Warming to Heavy Oil Prospects

In recent years, because of innovation aimed at exploiting unconventional resources, oil and gas industry economists have substantially increased estimates of the world’s remaining recoverable oil reserves. Now, operators are using those new technologies and others to exploit heavy oil sands and push peak oil even further into the future.

The world’s reserves of heavy oil are on par with those of the largest conventional oil fields in the Middle East and are located in more than 30 countries around the globe. Heavy oil reservoirs are expensive to drill and difficult to complete and require unique techniques to produce. Shallow, unconsolidated oil sands present drillers with wellbore stability and steering challenges. Completions must be designed to withstand high-temperature environments because many heavy oil production strategies require thermal recovery methods. At ambient temperatures, heavy oil and bitumen are resistant to flow through reservoir rock because of their high viscosities. Consequently, the energy expended to produce and upgrade a barrel of oil can be as high as 40% of the total energy available from the heavy oil resource.

To overcome these challenges, engineers have developed many technologies and recovery methods, including combinations of horizontal drilling, chemical and water injection, artificial lift and in situ heating. Operators in the oil sands of Western Canada are finding commercial success producing extraheavy oil and bitumen through steam chamber. To create a steam chamber in SAGD operations, the operator injects steam into a formation through a horizontal well. The steam chamber grows around and above the injection well. At the edge of the steam chamber, heated bitumen and steam condensate flow under the force of gravity to the production well. Ideally, the production well is located parallel to and below the injection well and a few meters above the formation bottom. (Adapted from Gates et al, reference 17.)

1. Heavy oil is defined as having 22.3 degree API or less. Oils that are denser than water—those of 10 degree API or less—are known as “extraheavy” when viscosity is less than 10,000 cP [10,000 mPa.s] at reservoir conditions and as bitumen when viscosity is greater than 10,000 cP.


Viscosity is a measure of a fluid’s resistance to flow and is defined as the ratio of shear stress to shear rate. Density is the ratio of mass per unit volume. Although density may vary slightly with temperature, viscosity decreases rapidly in response to increasing temperature.

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The steam chamber. To create a steam chamber in SAGD operations, the operator injects steam into a formation through a horizontal well. The steam chamber grows around and above the injection well. At the edge of the steam chamber, heated bitumen and steam condensate flow under the force of gravity to the production well. Ideally, the production well is located parallel to and below the injection well and a few meters above the formation bottom. (Adapted from Gates et al, reference 17.)
the process of steam-assisted gravity drainage (SAGD). The SAGD method employs pairs of parallel, horizontal wellbores drilled one above the other in the same vertical plane. During SAGD operations, steam is pumped into the upper wellbore and forced out into the formation to form a steam-affected volume called a steam chamber. As the steam chamber expands upward and laterally, the oil viscosity at the steam/oil front decreases, and the oil becomes more mobile. The mobile oil and condensed steam mixture flows by gravity downward along the steam/oil boundary to the lower, horizontal wellbore from which it may be pumped to the surface (previous page).

Heat reduces fluid viscosity (right). However, dispersing steam evenly throughout a formation is difficult, and such uneven dispersal often results in viscous fingering effects from oils of low viscosities flowing faster in the formation than

^ Heavy oil viscosity versus temperature. For two heavy oil samples (blue and red) that were obtained from fields located in different parts of the world, viscosity decreases as temperature increases.
oils of higher viscosities; a significant volume of oil may be left behind because of uneven steam chamber development along the lengths of a SAGD well pair. Therefore, production engineers must manage the flow of formation fluids to the production well, primarily through control of steam injection. To do so, they must understand the geologic and permeability heterogeneity of the formation.

This article looks at some of the tools and methods employed by SAGD operators to optimize production of heavy oil. The implementation of these innovations and their impact on production of bitumen and extraheavy oil are illustrated through case histories from Canada, currently the only country in the world with commercially successful SAGD projects.

Where to Drill

The economic success of most enhanced oil recovery (EOR) projects depends on efficient displacement of oil from the formation by another injected fluid. In the case of SAGD, displacement occurs at the expanding front of the steam chamber, where steam heats the bitumen, thereby increasing its mobility. The mobile oil and condensed steam then flow under the force of gravity to the production well. A uniform steam chamber can be maintained only when the oil in the reservoir is initially relatively immobile, which provides resistance to vertical steam fingering.

Reservoirs favorable for exploitation by SAGD methods must meet certain minimum requirements (left). Ideally, SAGD candidate reservoirs should be free of laterally extensive shale barriers, which may prevent steam chamber growth or uniformity. A SAGD reservoir should also have minimal thief zones and have a pay thickness greater than 15 m (50 ft) to provide sufficient height for steam chamber growth. Additionally, the formation must be sealed by an impermeable top layer, or caprock. These criteria may be established via typical oil and gas exploration tools such as vertical pilot wells, logs, formation testing, seismic data and cores.

Thief zones, in the form of a water leg below the oil zone or gas above it, impact the effectiveness of the steam chamber. The thermal efficiency of the steam chamber may be compromised by the gas leg thief zone, and heated mobile oil may flow more readily to a water thief zone below the formation than to the production well.

An indispensable element of most gas and oil zones is the presence of impermeable upper boundaries that isolate hydrocarbon-bearing intervals from surrounding formations. These barriers trap hydrocarbons in place to create reservoirs. During production, the barriers ensure that oil or gas flows or is swept to the production well instead of migrating to neighboring formations.

However, in SAGD wells, the caprock is exposed to continuous steam injection that may trigger complex thermal and hydraulic processes. It is, therefore, imperative that engineers planning SAGD wells analyze the caprock to ascertain if and how these processes might alter critical rock parameters of in situ stresses, rock strength or fracture systems. Engineers can then establish maximum safe operating pressures to ensure any effects on the caprock do not result in a containment breach.

How to Drill

After an operator has deemed an oil sand formation to be a candidate for exploitation through SAGD methods, engineers typically drill numerous pairs—a producer and an injector—of horizontal wells from a single pad. Each well has a length of 1,400 to 1,600 m [4,600 to 5,200 ft] measured depth that includes about 800 to 1,200 m [2,600 to 3,900 ft] of horizontal section in the pay zone. Subject to operator specifications, production wells are placed above and as close to the base of the formation as possible, and the injection wells are placed parallel to and about 5 to 6 m [16 to 20 ft] above the producers with no more than 2 m [6 ft] offset from the vertical plane containing the producer. Proper separation between the horizontal sections of the two wells is critical to ensure maximum recovery and efficiency. If the two are too close together, the steam will, in most cases, reach only the heel of the producer, resulting in inefficient recovery, lost production and poor asset economics. If the wells are too far apart, production could be delayed by months while a very large steam chamber is created.

A production well is drilled first using conventional directional drilling and MWD tools. An injection well is then drilled using conventional directional tools until the two well paths begin to converge. This typically occurs when the injector and producer are about 10 m [33 ft] apart and the injector is within 120 to 150 m [390 to 490 ft] of landing in the pay zone. This proximity of the injection well to the casing of the production well causes magnetic interference that renders conventional, magnetic-based MWD tools inaccurate.

Determining the position of one well relative to another well using magnetic measurements is called magnetic ranging; this method is commonly used for drilling planned well intersections such as those used for relief wells (next page, top right). At the point of magnetic interference, drillers may turn to active ranging, in which a magnetic source is conveyed in the producer by coiled tubing or a wireline tractor. When the MWD tool sensor package is nearly perpendicular to the magnetic source, the latter is activated, and the resulting measurements taken by the MWD sensors allow technicians to calculate the spatial relationship between the two wellbores. Once the injection well position has been determined, the source is conveyed down the production well to the next
As an alternative to the active magnetic source method, engineers may use premagnetized casing in the first well as a passive magnetic source (below right). Drillers then do not require access to both wells simultaneously and do not need a tractor or coiled tubing to move the source. Additionally, engineers are able to use standard directional drilling methods while obtaining a nearly definitive, real-time survey during drilling.?<br>

Schlumberger has developed the RADAR real-time analysis of drilling and advanced ranging service to help operators accurately determine the relative position of two wells. The RADAR service is a suite of software programs that may be used to drill a second well parallel to and 5 to 6 m above an existing horizontal wellbore with a precision of about 1 m [3 ft] over a length of 1 km [0.6 mi]. Among other applications, the RADAR service allows drillers to determine azimuth changes in magnetically challenging regions using gravity MWD tools, which are designed for use when magnetic interference prevents the use of a conventional MWD tool.

The nature of heavy oil sands causes other drilling problems. The bitumen and sand of the formation stick to the bottomhole assembly, generating increased drillstring torque. Additionally, when the bitumen reaches the surface, it often

3. Mobility is the ratio of permeability to dynamic viscosity and a measure of how easily a fluid can move through the formation. Because mobility is inversely proportional to viscosity, it improves as viscosity decreases in response to increasing temperature.

^ Relative wellbore separation measurements. The proximity of the injection and production wellbores is critical to SAGD success and is measured as a relative separation between the two along their horizontal sections. This relationship is typically presented as a bull’s-eye with a target box (red). The production well, already drilled, lies at the center of the bull’s-eye, and the relative position of the injection well being drilled is displayed as a series of dots (blue) in the box, which represent survey points. In this display, the most recent survey point is represented by a green dot. Measurements include the following: toolface to target—the angle from injector to producer measured clockwise from the injector; distance—radial distance between wells; right side—the lateral displacement of the injection well relative to the production well measured from the vertical plane of the production well; and high side—vertical displacement of the injection well relative to the production well measured from the horizontal plane of the production well. The sensor measurement is taken at the measured depth (MD), and TVD is the true vertical depth of the injection well path at the measurement point. Inclination and azimuth of the injection well path are also taken at the measurement point.

^ Premagnetized casing pattern. Manufacturers premagnetize production well casing in a specific pattern to maximize the extruded magnetic field. A series of opposing poles direct the magnetization away from the casing and increase the distance over which accurate ranging is possible. The magnetic gauging effect, or pattern, indicates flux direction (black lines), and flux intensity is indicated by color, ranging from most intense (magenta) to least (aqua). The amount of magnetization that can be imparted to the casing is a function of the amount of metal in the casing. The amount of magnetization imparted to the casing and the design of the magnetic pattern control the distance over which ranging can be reliably performed. (Adapted from Rennie et al, reference 7.)
Injecting high-pressure steam into oil sands has implications beyond testing the limits of steel and cement. It also challenges reservoir modeling techniques. High-pressure steam injection into the steam chamber causes pore pressure and temperature to increase. Increasing pore pressure reduces the effective stresses—total stresses minus pore pressure—on the rock matrix. The steam chamber dilates, or increases in volume, because of the increased pore volume of steam and thermal expansion of the steam chamber contents.

As the steam chamber is confined along its sides, most of the dilation manifests itself as uplift of the overburden. Uplifting the overburden stretches, or extends, the caprock laterally. Above the steam injector, lateral extension works against the horizontal principal compressive stresses. If, as a result, the minimum horizontal principal stress becomes tensile, the caprock will fracture in tension. Toward the sides of the steam chamber, lateral extension pushes outward and induces shearing stresses, which, if they exceed the shear strength, will cause shear fractures. These fractures become avenues of enhanced permeability that carry pressure and mobile fluid away from the steam chamber.10

Of overarching concern to SAGD operations is preservation of the caprock, which is exposed to many steam cycles throughout the life of the project. To establish the integrity of the caprock and estimate its response to cyclic heating in the Athabasca oil sands area in Alberta, Canada, engineers constructed geomechanical models from sonic log data, image logs, minifrac tests, formation pressure sensor measurements and core analyses. These models allow analysts to estimate the induced stresses and changes in rock strength resulting from steam injection and to predict shear and tensile failure of the rock (left).

Researchers analyzed various injection scenarios and used the ECLIPSE reservoir simulator to model changes in temperature ($\Delta T$) and pressure ($\Delta P$). The corresponding changes in stress, strain, porosity ($\Delta \phi$) and permeability ($\Delta k$) were computed using the VISAGE 3D finite-element geomechanics simulation software. The values of $\Delta \phi$ and $\Delta k$ were then fed back to the reservoir simulation model, which computed new $\Delta T$ and $\Delta P$ values. The new in situ stresses and stress paths—the ratio of the change in horizontal stress to the change in pore pressure—obtained from these models were checked against various failure criteria to predict possible occurrence and location of mechanical failure.11

**Thermal Reservoir Simulations**

While the SAGD method has been commercially successful for more than a decade, in the early days of its use, operators sometimes experienced disappointing recovery rates. These rates occurred partly because industry planners calculated reservoir response to steam based on simulation studies that assume oil sands are homogeneous. These assumptions, which have served reasonably well for many years in traditional EOR proj-
Projects, often caused engineers to inaccurately predict steam and pressure requirements and overestimate the volume of recoverable reserves within a bitumen reservoir.

That practice changed as SAGD experts realized that oil sands exhibit vast variations in geologic and reservoir properties. Taking advantage of recent improvements in simulation methods and computing technology, analysts today employ a fine-scale grid to capture the details of reservoir heterogeneity and are able to run full-field models. Additionally, with greater computing power in hand, engineers are able to create individual sections in the injection well annulus. The horizontal sections of both wells are perforated only where there is a minimum of 5 m [16 ft] of continuous sand (blue and green). Sections that have less than 5 m of continuous sand (purple) are not perforated. Simple completions (right) are cased and perforated along the entire horizontal section, and tubing is run only to the heel of both wells. (Adapted from Akram, reference 14.)

Simulation models may be used to gauge the impact of SAGD completion options on production, the steam/oil ratio (SOR) and project economics.8 Targeting a SAGD operation in the Athabasca oil sands of Alberta, Canada, one study used the Schlumberger Petrel E&P software platform for static modeling and the ECLIPSE thermal reservoir simulator to test the impact of a completion strategy known as smart, or green, completions (above).

1. Thomas et al. reference 1.
3. SOR, or steam/oil ratio, is a measure of the volume of steam required to produce a volume of oil. The ratio is commonly used to gauge the efficiency of a SAGD operation based on the assumption that the lower the SOR, the more efficiently the steam is used and the lower the fuel costs.
Engineers used the coupled model to determine how the location of baffles and barriers within the reservoir would interfere with the desired steam flow path, allowing them to configure the completion so that steam would flow upward in the reservoir and avoid the obstructions. Financial analysis was also performed using the Merak Peep planning, risk and reserves software to compare the economic outcomes of various technical options.

The study modeled and compared the conventional, smart and simple SAGD completion types over five years, reaching the following conclusions:

- The conventional design achieved the best SOR but because of high capital and operating expenditures (capex and opex) had the lowest rate of return on investment.
- The simple design achieved maximum recovery but required more steam and produced more water, increasing capex and opex not compensated for by incremental production increases.
- The smart design achieved optimized steam injection at slightly higher capex and lower opex, which resulted in the best net present value (NPV) of the three options.

Results of the study highlight the value of modeling thermal recovery operations and the potential pitfall of using a single indicator, such as SOR, to grade SAGD project success. Simulations showed that the conventional completion design produced the lowest SOR and that the simple completion design resulted in the highest cumulative oil production. However, when an economics model is included, the smart completion resulted in lower overall costs and yielded the best return on operator investment (left). 14

### Optimizing Production

Optimal economic results using SAGD methods require uniform steam chamber growth, or uniform conformance. However, the flow of bitumen and steam through the formation between SAGD well pairs is often irregular (next page, top right). Reservoir heterogeneities create uneven steam flow through the oil sands and varying oil phase mobility, which results in nonuniform oil flow. Additionally, steam is diverted by shale and mud layers. As a consequence, more than 80% of injected steam exits the well at the heel through the path of least resistance, and almost all the remaining steam exits at the toe. 15 To improve conformance through injection control, operators have used various strategies, including dual tubing strings inside slotted liners or other sand control screens for both the production and injection wells (left).

In the dual tubing configuration, one tubing string injects steam at the heel of the horizontal section of the injection well and a second tubing string carries steam to the toe. Because steam passes through the casing slotted liner into the formation along the entire horizontal length of the injection well, hydrocarbons enter the production tubing at both the toe and heel of the well. By placing injection and production points at both ends of the horizontal sections of both wells, flow is more evenly distributed between the well pair.

Dual tubing SAGD completions in Western Canada usually include gas lift rather than electric submersible pumps (ESPs) to lift oil to the surface but do not have downhole control valves. Dual tubing completions may also contain an instrumented coiled tubing string with a distributed temperature string or a thermocouple array. One study has proposed proportional integral derivative (PID) feedback controllers on each
injector tubing string to control injection rates. The PID controller monitors the temperature difference between the injected and produced fluids and maintains a specified difference between the two by regulating the rate of injection. The temperature difference between the injected steam and the produced fluids is a key control variable in SAGD operations and is called the subcool; it is typically maintained at between 15°C and 30°C [27°F and 54°F]. Dual tubing completions with PID controllers have improved steam chamber conformance by controlling injection rates to maintain a specific subcool value as the reservoir conditions change.

A follow-up study aimed at optimizing production and NPV examined the use of PID controllers in SAGD well pairs. Researchers concluded that the controllers can adjust injection rates quickly and thus attain and maintain a targeted subcool and achieve efficient SORs. Additionally, because the same subcool target is used on both the heel and toe halves of the well pair, PIDs may be able to improve steam chamber conformance along the length of the well pair.

Engineers may also attempt to create steam chamber conformance by installing inflow control devices (ICDs) as part of a sand screen assembly in either the injection or production well or in both. ICDs are designed to cause the pressure distribution, or flux, along the length of the wellbore to vary. When installed as part of the injection well completion, ICDs serve to better equalize the toe-to-heel steam flux. When installed as part of the production well completion, ICDs help equalize toe-to-heel influx of the steam-oil emulsion and thereby provide a more uniform toe-to-heel subcool.

Nozzle-based ICDs are viscosity independent, and the pressure drop varies with the square of the velocity through the nozzles, providing high steam choking capacity. The nozzles therefore act as self-regulating valves in SAGD production well completions because as the liquid level comes into close proximity to the ICD sand screen, the liquids flash, or vaporize, inside the valve, causing additional flow restriction for the same pressure drop. This process works to discourage steam from entering the production wellbore; if steam does enter the wellbore, it is at a much reduced rate that will not cause localized erosion damage to the sand screen, known as “hot spots.” Consequently, SAGD completions with ICDs are able to improve conformance without the need for a second tubing string extending to the toe of the production well.19

Experts from Schlumberger ran wellbore simulations of a SAGD well pair that included a base case in which the producer was equipped with ICDs and the injector was completed as a dual string PID-controlled well. Steam was injected at a maximum rate of 250 m³/d [8,800 ft³/d]; the subcool target was 3°C [5.4°F]. For this study, researchers used FluxRite ICDs, now called MeshFlux ICDs, which are a combination of MeshRite sand control technology and nozzle-type ICDs.

Installed with screens on 14 m [46 ft] long, 7-in. diameter basepipe, the production well ICD nozzle contained a 4.2-mm [0.17-in.] throat diameter; each well of the single SAGD well pair was 700 m [2,290 ft] long with 5-m [16-ft] vertical spacing. The simulated reservoir was based on available data for the McMurray formation in northeastern Alberta, Canada, which contains high viscosity bitumen at initial conditions and is highly heterogeneous.20

Four simulations were run:
- In Case 1 (base case), the average temperatures in the heel and toe halves of the producer were calculated using a temperature sort algorithm.
- In Case 2, the average temperatures in the heel and toe halves of the producers were calculated as an average of all inflowing temperatures.
- In Case 3, the target subcool changed from 3°C to 15°C.
- In Case 4, the producer was completed with dual tubing strings.

The study concluded that dual tubing string completions with PID controllers improved SOR and cumulative oil production. Use of a temperature sort algorithm to screen out low temperatures improved calculation of the subcool; a lower subcool target resulted in improved production and economics.21 Use of ICDs in the production completion resulted in a more stable pressure environment, more easily controlled production and more evenly distributed production along the entire horizontal length of the well than did producers completed with dual tubing strings.

Encouraged by reports of the impact of ICDs on production and efficiency in SAGD operations, engineers at Brion Energy performed a preliminary study to quantify the potential benefits of liner-deployed ICDs. They used a reservoir model based on their Mackay River Commercial Project (MRCP), located about 30 km [18.7 mi] northwest of Fort McMurray, Alberta. Because the initial model, which was based on ideal conditions and a perfectly homogeneous reservoir, did not show any benefit from the ICD, it was later replaced with one in which the absolute permeability of the reservoir cells on some of the planes perpendicular to the well trajectory were increased or reduced according to the maximum expected variation in the same reservoir area.

To accommodate the sand screens that are part of the ICD installation, the liner diameter was reduced from 8½ in. to 7 in. Modeling indicated this size change had no impact on the well pair SOR and cumulative production. For economic and technical reasons, the team chose nozzle-type ICDs combined with a low-profile filter media to allow the assembly to be run inside 9½-in. casing.

With this configuration, simulation showed that the well pairs with the ICDs in the producers had a higher cumulative production and lower SOR than wells without ICDs; most of the production benefit occurred during the first two years. At the end of this period, cumulative production was 12.2% higher in liners with ICDs compared with the same wells without ICDs. After six years, that difference fell to only 2.5% higher. However, SOR was reduced by 9.84% at the end of Year 2 and 10.3% at Year 6. The company deemed these benefits sufficient to move ahead with field tests.

Prior to field installations, a more detailed dynamic simulation was performed using an actual well pair trajectory and an updated reservoir geomodel in which the operator planned to run the first liner ICD completion. The simulation was run with a Petrel workflow using the ECLIPSE reservoir simulator in combination with a fully coupled multisegment well model. Also, based on the results of simulations using various nozzle sizes and downhole drawdown pressures, the operator chose to install two 2.5-mm nozzles per joint of liner in the producer, maintaining the wellbore subcool at 1°C [2°F].
With the well drawdown pressure set at 70 kPa [10 psi] lower than that of a standard completion, simulation results showed that the cumulative production could improve by 34% at Year 4 and 23% at Year 12 (previous page).

Based on the results of these simulations and concluding that ICDs have the potential to improve the performance of SAGD development, in October 2013, Brion Energy completed the first of two wells it planned to equip with ICDs. A second such well is planned for completion in 2014. Steam circulation is expected to begin during the second half of 2015, and production is expected to begin in the first half of 2016.22

Lightening the Load
As for all oil and gas production operations, SAGD operators continually strive to improve production, reduce costs and minimize the environmental impact of their operations. In SAGD wells, production and costs are both driven by steam. Maintaining bitumen production from SAGD wells without mechanical intervention requires constant increases in the steam injection rate and pressure to compensate for steam chamber leakoff and to help lift the oil-water emulsion to the surface. SAGD operators, knowing such increases are unsustained, have turned instead to artificial lift.

Operators investigated several artificial lift techniques and tools in the oil sands of Western Canada, including multiphase pumps, rudimentary gas lift and electric submersible pumps (ESPs). Because they had limited success with multiphase pumps and gas lift installations, operators have opted to install ESPs. Engineers understood that for these pumps to be effective, they had to control the subcool at the pump intake. When the subcool becomes too low, steam is able to flow directly into the production string, and energy efficiency drops. Steam entering the slotted liner may also cause liner failures, sand production and pump cavitation if the intake pressure falls below the specified net positive suction head.23

ESPs have a history of solid performance in fairly shallow oil wells. However, service life is reduced significantly when ESPs are exposed to high bottomhole temperatures or when the conditions at the intake are such that water vapor or steam is present. To avoid this mode of failure, pumps must be manufactured of materials with higher tolerances for thermal expansion than those used in standard applications. The motor oil must be able to withstand constant submersion in high-temperature fluids.

To address these requirements, engineers from Schlumberger and ConocoPhillips designed and tested a high-temperature ESP in a flow loop at C-FER Technologies laboratories in Edmonton, Alberta. The facility made it possible for the team to use a variety of downhole instruments to monitor the new ESP performance in a high-temperature environment (below). The REDA HotlineSA3 high-temperature ESP ran without failure for almost 42 days at fluid temperatures ranging from 150°C to 260°C [300°F to 500°F], which is the upper temperature design limit of the test loop.24

Real-Time Production Numbers
With time and experience, SAGD experts have significantly improved production and reduced costs of heavy oil recovery. Further fine-tuning of these operations requires timely and accurate flow rate data to optimize artificial lift efficiencies, to adjust steam injection rates and pressures and to test and revise the reservoir models used to furnish production forecasts.

Capturing these data through traditional, gravity-based separation systems is a daunting task in SAGD wells because production fluids often have very small contrasts between water and oil densities. Additionally, production from SAGD wells is usually marked by unstable flow regimes, high temperatures, emulsified foamy oil, hydrogen sulfide [H2S] and abrasive sand particles.

These and other possible sources of error led engineers from Suncor Energy, in Calgary, and Schlumberger to conclude that flow rate measurements using traditional production monitoring methods were insufficient to enable SAGD well optimization. In 2007, engineers sought a way around these limitations by testing and qualifying a multiphase flow meter (MPFM) on a SAGD well.25

The MPFM was based on Vx multiphase well testing technology originally developed by Schlumberger engineers for deepwater applications. The Vx system combines an instrumented venturi with a multienergy fraction meter and is able to measure total flow rate and fractions of


21. T. the temperature sort algorithm averages all temperatures in the producing wells with the exception of the coolest temperatures in each half of the well if they were significantly lower than the hottest temperatures in each half of the well and affected permeability-height calculations.


Pressure losses occur when liquids flow into a pump impeller. The net positive suction head is the minimum pressure required at the suction port of a pump to keep the pump from cavitating.


In 2009, following numerous design changes based on results of the 2007 tests, the team proposed replacing a centralized test separator with a Vx MPFM at each of nine wellheads on a single pad at the Suncor Firebag project in northeast Alberta (below). In addition to higher accuracy measurements from the MPFM, this arrangement would allow continuous flow measurements from each well. In the original arrangements, on the other hand, one separator per pad allowed engineers to test wells only intermittently for short time periods.

Flow measurements using the MPFM and the test separator for the same stable flow periods indicated consistent results between them. However, researchers found that the Vx meter consistently reported lower water/liquid ratio (WLR) measurements than did the test separator. Investigation showed that the test separator was over-reporting water and under-reporting oil production. More significantly, the Suncor and Schlumberger team concluded from the results of the three-year project that the Vx technology had good dynamic response, repeatability and measured flow rates from SAGD wells with a high degree of accuracy, which made it well suited as an optimization tool.26

**Optimization**

Applying the SAGD method is capital intensive; steam generation costs account for the bulk of operating expenses. SAGD engineers continually strive to improve steam distribution along well pairs through the practice of real-time optimization (RTO).

SAGD operations, however, are complex and require that many parameters be monitored and controlled; the most important variables include steam injection rates, subcool and downhole temperature and pressure.27 The task of applying RTO practices to SAGD operations is further complicated by the fact that engineers derive each required parameter by combining data from numerous sources (next page).28 While these many variables make optimizing SAGD operations difficult, their complexity also means these operations are good candidates for RTO solutions.

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Two of the most important measurements for use in RTO—temperature and pressure profiles along the length of the horizontal sections—are available through optical fiber distributed temperature sensors (DTSs). And MPFMs supply a third critical piece of information—real-time surface flow rates for each phase.

For RTO, these critical data are subjected to basic quality checks using software to remove obvious errors such as negative pressures and extremely high or low temperatures. These results are then further refined by a more rigorous procedure to ensure all parameters obey the laws of thermodynamics and are physically realistic and resemble what the system has seen in the past. Missing or previously discarded data are replaced using estimates based on related measurements. The measured data are quickly analyzed, and nonobvious relationships in a multidimensional dataset are identified to expose hidden correlations or trends. Often, these correlations are strong enough to describe the behavior of the observed data as the result of only a few input parameters.

Optimization may then proceed by comparing the subcool calculated from real-time DTS temperature measurements with a reservoir model and a target subcool range. When the system notifies the operator that the subcool value is out of range, engineers make changes to controls such as steam injection and multiphase pump rates. Ideally, these changes are made automatically in a closed loop system that constantly fine-tunes controls.

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**Flow Rate Measurement**

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<td>True pump flow rate</td>
<td>Single phase only; limitation on free gas</td>
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<td>Well test using separators</td>
<td>Readily available</td>
<td>Inconsistent, time-lagged results</td>
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<td></td>
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<td>Affects system backpressure</td>
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<td>Multiphase metering well testing</td>
<td>Consistent and accurate</td>
<td>Readings require adjustment to stock tank conditions</td>
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<td>Minimum interference with system pressures</td>
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<td>Ability to measure instability</td>
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**ESP Lift Completion Measurement**

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<th>Episodic Measurement</th>
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<td>Flowing gradient survey of pressure, temperature and flow</td>
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<tr>
<td>Casing pressure</td>
<td>Pump discharge pressure</td>
<td>Temporarily installed multiphase well testing</td>
</tr>
<tr>
<td>Total flow</td>
<td>Pump flow rate</td>
<td></td>
</tr>
<tr>
<td>Power</td>
<td>Intake temperature</td>
<td></td>
</tr>
<tr>
<td>Multiphase flow rate</td>
<td>Motor temperature</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Vibration</td>
<td></td>
</tr>
</tbody>
</table>

**Gas Lift Completion Measurement**

<table>
<thead>
<tr>
<th>Surface Measurement</th>
<th>Downhole Measurement</th>
<th>Episodic Measurement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing pressure and temperature</td>
<td>Tubing pressure below the orifice</td>
<td>Flowing gradient survey of pressure, temperature and temperature</td>
</tr>
<tr>
<td>Injection pressure and temperature</td>
<td>Casing pressure below the orifice</td>
<td>Temporarily installed multiphase well testing</td>
</tr>
<tr>
<td>Injection rate</td>
<td>Distributed temperature</td>
<td>Thermal profile survey with distributed temperature system</td>
</tr>
<tr>
<td>Multiphase flow data</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Steam Injection Completion Measurement**

<table>
<thead>
<tr>
<th>Surface Measurement</th>
<th>Downhole Measurement</th>
<th>Episodic Measurement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection pressure and temperature</td>
<td>Tubing pressure</td>
<td>Thermal profile survey with distributed temperature system</td>
</tr>
<tr>
<td>Injection rate</td>
<td>Distributed temperature</td>
<td></td>
</tr>
</tbody>
</table>

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^Surface and downhole measurements. Engineers must use various techniques to measure all the required variables for monitoring, surveillance, diagnosis and optimization of SAGD well operations. (Adapted from Mohajer et al, reference 29.)

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Heavy Oil Future

According to the Canadian Association of Petroleum Producers (CAPP), Canada produced 290,000 m³/d [1.8 million bbl/d] of oil from oil sands in 2012. Of that total, 130,000 m³/d [800,000 bbl/d] were from mining and the remainder from in situ methods, primarily SAGD. In that same report, CAPP predicted that by 2030, mining would account for 270,000 m³/d [1.7 million bbl/d] of production while in situ methods would increase to 560,000 m³/d [3.5 million bbl/d].

The ratio of production volumes from SAGD methods to production volumes from mining is increasing in favor of SAGD operations because much of Western Canada’s bitumen is too deep to mine, and SAGD project capital and operating costs are significantly less than those for mining operations. Small SAGD projects can be profitable and can be scaled up over time. Wells also have shorter lead times than mines; thus, companies can react to changing markets. Additionally, whereas bitumen mining operations require removal of all top soil and overburden, SAGD wells impose a relatively small footprint, rendering them much more environmentally attractive.

The oil sands of Canada offer exploration and production companies one other advantage: the reserves are known; thus, exploration costs and risks are virtually eliminated. Economic and environmental incentives, aided by the application of decades of upstream technology development, almost certainly will mean the oil sands of Canada will be a critical component of the global oil market for many years.

—RvF