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New Technology magazine

THE FIRST WORD ON OILPATCH INNOVATION

TECHNOLOGY STARS

RISING TO THE TOP

Daring to innovate sets apart these Technology Stars leading the industry into a brighter future

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CLEAN ENOUGH FOR EXPORT?

The Canadian oilpatch is in a state of flux such as it has not seen in a long time, with uncertainties in every direction. Its biggest and most loyal customer, the United States, has lately become largely indifferent to Canadian oil and gas as its own production and reserves steadily climb toward a possible surplus position of their own.

Gaining access to other markets is resisted at every turn, as pipeline construction that once flew under the radar incites protest seemingly wherever it goes while the spotlight simultaneously turns to lesser alternatives like rail in the aftermath of the tragic Lac-Megantic, Que., train crash. At this point, it's anyone's guess how soon major pipeline links to the U.S. Gulf Coast, the B.C. coast or the East Coast might proceed.

It is similarly difficult to predict how large an impact the energy industry's biggest technology story of the decade, the development of horizontal drilling and multistage fracturing, will have on the rest of the planet as the technology inevitably spreads to other promising basins.

And over all this hangs the federal government's promised but long-delayed regulations on Canada's oil and gas industry to limit greenhouse gas emissions in line with its sector-by-sector regulated approach to meeting the country's international pledge to trim emissions 17 per cent below 2005 levels by 2020, just six years away.

In this issue, we look at an issue not unrelated to that last uncertainty. The European Union (EU) could be close to implementing a Fuel Quality Directive (FQD) that would label oilsands crude 22 per cent more greenhouse gas intensive than conventional crudes, while California has enacted its Low Carbon Fuel Standard with a similar objective—to drive down the emissions intensity of the fuels they use throughout the transportation sector.

While Canada currently exports minimal oilsands to either jurisdiction, depending on how the cards land in the transportation conundrum, that could change in a hurry. If built, pipelines to the Gulf Coast and Canada's East Coast would find easy access to Europe's shores across the Atlantic, while a B.C. pipeline link to tidewater would put crude within easy shipping distance of California. The other risk, of course, is that fuel quality regulations spread to more jurisdictions.

The EU rule, in particular, has been harshly attacked and intensely lobbied against by the provincial and federal governments. Alberta recently dispatched two more cabinet ministers to criss-cross Europe to lobby against the FQD, while Ottawa, claiming the science behind the initiative to be faulty, announced plans in September to spend up to $200,000 on yet another study of life-cycle emissions. Natural Resources Minister Joe Oliver went so far as to threaten a complaint to the World Trade Organization if the FQD is implemented.

It is a situation tinged with irony. The federal government claims regulation—which is more blunt an instrument than the use of market forces that a price on carbon would achieve—is the best way to reduce emissions in Canada, but opposes other jurisdictions that take a regulatory approach. And while dithering on Canada's regulatory approach to the oil and gas sector—to the point it is very unlikely Canada can now meet its 2020 obligation—it lobbies against other jurisdictions' regulations that might actually encourage the kind of emission-reductions efforts among companies operating in Canada that could assist Canada in meeting its own target.

The final irony is that avoiding the emissions issue in Canada could very well work against the interests of oil companies, some of which favour a price on carbon and use one internally already. The United States has made clear it will take into account carbon emissions on decisions like the Keystone XL Pipeline to Texas. Taking real action to start us on the road to meeting our own targets would not only make the oilsands more exportable, but would diminish the arguments of opponents against their use in other jurisdictions. The alternative may be an increasingly stranded resource—and therefore a less valuable one. It may turn out that meaningful regulations (or a carbon price) could be a low price to pay to gain access to foreign markets.

■ ***Maurice Smith***

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www.newtechmagazine.com

EDITORIAL

EDITOR
Maurice Smith | *msmith@junewarren-nickles.com*

STAFF WRITERS
Lynda Harrison, Carter Haydu, James Mahony, Pat Roche, Elsie Ross

CONTRIBUTING WRITERS
Godfrey Budd, Gordon Cope, Jacqueline Louie

EDITORIAL ASSISTANCE MANAGER
Marisa Sawchuk | *msawchuk@junewarren-nickles.com*

EDITORIAL ASSISTANCE
Kate Austin, Shawna Blumenschein, Matthew Stepanic

CREATIVE

PRINT, PREPRESS & PRODUCTION MANAGER
Michael Gaffney | *mgaffney@junewarren-nickles.com*

CREATIVE SERVICES MANAGER
Tamara Polloway-Webb | *tpwebb@junewarren-nickles.com*

CREATIVE LEAD
Cathy Ozubko | *cozubko@junewarren-nickles.com*

GRAPHIC DESIGNER
Teagan Zwierink

CREATIVE SERVICES
Jenna O'Flaherty

SALES

SALES MANAGER—ADVERTISING
Monte Sumner | *msumner@junewarren-nickles.com*

SENIOR ACCOUNT EXECUTIVES
Nick Drinkwater, Tony Poblete, Diana Signorile

SALES
Terry Nelson Browning, Brian Friesen, Rhonda Helmeczi, Sammy Isawode, Mike Ivanik, Nicole Kiefuik, David Ng, Sheri Starko

For advertising inquiries please contact adrequests@junewarren-nickles.com

AD TRAFFIC COORDINATOR—MAGAZINES
Lorraine Ostapovich | *atc@junewarren-nickles.com*

DIRECTORS

CEO
Bill Whitelaw | *bwhitelaw@junewarren-nickles.com*

PRESIDENT
Rob Pentney | *rpentney@junewarren-nickles.com*

DIRECTOR OF SALES & MARKETING
Maurya Sokolon | *msokolon@junewarren-nickles.com*

DIRECTOR OF EVENTS & CONFERENCES
Ian MacGillivray | *imacgillivray@junewarren-nickles.com*

DIRECTOR OF *THE DAILY OIL BULLETIN*
Stephen Marsters | *smarsters@junewarren-nickles.com*

DIRECTOR OF DIGITAL STRATEGIES
Gord Lindenberg | *glindenberg@junewarren-nickles.com*

DIRECTOR OF CONTENT
Chaz Osburn | *cosburn@junewarren-nickles.com*

DIRECTOR OF PRODUCTION
Audrey Sprinkle | *asprinkle@junewarren-nickles.com*

DIRECTOR OF FINANCE
Ken Zacharias, CMA | *kzacharias@junewarren-nickles.com*

OFFICES

CALGARY
2nd Flr-816 55 Avenue NE | Calgary, Alberta T2E 6Y4
Tel: 403.209.3500 | Fax: 403.245.8666
Toll-Free: 1.800.387.2446

EDMONTON
220-9303 34 Avenue NW | Edmonton, Alberta T6E 5W8
Tel: 780.944.9333 | Fax: 780.944.9500
Toll-Free: 1.800.563.2946

SUBSCRIPTION INQUIRIES
Tel: 1.866.543.7888 | Email: circulation@junewarren-nickles.com
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> "We need to achieve zero emissions from fossil fuel sources by the second half of the century."
>
> *— Angel Gurria, secretary-general, Organisation for Economic Co-operation and Development*

Simply reducing fossil fuel emissions is not enough to lower the economic costs of climate change because CO_2 accumulates in the atmosphere and remains there for decades, Gurria told reporters at a briefing in London. "That doesn't mean by 2050 exactly, but it means by that time we need to be pretty much on the way to achieving it," he said, suggesting there needs to be a "big, fat price on carbon."

14 YEARS

Imperial Oil Resources Ventures Limited has taken the first step in the regulatory process that could see it and its partners drill an exploration well in deepwater offshore Beaufort Sea by the end of this decade, which would end a 14-year offshore drilling hiatus in the Canadian High Arctic. The company filed a project description with the Environmental Impact Screening Committee for drilling about 125 kilometres northwest of Tuktoyaktuk in water depths of 60–1,500 metres. The last well drilled in the Canadian Beaufort was in 2005-06 when Devon Canada Corporation discovered 240 million barrels of recoverable oil while drilling for natural gas.

ONE MILLION

Investment being made in Canada's rail capacity is expected to help get crude oil to critical markets, with total planned rail facilities adding up to more than one million barrels per day of takeaway capacity by 2014, according to James Cairns, vice-president of petroleum and chemicals, Canadian National Railway Company. "That's assuming every facility runs at capacity and is up and running and is running unit trains, which we know is not going to happen, but just the fact that it's being built out to be a million barrels a day means rail is going to be a significant part of that supply chain moving forward," he told the *Daily Oil Bulletin*.

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The future of carbon capture in the oilsands could involve storing CO_2 throughout that area in depleted gas pools with the right conditions for gas to become locked in water crystals, said researchers at September's International Acid Gas Injection Symposium. The Geological Survey of Canada identified 62 depleted gas pools in Alberta with temperature and pressure conditions suitable for the formation of hydrates, which consist of hydrogen-bonded water and CO_2 molecules. "I think it has a lot of potential and industry is very interested," said Olga Zatsepina, institute associate with the University of Calgary Schulich School of Engineering.

> "We have a great potential to be not only the top energy school in Canada, but also among the best in the United States and internationally."
>
> *— Chris Clarkson, University of Calgary geoscience professor and Encana–Alberta Innovates – Technology Futures chair in unconventional gas research*

The university is hiring more than 30 assistant professors, postdoctoral students and research chairs to collaborate on energy research. They will research new sources of energy, extraction with minimal impact, exports and plans for future energy developments in the areas of unconventional hydrocarbons, hydraulic fracturing, low-carbon energy and cumulative effects of energy-related processes.

OILSANDS

Reality Falling Far Short Of Theoretical

Low gas prices mask inefficiency of SAGD process, study suggests

From the standpoint of many of Alberta's thermal bitumen producers, a recent study on the efficiency of steam assisted gravity drainage (SAGD) could be titled "Thank God for low natural gas prices."

The paper, published last month in the journal *Fuel* by University of Calgary (U of C) professors Ian Gates (department of chemical and petroleum engineering) and Steve Larter (department of geoscience), underscores the importance of developing better technologies for in situ bitumen extraction.

"The analysis shows that although some SAGD operations are achieving good steam-to-oil ratios, many are not achieving thermally efficient operation, with cumulative steam-to-oil ratios (SOR) many times the theoretical value," the paper concludes. "This results from combinations of geological realities, operator decisions and the limitations of the SAGD process.

"The results demonstrate that on an energy and carbon dioxide emissions basis, bitumen or bitumen-based energy recovery processes need to step well beyond the capabilities of current steam-based bitumen recovery processes, such as SAGD, if practical and sustainable energy balance and emissions scenarios are to be achieved from the in-situ oilsands operations."

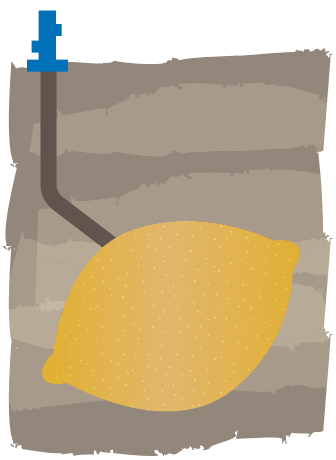
The study looks purely at the energy value of a barrel of bitumen versus the amount of energy required to produce it, but didn't assess current economics. With gas prices of less than $2 per gigajoule (AECO) coinciding with strong oil prices and a relatively healthy differential between heavy and light oil prices, it would be hard for thermal oil producers not to have good economics today.

But history has shown oilsands producers can't bank on such an enormous spread between the price of the gas they burn to convert water to steam and the price they get for their bitumen.

After analyzing the energy efficiency of SAGD, the U of C researchers wrote: "The results reveal that the overall net energy break-even point is now equal to a production CSOR [cumulative SOR] of about 6.5," (e.g., 6.5 cubic metres of water boiled to make steam, which, injected into the reservoir, yields one cubic metre of bitumen).

Based on CSOR field data, the analysis found that many operations exceed a CSOR of 6.5 and thus are not net-energy generation processes, though they may still be economic with low gas prices and high oil prices.

"With disconnected price markets for natural gas and bitumen, it is possible for bitumen recovery under these conditions to be economically viable today even though it makes no sense to pursue such an energy inefficient process when CSOR values are high," the paper says.



The paper says the theoretical minimum amount of energy required to heat a cubic metre of Athabasca oilsands at a reservoir temperature of 10 degrees Celsius (at which bitumen viscosities would be in the millions of centipoise) to a steam temperature of 200 degrees Celsius (resulting in a dead oil viscosity of 10 centipoise) would be about 1.75 gigajoules.

Unfortunately, the realities of the reservoir mean the actual amount of energy needed is much higher, since hot steam injected into the reservoir heats not only the oilsands, but also the overburden, non-productive rock and water in water-rich zones within the rock.

Also, the theoretical or ideal SOR is typically lower than the actual SOR because oilsands reservoirs are geologically variable with interbedded sandstones and shales that present a complex, variably permeable medium that steam, oil and water must migrate through, the paper notes.

"Actual oilsands reservoirs are completely different from the homogeneous sandstones with uniform fluids envisaged by the reservoir engineers that developed the early SAGD process. Geological heterogeneity impacts the recovery process through permeability changes of the reservoir sandstones within the oil column and the shale or mudstone barriers and baffles that prevent or retard fluid flow, respectively," the paper says.

"The more laterally extensive the barrier, the longer it takes steam or production fluids to go around it and the longer it takes for mobilized oil to get to the production well. Also, non-productive reservoir within the oil column represents a heat sink which erodes the thermal efficiency of the process. The main impact of fluid compositional heterogeneity is due to the effect of vertically and laterally varying oil phase viscosity."

And it isn't all about good reservoir management or well placement. Some companies just have better acreage. "In general, the best-performing well pairs are from regions with better-quality reservoir which have thick, highly oil-saturated accumulations with few shale barriers and high vertical permeability throughout the reservoir," the paper says. "Operator experience is clearly an important factor, but reservoir geology is king."

Using SAGD field data, the researchers found the majority of well pairs are operating with a thermal efficiency of less than 40 per cent.

"For those few well pairs operating above this limit, this is probably an artifact of interaction between proximal well pairs and implies that some well pairs are not operating independently and thus one may appear highly efficient whereas its neighbour does not. Well pairs operating between 30 per cent and 40 per cent efficiency are probably operating as thermally efficiently as can be expected," the paper says, adding, "Real SAGD is about 30 per cent as efficient as ideal SAGD with many well pairs less efficient than this."

Pat Roche

IMAGE: JENNA O'FLAHERTY

IMAGE: WESTERN INDUSTRIAL SOLUTIONS

HEALTH AND SAFETY

Document Automation Made Easy

Combination software and hardware product takes the paperwork out of oilfield safety data management

As concerns over safety for workers in the field have grown, so has the work involved in filling out the reams of documentation required by companies and government regulators—a task that can become a significant drain on a company's resources to manage.

When three friends in the B.C. Interior were laid off from a Crown corporation—friends who shared work experience in information technology and health and safety with various natural resource–related companies—they saw that growing problem as an opportunity.

They established Western Industrial Solutions (WIS) in Kamloops in 2011 and pooled their collective 60 years' worth of working knowledge to create a software/hardware solution called TaskSafe. Tailored to the oil and gas, mining and forestry sectors, and the uniquely harsh conditions of the Canadian outdoors, TaskSafe both simplifies and improves the documentation process while cutting costs, says Christopher Mitra, director of business operations.

Mike Waithe, the company's chief executive officer, was a health and safety officer for a petroleum company and "totally understood the pains involved with safety paperwork," says Mitra. "It's one of those mandatory things that has to be done, but the amount of paperwork that was coming through was incredible, and it was just taking up more time and resources than it needed to be."

The pair and third partner Grant Schaffer, chief technology officer, took up the task of writing software code over about seven months before it was beta-tested and rolled out into the marketplace almost a year ago.

"It's a combination of custom-written software and intrinsically safe tablet PCs that allow resource-based companies to have their field crews do all their safety paperwork on the job site. Instead of doing it all >

BEYOND PEN AND PAPER
Designed for field workers in resource industries, Western Industrial Solutions' TaskSafe both simplifies the task of filling in and filing safety documentation and helps workers develop better safety habits.

manually—there are a lot of inherent problems with that—what we have done is automated it so that all the paperwork is done on the tablet, signed off digitally, and date- and time-stamped, and locked from editing. And then when they have wireless connectivity, they are moved up to secure cloud storage."

TaskSafe also contains all the company's health and safety manuals and related documentation, like material safety data sheets, all searchable and updatable and contained on the tablet. "You no longer have to have binders full of documents, and when you do have to update those materials, they are updated in one place in a back office and synced out to all the tablets in the field."

Built-in cameras allow users to take and attach photos to documentation, while a stylus allows them to add signatures to documents in the field. This, along with the ability to date and time-stamp documents and lock them from editing, allows for the creation of legally binding contracts, Mitra says. The document can be saved as a picture so that WIS can verify the pixel count and ensure it is never altered, allowing the company to act as a third-party verification service.

WIS has a proprietary secure data transmission system to safeguard documents as they move over the Internet. Connectivity is enabled with wireless and 3G broadband, though the units operate independent of online access in remote areas. If a tablet goes missing or is stolen, it can be tracked with worldwide GPS capability, as well as locked down or have its front camera activated to see who is using it.

On the hardware side, WIS partnered with two companies that manufacture military-grade tablet PCs: Motion Computing, Inc. and Xplore Technologies Corp. "We did a lot of field testing with a number of different tablets and went with two that we felt were definitely well worth the value and able to withstand the rigours of working out in the field."

Xplore's C5 line is labelled as ultra-rugged, Mitra notes, and "is probably one of the best, most durable tablets there is, and has the certifications and ratings to prove it—it can handle anything," including a seven-foot drop onto concrete. They are also dustproof, sealed against liquids and contain "sunlight-readable" touch screens. Buttons on the interface are made large enough for gloved fingers to easily navigate.

Beyond the software and hardware, what sets WIS apart, Mitra says, is its consultative approach that results in a solution uniquely tailored to each company's needs. "We don't just provide our customers with off-the-shelf safety forms; we work with the client to take their safety forms and build them into our software, so they are not forced to change their safety processes. They use the forms they are comfortable with and that is actually a big benefit out in the field because the guys have a lower learning curve, they are already comfortable with the forms they are seeing on the tablet."

> "We don't just provide our customers with off-the-shelf safety forms; we **WORK WITH THE CLIENT** to take their safety forms and build them into our software, so they are not forced to change their safety processes."
>
> ***— Christopher Mitra, director of business operations, Western Industrial Solutions***

The forms are not just fillable PDF documents; there is built-in business logic behind them, he adds. "For instance, if someone does a safety form and they click off that they are working in a confined space, then the software will automatically open up that confined-space form and make sure that they fill that in. Because these are date- and time-stamped, they are required to fill them in at the time of the job, and they are also required to actually read what is on the screen, so they are more aware of the safety situations that are going on, but at the same time they are saving time. Some of the feedback that we have been getting from the guys out in the field is that this actually increases their safety awareness.

"And it lends itself very well to the generation growing up right now because they are very comfortable with this kind of technology. They work better with digital technology, the texting and the online keyboards, than they do with paper and pen."

The company, which won a Best Concept award from Small Business BC in February, is currently focusing much of its expansion efforts on the oilpatch to the east of the B.C. border. One early customer was Empire Gas Services Ltd. of Grande Prairie, Alta., which has used TaskSafe for almost a year.

"We tried the iPad before and it didn't match up to the computer system that I have in the office, and it was just too cumbersome—it wasn't user-friendly, where this one is," Steve Liscumb, field production foreman, says of TaskSafe. "And the guys, they all seem to love it. They think this is the way it is going to be going from now on—it's like the next step in technology for us."

Liscumb says Empire Gas Services, which specializes in remote-access well and compressor operations, plans to expand its use of TaskSafe, moving to the intrinsically safe Xplore model so that field workers can use it in areas like compression buildings. (An "intrinsically safe" classification signifies its circuits and wiring won't cause sparking or arcing and it can therefore be operated in potentially hazardous areas, such as gas plants and refineries.)

He says it is a time saver for both office staff and field personnel. "I can get real-time reports from my guys out in the field and they don't have to waste time coming back to the office to upload it to the computer," he says. "They can take all of their readings and upload them right away, and then I have them here instead of—like old school—where I would have to get them the next morning. I think this is the wave of the future."

Mitra says he has no regrets after striking out with the new partnership after the unexpected layoffs. "We were good friends to begin with and just figured we'd take our fate into our own hands and not have to worry about corporate downsizing anymore. When you work for a big company, you forget that you can do things. Working on our own has been amazing. It is a huge learning curve, but every day is something new, and I am impressed with what we have created so far—we are getting a lot of excellent feedback."

■ ***Maurice Smith***

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ENVIRONMENT

Doing A Slow Burn For Oilsands

Researchers create "activated" biocarbon from wood residue to help remediate oilsands water

Alberta's oil and gas, agriculture and forestry industries—even the environment—will all benefit if research being conducted at the University of Calgary (U of C) on charcoal manufactured from waste is successful.

The university's scientists are examining how Alberta-grown products such as straw and wood left over from farming and forestry operations can not only clean up contaminants in water from oilsands operations, but also prevent the formation and release of methane and provide a permanent "sink" for carbon that used to be in the atmosphere.

"We're looking to add value to biochar that will ultimately be used as a carbon sink, while also improving the environmental footprint of oilsands operations," says project lead David Layzell, a U of C biological sciences professor affiliated with the Institute for Sustainable Energy, Environment and Economy.

Most of the organic compounds in the processed water from Alberta's oilsands projects are toxic, corrosive naphthenic acids.

Microbes in the mining projects' tailings ponds convert these naphthenic acids to methane gas, which is emitted into the atmosphere. A greenhouse gas, methane has a much shorter lifetime in the atmosphere than CO_2, but because it is more efficient at trapping radiation, its impact on climate change is over 20 times greater than CO_2 over a 100-year period.

U of C researchers are working with the University of Alberta, Olds College and the industry to develop an activated biocarbon that would adsorb the naphthenic acids in that water, thereby preventing the formation and release of methane.

Biochar is essentially charcoal, and it is created by converting biomass or feedstock into a charred product >

CARBON SINK
University of Calgary researchers (from left) Josephine Hill, Andrei Veksha and David Layzell, in a laboratory housing a slow pyrolysis reactor, are studying the feasibility of using materials like waste wood and straw to both treat oil industry waste water and to store carbon.

by slowly burning it under oxygen-limited conditions. When created under the appropriate conditions, the biochar can be activated so that it acts as a sponge for organic compounds in water.

The spent biocarbon could then be used as either a source of renewable energy to displace fossil fuels, or landfilled as a permanent carbon storage, further reducing greenhouse gases.

Activated carbon made from coal is already used to remove undesirable tastes or smells from tap water, and researchers have established a method of creating a similar material from renewable biomass feedstocks.

Layzell estimates they have spent about $250,000 on the research project so far. Funding has been provided by Climate Change and Emissions Management Corporation, the Natural Sciences and Engineering Research Council of Canada and the Oil Sands Leadership Initiative.

The scientists are in discussions with agriculture, forestry and technology companies to find an activated biochar that works well in the laboratory and can be scaled up from the hundreds of grams they are using now to tens and even thousands of kilograms.

"This is obviously going to take time and resources," he says. "We have the material, but we need to find a process to make it less expensive. Then we'd look for partners to work with who are interested in a particular application: oilsands companies, companies that specialize in water treatment, technology companies."

They are also working on water used in steam assisted gravity drainage (SAGD) operations, but that is less promising, says Layzell. "The economics on the SAGD side don't work as well, because the concentration of organics is so much higher. This means we would have to use a lot more biochar material for the treatment of water associated with a given barrel of oil produced," he says.

He and his main collaborator, Josephine Hill, a U of C chemical and petroleum engineering professor and Canada research chair in hydrogen and catalysis, recently received funding from Alberta Innovates – Technology Futures and the University of Alberta for a project that is working to extend the research on biochar. Its main focus is on remediation of tailings water.

Researchers want to develop adsorbents made from biomass that will adsorb some of the contaminants like naphthenic acids and other organic carbon material from tailings water. The adsorbents have to be tailored physically and chemically for the species to be adsorbed.

Layzell is up against some stiff competition, says Joseph Fournier, a research contract specialist at Suncor Energy Inc., who is aware of the scientist's research through a conversation and meeting with Layzell several years ago, as well as Fournier's work with Hill on activation technology.

There is an application for activated carbon, which can be sourced from materials such as natural gas, in oilsands tailings ponds, but that's not new technology, says Fournier.

"I think the advantage that [Layzell] perceives is that because he can advertise it comes from tree trunks versus natural gas–derived carbon, that somehow that's got an earthier flavour to it. But performance-wise for water treatment, it may not stack up," says Fournier.

Skepticism from individuals in the oil industry doesn't surprise Layzell.

"The onus is now on the research community to develop some innovative technologies that will reduce the cost and enhance the performance of the adsorbing biochars we make," says Layzell. "If we can do this—and I think it should be possible—we can re-engage the energy industries and start to put together some exciting new approaches to link agriculture and forestry sectors with energy, and help reduce their environmental footprints."

Lynda Harrison

CONTACT FOR MORE INFORMATION

David Layzell, University of Calgary
Tel: 403-220-5161
Email: dlayzell@ucalgary.ca

RISING TO THE TOP

Daring to innovate sets apart these Technology Stars leading the industry into a brighter future

PRODUCTION

18 WINNER:
Schlumberger

20 RUNNER-UP:
NCS Oilfield Services Canada Inc.

EXPLORATION

21 WINNER:
Baker Hughes Incorporated

23 RUNNER-UP:
Energy Navigator Inc.

DRILLING

24 WINNER:
Cenovus Energy Inc.

26 RUNNER-UP:
Baker Hughes Incorporated

HEALTH, SAFETY & ENVIRONMENT

27 WINNER:
Halliburton

28 RUNNER-UP:
Axine Water Technologies Inc.

SCHLUMBERGER

PRODUCT: REDA HotlineSA3

SERVICE: High-temperature electric submersible pump

Pumped For Success

An overlooked mainstay of bitumen extraction, the electric submersible pump is built to take the heat

The oilsands of northern Alberta is one of the largest crude deposits on Earth, holding some two trillion barrels of bitumen, of which approximately 170 billion barrels are recoverable. According to the Canadian Association of Petroleum Producers (CAPP), operators produced 1.8 million barrels per day (bpd) in 2012, 800,000 bpd from mining operations and one million bpd from in situ (thermal) projects. By 2030, CAPP predicts oilsands production will climb to 5.2 million bpd, 1.7 million bpd from mining and 3.5 million bpd from in situ.

The growth of in situ production has been propelled by a host of technological advances, including horizontal drilling and steam assisted gravity drainage (SAGD), but one innovation has had a particularly significant impact.

“Until the introduction of high-temperature electric submersible pumps [ESPs], operators primarily used gas lift to produce bitumen to surface,” says Colin Drever, thermal ESP sales manager for Schlumberger Canada Ltd.’s artificial lift segment. “Our Hotline550 ESP was a big improvement, as it provided superior performance and could operate in lower reservoir operating pressures, resulting in lower steam-oil ratios and improved operating efficiency.”

An ESP module consists of a liquid pump driven by an electric motor, which is powered from the surface via cable. The artificial lift is positioned directly adjacent to the reservoir, allowing for efficient production. Schlumberger introduced the REDA high-temperature ESP system to the heavy oil industry in 1996.

The second-generation REDA Hotline550 ESP, launched in 2003, proved to be very popular and was widely used in oilsands operations. “After the introduction of the Hotline550, we had the opportunity to collect knowledge on ways to even further improve performance,” says Drever. “Although the REDA Hotline550 was rated to a temperature of 218 degrees [Celsius], there was an increasing industry need to develop an ESP that could operate at even higher temperatures.”

Schlumberger had plenty of cooperation from oilsands clientele such as Suncor Energy Inc. Suncor, which operates the Firebag in situ project near Fort McMurray, had been using previous versions of high-temperature ESPs, predominately the Hotline550 system.

Don Clague, senior vice-president of in situ at Suncor, describes how important it is to work collaboratively to advance new pumping technology. “Our engineering and field staff were very proactive in identifying opportunities for improvement. We are committed to finding a better product.”

Starting in 2007, Schlumberger’s engineering teams in Singapore and the United States began working on the unique architecture and

TEAMWORK
Schlumberger and Suncor worked collaboratively to develop a new-generation electric submersible pump that can withstand the uniquely high temperatures encountered in thermal oilsands production.

PHOTO: SCHLUMBERGER CANADA LTD.

components of a new-generation ESP. By 2010, they had developed a prototype that could be field tested and, in August 2011, unveiled the REDA HotlineSA3 to the commercial market.

“This represented a step-change in the ESP industry,” says Drever. “The HotlineSA3 has a number of advances. First, it has a higher temperature rating, at 250 degrees [Celsius]. We improved the insulating material in the motor winding, developed higher-temperature motor oil, and utilized high-performance elastomers and bearing materials. In terms of reliability, we changed the system architecture so the shaft seal module would provide even better protection to the motor.”

FIELD RESULTS

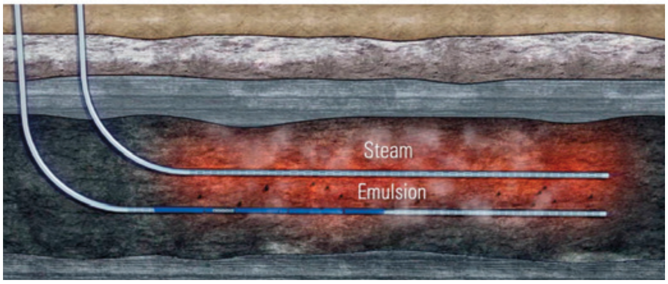
The new-generation ESP has delivered far better performance in the field. “Mean time to failure, or MTTF, ranges up to 1,300 days, which ranges up to twice the previous generation,” says Drever. “Increasing MTTF is key to a host of other operating factors, including fewer interventions and equipment replacements. As a result, operators saw overall operating costs decrease.”

Schlumberger also improved the installation process of their ESP at the wellsite. “We wanted to make it faster and simpler to install,” says

> *"The utilization of the REDA HotlineSA3 system enables the SAGD operator to run at higher temperatures and increase production."*
>
> *— Colin Drever, thermal ESP sales manager, artificial lift segment, Schlumberger*

Drever. "Most of the unit is assembled and serviced prior to shipment to the wellsite, so there is minimal assembly required on the rig floor. This speeds up installation and reduces the potential for error."

The HotlineSA3 has integrated temperature and pressure sensors to measure operating conditions in real time. "This allows the operator to



SAGD ENHANCED
Schlumberger's REDA HotlineSA3 is shorter than previous models, enabling easier passage through highly deviated sections of SAGD production wells.

optimize performance, and it also protects the unit," says Drever. "If the motor temperature gets too high, for instance, you can immediately shut it down and prevent damage. The REDA HotlineSA3 is also shorter in length, so it can pass through more highly deviated wellbores without compromising reliability."

The HotlineSA3 has proven to be a big hit with SAGD operators. Schlumberger has more than 400 REDA Hotline ESPs installed in Canadian SAGD projects; currently, more than 40 per cent are REDA HotlineSA3s. Over the next few years, the company expects the majority of SAGD wells in Canada to be equipped with the new-generation SA3.

"Every project is unique, so there are many variables to consider," says Drever. "However, the utilization of the REDA HotlineSA3 system enables the SAGD operator to run at higher temperatures and increase production."

Schlumberger is committed to finding ways to advance its ESP line. "Our focus going forward will be to continue to provide leading-edge pumping technology and service to the heavy oil industry," says Darrel Quennell, manager of Schlumberger Canada's artificial lift segment.

As far as the industry is concerned, the REDA HotlineSA3 has resulted in a step-change in high-temperature ESP performance and reliability. "Extending the longevity of equipment and enabling the application in challenging environments is instrumental to allow Suncor to economically and sustainably develop our vast in situ resources," says Clague. "The ongoing development of more robust subsurface pumps is an excellent example of the collaboration and commitment of our two organizations and the innovative people in each."

■ *Gordon Cope*

DIAGRAM: SCHLUMBERGER CANADA LTD.

RUNNER-UP
PRODUCTION

NCS OILFIELD SERVICES CANADA INC.

PRODUCT: Multistage Unlimited

SERVICE: Resettable frac sleeves

More Stages, Better Accuracy

Resettable frac sleeve promises long-term cost advantages

Multistage completion operations, whether performed with perf-and-plug or ball-drop systems, are typically horsepower-intensive, requiring large hydraulic fracture equipment commitments and lease footprints.

However, NCS Oilfield Services Canada Inc. says that its new resettable frac sleeves, using its proprietary Multistage Unlimited technology delivered through coiled tubing, can provide faster, more economic and more targeted fracs.

"The new generation of frac sleeves means operators can open and close the frac sleeves to isolate any segment of the wellbore as many times as they want," says Eric Schmelzl, vice-president of strategic business.

"That changes the game quite a bit, especially when you are pursuing oil or gas with the potential for unwanted water production."

According to Schmelzl, the technology offers inexpensive and rapidly executed conformance control over the life of the well.

Any individual sleeve in the wellbore can simply be closed, which can quickly and easily resolve unwanted production from any specific interval. Conversely, the ability to close multiple sleeves allows operators to go in and close everything except the specific interval that they want to deal with and treat the well like it's a single-stage wellbore, and subsequently revert back to a multiple-stage wellbore afterward at very low cost. As a result, dealing with wells that lack the ability to circulate fluids to surface may become a thing of the past, he says.

The resettable sleeves can also be used to facilitate out-of-sequence fracturing stages, and could help to minimize post-frac sand production.

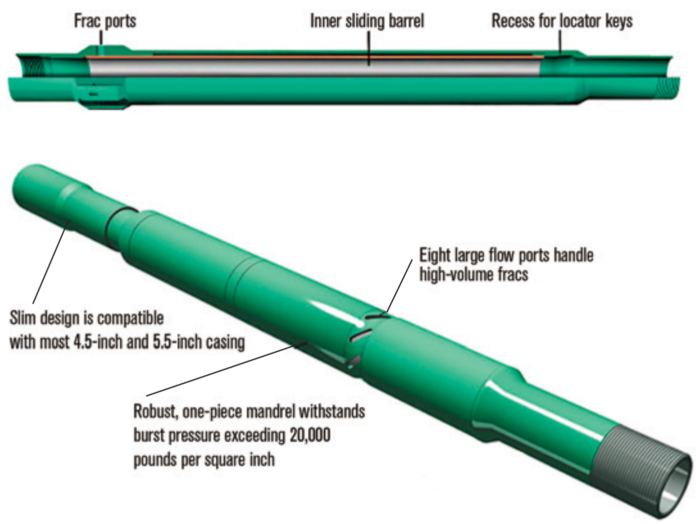
The new closable sleeve design has been successfully deployed in field trials where multiple intervals were sequentially fracture stimulated, and each sleeve was shifted closed and successfully pressure tested before it was reopened for production.

"Operators are also spending a tremendous amount of cash for horsepower, but most of that is used up in the wellbore as friction because they are pumping so fast," says Schmelzl. "But only a fraction of that horsepower actually gets down to the reservoir, and often the wellbore segments that get stimulated may be only a fraction of the targeted interval."

The coiled tubing work string provides a circulation path to the frac zone and also allows the use of the unique resettable frac plug that can be repositioned to isolate each stage for stimulation. Current coiled tubing capabilities are more than adequate to handle multistage completion operations, according to NCS.

"By pumping down the inside of the coiled tubing, it is also possible to circulate all fluids to the targeted interval," he says. "Operators can then simply shut the annulus and avoid bullheading wasted fluid into the formation."

When the last stage is completed and the resettable frac plug is pulled from hole, the well is ready to produce. There is no need to drill out plugs or ball seats. The bore is fully open, with no restrictions to impede further completion or intervention operations.



SLIDING-SLEEVE SYSTEM
The NCS grip/shift sliding sleeves (top) are combined with its resettable frac isolation in the Multistage Unlimited sliding sleeve/annular frac system to deliver fast and economical multistage completions. The pressure-actuated toe sleeve (bottom) incorporates a time-delay mechanism that permits a full casing pressure test before the sleeve opens to the formation, providing an effective means of ensuring initial formation access for multistage completions.

DIAGRAM: NCS OILFIELD SERVICES CANADA INC.

Earlier this year, NCS successfully placed 60 stages in a single well completion, demonstrating the reliability of its Multistage Unlimited system. The July project set a company record for the largest number of stages for a single wellbore in Canada.

The multistage completion was accomplished on a 4.5-inch cemented liner targeting the Torquay formation using 59 NCS frac sleeves and one abrasive cut. The well reached a total measured depth of 5,725 metres and a true vertical depth of 2,401 metres. The completion operation placed 639 tonnes of proppant in 120 hours. Sixteen sandoffs were successfully circulated clean without incident or significant lost time.

Although there are maximum pressure limitations on the use of coiled tubing, "in Canada you would probably never run into them," says Schmelzl. "We're typically not exploiting formations deep or high pressure enough to be limited by the CTU [coiled tubing unit] methodology."

While NCS has operated mainly in southern Saskatchewan and Manitoba, it is beginning to do more work in the Cardium in Alberta and soon plans to take on wells in the Montney gas play, as well.

Elsie Ross

BAKER HUGHES INCORPORATED

PRODUCT: JewelSuite

SERVICE: Reservoir modelling software suite

Works Like A Gem

Software platform deploys multidisciplinary approach to comprehensive reservoir-to-surface modelling and analysis

An oil or gas reservoir is developed and produced only once, so mistakes can be wasteful and costly. In today's environment where unconventional oil and gas reservoirs continue to assume ever-greater importance, the stakes, if anything, have risen. The costs and complexities of producing a well certainly have. "Unconventional reservoirs are hugely multidisciplinary," says Ryan Mohr, NEBC shale gas geology team lead for Nexen Energy ULC.

In the last year or so, to help deal with the growing complexity of workflows, which, in turn, stem from the increasing range of data types and the disciplines involved, Nexen has been using the Baker Hughes Incorporated JewelSuite software platform. "The challenge we had faced was to find a tool to evaluate information we were collecting on unconventional reservoirs, which lend themselves to a lot of different kinds of data," Mohr says.

He says that Nexen's introduction to the JewelSuite software came about while working with Computer Modelling Group Ltd., which "had a relationship with the reservoir simulation aspect of JewelSuite.

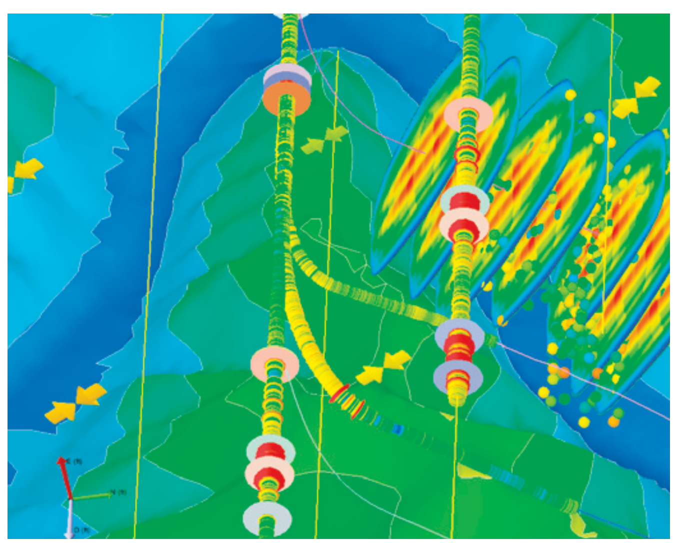
"The desire to incorporate the geo-mechanical components of these reservoirs into our reservoir [simulations and analysis] was intense, but it was not part of our standard workflow. For this, we would start with well data, seismic, microseismic, hydraulic fracture simulation and prediction, then simulation, performance, and production forecasting," Mohr says.

An aspect of unconventional oil and gas, which Mohr and others have noted, is that it requires geologists and engineers to work more closely together. Furthermore, not only is it important to understand static rock properties, but also "how you affect all those properties when you frac," he says.

He does not think that JewelSuite has all the answers to all the problems, but he is confident that the platform and its suite of products will only improve because the JewelSuite software people at Baker Hughes' Reservoir Development Services (RDS) "listen to their clients to a degree unmatched by the competition."

He adds, "The exciting thing about JewelSuite is the business model of how all the processes involved, fitting all the tools together, can be integrated into a workflow and how all the pieces fit together to help get to a better understanding of these unconventional reservoirs. You can have the best geo-mechanical modelling and the best reservoir simulator, but if all the parts are not working together, each component is not as useful as it could be with them all working together."

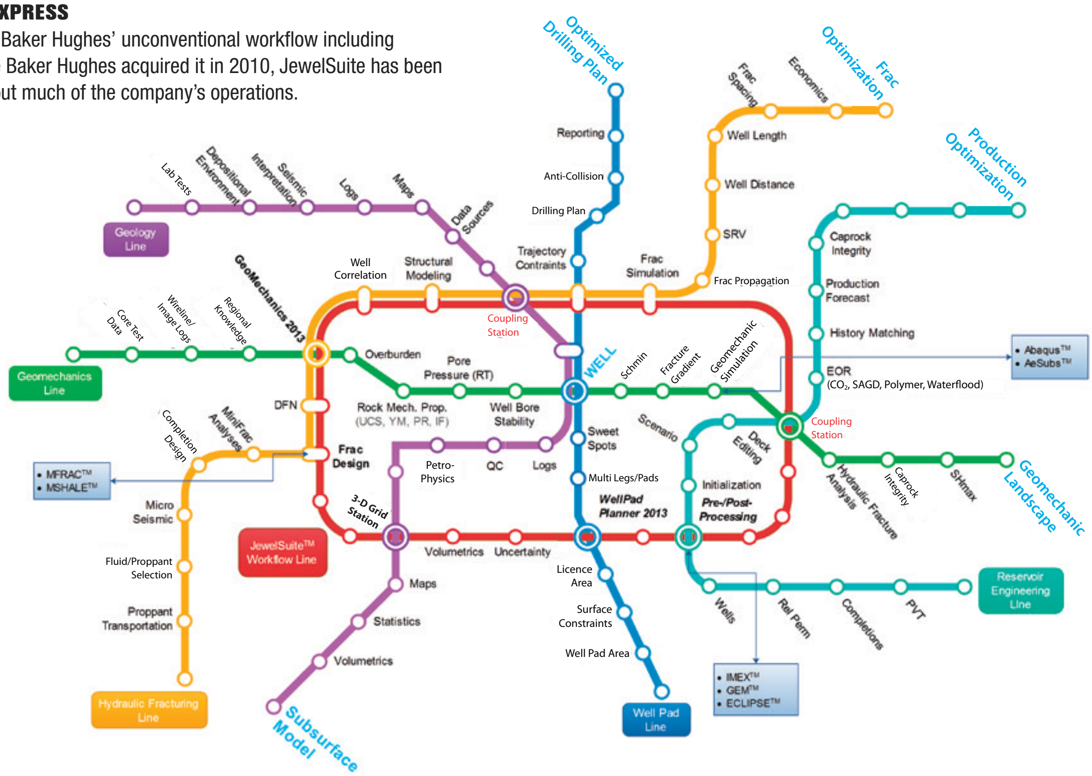
One of JewelSuite's latest offerings is a software tool that generates workflow modelling for planning well pad drilling and completions. Although it is too soon to say how well this new software performs >



COMPREHENSIVE PICTURE
Baker Hughes' JewelSuite integrates seismic, geologic, flow simulation and geomechanic models into a single, multidisciplinary workflow, enabling a comprehensive view of the reservoir. The company's geomechanics experts, who have worked around the world, help to minimize cost and optimize the reservoir lifecycle.

IMAGES: BAKER HUGHES INCORPORATED

SUBSURFACE EXPRESS
Flow diagram for Baker Hughes' unconventional workflow including JewelSuite. Since Baker Hughes acquired it in 2010, JewelSuite has been adopted throughout much of the company's operations.



on specific projects, it should significantly reduce the amount of time spent by skilled people on work that can be automated.

"The message was that a geologist was spending 80 per cent of the time on planning wellbores, etc., and 20 per cent on interpretation. We're just starting to use it. We're confident it will reduce the time operations staff spend on [well pad] planning. The hope is to reverse that 80:20 ratio every time you drill a well. The key to designing the tool is thinking about workflow and where workflows intersect each other," Mohr says.

JewelSuite had its origins about a decade ago at Netherlands-based JOA Oil & Gas BV. In 2010, when Baker Hughes completed its acquisition of the Dutch software developer, whose assets included a reservoir-modelling tool with patented 3-D gridding technology for reservoirs with complex geology, the Houston oilfield services giant indicated high hopes for its new product. "JewelSuite software has the potential to become a leading reservoir integration platform for technologies ranging from geosteering to modelling the performance of inflow control devices," John Harris, president of Baker Hughes' RDS group, said at the time.

The JewelSuite platform has been adopted throughout much of its new owner's operations. "It improves Baker Hughes' understanding of geo-science," says Jeroen Dankelman, an unconventionals senior sales and support engineer at Baker Hughes.

An engineering geologist by profession, Dankelman, who was part of the original design team that developed JewelSuite, provides a glimpse of the thinking behind the software and its design priorities in a discussion of some of the issues and challenges that operators are facing—especially in the unconventional sector.

"The focus is to be able to think and approach the reservoir from a well- and reservoir-centric perspective. An issue is that people are trying to solve reservoir-centric problems with well-centric solutions. People are trying to find the optimum frac design by looking at natural fractures, micro-seismic, frac design, rock properties in a well-centric way, as if the five metres around the wellbore told the whole story. It's not enough to make an extrapolation about the whole reservoir," he says.

The JewelSuite platform is designed to provide a fish-eye view of a large portion of, and, if possible, the whole reservoir. "A reason to do this is the geo-mechanics—this includes pore pressure, wellbore stability, caprock integrity, fault stability—all these issues must be analyzed from a reservoir-centric perspective. This is an approach that takes into account reservoir rock, mechanical properties of the reservoir itself and the overburden to the surface. Our competition does not take this into account," Dankelman says.

But they should, he says, as these factors can affect well production. "Taking overburden into account can minimize the risk of well collapse and so on."

When using JewelSuite software as a platform, a client can integrate seismic, structural, geologic, geo-mechanical and fluid flow models into a single multidisciplinary workflow. The program's 3-D gridding and meshing technology is designed to assist in creating accurate representations of reservoirs. "One of the key things is that we can combine a wide range of disciplines in analyzing, monitoring and improving the life cycle of the reservoir," Dankelman says.

The JewelSuite 3-D platform works with a range of existing industry software, including Abaqus FEA, Eclipse, Imex and MFrac.

Of the latest offering from JewelSuite, the well pad planner, Dankelman says, "It's very flexible and takes all the disciplines into account. It expedites planning. A 16-well pad could take eight months to design, incorporating all disciplines, and lots of management meetings. This really speeds up adjustments to design. All the stakeholders can see a change and approve, etc."

As Dankelman describes it, the JewelSuite 3-D platform, including its products for other applications besides well planning, combines the best attributes of seamless teamwork with the ability to get the job done fast. "There is a high level of collaboration of disciplines on a single platform," he says.

■ *Godfrey Budd*

DIAGRAM: BAKER HUGHES INCORPORATED

ENERGY NAVIGATOR INC.

PRODUCT: Value Navigator

SERVICE: Evaluation, forecasting and reserves management software suite

Plotting A Course For Unconventional Success

Software enables automatic forecasting of unconventional reserves with accuracy and speed

It used to be easy to forecast production for oil and gas wells: just draw a straight line on a production plot. But unconventional wells—those targeting unconventional shale gas and tight oil resources, which is what the world is turning to—require the manipulation of two linked equations, three variables in each.

"To be able to figure out what those three variables are in your head, to figure out which data to use and which not to use, and to figure out which segments to use is extremely difficult," says Boyd Russell, a petroleum engineer with more than 35 years of experience and president of Energy Navigator Inc.

Recently, Russell says, he forecasted the production of 160 randomly chosen unconventional wells in western Canada, testing the speed and accuracy of Energy Navigator's software package, Value Navigator (Val Nav). It took him 20 seconds and he was within 0.04 of one per cent of the correct answer, he says.

Then he did it manually and was accurate to two per cent of the correct answer, he says. "I spent six hours. And I'm very proficient."

Val Nav is a complete suite of engineering and economics tools for forecasting, reserves management, economics analysis, risk analysis, budgeting and reporting. It is designed to be a fully integrated, scalable and complete evaluation system with an auto-forecasting algorithm and economic engine. The software has at least 2,000 users in well over 300 companies in 30 countries with its major focus on Canada.

Russell established Energy Navigator in 1998, after more than 10 years as an engineer at a major company, where he found the available software tools "just didn't cut it," so he started writing his own programs.

He says Val Nav is the only software suite on the market that allows users to use both conventional and unconventional decline methods, including a new one called the "Five Year Equation."

One of the problems with forecasting, especially unconventional wells, says Russell, is that these wells flow under something called transient flow, which can last for a decade or more.

"After a period of time, the pressure drop, from the wellbore outwards, will hit a boundary," he explains. "When that occurs, traditional decline equations can be used. That flow period is called boundary-dominated flow. Forecasting unconventional wells requires a realistic, reasonable, easy-to-use method of determining when a well would potentially hit a boundary and how to automatically forecast the transition."

Energy Navigator has developed a method to forecast the transition, all automatically, with the Five Year Equation, he says. "It gives you a reasonable forecast to what the true behaviour of the well would be."

One aspect that makes Val Nav unique, says Russell, is that users can see all their data in grids. They can sort them, organize them, paste them directly into Excel and make changes, then paste them back into Val Nav.

OPPORTUNITY KNOCKS
Energy Navigator's Val Nav—a fully integrated, scalable and complete evaluation system with an auto-forecasting algorithm and powerful economic engine—allows companies to better manage their reserves.

PHOTO: CENTRAL GLOBAL RESOURCES ULC

Russell calls his software database agnostic. Some software companies only work when using certain brands, but Val Nav works with all the major databases in all formats. "We work in them all."

But the most important differentiation, he says, is the company's focus on support and engineering. From the company's inception, when other companies were charging ongoing fees, Val Nav has included upgrades, training and support.

Shila Stromsmoe, senior development and operations engineer at Central Global Resources ULC, has been using Val Nav since 2005 and was happy with the software even before the latest version, 6.2, hit the market. Stromsmoe uses Val Nav to make investment decisions and assess well economics, to test sensitivities on pricing and outcomes, project economics, acquisitions, divestments and reserves.

"I like the decline performance capabilities, especially on resource plays," says Stromsmoe. "It's much more efficient for updating wells and profiles, especially when you have a multi-segment performance profile."

Trent Green, chief operating officer of HEYCO Energy Group, Inc. based in Roswell, N.M., has used Val Nav for about one year, on about 75 conventional and unconventional wells. The petroleum engineer says he recommends it to others all the time. He especially appreciates that it allows him to perform reservoir evaluations, analysis and predictions with one package and instantly see how the economic scenarios of his wells play out.

"I'm very pleased with Value Navigator's graphics and intuitive nature. I'm an engineer and Value Navigator was written by and for engineers, so for me the workflow is very straightforward," says Green.

■ *Lynda Harrison*

CENOVUS ENERGY INC.

PRODUCT: SkyStrat

SERVICE: Heli-portable drilling rig

Soaring To New Heights

Oilsands producer sees heli-portable drilling as a game changer on several levels

Before producers of in situ oilsands punch a single production well into the ground, they need to have a very good idea where to aim the drill bit to maximize exposure to the reservoir. That typically means drilling a veritable pincushion of preproduction stratigraphic test wells spaced over a wide area to properly delineate the resource. And in the Fort McMurray region of northeastern Alberta, that area can cover vast swaths of dense woodland, unmolested by such modern conveniences as paved roadways.

For oilsands producers, that means a short and costly drilling season, typically limited to about 100 days of winter when freeze-up enables road building and the movement of heavy equipment to take place.

That was before Al Krawchuk, senior staff, SkyStrat drilling, and his drilling team at leading in situ oilsands producer Cenovus Energy Inc. began to take a closer look at how mining companies had long ago learned how to circumvent this hindrance—by taking to the air.

"On average, Cenovus drills between 400 and 500 stratigraphic test wells in our oilsands areas," says Krawchuk. "My personal involvement in that was managing 25–30 rigs to come into a project area for a three-month duration and drill those 400 or 500 wells. So from a boots-on-the-ground standpoint, you would have a whole temporary workforce that was coming in for 90 days or 100 days, upwards of 1,000 people or more, and the related safety challenges and personnel and logistical issues—that's the current standard in the industry.

"This was one of the main detractors from us becoming really efficient and safe about what we were doing. We thought, 'Wouldn't it be great if we could get out of this cycle?' And that was what was intriguing about looking at a different approach—and getting support from our executives to go and chase an idea to see whether or not we could succeed quickly, or fail quickly."

After some initial investigation, the team drew up a high-level plan in early 2010, he says. "We brought some mining experts in and we started to work with them very closely, and by April of that year, we completed our first pilot test to say this is feasible. We actually drilled some wells in our Foster Creek asset area down to a total depth of 550 metres, with similar technology to what the SSD [SkyStrat drilling rig] looks like today. After we did that, we all sat back and went, whoa, this is very interesting, but it's going to take a whole lot of effort and wherewithal to push it to the point of more than just a pilot."

In early 2011, Krawchuk left his job as a commercial drilling manager to focus solely on the SkyStrat rig project, "with strong support of our executive team," he says. He and his team worked to integrate the best of the two industries' technologies.

TAKING TO THE SKIES
Built to be flown to drill sites in pieces and assembled on site, Cenovus Energy's SkyStrat heli-portable drilling rig makes possible the drilling of stratigraphic wells without the need to construct roads to remote locations.

PHOTO: CENOVUS ENERGY INC.

As the team started to work more closely with the hard-rock mining experts, they "started to look through a different lens," Krawchuk says. "That was one of the real enabling factors. If we started from a typical oil-and-gas lens, I don't think we'd have gotten where we are today.

"We took what you would call the best from the hard-rock mining world and the best from our traditional oil and gas world, and we tried to integrate those technologies to come up with something that wasn't quite one or the other—that became what we call SkyStrat drilling."

Like a mining rig, the hybrid rig would need to be broken into pieces weighing less than the 6,000-pound capacity of the helicopter—while incorporating those elements unique to the oil and gas industry. The result is a rig that doesn't look too much like either of its parent rigs.

"If you were to bring a mining guy out to the site, he wouldn't recognize it because of the blowout prevention equipment [and] some of the solids control and waste management systems that we use—those are foreign to hard-rock miners. On the other hand, from an oil-and-gas standpoint, having equipment that is flyable is something else that wouldn't be recognizable."

Though he wouldn't reveal exactly how deep the rig can drill, the relatively shallow nature of the oilsands means the rig's already proven ability to drill to 550 metres makes it adequate to reach any of the company's existing oilsands deposits.

It takes about 100 loads to deliver the SkyStrat—about two-thirds the size and one-half the weight of a conventional rig—and its related equipment, which includes mats to support it on often marshy ground. A team of four to five people, working 24-7, takes four to five days to drill a well.

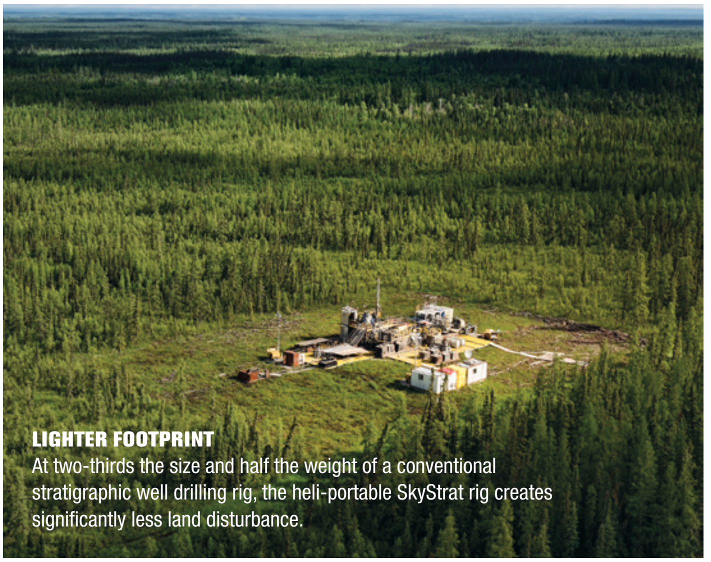
Prior to the chopper going in, Cenovus has hired local trappers with construction experience to trek in on foot and prepare the groundwork for the air drop. "Typically they will work on our winter projects and build leases for us. They are very familiar with the forest and the terrain."

> ***"We took what you would call the best from the hard-rock mining world and the best from our traditional oil and gas world and we tried to integrate those technologies to come up with something that wasn't quite one or the other—that became what we call SkyStrat Drilling."***
>
> ***— Al Krawchuk, senior staff, SkyStrat drilling, Cenovus Energy Inc.***

They only need to clear a small area, he notes, since the overall footprint is significantly less than that of a conventional drilling rig and associated equipment. Other aspects are also minimized. Early indications are that the use of the SkyStrat reduces water use by at least 50 per cent—not to mention a cost saving of at least 25 per cent. A 400-well drilling program costs about $400 million.

And there are less tangible benefits, Krawchuk says, such as reduced land disturbance by constructing fewer roads and an increased flexibility in the overall drilling campaign. "With the traditional method, you have to go in and build a large-scale project—you have to drill 50 wells or 100 wells in order for it to be economic, and ultimately, I think you end up drilling wells that you may not drill if you had the ability to adjust your drilling program real time. [Using SkyStrat] we are able to strategically develop our resource base and ultimately get more information for less disturbance and less money."

PHOTO: CENOVUS ENERGY INC.



LIGHTER FOOTPRINT
At two-thirds the size and half the weight of a conventional stratigraphic well drilling rig, the heli-portable SkyStrat rig creates significantly less land disturbance.

Following commissioning work in late 2011 and early 2012, when seven wells were drilled at the company's Christina Lake in situ oilsands project with ground transport, the company began fully heli-portable drilling operations.

"Once March hit and the roads came out, so did the rig. Around mid-June 2012, we flew it into our Steepbank asset area and we drilled 11 wells, 100 per cent heli-supported. [As of October] we are just in the final stages of wrapping up the drilling campaign for summer 2013, and we have completed 24 wells."

With the ability to now run a summer as well as a winter drilling program, a heli-portable rig can drill about 50 wells per year. A second SkyStrat rig under construction will give Cenovus, which has over 500,000 hectares of oilsands leases, the capacity to do about 100 air-supported wells annually, about a quarter of its stratigraphic well drilling program.

Working with fabricators in the Edmonton-Calgary corridor for its second rig, Cenovus is incorporating some learnings from the first. It's also sourcing equipment, sometimes from unrelated industries, from around the world. "As we get further down the development curve and are understanding what requirements are nice to have and need to have, we are keying in on some unique equipment. We just brought some equipment in from Italy, actually. If it is out there, we will find it and we will apply it."

Krawchuk credits his team for pushing the project through to this stage to create something truly unique. "There are people who have a passion for trying to do things in a different way and improve the current footprint of what our industry is doing, and I think if I can communicate anything, I really want to reinforce that message," he says.

And he thinks the first two rigs are only the tip of the iceberg. "We do plan to share this [technology] with the broader industry as we work through some of the outstanding issues, third-party rights, patents and legal issues." Krawchuk believes there may also be export opportunities. Heli-portable drilling has been used in Papua New Guinea and parts of South America, the Middle East and central Asia, he notes.

"Ultimately, we would like to see this widely deployed in the industry. We think it is a game changer as far as what it is able to bring, from a benefits standpoint, to all oilsands operators, not only Cenovus. So we are actually very excited about what that opportunity looks like."

Maurice Smith

RUNNER-UP
DRILLING

BAKER HUGHES INCORPORATED

PRODUCT: Talon drill bit

SERVICE: High-efficiency PDC bit for challenging environments

Diamond In The Rough

A PDC bit designed to tackle directional drilling and drilling in unconventional shales

CUTTING EFFICIENCY
The Talon high-efficiency drill bit incorporates advanced diamond technology that helps cutters stay sharper longer to increase rate of penetration and durability.

For drilling contractors, polycrystalline diamond compact (PDC) bits—once the industry's cutting edge—have become familiar in the North American oil and gas sector, especially in performance drilling scenarios. Among PDC bit makers, competition is intense, as each strives to stake out territory based on unique bit design, mechanical characteristics and field applications.

According to Baker Hughes Incorporated, the company's new Hughes Christensen Talon 3D PDC drill bit is well-suited to non-vertical drilling, especially in the build and lateral legs of directional wells, which make up a growing portion of North American wells.

Baker Hughes claims a range of benefits for the Talon bit, including better rate of penetration (ROP), drilling efficiency, and directional control in curve and lateral sections in unconventional formations. As well, the company says the bit's synthetic diamond cutters help to avoid pack-off incidents and allow the bit to drill farther and faster.

The Talon bit includes hard-facing, a process that uses metallurgy and precision welding to give maximum strength and durability. The company adds that the process also reduces bit wear and prevents damage from rock formations and debris—qualities that tend to improve run life.

According to engineer Alex Haworth, director of Canadian drill bit operations for Baker Hughes, the bit can also handle some of the adverse phenomena encountered during faster drilling. "When you're going after ROP, you tend to use a more aggressive bit," he says. "That means the [PDC] cutters take a bigger depth of cut—more rock per revolution—as the bit spins. The more rock you take, the faster the bit goes, but the formation fights back and the bigger the cut, the more torque you get on bit."

In response, Baker Hughes has incorporated certain technologies in the Talon bit. One, concentrated centric aggressiveness, is geared to cutting the torque generated during drilling and steering, Haworth says. "What it comes down to…is being able to maintain tool face control, so you can gain build-up rates during the [well's] build section, and have an increased rate of penetration because of it," he adds.

Due to the high-volume cuttings generated during drilling, the bit's designers also added diverging junk slots—channels that direct cuttings and debris away from the tool face during drilling. "No point cutting rock if you can't remove it quickly," explains Haworth.

"You want to maximize [cuttings removal], but still have the most wellbore coverage in a 360-degree sense. With diverging junk slots, the bit's blades are curved and their edges are still in contact with the wellbore for stability, but you have maximum [cuttings] flow."

> ***"What it comes down to…is being able to maintain tool face control, so you can gain build-up rates during the [well's] build section, and have an increased rate of penetration because of it."***
>
> ***— Alex Haworth, director of Canadian drill bit operations, Baker Hughes Incorporated***

While *New Technology Magazine* did not survey bit users, one Canadian producer shared his experience using the bit. "Using the Baker Hughes eight-and-three-quarter-inch PDC bit with Talon cutters through our intermediate wellbore section more than doubled penetration rates in upper-hole formations, almost tripling the rate in the Nikanassin Formation," says a drilling manager for a major operator.

"This performance significantly cut days on well and AFE [authorization for expenditure] costs."

James Mahony

PHOTO: BAKER HUGHES INCORPORATED

WINNER
HEALTH, SAFETY & ENVIRONMENT

HALLIBURTON

PRODUCT: UniStim

SERVICE: Hydraulic fracturing fluid system

From Waste To Asset

Reclaiming produced water as base fluid for fracking reduces freshwater use, cuts costs

Halliburton's UniStim water management technology promises to be a major step forward in oilfield water management by allowing the use of produced and flowback water for hydraulic fracturing, while at the same time reducing companies' need for fresh water.

"We can take a waste stream and use it as part of the supply chain, with both economic and environmental benefits. For every barrel you recycle, you negate a barrel of fresh water," says Walter Dale, strategic business manager, water solutions, based in Houston. "We have significantly changed the thought process to recycle for hydraulic fracturing."

UniStim universal recycle cross-linked fracturing fluid enables Halliburton to recycle produced water—mostly comprised of formation water and injected fluids from previous treatments, containing hydrocarbons, high levels of total dissolved solids (TDS), suspended solids and residual production chemicals—to make stable frac fluids.

"Halliburton had been making stable frac fluids out of ocean water, so we basically looked at how we could make stable frac fluids out of the waters being produced by wells today," Dale says.The large volumes of water used in horizontal multistage fracturing have been a concern for many in the industry, as the significant increase in fracking in recent years has been accompanied by a sharp rise in the amount of fresh water that companies consume—up to six million gallons per well. "Essentially, the industry has always used fresh water to make stable cross-link frac fluids," Dale says. Cross-link frac fluids have a greater ability to carry proppants into the formation.

PHOTO: HALLIBURTON

WATER RECYCLE
By enabling operators to use minimally treated produced or flowback water, Halliburton's UniStim hydraulic fracturing fluid system reduces the need for fresh water, as well as the expense of treating, hauling and disposing of contaminated water.

As one alternative, the market has been looking at water recycling, by mixing with fresh water to overcome fluid compatibility concerns. However, the costs have been prohibitive, and as a result, recycle adoption has been slow.

As another option, the industry has been trying to use advanced water treatment technologies to remove elements such as boron, calcium and chloride from these waters, since they traditionally interfere with stable frac fluid development. "In doing so, you create very large waste streams that have costs, and you pay more in water treatment," Dale notes.

What Halliburton did instead was to look at changing the frac fluids, so that it didn't have to use advanced water treatment technologies or fresh water to overcome traditional fluid limits, yet could still make use of available impaired waters.

"By adjusting the frac fluid formulation so that things like boron are not an issue, we have been able to negate those costs, negate the use of fresh water and allow customers to use waters that were once a waste stream. Conventional fracturing fluids have limits, based on the >

total salt and mineral content you can use to make stable frac fluids. By adjusting the frac fluid formulation and coming up with a new innovation, we were able to develop stable frac fluids that can use any source of impaired water, as opposed to fresh water.

"We were recycling in 2011, but hadn't overcome the high TDS challenge when it comes to making stable frac fluids. In 2012, we put the focus on using 100 per cent impaired waters with high TDS values, and on developing stable frac fluids that would allow us to use those fluids as alternative source waters, instead of fresh water."

For every barrel of hydrocarbon a company produces, wells make three to five barrels of both produced and flowback waters, which companies typically send to a disposal well. With UniStim, companies can now take that waste water and, with minimal treatment, use it for their supply chain needs. The water doesn't need to be treated to potable water standard, as some treatment processes do, but rather only to a level where contaminants that hinder development of cross-linked fluids or cause scale buildup are removed. UniStim also potentially eliminates the use of disposal wells, and significantly reduces the amount of fresh water being transported by companies.

"We looked at how we can use those produced and flowback waters in a way that ultimately lowers the economic price point for customers to recycle frac fluids," says Dale, noting that this is a technology that is applicable anywhere in the world.

A recent Society of Petroleum Engineers paper, which discusses the laboratory and field results of a study that Halliburton conducted for an energy company, demonstrates it is feasible to use treated produced water as the base fluid for cross-linked, gel-based hydraulic fracturing. The field trial, involving seven wells and 97 frac stages, showed that electrocoagulation-treated produced water with TDS of up to 285,000 parts per million (ppm) generated proper cross-linked rheology for hydraulic fracturing. Production aligned with that from offset wells.

The benefits included the use of more than eight million gallons of produced water, replacing fresh water, and reduced trucking of approximately 1,400 loads of fresh water from off-lease. The water management cost, versus purchasing and transporting fresh water, was a reduction per well of US$70,000–US$100,000.

Halliburton, which launched UniStim this past summer, had been working on the technology since mid-2012. In the past year, more than 60 wells and 260 frac completion stages—mostly in the Permian Basin in Texas and the Bakken in North Dakota—have been completed using 100 per cent flowback and produced waters with high TDS, at over 270,000 ppm. There were no cross-link issues and no scaling issues. Average savings were US$100,000–US$200,000 per well.

"These wells have shown no loss of production versus those that use fresh water," Dale says. "We are very pleased. We think that, in terms of hydraulic fracturing and fluid technology, it is a fundamental shift in thought process for how you do what we do."

UniStim has been very well received, and as Halliburton continues to educate new customers about the technology—including producers in Canada—it's seeing a lot of interest, Dale says.

It's no surprise, given what the technology has been shown to do. "For every barrel of water you recycle, you negate the cost of buying fresh water. You negate the cost of disposing of a produced and flowback barrel of water. You also negate the cost of adding brine for clay stabilization. And, when you do it correctly, you can reduce the number of trucks used in the transportation of fresh water to a well, and the transportation of waste water to a disposal well," says Dale.

■ *Jacqueline Louie*

RUNNER-UP

HEALTH, SAFETY & ENVIRONMENT

AXINE WATER TECHNOLOGIES INC.

PRODUCT: Electrolytic oxidation cell

SERVICE: Chemical-free treatment of organic pollutants in industrial waste water

A Radical Solution

Using dangling bonds to clean industrial waste water

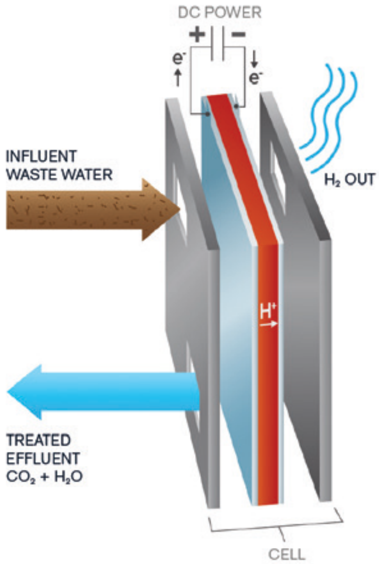
Since hydroxyl radicals are highly reactive to many pollutants, one company has figured out that developing a simple catalyst to produce this low-cost, chemical-free solution for treating organic toxins in industrial waste water is potentially very beneficial for the oil and gas sector.

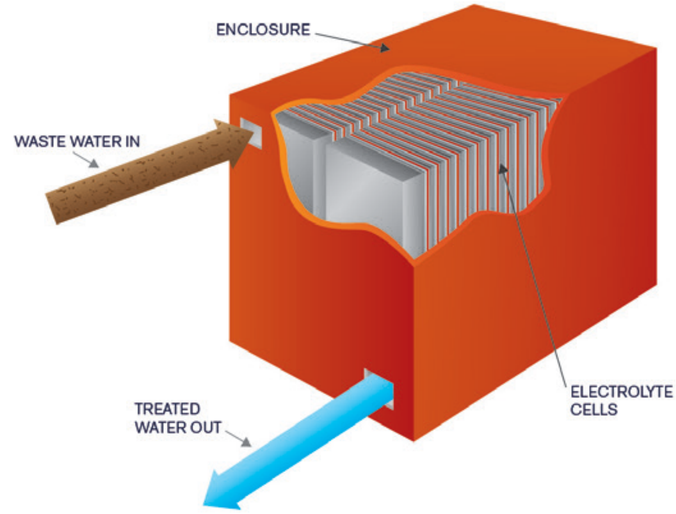
"This is one of the most aggressive oxidants that exists," says Jonathan Rhone, president and chief executive officer of Vancouver-based Axine Water Technologies Inc.

"What these hydroxyl radicals do is they attach themselves to these long, organic molecules—whether their phenyls or benzenes or long-chain hydrocarbons—and they effectively break them down into their basic building blocks of carbon dioxide, water and hydrogen without requiring any chemicals."

The company's modular electrochemical oxidation technology, which has yet to receive a trademark name, consists of multiple one-metre by 30-centimetre units, which can be stacked into networks as required.

Rhone says, "The core of the technology is an electrochemical cell. We use off-the-shelf membrane technology, and then we coat the membrane with this catalyst layer, which is our own proprietary design. Then we put the catalyst-coated membrane in a plastic shell."





PLUG AND PLAY

Axine's scalable waste water treatment system starts with its proprietary electrolytic cell (left) capable of oxidizing the most challenging organics into CO_2, water and nitrogen. Cells are assembled into a module of cells (right), then into stacks of modules and finally into a commercial container system capable of handling tens of thousands to millions of gallons of waste water per day.

DIAGRAMS: AXINE WATER TECHNOLOGIES INC.

Tainted water flows down each cell, Rhone says, and as it flows across the catalyst surface, the hydroxyl radicals are produced.

"One of the problems is that the water produced from those formations contains these chemicals—these polymers and surfactants—that are highly toxic, and they're resistant to conventional water treatment systems. So the customers we are working with are really interested in our technology because we can effectively oxidize these chemicals without requiring any chemicals and without producing any residual waste."

While the technology is still in the pre-commercial stage of development, Rhone says it should significantly reduce in situ production costs and improve performance of water reclamation. "We believe that our technology can dramatically reduce the cost of water treatment and improve the economics of steam assisted gravity drainage [SAGD], reducing the cost of producing a barrel of bitumen up to $2 per barrel. That is what preliminary assessment is showing."

Conventional water treatment systems do not effectively dissolve organic components in produced SAGD water, Rhone suggests, and as a consequence those residual particles create several production bottlenecks regarding equipment or technical gear fouling.

"So we have been working with some of the producers who evaluate the technology to eliminate those bottlenecks, and we've had some really significant breakthroughs in terms of our testing. We're hoping those [breakthroughs] will result in some on-site pilot work with producers in the next couple of years."

Working with companies in the oil and gas, refining and chemical markets, Axine recently completed six months of performance testing and validation of waste waters using a 10-times scale-up of its electrolytic oxidation cell, verifying the technology on real-world waste waters containing aromatic acids, phenols, benzene, toluene, ethylbenzene, xylenes, hydrogen sulphide and ammonia ranging in concentration from 900 to 9,000 milligrams per litre of chemical oxygen demand. Organics were oxidized to CO_2, water and nitrogen gas by hydroxyl radicals generated on the surface of Axine's proprietary catalyst, and the scaled-up cell achieved high efficacy treatment at low-cost and low-energy consumption, the company says.

Axine's chief engineer Colleen Legzdins founded the company in 2010 by developing the concept and building very small prototypes in her basement and a rented laboratory. Legzdins, who has a PhD in materials engineering from the University of British Columbia, held senior technical positions at hydrogen fuel cell pioneer Ballard Power Systems Inc.

"It's a classic sort of technology start-up," Rhone says. "She proved the technology could work at a proof-of-concept stage, and then last summer in mid-2012 we closed a seed-round of funding with Chrysalix Energy Venture Capital and the Business Development Bank of Canada to get the company properly funded so we could take it to the next stage.

"We spent the last year proving up the technology and testing customer waste water at the scale-up stage, and now we are at the point where we can move to commercialization agreements and onto early-product customer sites."

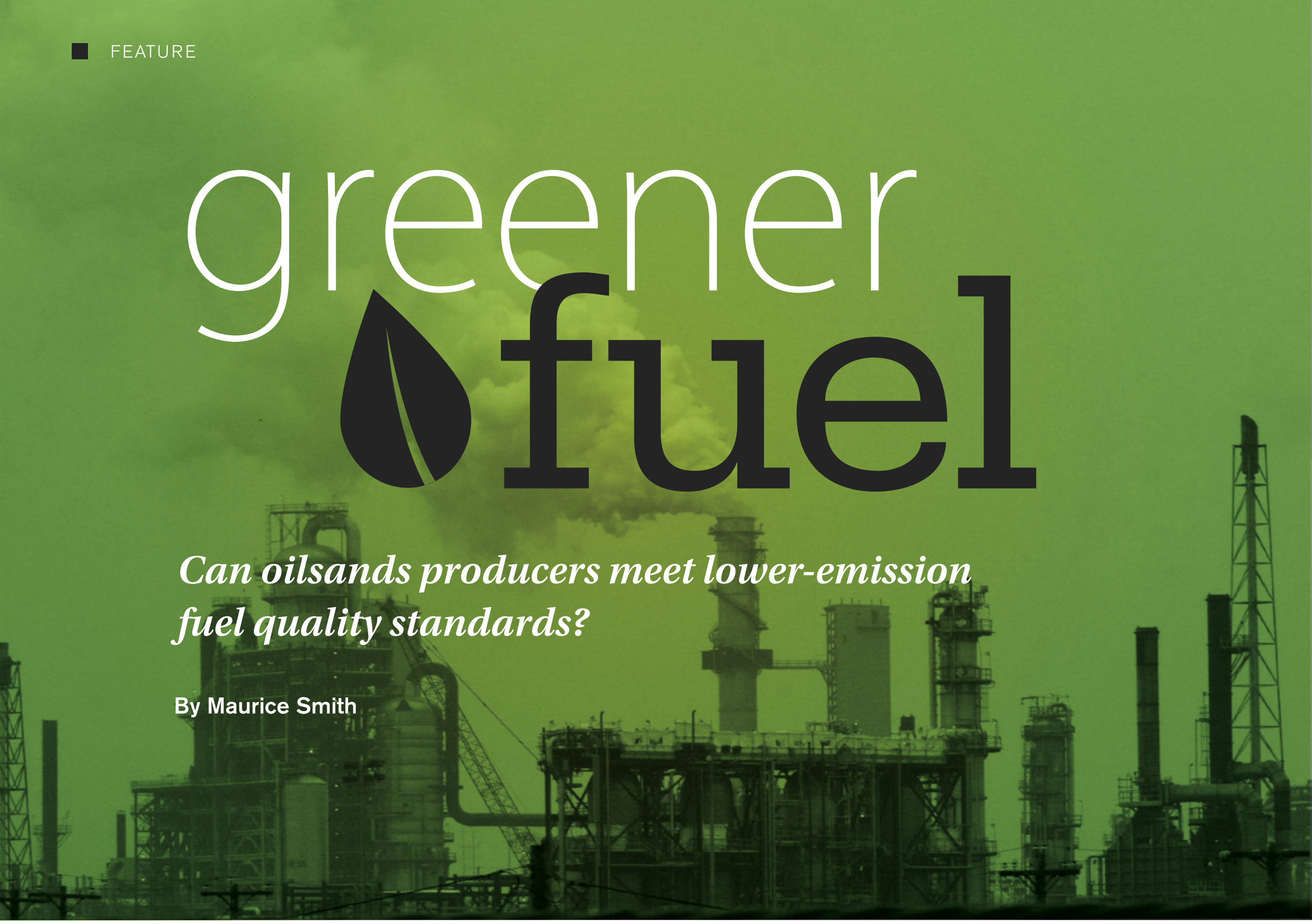
Chrysalix associate James Wells says water is a particularly annoying, difficult issue with which SAGD and enhanced oil recovery operators must contend. Therefore, he says, while it is still in the early stages of development, large oil and gas companies should appreciate Axine's robust catalyst design that is chemical free and can be easily scaled up to meet particular in-field demands.

"If you can mineralize all these toxic compounds right down to their simplest forms because you don't have any additional by-products or waste stream, then I think operators are just going to breathe a big sigh of relief once they see this thing performing."

Today Rhone—the founder and former president and chief executive officer of Nexterra Systems Corp., a leader in biomass gasification heat, power and syngas systems—chairs the B.C. Cleantech CEO Alliance and is a member of the B.C. Premier's Technology Council.

Rhone says several major oil companies are working with Axine and its simple, reliable and highly durable electrolytic waste-water treatment technology, eager to see a finished product hit the market. "I think the next step for us will be very important, and we plan to be on customer sites with field pilots in 2014 and with early commercial pilots in 2015. So we are under the gun to get to the next stage of commercialization."

■ *Carter Haydu*



greener fuel

Can oilsands producers meet lower-emission fuel quality standards?

By Maurice Smith

With oilsands production set to double in a decade, creating a growing need to secure new markets outside those traditionally served, new restrictions being placed on high-emission fuel sources could move beyond the theoretical to the practical in the minds of producers. As California and the European Union (EU), in particular, enact potentially restrictive regulations with the goal to reduce the level of greenhouse gases (GHGs) emitted in producing their fuels, the dynamics of the marketplace could shift, impacting Canadian producers that currently ship very little product to those jurisdictions.

While there is little doubt oilsands production, on average, emits higher levels of greenhouse gases using today's high-energy-consuming extraction methods, there is heated debate over how much higher its emissions are, against which they should be measured and how they should be categorized. At stake, potentially, is the freezing out of oilsands to some foreign markets at a time when they are most needed. On the other hand, as the need to export ramps up, such rules could encourage producers to invest in cleaner technologies more quickly.

Numerous studies have examined the level of oilsands emissions production compared to conventional production, often comparing quite different inputs and cut-off points along the supply and combustion chain, and coming up with often-divergent results. As part of its examination of emissions impacts of the Keystone XL Pipeline linking the Alberta oilsands to Texas refineries, a report was prepared by the Congressional Research Service for the U.S. Congress, published in March, that compared several of the publicly available life-cycle assessments.

In general, the report, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, found production emissions from a weighted average of Canadian oilsands crudes (well to tank) fell into a range from 72 to 111 per cent over the average emissions of other U.S.-imported crudes (2005 baseline). Against some specific sample crudes, oilsands GHG emissions were found to be 102 per cent, 53 per cent and 92 per cent higher than the production emissions from Middle Eastern sour, Mexican Mayan and Venezuelan conventional crudes, respectively.

Well-to-wheel emissions—taking into account the 70–80 per cent of fossil fuel emissions produced from combustion in a vehicle or furnace—from gasoline produced from the weighted average of oilsands crudes are 19 per cent, 12 per cent and 18 per cent higher than the life-cycle emissions from Middle Eastern sour, Mexican Mayan and Venezuelan conventional crudes.

The oilsands are hampered by two main disadvantages: they are heavier and more viscous on average, requiring more energy- and resource-intensive extraction techniques to produce; and they are deficient in hydrogen and have a higher carbon, sulphur and heavy metal content, requiring more processing to yield consumable fuels, notes the report.

Oilsands emissions can vary significantly from project to project and among different means of production. Generally, thermal in situ production of synthetic crude oil (SCO) is the highest emitter due to high-energy consumption while mining-produced diluted bitumen (dilbit) is the least GHG emissions intensive.

PHOTO: THE PEMBINA INSTITUTE

PRODUCTION PROCESS RANKING

An IHS CERA study published at the end of 2012, *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*, found steam assisted gravity drainage (SAGD)–produced SCO to be 23 per cent above the average U.S. refined barrel (2005) on a well-to-wheel basis, followed closely by cyclic steam stimulation–produced bitumen at 21 per cent, both significantly above the average oilsands figure of 14 per cent over conventional. Fairing best was oilsands-mined dilbit at four per cent above average. Just one crude ranked higher than the highest-emitting oilsands product—California's heavy, thermally produced Midway-Sunset, at 25 per cent over the average well-to-wheel value—while three North Sea fields ranked best, with values four to six per cent less than the average.

The IHS CERA meta-analysis examined 12 life-cycle emissions studies to come up with the best estimate of oilsands emissions compared to other crudes, says Jackie Forrest, IHS CERA senior director, global oil.

Though a few producers are close to the level of conventional crude production, Forrest says any technology that could bring oilsands in general down to conventional levels is likely at least a decade away. And while mining projects are less carbon intensive, as a more mature technology that sector holds less promise for significant cuts.

For in situ, the opportunity in the near term, probably in the next 10 years, is to reduce the steam to oil ratio as much as possible, and use solvents, which are being piloted in a number of places right now, she says. "We estimate we could see about a 25 per cent improvement in [production emissions] if solvents did turn out to work and became widely adopted."

But with production emissions about 55 per cent higher by IHS calculations, even a 25 per cent improvement would still leave a big gap compared to conventional production. "It wouldn't get you there. Whether it be solvents or steam, you are going to have to have more energy than like a conventional crude."

And any means of low-GHG-emissions energy, such as nuclear or renewables, appears to be over a decade away, at least, and far further off to see any kind of widespread use that could significantly move the needle.

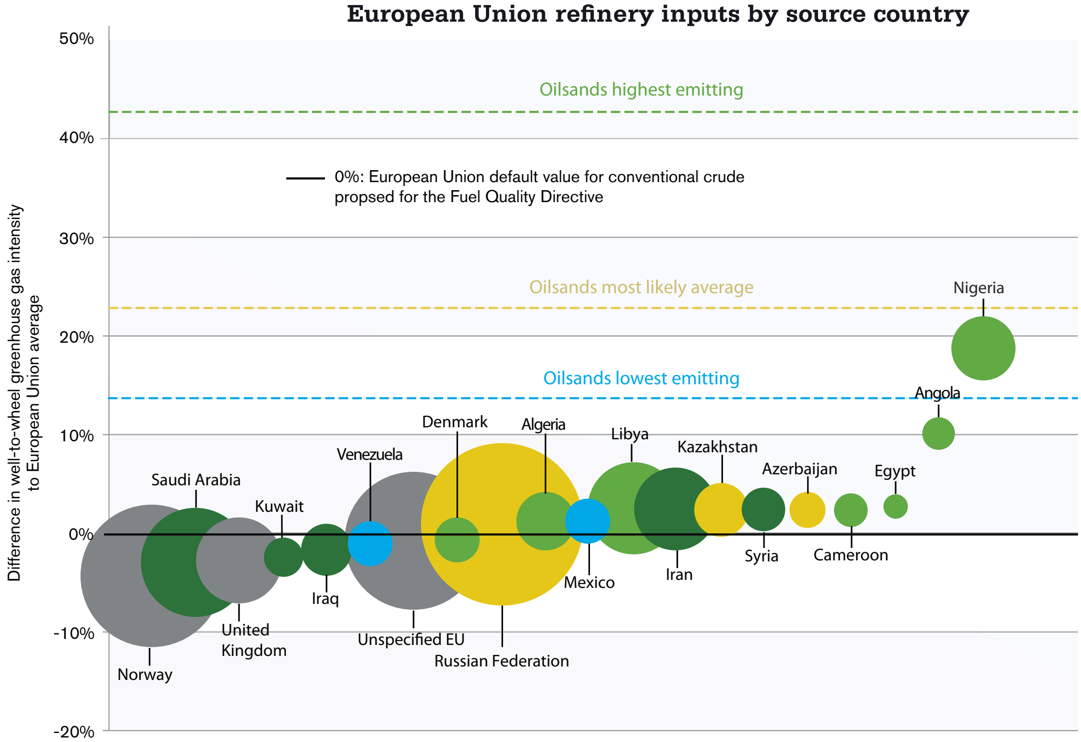
"If one particular operator is doing it, the aggregate GHG emissions for the whole industry don't change much—it has to be pretty widely deployed before, as an industry, the average comes down. That is one of the advantages of hybrid solvent [processes] over some of the other more revolutionary technologies…that in theory it should be something we can deploy on the existing operations if successful, and that means it can bring down the emissions of the industry as a whole."

Forrest says her concern with the EU or California establishing a specific number for a sector like the oilsands, such as the EU's proposed 22 per cent default figure, is that once established, such figures tend to become a permanent standard. "The thing to worry about is that it tends to be that once these numbers are out there and in law, they seem more credible than others and they tend to really stick in terms of people's perceptions of emissions associated with oilsands. My concern is more around that these numbers are accurate and they really do characterize the GHG emissions of oilsands."

FUEL CATEGORIZATION

The EU's Fuel Quality Directive (FQD) aims to reduce the carbon intensity of transport fuels entering Europe by six per cent from the 2010 level by 2020, part of its larger efforts to reduce emissions from all sectors. It proposes to use default GHG intensity values for basic fossil fuel categories based on the average or most likely value for each, >

Greenhouse gas emissions intensity of conventional European Union refinery inputs by source country



COMPARING INPUTS
Types of conventional crudes imported into the European Union (EU), with the size of circle representing how much of the total supply of crude is produced from that source. Vertical placement of circles denotes the difference compared to the average weighted greenhouse gas intensity from all conventional crudes supplied to the EU.

SOURCE: ADAM R. BRANDT, *UPSTREAM GREENHOUSE GAS (GHG) EMISSIONS FROM CANADIAN OIL SANDS AS A FEEDSTOCK FOR EUROPEAN REFINERIES* assigning, for example, a full life-cycle value of 87.5 grams of CO_2 per megajoule to conventional oil and 107 grams to natural bitumen (from Canada or elsewhere), defined according to density (API gravity) and viscosity. Other categories include gas to liquids (97 grams), oil shale (131 grams) and coal to liquid (172 grams).

The Alberta and federal governments have roundly lobbied against the directive. Natural Resources Canada protests in a backgrounder that this "unfairly stigmatizes Canadian crude oil," since some conventional crudes can reach oilsands emissions levels (in rare instances, usually due to excessive flaring), and states that a categorization of oilsands as 22 per cent more GHG intensive than conventional oil "is demonstratively untrue."

But the backgrounder doesn't state that any oilsands producer can avoid the default value, if its emissions are lower, by providing emissions data and establishing their own value based on that. Therefore, producers outperforming the default level are not penalized by it, while those over the default level are only held to account to the 22 per cent above level, though they may be much higher.

In fact, the directive in this way creates an incentive for innovation and rewards past improvements, points out the Pembina Institute, which contends the directive is fair. It notes that the directive does not ban oilsands imports, but does create a market-driven incentive for producers to reduce their emissions intensity.

It also notes that while a few conventional producers out-emit the oilsands average, an independent study found that even the lowest-emitting oilsands projects have higher life-cycle emissions than 97 per cent of conventional crudes entering Europe.

"Industry's position is that the absolute worst conventional oils overlap with the absolute best oilsands emissions, so therefore it is unreasonable to include these in separate categories, whereas the data is actually very clear that the average values and the values of the vast majority of the emissions from both sources are very different, so it is appropriate to report on them differently," says Simon Dyer, policy director at the Pembina Institute. He adds the directive "doesn't discriminate against Canadian oilsands, it discriminates against high-carbon feedstock, which is natural bitumen."

FQD opponents also protested that the directive penalizes countries with transparent GHG reporting while rewarding countries that do not provide data. But the directive will require fuel suppliers to report annually on the GHG intensity of the fuels they supply.

That reporting requirement, in fact, may already be encouraging those producing at high emissions intensities to prepare for its implementation. Companies operating in Nigeria, the world's second-worst flaring offender after Russia, are investing heavily in reduction measures. Royal Dutch Shell plc, operator of Nigeria's largest oilfields, says it has invested $3 billion to cut flaring 60 per cent over the past decade, and in 2012 announced another $2 billion to cut further, a measure that would help better position the producer against fuel-standard penalties.

California's Low Carbon Fuel Standard (LCFS), which requires refineries and fuel distributors to reduce the carbon intensity of fuels by 10 per cent by 2020, is designed to encourage production and use of alternative, low-carbon fuels through a carbon credit scheme, allowing the free market to decide what technologies will get it there. It, too, won't outright ban oilsands and heavy crudes, though they will be disadvantaged.

In fact, the LCFS makes some concessions to high-emissions heavy oil production where innovative recovery methods are used, a not insignificant factor in a state producing, via thermal recovery, the nation's highest emission-intensity crude. It defines an innovative method as involving production "using carbon capture and sequestration or solar steam generation" implemented during or after 2010 that reduces carbon intensity, well to refinery, by at least one gram of CO_2 equivalent per megajoule. At least two companies, BrightSource Energy, Inc. and GlassPoint Solar Inc., already offer solar steam generation to the oil industry. Since the standard is performance based, it is expected producers from other jurisdictions could incorporate similar technologies for carbon credits. And an oilsands producer like Shell could benefit from its $1.35-billion Quest CO_2 sequestration project now under construction in Alberta, with first injection anticipated in 2015.

ALREADY THERE?

A few other major oilsands producers believe they can already meet fuel quality standards. Imperial Oil Limited says its recently completed Kearl oilsands mining project emits GHGs in the range of conventional production, while a cyclic solvent process project could lead the way in low-emission in situ oilsands production.

Kearl, which is expected to reach full capacity of 110,000 barrels per day this year, benefits from both cogeneration and froth treatment. By cogenerating electricity and steam at the same time, Imperial estimates it will reduce CO_2 emissions by half a million tonnes per year compared to purchased power for the first phase of the project.

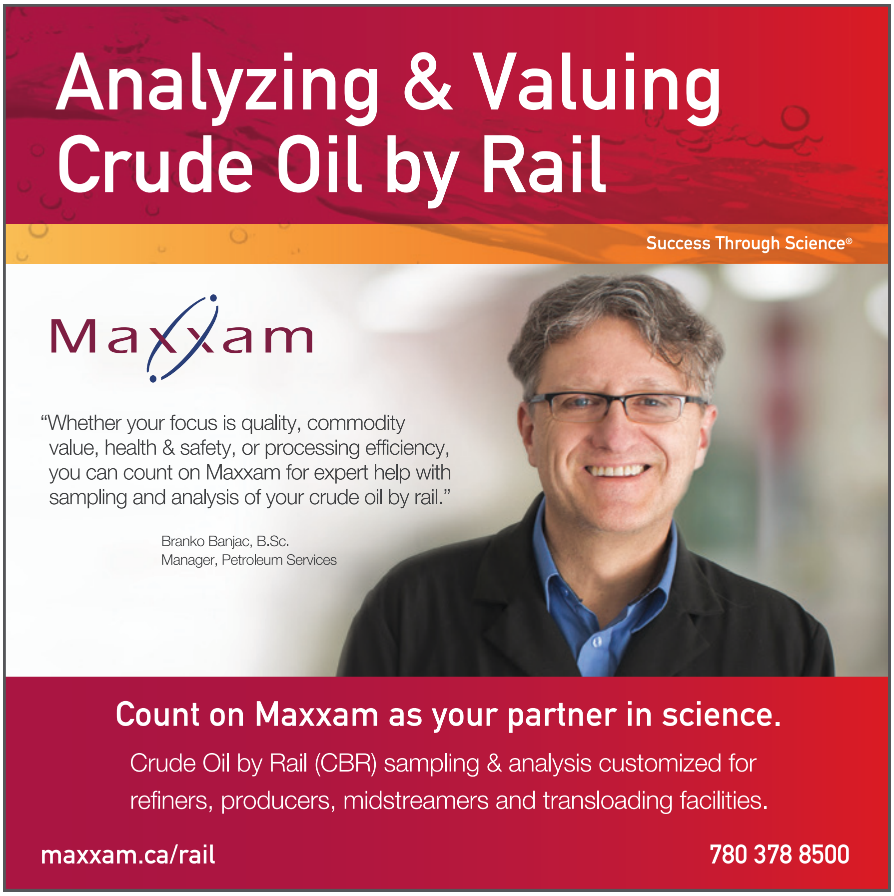
"The thing to worry about is that it tends to be that once these numbers are out there and in law, they seem more credible than others and they tend to really stick in terms of people's perceptions of emissions associated with oilsands."

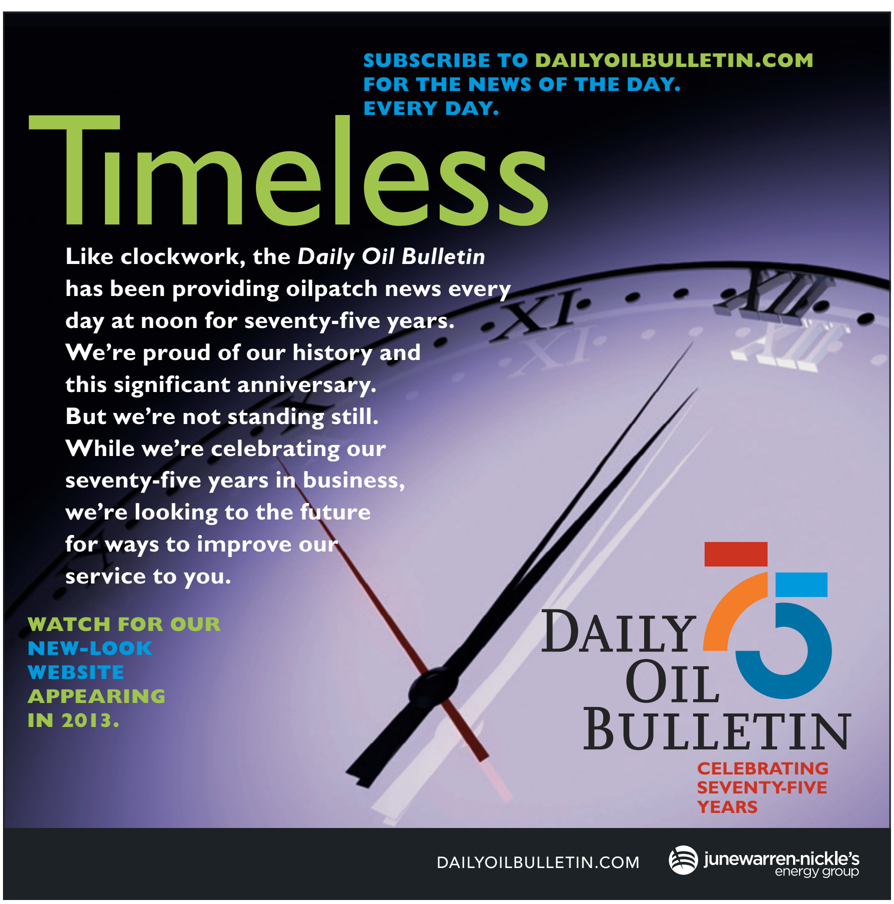
— Jackie Forrest, senior director, global oil, IHS CERA

The company's proprietary paraffinic froth treatment technology removes fine clay particles and water from the bitumen to produce a product suitable for pipeline transport with diluent to market, making Kearl the first oilsands mining operation that does not require an upgrader to produce a saleable crude oil. Processing bitumen once rather than twice (as in an upgrader and a refinery, both energy-intensive processes) significantly reduces life-cycle GHG emissions.

Though he says he couldn't comment on how it might fare against fuel quality standards, Imperial spokesman Pius Rolheiser says using cogeneration and paraffinic froth treatment "results in a well-to-wheels greenhouse gas emission footprint comparable to the average of barrels refined in North America."

On the in situ side, Imperial is already testing the use of solvents to assist thermal processes with solvent-assisted SAGD and liquid addition to steam to enhance recovery (LASER) for cyclic steam stimulation wells. But for truly deep cuts, Imperial is looking to its cyclic solvent process. >





"Solvent-assisted SAGD and LASER are enhancements to the existing technologies, whereas cyclic solvent would be a completely different technology, replacing steam with solvent. We estimate direct greenhouse gas emissions will be reduced by more than 95 per cent and direct plus indirect greenhouse gas emissions [covering overall production] will be reduced by more than 65 per cent.

"It is a technology that we see being a game-changing technology for our Cold Lake operation, which currently uses cyclic steam stimulation, eventually replacing cyclic steam stimulation. So we would no longer produce bitumen with steam, we would produce it with solvent instead." A multi-year $100-million field pilot under construction is expected to start up in 2014.

And Cenovus Energy Inc. believes its best-performing thermal in situ projects, with among the most efficient steam to oil ratios in the industry, could already meet the mark. "At our current steam to oil ratio [about 2:1], both Foster Creek and Christina Lake [SAGD projects] are comparable to conventional production when it comes to emissions. So we believe that in the case of the California LCFS, refiners can be comfortable accepting and processing our oil," says Jessica Wilkinson, company spokeswoman.

Cenovus is also experimenting with solvent technology with its solvent-aided process (SAP) pilot project at its Christina Lake SAGD facility. "We're basically injecting a solvent [butane] with the steam. Butane dissolves into the oil, making it thinner and allowing it to flow more freely to the producing well. We anticipate a 30 per cent increase in production and a 20–25 per cent decrease in the steam to oil ratio. We also expect to recover about 15 per cent more of the oil in the reservoir."

Cenovus is planning to exclusively use SAP on its next oilsands development at Narrows Lake, representing the industry's first full-scale commercial deployment. "We're also experimenting with a number of different solvents to see what works best," Wilkinson says.

Others, such as the Pembina Institute, remain unconvinced. "We would love to see the data and validate those claims, but we haven't seen it so far," says Dyer. "The ball is in the companies' court to actually demonstrate that performance."

Publicly sharing such data could allow oilsands producers "to prove that they can compete in a low-carbon world, and could go a long way toward improving the image of the oilsands in the global energy market," the institute maintains. ■

PHOTO: PUMPWELL SOLUTIONS LTD.

PRODUCTION

Smart Pumpjacks

Outsourcing pumpjack optimization can dramatically cut downtime, boost oil production

As the production focus in western Canada recently shifted to oil from natural gas, pumpjacks have become more important than ever. These nodding donkeys, as they're sometimes called, have been part of the landscape across much of western Canada for so long that their performance is probably taken for granted.

But as the most common method of lifting oil from a well, the pumpjack is one technology where improvement could yield meaningful gains in efficiency and productivity, says an oilpatch entrepreneur who has done just that.

When mechanical engineer Krzys (pronounced Chris) Palka worked in manufacturing, he had a chance to learn from retired Japanese engineers who were consulting in North America. He was greatly impressed by the Japanese devotion to continuous improvement and innovation, which he put into practice in industrial manufacturing. Meanwhile, Palka's father-in-law, a retired professor, had a small company selling software to analyze well performance.

"One of the things that got my attention was there are thousands of pumpjacks in Alberta, but if you look at how they operate, you could almost argue they operate in exactly the same way they operated 30 or 40 years ago," Palka recalls. "It almost looked like innovation and the drive for improvements stalled."

In 2002, Palka started a research project with his father-in-law to find ways to improve the profitability of pumping oil wells. The answer: automated mathematical procedures that take information from a variety of sensors to achieve optimum efficiency by manipulating the movement of the pumpjack.

"We mathematically found there is a better way of operating even the old, tired conventional pumpjack that will bring more oil—if oil is available in the well—but will definitely lower the amount of wear and the failure of the pumping system," Palka says. >

CONTINUOUS IMPROVEMENT

Observing the little amount of improvement in pumpjack design over previous decades, PumpWell Solutions turned to automated mathematical procedures to create a better pumpjack.

WELL AUTOMATION
Using the latest technology in AC motor speed control combined with powerful computer, communication components and a variety of external sensors, PumpWell implements the best operating parameters for a well.

PHOTO: PUMPWELL SOLUTIONS LTD.

This was the theory. To put it into practice, Palka founded PumpWell Solutions Ltd. in 2004 with three employees. They built a prototype and installed it on a well two months later. The technology, called WellEXPERT, is a combination of proprietary well controllers and software designed to reduce wear and maintenance, extend run times and produce more oil.

"We found the initial results were extremely promising. We were able to produce about 20 per cent more oil—the well had additional production available," he recalls. "That was a well that was giving a lot of trouble to the producer and the failure rate was about every three months. [Once WellEXPERT was installed], the well was working for over a year before we had enough wear in the downhole components that there was a workover to resolve those issues."

If instant success with a prototype sounds incredible, what's even more astounding is none of the original three employees—Palka, another mechanical engineer and an electrical engineer—had any previous oilpatch experience.

"We really believe there are some universal values and qualities which are not dependent on the industry, but are dependent on individuals and on the need to achieve greater results," he says. "And I think you can never undervalue common sense. You can never undervalue curiosity. You can never undervalue being self-motivated...having bias for action...being a team player, being flexible, having high work ethic."

In an interview, Palka repeatedly stresses that PumpWell tries to hire people with those qualities. And while acknowledging industry experience could be a "tremendous" asset, he says: "I think sometimes coming from the outside—having a new look and the ability to look differently at the industry—could be extremely beneficial."

OUTSOURCING PUMPJACK OPTIMIZATION

Now with nearly a decade of experience under its belt, PumpWell feels it offers something producers increasingly don't have in-house—specialists focused solely on a single production technology. With PumpWell managing artificial-lift optimization, production engineers can focus on their other responsibilities.

"There is a lot of pressure on those engineers to do many things today," Palka says. "In the past they were able to focus on a couple of things very well. Today those engineers have to handle a lot of things, and a company like ours—which takes some of the load from their shoulders and ensures the results are delivered—creates a huge potential for them to have those resources available for other opportunities. [It] puts [the] onus for delivering results on our shoulders.... If the results are not being delivered, we have no right to exist."

In the early days of the industry, oil and gas producers owned and operated drilling rigs. Today, with a tiny number of exceptions, producers outsource drilling, along with completions, workovers and much else, to independent contractors.

While PumpWell provides technology and remote, real-time monitoring of wells, Palka says the main value is in its specialists using their knowledge and experience to make changes to reduce wear and improve oil production. "Even though we have this amazing technology, we really do not sell technology on its own," he says, and uses a race-car analogy: "You can go and buy the best car, but it does not make you a winning driver.... We provide the race car—but we also provide the driver and the pit-stop team."

As production engineers take on more and more responsibilities, artificial-lift optimization becomes a smaller and smaller part of their jobs. At the same time, the lion's share of wells being drilled in western Canada these days are horizontals, which require more knowledge and expertise to effectively produce.

"Those new conditions are difficult, at best, to deal with even if you are a good operator, etc." says Dan Lechman, operations specialist at Athabasca Oil Corporation. For example, some of the horizontal wells are quite gassy. And unlike on a vertical well, Lechman points out, "you cannot run down into the cellar to avoid the gas." He says it's "definitely a benefit" to have an engineering group like PumpWell in town with expertise in optimizing such wells.

Lechman was introduced to PumpWell in 2008 when he was working for another producer. The company had lots of pumping oil wells, but operations were constrained by lack of sufficient operators. When he went to work for Athabasca Oil almost two years ago, the new company had no operators because it had no wells on production.

Athabasca Oil, which had second-quarter 2013 production of more than 7,000 barrels of oil equivalent (boe) per day, used PumpWell right from the start. "It was instrumental for me to monitor and optimize wells with minimal field personnel," Lechman says.

PumpWell's optimization decreases downtime and increases production, he says. "We've seen gains of at least up to 25 per cent." In the long term, Athabasca's operations specialist assumes that this ability to produce more oil more quickly will boost ultimate recoveries, and hence proved reserves.

Day to day, PumpWell's engineers and technologists effectively serve as an extension of Athabasca's in-house engineering team, Lechman says. "Probably one of their biggest strengths is the service side of it."

In 2009, newly minted Elkhorn Resources Inc. was gearing up operations. All its wells were sour, high-salinity oil wells with a high water cut. They're near a major waterway, the Souris River in southeastern Saskatchewan, and just north of the U.S. border.

"One of my concerns was the environmental impact that could potentially hurt a junior company if we ever did have a spill," recalls Kory Galbraith, Elkhorn's vice-president of engineering.

The primary goal was to quickly detect and deal with potential leaks, thereby minimizing any health, safety and environmental impact. The other objectives were artificial-lift optimization and well performance monitoring.

A former boss who had been a senior manager at a major oil and gas producer introduced Galbraith to PumpWell. Four years later, Elkhorn has PumpWell's technology on more than 50 wells. In fact, the only wells that it isn't on are 28 decades-old vertical wells, which are "not really a fit for the application," Galbraith says.

As a private company, Elkhorn doesn't publicly disclose its financial and operating results, but Galbraith says its production is more than 2,000 barrels per day. At less than $10 per barrel, he says Elkhorn's operating costs are less than those of producers it considers its peers in the public market. Without PumpWell's pump optimization—and the resulting reduction in repair and maintenance costs and downtime—Galbraith estimates Elkhorn's operating costs would be $1.50 per barrel higher.

That doesn't include production gains from reduced well downtime. Galbraith says there are no before-and-after comparisons of downtime and repair costs because Elkhorn has always used PumpWell's technology. And though it's too early for a specific estimate, he believes it will improve ultimate oil recovery.

The other benefit is the technical expertise Elkhorn gets from having PumpWell personnel integrated into its team. Says Galbraith: "I have direct contact with a group of individuals there that are constantly watching our wells. So for a small junior company, instead of having to hire a production engineer or trying to get 25 hours out of a 24-hour day, I've utilized the expertise and the resources at PumpWell to become integrated into our operation. And they act as a production engineering solution for Elkhorn."

Privately held PumpWell, which has grown its workforce tenfold to 30 employees, says it is now optimizing hundreds of wells in western Canada with combined output exceeding 30,000 boe per day. With North American oil drilling and production at its highest level in decades, there's plenty of room for this little company to grow.

■ ***Pat Roche***

CONTACT FOR MORE INFORMATION

Krzysztof Palka, PumpWell Solutions Ltd.
Tel: 403-542-9363
Email: kpalka@pumpwell.ca

COMPLETIONS

Ever Farther

Longer wellbores, more frac stages inspire new technology advances

Producers of shale gas and tight oil have reached levels of horizontal length and numbers of fracture stages per well along the lateral that would be unimaginable a decade ago. But they appear unwilling to allow the limits of technology prevent them from going even farther—as the technology catches up.

It's not just the drilling that limits longer lengths—the ability to go into the wellbore following fracturing to mill out the frac plugs or ball seats that enable multistage fracking can also limit how far operators can effectively penetrate into the formation. The drive for longer horizontals has prompted companies that specialize in jobs like mill outs to advance an array of technologies to push those limits.

"The biggest part of the coiled tubing market now is milling out plugs and frac sleeves—I think the latest number is over 80 per cent of all the work in North America," says Don McClatchie, engineering adviser, corporate coiled tubing, at Calgary-based Sanjel Corporation. "So that is the big focus for everybody, and of course over time, the number of fractures the oil companies want to put in the horizontal section of the well just goes up and up and up, and these horizontal sections get longer and longer and longer."

In the Bakken Formation—which spans areas of North Dakota, Montana and southern Saskatchewan and has become a mammoth tight oil producer at over 800,000 barrels per day, second only to Texas in the United States—Sanjel has been active since the play started to boom in 2007. As the drilling frenzy has grown, so has Sanjel's ability to run coiled tubing to greater depths—including recent record lengths of over 20,000 feet (6,096 metres) for leading Bakken producer Continental Resources, Inc., a pioneer of the play. As of June, Continental was operating 22 drilling rigs across the Bakken and producing more than 100,000 barrels of oil equivalent per day.

The desire to go farther "creates an ever-increasing challenge, first of all, to reach all the way out to the end of the well, and secondly, as the coiled tubing strings get longer, it gets harder to pump fast enough to clean out the wellbores," McClatchie says.

Just a few years ago, companies were struggling to get past 17,000 feet total depth in the U.S. Bakken, he says. Today, wells can reach 9,000–10,000 feet in the vertical section and another 9,000–10,000 feet in the horizontal section for a total measured depth inching up over 20,000 feet. This has been accomplished through a number of incremental improvements to string designs, downhole tools, friction reducers and simulation software, all of which played a role in Sanjel's record runs.

"When you are talking about these kind of extended reaches, every little bit of technology improvement can get you another couple hundred feet, creating incremental gains week after week, month after month, to the point now where we are getting close to 21,000 feet," says McClatchie.

Sanjel's record runs in August reached 20,164 feet (6,146 metres) and 20,783 feet (6,334 metres), using a string that has a diameter of two inches (50.8 millimetres), working from a multi-well pad. The company successfully milled out 26 plugs in a single trip.

The records were foreshadowed by 20,000-foot measured depths described in a Society of Petroleum Engineers paper, 159574, last year, co-written with Continental that pointed to gains of 10 per cent in extended reach using downhole water hammer tools and frictional >

RECORD RUNS
Advancements in a number of technologies enabled Sanjel to reach new milestones in its coiled tubing operations in the Bakken.

drag reducers. The case study of over 40 wells outlined methods to more accurately forecast coiled tubing lock-up depths when using these technologies.

McClatchie says Sanjel has undertaken studies of a number of friction reducers to narrow down which will get the company that extra distance downhole. "We just finished evaluating 15 different products and came up with the top two—one is better for fresh water and acids, one is better for brines."

Metal-to-metal friction reducers lessen the drag from the normal force acting between the coiled tubing and wellbore completion by creating a low-friction layer between the two, maximizing weight transfer to the bit and reducing helical buckling of the string. Circulating the pressure friction reducers lower pump pressures and allow for higher rates and reducing pipe fatigue.

In its study with Continental, Sanjel observed significant improvement in cases where "circulating the drag reducer was started at early stages instead of waiting to experience severe weight loss before pumping metal-to-metal lubricants." And it concluded the use of acrylic copolymer circulating pressure reducers reduced pump pressures along the string at least 50 per cent, allowing higher pump rates and positive displacement motors and water hammer tools to be operated at their optimal flow rates.

Downhole tools, such as water hammer tools, run near the motor and bit, creating a vibrating agitation that further assists to tug the coiled tubing out. "There are probably half a dozen such tools out in the industry and some work better than others. It's a matter of understanding what you are going to be doing in the well and how fast you are going to pump, how to configure the tools in order to get the maximum performance out of them."

While coiled tubing strings, made of carbon steel by manufacturers in Texas, are fairly standard, for long-reach applications, they are custom designed to be tapered toward the end. Part of the impetus for tapering is the road weight restrictions limiting the size of coil that service companies can get to the wellhead. "One of the balancing acts, an art that must be mastered, is to determine exactly what wall thickness is the bare minimum to reach out to the end of the well, but will still be light enough to drive down the road."

The strings are often optimized for a particular play, since parameters like depth will vary. Wall thickness may range from 0.175 inches down to 0.125 inches, which, though it doesn't sound like much, over a significant length "that is quite a bit of weight you are saving," McClatchie says. For example, while larger diameters help with extended reach and well cleaning, merely going from a two-inch to a two-and-three-eighth-inch 23,000-foot coiled tubing boosts the weight from 70,000 to 89,000 pounds.

Tapering changes other factors that need to be accounted for. "If you make the wall a little bit thinner, it brings down your pump pressure a little bit because you have got a bigger inner diameter—it's a fractional amount, but over 23,000 feet it adds up," McClatchie notes.

A recent finding, meanwhile, overturns the rule of thumb that suggests a more viscous fluid, created by pumping gels with water, always assists in cleaning debris out the well. While that's true in the vertical section, Sanjel found that in the horizontal section increasing viscosity decreases turbulence that is experienced when using plain water.

"We have discovered recently, doing some testing in some flow loops we have on surface and some research we are doing in conjunction with the University of Oklahoma, that in the horizontal, if you go with regular water, which has low viscosity, you can get more turbulent flow, which stirs up all the solids and carries them out. Whereas if you used something very viscous, it would be much less turbulent and the solids will eventually settle out over a 10,000-foot horizontal. So you have to understand what fluid to pump when, and if you are good at that, you can literally cut the job time in half."

Of course, such discoveries aren't kept quiet for long. Though Sanjel may be a front-runner in Bakken extended-reach coiled tubing work, McClatchie knows the competition is right behind. "We seem to get out to these milestones first, but there are no secrets to the industry—people will eventually copy and catch up."

Could the wells go longer still? "We are getting requests to go as far as 23,000 feet total depth, 10,000 [feet] vertical and 13,000 [feet] sideways in the Bakken, so if we could go farther, the oil companies definitely would."

■ ***Maurice Smith***

CONTACT FOR MORE INFORMATION

Don McClatchie, Sanjel Corporation
Tel: 403-776-4800
Email: dmcclatchie@sanjel.com

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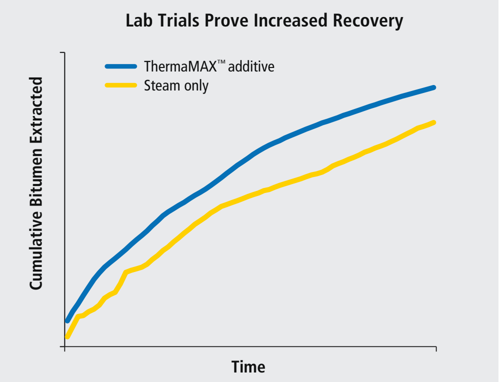

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