low pressures, whereas at high pressures they have been demonstrated to be inconsequential as SAGD inhibitors.

SAGD thermo-economics are highly dependent upon the operating pressure. Given that SAGD is capital-intensive in terms of both capital costs and operating costs, there are large potential benefits in properly optimizing the operating pressure and the process, with potential savings in the millions.

Some comparisons are made in **Table 1**, in which the effects of operating pressure on different aspects of SAGD are listed. This is by no means a complete list, since items such as water and dissolved gas chemistry are omitted. However, it does summarize some of the issues discussed.

Table 1 Comparison of Low vs. High Pressure SAGD

	Low-Pressure SAGD	High-Pressure SAGD
Lift	pumps or lift system	free-flowing
Heat Exchange	lower pressure system	larger high-pressure system
Water Treatment	lower rates	higher rates
Viscosity	higher viscosity, lower rates	low viscosity, higher rates
Wells	higher initial CAPEX; narrower wellpair spacing, → more wells	fewer wells at onset; wider wellpair spacing, deferred CAPEX, more flexibility
Heat Losses	longer exposure	higher temperatures for much shorter term
Geomechanical Enhancement	limited	ample
Residual Oil		slightly lower

Acknowledgement

This paper was not based on work for any client operating company. However, individuals and operating companies were solicited for operating data. A number of these companies were generous enough to provide data on the condition of anonymity. Those individuals and their companies are gratefully, if but silently, acknowledged and thanked.

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V20040618

App. A: Heat Exchanger Effectiveness

The effectiveness of a heat exchanger[25] is the ratio of its heat transfer rate to the maximum possible heat transfer rate:

$$\varepsilon = \frac{q}{q_{\max}} \quad \text{(A1)}$$

Heat transfer is dependent upon the thermal capacities of the hot and cold fluid streams. Each of their heat capacity rates is a product of their mass flow rate and mass heat capacity:

$$C_c = \dot{m}_c c_{p,c} \quad \text{(A2)}$$

$$C_h = \dot{m}_h c_{p,h} \quad \text{(A3)}$$

the heat capacity ratio, C_r

$$C_r = \frac{C_{\min}}{C_{\max}} \quad \text{(A4)}$$

where C_{min} and C_{max} are the smaller and larger of the hot and cold heat capacity rates, C_h and C_c. For a concentric tube counterflow arrangement, the heat exchanger effectiveness is given by **Equations A5 and A6**:

for $C_r < 1$,

$$\varepsilon = \frac{1 - \exp[-NTU(1 - C_r)]}{1 - C_r \exp[-NTU(1 - C_r)]} \quad \text{(A5)}$$

and for Cr = 1,

$$\varepsilon = \frac{NTU}{1 + NTU} \quad \text{(A6)}$$

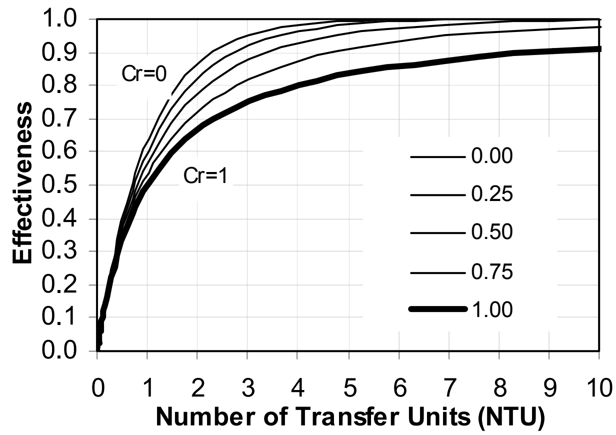
The number of transfer units, NTU, is a function of the area of contact, A, the minimum heat capacity rate, C_{min}, and the overall heat transfer coefficient, U:

$$NTU = \frac{UA}{C_{\min}} \quad \text{(A7)}$$

The heat transfer coefficient is the power flux per degree of temperature difference across the heat exchanger interface. It incorporates the effects of design, such as the interface's thermal conductivity, fluid convection coefficients, fouling factors, and geometrical effects.

Higher values of NTU result in more effective heat transfer, therefore heat exchangers with larger surface areas and higher heat transfer coefficients will provide more heat recovery. This is shown in **Figure A1** in which heat exchanger effectiveness is plotted versus NTU, for a range of values of Cr.

Figure A1 Counterflow Effectiveness



The effectiveness, ε, is somewhat misleading in that it is relative to the maximum possible heat transfer rate, q_{max}:

$$q_{\max} = C_{\min}(T_{h,in} - T_{c,in}) \quad \text{(A8)}$$

where $T_{h,in}$ and $T_{c,in}$ represent the hot and cold entrance temperatures. The maximum heat transfer rate is higher for high-pressure operation. This is because the produced fluids are near the higher steam saturation temperature, T_{sat}, and because the water's heat capacity rate, C_{min}, is higher due to the larger water flow rate at the higher SORs. In effect, there is more power to recover in high-pressure operations. Heat exchangers for low-pressure operations can recover heat more easily (i.e., smaller areas) because of the disproportionate heat capacity rates and therefore the lower heat capacity ratio, C_r, but there is less recoverable heat.

Outlet temperatures are calculated from the effectiveness of the system, using the inlet temperatures and heat capacity rates:

$$\varepsilon = \frac{C_h(T_{h,in} - T_{h,out})}{C_{\min}(T_{h,in} - T_{c,in})} \quad \text{(A9)}$$

and

$$\varepsilon = \frac{C_c(T_{c,out} - T_{c,in})}{C_{\min}(T_{h,in} - T_{c,in})} \quad \text{(A10)}$$

where the hot and cold inlet and outlet temperatures are denoted by their subscripts. From **Equations A9 and A10** it is clear that the fluid stream with the lowest heat capacity rate will undergo the largest temperature change. Under normal SAGD operations, we recover more fluid than we inject (i.e., the water plus the bitumen), therefore the heat capacity rate of the produced fluids will always be higher, and the cold stream will always undergo the higher temperature change.