CSUG/SPE 149226-PP

Effective Caprock Determination for SAGD Projects

P.M. Collins, Petroleum Geomechanics Inc.; D.A. Walters, Taurus Reservoir Solutions, Ltd.; T. Perkins, J.D. Kuhach, and E. Veith, Ivanhoe Energy Inc.

Copyright 2011, Society of Petroleum Engineers

This paper was prepared for presentation at the Canadian Unconventional Resources Conference held in Calgary, Alberta, Canada, 15–17 November 2011.

This paper was selected for presentation by a CSUG/SPE program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of SPE copyright.

Abstract

In the oil sands of western Canada, caprock integrity has become a central issue in projects using steam injection recovery processes such as SAGD (steam-assisted gravity drainage). Caprocks contain steam and fluids within the reservoir and understanding the integrity of the caprock over the life of the operation is critical in order to ensure a safe and economically viable project.

A multi-disciplinary study was undertaken to evaluate geological facies as potential caprock for Ivanhoe Energy's Tamarack project. This examination of the historical performance of operating SAGD projects correlated the maximum vertical growth of the steam chamber with geology and the steam-injection operating pressure. The study found that SAGD steam chambers are being constrained by geological facies grading upward to poorer reservoir quality rather than being constrained by shallower, regionally extensive, massive, low-permeability barriers.

Geomechanical reservoir simulations of Ivanhoe Energy's proposed Tamarack SAGD Project predict that the steam chamber will be similarly constrained as reservoir quality degrades upward. The simulations show the pressure and stress gradients in the formations above the steam chamber as a function of time and operating conditions, allowing for a more accurate assessment of steam containment and the risk for shear and/or tensile failure.

The findings are significant because they confirm that the vertical growth of SAGD steam chambers has been effectively halted by facies consisting of interbedded sands and mudstones. These effective caprock facies have higher fracture pressures than the regionally extensive low permeability barriers because these facies are found at greater depths. The higher fracture pressure justifies a higher maximum operating pressure, with its associated higher reservoir temperatures resulting in much lower bitumen viscosities. As a result, SAGD well productivity and project economics are greatly improved, particularly for shallow SAGD projects.

Introduction

Only the shallowest deposits of the extensive oilsands resources of western Canada are recoverable with surface mining. The vast majority of these resources are too deep or too thin for the economical removal and replacement of the non-bituminous overburden. As such, only *in-situ* recovery processes are viable over the majority of these resources. Of these, the two most predominant recovery processes are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). Historically, steam injection has been the preferred means of reducing the viscosity of the bitumen that is needed to allow for economically viable bitumen production rates.

CSS involves the injection of steam into a well completed in the oil sands formation. This is followed by a "soak" period during which the well is shut in and the steam is allowed time to condense, releasing its heat to the oilsands formation, including the bitumen. The well is put on production and the hot bitumen and steam condensate (water) are produced. When the bitumen production rate is sufficiently low, the entire process of injection, soak, and production is repeated. Several production cycles occur until the oil to steam ratio becomes uneconomical.

Unlike other bitumen and extra heavy oil deposits in the world, the viscosities of the bitumen contained in the Athabasca oilsands of the Fort McMurray region generally exceed 1 million centipoises at reservoir temperature, resulting in extremely low initial matrix injection. Instead, steam is injected above fracture pressures. Fortunately the local and induced stress regimes favour the formation of horizontal fractures in most projects (see Bell et al; Gronseth and Kry). These large horizontal fractures allow for the immediate and extensive contact between steam and the oilsand formation, followed by a considerable compactive and solution gas drive component during the early production phases.

In contrast, SAGD operates below fracture pressure. A horizontal well pair, consisting of an injector well overlying and parallel to a producer well (that is separated by 5 metres), is placed near the bottom of the oilsands pay zone. Using concentric tubing in each of the two wells, steam is circulated within the wells. This heats an annulus of oilsands around each well. Once these two heated annuli coalesce, the injector is in communication with the producer and operation changes from steam circulation to SAGD, in which steam is injected into the upper injector well and the steam condensate (water) and hot bitumen are produced from the lower producer well.

SAGD is not dependent upon displacement, however; it relies on gravity for its drive mechanism. The well pair essentially operates iso-barically, with a small backpressure on the producer well to ensure that it does not produce live steam. Steam leaving the injector well migrates to the perimeter of the swept volume ("steam chamber") which is essentially at a uniform pressure. The volume change associated with steam condensation at the perimeter creates a small pressure drop that ensures continued steam flow to the outside of the steam chamber.

The condensed steam and heated bitumen flow down the sides of the steam chamber from the top towards the producer well and are produced.

There are several differences between CSS and SAGD, but for this study the essential difference is the effect of each process on the oilsands formation and its caprock. With CSS, steam is injected at pressures intended to fracture the oilsands formation. This requires a forgiving caprock that can withstand the high pressures itself, and withstand the changing stresses due to high pressures, temperatures and large deformations within the reservoir. SAGD is seen as the gentler process because it does not create tensile fractures within the reservoir, and by extension, requires less from its caprock. The anomalous steam release at the Joslyn Creek SAGD project resulted in a re-examination of that assumption and the determination of what truly constitutes a caprock for SAGD. This paper presents the findings of our study of SAGD caprock and focuses on the facies which have been observed to impede steam rise and thereby contain the SAGD process.

Caprock Criteria for SAGD

There are several criteria required of a potential caprock formation for SAGD. These are:

1. constrain steam chamber rise;
2. prevent the loss of reservoir fluids to the overburden;
3. prevent the ingress of cold water from above;
4. prevent the development of excessive pressures in the overburden;
5. withstand the existing and induced stresses and pressures over the life of the project;

Constrain Steam Chamber Rise. While the SAGD process occurs within the oilsands pay zone, the steam chamber slowly grows upwards and establishes a well-defined boundary. Within the steam chamber, oil saturations approach low residual saturation values. Outside of and above the steam chamber, there is no steam present. Temperatures fall from saturated steam temperature at the steam chamber upper boundary to original reservoir temperatures within a few metres above, with most of the heat transfer being conductive. Near the steam chamber boundary, formation fluid pressures are essentially at steam pressures. The steam chamber rises because the heated bitumen at the periphery becomes mobile and can flow downward as steam rises to occupy the vacated pore space. This could occur as counter-current flow, in which the liquid phase flows down past the rising gas phase. Given the limitations imposed by relative permeability effects, particularly for counter-current flow, it is more probable that steam rise is conceptualized by an inverted U-tube phenomenon in which the heated bitumen drops through one pore throat while steam rises through an adjacent pore throat.

Capillary Entrance Pressure. Once the steam chamber encounters geological facies that are finer grained than the oilsands, this process becomes more difficult because the steam, which is a gas, cannot enter the pore throat until it exceeds the capillary entrance pressure of the smaller pore throats. Liquid water is the wetting phase, so steam cannot enter the pore space until the pressure differential between the two phases overcomes the interfacial tension at the perimeter of the pore throat. Field instrumentation has shown that formation fluid pressures approach steam pressures far in advance of any thermal front, so there is a considerable back pressure to overcome as well.

Thermally induced gas exsolution could create a gas phase in the heated perimeter outside of the steam chamber, which would offset capillary effects and allow steam rise. However, in the vicinity of the SAGD steam chamber, this is prevented by the rise in formation pressures from their naturally under-pressured state to steam pressures. Thermally induced gas exsolution can occur adjacent to production risers where formation pressures have not increased appreciably.

As such, fine-grained facies can be a considerable impediment to steam rise. Exceptions could include geometries where graded facies are inclined, which allows for gravity drainage in the coarser facies; when the facies are discontinuous, which allows for spill points at the edges of the facies; and, where geomechanical effects result in shearing of the facies which create new flow paths and decreased capillary pressure.

An excellent regional example of capillarity as a barrier to gas rise is the Clearwater Formation. The predominant facies is a massive, laterally extensive mudstone that is recognized as a very competent caprock formation. Yet, in geological terms, this formation is an aquiclude or a formation that permits flow through it on a geological timescale. Meteoric water continuously permeates down through this formation, recharging the laterally continuous sand of the Wabiskaw Member at its base, yet over geological time the Clearwater mudstone is a very effective barrier to the upward flow of the natural gas found in the same Wabiskaw sand. Pressures are transmitted through the Clearwater mudstone but gas does not migrate upwards, as evidenced by the lack of a gas phase

Most major gas reservoirs are vertically contained by capillary pressure effects, not by the lower permeability of their caprocks. Lower permeability formations are seen as good caprocks, not because of their permeability, but because of their associated small pore throats and high capillary entrance pressures prevent the gas from escaping. If permeability were the restricting parameter, gas reservoirs would not be gas-filled because the gas would slowly flow through the caprock over geological time.

Prevent Reservoir Fluid Losses. Reservoir fluids consist of steam, water (both connate water and condensed steam), bitumen, and natural gas, if present. In SAGD operations steam losses need to be minimized in order to retain the heat within the reservoir. Any significant steam loss will result in a higher steam to oil ratios, and it may not be possible to make up the lost volume of water under physical or regulatory constraints.

Water and steam losses need to be prevented in order to retain heat within the reservoir, to conserve water, and to prevent any potential contamination of aquifers.

Bitumen losses need to be prevented in order to retain heat, prevent aquifer contamination, and to minimize the loss of saleable product.

Natural gas losses imply strong pressure communication through the caprock, and this would result in a drop in reservoir pressure, requiring a steam injection pressure that is balanced with the overlying zone. This can severely reduce the operating pressure which can lead to a lower recovery factor and production rates.

Steam and gas losses are strongly curtailed by the capillary effects previously mentioned. Liquid losses through the caprock are minimized by gravity segregation that keeps liquids flowing to the base of the steam chamber.

Prevent the Inflow of Water. A very serious threat to the SAGD process is the quenching of the process by water cascading from above, or “top water”. This can occur when a bitumen-lean water-filled zone exists at the top of the pay zone, or if there is a breach in the caprock that connects to top water. Water can encroach laterally in a zone with top gas if a pressure transient is created by gas production.

The influx of water cools the steam chamber causing steam condensation without any associated bitumen production. As such, it essentially quenches the process. In a pattern of SAGD wellpairs, it may be possible to sacrifice the upstream wellpair to intercept water incursion into the other wellpairs. A continuous low-permeability caprock would impede water inflow from above.

Prevent Excessive Overburden Pressures. The presence of caprock restricts the transmission of pressure to overlying formations through a combination of the capillary entrance pressure and pressure losses across the caprock. Without this, the high steam chamber pressures could result in increasing overburden pressures. This could result in accidental hydraulic fracture of these shallower formations and catastrophic steam loss.

Resiliency in Response to SAGD. The non-uniform growth and development of SAGD steam chambers result in changes in stress and pressure. These include large reductions in effective stress due to the higher steam injection pressures and unloading due to uneven volume changes in the reservoir. Thermal stresses can impose large differential stresses that can contribute to existing differential stresses. The caprock must be able to withstand these changes in stress over the life of each SAGD pattern.

Geological Stratigraphy

Geological variations worldwide preclude a global “type” geological model for the SAGD process. However, many SAGD projects, particularly in the Athabasca oilsands of western Canada, have comparable geological profiles. An idealized generic geological profile for these projects is shown in **Figure 1**.

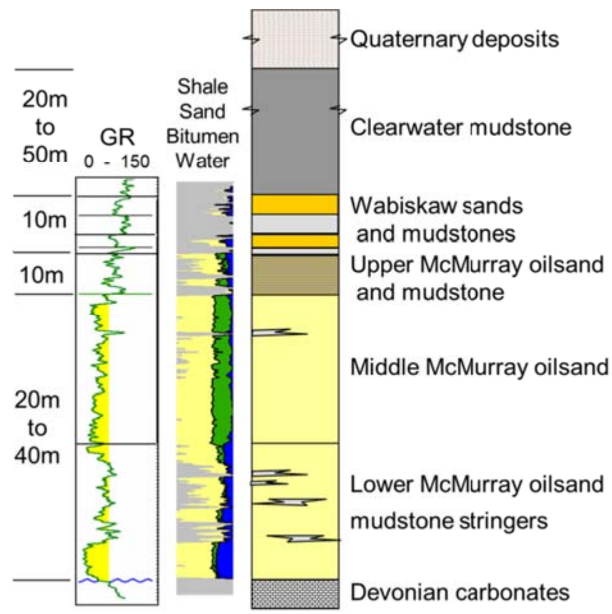

Figure 1 Typical Geological Profile, Athabasca Oilsands

The Cretaceous Athabasca oilsands overlay Devonian carbonates, unconformably. A paleosol may exist at the unconformity but in most cases it is absent. Karsting or salt dissolution in the Devonian formations can result in additional voidage into which the overlying oilsands and caprock will drape. If this occurred after the deposition of the caprock formations, this will result in a reduction in rock stresses.

The stratigraphic profile shown includes a basal water sand with little to no bitumen saturation. This feature is not always present. Similarly, bitumen-lean zones are sometimes seen at the top of the oilsands pay zone, beneath the fining-upward sequences, with gas and/or water occupying much of the pore space.

Within the Lower and Middle McMurray oilsands there are essentially no barriers to steam rise. Mudstone stringers will impede steam rise as baffles, not barriers.

Above the Middle McMurray oilsands are the interbedded tidal flat sequences. These are alternating thin beds of oilsands and water-saturated clay rich silt mudstones. This highly variable zone contains mudstones with sufficiently high capillary entrance pressures to prevent steam entrance.

The Wabiskaw member at the base of the Clearwater Formation includes laterally continuous sands and laterally continuous mudstones. These mudstones are effective barriers to steam rise. The sands are usually saturated with gas and/or water and may be bitumen-stained.

The massive, laterally continuous Clearwater mudstone is an effective caprock. Down-cutting into this unit from Quaternary channels may be a concern and should be considered in any exploratory or delineation program.

Comparable SAGD Projects

By far, the best method for assessing the effectiveness of a formation as a caprock is to assess operating data in other mature projects. Analogue projects, in terms of geology, depth, and operation strategy, were examined to determine where steam rise was halted.

Suncor's Dover SAGD Project (formerly UTF). This project was known as the Alberta Oil Sands Technology and Research Authority's Underground Test Facility (AOSTRA's UTF). The first successful SAGD pilot projects, Phase A and Phase B, were tested here and their success precipitated the subsequent investment in SAGD as the *in-situ* recovery process of choice in the Athabasca oilsands deposit. With a SAGD history dating back to 1987, this project has provided excellent data for both pilot and mature projects.

Phase A, the laboratory-scale pilot, had inter-wellpair spacing of 25m to ensure early maturation of the pilot. After 2 years, the steam chambers around the 3 wellpairs had coalesced. **Figure 3** shows a cross-section through the Phase A pattern that transects the middle of all three wellpairs. Observation Well AT4 was located directly above middle Wellpair A1. The inset graph shows temperature profiles in Well AT4 at different times. The lack of upward movement of the thermocouple which points at the saturated steam temperature of 229°C indicates that vertical steam chamber growth had stopped at this well after 379 days and remained stagnant until the end at 700 days. Steam was contained by the Upper McMurray tidal flat unit.

Phase B was the commercial pilot spaced wellpairs and was operated under SAGD between 1991 and 2003, after which tertiary recovery methods were tried. This pilot was within a north-south fluvial-estuarine channel sand deposit of 500m to 800m in width. The highest quality reservoir is at the base, and there is some degradation towards the top with the appearance of bioturbated inter-bedded mudstones. Again, the steam chamber was contained below the Upper McMurray tidal flat unit.

Suncor's MacKay River Project, Section 16. This project is adjacent to their Dover Project, with similar geology except that the oilsands are slightly shallower.

The caprock at MacKay River is a combination of Wabiskaw D and Upper McMurray mud-dominated sediments. This is the same as in the Tamarack Lease as supported by both core and log data. Steam chamber rise after 5 years' operation showed that the steam was contained below the base of the Upper McMurray Formation ("KMU").

(a) Tamarack Well 08-27-090-09W4: 90-95 meters

(b) MacKay Well 07-04-93-12W4: 94-98.5 meters

(c) MacKay Well 08-17-93-12W4: 85-89.5 meters

Figure 2 Tamarack/MacKay Core Comparison showing Consistent Wab D / U.McM Contact (red arrows)

The mudstones within the Upper McMurray were sufficient to prevent steam breakthrough. (Suncor

MacKay, 2010). **Figure 2** shows a comparison of the contacts at the base of the Upper McMurray. The transition between clean, bitumen-rich oilsands and the muddier units above is quite sudden. The facies seen at MacKay River are comparable to those at Tamarack.

Suncor's MacKay River Project, Wellpair C4. After 10 years of operation, the steam chamber was contained below the base of the Upper McMurray Formation, as seen in **Figure 4**. Observation wells OB2 and OB3 are near the centre-line of Wellpair C4; Well OB5 is offset by 50m and shows the downward growth of the steam chamber as it progressed laterally from the

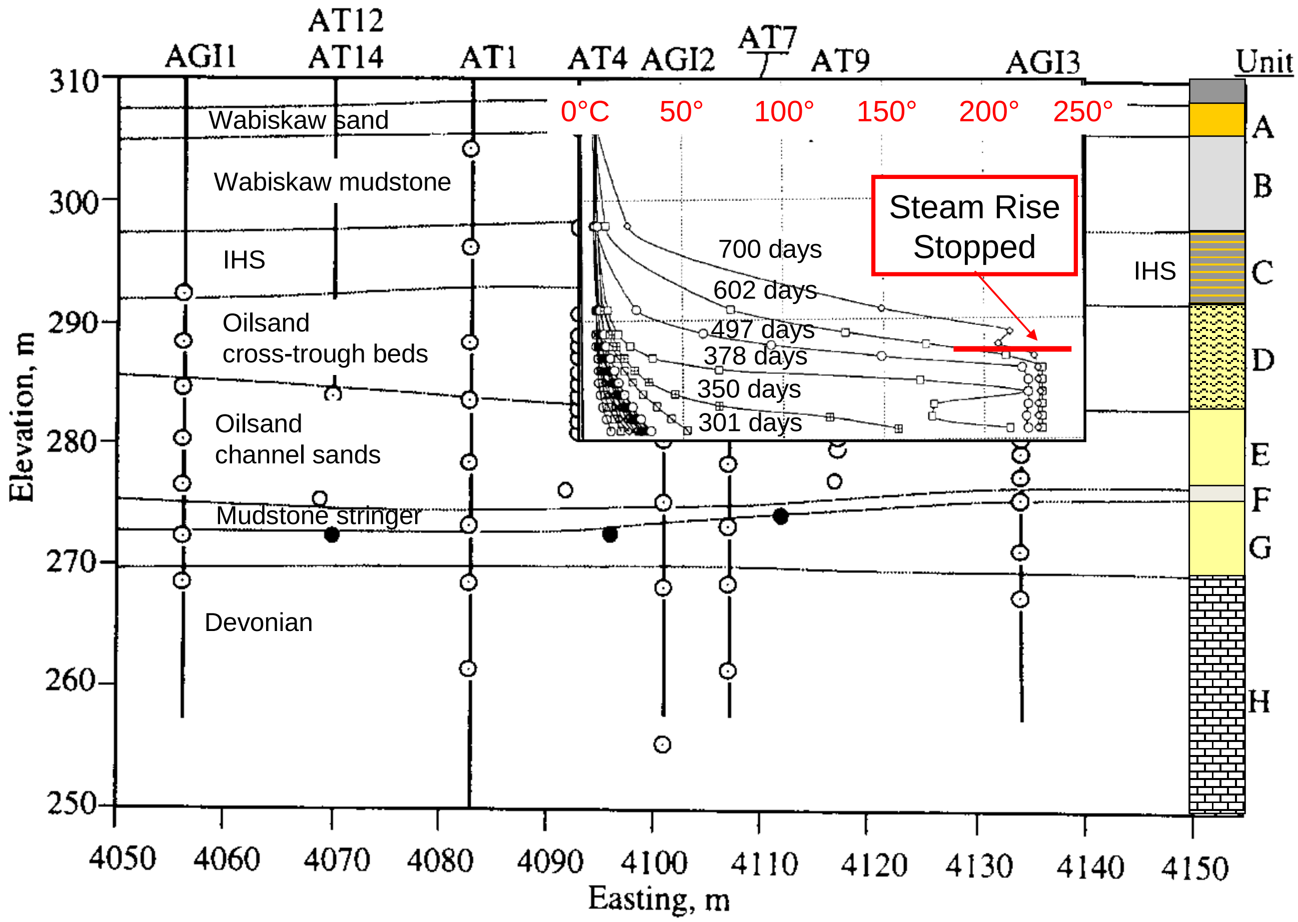

Figure 3 Steam Chamber Stopped over Wellpair A1, UTF Phase A, at Observation Well AT4

mod. after Chalaturnyk (1996)

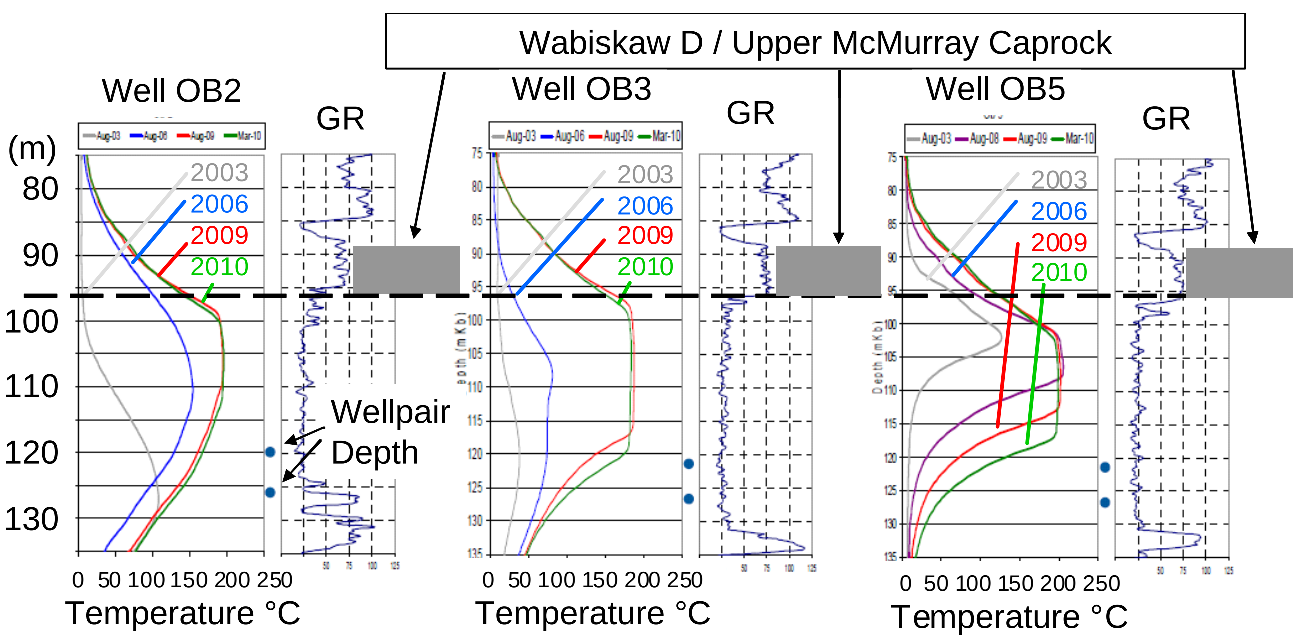

Figure 4 Steam Chamber RIse over 10 Years, MacKay River SAGD, Wellpair C4

wellpair. Significantly, over the same time there was no upward growth into the Upper McMurray caprock.

TOTAL's Joslyn Creek. This project is considerably shallower than most projects. Formations that could be considered as caprock are approximately 33m shallower than at Ivanhoe's Tamarack Project. This project also operated with a markedly different strategy than that proposed for Tamarack.

TOTAL's Joslyn Creek SAGD Project incurred a steam release in 2006, just as it was starting to convert its Phase 2 wells from circulation to SAGD. This resulted in the catastrophic eruption of steam at surface. A review by the Alberta Energy Resources Conservation Board (ERCB) concluded that the root cause of the incident was excessive steam pressure (ERCB, 2010).

Other SAGD Projects. In addition to the analogue projects to Tamarack, other SAGD projects were examined as part of our steam chamber development review (**Table 1**).

Table 1 Other SAGD Projects

SAGD Project	Years of Operation
Devon Jackfish	4
Cenovus Christina Lake	9
Suncor Firebag	7.5
JACOS Hangingstone	14
Cenovus Foster Creek	10

In all cases, the available temperature profile data were examined and it was observed that steam did not rise above the base of the Upper McMurray Formation. Given that the life of a SAGD pattern is 8 to 15 years, and most of these projects have been operating for that long, this indicates that the mixed facies Upper McMurray is effective as a barrier to steam rise.

Operating Pressure

Obviously, a low permeability caprock is required to prevent pervasive fluid losses from the reservoir. However, the ability of any caprock to withstand the maximum operating pressure (MOP) at a given stage of SAGD development is dependent upon the stresses in the caprock and not on its permeability.

Various SAGD projects were analyzed in terms of their stated operating pressures and the fracture gradients of four marker depths:

1. base of the Clearwater mudstone;
2. base of the Wabiskaw D mudstone;
3. base of the Upper McMurray tidal flat unit;
4. depth of the wellpair's injector;

For the fracture gradient, it was assumed that all other shallow projects were limited by the overburden gradient. This was assumed to be 21 kPa/m for all projects except Joslyn Creek, for which a value of 20 kPa/m better reflected its very shallow depth. For the Tamarack project, the fracture gradients were determined from mini-fracs in two wells which were found to be anomalously low. Potentially the effects of lateral stress relief and reservoir depressurization combined to lower *in-situ* stresses.

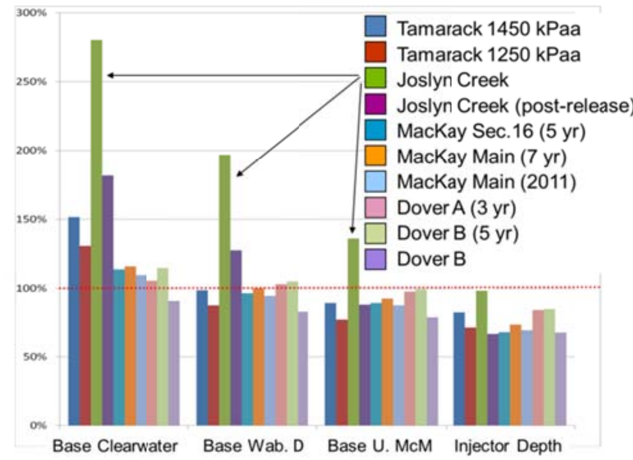

Figure 5 Ratio of Injection Pressure to Fracture Pressure at 4 Marker Depths for SAGD Projects

Figure 5 shows the results of this analysis. The vertical axis is the ratio of the steam injection pressure to the fracture pressure at initial stress state for the 10 projects shown, with those for Tamarack being proposed. Anything above 100% indicates that the injection pressure exceeds the fracture pressure at the initial stress state so fracturing might be expected. Some projects have more than one value, reflecting the fact that the operating pressure was changed during the life of those projects.

The outlier values are for the Joslyn Creek project, which had just converted to SAGD mode. These values are obviously unrepresentative of all other SAGD projects reviewed in this paper.

The data suggests that other projects have typically operated above the fracture gradient for the Clearwater mudstone. This is understandable, given that this formation is many metres above the wellpair so it has a much lower fracture pressure. Obviously, deeper formations are acting as caprock for these projects.

The Wabiskaw D mudstone is a potential caprock for most projects. Some projects' injection pressures exceed its fracture pressure, which indicates that a deeper formation is acting as the effective caprock, at least for the early life of the projects. The proposed pressure for the Tamarack project is ramped down from 1450 kPaa to 1250 kPaa as the steam chamber rises in order to maintain an acceptable factor of safety at the Wabiskaw D unit.

The Upper McMurray, which is comprised of tidal flat facies, is the observed caprock for all projects except the start-up Joslyn Creek project which injected at anomalously high normalized operating pressure above the fracture pressure of the Upper McMurray. As an example, Dover Phase A operated at 2750 kPaa to maturity with the base of the Upper McMurray unit at 140mKB. Adjusting to ground level and using a fracture gradient of 21 kPag/m, this project operated at 91% of the fracture pressure without incident.

Geomechanical Analysis

An explicitly coupled (see Settari and Walters) geomechanical and reservoir simulation analysis was performed to predict the behavior of the Tamarack SAGD project. Conservative parameters and reservoir and geomechanical material descriptions specific to Tamarack were used. The results showed no tensile nor shear failure for the life of the project. This was due in part to the Upper McMurray (a low quality sand with shale inter-bedding) acting as an effective buffer (or caprock) to steam rise and pressure transmission to the base of the Wabiskaw D and Clearwater mudstones. Geomechanical effects previously discussed were observed to cause a transient stress state that develops in and around the steam chamber due to elevated pressure, temperature and volumetric strain. This transient can increase or decrease the minimum total principal stress depending on the location relative to the steam chamber. Regardless, the simulation analysis showed no caprock failure.

Figure 6 shows a profile of the minimum stress, minus the formation fluid pressure. A value less than zero indicates potential tensile failure (at zero effective stress). In addition, reduction factors of 90% and 80% were applied to the stresses in order to determine what margin of safety was available. For all cases, no tensile failure occurs. Note that the stresses in the Wabiskaw D mudstone caprock are far from any tensile failure.

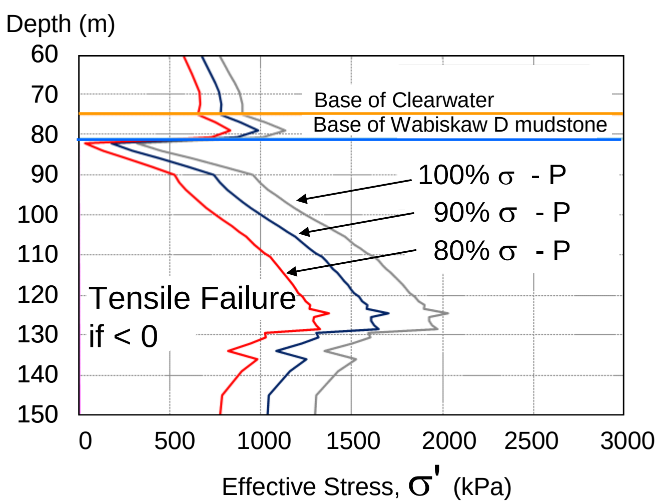

Figure 6 Profiles of Factored Minimum Stress as an Effective Stress after 7.7 years

Conclusions

The intent of this study was to take a pragmatic approach to the assessment of different geological facies as potential caprocks for Ivanhoe Energy's Tamarack SAGD Project. Our means of accomplishing this was to examine the performance of analogue SAGD projects with the expectation that trends would be observed that could be applied to Tamarack. Geomechanical modeling was used to extrapolate the observed behavior to Tamarack's specific geology, geomechanics, and operating conditions.

This study found that:

1. the proposed Upper McMurray tidal flat and Wabiskaw D mudstone caprocks for the Tamarack SAGD project are consistent with the effective caprock in all successful long-term SAGD projects reviewed;
2. steam rise was found to be consistently constrained by the base of the Upper McMurray in comparable projects with long-term operation;
3. when depth and fracture gradient variations were taken into account, the proposed Tamarack operating pressures are consistent with those of comparable projects operating safely over long periods of time;
4. geomechanical modeling supports the determination of safe operating pressures for the proposed Tamarack project.

Nomenclature

CSS = cyclic steam stimulation (huff'n'puff)
P = pressure
SAGD = steam-assisted gravity drainage
UTF = Underground Test Facility
σ = stress

σ' = effective stress
~ = "*approximately*"

References

1) Chalaturnyk, R.J (1996) **Geomechanics of the steam assisted gravity drainage process in heavy oil reservoirs**, Ph.D. dissertation, Dept. of Civil Eng., U. of Alberta, Edmonton, Alberta 576 pp.

2) Suncor MacKay (2010) ERCB In-situ progress report: 2010AthabascaSuncorMacKayRiverSAGD8668 Subsurface

3) ERCB (2010) ERCB Staff Review and Analysis: Total E&P Canada Ltd. Surface Steam Release of May 18, 2006, Joslyn Creek SAGD Thermal Operation, unpubl. report by the Alberta Energy Resources Conservation Board, February 11, 2010, 177pp.4) Geological Atlas of the Western Canada Sedimentary Basin, Chapter 29 In-situ Stress in the Western Canada Sedimentary Basin, J.S.Bell, P.R.Price, P.J. McLellan

4) Li, Kewen and Horne, Roland N. (2000): "Steam-Water Capillary Pressure in Geothermal Systems", Preceedings o the 25th Worshop on Geothermal Rservoir Engineering Stanford University, Standford, California, January 24-26, 2000

5) Gronseth, J.M. and Kry, P.R. (1983): Instantaneous Shut-in Pressure and its Relationship to the Minimum In Situ Stress. In Hydraulic Fracturing Stress Measurements (M.D. Zoback and B.C. Haimson, eds.), National Academy Press, Washington, D.C., pp. 55-63.

6) Settari, A. and Walters, D.A.: "Advances in Coupled Geomechanical and Reservoir Modeling With Applications to Reservoir Compaction", SPE Journal, Vol. 6, No. 3, Sept. 2001, pp. 334-342.

Metric Conversion Factors

1 ft ≡ 0.3048 meter
≡ 304.8 millimeter

$$°F \equiv (°C \times 1.8)+32$$

Author's Biography

Patrick M. Collins, P.Eng. is the president of Petroleum Geomechanics Inc., Calgary, Alberta, and has engineering degrees from the Universities of Toronto and Alberta. He has over 25 years' heavy oil experience in topics such as oil sands, CHOPS, CSS, and SAGD; as well as in geomechanics related to drilling and completions such as wellbore stability, rock stress analysis, formation overpressures, hydraulic fracture and sanding potential.

Mr. Collins spent over three years on the AOSTRA Underground Test Facility SAGD pilots before working internationally in geomechanics for several years. He is now an independent consultant for oil companies on projects worldwide. He is an expert witness in geomechanics, and is a member of SPE, CSPG, CWLS, CHOA, AAPG, and APEGGA.
email: collinsp@telus.net, help@petroleumgeomechanics.com

Dale Walters is Vice President of Taurus Reservoir Solutions, Ltd. Dale has 15 years of engineering experience, participating in large reservoir and geomechanical engineering studies throughout the world within a multi-disciplinary team environment. Coupled reservoir and geomechanical experience includes steam stimulation projects of heavy oil reservoirs, compaction of sandstone and chalk reservoirs, compaction induced seismicity, modeling fracturing in jointed media, produced water reinjection, waterflood fracturing, stress dependence of fractured reservoirs, sand production and wellbore stability. He is a principal and co-founder of Taurus Reservoir Solutions Ltd since 2000. He is a registered Professional Engineer with APEGGA and holds BSc. and M.Sc. degrees in Civil and Geotechnical engineering from the University of Calgary.

Joseph Kuhach is Vice President Engineering with Ivanhoe Energy and is responsible for upstream engineering and integration with Ivanhoe's HTL upgrading technology. Mr. Kuhach has 26 years of global heavy oil recovery experience and has worked projects throughout North America as well as Latin America and the Middle East.

He has managed engineering and geo-science with regard to heavy oil field development, surveillance, and surface processing. Prior to joining Ivanhoe he spent 20 years with Shell Oil Company and subsidiaries predominantly focused on heavy oil recovery. As Manager of Technology he was responsible for Shell's largest thermal recovery projects. He holds an S.B. degree in Chemical Engineering from Massachusetts Institute of Technology and an M.S.in Chemical Engineering from Colorado School of Mines and is a member of SPE and CHOA.

Ed Veith, EVP Upstream of Ivanhoe Energy, has over 28 years of experience in the oil industry with a focus on heavy oil recovery techniques. Mr. Veith joined Ivanhoe Energy in 2001 from Aera Energy, a California joint venture of Shell and ExxonMobil, where he had responsibility for heavy oil development and operations in the giant Belridge and Cymric heavy oil fields in California. He managed thermal horizontal and vertical well development projects using state of the art reservoir management techniques and utilized advanced 3-D reservoir visualization methods to integrate complex data sets. He planned new project expansions and investigated new development scenarios using reservoir simulation and advanced economic modeling. He previously worked with Insight Energy, LLC, Bechtel and Williams Brothers. As President of Insight Energy, LLC, Mr. Veith evaluated major oil fields for acquisition and joint ventures.

Mr. Veith has a B.S. in Petroleum Engineering from the University of Oklahoma, a MS in Petroleum Engineering from the University of Southern California and a Professional Engineers license in the state of California.

Thomas W. Perkins is Chief Geologist with Ivanhoe Energy,. Mr. Perkins has over 30 years of experience in international oil and gas exploration and production with Phillips, Occidental, and Ivanhoe. He has spent the last six years with Ivanhoe working on heavy oil projects in California and Canada. . Mr. Perkins has a B.S. in Geology from the University of Illinois, and and an M.S. in Geology from the University of Kansas.