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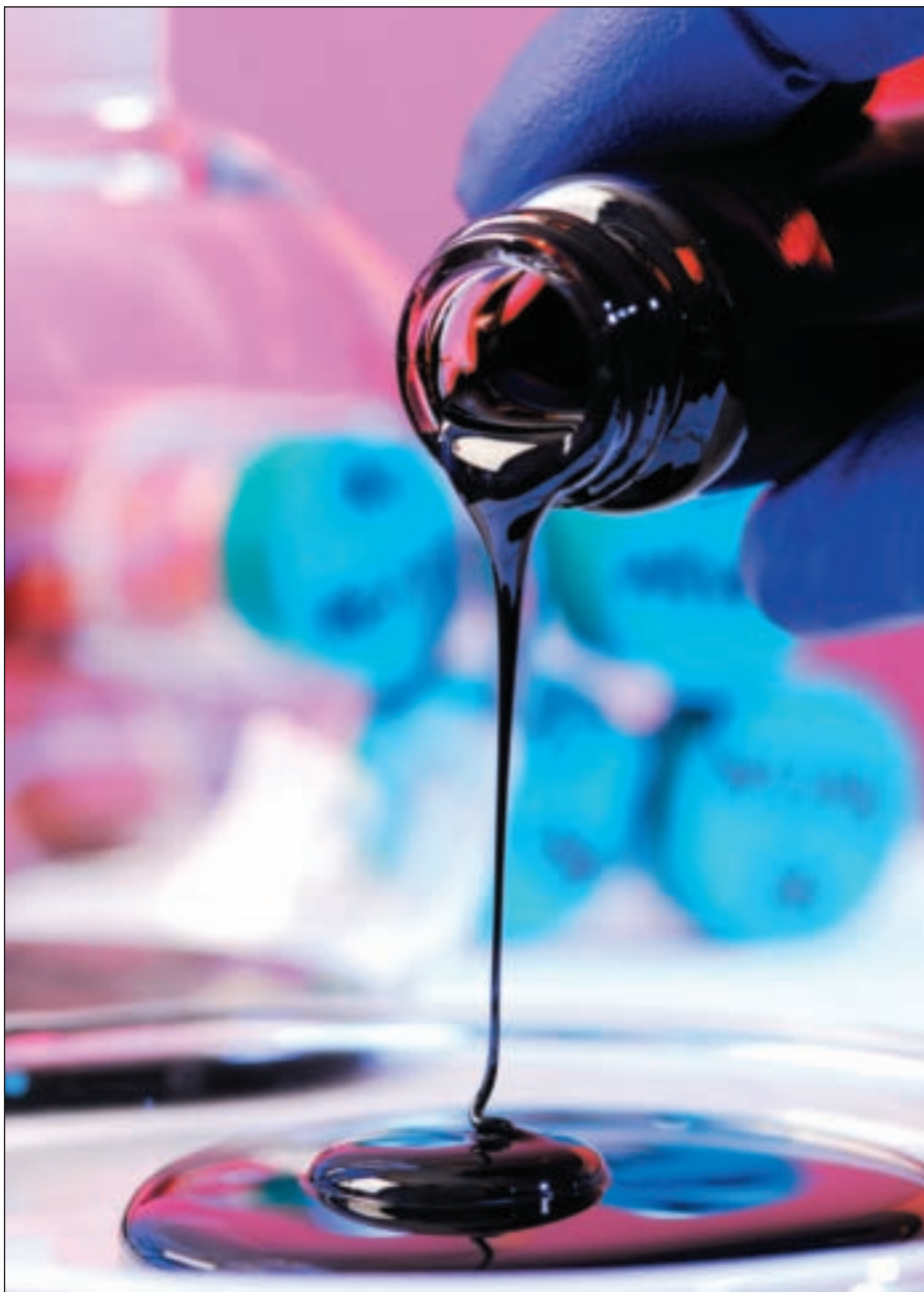
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AIT (Array Induction Imager Tool), CMR-200 (Combinable Magnetic Resonance), DSI (Dipole Shear Sonic Imager), Hotline, LFA (Live Fluid Analyzer), MDT (Modular Formation Dynamics Tester), PhaseTester, Platform Express, Quicksilver Probe, REDA, VDA (Viscoelastic Diverting Acid) and Vx are marks of Schlumberger.

THAI (Toe-to-Heel Air Injection) is a trademark of Archon Technologies Ltd.

Highlighting Heavy Oil

Dwindling oil supply, high energy prices and the need to replenish reserves are encouraging oil companies to invest in heavy-oil reservoirs. Heavy and viscous oils present challenges in fluid analysis and obstacles to recovery that are being surmounted by new technology and modifications of methods developed for conventional oils.



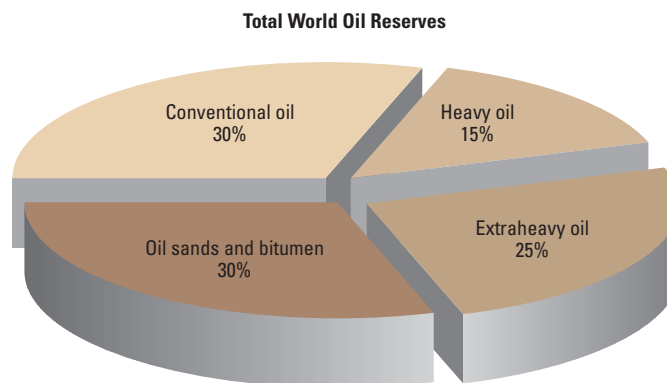
Most of the world's oil resources are heavy, viscous hydrocarbons that are difficult and costly to produce and refine. As a general rule, the heavier, or denser, the crude oil, the lower its economic value. Less dense, lighter ends of crude oil derived from simple refining distillation are the most valuable. Heavy crude oils tend to have higher concentrations of metals and other elements, requiring more effort and expense to extract useable products and dispose of waste.

With high oil demand and prices, and production of most conventional-oil reservoirs in decline, industry focus in many parts of the world is shifting to exploitation of heavy oil. Heavy oil is defined as having 22.3°API or less.¹ Oils of 10°API or less are known as extraheavy, ultraheavy or superheavy because they are denser than water. In comparison, conventional oils such as Brent or West Texas Intermediate crudes have densities from 38° to 40°API.

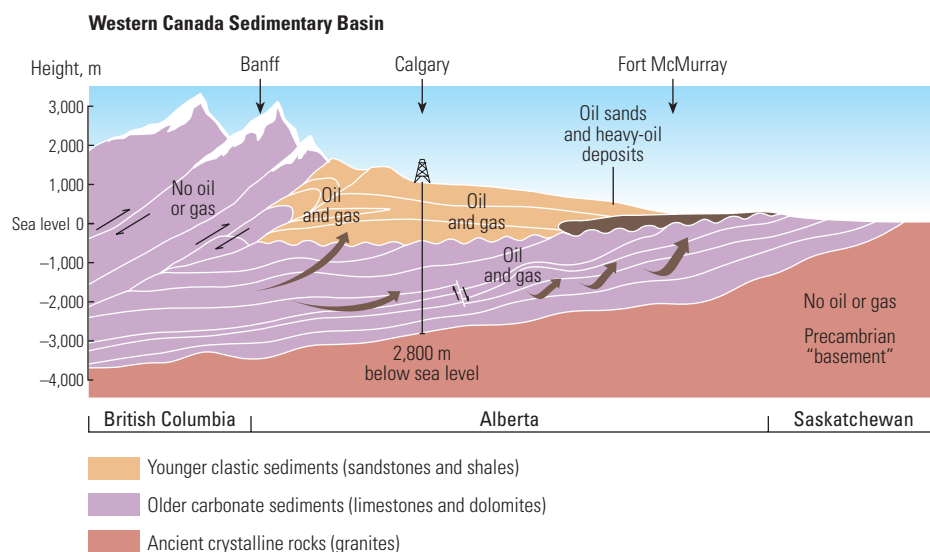
While oil density is important for evaluating resource value and estimating refining output and costs, the fluid property that most affects producibility and recovery is oil viscosity. The more viscous the oil, the more difficult it is to produce. There is no standard relationship between density and viscosity, but "heavy" and "viscous" tend to be used interchangeably to describe heavy oils, because heavy oils tend to be more viscous than conventional oils. Conventional-oil viscosity may range from 1 centipoise (cP) [0.001 Pa.s], the viscosity of water, to about 10 cP [0.01 Pa.s]. Viscosity of heavy and extraheavy oils may range from less than 20 cP [0.02 Pa.s] to more than 1,000,000 cP [1,000 Pa.s]. The most viscous hydrocarbon, bitumen, is a solid at room temperature, and softens readily when heated.

Since heavy oil is less valuable, more difficult to produce and more difficult to refine than conventional oils, the question arises as to why oil companies are interested in devoting resources to extract it. The first part of the two-part answer is that under today's economic conditions, many heavy-oil reservoirs can now be exploited profitably. The second part of the answer is that these resources are abundant. The world's total oil resources amount to roughly 9 to 13 x 10¹² (trillion) barrels [1.4 to 2.1 trillion m³]. Conventional oil makes up only about 30% of that amount, with the remainder in heavy oil, extraheavy oil and bitumen (top right).

1. Calculation of API gravity uses surface measurement of specific gravity of degassed oil. The formula relating specific gravity (S.G.) at 60°F to API gravity is $API\ gravity = (141.5/S.G.) - 131.5$. Conaway C: *The Petroleum Industry: A Nontechnical Guide*. Tulsa: Pennwell Publishing Co., 1999.



^ Total world oil reserves. Heavy oil, extraheavy oil and bitumen, make up about 70% of the world's total oil resources of 9 to 13 trillion bbl.

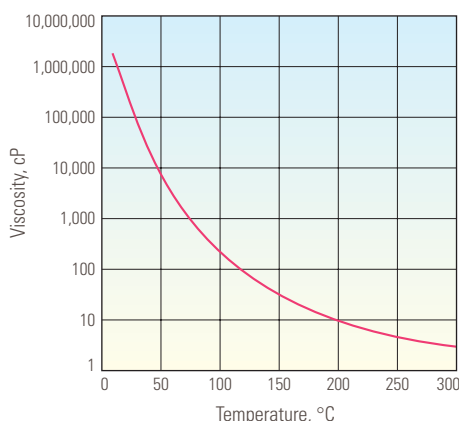


^ Geological setting of one of the world's largest deposits of heavy oil. During mountain-building events, foreland basins are formed in front of the mountain range by bending of the Earth's crust. Marine sediments in the basin (purple) become source rock for hydrocarbons (dark brown) that migrate updip into sediments (orange) eroded from the newly built mountains. Microbes in these relatively cool sediments biodegrade the oil, forming heavy oil and bitumen. Where the overburden is less than 50 m [164 ft], the bitumen can be surface-mined.

Heavy oil promises to play a major role in the future of the oil industry, and many countries are moving now to increase their production, revise reserves estimates, test new technologies and invest in infrastructure to ensure that their heavy-oil resources are not left behind. This article describes how heavy-hydrocarbon deposits are formed and how they are being produced. Important steps along the way are the selection of recovery method, downhole and laboratory analysis of fluid samples, well testing and completion, and monitoring of the heavy-oil recovery process.

Formation of Vast Resources

Of the world's 6 to 9 trillion barrels [0.9 to 1.4 trillion m³] of heavy and extraheavy oil and bitumen, the largest accumulations occur in similar geological settings. These are supergiant, shallow deposits trapped on the flanks of foreland basins. Foreland basins are huge depressions formed by downwarping of the Earth's crust during mountain building. Marine sediments in the basin become source rock for hydrocarbons that migrate updip into sediments eroded from the newly built mountains (above). The new sediments often lack sealing caprocks. In these shallow, cool sediments, the hydrocarbon is biodegraded.



^ Relationship between viscosity and temperature of heavy oils. Every heavy oil, extraheavy oil and bitumen has its own temperature-viscosity relationship, but they all follow this trend, with viscosity decreasing as temperature increases.

Biodegradation is the main cause of the formation of heavy oil.² Over geologic time scales, microorganisms degrade light and medium hydrocarbons, producing methane and enriched heavy hydrocarbons. The effect of biodegradation is to cause oxidation of oil, decreasing gas/oil ratio (GOR) and increasing density, acidity, viscosity and sulfur and other metal content. Through biodegradation, oils also lose a significant fraction of their original mass. Other mechanisms, such as water washing and phase fractionation, contribute to the formation of heavy oil, separating light ends from heavy oil by physical rather than biological means. Optimal conditions for microbial degradation of hydrocarbons occur in petroleum reservoirs at temperatures less than 80°C [176°F]; the process is therefore restricted to shallow reservoirs, down to about 4 km [2.5 miles].

The largest known individual petroleum accumulation is the Orinoco heavy-oil belt in Venezuela with 1.2 trillion barrels [190 billion m³] of extraheavy, 6 to 12°API oil. The combined extraheavy oil accumulations in the western Canada basin in Alberta total 1.7 trillion bbl [270 billion m³]. The sources of these oils are not completely understood, but it is agreed in both cases that they derive from severely biodegraded marine oils. The 5.3 trillion barrels [842 billion m³] in all the deposits of western Canada and eastern Venezuela represent the degraded remains of what was probably once 18 trillion barrels [2.9 trillion m³] of lighter oils.³

In any depositional environment, the right combination of water, temperature and microbes can cause degradation and formation of heavy oil. Tar mats occur in many reservoirs near the

oil/water contact, where conditions are conducive to microbial activity. The depositional environment, the original oil composition, the degree to which it has been degraded, the influx of, or charging with, lighter oils and the final pressure and temperature conditions make every heavy-oil reservoir unique, and all of them require different methods of recovery.

Recovery Methods

Heavy-oil recovery methods are divided into two main types according to temperature. This is because the key fluid property, viscosity, is highly temperature-dependent; when warmed, heavy oils become less viscous (left). Cold production methods—those that do not require addition of heat—can be used when heavy-oil viscosity at reservoir conditions is low enough to allow the oil to flow at economic rates. Thermally assisted methods are used when the oil must be heated before it will flow.

The original cold method of heavy-oil recovery is mining. Most heavy-oil mining occurs in open-pit mines in Canada, but heavy oil has also been recovered by subsurface mining in Russia.⁴ The open-pit method is practical only in Canada where the surface access and volume of the shallow oil-sand deposits—estimated at 28 billion m³ [176 billion barrels]—make it economic.⁵

Canadian oil sands are recovered by truck and shovel operations, then transported to processing plants where warm water separates bitumen from sand (right). The bitumen is diluted with lighter hydrocarbons and upgraded to form synthetic crude oil. After mining, the land is refilled and reclaimed. An advantage of the method is that it recovers about 80% of the hydrocarbon. However, only approximately 20% of the reserves, or those down to about 75 m [246 ft], can be accessed from the surface. In 2005, Canadian bitumen production was 175,000 m³/d [1.1 million bbl/d]. This is expected to grow to 472,000 m³/d [3 million bbl/d] by 2015.⁶

Some heavy oils can be produced from boreholes by primary cold production. Much of the oil in the Orinoco heavy-oil belt in Venezuela is currently being recovered by cold production, as are reservoirs offshore Brazil.⁷ Horizontal and multilateral wells are drilled to contact as much of the reservoir as possible.⁸ Diluents, such as naphtha, are injected to decrease fluid viscosity, and artificial lift technology, such as electrical submersible pumps (ESPs) and progressing cavity pumps (PCPs) lift the hydrocarbons to the surface for transport to an upgrader.⁹ An advantage of the method is lower capital



^ Bitumen recovery from oil sands. When overburden is less than 50 m, bitumen can be mined from the surface. The process, depicted in photographs oriented from top to bottom, starts by recovering oil sands by truck and shovel operations. The sands are transported to processing plants where warm water separates bitumen from sand. The bitumen is diluted with lighter hydrocarbons and upgraded to form synthetic crude oil. Finally, the land is refilled and reclaimed. (Images courtesy of Syncrude Canada Ltd.)

expenditure relative to thermally assisted techniques, but the recovery factor is also low—6 to 12%. An additional challenge is the increase in fluid viscosity that arises with the formation of oil-water emulsions, caused by mixing and shearing in pumps and tubulars.

Cold heavy-oil production with sand (CHOPS) is another primary production method that has applicability in many heavy-oil reservoirs. In hundreds of fields in Canada, sand—up to 10% “sand cut” by volume—is produced along with the oil (right). Gas exsolving from the depressurized oil helps destabilize and move sand grains. Sand movement increases fluid mobility and forms channels, called wormholes, which create a growing zone of high permeability around the well. The overburden weight helps extrude sand and liquids. Sand and oil are separated by gravity at surface, and the sand is disposed of into permeable strata. The method requires multiphase pumps that can handle sand, oil, water and gas, and has been applied in reservoirs with oil viscosity from 50 to 15,000 cP [0.05 to 15 Pa.s].¹⁰ In Canada, annual production of heavy oil by the CHOPS method was 700,000 bbl/d [111,230 m³/d] as of 2003.

Waterflooding is a cold enhanced oil-recovery (EOR) method that has been successful in some heavy-oil fields. For example, offshore fields on the UK continental shelf use waterflooding to produce 10- to 100-cP oil from long, screen-supported horizontal wells to a floating production, storage and offloading (FPSO) system.¹¹ The method is being considered for nearby fields with higher viscosity fluids, but the recovery factor decreases with increasing oil viscosity. High-viscosity oils cause viscous fingering in waterflood fronts, resulting in poor sweep efficiency.



▲ Slurry produced by cold heavy-oil production with sand (CHOPS). This tank-bottom sample was recovered from a tank farm at an oil-cleaning battery near Lloydminster, Saskatchewan, Canada, and is composed of approximately 10 to 20% fine-grained clay and silica, 20 to 30% viscous oil and 50 to 60% water. (Photograph courtesy of Maurice Dusseault.)

Vapor-assisted petroleum extraction (VAPEX) is a relatively new process being tested in Canada. It involves the injection of a miscible solvent, which reduces the viscosity of heavy oil. The method can be applied one well at a time or in well pairs. In the single-well approach, the solvent is injected from the toe of a horizontal well. In the double-well case, solvent is injected into the upper well of a pair of parallel horizontal wells. Valuable gases are scavenged after the process by inert gas injection. VAPEX has

been studied extensively in the laboratory and in simulations, and is undergoing pilot testing, but has not yet been deployed in large-scale field operations.

Thermal methods, like their cold counterparts, have advantages and limitations. Recovery factors are higher than for cold production methods—with the exception of mining—but so are costs associated with heat generation and water treatment. Cyclic steam stimulation (CSS), also known as steam soak, or

2. Head IM, Jones DM and Larter SR: “Biological Activity in the Deep Subsurface and the Origin of Heavy Oil,” *Nature* 426, no. 6964 (November 20, 2003): 344–352.

3. Meyer RF: “Natural Bitumen and Extra-Heavy Oil,” World Energy Council Survey of Energy Resources, www.worldenergy.org/wec-geis/publications/reports/ser/bitumen/bitumen.asp (accessed June 1, 2006).

4. Alberta Chamber of Resources: “Oil Sands Technology Roadmap: Unlocking the Potential,” http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf (accessed June 24, 2006). Meyerhoff AA and Meyer RF: “Geology of Heavy Crude Oil and Natural Bitumen in the USSR, Mongolia and China: Section I: Regional Resources,” in Meyer RF (ed): *Exploration for Heavy Crude Oil and Natural Bitumen. AAPG Studies in Geology no. 25*. Tulsa: AAPG (1987): 31–101.

5. National Energy Board of Canada: “Energy Market Assessment, Canada’s Oil Sands: Opportunities and Challenges to 2015: An Update,” http://www.neb-one.gc.ca/energy/EnergyReports/EMAOilSandsOpportunitiesChallenges2015_2006/EMAOilSandsOpportunities2015QA2006_e.htm (accessed June 3, 2006).

6. National Energy Board of Canada, reference 5.

7. Capeleiro Pinto AC, Branco CC, de Matos JS, Vieira PM, da Silva Guedes S, Pedrosa CJ, Decnop Coelho AC and Ceciliano MM: “Offshore Heavy Oil in Campos Basin: The Petrobras Experience,” paper OTC 15283, presented at the Offshore Technology Conference, Houston, May 5–8, 2003.

8. Stalder JL, York GD, Kopper RJ, Curtis CM, Cole TL and Copley JH: “Multilateral-Horizontal Wells Increase Rate and Lower Cost Per Barrel in the Zuata Field, Faja, Venezuela,” paper SPE 69700, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Marguerita Island, Venezuela, March 12–14, 2001.

9. Robles J: “Application of Advanced Heavy Oil Production Technologies in the Orinoco Heavy-Oil-Belt, Venezuela,” paper SPE 69848, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Marguerita Island, Venezuela, March 12–14, 2001.

Upgrading is the hydrogenation of heavy crudes by the addition of hydrogen. The product of upgrading is synthetic crude oil.

10. Course notes from Professor Maurice Dusseault, University of Waterloo, Ontario, Canada.

11. Etebar S: “Captain Innovative Development Approach,” paper SPE 30369, presented at the SPE Offshore Europe Conference, Aberdeen, September 5–8, 1995.

Rae G, Hampson J, Hiscox I, Rennie M, Morrison A and Ramsay D: “A Case Study in the Design and Execution of Subsea Production Development Wells in the Captain Field,” paper SPE 88837, *SPE Drilling & Completion* 19, no. 2 (June 2004): 82–93.

huff and puff, is a single-well method applied in stages ([below](#)). First, steam is injected. Then, during the soaking, or waiting, period, the oil heats up. Finally, the heated oil and water are produced and separated, and the process repeats. The method obtains recovery factors up to 30%, has high initial production rates and works well in stacked or layered reservoirs. The Cold Lake field in Alberta, Canada, is an example of CSS application.

Steamflooding, another thermal method, is a multiwell process. Steam is injected into injector wells in a variety of spacing and location patterns, and oil is produced from producer wells. Steamflooding can achieve up to a 40% recovery factor, but requires good interwell mobility to inject steam at effective rates. Challenges with this method are gravity override of the low-density steam, reservoir heterogeneities and monitoring the steam front. Examples are Duri field in Indonesia, Kern River field in California, and Pikes Peak Lloydminster in Canada.

Steam-assisted gravity drainage (SAGD) works for extraheavy oils. A pair of parallel horizontal wells is drilled, one well about 5 to 7 m [16 to 23 ft] above the other ([next page, top](#)). Steam injected into the upper well heats the heavy oil, reducing its viscosity. Gravity causes the mobilized oil to flow down toward the lower horizontal producer. Initial communication is established between the injector and producer by steam, cyclic steam or solvent injection. The estimated recovery factor for this method is between 50 and 70%.¹² However, formation layering can significantly influence SAGD recovery.¹³ SAGD is used in many fields in Canada, including Christina Lake and MacKay River.

In-situ combustion, also known as fireflooding, is a method for mobilizing highly viscous oils. It is a multiwell process in which a combustion front initiated at an air-injection well propagates to a producing well. The in-situ combustion burns some of the oil, and the heat sufficiently reduces the viscosity of the rest to

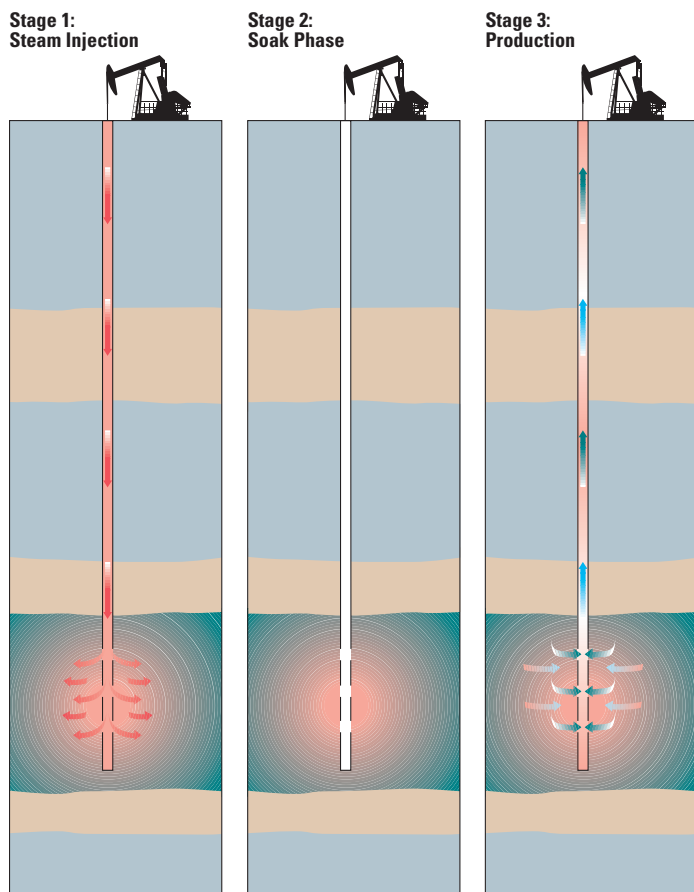
allow production. The burnt oil, or combustion residue, is left behind. The combustion upgrades the crude oil by cracking, or separating small molecules from large ones. Most attempts at field application have found the process to be unstable. However, in Romania, the large-scale fireflooding operation in the Suplacu de Barcău field has been operating since 1964.¹⁴

New technologies are being developed to stabilize the combustion front in the in-situ combustion process. For example, the THAI Toe-to-Heel Air Injection method, a trademark of Archon Technologies Ltd., uses a combination of vertical injector and horizontal producer. The method is currently in field pilot test in the McMurray formation near Conklin, Alberta.¹⁵

Selecting a Recovery Method

With various recovery methods available, selecting the best one for a particular reservoir requires a comprehensive study that incorporates many factors, such as fluid properties, formation continuity, rock mechanics, drilling technology, completion options, production simulation and surface facilities. This multidisciplinary team effort must also consider trade-offs between factors such as reserves, expected recovery rates and production rates. Also required is consideration of the cost of energy generation and the environmental sensitivity of the surroundings. An example of the type of screening study that can help companies decide how to produce heavy-oil resources comes from the North Slope in Alaska, where BP Exploration (Alaska) Inc. is assessing methods for producing the high-viscosity oil in the Ugnu sands ([next page, bottom](#)).

The Ugnu sands and their deeper neighbor, the Schrader Bluff formation, were first encountered in 1969, when operators drilled and tested the deeper Kuparuk formation.¹⁶ At the time, there was no viable technology to develop the highly viscous oils in the Ugnu and Schrader Bluff sands, so the companies concentrated on the prolific Kuparuk formation. The Schrader Bluff formation is a stratigraphically deeper formation and contains relatively lighter viscous oil than the Ugnu. Sections of the Schrader Bluff formation are on waterflood and have been producing since the early 1990s. Over the years, several companies conducted simulations and pilot studies to assess the feasibility of waterflooding and other enhanced oil-recovery (EOR) methods for producing the Ugnu, but failed to find economic means to exploit the heavy-oil resources.¹⁷

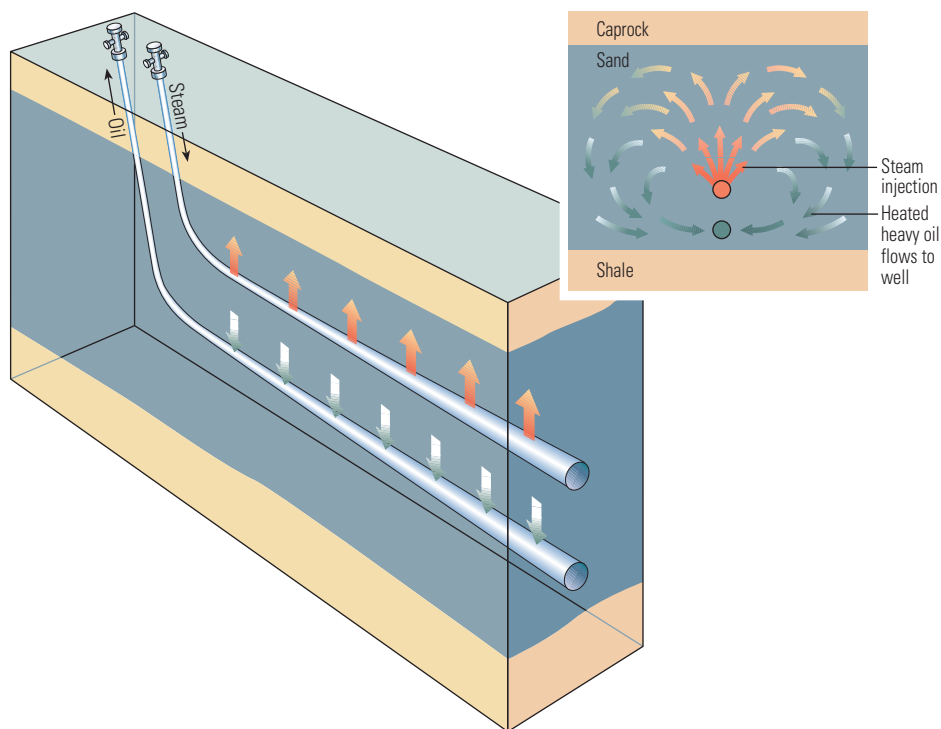


▲ Cyclic steam stimulation (CSS), a single-well method applied in stages. First, steam is injected (*left*). Next, the steam and condensed water heat the viscous oil (*center*). Finally, the heated oil and water are pumped to the surface (*right*). The process is then repeated.

BP is currently evaluating development of the heavy-oil reserves in the Milne Point unit of the North Slope. The total prize is estimated to be billions of barrels of oil originally in place in the Lower Ugnu formation, with a significant percentage positioned in BP's Milne Point unit. The reservoir and fluid properties vary across the field, and are generally represented by high oil density and viscosity and a low reservoir temperature of 75°F [24°C]. This means the reservoir clearly requires nonprimary recovery methods such as some form of enhanced cold production, cyclic steam stimulation, steamflooding, SAGD or hybrid process.

To determine the best approach, a 30-member team comprising BP and Schlumberger specialists conducted a screening study. The objective of the study was to identify the development technique that would economically maximize oil production rates and recovery factor, while ensuring minimal and acceptable heat loss to permafrost and minimal effect on naturally occurring gas hydrates. The screening study emphasized CO₂ and greenhouse-gas handling and usage, and enforced the highest standards of HSE. A joint BP/Schlumberger technology study is currently under way to examine options to bring heavy-oil developments in line with BP's Green Agenda. The study results will be input to the BP Appraise Stage Plan for final decision making on Ugnu development.

The screening study reviewed previous studies and reports issued during the last 25 years. With these studies and available data,



^ Steam-assisted gravity drainage (SAGD, pronounced sag-dee). A pair of parallel horizontal wells is drilled, one above the other. Steam is injected into the upper well to heat the heavy oil, reducing its viscosity. Gravity causes the oil to flow down toward the producer.

12. Course notes from Professor Maurice Dusseault, University of Waterloo, Ontario, Canada.

13. Contreras C, Gamero H, Drinkwater N, Geel CR, Luthi S, Hodgetts D, Hu YG, Johannessen E, Johansson M, Mizobe A, Montaggioni P, Pestman P, Ray S, Shang R and Saltmarsh A: "Investigating Clastic Reservoir Sedimentology," *Oilfield Review* 15, no. 1 (Spring 2003): 54-77.

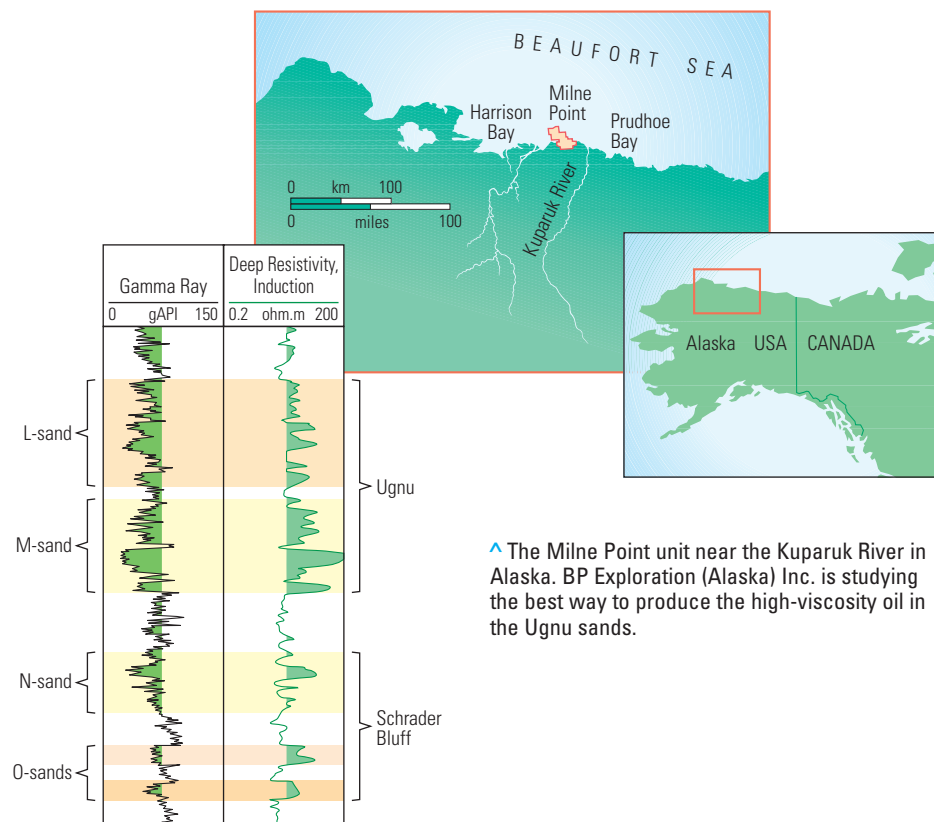
14. Panait-Patică A, Șerban D and Ilie N: "Suplacu de Barcău Field—A Case History of a Successful In-Situ Combustion Exploitation," paper SPE 100346, presented at the SPE Europec/EAGE Annual Conference and Exhibition, Vienna, Austria, June 12-15, 2006.
Paduraru R and Pantazi I: "IOR/EOR—Over Six Decades of Romanian Experience," paper SPE 65169, presented at the SPE European Petroleum Conference, Paris, October 24-25, 2000.

15. "WHITESANDS Experimental Project," http://www.petrobank.com/ops/html/cnt_white_project.html (accessed July 3, 2006).

16. Bidinge CR and Dillon JF: "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels," paper SPE 30289, presented at the SPE International Heavy Oil Symposium, Calgary, June 19-21, 1995.

17. Bidinge and Dillon, reference 16.

Werner MR: "Tertiary and Upper Cretaceous Heavy-Oil Sands, Kuparuk River Unit Area, Alaskan North Slope: Section V: Exploration Histories," in Meyer RF (ed): *Exploration for Heavy Crude Oil and Natural Bitumen. AAPG Studies in Geology no. 25.* Tulsa: AAPG (1987): 537-547.



^ The Milne Point unit near the Kuparuk River in Alaska. BP Exploration (Alaska) Inc. is studying the best way to produce the high-viscosity oil in the Ugnu sands.

Performance/Knowledge		Key Performance Indicators	Production			Subsurface				Surface			Costs				
			Production rate per well	Reserves per well	Reservoir recovery	Petrophysics	Geology	Fluid characterization	Rock-mechanical properties	Gas hydrates	Artificial lift configuration	Permafrost characteristics	CO ₂ emissions	Fuel requirements	Facility costs	Drilling costs	Completion costs
Viable EOR Techniques																	
Continuous steamflood injection																	
Cyclic steam stimulation (CSS)																	
Steam-assisted gravity drainage (SAGD)																	
Hot waterflood injection																	
Cold oil production (CHOPS)																	

^ Sensitivity matrix from the Ugnu screening study, quantifying the sensitivity of each recovery method to production, subsurface, surface and cost factors. Each matrix block was colored according to factor sensitivity to performance or knowledge importance. In terms of performance, green means excellent, yellow means fair and red means poor. In terms of knowledge importance, green means less important, yellow means important and red means critical. For example, in the production categories, CSS was rated excellent performance for production rate per well, reserves per well and reserves recovery. Of the subsurface factors, for example, fluid characterization and rock-mechanical properties are rated of critical knowledge importance for every EOR method assessed. In the interactive version of the matrix, clicking on a box accesses the reports and studies behind the evaluation.

three representative wells in the Milne Point area were selected for a detailed review. The wells penetrated intervals of varying reservoir quality. To determine the best recovery method, several were simulated, including steamflooding, CSS, SAGD, hot waterflooding and primary production. The effects of vertical, deviated and horizontal wells were also tested in the simulation runs.

The results of the study were compiled in an interactive matrix that quantified the sensitivity of each recovery method to production, subsurface, surface and cost factors (above). Each matrix block was colored according to factor sensitivity and acted as a link to reports, analysis and presentations that supported the sensitivity rating. For example, of the subsurface factors, improved fluid characterization and rock-mechanical properties are rated of critical knowledge importance for every EOR method assessed. A brief look at the available information shows why.

Reservoir fluid PVT properties, in particular fluid viscosity and its variation with temperature, are crucial factors in selection of a recovery technique.¹⁸ These were inadequately known for the fluids in the Ugnu formation. Measured oil-viscosity data were limited to two production samples with dead-oil viscosities of 200 and 2,500 cP at 80°F [0.2 Pa.s and 2.5 Pa.s at 27°C]. These samples are not thought to be representative of the entire range of viscosities present in the Ugnu sands. Geochemical transforms were used to predict oil viscosity from sidewall core samples. However, this technique relied on extrapolation beyond the range of measured viscosities and made the assumption that Ugnu oils have the same controls on oil quality as the Schrader Bluff oils. Although the model served as a good starting point, fine-tuning this model for predicting oil viscosity and collection of additional samples was one of the recommendations made in the study.

Another critical factor, rock-mechanical properties, was assessed by examination of core and analysis of DSI Dipole Shear Sonic Imager logs from the MPS-15 well. Ugnu sand has extremely low strength, less than 200 psi [1.4 MPa] in estimated unconfined compressive strength; the core is soil-like and easily crushed by hand, foreshadowing potential wellbore-stability and completion challenges. Additionally, two distinct peaks were noted on the sand size distribution. These indicate that a considerable amount of silt, 5- to 60-micron sized, may be produced along with fine- to very-fine-grain sand of 60 to 250 microns. These fines will have to be either controlled or managed with Ugnu oil production.

To determine suitable drawdown pressures and a depth-stability envelope for production, estimates of mechanical-property data and completion options, such as perforation size and orientation, were input to the Sand Management Advisor software. These initial calculations

18. PVT stands for pressure, volume and temperature. PVT properties are equations for the density of a fluid as a function of temperature and pressure, the pressure-temperature coordinates of the phase lines, and related thermodynamic properties.

19. Freedman R, Heaton N, Flaum M, Hirasaki GJ, Flaum C and Hurlimann M: "Wettability, Saturation, and Viscosity from NMR Measurements," paper SPE 87340, presented at the SPE Annual Technical Conference and Exhibition,

San Antonio, Texas, September 29–October 2, 2002; also in *SPE Journal* 8, no. 4 (December 2003): 317–327.

20. Bryan J, Kantzas A and Bellehumeur C: "Viscosity Predictions from Low-Field NMR Measurements," paper SPE 89070, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002; also in *SPE Reservoir Evaluation & Engineering* 8, no. 1 (February 2005): 44–52.

Mirotchnik KD, Allsopp K, Kantzas A, Curwen D and Badry R: "Low-Field NMR Method for Bitumen Sands Characterization: A New Approach," paper SPE 71208, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002; also in *SPE Reservoir Evaluation & Engineering* 4, no. 2 (April 2001): 88–96.

21. Relative hydrogen index (RHI) is defined as a ratio of amplitude indexes (AI): $RHI = AI_{oil} / AI_{water}$, where AI = amplitude of fluid signal/mass of fluid.

determined that any drawdown greater than 1 psi [6.9 kPa] would cause complete sand failure. The recommendation was to anticipate sand production during drilling and completion, and to develop creative sand-management strategies, such as microslotted liners.

Of the five recovery methods assessed, cyclic steam stimulation gave the best recovery and production rates. If this method is selected, care will have to be taken not to overheat the permafrost. This should be possible since the reservoir is isolated from permafrost layers by a thick, impermeable shale. Other methods, such as primary cold production, would have minimal impact on permafrost, but may have difficulty yielding economic recovery or production rates. SAGD, while having a similar environmental impact as CSS, would not be as effective in the study location, because it requires a high ratio of vertical to horizontal permeability for development of a steam chamber. Continuity of the Ugnu formation will significantly influence the final recovery factor, and reservoir description will be a critical component of ongoing work.

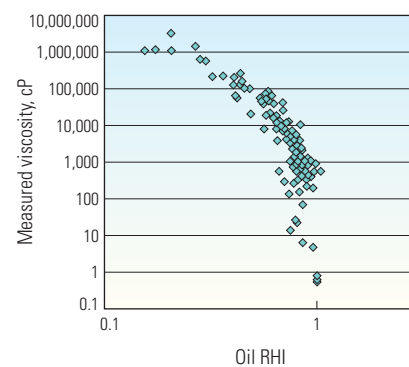
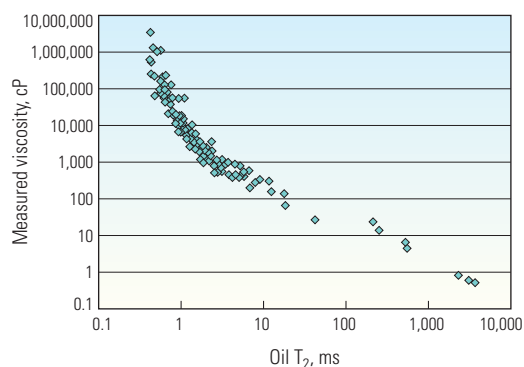
Ultimately, the screening study recommended cyclic steam stimulation as the optimal recovery method for the area of study in the Milne Point unit, and outlined well spacing, orientation and patterns. Also, additional simulation was recommended to assess the effects of varying steam-injection rates and volumes and to investigate the feasibility of converting to steamflooding.

Characterizing Heavy Oils Downhole

A critical step in determining the best heavy-oil recovery method is to characterize reservoir fluid properties. For the purposes of grading reserves and selecting sampling intervals, companies turn to downhole measurements of fluid properties, especially viscosity.

Knowledge of viscosity throughout the reservoir is vital for modeling production and predicting reserves recovery. However, heavy-oil viscosity can exhibit large variations, even within the same formation. Building a viscosity map requires adequate sampling and logging-derived information of in-situ viscosity.

Nuclear magnetic resonance (NMR) logging has been used successfully to determine in-situ viscosity of conventional oils, but current commercial methods have limitations in heavy and viscous oils.¹⁹ This is because as fluid viscosity increases, NMR relaxation time, T_2 , decreases. When relaxation times are extremely short, NMR logging tools cannot detect them.



▲ Correlation between laboratory-measured viscosities and two laboratory-measured nuclear magnetic resonance (NMR) parameters. NMR relaxation time, T_2 , decreases as viscosity increases (*left*). However, at extremely high viscosities, there is little change in T_2 . Relative hydrogen index (RHI) also decreases with increasing viscosity (*right*), but is more sensitive to viscosity change at high viscosities. (Adapted from Bryan et al, reference 20.)

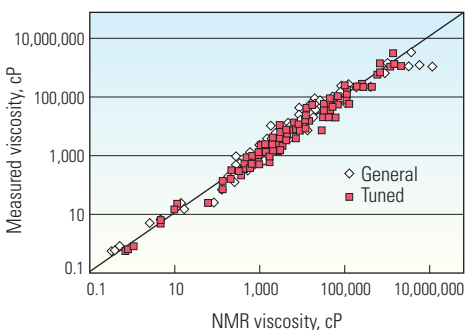
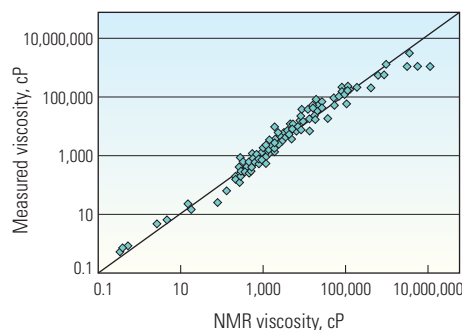
When viscosity is greater than about 100,000 cP [100 Pa.s], NMR tools see most of the heavy oil or bitumen as part of the rock matrix.

To improve understanding of the correlation between viscosity and NMR response, researchers at the University of Calgary and its affiliate institute, the Tomographic Imaging and Porous Media (TIPM) Laboratory, acquired and interpreted laboratory NMR measurements on a large selection of Canadian heavy oils.²⁰ Oils in the database have viscosities ranging from less than 1 cP to 3,000,000 cP [0.001 to 3,000 Pa.s].

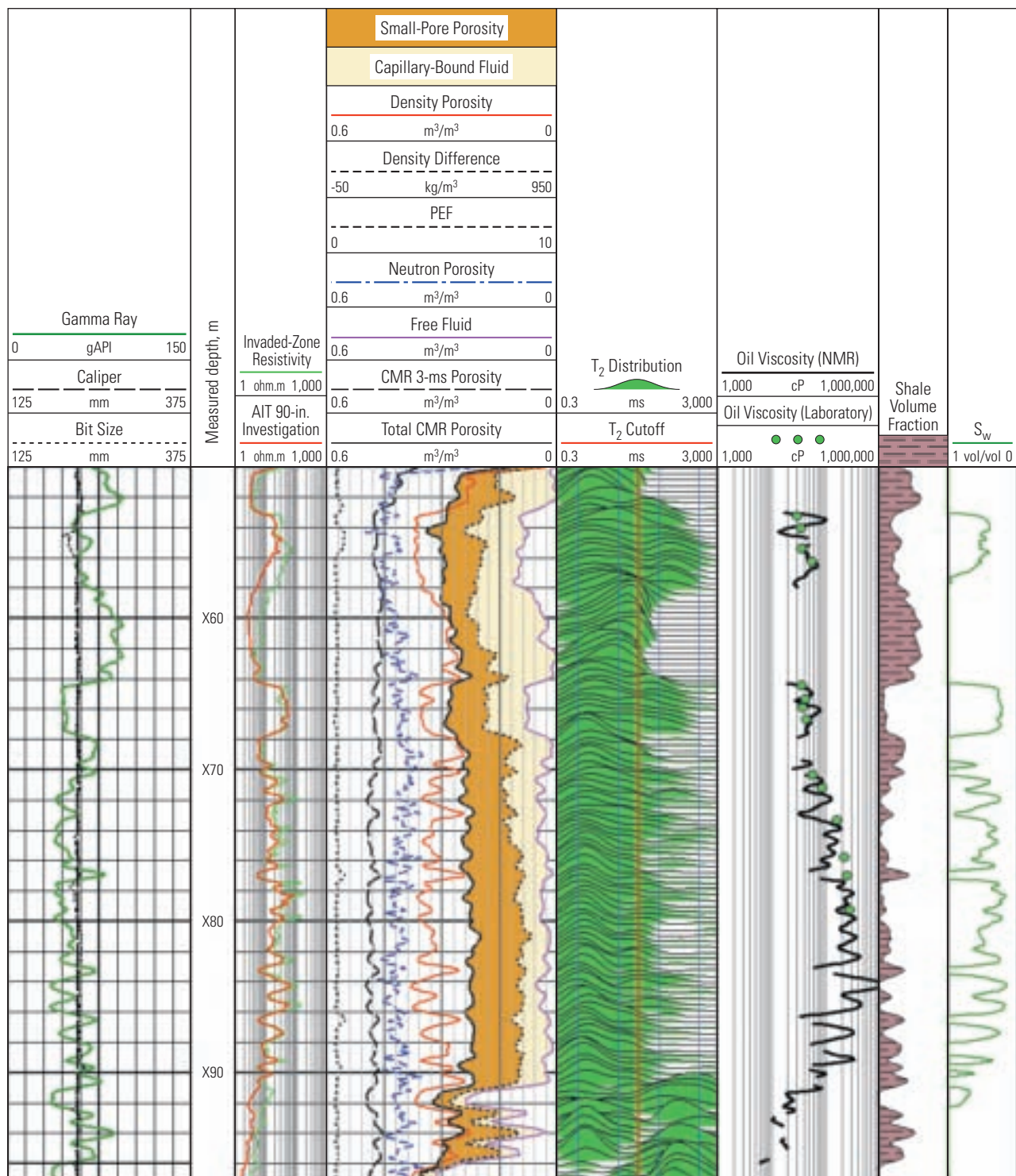
Measured viscosities showed a correlation with two NMR parameters, but with differing sensitivities. With increasing viscosity, T_2 decreased and, at high viscosities, became less sensitive to changes in viscosity. However, increasing viscosity caused the decreasing

relative hydrogen index (RHI) to become more sensitive to viscosity change at high viscosities (*above*).²¹ On the basis of these findings, the researchers developed a new empirical relationship between the NMR parameters and fluid viscosity. The relationship was adjusted to provide the best possible fit for the five oils in the database for which viscosity data were available over a range of temperatures (*below*).

Translating this laboratory NMR-viscosity relationship to one that works for NMR logging tools is not straightforward. Heavy oils in rocks are mixed with other fluids and exhibit behaviors that differ from bulk fluids in the laboratory. However, the right combination of laboratory and logging measurements can provide the information necessary to fine-tune the viscosity relationship and produce a continuous viscosity



▲ Correlation between measured viscosity and viscosity calculated using an empirical relationship based on NMR parameters T_2 and RHI. The correlation between measured and calculated viscosities (*left*) is good, but improves when tuned to fit viscosity data acquired over a range of temperatures (*right*). (Adapted from Bryan et al, reference 20.)



^ A continuous oil-viscosity log produced from Platform Express data and CMR-200 measurements, calibrated to laboratory oil-viscosity values. From X64 to X80 m, the continuous viscosity log (Track 5) shows a viscosity gradient, with oil viscosity increasing from 30,000 to 300,000 cP.

log (above). In this heavy-oil example from Western Canada, data from the Platform Express integrated wireline logging tool and CMR-200 Combinable Magnetic Resonance measurements

were used to produce an oil-viscosity log that showed good agreement with laboratory oil-viscosity measurements in a range from 30,000 to 300,000 cP [30 to 300 Pa.s].

Viscosity measurements in this well show not only variation, but also a gradient of increasing viscosity with depth in the interval from X64 to X80 m. While this type of gradient is common in this area, other regions show the opposite effect,

with viscosity decreasing with depth. The ability to estimate heavy-oil viscosity will help companies map viscosity changes throughout their heavy-oil reservoirs and ultimately aid in determining the appropriate completion and recovery strategies.

Sampling Heavy, High-Viscosity Fluids

Evaluating the productivity potential of heavy-oil reservoirs has been difficult because high fluid viscosity and unconsolidated formations make it difficult to acquire representative fluid samples and test reservoir dynamics (right). There is no unique solution to the problem of collecting heavy-oil samples in unconsolidated sands, but best practices and sampling techniques developed for the MDT Modular Formation Dynamics Tester are allowing improved characterization of many heavy-oil reservoirs.

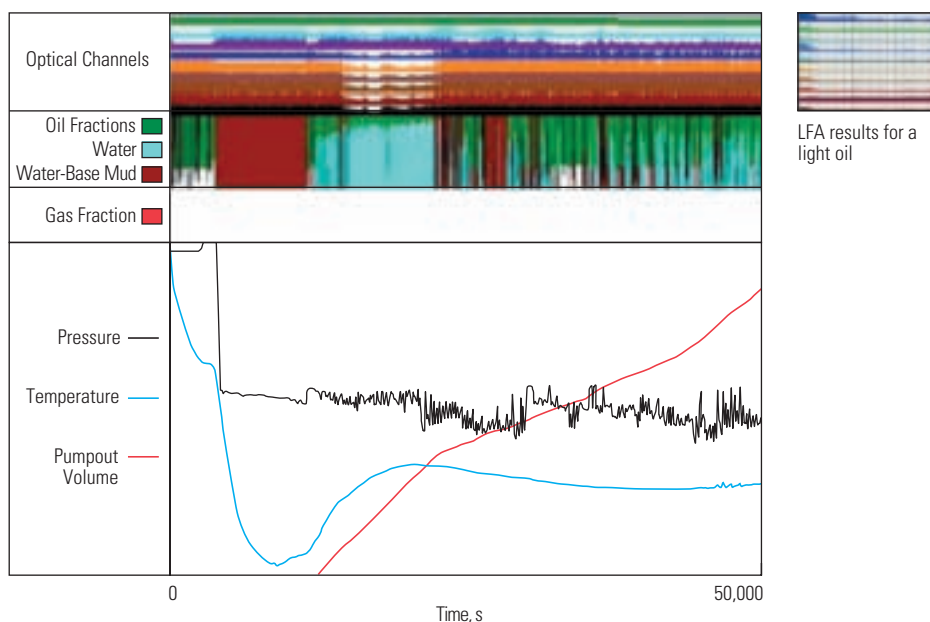
Some of the new technology includes an extra-large-diameter probe, a focused probe, dual packers with customized gravel-pack screens, an extra-high-pressure displacement pump for low flow rates, advanced downhole fluid analysis and specialized sampling methodology.

A methodology that has successfully collected samples of high-viscosity oil starts by simulating the multiphase flow around the wellbore to model the decrease in drilling-fluid contamination with time as fluid is pumped into the wellbore. By varying oil viscosity, permeability anisotropy, drilling-fluid invasion, flow rate and MDT position, it is possible to estimate the pumping time required to collect a sample of sufficiently low contamination.²² The cleanup time is highly dependent on the effective radius of invasion. Fortunately, oil of extremely high viscosity restricts invasion, reducing the volume of fluid that needs to be pumped before uncontaminated fluid is pulled into the tool flowline. In one case in South America, a technique using the MDT dual-packer module and a flow rate less than 1 cm³/s successfully sampled oil of viscosity greater than 3,200 cP [3.2 Pa.s] (right).²³

In another case, exploring in the northwest state of Rajasthan, India, Cairn Energy discovered the Bhagyam field in 2004. The Bhagyam field is one of 17 fields in the Barmer basin, and produces from the high-permeability Fatehgarh sandstone. Oil reserves in the basin are currently estimated at 650 million bbl [103 million m³].



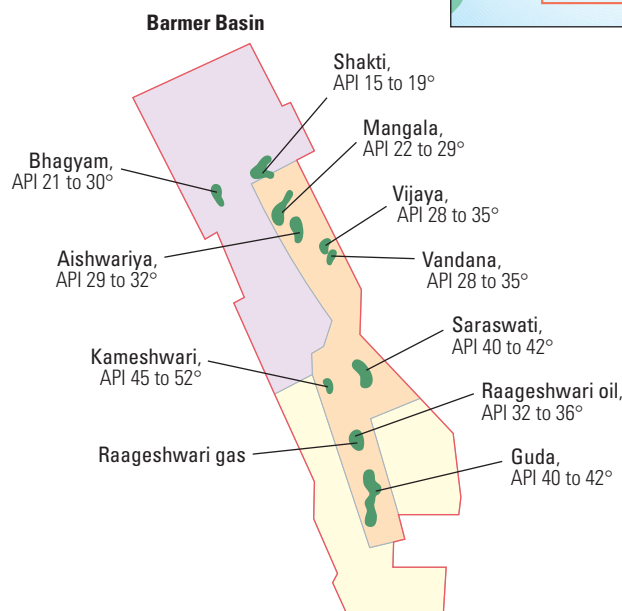
^ High-viscosity South American heavy oil acquired by wireline sampling.



^ Fluid-sampling log from South America, using the MDT dual-packer module and the spectroscopic LFA Live Fluid Analyzer. The optical channels of the LFA measurement (top) are color-coded by optical density, which corresponds to hydrocarbon-component chain length. Channel 1 (black) corresponds to methane. Channel numbers increase upward. In this example, all optical channels show high amplitudes, indicating an opaque heavy oil. For comparison, LFA results for a light oil are shown to the right, with low amplitudes in most channels. In the water, water-base mud (WBM) and oil-fraction track, blue corresponds to mass fraction of water, green represents mass fraction of oil, and reddish brown corresponds to slugs of WBM. The absence of gas readings in the gas-fraction track is another characteristic of heavy oil.

22. Cañas JA, Low S, Adur N and Teixeira V: "Viscous Oil Dynamics Evaluation for Better Fluid Sampling," paper SPE/PS-CIM/CHOA 97767, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, November 1–3, 2005.

23. Cañas et al, reference 22.

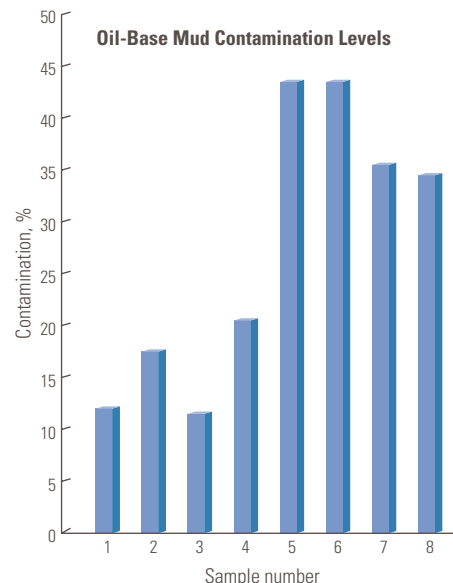


^ Bhagyam field in the Barmer basin in Rajasthan, India, where Cairn Energy produces crude oils with widely varying API gravities.

Crude-oil properties vary widely in the basin, from 15°API in the north to 52°API farther south (above). In the Bhagyam field, oil density ranges from 21°API at the bottom to 30°API at the top. Although they are not as dense as other heavy oils, Bhagyam oils have high wax and asphaltene content, giving them high pour point and high viscosity at reservoir temperature.²⁴

Acquiring representative, PVT-quality samples of these viscous oils has been a

challenge.²⁵ Reservoir sections are drilled with oil-base mud (OBM) to avoid shale collapse. During sample collection, OBM filtrate is collected along with reservoir fluid, contaminating the oil sample. Of the more than 30 samples acquired by Schlumberger and another service company using traditional formation testers, all have been deemed nonrepresentative—too contaminated to yield correct PVT properties during laboratory analysis. Filtrate contamination can be assessed



^ Oil-base mud (OBM) contamination levels for samples acquired in Well Bhagyam-4 using conventional sampling techniques. The heavy-oil samples had so much OBM contamination, they could not be used for PVT analysis.

downhole by the LFA Live Fluid Analyzer in real time before fluid samples are collected. For example, at one sampling station in the Bhagyam-4, LFA analysis quantified volume-percent contamination at 43% even after 105 minutes of pumping (above).

Using a new sampling module on the MDT tool, it is now possible to achieve zero filtrate contamination. The Quicksilver Probe wireline sampling tool uses a focused sampling approach whereby contaminated fluid is pumped into one flowline, completely isolated from pure reservoir fluid collected in a second sampling flowline.

This focused sampling approach was used in two Bhagyam wells with excellent results. In Bhagyam-5, after 27 minutes pumping time, the Quicksilver Probe sampler drew in fluid that registered 0% OBM contamination on the LFA detector. Later, independent laboratory analysis confirmed a contamination level of 0%. In Bhagyam-6, the Quicksilver Probe-LFA combination sampled fluid that averaged 2.2% contamination after 52 minutes of pumping. Subsequent laboratory analysis determined a contamination level of 0%. Of the 18 samples collected from the two wells, 15 were of PVT quality and 6 samples showed zero contamination (next page, top).

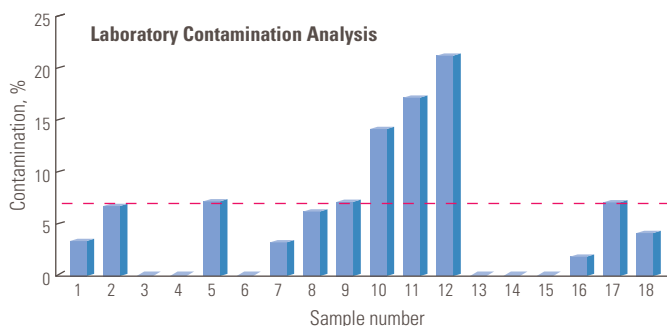
Laboratory Analysis of Heavy Oils

Compared with conventional oils, viscous heavy-oil samples not only are more difficult to acquire, they also present several challenges in laboratory fluid analysis. Traditional techniques for analyzing key fluid properties can fail to fully characterize heavy-crude samples. To solve this problem, researchers and engineers at the Schlumberger Reservoir Fluids Center (SRFC) in Edmonton, Alberta, Canada, have developed new methodologies for determining phase and viscosity behavior of heavy oils (bottom right). In addition, compositional analysis techniques currently used on conventional oils have been applied to heavy oils, with a view to understanding the limitations and identifying potential improvements.

Of the several laboratory techniques that have been developed to describe the chemical composition of oils, the most common is gas chromatography (GC).²⁶ This type of analysis describes the chemical nature of the oil in sufficient detail to capture differences between oils without significantly increasing simulation time. Standard GC analysis can determine chemical composition of a conventional oil up to C₃₆₊.²⁷ Its strength is in detecting the light components of conventional oils. However, standard GC cannot differentiate the high number of large compounds in heavy oils with sufficient detail to use in simulation.

For compositional characterization of heavy oils, SRFC engineers perform additional analysis techniques that more fully examine these high-density, high-viscosity fluids. The techniques include analysis of saturate, aromatic, resin and asphaltene (SARA) fractions and simulated distillation.²⁸ Each of the techniques has advantages and inherent limitations.

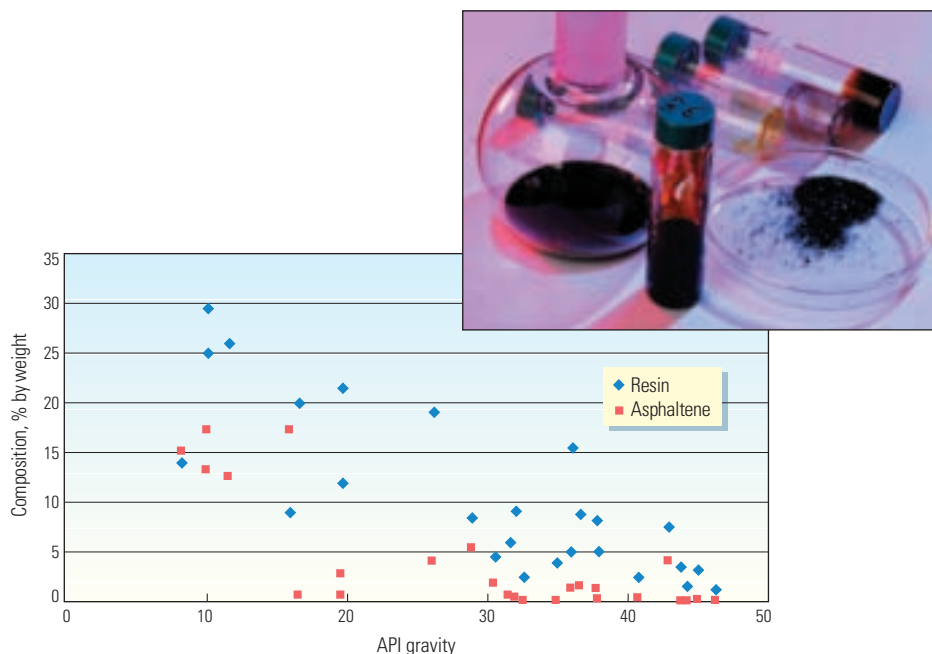
24. Pour point is the minimum temperature at which oil pours or flows.
25. PVT-quality samples are those that have sufficiently low contamination, such that PVT properties measured in the laboratory correspond to those of an uncontaminated sample. The maximum allowable contamination varies by company and laboratory. A common standard is 7% contamination for this basin.
26. In GC, a sample is vaporized, then carried by an inert gas through a column that separates components. Each component produces a separate peak in the detector output.
27. The phrase "composition to C₃₆₊" indicates that compounds of up to 35 carbon atoms are separately discriminated, with the remainder combined into a fraction indicated as C₃₆₊.
28. Crude oil is a complex mix of components of different molecular structures and properties. Saturates, also known as alkanes or paraffins, are long hydrocarbon chains of the form C_nH_{2n+2}. Aromatics incorporate one or more benzene [C₆H₆] rings. Resins are nonvolatile constituents that are soluble in n-pentane [C₅H₁₂] or n-heptane [C₇H₁₆]. Asphaltenes are nonvolatile constituents that are insoluble in n-pentane or in n-heptane.



▲ Laboratory contamination analysis. Low contamination levels were achieved in fluid samples acquired with the Quicksilver Probe focused sampling tool. Laboratory analysis corroborated downhole fluid-analysis results. Of the 18 samples collected, 15 were of PVT quality, and 6 of these showed no contamination. The dashed pink line indicates the contamination level, 7%, below which samples are considered to be of PVT quality.



▲ The Schlumberger Reservoir Fluids Center (SRFC), in Edmonton, Alberta. At SRFC, experts carry out both research and engineering activities, focusing on areas of phase behavior, flow assurance, enhanced oil recovery and heavy-oil production.



▲ Correlation between API gravity and resin and asphaltene content from SARA analysis (*bottom*). The heavier the oil, the greater the content of resin and asphaltene. In the photograph (*top*), the flask contains the heated heavy-oil sample. The standing tube contains resin, the Petri dish contains asphaltene, and the other tubes contain saturates and aromatics. (Data taken from Table 1 in reference 30.)

SARA analysis fractionates stock-tank oil into weight percent saturate, aromatic, resin and asphaltene by solubility and chromatography.²⁹ Although SARA analysis resolves only four components and seems low-resolution compared with the thousands of components resolvable by GC techniques, the strength of the method is that it analyzes the entire sample, from light to heavy compounds, and so allows all oils to be compared on a consistent standard. For example, SARA analysis confirms the expected increase in resin and asphaltene content with decreasing API gravity (*above*).³⁰ In addition, for conventional oils, SARA analysis gives an indication of fluid stability with respect to asphaltene precipitation, an important consideration when designing production schemes and facilities.³¹ In the case of heavy oils, SARA analysis is less useful as an indicator of asphaltene precipitation, which typically occurs when the heavy oil is diluted with certain gases or solvents. Also, SARA-analysis practices can vary, making it difficult to compare measurements made at different laboratories.

Simulated distillation is a GC technique that identifies hydrocarbon components in the order of their boiling points.³² It is used to simulate the time-intensive, true-boiling-point laboratory procedure. When performed at high temperatures, 36 to 750°C [97 to 1,382°F], the technique can resolve components up to C₁₂₀. The results are valuable for modeling downstream refining processes and can help refiners select crude oils that will produce favorable economic returns. In heavy oils, simulated distillation has limited application, since the larger compounds that make up a significant portion of the heavy oil will undergo chemical degradation at elevated temperatures; cracking begins to occur above 350°C [662°F].

Another important measurement required of an oil sample is its phase behavior, known as PVT behavior. These measurements describe how the properties of an oil are affected by changes in pressure, temperature or composition that may occur during a production process. In the case of heavy oils, new techniques and modifications of existing techniques have been developed to accurately determine heavy-oil fluid properties as functions of pressure, temperature and composition.

Standard laboratory techniques measure PVT properties such as bubblepoint, compressibility, composition of fumes—known as off-gas—density and gas/oil ratio (GOR). Although it is not precisely a phase property, viscosity also may vary dramatically with pressure, temperature and composition, and so it is included in this set of measurements. For heavy oils, characterizing viscosity behavior is especially important, since even small changes can have large effects on production rates and recoverable oil volumes. In some heavy-oil reservoirs, the apparent viscosity of the oil may change as the oil mixes with gas or water. Gas that evolves from heavy oil during production can form a foam. Mixing heavy oil with water can create an emulsion. The resulting viscosities are markedly different from that of the heavy oil alone.

Some heavy-oil recovery techniques call for injection of steam, gas or viscosity-reducing solvents, such as naphtha, for assisting production or artificial lift. To confirm the viability of these recovery techniques, laboratory measurements quantify the changes in bubble-point, density, compressibility, composition and number of liquid hydrocarbon phases caused by the addition of gases and solvents. The addition of gases and solvents can further modify heavy-oil properties by causing precipitation of asphaltenes.

To avoid unwanted changes in viscosity and the precipitation of solids, laboratory measurements monitor rheology and solubility changes on live oil with changes in pressure and temperature. Solids screening by titration with potential diluents or injection gases looks for the concentration at which asphaltene precipitation may be induced for a given temperature or pressure.

29. Alboudwarej H, Beck J, Svrcek WY, Yarranton HW and Akbarzadeh K: "Sensitivity of Asphaltene Properties to Separation Techniques," *Energy & Fuels* 16, no. 2 (2002): 462–469.

30. "Asphaltene Deposition and Its Control," http://tigger.uic.edu/~mansoori/Asphaltene.Deposition.and.Its.Control_html (accessed June 26, 2006).

31. De Boer RB, Leerlooyer K, Eigner MRP and van Bergen ARD: "Screening of Crude Oils for Asphalt Precipitation: Theory, Practice, and the Selection of Inhibitors," paper SPE 24987, presented at the SPE European Petroleum Conference, Cannes, France, November 16–18, 1992; also in *SPE Production & Facilities* 10, no. 1 (February 1995): 55–61.

32. Villalanti DC, Raia JC and Maynard JB: "High-Temperature Simulated Distillation Applications in Petroleum Characterization," in Meyers RA (ed): *Encyclopedia of Analytical Chemistry*. Chichester, England: John Wiley & Sons Ltd. (2000): 6726–6741. <http://home.earthlink.net/~villalanti/HTSD.pdf> (accessed May 25, 2006).



^ A PVT-analysis apparatus at SRFC, used to measure bubblepoint pressure by depressurizing a sample in a constant composition expansion (CCE) test. The bubblepoint is the pressure at which the sample volume increases significantly. A CCE test that mixes the heavy-oil sample yields a bubblepoint that matches ideal calculations, while the traditional CCE method produces a bubblepoint that is too low.

A fluid property of particular interest in heavy-oil reservoirs is bubblepoint pressure—the pressure at which dissolved gas comes out of solution. In the laboratory, bubblepoint is traditionally determined by depressurizing a sample in what is called a constant composition expansion (CCE) test. The bubblepoint is the pressure at which a large increase in sample volume occurs.

The traditional CCE method does not give reliable bubblepoint measurements for heavy oils. To obtain the true bubblepoint when the traditional CCE method fails, SRFC analysts use a CCE test designed for heavy oils (above). The true bubblepoint is obtained by allowing time for the gas to separate slowly from the oil and by controlled mixing of the fluid. Performing the

test in the short time allowed for conventional oils can result in a bubblepoint that is hundreds of psi lower than the true value.

Similarly, procedures developed for measuring viscosity of conventional oils can lead to large errors when applied to viscous oil. Rheometers or high-pressure capillary viscometers with accurate temperature control are capable of obtaining viscosity values with a measurement error on the order of 5% (above right).

As mentioned earlier, the quality of data depends on obtaining representative samples of the reservoir fluids. In some cases, it is difficult to obtain representative bottomhole and wellhead samples for some of the fluids of interest. Therefore, a procedure was developed to generate recombined heavy-oil samples from liquid samples



^ Measuring viscous-oil viscosity with a rheometer. Rheometers measure changes in viscosity with variation in flow rate. This is important for characterizing viscous oils that exhibit non-Newtonian behavior, meaning their viscosity is a function of shear rate.



^ Sample-recombination equipment at SRFC for obtaining representative fluid samples from fluids extracted at the wellhead.

collected at the surface (above). As with the bubblepoint measurement, recombination must allow time for the gas to diffuse and become fully dissolved in the heavy oil.

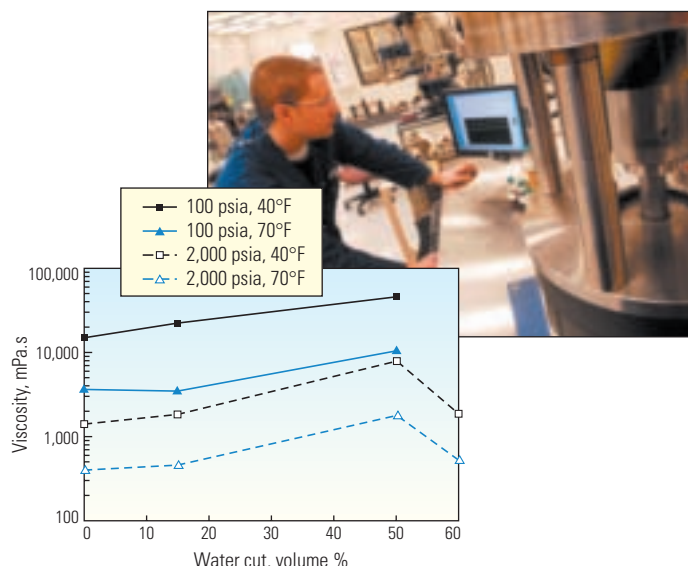
To test the effectiveness of the fluid-recombination technique, the fluid derived from the recombination procedure can be tested against wellhead samples for bubblepoint and viscosity. When PVT and viscosity measurements on recombined fluids give comparable results to the wellhead samples, engineers are able to generate an accurate field-specific model for predicting the properties of the heavy oil.

In one case, an oil company was concerned about the presence of emulsified water in some South American live heavy oils.³³ Most heavy oils are produced along with water, whether the water occurs naturally in the reservoir or has been injected in the form of water or steam. During the production process, shear forces stemming from high flow rate through pumps or flow constrictions may be great enough to cause the water to become emulsified in the heavy oil, leading to a rise in viscosity. This, in turn, will affect the efficiency of artificial lift, dramatically increase the energy required to transport the heavy oils and, in some cases, impact the choice of production equipment.

The viscosity and stability of oil-water emulsions depend on water cut and on which phase is continuous. The viscosity of oil-continuous, or water-in-oil, emulsions may increase by more than an order of magnitude over the dry-oil viscosity. The viscosity of a water-in-oil emulsion increases with water cut up to the emulsion inversion point, beyond which the continuous phase changes to water, producing an oil-in-water emulsion. In oil-in-water emulsions, viscosity decreases with water cut.

Characterizing the stability and viscosity of the South American heavy-oil emulsion required development of new experimental techniques at SRFC. Most experimental work on emulsions is performed on stock-tank oil samples. However, live oils contain dissolved gases that may affect the viscosity of the oil and emulsion. SRFC engineers developed a technique to generate emulsions in live oils by recombining stock-tank oil samples with gas to create a live oil. The live oil was then blended with water at various water cuts in a high-pressure, high-temperature (HPHT) shear cell. The shear cell generated emulsions with an average droplet size of 2 to 5 microns. Visual inspection and drop-size analysis confirmed that the live-oil emulsions remained relatively stable up to the inversion point.

The apparent viscosity of the resulting emulsions was measured at two pressures using an HPHT capillary viscometer (top right). The viscosity of the emulsified live heavy oil is clearly higher than the water-free heavy oil, up to five



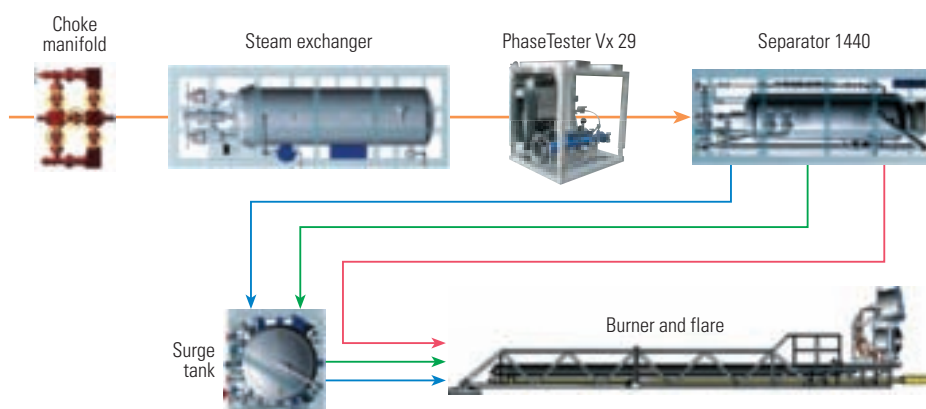
^ The apparent viscosity of oil-water emulsions created by sample recombination, measured at two pressures and temperatures using an HPHT capillary viscometer. The viscosity of the emulsified live heavy oil increases with water cut. At 50% volume water cut, viscosity reaches up to five times its water-free value. The system converted from a water-in-oil emulsion at or below 50% volume to an oil-in-water emulsion at 60% volume.

times greater at 50% volume water cut. The lower viscosity at 60% volume water cut indicates an inversion point, where the system converted from a water-in-oil emulsion at or below 50% to an oil-in-water emulsion at 60% volume. The maximum live-oil viscosity in the system occurs, as expected, just prior to the inversion point. Similar to water-free heavy-oil systems, the emulsion viscosity is reduced by an increase in temperature or by an increase in the amount of saturated gas. Clients can use these results to determine pump sizes, estimate the energy required to pump fluids from the reservoir to surface facilities, and design surface separators.

Drillstem Testing in Heavy-Oil Reservoirs

To confirm the economic potential of a discovery well, companies perform drillstem tests (DSTs). DSTs provide short-term production to estimate reservoir deliverability, and also to characterize permeability, completion damage and reservoir heterogeneities under dynamic conditions. Drillstem testing typically involves producing a well with a temporary completion, recording pressure, temperature and multiphase flow rates, and acquiring representative fluid samples.

Drillstem testing is especially challenging in reservoirs with high fluid viscosity, low reservoir strength and the presence of emulsions. To



^ Surface equipment for testing a heavy-oil well in Brazil. By including the PhaseTester Vx multiphase well testing technology, accurate three-phase flow measurements are possible. In conventional systems, flow is measured only after being separated by the separator. The orange line represents three-phase flow, with oil, water and gas. The separator outputs three individual phases.

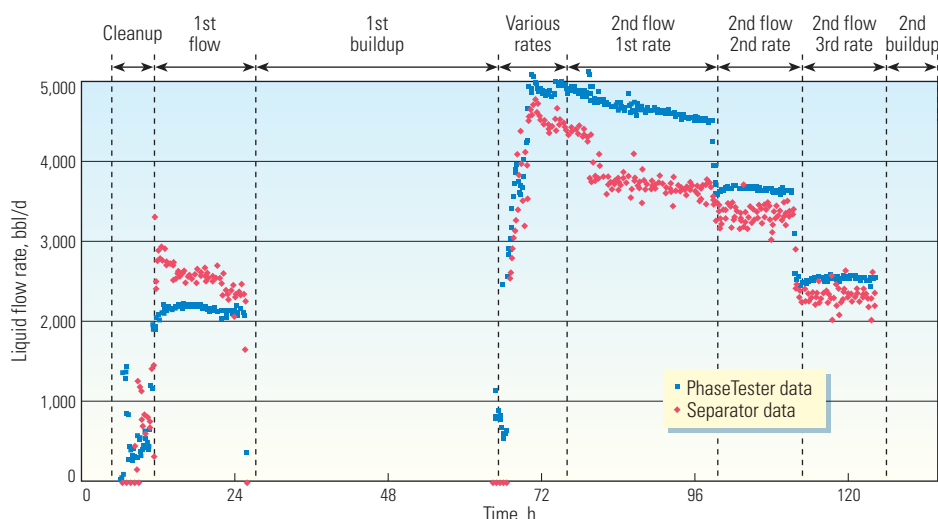
overcome these challenges, Schlumberger engineers devised and implemented a testing scheme that integrates high-resolution pressure and temperature sensors for monitoring fluid phase behavior, ESPs for fluid lifting, multiphase flowmeters for flow-rate measurements and separators for phase separation and sampling. Test efficiency has been enhanced by real-time data transmission, allowing faster and better decision making.

Using this combination of hardware and best practices, Schlumberger engineers have performed DSTs in more than 20 heavy-oil exploration wells offshore Brazil, with successes in extraheavy oil of 9°API and viscosity as high as 4,000 cP [4 Pa.s].

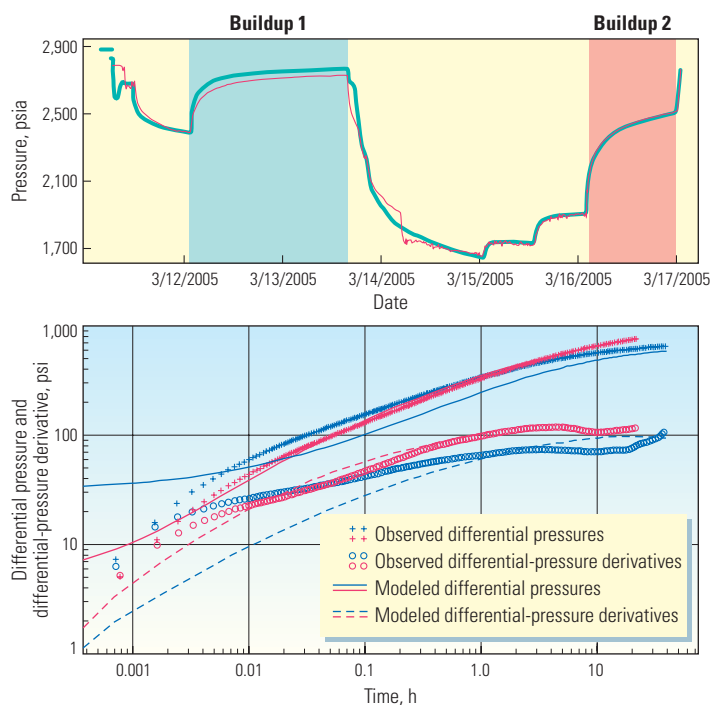
In one case, Devon Energy wanted to characterize a heavy-oil reservoir in the Macaé formation, a loosely consolidated carbonate grainstone in the Campos basin offshore Brazil. The Macaé formation was a potential candidate for acid stimulation, but core analysis indicated that deconsolidation following acid stimulation could lead to borehole instability.³⁴ The variable permeability, with higher values in the upper portion of the completion interval—in some zones exceeding 1 darcy—could make it difficult to adequately divert acid throughout the entire completion interval. The heavy crude oil of 17 to 21°API, with viscosity ranging from 50 to 90 cP [0.05 to 0.09 Pa.s], also raised concerns about compatibility with stimulation fluids. The well was perforated, and then, to ensure optimal fluid placement, was stimulated with VDA Viscoelastic Diverting Acid.³⁵ The acidizing results were positive and the well exhibited good diversion and cleanup after treatment.

Following acid treatment, the well was tested using Schlumberger heavy-oil DST best practices. This included real-time monitoring and PhaseTester portable multiphase periodic well testing equipment (previous page, bottom). The compact PhaseTester system combines a venturi mass-flow measurement with measurements of dual-energy gamma ray attenuation and fluid pressure and temperature to calculate gas, oil and water fractions.³⁶ PhaseTester oil flow-rate results have proved to be more accurate and more stable than flow-rate measurements made by traditional phase separators (top right).

Increased accuracy and stability result in more confident interpretation of DST data. In this Devon well, interpretation of pressure-transient data from the test separator results in a discrepancy between modeled and observed pressures and derivatives (bottom right). However, interpretation of the PhaseTester



▲ PhaseTester oil flow-rate measurements (blue) for Devon Energy in Brazil, showing more stability than flow-rate measurements made by traditional phase separators (red). Flow rates are in barrels per day at stock-tank conditions.



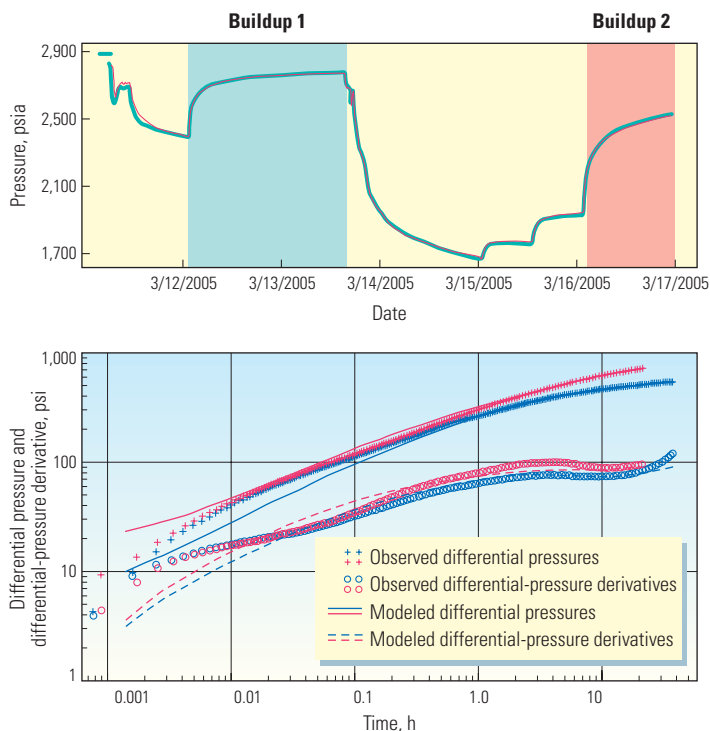
▲ Interpretation of pressure-transient data using production rates from the separator. The well-test history plot (top) shows discrepancies between observed pressures (green) and the modeled curve (red). In the log-log diagnostic plot (bottom) of the pressure and its derivative for the second buildup period (blue) and the third buildup period (red), the modeled curves for the pressure (solid curves) and the derivative (dashed curves) show large differences from the observed data.

33. Alboudwarej H, Muhammad M, Dubey S, Vreengoor L and Saleh J: "Rheology of Heavy-Oil Emulsions," paper SPE/PS-CIM/CHOA 97886, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, November 1–3, 2005.

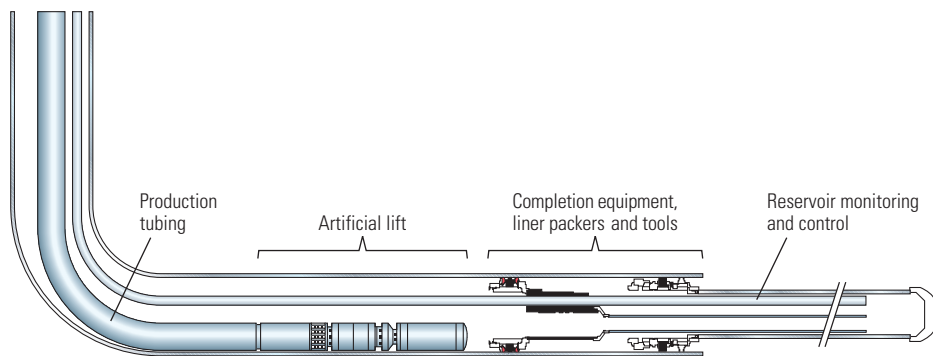
34. Lungwitz BR, Hathcock RL, Koerner KR, Byrd DM, Gresko MJ, Skopec RA, Martin JW, Fredd CN and Cavazzoli GD: "Optimization of Acid Stimulation for a Loosely Consolidated Brazilian Carbonate Formation—Multidisciplinary Laboratory Assessment and Field Implementation," paper SPE 98357, presented at the SPE International Symposium and Exhibition on Formation Damage and Control, Lafayette, Louisiana, USA, February 15–17, 2006.

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Lungwitz et al, reference 34.
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▲ Interpretation of pressure-transient data using production rates from the PhaseTester system. The well-test history plot (*top*) shows a good match between observed pressures (green) and the modeled curve (red). In the log-log diagnostic plot (*bottom*) of the pressure and its derivative for the second buildup period (blue) and the third buildup period (red), the modeled curves for the pressure (solid curves) and the derivative (dashed curves) show good matches with the observed data.



▲ A proposed completion for a horizontal CSS or SAGD well. Thermal liner hangers provide pressure-tight seals to increase effectiveness of steam injection. The REDA Hotline 550 artificial lift system operates continuously at up to 550°F internal motor temperature. Distributed temperature sensing (DTS) systems monitor temperature changes during steam injection and oil production.

pressure-transient data results in a good match between observed and modeled pressures and derivatives (*left*). The models underlying the two interpretations have permeabilities that differ by 16%. The permeability inferred from the PhaseTester data also agrees well with permeability from scaled-up core measurements.

Constructing and Completing Heavy-Oil Wells

Wells in heavy-oil reservoirs present a variety of well-construction and completion complexities. These include drilling stable boreholes in weak formations, accurately landing horizontal wells, designing tubular systems and durable cements for wells that undergo temperature extremes, and installing sand-control, completion and artificial lift equipment that must operate efficiently under the harshest conditions. All these operations benefit from an integrated engineering approach that can draw on global experience to provide solutions to new heavy-oil problems.

Wells that experience extreme variations in temperature, such as in CSS and SAGD projects, require specialized, high-performance completion equipment. High temperatures and temperature variation can cause common elastomers to fail. This results in broken seals, allowing pressure and fluids to escape up the casing, increasing the potential for casing corrosion and reducing effectiveness of steam injection.

Recently, Schlumberger engineers developed nonelastomeric systems capable of operating at cycled temperatures up to 650°F [343°C] and pressures up to 21 MPa [3,046 psi]. These systems maintain pressure integrity while allowing deployment of reservoir monitoring and control equipment (*left*).

Schlumberger high-temperature thermal liner hangers have been used in the Cold Lake field, where a major operator in Canada has been piloting a horizontal-well CSS program.³⁷ With customized liners and pressure-tight seals at the top of the liner, the operator has been able to achieve good steam conformance—steam intake spread evenly over the length of the horizontal well—verified by time-lapse seismic surveys over the pilot area.

SAGD wells also need downhole equipment with high temperature ratings. These wells require high build rates, proximity control between injector and producer, flexible cement, sand control, and liner hangers, packers and artificial lift equipment capable of operating at temperatures that may exceed 280°C [536°F].

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39. Krawchuk P, Beshry MA, Brown GA and Brough B: "Predicting the Flow Distribution on Total E&P Canada's Joslyn Project Horizontal SAGD Producing Wells Using Permanently Installed Fiber Optic Monitoring," paper SPE 102159, prepared for presentation at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 24–27, 2006.

Steam generation is approximately 75% of the operating expense of a SAGD well. Reducing the steam/oil ratio (SOR) while maintaining production rate is key to improving operation profitability (right). Reducing steam input saves energy costs, decreases produced-water volume and treatment expenses and cuts down on CO₂ emissions.

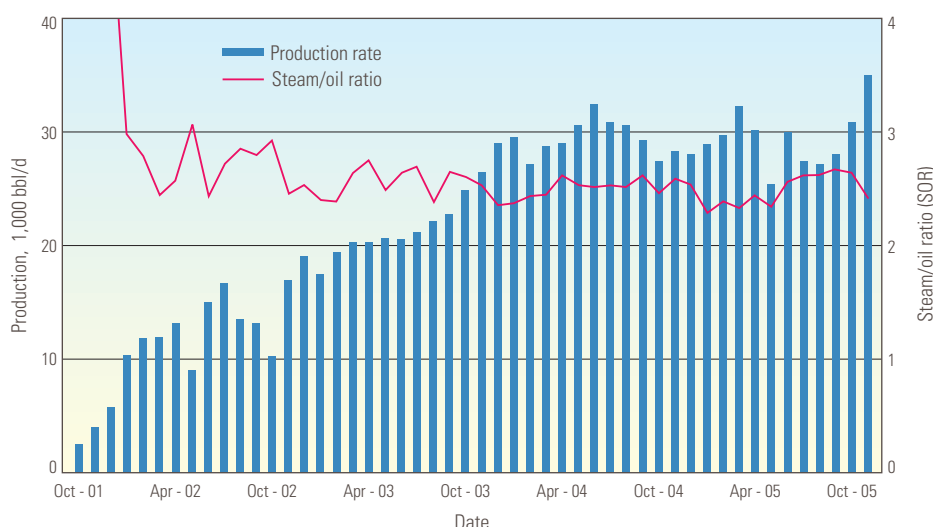
An important component in the effort to reduce SOR is the REDA Hotline 550 high-temperature electrical submersible pump system, rated to run continuously at up to 550°F [288°C] internal motor temperature, or 420°F [216°C] bottomhole temperature. Its high-temperature thermoplastic motor-winding insulation was initially developed and patented for geothermal and steamflood wells. The complete system is designed to compensate for variable expansion and contraction rates of the different materials used in the pump design.

Use of an ESP allows the reservoir to be produced at a pressure that is independent of wellhead pressure or separator pressure, increasing the quality of steam that can be injected. This can decrease the SOR by 10 to 25%, saving about US\$ 1.00 per barrel of oil produced. In addition, the Hotline 550 ESP has excellent reliability statistics; the longest running installation has been operating for 844 days. The Hotline 550 ESP is used by a number of Canadian operators, including Encana, Suncor, ConocoPhillips, Nexen, Total, Husky and Blackrock.

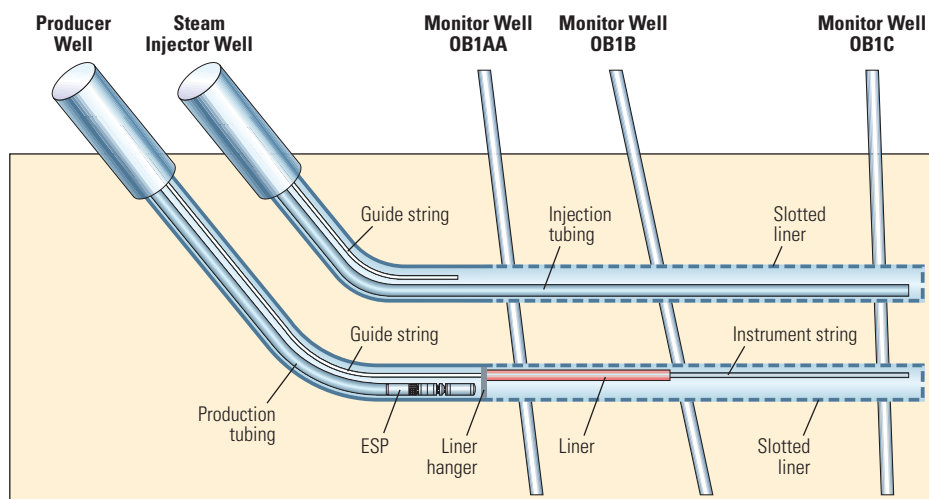
Monitoring Heavy-Oil Recovery

Understanding fluid flow in heavy-oil reservoirs is important for optimizing recovery methods, especially when heat is required to reduce viscosity and mobilize fluids. Several techniques have been developed, including distributed temperature sensing (DTS) systems, permanent pressure gauges, crosswell seismic and electromagnetic surveys, microseismic techniques and time-lapse seismic monitoring.³⁸

In 2004, Total E&P Canada installed an optical-fiber DTS system along a pilot SAGD production well to monitor temperature during production startup in the Joslyn field in Alberta, Canada.³⁹ The reservoir produces from the McMurray formation, which is mined for bitumen in the eastern part of the lease. In the western part, bitumen in the 50-m interval is heated by injection of steam and pumped to surface.



^ Decreasing the steam/oil ratio (SOR) while maintaining or building production rate. Reducing the SOR decreases the energy required to heat heavy oil, lowers the volume of water produced and also reduces water-treatment expenses. [Data are from Encana Investor Day, November 7, 2005 <http://events.onlinebroadcasting.com/encana/110705/pdfs/oilsands.pdf> (accessed July 28, 2006).]



^ Total E&P Canada SAGD pilot project, with producer-injector SAGD pair of horizontal wells and three monitor wells to record temperatures in the injector-producer region.

Correlating temperature change with viscosity and flow rate, especially when the injector-producer region is first warming up, helps reservoir engineers modify steam injection to ensure that enough heat reaches the entire intrawell region. In addition to the fiber-optic temperature-sensing system in the producing

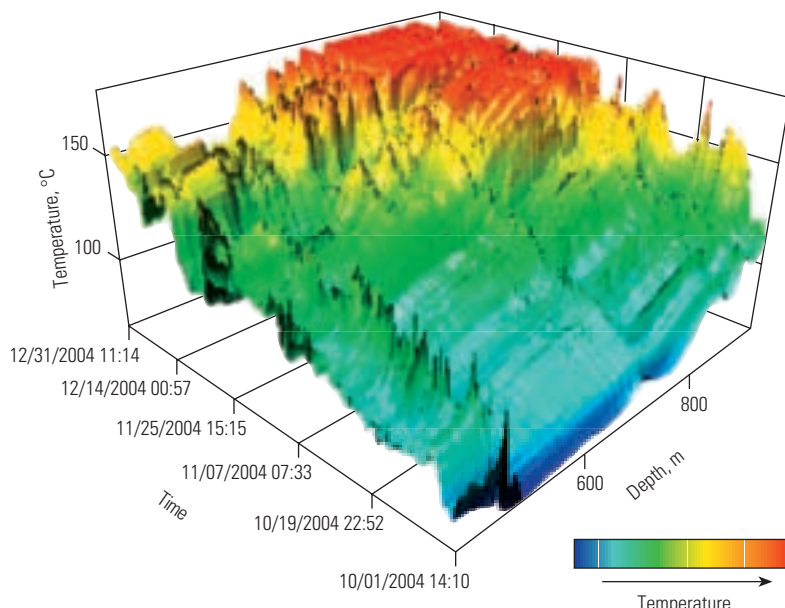
well, the pilot project included three observation wells that penetrated the injector-producer region within 1 to 2 m [3 to 7 ft] of the SAGD wells (above). Observation-well temperature measurements were recorded by thermocouples over a 45-m [148-ft] interval.

To initiate the SAGD process, steam was injected into both wells for several months to reduce bitumen viscosity. In September 2004, a pump and DTS instrumentation string were placed in the producer, and production began while steam injection continued in the injector with a bias toward the toe. DTS data acquired from October through December show a general warming of the injector-producer region, but one zone near the heel of the well did not follow the trend (right).

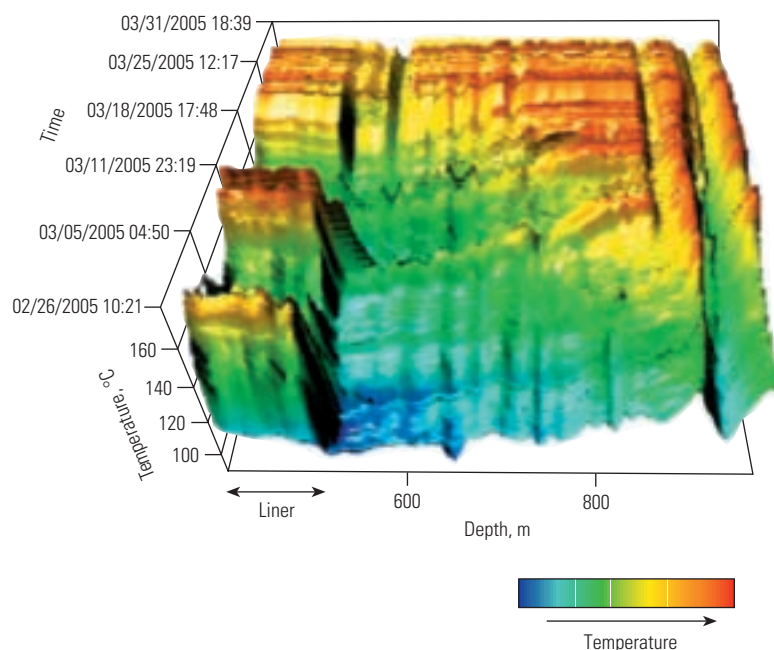
In January 2005, the pump was replaced with an ESP. During the workover, steam injection halted and the DTS string was temporarily removed. A liner was also installed, and the DTS string was reinserted. Then steam injection resumed, concentrating on the heel of the injector. The new DTS data reveal rewarming of the injector-producer region (below right).

Closer inspection of the DTS data acquired after the workover shows an unexpected oscillation of up to 20C° [36F°] (next page, top). In comparison, DTS data prior to the workover show little such fluctuation. It is believed that the temperature oscillation in the postworkover data is caused by spiraling of the coiled tubing string that contains the DTS instrumentation. Before workover, the DTS string was probably lying along the bottom of the slotted liner. However, during workover, the string was reinserted, and buckled inside the slotted liner.

The observed temperature oscillation corresponds to temperature values seen at the top and bottom of the producing well. The heated bitumen is up to 20C° hotter along the top of the horizontal producer than at the bottom. The observation-well temperature data acquired in Well OB1C before and after the workover also indicate that a significant temperature gradient can exist across the cross section of the producing well (next page, bottom). Interpreting temperature data therefore requires knowledge of the position of the temperature sensors in the wellbore. The continuous set of measurements provided by DTS instrumentation helped clarify the well's performance.



^ DTS data acquired for three months starting in October 2004, showing warming of the injector-producer region. Depth increases from the heel to the toe. One zone near the heel of the well did not warm as much as the rest of the intrawell region.



^ DTS data acquired after the workover, showing rewarming of the injector-producer region.

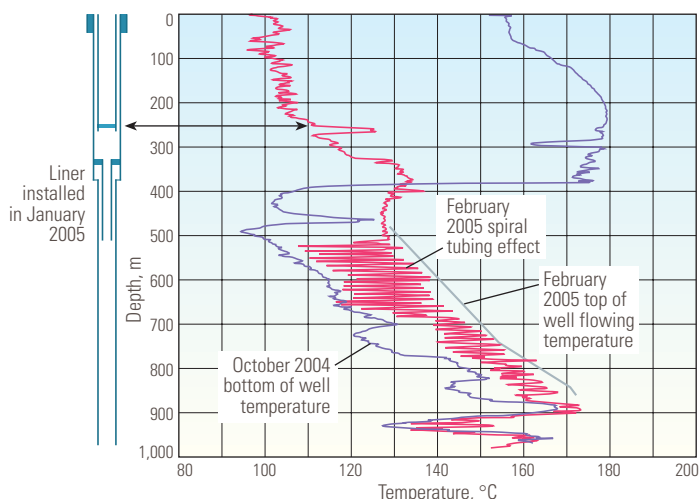
40. Belani A: "It's Time for an Industry Initiative on Heavy Oil," *Journal of Petroleum Technology* 58, no. 6 (June 2006): 40, 42.

41. Alberta Chamber of Resources, reference 4.

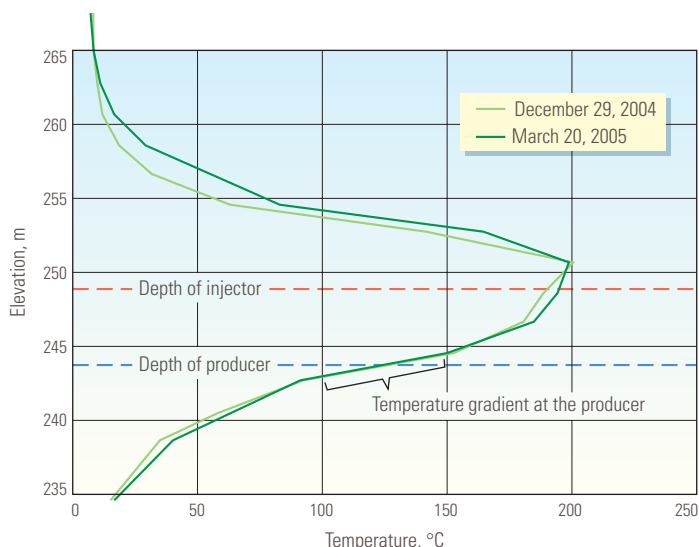
42. Freed DE, Burcaw L and Song Y-Q: "Scaling Laws for Diffusion Coefficients in Mixtures of Alkanes," *Physical Review Letters* 94, no. 6 (February 17, 2005): 067602.

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▲ Close-up of DTS data acquired after the workover, showing an high-frequency oscillation of up to 20°C (red curve). In comparison, DTS data from before the workover are much smoother (blue curve). The temperature oscillation in the data acquired after the workover is caused by spiraling of the DTS instrumentation. The temperature oscillation represents the difference in temperature between the top and bottom of the borehole.



▲ Temperature data recorded in an observation well, showing the high temperature at the level of the injector and the large temperature gradient at the level of the producer.

Moving Ahead in Heavy Oil

With heavy-oil reserves so abundant, companies that currently concentrate on production of conventional oils are entering the heavy-oil arena, joining companies that have produced heavy oil for decades.⁴⁰ These newcomers may bring new technologies, helping to fill technology gaps that have been identified by long-time producers and other organizations. For example, the Alberta Chamber of Resources has compiled a list of advances necessary to allow production from oil

sands to reach 5 million bbl/d [800,000 m³/d], or 16% of North American demand by 2030.⁴¹ Achieving this vision will require investment in technology improvements for mining, in-situ recovery methods and upgrading.

For every advance made toward enhancing heavy-oil recovery methods, numerous new avenues point to directions needing more work. In the area of fluid characterization, scientists are trying to extract more information about oil chemistry and component structure from logging

and laboratory measurements. For example, progress is being made in linking NMR diffusion distributions with molecular chain lengths of crude oils.⁴² Researchers are working to add fluorescence measurements to current downhole fluid-analysis practices based on spectrometry, allowing more accurate fluid characterization and acquisition of continuous downhole fluid logs. Efforts are being made to standardize laboratory techniques, such as SARA analysis, so that results from different laboratories may be compared. Advances in understanding crude-oil's heaviest components—*asphaltenes*—have the potential to not only improve heavy-oil recovery, but also help solve flow-assurance problems in lighter oils.⁴³

Heavy-oil experts agree that there is no universal solution for evaluation and recovery of heavy oil. Some improvements, such as in log interpretation, may need to be customized for a particular region. In other cases—for example, the development of new materials that raise the operating temperatures of downhole completion equipment—successes may have widespread application. Still other developments, including advances in real-time monitoring, may come from the combination of methods already proven effective separately.

Another point of agreement is the need to continue to factor environmental concerns into the development of heavy-oil resources. In bitumen mining and current in-situ recovery projects, environmental and cultural considerations form important parts of the business model, including reclamation of mined areas, mineral recovery to make use of waste materials, minimization of water usage, issues related to indigenous peoples and reduction of greenhouse-gas emissions. New projects will have to be sensitive to these and other factors, including CO₂ emissions, preservation of permafrost and other fragile ecosystems and reduction of the energy expended to heat heavy oil.

If heavy-oil reservoirs have one advantage over their lighter counterparts, it is their longevity. Heavy-oil fields can produce for 100 years or more, as do the ones discovered in California in the late 1800s. By some estimates, the oil sands in Canada can produce for several hundred years. Investments made now will pay off long into the future. —LS