High Prices Boost Global Heavy Oil Activity

CO_2 is getting more attention.

Oil sand is fed to cyclofeeder at Syncrude's North mine. *Courtesy Syncrude Canada Ltd.*

Today's oil price is good news for heavy oil developers. But the past year has also brought new economic realities in the two biggest heavy oil resource countries — Canada and Venezuela — and increased scrutiny of environmental issues surrounding unconventional oil development.

The inclination is to call these challenges "non-technical." But all the challenges that heavy oil development faces will ultimately be dealt with through the development of new technology, said Kambiz Safinya, heavy oil theme director, Schlumberger.

GLOBAL ACTIVITY

One of the most significant economic events related to heavy oil during the past year was a doubling of heavy oil prices, Safinya said.

"That has increased the optimism around the world for heavy oil and reaffirmed Schlumberger's commitment to investing in heavy oil recovery technology."

The past year's dramatic increase in the price of heavy oil has increased interest in the resource almost everywhere. The one significant exception is in Canada, where limits on the availability of people and equipment prevented any significant increase in activity.

In the United States in recent months, infill drilling has picked up in heavy oil reservoirs in California and elsewhere. In Mexico, there is a sharp increase in activity in part because **Cantarell** field is rapidly declining and its output needs to be replaced.

In Venezuela, much of the current increase in drilling is for "cold production" operations, but it also is likely that several thermal pilot projects will be started.

Venezuela realizes that the secret to higher recovery rates is thermal processes, according to Safinya. The goal of achieving 20% recovery in the Faja region, for example, will likely not be possible with current methods.

"But for thermal methods it ultimately will be achievable. It's a matter of selecting the right method for each reservoir," Safinya said. "The main delays will be in the time and capital it takes to build up-graders."

In the Middle East, Oman is investing to slow the country's declining heavy oil production. And, in Kuwait and Saudi Arabia, some heavy oil activity results from an effort to diversify production. In these countries, developing heavy oil assets would also reduce the stress on conventional reservoirs and boost ultimate recovery, said Safinya.

The activity in Indonesia is aimed at reversing the decline in mature fields, and in China, robust oil demand requires the country to look at all possible sources, including its significant heavy oil deposits.

"Heavy oil will continue to be a very important resource," said Safinya. "Future challenges will be met through the further development of technology that uses conventional methods to develop unconventional reserves."

CANADIAN, US OIL SANDS

While current heavy oil production is only about 8 million b/d, between 500 and 1,000 billion bbl are considered recoverable with today's technology and prices. In Canada, the Alberta Energy Resources Conservation Board estimates Alberta's in-place oil sands reserves at 1.7 trillion bbl. More than 175 billion bbl are recoverable with current technology; with technical advances, 315 billion bbl could be recovered.

Oil sands production was 1.126 million b/d in 2006, according to the Alberta Department of Energy and could reach 3 million b/d by 2020 and 5 million b/d by 2030. In 2006, about 61% came from mining operations, the rest from *in situ* processes.

In early 2007, a survey by the Canadian Association of Petroleum Producers and the Regional Issues Working Group indicated the Alberta oil sands industry could spend C $110 billion on projects from 2007 to 2011, compared with C $47 billion during 1996 to 2006.

In the United States, the in-place tar sands resource is estimated at 60 billion to 80 billion bbl, according to the June 2007 US Department of Energy (DOE) report, "Secure Fuels from Domestic Resources — The Continuing Evolution of America's Oil Shale and Tar Sands Industries."

About 11 billion bbl may ultimately be recoverable, according to the report. How fast the resource might be developed depends not only on oil prices, but on access to federal lands. Based on current price forecasts, the DOE report said US tar sands production in 2025 will not be more than 250,000 b/d.

US tar sands are "generally leaner in grade, less uniform in quality, and have higher sulfur content" than Canadian oil sands, according to DOE. US tar sands are typically hydrocarbon-wet rather than water-wet.

Utah has about one-third of the US tar sands resource; most of the rest is in Alabama, Texas, California, and Kentucky.

The past year also brought progress on a new connection between Canadian heavy oil supply and the US market.

Altex Energy Ltd.'s Chief Executive Officer Jack Crawford said in late March that Altex Energy's pipeline to connect northern Alberta crude with Gulf Coast refineries will be a 36-in. line with an initial capacity of 425,000 b/d.

"We're in fairly advanced discussions with enough players with enough volume that we think (the volume) is there," he said.

If the process gets finalized in "the next short while," the line could be in operation by late 2012. "The objective is to synchronize the startup with the transportation plans of our customers," according to Crawford.

OPTIMIZING RECOVERY

Both oil sands mining and several *in situ* heavy oil production techniques — steam-assisted gravity drainage, cyclic steam stimulation, combustion, and others — offer options for choosing the best recovery method.

That choice depends heavily on accurate characterization and modeling of the reservoir and its fluids.

"Simulation is even more important for heavy oil than for conventional oil," Safinya said. "It is much more expensive to drill and test a well than to simulate it."

Today's simulation capabilities can help design a production system that will create well paths and drainage patterns that optimize production throughout the life of the field. Reservoir simulators need to be able to handle detailed nonlinear geo-mechanical variables across the reservoir at a scale as small as 3 ft (1 m).

With a thorough understanding of the reservoir and its contents, intelligent completions can monitor and control flow into and out of the well bore.

Schlumberger's technologies to plan and design production strategy aimed at improving heavy oil recovery include micro-seismic technology and a specially calibrated nuclear

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magnetic resonance tool. Fiber optic sensor technology can measure temperature distribution along a well, and ultimately work with a variety of completion systems to improve steam conformance.

NEXT GENERATION

There is a risk that the CO_2 issue will have a significant negative impact on future oil sands development, said Eddy Isaacs, executive director, Alberta Energy Research Institute (AERI).

"Canada is paying a lot of attention, at both the federal and provincial levels, to carbon capture and storage," he said. An important goal of AERI's focus on next-generation technologies is to develop those with smaller CO_2 footprints and to learn how to capture CO_2.

"The CO_2 component is part of all of these technologies," Isaacs said.

In December 2007, AERI invited expressions of interest in the next generation of carbon capture processes, including new concepts for CO_2 separation, dehydration, and compression from stationary and mobile sources.

In early March, AERI invited proposals for "well-to-wheel" Life Cycle Assessment comparisons of North American and imported crudes, including oil sands crude.

AERI's key strategies for developing next-generation oil sands technologies involve

- Adding value by producing refined products and petrochemicals;
- Reducing CO_2 emissions;
- Reducing water use;
- Reducing natural gas use; and
- Improving energy security.

"We are looking at technologies that will satisfy all these drivers," said Isaacs.

AERI is keen on two of what it considers next-generation recovery technologies – electric heating and *in situ* combustion, specifically "gravity stable" combustion techniques like the toe-to-heel air injection process now being pilot tested.

Whether electric heating offers a benefit in reducing CO_2 emissions depends on its fuel source. But it does offer lower water requirements. And *in situ* combustion injects oxygen or "enhanced air" instead of steam, also reducing water use. In addition, the fuel is in the reservoir. Some reservoirs can also store the part of the CO_2 resulting from combustion.

Electric heating has shown some encouraging results, according to Isaacs. The technology operates differently in oil sands than in oil shale; in oil sands, the oil starts to flow and electric heating enhances flow behavior.

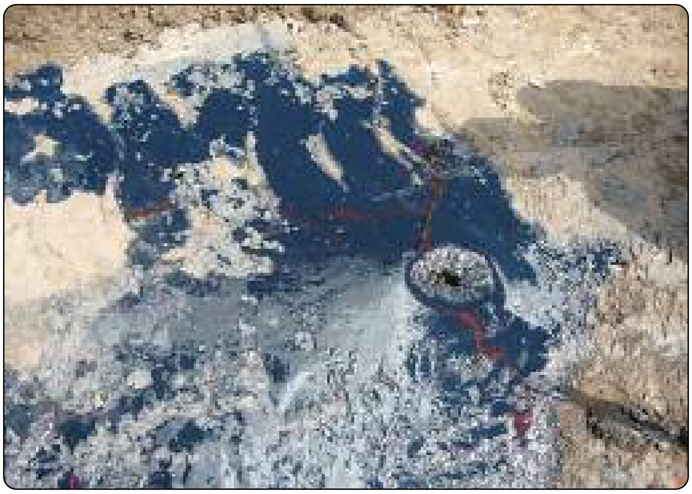
"It does require a water-wet reservoir," said Isaacs. "If there is a continuous water film, then this is a good process."

E-T Energy Ltd.'s first test of its E-T-DSP™ electrical heating technology was successful, and the project is now in a more commercial Phase II, using longer distances between wells.

AERI also has plans to meet soon with another company pursuing electric heating technology, Electro Petroleum Inc. It has a project in Saskatchewan and has demonstrated its Electrically Enhanced Oil Recovery process in an 18-month field test.

In its Hydrocarbon Upgrading Demonstration Program, AERI also has six projects in various stages, said Isaacs. One is a pilot that will test the use of Alberta petroleum coke and Alberta coal in a catalytic gasification process.

"We think it is a great technology." Isaacs said. "It still is in a very early stage of development, but we think it will go to another stage." •



Oil rises to the surface in the Horizon mine. *Courtesy Canadian Natural Resources Ltd.*