oilsandsreview™

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UNLEASHED

How tiny Osum is pushing SAGD performance well beyond the record of a global supermajor

PLUS:
What does the future hold for in situ combustion technology as we say goodbye to THAI?

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Shale oil drillers dodge the downturn by packing up their rigs, while the oilsands toughs it out with long-term cost cuts

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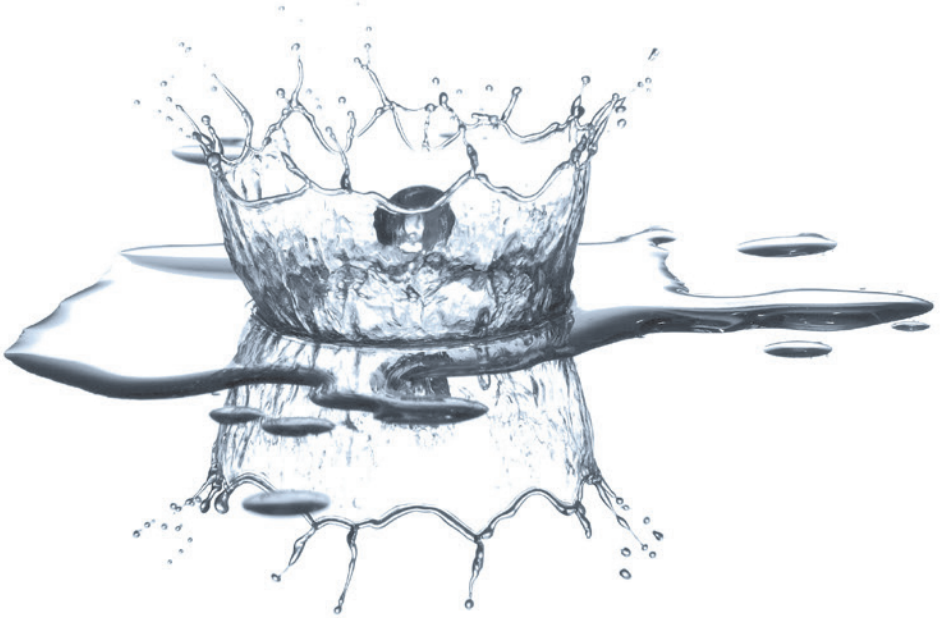
Why today's downturn hurts, but it's not like 1986



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VOLUME 10 | NUMBER 10 | OCTOBER 2015

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ON THE COVER:

It's been just over a year since Osum took over the Orion SAGD project from Shell, but the company appears to have cemented it into a new trajectory.

PHOTO: DEBORAH JAREMKO

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editor's note

INSIGHTS INTO OILSANDS TRENDS

Ten years ago, in a market absent the momentous growth of light tight oil, junior oilsands producers had a lot of room to move. Capital was relatively easy to come by, and the experience of commercial SAGD was so fresh that speculation about new projects came with a good deal of trust. Not anymore.

Long before the oil price nosedive, the party was over. The market had lost its broad confidence in the ability of producers, especially juniors, to execute SAGD projects within forecast cost boundaries and to operate them at the levels of efficiency that had been projected. Notwithstanding the well-documented capital cost challenges, SAGD operationally doesn't always work as planned. The lost opportunity for the oilsands sector is ongoing and significant, particularly as the line of sight to WTI pricing north of $70/bbl is fragile at best.

But there are cases that show that a SAGD project operating with low utilization and high steam to oil ratios (SORs) can be fixed. Osum Oil Sands' brief experience thus far at Orion is one of these cases.

In the approximately 14 months since Osum acquired the Orion SAGD project from Royal Dutch Shell, the company has been able to widely apply the optimization strategy that the supermajor cautiously started, resulting in sustained production increases of more than 2,000 bbls/d and average SOR reductions in the order of two points per barrel. It's a small project, but it is a major achievement—perhaps even more so because as a new and tiny operator, Osum is being measured alongside SAGD giants.

Every company, and every project, is different. Perhaps Osum has it relatively easy at Orion; as an outfit with one operated asset, the company is able to take rifle shots with its resources. And maybe the fixes—starting in the reservoir with well recompletions and now moving to debottlenecking at the plant—are relatively simple compared to what other challenged SAGD installations face. But it is important to recognize bright lights in the oilsands constellation. Especially when they can inspire confidence, the most sought after asset of all.

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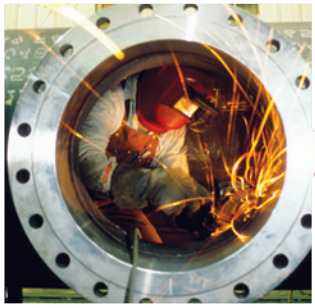
next *issue*



Special supply chain edition
The real solutions to surviving during low oil prices

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Web extras with the October 2015 edition

- **Latest financial results analysis Canoils:** Oilsands opeators begin recovery following a rough first quarter

in review

OCTOBER 2015 // ROUNDING UP THE LATEST OILSANDS NEWS

The mid-July pipeline spill at Nexen's Long Lake SAGD project has now resulted in the suspension of 95 pipelines carrying various substances at the facility. The AER says the lines will remain shut in until Nexen provides evidence the equipment will be operated safely.

AER SUSPENDS PIPELINE OPERATIONS AT LONG LAKE AFTER NON-COMPLIANCE REPORTED

The Alberta Energy Regulator (AER) has issued a suspension order to Nexen due to pipeline non-compliance at the Long Lake SAGD project. The order, issued on August 28, directs the company to immediately suspend 15 pipeline licences, which requires shut in of 95 pipelines that are carrying natural gas, crude oil, salt water, fresh water and emulsion. The company must also provide sufficient documentation to assure the AER that these lines can be operated safely.

In mid-July, a pipeline spill at Long Lake resulted in release of approximately 31,500 barrels of bitumen emulsion into the environment.

Nexen says that it initiated an internal audit of its corporate pipeline integrity management system in early July 2015, which identified a number of non-compliances primarily related to documentation of maintenance activities. On August 25, Nexen voluntarily self-disclosed all non-compliances to the AER.

"As stated in our self-disclosure to the AER, Nexen considers regulatory compliance to be of the utmost importance in our operations, and we are committed to continuous improvement, regulatory compliance and cooperation with the AER," the company says.

The suspension order followed the self-disclosure.

"Given that this company has already had a pipeline failure at this site, the AER will not lift this suspension until Nexen can demonstrate that they can be operated safely and within all regulatory requirements," says AER president and chief executive officer Jim Ellis. "We will accept no less than concrete evidence."

The level of non-compliance or the enforcement action that Nexen may face will be determined by the AER as part of the investigation into this matter.

The AER investigation into Nexen's Long Lake pipeline incident is ongoing. Once the investigation is complete, the AER will publish its findings.

Fort McMurray to host new MBA program

Downtown Fort McMurray.

Professionals in the heart of the oilsands will soon be able to access an MBA program without leaving town, according to a recent report by *Fort McMurray Today.*

The paper says the Executive MBA Americas program is a joint program between Cornell University in Ithaca, N.Y. and Queen's University in Kingston, Ont.

"It will teach local professionals business management skills in a boardroom setting via video conference with professors at Cornell and Queen's.

"The initiative came about through mutual interest from the Casman Group of Companies and the two universities in seeing an MBA program in Fort McMurray. Casman learned of the joint Cornell-Queen's program and began discussions with both universities to bring the program to Fort McMurray."

The Fort McMurray MBA classes are expected to begin in late June 2016.

PHOTOS: (TOP) NEXEN; (BOTTOM) REGIONAL MUNICIPALITY OF WOOD BUFFALO

minus 280k
barrels per day

REDUCTION EXPECTED BY IHS IN ITS NEWEST OILSANDS PRODUCTION FORECAST BETWEEN 2015-20 DUE TO THE MARKET DOWNTURN

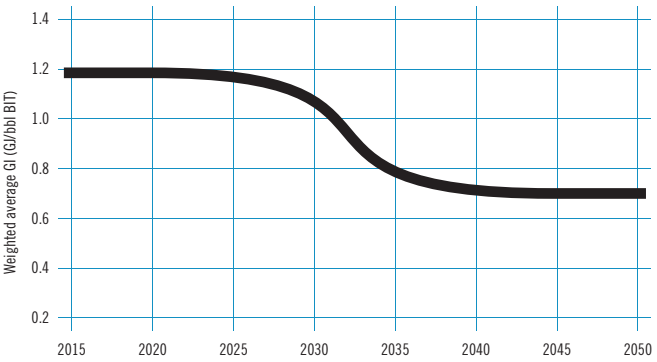
28.7%

REDUCTION IN GHG EMISSIONS CERI SAYS THE OILSANDS INDUSTRY CAN REALIZE THROUGH INCREASED ENERGY EFFICIENCY WHILE CONTINUING TO GROW PRODUCTION

30

BLUE HERONS WERE FOUND DEAD IN A RUNOFF POND AT THE SYNCRUDE MILDRED LAKE FACILITY IN EARLY AUGUST

Transition from business as usual to increasing energy efficiency (GJ/bbl)[3]



Source: CERI

CERI says the oilsands industry could significantly reduce energy use per barrel by applying technologies that improve the energy efficiency of operations.

CERI: oilsands can grow while meeting GHG targets

A new study has found that there are options available to continue oilsands production and production growth while meeting greenhouse gas emission targets, whatever they might be.

"I think it's good news for Canada because the [oilsands] industry creates a lot of economic wealth for the country, and it's a good thing if we can continue that economic activity while addressing some environmental challenges," says Allan Fogwill, president and chief executive officer of the Canadian Energy Research Institute (CERI), which prepared the study.

CERI's report says that the growth of the industry is not necessarily limited by environmental policies because there are solutions to meet those policies while continuing growth in the sector, said Fogwill.

"We're looking at improving the efficiency of technologies such as pumps and motors and of processes such as moving towards solvent extraction, and putting a number of those various, more efficient technologies and processes in place across the sector will get you some significant reductions in energy use and therefore greenhouse gas emissions."

For its study, entitled *Oil Sands Industry Energy Requirements And Greenhouse Gas Emissions Outlook (2015-2050)*, CERI developed six scenarios to explore the impact of different parameters. The business-as-usual case sees production increasing to 4.55 million bbls/d by 2050.

Under the constrained-growth scenario, cumulative production volumes for oilsands from 2015 to 2050 are 32.8 per cent lower compared to the business-as-usual scenario, cumulative energy use decreases by 32 per cent, and cumulative GHG emissions decrease by 31.7 per cent.

However, in all four other scenarios, oilsands production continues to grow to 4.55 million bbls/d. Most notably, under the increased-energy-efficiency scenario, increasing energy efficiency results in a 29.5 per cent decrease in cumulative energy used compared to the business-as-usual scenario, and subsequently, a 28.7 per cent decrease in cumulative GHG emissions.

"Massively discounted" Kearl crude sent by tanker to Delaware

According to a recent report by Reuters, U.S. oil refiner PBF Energy is shipping a cargo of crude from western Canada to supply its plant on the other side of the continent, "a rare move traders say is a sign steep discounts for oilsands are upending age-old trade routes."

Reuters says that sending the cargo by tanker on a 7,000-mile trek through the Panama Canal to the company's plant in Delaware is remarkable for many reasons.

"East Coast refiners usually receive crude by rail from domestic shale plays or by oil tanker from locations including West Africa, eastern Canada and Mexico.

"Western Canadian crude comes into the United States by train or pipeline, rarely by boat, and even more unusually to the East Coast."

Syncrude identified 30 deceased blue herons in a runoff pond at its Mildred Lake facility.

PHOTO: STANLEY PARK ECOLOGICAL SOCIETY

Syncrude issued AER environmental protection order in blue heron deaths

The Alberta Energy Regulator (AER) has issued an environmental protection order to Syncrude Canada in response to approximately 30 blue heron fatalities at the Mildred Lake oilsands mine site north of Fort McMurray.

The remedial order directs the company to collect water and soil samples from the site, publish daily public reports to the Syncrude Canada website and submit a final report to the AER within 30 days of the completion of all work.

An investigation by the AER is also underway, and its findings will be published once the investigation is complete.

In 2010, Syncrude was fined $3 million for negligence after 1,600 ducks died after landing on a company tailings pond in April 2008. Most of the money was contributed to wildlife and habitat conservation programs in northern Alberta.

in review

ROUNDING UP THE LATEST OILSANDS NEWS

Suncor president and chief executive officer Steve Williams.

Suncor says Line 9 approval process taking too long

Suncor Energy is growing impatient with the length of time it is taking for the reversal and expansion of Line 9 to be approved, a recent conference call heard.

"We've been disappointed by the [National Energy Board] process," Steve Williams, Suncor's president and chief executive officer, said in a conference call to discuss second-quarter results.

"Of course we completely support the need for stringent safety and environmental controls, but the length of this process, in our judgment, has been too long," said Williams. "I am optimistic that it's still coming; I still believe progress is being made even though the NEB have put very high standards, which I'm pleased that they have done, around that. We support them."

Enbridge's Line 9B Reversal and Line 9 Capacity Expansion Project will reverse the 639-kilometre segment of the pipeline between North Westover, Ont., and Montreal. It would also increase the entire Line 9 capacity from Sarnia, Ont., to Montreal to approximately 300,000 bbls/d from 240,000 bbls/d, and allow transportation of heavy crude.

The board approved Enbridge's application on March 6, 2014, subject to 30 conditions. Enbridge had already obtained approval to reverse the pipeline's flow for the section running between Sarnia and North Westover, in southwestern Ontario.

The Wood Buffalo Environmental Association says that the overall negative impacts of oilsands operations dust likely outweigh the positive neutralizing impacts on the boreal forest.

Oilsands operations dust neutralizes acid deposition impact on forest: WBEA study

The boreal forest near oilsands operations appears to be both endangered by associated air pollution and protected by industrial contaminants at the same time, says a recently released study from the Wood Buffalo Environmental Association (WBEA).

The study found alkaline dust—rich in calcium and magnesium—appears to offset the impact of acid dispositions on the surrounding vegetation.

"The major conclusion of the report is that the risk of adverse biological effects on the forest from acid dispositions is considerably less than what we thought it was 15 years ago when this whole long-term monitoring was established," Kevin Percy, executive director of WBEA, says.

"With the soil pH, for instance, which is one measure of acidification, there are some subtle changes in the levels, but nothing that is statistically significant over the 1998, 2004 and 2011 sample cycles."

The findings are part of *Assessing Forest Health in the Athabasca Oil Sands Region*, which summarizes 15 years of results from the WBEA's forest health monitoring program that determines the relationship between air pollutants and forest ecosystem function.

Percy emphasizes that the overall negative impacts of the dust likely outweigh the positive neutralizing impacts.

"Dust is really acting both in a sort of neutralizing way," he says, "but with the dust are also some other elements including heavy metals that are carried in that dust out to lakes, rivers and soils." The concern is that, at a high enough level, the heavy metal contaminants could pass a toxicity threshold.

Nonetheless, the WBEA study raises certain questions for environmental managers in industry and government about the risks associated with dust suppression, Percy notes.

Efficient dust suppression, for instance, could raise the level of acid disposition by removing the neutralizing effect of the dust itself.

"Biological systems are very dynamic," he says, "and they respond to many more than one input and stress connector at any one time. Changing one [factor] could well have a consequential effect on something else."

Black Diamond Group signs long-term renewal on workforce housing camp

Black Diamond Group, a provider of workforce accommodation and modular workspace solutions, recently announced that it has renewed a workforce housing camp contract in the SAGD region of Alberta's oilsands.

"We continue to work closely with our oilsands customers through this challenging commodity price environment," says Trevor Haynes, chair and chief executive officer of Black Diamond. "This contract is a great example where, by working closely with our customer and taking a flexible approach to meeting their needs, we have been able to retain their business."

The renewal for 448 beds is expected to generate revenue of $26 million over its two-year term. The contract includes an option to extend the term for one additional year at the same rates.

PHOTOS: (LEFT) SUNCOR ENERGY; (RIGHT) JOEY PODLUBNY

eyes on the oilsands

WHAT PEOPLE ARE SAYING ABOUT THE INDUSTRY IN THE MEDIA AROUND THE WORLD

"[U.S. president Barack] Obama has arguably done more for Iran's energy independence than he has for America's....

Throughout the Obama presidency, it's been hard to decipher his foreign policy. But I'd love to know how liberating Iranian oil for China and alienating next-door neighbor Canada fits into Obama's grand plan."

— Columnist **Rachel Marsden** commenting on the Obama administration's focus on a nuclear deal with Iran that would lift oil sanctions while at the same time blocking Canadian oil imports through Keystone XL. *The Baltimore Sun*, August 10.

"It seems like heresy today to call for a moratorium on oilsands development or any kind of control over this destructive industry. But if we are to gain back any respect in the international community we need to take a serious look at what we are doing to the planet because of our commitment to the oilsands."

— Columnist **Doug Cuthand**. *Saskatchewan Star Phoenix*, August 14.

Liberal leader: Justin Trudeau

Conservative leader: Stephen Harper

Green Party leader: Elizabeth May

NDP leader: Tom Mulcair

"WILL WE GET THE ENERGY DEBATE WE DESERVE [DURING THE FEDERAL ELECTION CAMPAIGN]? THE ISSUES ARE BOTH EMOTIONAL AND COMPLEX. THE MEDIA ARE UNDERINFORMED, AND THE VOTERS ARE IMPATIENT WITH LONG AND COMPLICATED ANSWERS. THE LEADERS BENEFIT FROM OBFUSCATION. SO DON'T HOLD YOUR BREATH."

— Columnist **Margaret Wente**. *The Globe and Mail*, August 10.

"There are no magic fixes for what ails Canada's economy. In a competitive world, we'll simply have to become efficient, productive—and yes, environmentally responsible—if our vital resource industries are to continue to sustain our comfy 21st century lifestyle.

That's the truth, whether the politicians want you to believe it or not."

— Columnist **Gary Lamphier**. *Edmonton Journal*, August 14.

PHOTOS: (TOP-LEFT) HUFFINGTON POST; (TOP-RIGHT) GREENPEACE; (PORTRAIT-1) HUFFINGTON POST; (PORTRAIT-2) CITY NEWS; (PORTRAIT-3) HUFFINGTON POST; (PORTRAIT-4) HUFFINGTON POST; (BOTTOM) NEXEN


Now's not the time to find out your work wear isn't as tough as you are.

SAYING GOODBYE

If in situ combustion is the extraction technique of choice in some parts of the world, why isn't it here?

By R.P. Stastny

TOUCHSTONE EXPLORATION'S July disposition of its Dawson asset is the latest evidence against the future of toe to heel air injection (THAI), the much publicized in situ combustion oilsands technology of the mid-2000s that fell off through unsuccessful piloting. But the demise of Petrobank (the predecessor to Touchstone) and its efforts to deploy THAI shouldn't be seen as a blemish on ISC, say the technical experts who are active in successfully implementing this technology internationally.

The typical response to this statement by western Canadian producers, however, seems to be something like this: "Blemish? You mean in situ combustion actually works somewhere?"

Well, yes. There are economic ISC projects as far away as Russia, Kazakhstan and India, and as close as the Williston Basin of North and South Dakota. The Alberta industry still doesn't fully appreciate this fact, nor that ISC works in all kinds of reservoirs, irrespective of depth, pressure, temperature, salinity, permeability or oil viscosity. According to ISC experts, the unit displacement efficiency of the technology is on average the highest of any enhanced recovery process, and it's more energy efficient than steam injection.

"There are no mysteries to unlock in ISC," says John Belgrave, president and chief executive officer of Belgrave Oil and Gas. "The technology works. It's just that some people don't get it."

Belgrave's expertise is sought after around the world. He is a former associate professor at the University of Calgary who worked with U of C's Robert Gordon Moore and Raj Mehta, two Schulich School of Engineering professors who co-lead the In Situ Combustion Research Group, which consists of 11 researchers and about 10 graduate students. The school is also home to a laboratory for testing in situ combustion described as the best in the world.

Alberta producers might not "get" ISC today, but they might start to as environmental pressures mount and a new, potentially much lower, oil price reality sets in. New production efficiencies will need to be found.

"[ISC] is profitable at these oil prices," Belgrave says. "There are ways to implement it. People don't know that. It has been demonstrated commercially and economically as a follow-up process to waterflooding and steam."

COMMERCIAL SUCCESS

When Petrobank was promoting THAI around 2006, the footnote in the sales pitch was that ISC is a proven technology that was already being used elsewhere. Strangely enough, the details of this never attracted much attention. For the record, here's the short list of ISC successes.

In Romania, the Suplacu de Barcau project has been operating since 1964 and continues to this day. It produces about 8,000 to 10,000 bbls/d. In India, the Balol and Santha oilfields started in situ combustion in 1994 and produce about 15,000 bbls/d.

The Indian success is a source of pride for the University of Calgary's In Situ Combustion Research Group, which has collaborated on the project since 1993.

"They are now at about 50 per cent recovery in one part of the reservoir and 53 per cent on another part of the reservoir," Mehta says. "Primary [recovery] was originally estimated at just six to eight per cent."

South of the border, the Williston Basin in the Dakotas has seen nine light-oil ISC projects since 1978. In 2008, Continental Resources's Cedar Hills North Unit in North Dakota was producing 11,500 bbls/d from ISC operations. "It was originally started by Koch Exploration Company in 1978," says Metha. "Then Harold Hamm, the billionaire who owns Continental Resources, took over from Koch."

Bellevue, La., has among the longest-running ISC projects. Oil was discovered there in 1921, and production peaked in 1923 at 7,000 bbls/d. In 1963, Getty Oil started an ISC pilot that in 1982 had 223 wells producing about 2,750 bbls/d. Today, Bayou State Oil Corporation continues to operate the project with modest production.

In Canada, ISC also has a rich history. Mobile Oil's Battrum, Sask., project, which saw economic ISC production from 1965 to 2003, is just the tip of the iceberg.

"Battrum produced about 8,000–10,000 bbls/d," Metha says. "When Exxon took over Mobil, they didn't want to have another technology, so they shut it down."

According to an Oil & Gas Journal report, total world oil production from ISC in 1992 was about 32,000 bbls/d from 26 reported projects: 4,700 bbls/d came from eight U.S. projects; 8,000 bbls/d from 10 projects in the former Soviet Union; 7,300 bbls/d from three projects in Canada and 12,000 bbls/d from five projects in Romania.

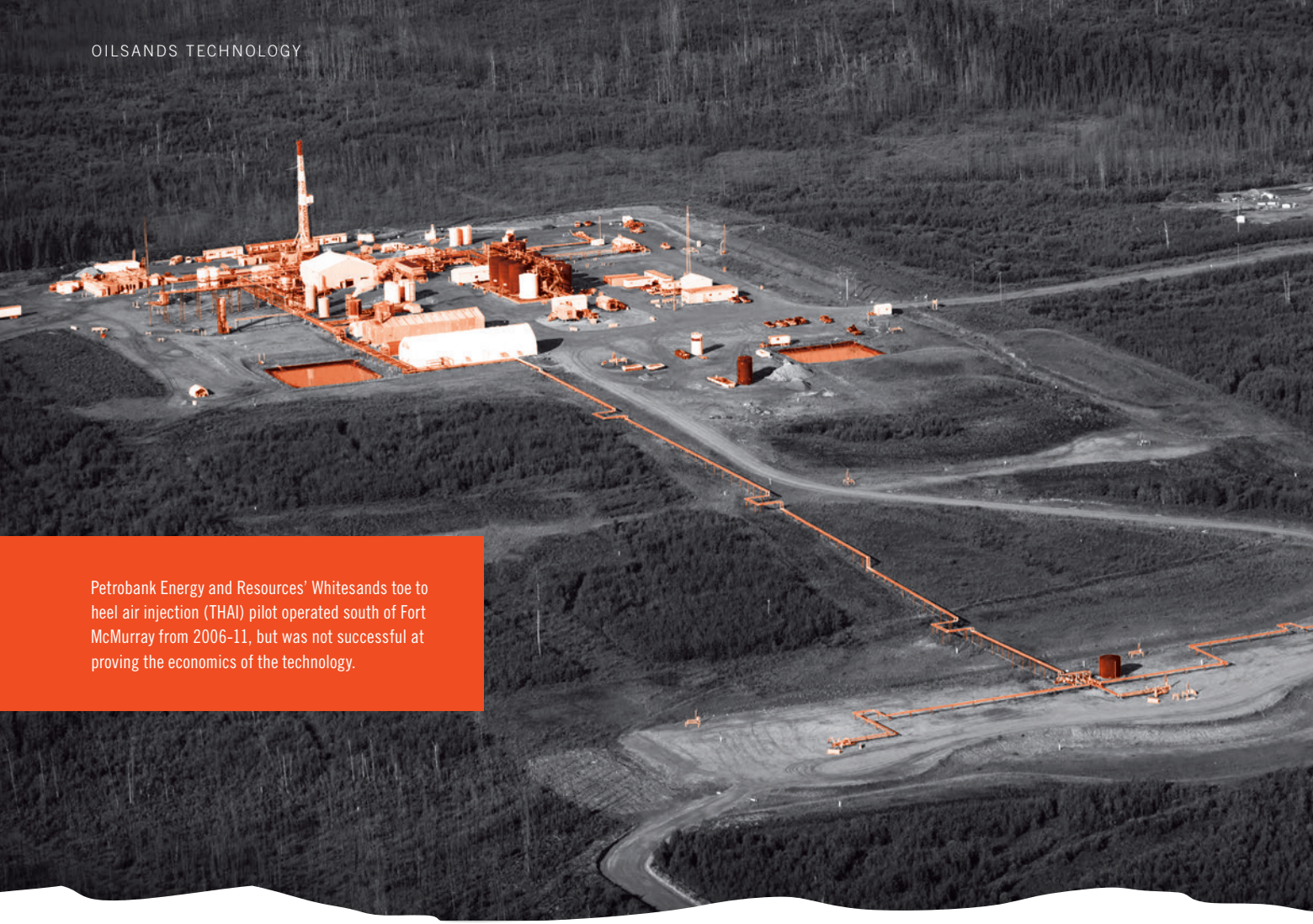
OVERLOOKED

Okay, so the technology works. But why isn't it in the oilsands?

The short answer is that historic ISC field tests have succeeded in the oilsands, however, bitumen is a more challenging application than lighter oil because very heavy oil reservoirs require preheating before the combustion process can effectively move bitumen. A bigger challenge, according to Moore, is that in western Canada, there always seems to be someone who thinks ISC is no good, "mostly people who read too much and know too little."

A general understanding of ISC has not emerged, partly because the technical literature on ISC is fragmented. This is partly because there have been numerous steps in the development of ISC over its 40-year development and partly because other technologies have overshadowed ISC.

Early tests in California, for example, ran into safety issues. The converted natural gas compressors that were initially used to compress air for the ISC process led to blow-by air in the compressor cylinders going directly into non-synthetic oil lubricant inside the compressors, which created peroxide that could explode. Early on, those safety concerns



Petrobank Energy and Resources' Whitesands toe to heel air injection (THAI) pilot operated south of Fort McMurray from 2006-11, but was not successful at proving the economics of the technology.

pushed the industry towards another technology that was being developed by Shell, steam injection. Steam took the lead, even as purpose-built air compressors allayed safety concerns in ISC.

Cyclic commodity price downturns and lower-hanging fruit took their toll on ISC. Early success in California ran into $0.63/bbl oil, Battrum into pro-rationing in the 1970s, and BP, which did important work in Canada on ISC, got shut in by the National Energy Program's subsequent low oil prices in he 1980s. In 1977, oil production from Prudhoe Bay, Alaska, had a dampening effect on the industry's interest in ISC similar to the impact the shale gas revolution had on Arctic gas development in Canada.

The application of ISC in very heavy oil reservoirs also took some time to figure out. When ISC was patented in 1923, it was originally intended for heavy oil because it was thought that high downhole temperatures would consume all the light oil. The early California tests proved that premise wrong. ISC worked fine in light oil, sending only 20–30 per cent of the oil up the stack.

ICS in Battrum produced 18-degree API oil, and in California heavy oil reservoirs, it was 14 degrees. In both cases, there was sufficient oil mobility for ISC (the warm California environment helped in the latter case). But in very heavy and cold reservoirs, such as in the Athabasca oilsands, ISC runs into problems in anything but short-interval well spacing designs.

"The combustion starts to move the oil, but you lose your gas saturation," Moore explains. "It's like a snowplow pushing snow. If you have a straight blade it piles up and up. In a heavy oil reservoir, the heavy oil will build a high liquids saturation, which then will cause you no end of grief trying to get the air in.

"You have to realize that ISC is a displacement process. As you push the hot oil out into the cold part of the reservoir, it still needs to get to a production well."

Belgrave is emphatic about this point. "Steam is a thermal process. It's more diffusive in nature. It heats by conduction and convection and so on, whereas combustion is a displacement process. People don't get that," he says.

Of Petrobank's THAI experiments, he says, "that team is to be commended for recognizing the potential benefits associated with combustion's high displacement efficiency; however, THAI is/was geometrically challenged. It was a very goodscience project that expanded the conversation and knowledge considerably, but it was conceptually flawed from a commercial standpoint."

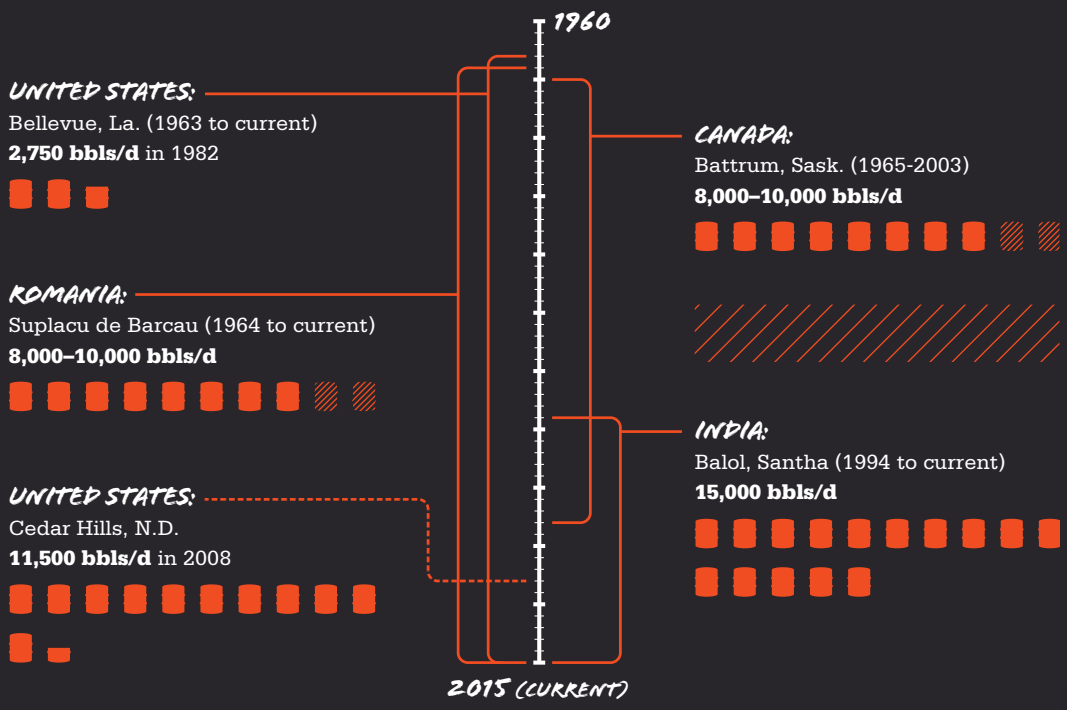
Belgrave continues, "SAGD uses well pairs, horizontal laterals. You can't do that with combustion from the get-go. It doesn't work in a bitumen situation without substantial preheating with steam. Steam will move vertically and migrate laterally. But combustion will only go where the flue gas goes. So if you have to vent the combustion process

PHOTO: PETROBANK ENERGY & RESOURCES

FIRED UP

Examples of successful in situ combustion projects throughout history

= 1,000 bbl/d



to the bottom well, that's where the combustion is going. It's not going to move out laterally."

MAKING IT WORK

ISC can work in the oilsands, but it needs to be implemented by people who have experience with the technology, Belgrave says. It also helps if the company can afford to take a longer a view of ISC development than typical public-company quarterly reporting affords.

Petrobank understood that in very heavy oil situations, combustion needs steam to condition the reservoir before injecting air to avoid the snowplow effect. It just didn't get the well geometry right. But the lessons learned in other heavy oil ISC applications worldwide can guide an effective well design in the oilsands. There is no need to reinvent the wheel if technical experts can learn from one another.

This is the approach India took before launching its ISC work in Balol and Santha. It consulted with U of C's In Situ Combustion Research Group. "We told them that if you want to inject a small amount of air, don't even try. Shut it down. Don't annoy your reservoir," Mehta says, discussing the ISC learnings of that era. "This was in 1993. In 1996, we went there. They had two air compressors with a capacity of 65 million standard cubic feet per day each and they had very good production. The rest is history."

Today, Moore says that the In Situ Combustion Research Group does a lot of international work but also some local consulting with companies such as Nexen and Cenovus. So the tide may be turning for ISC in western Canada.

Cenovus specializes in SAGD extraction but, since 2007 (as Encana), it has been conducting tests and pilots on a form of ISC it calls AIDROH (Air Injection Displacement Horizontal Oil Recovery).

"We have been using this method to recover small amounts of oil from bitumen deposits in northern Alberta, by igniting and thus heating oil below the natural gas zone [natural gas sits on top of the bitumen reservoir]," Cenovus says. "We have shown that it is possible to safely ignite in the natural gas zone and sustain combustion in a reservoir to increase its pressure. The heat thus created travels downward to heat bitumen situated below the natural gas zone, softening the oil sufficiently to allow us to pump it to the surface."

The company says that AIDROH has the potential to reduce the amount of natural gas needed to generate steam in SAGD operations, which could help reduce steam to oil ratios.

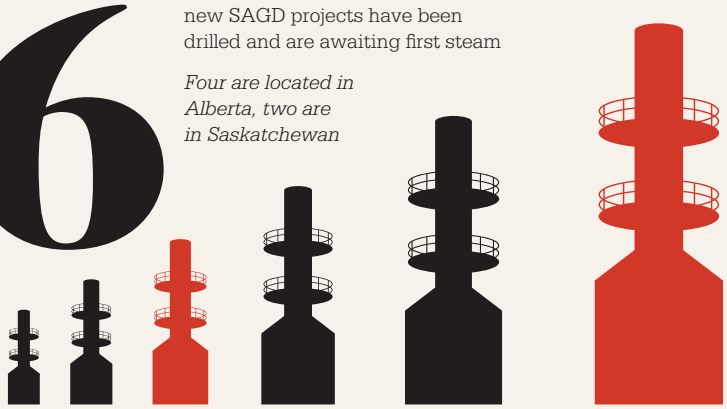
"We believe AIDROH is an encouraging technology that may find large-scale application in suitable reservoirs. The technology is in the very early stages of development. In the next several years, we plan to do more lab testing and field trials to demonstrate that this technology has the potential to work on a larger scale." As for THAI, Touchstone says that it is still using the technology at its Kerrobert, Sask., property, although the project is evolving to a "more conventional operation with a focus on economic recovery." OSR

There are currently **38** operational SAGD project phases in Alberta

In Saskatchewan, there are **10** operational projects with SAGD wells

6 new SAGD projects have been drilled and are awaiting first steam

Four are located in Alberta, two are in Saskatchewan

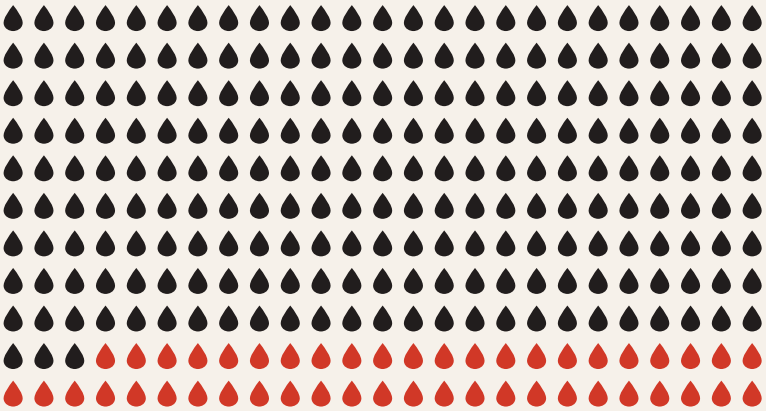


275 infill wells have been drilled in Alberta

228 have been operational at eight different SAGD projects

In Alberta, **1,965** SAGD wellpairs have been drilled

1,490 have been operational as of May 2015



Enhancing SAGD

Techniques and technologies for improving a first-choice thermal recovery mechanism

By Trevor Phenix

STANDARD SAGD DESIGN AND BASIC operational principles in the highest-quality heavy oil assets in Alberta and Saskatchewan have driven rapid production growth and increased awareness of this technology. The overall success of SAGD has typically been driven by large projects with access to these extremely desirable resources, but this is changing.

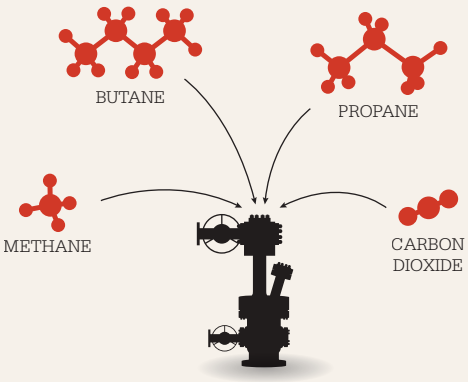
SAGD growth is increasingly supported by new projects developing lower-quality resources, as well as existing projects being forced to place sustaining wellpads away from their initial top-tier target areas.

Operators are looking for ways of increasing value from future phases, as well as actively deploying new technologies as a way of increasing recovery from mature fields. Just as SAGD is now a well-understood operational process,

140

SAGD wellpairs in Alberta have used some type of gas for co-injection

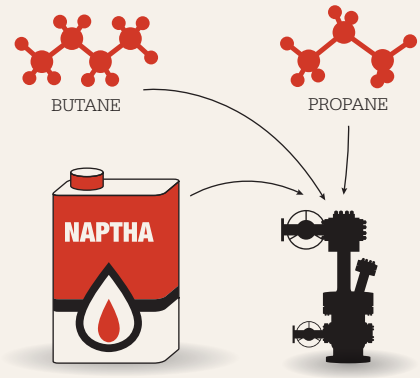
Most commonly, natural gas



60

SAGD wellpairs in Alberta have used some type of solvent

The majority for solvent soak prior to start-up



170

SAGD wellpairs have been drilled in Saskatchewan

150

have been operational as of May 2015

SAGD is now a well-understood operational process. Operators are looking for ways to increase the value of future phases and are implementing new technologies to further increase recovery from mature fields.

many of these tools are becoming second nature for the majority of thermal operators.

START-UP STRATEGIES

The start-up or circulation period is one of the most influential aspects on the ultimate performance of any wellpair. As such, many strategies have been trialled as a means to reduce the time to complete this period or to increase its overall effectiveness. The most commonly utilized start-up enhancements are solvent soaks, dilation or a combination of both.

A solvent soak is the most popular start-up enhancement as it is relatively low risk and typically requires little equipment to complete. A typical solvent soak consists of landing a batch of condensate or diluent in the producer, injector or both wellbores with the hope that it will propagate into the formation and diffuse into the heavy oil. The solvent is typically landed at least six months before the well is started up by way of the circulation or bull-heading strategy. The goal is ultimately to enhance inter-well connectivity without heat, which ultimately reduces the volume of steam and time required to initiate movement of the oil in the reservoir.

The dilation process attempts to increase the near wellbore permeability by realigning sand grains and increasing porous space between the injector and producer wells through a short-term pressurization and flow cycle lasting only a few days. The pressure and rate utilized are managed to mitigate the potential of any impact outside of the inter-well space. In this case, the hope is to reduce the time required for communication to occur between the injector and producer, ultimately reducing circulation time.

FLOW CONTROL DEVICES

In an attempt to enable longer SAGD wellpairs, more uniform steam chamber development and optimized artificial lift performance, the majority of operators are now utilizing a variety of different flow control devices for both steam injection and fluid production.

Two different device configurations exist: liner-deployed systems, which are permanently installed during the drilling process, and the more prevalent tubing-deployed systems, which are generally easier to modify or remove.

These flow control devices are designed to promote a more uniform distribution of steam along the injection well and fluid draw-down to the production well. They are also often utilized as a way of ensuring pump longevity by reducing the likelihood of steam interaction with artificial lift. In the past few years, it has

Standard SAGD operating procedure

The fundamentals of SAGD are fairly well understood, and although some variations exist from reservoir to reservoir, the general well design and operating philosophies are similar across Alberta and Saskatchewan.

A typical SAGD wellpair consists of two horizontal wells, an injector and producer that are drilled at the base of the exploitable reservoir. The injector is orientated directly above the producer with a vertical separation of approximately five metres for a horizontal length of approximately 700–800 metres, although shorter and longer wells are common. The horizontal portions of the well are equipped with a specially designed liner system, which allows for fluid movement in and out of the well while preventing any significant reservoir sand production.

Typically a thermal well requires some type of initial steam stimulation to heat up the near wellbore region, allowing the oil to become mobile. The overall success of this initial stimulation has a significant impact on determining the overall performance of a wellpair and can be detrimental to the well if certain reservoir heating goals are not met. The two most common start-up strategies for SAGD wellpairs are a steam bullhead and steam circulation; the method employed is determined by the reservoir and operational characteristics.

Upon completion of the initial stimulation, the well is then operated as a typical SAGD wellpair, where steam is injected into the injector only, and fluid is produced from the producer. A steam chamber will begin to grow vertically, and as it does, it transfers heat to the formation to mobilize the heavy oil, allowing oil and condensed steam to drain to the producer.

become more common to include technology that hydraulically isolates various regions of the wellbore to ensure a more even distribution of injected steam or produced fluid.

INFILL WELLS

Infill wells are the most common method for increasing overall project resource recovery as a complement to SAGD wellpairs. An infill well is a single well drilled between two adjacent SAGD wellpairs, and is typically utilized as a way of accelerating pad production and producing some of the oil that may be left behind with SAGD wellpairs alone. The infill well's success is largely dependent on the adjacent SAGD wellpair's steam chamber development, and as such they tend to be most successful after two adjacent steam chambers have coalesced.

Although most SAGD projects did not include infill wells in the original project applications or scope of design, most are using or planning on using infill wells as a way of increasing and/or accelerating recovery from a SAGD drainage pattern and maintaining a lower steam to oil ratio. This strategy has allowed many projects to surpass performance expectations and has significantly increased the ultimate recovery of mature assets.

CO-INJECTION

After the steam chamber is grown to a certain size, the most common operational enhancement process is co-injection, where a gas or hydrocarbon liquid is injected simultaneously with the steam into the reservoir. The most commonly utilized fluids are gas and solvents. Gas typically refers to a fluid that is in a gaseous state prior to injection, where solvent is often a liquid (such as diluent or condensate) prior to mixing with the steam.

Among the co-injection cases, more SAGD well pairs have injected natural gas than any other alternatively injected fluid stream as a way of reducing the volume of steam required to operate a SAGD wellpair. The steam that is saved is then directed toward new SAGD wellpairs or infill wells, as often a steam constraint exists within the facility. Natural gas is the most commonly injected gas due to its low cost and the relatively low capital required for implementation. CO_2, butane, propane and air have also been trialled.

Gas co-injection has historically been a transition phase to a full blowdown phase where only gas is injected to a well, but it is now being utilized much earlier in the life of many SAGD wells in some projects. The overall success of gas co-injection is typically determined by the volume of gas injected (and steam volume offset) and how early in the life cycle of the wellpair that it occurs. Gas injected in the late stage of a well's life typically has less of an impact on the overall oil production from any given well.

Solvent co-injection trials are becoming more common, and this is one of the most discussed alternative enhancements to typical SAGD operations. Solvent co-injection can increase the produced oil rate due to the solvent's ability to dilute and further mobilize the draining oil. The process can potentially reduce the residual oil saturation within the steam chamber, increasing ultimate recovery. It can also reduce the steam requirements for the operation and reduce its energy intensity, which in turn decreases greenhouse gas emissions.

The biggest disadvantages associated with solvent co-injection are the cost of the solvent, the large capital requirement for facility modifications and the potential for solvent losses within the reservoir. Facilities will typically undergo major modifications in order to properly capture the solvent for reuse and to mitigate the amount of solvent that is burned in the boilers. Due to the cost associated with the solvent, mitigating the volume of lost solvent within the reservoir is critical. This means that any well that is being considered for solvent co-injection must not have the potential of substantial loss to thief zones, and likely has operational history that proves little to no steam losses throughout regular SAGD. Performing various solvent co-injection trials is typical, as each formation and oil type reacts differently to various solvent streams and concentrations.

OUTLOOK

The ongoing development of new technologies and operational philosophies will not only have a large impact on existing SAGD operations, but will be critical to the success of many of the future's challenging reservoirs. Due to the variety of heavy oil reservoirs now utilizing SAGD, it has become much more difficult to simply apply a technology or operational principle that may have been successful elsewhere. Each resource needs to be optimized on its own, which makes it extremely important to understand how variation in reservoir and operation will impact the overall project.

It is critical that the industry transparency and information sharing continues and realistic expectations are put forward for each particular resource. OSR

Trevor Phenix is a production and reservoir engineer consulting for Top Analysis.

UNLEASHED

How tiny Osum is pushing SAGD performance well beyond the record of a global supermajor

By Melanie Collison and Deborah Jaremko

OF all Alberta's operating SAGD projects, Orion has never really stood out as an incredibly high performer. But if Osum Oil Sands keeps the project's new momentum going, that is set to change. And that means a lot for a junior producer in a challenging market.

Located in the Cold Lake oilsands deposit, the Orion facility builds on some of the longest SAGD history in the oilsands. In March 2006, a small company called BlackRock Ventures initiated construction of the 10,000-bbl/d commercial project following nine years of successful operations at its two-well Hilda Lake pilot. But BlackRock had other assets too, including an 80,000-acre-plus land position in the Peace River region that was highly attractive to Royal Dutch Shell. In June 2006, Shell acquired BlackRock for $2.4 billion, and although the main target was Peace River, Orion came with the deal.

Shell started up Orion in 2007, ramping up to 22 wellpairs on stream in 2010. During this time, production grew to about 4,000 bbl/d, and then slowly increased to about 6,000 bbls/d by the end of 2013. According to data from the Alberta Energy Regulator (AER), the project's steam to oil ratio (SOR) generally hovered between 4:1 and 6:1 between 2010-13.

Measured on capacity utilization and SOR, the main metric for SAGD performance, Orion was at best in the middle of the pack, but in 2013, Shell's optimization efforts started to reap results. By July 2014, when junior Osum Oil Sands finalized its $325-million acquisition of the Orion asset, the AER says production had increased to approximately 7,000 bbls/d, with an SOR of 3.2:1.

Under Osum's ownership, Orion exited 2014 producing 8,800 bbls/d with an SOR of 2.95:1. AER data shows that from January to June 2015, a period that included a maintenance turnaround, production averaged 8,000 bbls/d with an SOR of 2.4:1. For one stretch, Osum says Orion reached its nameplate capacity of 10,000 bbls/d. The operations team has every intention of achieving that rate again.

"We had a number of theories about what we would do with the asset if we had it," says Osum president and chief executive officer Steve Spence. "Shell was also pursuing a number of very similar theories."

Spence, who left a senior leadership position with Shell to join Osum in 2008, says the acquisition of Orion has markedly changed the trajectory of the company—particularly in the context of sub-$50 WTI.

In the first quarter of 2015, when WTI averaged $48.56/bbl, Osum reported a cash operating netback of $11.10/bbl.

"Without Orion, we think we'd be in an extremely different place. It moved the company forward a number of years in one step," he says. "This has given us a number of options to move forward. It positions us for the future."

Spence says that Orion ensures Osum's cash flow is sufficient to cover debt servicing and sustaining capital at current oil prices. The company is confident it is well capitalized, with approximately $200 million in net working capital and $262 million of debt.

COLD LAKE HOME BASE

From his first experience in the Cold Lake area nearly a decade ago, Spence knew he liked the region's attractive operating netbacks, proximity to markets and connections to infrastructure, as well as the established community with its stable skilled labour force.

As he notes, Orion was part of Osum's life long before it was considered for acquisition. The company had been watching the project closely as it progressed plans for its proposed 45,000-bbl/d Taiga SAGD/CSS project nearby.

"Orion was one of the analogues we looked at an awful lot for how [Taiga] might perform and what the challenges might be,"

Since taking ownership of the Orion project in summer 2014, Osum has recompleted 20 out of 22 SAGD wells, leaving the original pilot wells as originally drilled.

Located in the Cold Lake oilsands region, the Orion SAGD facility has been operationally challenged since its 2007 start-up, but recently has seen significant movement towards higher production volumes and efficiency.

Now that Osum has improved reservoir operations, the company is moving into facility debottlenecking, including at its evaporator water treatment units.

PHOTOS: DEBORAH JAREMKO

Spence says, adding that Osum paid particular attention to the difference between Orion's pilot and commercial operations.

"When our team looked at the Orion project, they looked also at the Hilda Lake pilot, which had performed extremely well historically and could see the differences, especially how trthe wells were completed between the pilot wells and the commercial wells. There were a number of things about the Cold Lake region that made the difference make sense."

ORION PROJECT CHALLENGES

The two-well Hilda Lake pilot, which started operating in 1997, averaged production of about 500 bbls/d with an SOR between 3:1 and 3.5:1, data shows.

"We've got a long history of wells that work well and a short history of wells that were challenged," Spence explains. "We were focusing on the opportunity to make the commercial wells operate like the pilot wells."

In 2011, Shell described its challenges in its annual project performance presentation to the AER. The company reported that the heterogeneity of the reservoir was more complicated than originally thought, steam shortages during the first two years of operations impacted steam chamber development, some wells had been drilled into lesser quality reservoir, and precipitation and scaling around liners had impacted productivity of the wells.

On the upside, Shell said production from wellpairs in more moderate quality resource improved as their steam chambers evolved with continuous injection, that chemical stimulation on the producers and liner perforation reduced the differential pressure and there was a noticeable improvement in SORs after the installation of artificial lift. The company expected to be able to place future wellpairs within higher quality resource, and in 2013 reported an improvement in plant and field reliability.

But for Shell, Orion was always a non-core project, and the company spread its focus across many Canadian properties.

TECHNICAL HURDLES AND WINS

With the Orion acquisition complete last summer, Osum gained the opportunity to test ideas it had developed during its years of observing the project. Spence says it all started with the reservoir, including adjustments like perforating slotted liners to increase inflow and applying certain kinds of stimulation techniques.

"Shell was progressively doing some of those things in a small number of wells, cautiously proving the concept. We were able to take those concepts and build on them really across the whole field once we had ownership of the asset."

Today, all but the original pilot wells have been recompleted. As production began to increase, Osum's focus shifted to the facility.

> **"WE WOULD LOVE TO GET [THE EXPANSION] PROJECT INTO EXECUTION IN 2016...IT WOULD BE A WONDERFUL ENVIRONMENT TO MOVE COUNTER-CYCLICALLY IN CONSTRUCTION."**
>
> — **Steve Spence**, president and chief executive officer, Osum Oil Sands

"As we move now more to the plant side, those are the new challenges, where we're hitting operating conditions we've never seen before," Spence says, adding that the debottlenecking process is something of a scientific art.

"That's how you can make a lot of money with these facilities, frankly, is by finding the right way to unlock capacity in a low-cost way so you can get just a bit more through the system and then chase the next constraint."

Operations manager Dennis Ozaruk says that, for example, Osum faced skim tank problems such as poor water quality and treating issues once it hit about 8,300 bbls/d. By working with its

PHOTO: DEBORAH JAREMKO

The Orion SAGD facility seen from the air.

Orion's nameplate capacity is 10,000 bbls/d, but the project has regulatory approval to expand to 20,000 bbls/d. Many of the long-lead items are already at site, purchased before the market downturn in 2009.

Reservoir operations have improved to the point that Osum says the project has, for a stretch this year, reached nameplate capacity.

chemical vendor, the company was able to get a better emulsion breaker and reduce costs.

Shell may have begun the improvements, but as Ozaruk says, "Orion is the biggest thing Osum has. We're able to put a lot of focus and energy into it. This facility gets us to the growth to add additional facilities and projects."

He notes that the project produced over 10,000 bbls/d for nine or 10 days earlier this year, and the company believes it can get back to those numbers. The issue at the time was boiler reliability, which has been addressed. Now it is working on its water delivery in order to increase steam.

THE PERSONAL TOUCH

Even before the acquisition, personnel as well as technical interest tied Osum to Shell.

Spence was with Shell for 24 years. He did some of the Phase 1 planning for Orion but moved to a different project before its commissioning and start-up. Vice-president of geoscience Jen Russel-Houston also worked for Shell before joining Osum in 2008.

When Osum bought Orion, it sought to recruit the existing field team as well as taking on the physical facilities.

"Not only were the people the biggest asset, they were the main asset," says operations foreman Keith Bureau, who joined Osum in 2011. "We've had to rely on their experience."

For the Shell people who signed on, it has been a welcome move from a huge corporation to a company totalling 124 office and field staff, plus about 10 contractors.

"We each have a personal stake in it," says production coordinator Terry Cowan, who has been on site at Orion for many years. "Every employee feels they can have a huge stake in Osum's future, which impacts their own future as well.

"The people who came with Osum understood this facility has had success and a good safety record. They were never shy about engaging the people, and that resonated well with the people on site. You feel respected and valued."

THE NEXT PHASE

Meanwhile, planning carries on to expand Orion to the 20,000 bbls/d approved by the regulator.

Given its own analysis of the reservoir, Osum reconfigured the pad design and applied in April to defer two originally planned pads and develop one new sustaining well pad as well as three new well pads.

For the expansion, Osum already has some of the long-lead equipment it will need. Shell was aggressively pursuing the growth project back in 2008, and the equipment arrived on site in 2009-10, Spence says. But the economy was in a downturn by that point, and the company essentially shrink-wrapped the equipment against the day industry prospects recovered.

"The site is designed for essentially twinning the existing equipment," he notes. "Everything we're looking at says this should happen, it's the right thing to do. We would love to get this project into execution in 2016, but moving forward is dependent on financing. It would be a wonderful environment to move counter-cyclically in construction." OSR

PHOTOS: DEBORAH JAREMKO

FRACK BE *nimble,* FRACK BE *quick*

Shale oil drillers dodge the downturn by packing up their rigs, while the oilsands toughs it out with long-term cost cuts

By Joseph Caouette

There's nothing like an extended price trough to remind everyone that the oil industry is not a monolith, but rather a group of distinctive sectors, each with their own unique qualities. For instance, the oilsands is the slow-moving behemoth of the bunch. The bulk of its projects feature long lead times and high upfront capital costs that naturally favour only the largest, most patient players. But if the oilsands is an elephant, then shale oil—or light tight oil, as many call it—is more like a mouse darting quickly from one hole to another.

"It's a lot more nimble," says Peter Argiris, principal analyst of Canada upstream oil and gas for Wood Mackenzie. "You can pack your rigs up and head home and come back tomorrow, if you have that financial capacity."

Stories of elephants stampeding fearfully at the sight of a mouse are more myth than fact, but the oilsands sector has plenty of reasons to be anxious about tight oil. Rising production out of the Bakken and other shale formations in the U.S. have played a serious role in the current decline in oil prices. Defined by heavy initial production rates, shale wells typically make back their costs within the first year of production, whereas an oilsands project could take a decade or longer after construction begins before it breaks even.

Oilsands developments are also slow to start and slow to stop, which means production has continued to rise through the current downturn, while shale drilling has dropped by nearly 50 per cent, according to Greg Stringham, vice-president of markets, transportation and oilsands with the Canadian Association of Petroleum Producers.

"The oilsands has momentum both ways, but tight oil has responsiveness both ways," Stringham says. "Not only is it quicker to turn down at lower prices, but if prices did come back—and I'm not predicting that, but if they did—they'd probably be the faster to turn back up again."

Oilsands and tight oil projects may differ greatly in size, but both sectors are looking to slim down as prices continue to flounder below $50/bbl. In the oilsands, project deferrals have tallied in the billions of dollars, while thousands of jobs have been shed. Notably, Suncor Energy cut 1,300 positions earlier this year—eight per cent of its workforce—in an effort to keep costs under control. Cenovus Energy chopped 800 positions in February, and has since announced plans to save $100 million by laying off another 300–400 people in its Calgary offices by the end of the year. And these are just a few of the companies looking to reduce payrolls.

Not all cost reduction efforts need be so painful, however. Both Stringham and Argiris note that the oilsands sector is changing how it builds and expands projects. Gone are the high-cost—and high-risk—megaprojects of old. Instead, the industry is moving away from greenfield developments and major expansions toward smaller, repeatable brownfield phases at existing projects.

"They're taking smaller, bite-sized pieces that are more cost-efficient to do," Argiris says. "They are better able to control the cost because it is a smaller addition, and it builds on their already existing project."

This trend, while accelerated by the current price crash, began several years ago. Husky Energy has been a vocal proponent of using smaller expansions to minimize costs and execution risks as part of its larger strategy to become a low sustaining capital business. Since 2010, the company has been working on reducing its operating costs so that it can lower capital spending during downturns and—in the words of company president and chief executive officer Asim Ghosh—"not have the business fall out of bed." Over the past five years, the company has reportedly realized $1.3 billion in supply and procurement savings as part of this effort.

Husky has been reaching out to suppliers for cost-saving ideas, and it has the added advantage of controlling its entire value chain, from production to refining to retail. But it is also working with its front line workers to find other ways to save money. On horizontal wells and cold heavy oil production with sand, Husky has begun passing along real-time financial data to operations staff to ensure they are considering revenues and costs in their own decisions. Wherever this method has been implemented, savings have been in the range of 10 per cent, the company reports.

Others in the industry have seen similar successes. Comparing the second quarters of 2014 and 2015, Cenovus saw a 30 per cent drop in its per-barrel oilsands costs. In that same period, Canadian Natural Resources saw costs at its Horizon mine drop by 20 per cent, while light oil production came in 13 per cent cheaper. For the year, the company's Primrose in situ oilsands project is expected to reduce operating costs by 13 per cent. Suncor's oilsands cash operating costs dropped to $28/bbl in the second quarter thanks to a host of initiatives, including using more local labour to cut down on fly-in costs and increasing productivity to avoid overtime.

In fact, productivity is one of the major sources of potential cost savings throughout the oilpatch. According to Stringham, both the conventional and the oilsands sectors are working

> "Our belief is that about two-thirds of these [oilsands cost] savings are sustainable and will not be given back in a higher price environment. And we haven't finished yet."
>
> — **Steve Williams**, president and chief executive officer, Suncor Energy

together to create more comprehensive safety training. Hours of labour are lost if a worker needs to go through a safety orientation each time he or she enters a new site. Safety passports that can apply more widely could help salvage much of the time spent in redundant training.

But the most prized cost reductions are those that also improve environmental performance. Both the tight oil and the oilsands sectors are looking at ways to cut water use in hydraulic fracturing or in situ projects, or reducing energy consumption to save on natural gas costs. Unlike some cost-saving measures, these sorts of changes become integrated into an operation.

"Those won't change if the price comes back again," Stringham says. "They'll be embedded, and they'll be permanent."

Companies are keen to change their cost structures in ways that will last. Cenovus has claimed $280 million in operating, capital and general and administrative cost reductions this year, and considers about half of those cuts sustainable. Husky has slashed $575 million so far this year, with 70 per cent of that coming from procurement and 30 per cent tied to workforce and corporate adjustments. The company insists that the bulk of the reductions will stand even under higher prices.

Suncor was no less insistent in its second-quarter conference call at the end of July that it was making meaningful changes to its cost structure, and not just chasing temporary savings. Comparing the second quarters of this year and 2014, the company saw labour and commodity costs drop by 18 per cent. Savings for 2015 are currently expected to come in at $600 million to $800 million, although the company suspects costs aren't quite done deflating.

"Our belief is that about two-thirds of these savings are sustainable and will not be given back in a higher price environment," said Steve Williams, Suncor's president and chief executive officer, during the call. "And we haven't finished yet."

Pessimism seems to be the ruling mood in the industry these days, and even the most hopeful forecasts are calling for a slow recovery. If there is any optimism to be found, it is in using low oil prices as a springboard to building a cheaper, more sustainable business. But how much room is there for more cost cutting? How much lower can companies go?

Argiris believes there are still many improvements to be found in tight oil techniques. Companies are still fine-tuning processes and discovering ways to reduce drilling times and improve efficiency. Laterals are getting longer, and the numbers of fracks are increasing. Drillers are experimenting with the type and amount of sand used, or exploring different hybrid fracks. Instead of designing rigid 20-well programs, companies are looking at the specific geology of each individual well to maximize production.

"It's as much about technology improving as it is about the operators improving their efficiencies and the way they approach drilling wells," he says.

On the tight oil side, Stringham expects most cost reductions to come incrementally—moving from 50 fracks per well to 100 fracks, for example. But there is still the potential for a new game-changing technology to help shake up the in situ oilsands sector, he suggests.

"We've been doing hydraulic fracturing vertically for probably 50 years," Stringham says. "In situ's only been around 20 years now, and there is still ample room for incremental and breakthrough improvements on that side." OSR

project news & data

1 Plains Midstream Canada has received regulatory approval for the Indigo Pipeline project, a dual 130-kilometre pipeline that will connect Shell's upcoming Carmon Creek thermal project to Plains' existing Nipisi terminal.

One 24-inch pipeline will transport blended crude bitumen from Carmon Creek to Nipisi, while a parallel 12-inch high vapour pressure line will ship condensate and butane products from the Nipisi terminal to Shell's Peace River in situ project.

Subject to regulatory approvals, the project would be in service in the second quarter of 2017, with right-of-way clearing in the first quarter of 2016 and construction of the pipeline and pipeline installations beginning in the third quarter of 2016. Earlier this year, Shell announced it was pushing out the ramp-up of Carmon Creek by two years with first oil currently planned for 2019.

2 Baytex Energy says that it will pause drilling for heavy oil this year in the wake of an expected protraction of low crude oil pricing.

"Despite achieving cost reductions of approximately 20 per cent, current prices do not support further drilling at Peace River or Lloydminster at this time," says James Bowzer, president and chief executive officer. Baytex has drilled six of eight budgeted wells at Peace River and 21 of 26 budgeted wells at Lloydminster.

3 KBR says it has received a reimbursable contract to provide construction services at the Fort Hills oilsands project currently under construction by Suncor Energy and its partners.

KBR's scope includes on-site construction management and direct hire field construction services for the project's secondary extraction facility. This scope, which was awarded by SK E&C subsidiary Sunlake, follows KBR's contract to perform a detailed constructability study for the project.

The contract value was not disclosed. Work on the projects has started and will be executed over the next 18 months, with completion expected in the first quarter of 2017.

4 ConocoPhillips Canada has achieved first oil at the 118,000-bbl/d Surmont 2 SAGD project. First steam was achieved in June, and production is expected to ramp up through 2017. ConocoPhillips Canada has also announced it will lay off 400 employees and 100 contractors.

5 Husky Energy has started steam operations at the second of its two plants at the Sunrise SAGD project. The first plant began bitumen production in March 2015. Production from the second plant is expected later this year.

6 TransCanada has announced that the southernmost portion of the upcoming 20-inch Grand Rapids diluent pipeline will be contributed into a 50-50 joint venture with Keyera. The Grand Rapids Pipeline partnership is owned 50-50 by TransCanada and Brion Energy.

Grand Rapids expects its total contribution to the joint venture will be approximately $140 million. Keyera will operate the pipeline once construction is complete and the facilities are in service, which is anticipated in 2017.

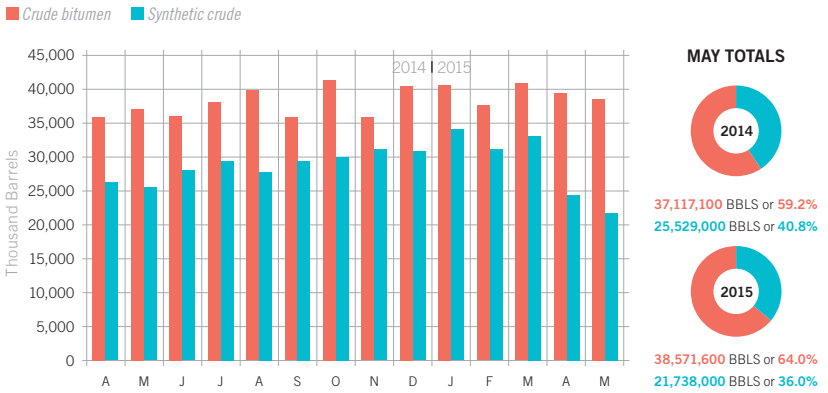
7 CB&I says that it has been awarded a $60-million contract by a major energy company to provide maintenance services for three separate oilsands facilities in Alberta.

8 Enbridge has received regulatory approval for the Norlite diluent pipeline, a new 24-inch system from the Edmonton-Fort Saskatchewan area into the Athabasca oilsands region. The pipeline will be anchored by throughput commitments from the Fort Hills oilsands project.

Initial plans called for a 20-inch outside diameter pipeline with capacity of 280,000 bbls/d. Keyera will participate in the Norlite pipeline as a 30 per cent non-operating owner. Enbridge says that construction is underway, with an expected in-service date in the summer of 2017.

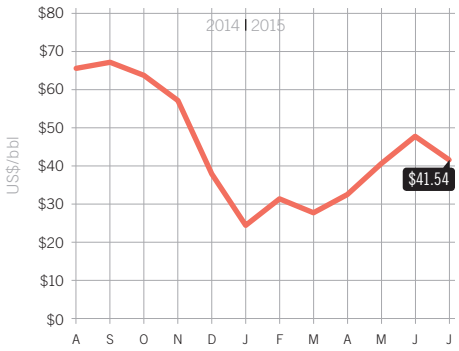
Oilsands Review provides timely analysis of key project developments and operational performance metrics. For a comprehensive oilsands project status listing and access to deep oilsands data sets, subscribe to the *Daily Oil Bulletin* Intelligence Essentials. For more information, please visit **dailyoilbulletin.com/about.**

Alberta crude bitumen and synthetic crude production 2014-2015



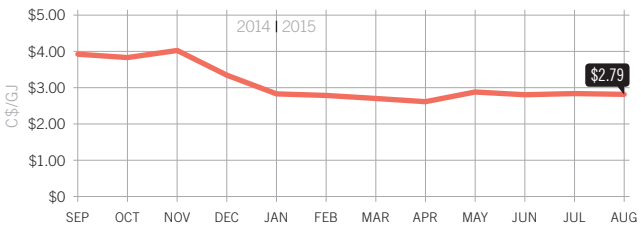
Bitumen royalty valuation at Hardisty, Alta.

Calculated using NetThruPut monthly WCS Index.



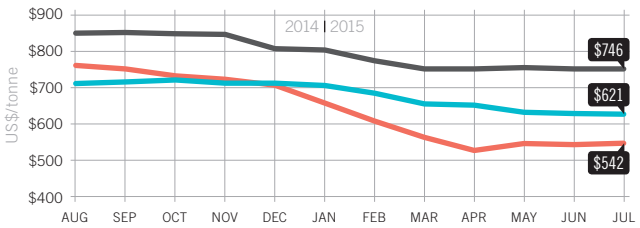
Natural gas: Spot prices at AECO trading hub in Alberta

Monthly averages to Aug. 21, 2015.



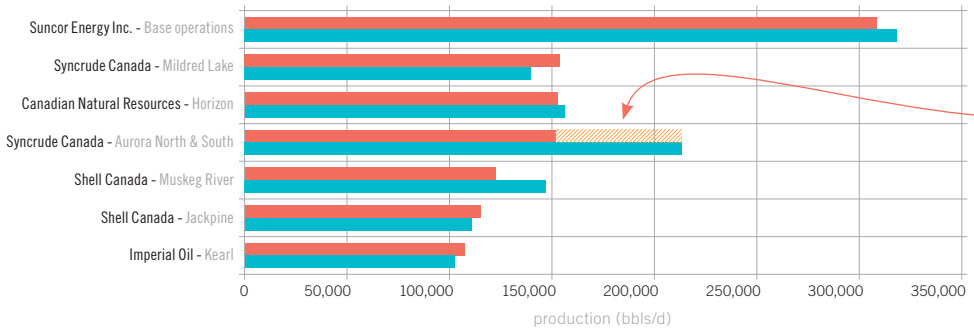
North American carbon steel prices

Hot rolled coil *Structural sections and beams* *Reinforcing bar*



Mined oilsands bitumen production

Current 3 month avg. (April 2015 - June 2015) *Previous 3 month avg. (January 2015 - March 2015)*



BIGGEST MOVER

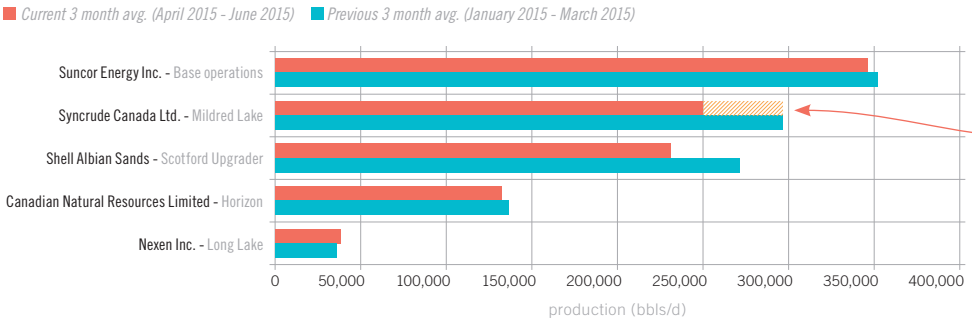
Syncrude Canada - Aurora North & South

-61,837.9 (From 213,421.9 to 151,584.2)

TOTAL MINING AVERAGE

Current three months	Previous three months
1,111,373.80	1,187,810.6

Alberta synthetic crude oil production



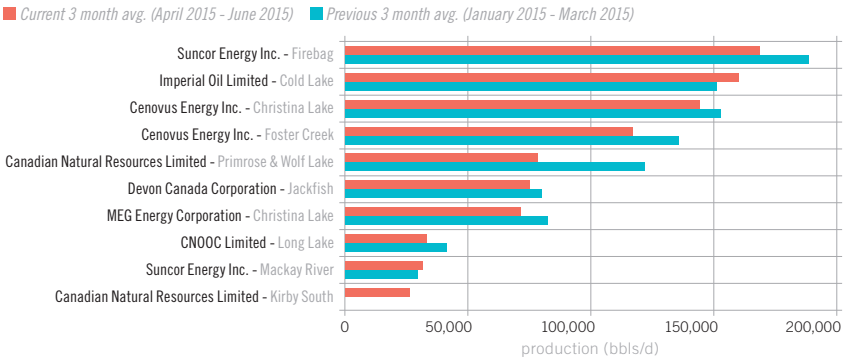
BIGGEST MOVER

Syncrude Canada - Mildred Lake
-46,360.8 (From 296,309.52 to 249,948.80)

TOTAL CRUDE PRODUCTION AVERAGE

Current three months	Previous three months
997,996.20	1,092,364.06

Top 10 thermal oilsands projects bitumen production



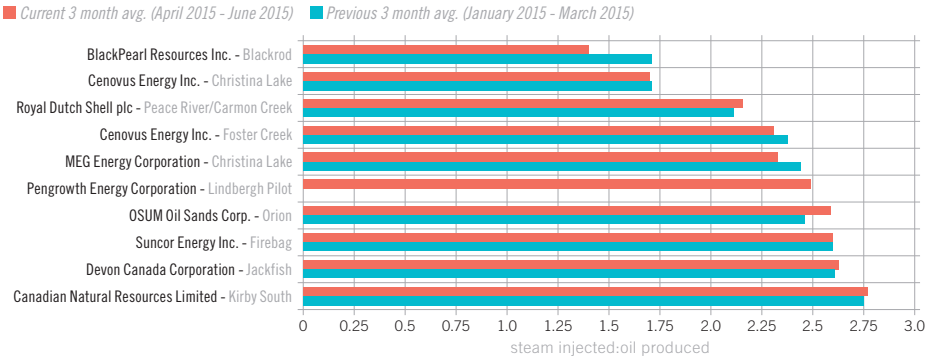
BIGGEST MOVERS

Canadian Natural Resources Limited Primrose & Wolf Lake	-43,784.60	From 121,936.4 to 78,151.7
Suncor Energy Inc. Firebag	-19,828.40	From 188,303.1 to 168,474.7
Cenovus Energy Inc. Foster Creek	-18,425.20	From 135,538.7 to 117,113.6

TOTAL CRUDE PRODUCTION AVERAGE

Current three months	Previous three months
1,272,219.9	1,375,943.5

Lowest 10 thermal project steam to oil ratios

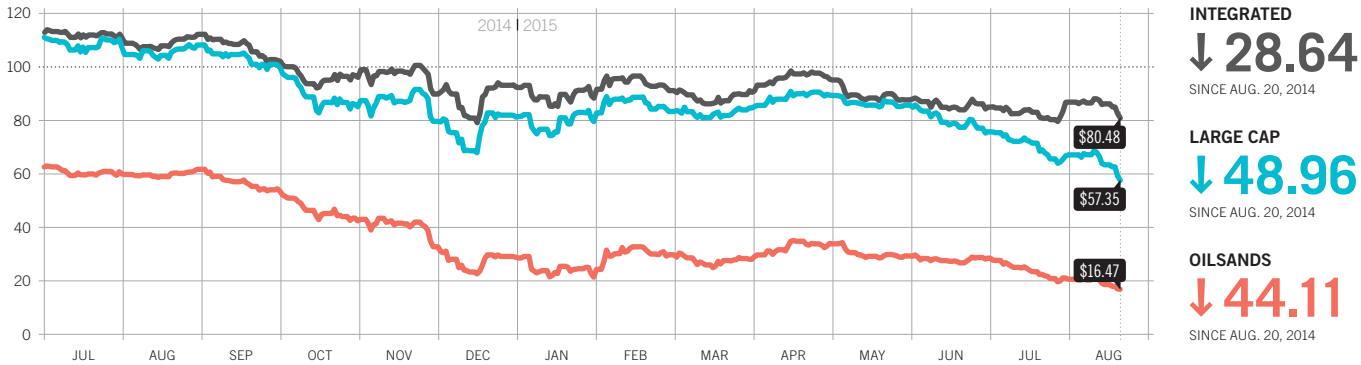


BIGGEST MOVERS

Athabasca Oil Corporation Hangingstone	135.51	From 0 to 135.51
Husky Energy Inc. Sunrise	-8.77	From 25.33 to 16.56
Pengrowth Energy Corporation Lindbergh Pilot	-7.1	From 9.59 to 2.49

Top ten average - current three months	2.29
Top ten average - previous three months	2.31

FirstEnergy oilsands, integrated and large cap indexes



Index launched Jan. 1, 2007. FirstEnergy complimentary indexes are available daily on the homepage at firstenergy.com. FirstEnergy Capital Corp. is a member of the Canadian Investor Protection Fund and IIROC.

Crude oil differential: WTI-WCS

FirstEnergy Capital Corp. crude differentials update

Canadian heavy oil prices have once again been put in the penalty box in the past two months. The light-heavy crude oil price spread has quickly widened to a little more than US$20/bbl from the single-digit range of earlier this year. With the additional sharp drop in WTI prices recently, the absolute value of WCS has fallen to one of its lowest levels in the past decade.

How did the market for Canadian heavy oil end up in this predicament so quickly? During May and the first half of June, when the price differential was in the single-digit range, there was a considerable amount of field maintenance taking place that was holding back on the order of 200 thousand bbls/d of heavy oil supply from the market. Around this time, there were also threats from forest fires that resulted in the additional shut-in of about 230 thousand bbls/d of heavy oil supply. As such, around the middle of June, there was more than 400 thousand bbls/d of heavy oil supply out of commission.

Fast forward two months and all of that supply has returned in full force. Moreover, significantly better than anticipated production results from Imperial Oil's Kearl project has further increased the production of heavy oil supply by more than 70 thousand bbls/d. Layer in the original production that Kearl was producing, and supply from this project is now approaching 200 thousand bbls/d. When putting it all together, Canadian heavy oil supply has increased better than 500 thousand bbls/d in the past two months, a significant amount of supply for the market to swallow in such a short time.

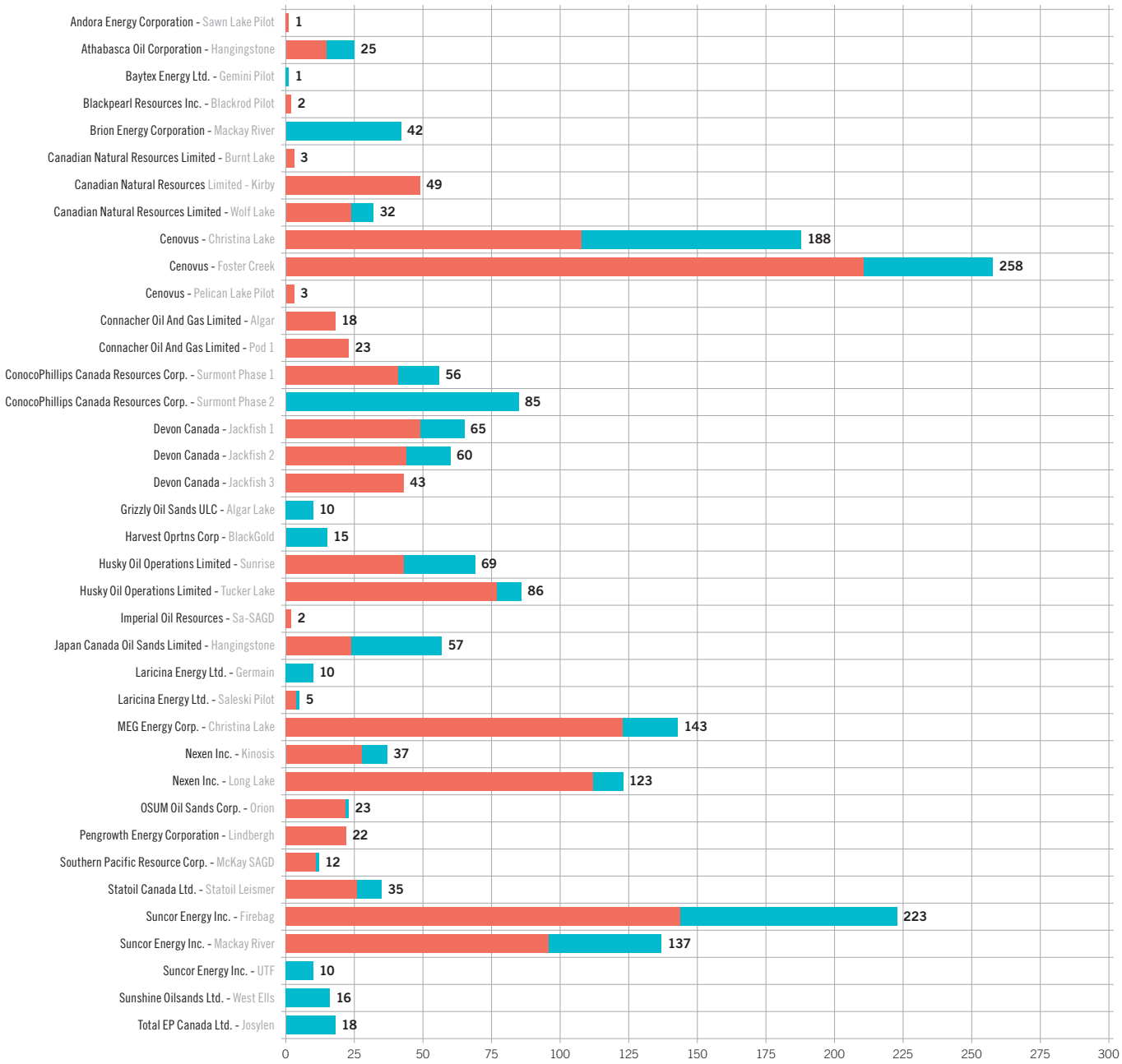
Adding insult to injury has been the unexpected outage of a major part of the Whiting, Ind., refinery, which is a major consumer of Canadian heavy crude oil. The affected part of the refinery is that which consumes heavy oil. With this outage of around 220 thousand bbls/d and no clear timeline to repair at the time of writing, a large increase in heavy oil supply has run up a significant drop in heavy oil demand. The end result has been a sharp widening of the WCS-WTI price differential.

With the differential as wide as it has been for some time, we think the significant availability of railing capacity to move Canadian barrels to market will act as a rough ceiling for the WCS-WTI price differential. With transportation costs from Alberta to the U.S. Gulf Coast around US$16–US$18/bbl by rail, we think the increased supply will be quickly placed in railcars and make its way to market. It may take some time to work though all of the additional supply, but we expect that the WCS-WTI price differential will narrow back into the mid- to low teens by the fall.

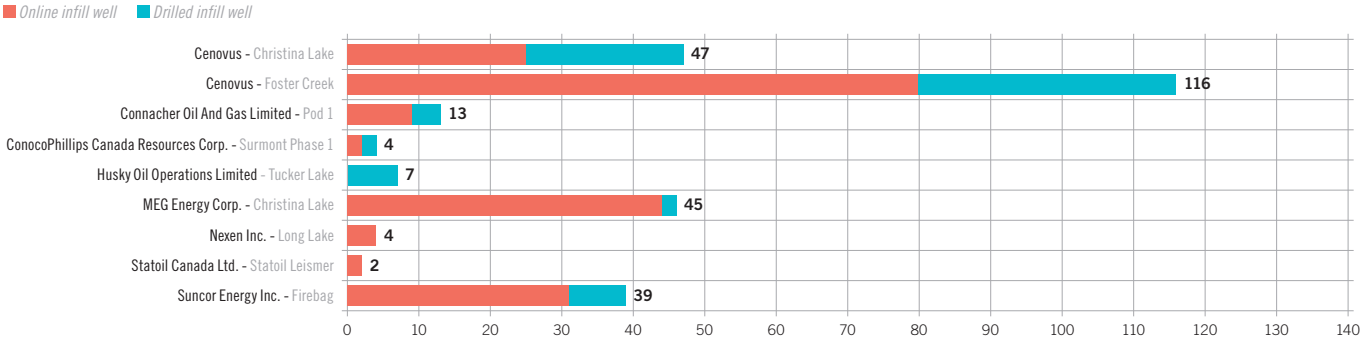
— **Martin King**, vice-president, institutional research, FirstEnergy

Sources: Alberta Energy Regulator; Energy Information Administration; FirstEnergy Capital Corp.; Flint Hills Resources Ltd.; MEPS International ; Natural Gas Exchange Inc.; TOP Analysis

TOP Analysis Alberta SAGD wellpairs August 2015



TOP Analysis Alberta SAGD infill wells August 2015



A changing climate in Alberta?

The new commitment to transparent climate policy discussion is refreshing. Applying the same approach to tailings management could create the route for social acceptance.

BY SIMON DYER

By the time this magazine hits shelves, Alberta should be deep in its Climate Leadership discussions—a plan to consult with Albertans before developing a new climate policy. Led by Andrew Leach of the University of Alberta, a strong panel has been announced with expertise in carbon pricing, renewable energy policy and oil and gas extraction.

The goal? To develop a credible climate plan that puts Alberta on track to doing its fair share to reduce greenhouse gas pollution. If Alberta is able to deliver on that promise, an attractive side benefit could be less opposition to development of the oilsands.

"Action to reduce greenhouse gas emissions goes far beyond the most talked-about industries. All Albertans must be part of the solution," Leach said in initiating the discussions. "We look forward to hearing about ways Albertans can reduce emissions in their day-to-day lives, about new technologies and the opportunities for success they bring and about how the province can continue to prosper in a lower-carbon future."

Leach added that the panel will hear from Alberta's citizens, labour, industry, communities, other jurisdictions, scientists, economists, traditional knowledge shared by Indigenous Peoples and experts in a variety of emerging and already prominent industries.

It's noteworthy that, from 2008 until 2015, the Alberta Government held no public discussions on climate change. None. Since 2008, Alberta has barely reported on progress in terms of reducing emissions. Its bold (some would say unrealistic) goal of delivering 139 million tonnes of CO_2 emissions reductions annually from carbon capture and storage (CCS) projects has languished, hindered from the beginning by a lack of political will to implement the policies necessary to drive emissions reductions and make options like CCS cost-competitive.

This is why a commitment to a transparent discussion on how Alberta will meet the challenge of climate change is so refreshing.

The government has initiated this multi-stakeholder engagement process in response to the complexity of Alberta's climate challenges, and in recognition of the fact that the government needs a different approach to address these challenges to the public's satisfaction. Convening stakeholders with a range of perspectives has the potential to deepen understanding of the various challenges the province is facing, and of different stakeholders' positions. It can generate a dialogue that goes beyond positions to explore a mix of concerns and priorities, and allows decision makers to hear all viewpoints and understand the competing interests involved in a transparent and accessible manner. The process is more likely to produce credible results since it aims to build a shared understanding of the issue, creates space to negotiate solutions and can show that a wide range of society was included, engaged and helped form the final result.

Other opportunities to apply this approach

Tailings management is another area where enhanced public participation may result in better outcomes for the oilsands industry.

PHOTO: PEMBINA INSTITUTE

The Alberta Energy Regulator (AER) is now engaged in the full life cycle of project decision making, responsibility for regulatory functions (previously held by Alberta Environment and Sustainable Resource Development) and the management of the energy resource sector's impacts on public lands and Aboriginal treaty rights. This expanded role changes the engagement landscape for the AER and creates a space for the government to build new conventions around multi-stakeholder consultation processes.

Tailings management has been a sore spot for the oilsands industry and has resulted in substantial local and international criticism. The Government of Alberta's Tailings Management Framework, and now the AER's work on the Tailings Regulatory Management Initiative, will need to show that Alberta and industry are serious about increasing the pace of reclamation and correcting their lacklustre record.

For the Tailings Regulatory Management Initiative, a multi-stakeholder process could build credibility for the implementation of the overall tailings framework. The AER should work with stakeholders from First Nations and Métis communities, local government, ENGOs, industry, academia and others to create a multi-stakeholder advisory committee to support the AER in creating processes for the initiative and reviewing companies' tailings submissions. The AER would retain decision-making authority, yet the multi-stakeholder advisory committee could create common understanding of challenges and regulatory approaches.

While the oilsands is facing tough headwinds driven by low oil prices, the resulting moderation in the sector's pace of growth may provide a timely opportunity to address some of the underlying challenges the industry is facing.

Let's bring back public involvement in energy decisions

While the development of an arm's-length single energy regulator did not need to result in weaker environmental outcomes, some of the enabling legislation and regulations that were implemented as part of the birth of the AER unnecessarily eroded public participation in Alberta's energy decision-making process.

The Responsible Energy Development Act removed the language about decisions being in the public interest and also resulted in the loss of a mandatory requirement for hearings for landowners impacted by energy development. These are some important gaps that could be addressed to further strengthen public support for, and confidence in, the regulatory process for oil and gas development in Alberta.

Too often, the perception, and frequently the reality, around oilsands issues has been that decisions were made through overly cozy discussions between government and industry, while other voices—First Nations, landowners, environmental organizations—were excluded.

While the oilsands industry is facing tough headwinds driven by low oil prices, which are resulting in project deferrals and cancellations, the resulting moderation in the sector's pace of growth may provide a timely opportunity to address some of the underlying challenges the industry is facing. Rather than fearing public scrutiny and informed debate on the industry's biggest challenges—climate and tailings—frank public discussion from a shared baseline of facts and costs may lead to regulatory changes that are broadly supported by Albertans and our global customers.

As Alberta prepares to develop a new credible climate plan, with the COP21 meetings in Paris in December as a firm deadline, there is a new sense of optimism that taking a more holistic approach to public participation will result in not only better decision-making, but also broader acceptance for the oilsands at home—and beyond our borders. OSR

Simon Dyer is the regional director for Alberta and the North at the Pembina Institute, and former director of the Institute's oilsands program.

Levering LNG

The case for replacing diesel with natural gas for oilsands mining fleets

BY CHRISTOPHER ZULIANI, EBRAHIM SALEHI, GREG ALMQUIST AND SANJIV SAVE, HATCH LTD.

Before the North American shale revolution, Alberta's abundant natural gas supplies had a steady customer in U.S. markets. But now, horizontal drilling and hydraulic fracturing have increased U.S. oil and gas supplies and depressed prices by allowing for production from large, previously inaccessible shale deposits.

With few near-term prospects for new export markets, Canadian gas producers must find alternative end uses, such as diesel replacement. Diesel, on an energy intensity basis, is much more costly than natural gas. Thus high-diesel users can achieve considerable fuel savings if they run their vehicles on natural gas.

Mineable oilsands operations fit well as a niche model. There is a well-established gap between bulk pricing for diesel on the Gulf Coast versus Alberta, where diesel commands a US$10/bbl premium on average. Also, oilsands mining sites consume large amounts of diesel—typically over 100,000 gallons per day—within a very small geographic area. This minimizes the necessary infrastructure changes and provides significant fuel savings to the operation.

To properly evaluate the suitability of LNG to feed mineable oilsands operations, a case study was performed. The hypothetical mining project's battery limit included 40 heavy haul trucks and five heavy lift shovels, which consumed 2,000 bbls/d of diesel. The full-cycle capital expenditure for replacing diesel with LNG included the cost of the micro-LNG plant, refuelling stations and engine modifications. For all the scenarios considered, the cost of natural gas was fixed at US$3.3/mmBtu, which is the long-run average AECO price since 2010. For the base case, Alberta's long-run average diesel-gas price ratio of seven was used.

Economic model results showed a very attractive after-tax rate of return of 32 per cent and a payback period of three years. Upon applying a 10 per cent discount factor, a net-present value of US$143 million was calculated. Some sensitivity analyses were also performed, which showed that the LNG route is robust enough to withstand changes in Alberta diesel-to-gas prices as well as the potential cost increases in implementing the project.

The fuel substitution percentage also required a sensitivity analysis. Dual fuel engines offer a replacement rate of up to 70 per cent, but they run entirely on diesel while idling and at low RPM. Therefore, the actual overall amount of diesel replacement is dependent upon truck movements and the mine topography. Also, as the diesel replacement changed, so too did the size of the LNG plant producing it. Moving to lower diesel substitution rates was partially mitigated by reduced plant size.

Curiously, LNG adoption has not begun despite such compelling arguments in its favour. It may be that operating companies do not wish to distract their core business with LNG production, are understandably adverse to a full-site adoption model or are hesitant to move ahead with large projects in a low-cost environment. However, these issues can be addressed through an over-the-fence business model.

This model actually works very well in the oilsands as there are several mining operations close to Fort McMurray. There is potential demand for over one million gallons per day of diesel in the region. To replace 50 per cent of this diesel demand by adopting dual fuel engines will require a centralized LNG plant with a production capacity of close to one million gallons per day, which could be financed, constructed and operated by a third-party LNG supplier leveraging economies of scale. In the base case economic scenario, 70 per cent of the capital required for the project was directed towards designing and building the LNG facility. Removing this from the oilsands operators' costs offers considerable savings on upfront capital.

Study results show a very attractive 32 per cent after-tax return and a three-year pay back period from switching oilsands haulers to diesel.

This would also allow for a pilot trial first. In performing some preliminary calculations with this model—assuming five per cent regional diesel replacement in the first year, 15 per cent in the second and 50 per cent in the third—even the economics associated with the pilot stage are highly positive. The plant would be paid for in five years, and the oilsands operators would recover the cost of converting their trucks and installing fuelling stations in less than three years. OSR

PHOTO: JOEY PODLUBNY

upcoming events

OILSANDS HAPPENINGS TO CALENDAR

October 2015

sun	mon	tue	wed	thu	fri	sat	sun	mon	tue	wed	thu	fri	sat
				1	2	3	4	5	6	**7**	**8**	9	10
11	12	13	14	**15**	16	17	18	19	20	21	22	23	24
25	26	**27**	**28**	**29**	30	31							

Wednesday, October 7

Oilweek Speaker Series: Water Wisdom Sponsored by CH2M
Calgary Petroleum Club
junewarren-nickles.com/index.php/events

Thursday, October 8

Canadian Heavy Oil Association Technical Lunch: Business, marketing & transportation
Calgary Petroleum Club
choa.ab.ca/events

Thursday, October 15

2015 PTAC Air Issues Forum
Calgary Petroleum Club
ptac.org

Tuesday, October 27

Canadian Energy Technology Forum
BMO Centre, Calgary
energytechforum.ca

Wednesday, October 28

Canadian Energy Supply Chain Forum
BMO Centre, Calgary
supplychainforum.ca

Wednesday, October 28—Thursday, October 29

Canadian Crude Marketing Cost Reduction Congress 2015
Clarion Hotel & Conference Centre, Calgary
crude-marketing-canada-2015.com

Thursday, October 29

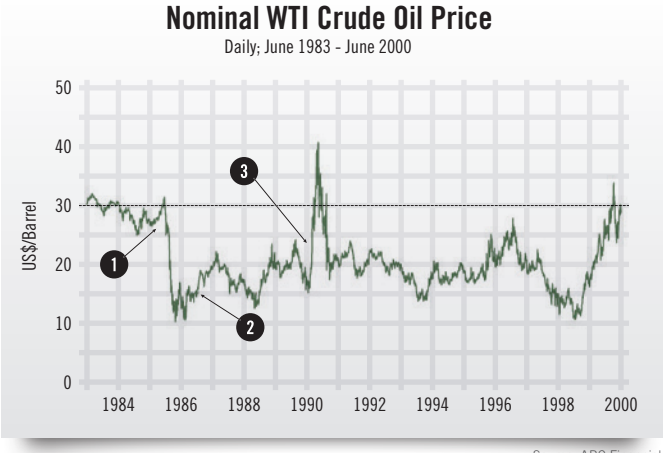
Canadian Energy Projects Forum
BMO Centre, Calgary
projectsforum.ca

For more events, please visit:
events.nickles.com

advertisers' *index*

Today's downturn hurts, but it's not a rerun of 1986

BY JACKIE FORREST



Source: ARC Financial

With WTI hovering near US$40/bbl, widespread pessimism is taking root with a growing number of voices associating this downturn with the sickly era circa 1986.

The downturn of the mid-1980s was certainly grim. With the exception of a short-lived price spike when Iraq invaded Kuwait in 1990, it took about 15 years for the price of oil to recover to its pre-1986-crash levels.

Although oversupply was the initial catalyst of both the 1986 and current price crashes, with OPEC actions centre stage in both cases, there are many differences between 1986 and today. The 1986 crash and the resulting decade and a half of low prices was the result of a truly massive oil oversupply, unlike the situation we are now facing.

Let's rewind the clock back to the 1970s. In response to the 1973 oil price shock, oil-importing countries implemented legislation aimed at reducing demand.

Between 1979 and 1985, a weak economy and new government mandates reduced global oil demand by five million bbls/d. At that time, OPEC's policy was to hold the oil price near US$30/bbl (almost $70/bbl in 2015 real dollars). To maintain this price in the face of declining demand, OPEC was forced to ratchet down its oil production by 14 million bbls/d. At the same time, the artificially high oil price caused non-OPEC supply to surge.

By December 1985, OPEC production levels were unsustainably low, and its market share had dropped from 46 to 29 per cent. Cutting more production was no longer an option, and OPEC decided to switch from focusing on price to regaining market share. In the next year, OPEC's average production increased by over 2 million bbls/d. Spare OPEC capacity was pegged at over 12 million bbls/d, or about 20 per cent of the 61-million bbl/d of global demand.

By the end of 1986, OPEC tried to boost the oil price by making a cut of over 1 million bbl/d. But by that point, the level of oversupply was well beyond what OPEC could control. The glut was amplified by newly commissioned non-OPEC projects such as those in the North Sea and Alaska that could expand at a low cost.

Using the latest figures from the International Energy Agency (IEA), today OPEC's spare capacity sits at 2.2 million bbls/d. Even adding the 1.8 million bbls/d that is being produced above current demand levels, the amount of "spare oil" is now at most 4 million bbls/d or 4 per cent of global demand. Compare this to 20 per cent in 1986. If it took fifteen years to sort out a 20 per cent oversupply, assuming that all else is equal, a mere 4 per cent glut should take far less time.

Of course, not everything is equal. Some things are better. Today's non-OPEC production sources are not as amiable to low cost expansion as in 1986. Tight oil declines quickly and needs constant investment. Expanding oilsands or deep water is not economic at current prices, and, even assuming a markdown in capital costs, it is tough to imagine how growth could become profitable at today's oil price.

1. Between 1979-85, global demand dropped and OPEC's market share dropped from 46 per cent to 29 per cent.

2. By the end of 1986, OPEC tried to boost prices by cutting >1 million bbls/d, but by that point, the level of oversupply was well beyond its control.

3. Other than a short-lived price spike when Iraq invaded Kuwait in 1990, it took about 15 years for the price of oil to recover after 1986.

And some things are the same—notably the law of supply and demand. Low price stimulates consumption. Despite conservation efforts in the early 1980s, between 1986 and 2000 cheap oil spurred 2 per cent annual consumption growth. The IEA now expects oil demand to grow by 1.7 per cent this year, more than twice last year's pace.

This is not a 1986 rerun. With the exception of OPEC's policy curveball, by many measures the situation is not as dire today, although it feels like it. Even without a wildcard such as a major supply outage (from a civil war or a terror attack for example) or a voluntary cut by OPEC, robust growth in global oil demand along with an inevitable slowdown in global supply growth should conspire to strengthen prices much faster than 1986. OSR

Jackie Forrest is vice-president of ARC Financial. This column originally appeared in the ARC Energy Ideas blog.

CANADIAN ENERGY **SUPPLY CHAIN** FORUM

OCTOBER 28, 2015 • BMO CENTRE • CALGARY, AB

The Canadian Energy Supply Chain Forum is the largest energy sector event exclusively dedicated to improving the performance and competitiveness of the petroleum industry through supply chain management excellence.

Join an estimated 600 industry professionals as you learn from major energy producers, engineering, procurement and construction firms who have successfully delivered multi-billion dollar energy projects on time and on budget.

TAKE ADVANTAGE OF EARLY-BIRD RATES BY REGISTERING BEFORE SEPTEMBER 30.

Additional discounts are available for supply chain management professionals.

COLLOCATED WITH CANADIAN ENERGY **PROJECTS** FORUM OCTOBER 29, 2015

With a history of projects being completed over budget and behind schedule, the Canadian Energy Projects Forum will focus on the collaborative construction process, demonstrating how small process changes can yield dramatic results.

Together with the Canadian Energy Supply Chain Forum, delegates will be provided a comprehensive overview of how to improve the productivity and efficiency of all stages of the petroleum production process, including operations and major projects.

TOPICS TO BE EXPLORED

- **A Global Investor Perspective:** SWOT analysis of Canada's energy industry
- **Aligning Supply Chain with Strategic Business Objectives**
- **Productivity, Not Just Price:** The real solution to surviving low oil prices
- **"We Need a 25% Cost Reduction!"** What producers and suppliers are doing together to achieve sustainable cost reductions
- **SAGD Well Pad Replication Strategy:** Cost savings through innovation, repeatability and supply chain collaboration
- **Applying Technology Innovation Lessons Learned from Other Industries:** Using aerospace coatings technology in oilsands pumps
- **Collaboration Opportunities and Insights:** North Sea oil and gas operations
- **Driving Productivity:** Using RFID technology

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