SEPTEMBER 2015

# New Technology magazine

THE FIRST WORD ON OILPATCH INNOVATION

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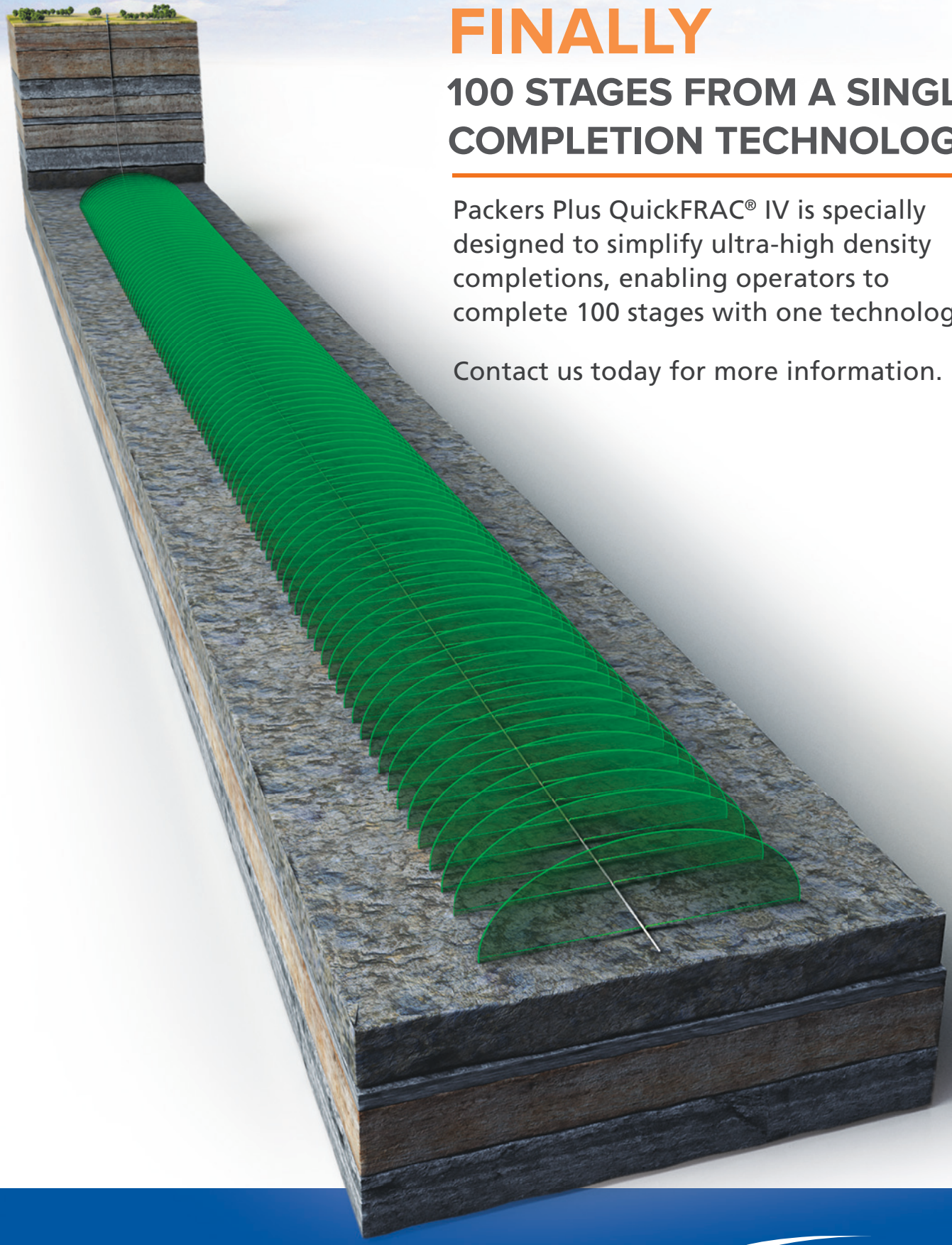

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# POWERING THE OILSANDS

California-based solar developer GlassPoint recently announced plans to build the world's largest solar project. It stands out not only for its size, but also for its purpose—it is not a subsidized green initiative to promote some jurisdiction's drive for renewables. Rather, the $600-million, 1,000-plus-megawatt facility's sole purpose is to supply steam for enhanced oil production for the state oil company of Oman.

Petroleum Development Oman (PDO) has been consuming massive amounts of natural gas to generate steam to produce heavy oil. After a three-year study, it found solar to be more cost-efficient and better for the local economy, as well as cleaner.

And the installation, for the Amal field, may be only the beginning. The country has 20 other fields under steam-powered enhanced oil recovery that are potential candidates, and Oman's neighbours are also interested. Royal Dutch Shell, which owns 30 per cent of PDO and is an investor in GlassPoint (which also supplies solar-produced steam to Chevron in California), may also look to other projects.

In many ways, the Alberta oilsands are in a similar situation, consuming enormous amounts of natural gas to produce the steam required to coax bitumen to the surface. That consumption is largely responsible for its growing greenhouse gas (GHG) emissions, which represents probably the largest perception problem facing the oilsands—and leads to its inability to garner goodwill in constructing pipelines to give it wider market access.

There is one lower-emissions success story: several projects have adopted gas-fired cogeneration as a means to both produce the heat required for steam generation and simultaneously meet their electricity needs—and in some cases feed excess power into the provincial grid. Compared to using power from the grid, which is still more than 40 per cent provided by GHG-intensive coal combustion, such facilities are actually greening the grid, as detailed in this issue of *New Technology Magazine*. If the new provincial government moves on its promise to speed up the phase-out of coal power, cogen is in a position to help replace some of that power.

While that would be a good start, it falls short of the game-changing innovation exemplified by the Oman solar solution. As the province, and the country, move to deal more effectively with GHG emissions as promised, cogen alone won't suffice. In order to square increasing bitumen production with decreasing GHG emissions, we need technology game-changers.

Solar power is not as attractive in northern Alberta as it is in the sun-drenched Middle East. But there may be other means to harness renewable power to reduce emissions—and perhaps develop a new industry. Geothermal power, for instance, might be one technology to encourage, given western Canada's existing expertise in drilling.

"I think Alberta is perfectly situated to make the [geothermal] technology work," Todd Hirsch, chief economist with ATB Financial, told the CBC in July. "I think geothermal energy might be one that Alberta wants to champion specifically because it doesn't work here. If we can make it work here in Alberta, then it is a cinch to sell the technology to the Chinese and the Germans and everyone else where geothermal doesn't work."

Or hydroelectric power. Steven Fletcher, a west Winnipeg MP, suggested in 2013 a transmission line bringing "some of the cheapest and most environmentally friendly power on the planet" from Manitoba to Alberta. It could represent a win for the oilsands and for both provinces, he said. "Moreover, diversifying the energy supply would go a long ways toward addressing President Obama's concern about the Keystone XL pipeline."

It's too early to tell whether geothermal, hydro, wind, carbon capture and storage, or some other low-emission technology could reverse the emissions growth trajectory forecast for the oilsands. But projects like that in Oman suggest there are out-of-the-box solutions that could have a big impact. At the risk of stunting future oilsands growth, it makes plenty of sense to start seriously investigating the alternatives soon.

■ ***Maurice Smith***

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# 12 bcf/d until 2030

Without access to global LNG markets, Canadian natural gas production will decline over the next decade, then remain flat at about 12 bcf/d until 2030, the Canadian Association of Petroleum Producers predicted in its natural gas outlook. Access to global markets would enable recovery to current levels of 14.5 bcf/d, while natural gas demand to fuel liquefaction plants could raise production to 17 bcf/d by 2030.

Texas record-breaking production:

# 1.28

billion barrels in 2015

Despite the tumble in oil prices, Texas is on the cusp of record production, not reached in 43 years, of 1.28 billion barrels this year, exceeding the state's record of 1.26 billion barrels set in 1972, the *Houston Chronicle* reported in July. Technological advances are helping keep oil production high amid falling rig counts and more than 20,000 industry layoffs.


Energy companies have shelved $200 billion of spending on new projects amid the collapse in oil prices, consultancy Wood Mackenzie reports. Projects that are technically challenging, have significant upfront costs and/or low returns have proved most vulnerable—over 50 per cent of the 20 billion barrels of production deferred is located in deepwater projects, and nearly 30 per cent in the Alberta oilsands, where spending may not pick up until 2017.

magnitude

# 3.0

and up

Oklahoma regulators imposed new restrictions on energy companies injecting waste water, a by-product of booming oil and gas production, underground in response to a sharp increase in earthquakes. Noticeable quakes, above magnitude 3.0, now strike Oklahoma at a rate of two per day or more, compared with two or so per year before 2009, Reuters reported in August. Three quakes of magnitude 4.0 or higher struck in a single day in July.

# 2019

In an innovative means of dealing with its surplus of coke, a by-product of oilsands upgrading, Suncor Energy is creating a solid surface for a tailings pond. "Suncor's Pond 5 project uses some of the greatest field tailings technology in the world and is projected to be completed in 2019," the Alberta Energy Regulator said in July. "Although coke capping is not the ultimate solution for closing ponds quicker, it is certainly becoming a viable method to accelerate the process."

COMMUNICATIONS

# VIRTUAL PRESENCE

Live visual streaming technology remotely connects experts to the field

The rollout of what tech giants like Cisco Systems call the Internet of Things (IoT)—the company predicts there will be 50 billion devices connected online by 2020, with a total market valued at $19 trillion—is increasingly making inroads in an oil and gas sector keen to cut costs in today's low price environment. A small Winnipeg-based company that has developed a technology that allows users to literally see those devices at work is doing its part to advance the IoT transition.

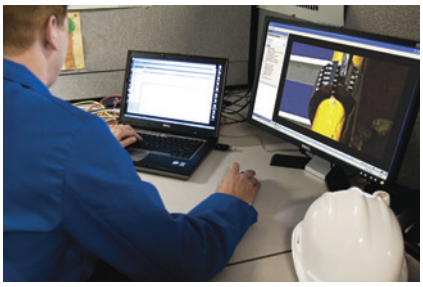
Librestream Technologies has taken fast-growing video conferencing formats, such as Citrix Technology's GoToMeeting and Cisco's WebEx, now an $11-billion-per-year business, to a new level, extending video conferencing and collaboration so that, using mobile devices, workers can visually connect to experts at work stations from difficult-to-access locations, such as plant floors, oil rigs, aircraft repair hangars, mines and emergency response sites.

The company's patented Onsight Mobile Collaboration System, now deployed across a wide range of industry sectors, enables full and immediate collaboration for remote workers using its family of hand-held wireless devices and collaboration software, allowing workers to connect with experts using a desktop and Librestream's Onsight Expert software.

Thanks to a collaboration agreement between Cisco and Librestream, the company's technology can also be used to extend collaboration with additional participants through the use of Onsight Expert for desktops and Cisco WebEx and its related TelePresence product. >

**^ REAL-TIME COLLABORATION**
Librestream's mobile collaboration system allows workers in the field to visually connect to experts located virtually anywhere for real-time problem solving.

PHOTO: LIBRESTREAM



**SEEING IS BELIEVING**
Onsight mobile collaboration enables assessment of field operations that can be almost as good as being on location, without the costs associated with sending experts to remote locations.

> **BY THE TIME YOU FLY A SPECIALIST [AND OTHER STAFFERS] TO AN OFFSHORE PLATFORM WITH A HELICOPTER, YOU'RE BURNING THROUGH A LOT OF MONEY. USING THIS TECHNOLOGY WE CAN AVOID THAT."**
>
> *— Philippe Flichy, senior digital oilfield adviser, Baker Hughes*

In late May, Cisco selected Librestream as a winner of its prestigious Cisco Solution Partner Program Business Outcome Contest in the manufacturing and energy category. Cisco said it was honouring the company's technology because it "recognizes its outstanding innovation in solving real-life business challenges."

For oilfield service giant Baker Hughes, the use of the technology has been a godsend, particularly when used at offshore rigs in the Gulf of Mexico and elsewhere.

Philippe Flichy, the Houston-based senior digital oilfield adviser with the company's enterprise technology division, says the Onsight system has allowed the company to shift to a rig monitoring, maintenance and repair system that is similar to aircraft control systems that have been in use for decades.

"It allows us to do more with less," he says. "By the time you fly a specialist [and other staffers] to an offshore platform with a helicopter, you're burning through a lot of money. Using this technology we can avoid that."

He says Baker Hughes is contractually responsible for non-productive time on offshore platforms if there is an equipment failure or other problems. "That can cost us half a million dollars a day on an offshore platform."

Librestream's rugged cameras, built for industrial sites, are ideal for the rough world of the offshore energy industry, says Flichy.

"Because their cameras go from micro to zoom, it's perfect for us," he says. "The image is clear and we have our own system to compress the image and send it back and forth. On the back of the camera there's a device that lets you circle an area and take a fixed image [telestration], which allows for advanced consultation."

## GLOBAL REMOTE SUPPORT

Baker Hughes uses the system on 40 offshore platforms and on rigs and other installations worldwide. Using the camera systems on rigs in Africa, the Middle East and other hard-to-reach locations has saved many millions of dollars, he says.

"Getting a visa for a specialist who needs to go to Africa can take three to five weeks, but using this system can help us avoid that," he says.

Using what he likens to a control tower, Baker Hughes' complementary workflow system, with a specialist at the helm, can guide field workers through a list of questions and tasks, with the Onsight systems providing visual access that is almost as good as being at the location—but without the associated costs.

In addition, Flichy says the systems assist in worker health and safety, an important consideration for Baker Hughes. Because specialists don't have to be flown or otherwise transported to remote sites, they are kept out of harm's way.

The company also uses the cameras in the oilsands and the conventional oil and gas business in Canada. "We have one type of use in our warehouses [in Alberta] where we receive used equipment that is coming back from the field," he says. "Rather than having clients come to the warehouses, we can show them what the problems are."

Baker Hughes, which is in the process of being bought for US$35 billion by rival Halliburton, has bought 200 Onsight systems.

Jereme Pitts, Librestream's Los Angeles area-based chief operating officer, is a successful tech entrepreneur with experience in video technology and software sales. In 1999, he co-founded Accordent Technologies, a leading provider of video content management and delivery solutions. He was senior vice-president of sales and marketing for that firm, which was sold in 2011 to Polycom for US$50 million. He has also been involved with other successful start-ups.

Pitts joined Librestream in 2013 after having developed a close relationship with Cisco, which in 2010 acquired European-based enterprise video leader Tandberg for $3.3 billion. Pitts had previously worked with Tandberg.

"A friend from Cisco said 'you should know about this company,'" says Pitts, who had been semi-retired prior to joining the firm. "They [Librestream] didn't have a sales structure [appropriate] for a $17-million-a-year [in revenue] company, so I joined them."

PHOTOS: LIBRESTREAM

He had one condition. "I didn't want to move to Winnipeg with my family," he says, alluding to the city's reputation for cold winters.

But he certainly warmed to its technology, which is why he joined the company.

## EXPANDED REACH

That has led to a significant ramp-up in sales and marketing efforts, and to some large new contracts for the company, which now earns about $20 million a year in revenue, which he says he expects to double or triple in the near future.

Librestream has developed software that allows its technology to be embedded on smartphone and tablet apps. Taking its business model beyond just selling its high-tech cameras, the company in mid-February announced a deal with San Antonio–based USAA using those apps. USAA is a financial services and insurance organization that services more than 10 million current and former members of the U.S. military.

The sale of its Onsight Connect software to such a large customer was described at the time by Kerry Thacher, Librestream chief executive officer and founder, as a "watershed deal" because millions of USAA customers will potentially use the technology to connect with claims representatives.

Using its Onsight Connect product, images and audio can be shared in a secure environment to assess losses, determine needed services and, in some cases, adjust claims in real time, Librestream said. The secure network Librestream offers lets clients interact with a claims adjuster who can direct the client to point the camera at a damaged vehicle, for instance. The adjuster can zoom in or freeze the frame, as well as access other features.

No financial terms were announced, but Thacher, an engineer by training, says it was one of the largest deals ever for the company, which he founded 12 years ago. "This is a new customer service model," Thacher said then. "There are others talking about it, like aircraft manufacturers, auto companies or companies that service IT facilities. They all like the idea of customers showing what is going wrong and getting immediate help."

Pitts says the new software product should open up large new markets for the company. However, he certainly won't be ignoring the core market for its high-tech cameras, led by the oil and gas industry. "In the early days our biggest customers were in the oil and gas industry," he says.

Aside from the obvious benefits of its technology for the sector, the company has benefited from being embraced by Winnipeg's business elite. For example, George Taylor Richardson, the scion of Winnipeg-based grain and securities giant James Richardson & Sons, sat on the company's board prior to his death last May and members of the family remain active in the company, which has deep links to the Canadian oil and gas industry.

"In the oil and gas industry we have cameras everywhere you can legally have a camera," Pitts joked.

**CAMERA READY**
Librestream manufactures its own cameras and has developed software that allows its technology to be embedded on smartphones and tablet apps.

PHOTO: LIBRESTREAM

## CREW CHANGE SOLUTION

Aside from the financial challenges now facing the energy industry as a result of lower commodity prices, it is faced with the prospect of older, experienced workers retiring.

Cisco executives have touted Librestream's technology as one important way of leveraging shrinking human resources in an industry faced with the loss of many skilled workers going forward, the tightening of regulations affecting the industry and social licence factors facing the sector in the wake of BP's Deepwater Horizon spill in the Gulf of Mexico.

Technological advances, such as the development of better and cheaper sensors and cloud computing, have also played a role in the move by more and more companies in many different sectors to embrace Librestream's technology.

Pitts says the Onsight offerings aren't reliant on access to wireless Internet service. "The technology is designed for low bandwidths," he says. "When they don't have access to wireless, our customers can use cellular or satellite services."

He says oil and gas customers routinely save hundreds of thousands of dollars by using the company's camera technology.

"For instance, we had an oil and gas customer who had a manhole cover drop three storeys from a platform. They would normally have sent three people by helicopter to deal with the situation. But they were able to use our camera system to deal with it all remotely, by connecting the experts with the field crew."

There are also many environments, such as high-pressure and extreme heat units in refineries, where the use of the cameras allows companies to avoid sending workers into dangerous environments.

Librestream's cameras are manufactured in Winnipeg, which is also where its software is developed and managed.He says the company's high-tech camera systems sell for between $5,000 and $15,000 each, while the deployment of its newer software product on a company's network can cost in the millions of dollars.

The company, which employs 60 people, may eventually go public. Meanwhile, he says it has a lot of growth ahead of it. "I think the sky is the limit," he says.

*Jim Bentein*

# Predicting FAILURE

## Asset performance management foretells equipment breakdown, avoids costly downtime

Gordon Cope

Electrical submersible pumps (ESPs) are an essential component of crude production. Over 130,000 EPSs are in use around the world in high-asset wells, accounting for approximately 60 per cent of the world's oil production.

But ESPs can also fail dramatically, taking down tens of thousands of barrels per day through lost production until they can be fixed. Clearly, being able to predict when they are going to crash—and being able to swap them out beforehand—is valuable information.

Apache operates thousands of ESPs in North America and around the world. Thanks to real-time monitoring, the Texas-based company has collected a huge volume of ESP performance data, along with completions, subsurface characteristics and geological information. Apache worked with GE to analyze the hybrid data in order to pick the right pump for the right well, then to help pumps last longer, and finally, to predict when they might fail.

In the end, the process helped Apache avoid significant loss of production, a benefit that could be passed on to the industry as a whole. According to the company, a one per cent improvement in global ESP performance would provide over a half-million additional barrels of oil per day. Even at today's low prices, that amounts to billions of dollars per year.

Apache's success came from leveraging a hardware and software application that is generically referred to as asset performance management (APM). Real-time monitors transmit a spectrum of data to central facilities where they are processed with software that uses big data analytics to search out patterns invisible to the human eye.

Various terms are used to describe the process, including artificial intelligence, machine learning and machine intelligence. At its most generic, software developed around specialized algorithms takes a wide array of space and time data—not only quantitative data, such as temperatures and pressures, but language, images, speech and metadata—and makes sense of it all. >

# Asset Performance Management

reduces costs by **30%**

cuts repairs by **12%**

reduces breakdowns by **70%**

According to a GE-Accenture study, APM can reduce maintenance costs by 30 per cent, cut scheduled repairs by 12 per cent and reduce breakdowns by up to 70 per cent.

"The work we do with customers shows that big data analytics can make a difference," says Orvil Smith, the Canadian general manager of GE Oil & Gas Measurement and Control. "When an ESP fails, it can take a long time to get the well back up. If you can anticipate a problem before failure, know when to turn it down and order new replacement parts, then it can avoid a lot of down days."

APM is just one dimension of a revolution underway across all facets of the economy. Smart devices, ranging from electric meters to pipeline substations, are gathering data and transmitting it via the internet. As the Internet of Things (IoT) quickly permeates all walks of life, vast amounts of data are being generated. According to Cisco, there are already 25 billion smart devices connected to the internet. By 2020, that number is expected to double.

Already, smart devices are ubiquitous in the utility market. Bit Stew, an APM firm based in San Francisco, began operations in California a decade ago, right when utilities were beginning to address smart meters and distributed energy sources. The founders felt that the solutions for connecting smart machines were inadequate, and developed their proprietary Mix Core platform and Mix Director application.

"Bit Stew chose the utility market because they were just entering the usage of smart meters and digital-enabled substations, so there was a plethora of data available," says Franco Castaldini, vice-president of Bit Stew Systems.

Bit Stew helped one of its clients, BC Hydro, develop an APM system. "We aided them with their smart meter roll-out," says Castaldini. "Our software originally supplied 100 per cent visibility to meter performance, faulty machines and installation errors." Since then, Bit Stew has worked with BC Hydro to augment the APM system, adding new abilities. "We now aid in the management of operations, looking at technical issues, theft of energy, and faults."

The ability to expand APM into other processes is almost limitless. SoCal Gas, the largest gas distribution company in the U.S., needed to beef up its safety response service. "A few years ago, there was a tragedy in the [San Francisco] Bay area, and there is huge sensitivity to gas distribution," says Castaldini. (In 2010, a 30-inch gas pipeline owned by Pacific Gas & Electric exploded in San Bruno, a San Francisco suburb, killing eight people and destroying almost 40 homes; PG&E was subsequently fined US$1.6 billion for safety violations.)

SoCal was searching for a way to increase public safety, and asked Bit Stew to help them build a better alarm system. "When it comes to alarms, there are a large number of false positives, and this leads to crew fatigue," says Castaldini. "We helped them connect crew management, construction operations and alarm response. Now, all information is on a single pane of glass."

## VALUE TO THE OIL AND GAS SECTOR

Already, the oil and gas sector is creating immense volumes of data with smart devices. Operators calculate that monitors on a 3,000-kilometre gas pipeline generate 30 terabytes of data every month, which is triple the amount of information stored in the Library of Congress.

Taking lessons learned from utilities and other sectors, companies are looking at a range of ways to integrate APM and its offshoots into the oil and gas industry. Recently, Bit Stew conducted a downtime proof-of-concept for drillships.

"The most common cause of downtime is when an asset fails and there is an inefficiency of response," says Castaldini. "The replacement part is not in inventory so there is lost time while the OEM [original equipment manufacturer] supplies a part or the operator searches for a replacement on another ship."

Bit Stew's algorithms allow the driller to analyze their level of risk through condition-based maintenance based on actual performance details. "It gives you a visibility to parts inventory that allows a faster response."

Bit Stew's first oil and gas sector APM-related application is designed to maintain pipeline integrity. "The pipeline integrity application looks at the flow, pressure, vibrations and valves, and geospatially visualizes everything in one place," says Castaldini. "You can then integrate weather, fire and seismic events so that you can understand the risk to assets and take action. It improves the efficiency of response to events."

Ayata Prescriptive Analytics, based in Houston, is one of the pioneers of incorporating a wide variety of information—from gauge data to videos, images, text and sound—into analytics. Ayata breaks analytics down into three categories: descriptive analytics (what is happening, and why); predictive analytics (what will happen); and prescriptive analytics (how can we improve what will happen in the future).

According chief executive officer Atanu Basu, the company is working with Chevron, Apache and other oil and gas firms to make developing unconventional resources safer and more efficient. Ayata's application analyzes 3-D seismic data, real-time drilling logs, fracture pressures, water use, casing information and production statistics. By combining all the available data sets with prescriptive analytics, the company claims that operators can devise better decisions that look much further ahead, as opposed to the current practice of reviewing data and making incremental improvements on the next well.

Of course, all innovation comes with a price tag. "The cost of a pilot program is in the low six figures, and deployment into the entire infrastructure is in the seven-figure range," says Castaldini. "With utilities, we aim for a three to five times ROI [return on investment] in the first five years. For new sectors, we aim for a seven to 10 times ROI in the first five years."

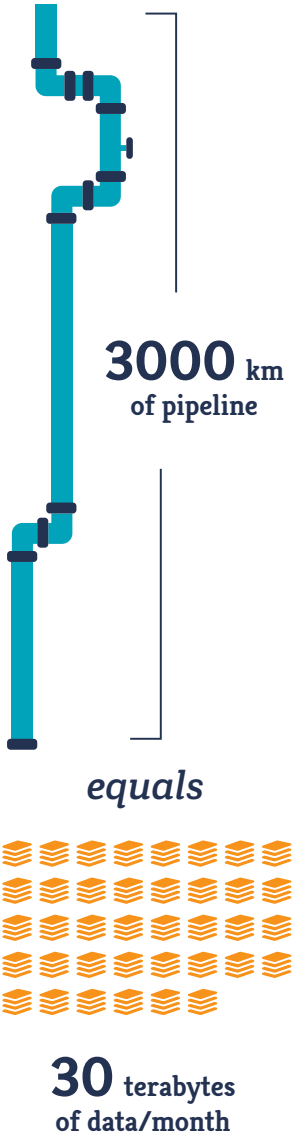
APM-related applications can be installed relatively quickly, however. "In the utilities sector, we can go from original data to a pilot application in under four weeks," says Castaldini. "In the O&G [oil and gas] sector, we are currently looking at three months, but we expect that to decrease as we co-develop applications and get a better understanding of the sector needs."

## THE FUTURE

Using APM to monitor equipment, schedule maintenance and enhance safety is merely scratching the surface. GE has been offering such services to oil and gas clients for several years, and is now engaged in stretching the boundaries. "GE is working with our customers in O&G to evolve big data analytics to go beyond equipment management and to optimize the entire production process," says Darren Massey, program leader, Customer Innovation Centre, at GE Canada Global Growth and Operations.

"Any knowledgeable person in the O&G sector knows that when they see a pump gauge pass the red line, the pump is going to burn out. What big data analytics does is look at a wider range of available data to find patterns that are not as obvious to extend the life of that pump but also optimize the way it operates to get the most production out of it."

One of the aspects that GE is exploring is referred to as operational intelligence. "Some operations take place in a closed environment, like a factory, in which processes are well understood and controllable," says Massey. "But O&G processes take place in the wild with far less homogeneity and consistency. That means it's harder to optimize, but it also means that there is opportunity to do so. GE believes there is a lot of promise for optimization in O&G. Our customers think so too."




Developing customized analytics requires a cooperative approach with clients in order to learn the ins and outs of the oil and gas industry. "Business rules and rules of thumb change from operator to operator, so a higher degree of collaboration is involved," says Massey. "This is very important, and requires some change of thinking."

What will the longer-term future bring? GE is working on a holistic approach called asset life cycle management that draws in not only every piece of equipment currently being used, but its entire time in service. "We are working on how to get more bang for your buck throughout the cycle of an asset," says Massey. "You look at the acquisition, and how it tracks through its work, to the point where it needs to be retired and eventually replaced."

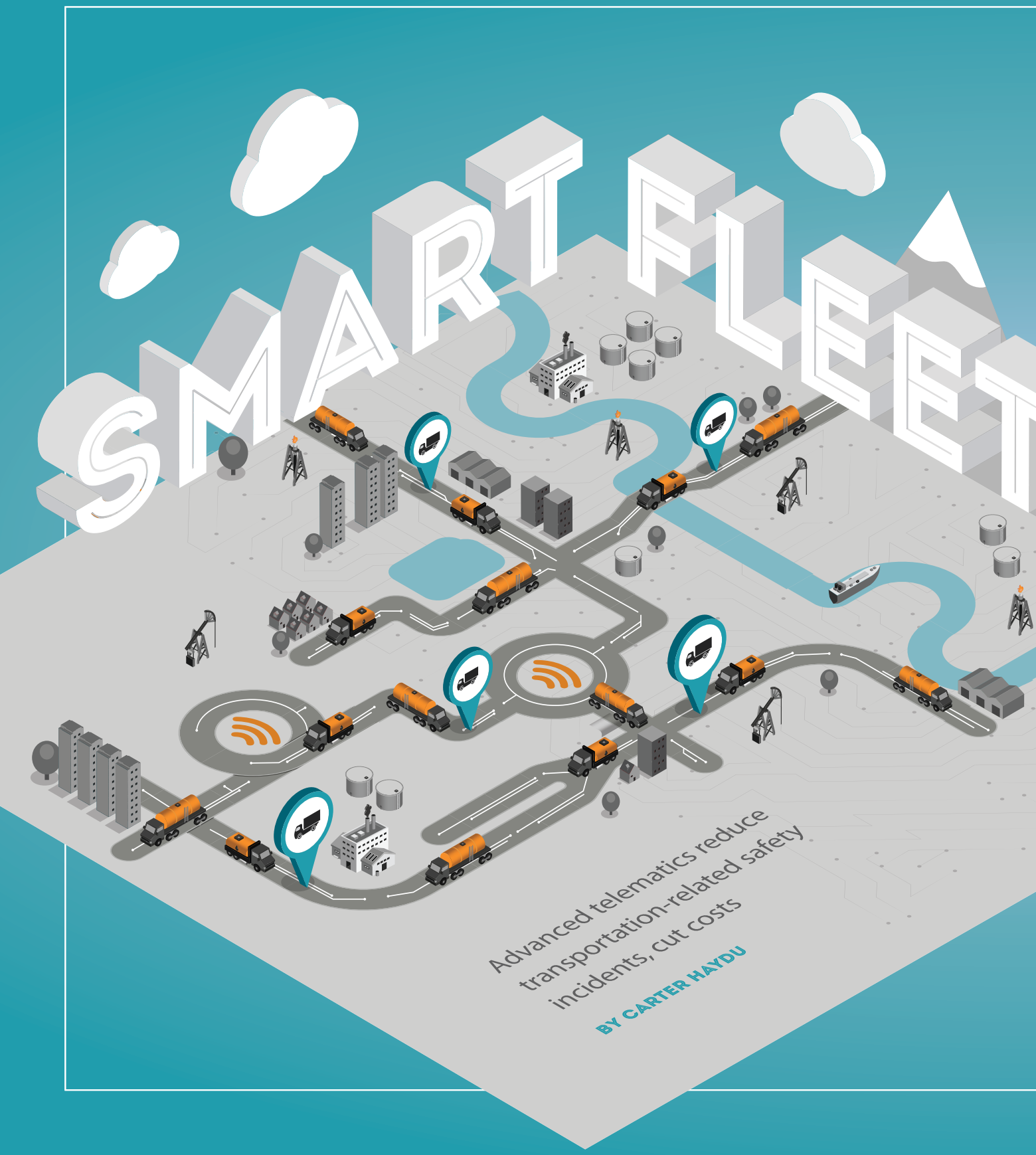
Bit Stew envisions a time when computers will do most of the work. "Ten years from now, we will have come full circle, where software-defined applications help to automate a closed loop," says Castaldini. "The software will go from solving a higher degree of problems to reaching a higher degree of solutions. Humans will always be involved, but they will be able to focus on high value problems."

In the meantime, service companies and oil and gas firms can benefit from the knowledge and experience gleaned in other sectors. "For many years, the North American oilpatch has been going through the challenges of dealing with a period of tremendous growth," says Smith. "Now that conditions have changed, this is the right time to learn to gather data and move it in an efficient way so that it can be analyzed for insight."

And they can do so in an efficient, cost-effective manner. "Many aspects of the enabling infrastructure necessary for big data analytics have matured," says Smith. "For instance, the economies of the Cloud now allow us to store, move and analyze data much more efficiently. Historically, this data has been stranded in isolated databases, unable to be related to give big picture insights. O&G professionals have done a lot of work mining data and making operational improvements. What GE is offering is taking this analysis one step further." ■

PHOTO: BIT STEW SYSTEMS

*This article is part of a four-part series with sponsorship from GE exploring the Internet of Things and its impact on the oil and gas industry. While GE professionals were interviewed for this story, the company had no involvement in its creation or production.*



# SMART FLEET

Advanced telematics reduce transportation-related safety incidents, cut costs

BY CARTER HAYDU

One of the most dangerous jobs associated with the upstream oil and gas sector is also perhaps one of the most mundane—driving to and from the work site. Fortunately, the latest advancements in fleet management technology can help reduce the safety risks associated with this routine task by monitoring and collecting data, prompting better driving habits and mapping out more efficient transportation routes.

"If you can minimize that windshield time, then you protect those workers," says Geoff Scalf, head of business development, oil and gas division, at Telogis. Telematics can also help companies effectively manage and allocate transportation resources, he adds. "From a pure safety standpoint, location intelligence tells you not only how workers are driving, but also how much they are driving, as well as where they are driving and working."

According to Enform's *Journey Management: A Program Development Guide*, between 2010 and 2014 in Alberta, British Columbia and Saskatchewan, vehicle-related injuries resulted in five per cent of Workers' Compensation injury claims in the oil and gas workplace, 13 per cent of claim costs and 24 per cent of days lost.

In-vehicle monitoring systems can assist in journey management, the report suggests, connecting workers to their supervisors through a communication system, interfacing with other workflow processes and monitoring lone workers in remote areas. They can provide global positioning system (GPS) location and mapping for drivers and administrators as well as vehicle telematics, hours-of-service monitoring and compliance assurance, and alertness monitoring.

Enform emphasizes that such technologies alone do not ensure a sufficient journey management program, although the associated data could provide feedback to stakeholders for development of continuous improvements and positive changes in driver behaviour—a sentiment shared by Colin Sutherland.

"Normally, a fleet that is managing their technology for safety and has an aggressive safety policy can reduce their claims costs on a vehicle by about 30 per cent," says the vice-president of sales at Geotab. He suggests safety-focused companies can expect dramatic operating-cost savings when strong, enforced corporate policy backs up the technology.

"I think what we are seeing now is an increasing trend that emerged in 2015, which is more about how to guide the fleet manager to be more specific on what actions to take with this data, as opposed to just looking at the data itself. So it is about the interpretation of the data on behalf of the fleet."

The oil and gas industry is so heavily regulated that it really is not a matter of deciding whether fleet management technologies are necessary, but rather figuring out the best way to deploy such technologies in order to meet those regulations, says Sutherland. For example: "In some cases, if you exceed the speed limit on the private roads created by the industry itself, often the entire business can be prohibited from driving on those roads.

"The industry polices itself on those private roads, and you cannot disobey the safety rules when it comes to speed or aggressive driving."

Electronic driver log (ELD) technology designed by inthinc Technology Solutions ensures compliance with corporate and jurisdictional rules—an attractive feature for major oil and gas producers in both Canada and the U.S. that are using fleet-management technologies to guarantee compliance with government, local and corporate policies.

"When a driver gets inside a vehicle equipped with our ELD technology, as soon as he puts the vehicle in drive it automatically registers him as 'on-duty driving' and starts the clock in accordance with the legislated rule set assigned to him," explains Lisa Cooper, inthinc's vice-president of Canadian sales.

## RACE CAR LEGACY

What started out as a black box technology company combating fraudulent insurance claims in the mid-1990s was quickly transformed with the tragic death of race car driver Dale Earnhardt in 2001. Recognizing the increasing dangers associated with the sport, the National Association for Stock Car Auto Racing (NASCAR) established a relationship with inthinc to have race cars equipped with black boxes.

"Installed inside the vehicles, the data-recording technology gathered critical vehicle and driver data, allowing [NASCAR] to create significantly safer racetracks, safer barriers and most importantly safer cars," says Cooper. Major oil and gas producers took note of this technology and solicited the Utah-based company to work with their fleets as well. The end product: a technology that enables oilfield drivers to operate with greater safety and efficiency.

"We really are saving lives in this marketplace. The clients we work with truly are helping their employees arrive home safe to their families at the end of the day."

A more recent product offering, the waySmart Connect, leverages the world of expansive mobile apps for fleet managers and drivers, providing a true mobile solution for optimizing fleet operations with the ease of a download. "You choose the apps your drivers need to effectively complete their job and which ones they don't, making your entire fleet more safe, efficient and compliant," notes Corey Catten, chief technology officer at inthinc. >

ILLUSTRATION: ©ISTOCK.COM/ASKOLD ROMANOV; ©ISTOCK.COM/MAARTJE VAN GASPEL


**> KEEPING TRACK**
Geotab's GO7 device can perform several functions, from providing diagnostics on vehicle condition to tracking the speed and location of vehicles, providing real-time coaching and tracking lone workers in the field.

According to an inthinc case study, within six months of installing the waySmart solution, the participating oil services company experienced a 300 per cent increase in safe driving behaviour, a 97 per cent reduction in speeding violations, an 89 per cent reduction in aggressive driving and a 57 per cent increase in seatbelt use, saving the company $18 million in one year alone.

"The in-cab device actually coaches drivers to check their speed. It compares current speed of the vehicle against posted speed limits, and then coaches the driver to check their speed," adds Cooper. "Additionally, when a driver gets in his vehicle, puts it in drive and pulls away from his parking space without buckling his seatbelt, the device will remind him to do so."

The inthinc solution verbally coaches drivers in real time to discourage aggressive driving behaviors such as rapid accelerations, sharp turns and hard braking. Additional mentoring for seatbelt use, excessive idling and smartZone geofencing are standard system features.

With inthinc's in-cab verbal prompting, the driver can correct poor driving behaviour in real time. If the driver ignores the verbal coaching, then inthinc's risk profile can alert management immediately. Management can then assess the employee's overall driving habits for safety and identify areas needing improvement and/or training.

## GAME OF PROMPTING BETTER HABITS

Telogis Coach is part of a multi-pronged approach to driver safety, which includes real-time, in-cab alerting when an employee exceeds a company threshold, as well as the gamification of driver safety by allowing employees to see how they rank amongst their peers.

"They can see what their driving score is and if they are moving up or down the leaderboard," Scalf says, adding most employees want to manage their own driving behaviour without necessarily being confronted by a supervisor, and a mobile arena for competition amongst coworkers does that while also appealing to many younger "gamer" employees in the oil and gas sector.

"What we have seen with fleets out in the operator space is they may have somewhere between three to four speeding incidences per 100 miles. However, once they turn on the in-cab alerting and follow up with the scorecard, they will drop that [incident rate] typically down to 0.5 [speeding incidences] or lower per 100 miles driven, due to the driver's awareness of what is expected of him…both through Telogis Coach and the in-cab alerting.

"However, it is also about the driver being aware that someone in management is actually looking at this and is aware of how [he] is driving."

With InSight Alerts, Telogis provides real-time alerting and notifications in accordance with a company's particular rules. "There are probably 500 to 700 different canned alerts customers can go in and set up," Scalf says. "They can select the alerts, select the thresholds and select when it is active." Supervisors can quickly view how adherences to such things as maintenance and driver performance rules are trending within the fleet, he adds.

"They have that control over the reporting if they choose to have a multi-condition alert. So maybe they want to know when the tire pressure is low and the driver is speeding over 80 miles per hour. They can create that level of sophistication in their alerts."

One of Telogis's strengths is it builds software, not hardware, and can therefore leverage the latest and greatest hardware technologies available on the market from those companies that do build the physical components. Telogis is the only telematics company with a direct original equipment manufacturer strategy, Scalf notes, and the technology can support everything from a frac tank to an all-terrain vehicle, a pickup truck to a heavy-duty tractor unit.

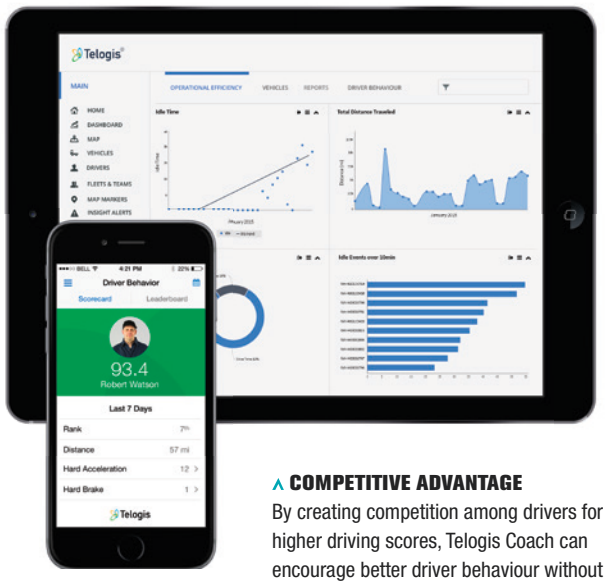
The ability of Geotab's GO7 device to collect safety information within a fleet and automatically verbally coach drivers when aggressive driving habits are detected also appeals to Canadian producers, Sutherland says. "So if [the driver] speeds, then rather than the device just beeping at the driver, it will speak to him and say, 'excessive speed.' If he is not wearing a seatbelt, then it will say, 'seatbelt unbuckled.' It is a real-time, in-vehicle coaching tool."

Geotab's application in the energy sector is extensive and crosses a range of equipment, he adds. "We are literally in everything from remote diesel generators that are operating in the field, right up the pipeline to ATVs to pickup trucks to Class-A highway tractor trailers.… We are literally in every make and model of vehicle that you can imagine. There really is not any limit at all."

## LIFELINE FOR MOBILE WORKERS

Geotab's GO7 device plugs directly into a vehicle's OBDII port (or an adapter) to provide diagnostics on the health of the vehicle, while the accelerometer keeps track of speed and the GPS component tracks location, Sutherland says. The device also helps keep workers safe when they are alone in the field.

"In places like Alberta, you cannot work alone unless you have a compliant technology that protects the safety of the individual. You need a panic button. You have to have a distress signal. Sometimes cellular does not work and so you must have an Iridium satellite [connection, Iridium Communications' worldwide satellite communications




**^ COMPETITIVE ADVANTAGE**
By creating competition among drivers for higher driving scores, Telogis Coach can encourage better driver behaviour without the need for intervention by supervisors.

PHOTOS: (TOP) GEOTAB; (BOTTOM) TELOGIS


**< DRIVER TRAINER**
Leveraging the growing availability of mobile apps, the ability of inthinc's waySmart Connect to actively coach drivers to encourage better driver behaviour has been shown to significantly reduce speeding and aggressive driving.

system] that works even if there is no cellular coverage. By and large, the oil and gas sector has been an early adopter in telematics, really for the safety of those individual, lone workers."

Expandability for add-on peripherals is part of the Geotab's base platform, he notes. For the oil and gas sector, a popular add-on component is the panic button, which connects to a waist-belt device that when activated within a 300-metre range of the GO7 will transmit an alert via satellite or cellular signal to the proper authorities.

"Your car will start to honk as an alert, and only when the call centre has confirmed receiving the distress signal will beeping of the car stop," he says. "You can be assured that as soon as you are in trouble, you sent your distress [signal] because when the alarm in your car goes quiet you know you have actually been heard and someone has received the distress signal, which is great."

Built-in accelerometers enable inthinc to alert a customer's HSE department for immediate response in the event of a vehicular collision or rollover, notes Cooper. The inthinc solution—currently installed in about 47,000 vehicles, predominantly throughout North America—can also issue useful advisories across the fleet.

"We can alert drivers before they enter a hazardous area to watch their speed, be careful of passing, or whatever the message is that must be displayed," further explains Cooper. She says the power of their road hazard awareness is that it is customizable and can account for road condition scenarios such as road construction, black ice, severe storms or anything else—a handy tool for drivers to stay informed, and to inform other fleet operators.

Drivers can simply pull over and set up on-the-spot messages alerting other drivers if there is a problem when driving into the area. The message is automatically relayed to dispatch, who can then approve the alert and notify other drivers, keeping the fleet safer and more efficient.

Companies experience a 70–80 per cent safety improvement after using Telogis solutions, measured on the number of alerts for speeding, seatbelts, hard accelerations, traditional safety metrics and incident rates, Scalf says. Those changes translate directly into employee safety.

"Safety is always at the forefront of everybody's mind in the oil and gas space. Safety is about driver safety, which is typically how most people think about telematics and safety in the oilfield. However, it is also about knowing when your guys go in and out of hazardous sites—$H_2S$ wellsites and $H_2S$ fields. It is also about how much time employees are spending behind that windshield." ■

PHOTO: INTHINC TECHNOLOGY SOLUTIONS

# Co-Benefi

*Timing right for higher-efficiency, lower-emission cogeneration to power the oilsands*

Jim Bentein

PHOTO: IMPERIAL OIL


EDC Associates, a Calgary-based economics consulting firm, looked at the prospects for more cogeneration plants being developed in Alberta, particularly in the oilsands.

The title of the study, produced in May, 2014, says it all: *Full Steam Ahead*.

The firm, which specializes in the analysis of energy pricing and procurement and the electricity sector, concluded that the potential for cogeneration in Alberta is far beyond the approximately 4,500 megawatts (MW) that exist now, even though that already represents a substantial amount of the more than 16,000 MW of installed capacity in Alberta.

Duane Reid-Carlson, president of the company, says the province's industry-intensive power consumption, along with the size of its oilsands sector—which has what the report called "a voracious appetite" for steam, which cogeneration facilities produce along with electricity—means the technology is a perfect match for the province's electricity sector.

In addition, he says the recent move by the newly elected NDP government to phase in an increase in the carbon fee on heavy industry in the form of the Specified Gas Emitters Regulation, which will raise the fee to as much as $6 per tonne by 2017 from a maximum $1.80 now, provides an added incentive for the development of cogeneration. Cogen is less $CO_2$-intensive than a combined cycle natural gas plant or a modern coal-fired plant.

"The [former] Conservative government was looking at carbon capture and storage to play a role in reducing greenhouse gas [GHG] emissions, but the NDP is talking about more of a reliance on cogeneration," says Reid-Carlson, emphasizing that's his personal view. "Cogen produces half to two-thirds of the GHG emissions of a combined cycle gas plant and one-quarter to one-half of those from a coal-fired plant [equipped with $CO_2$ reduction technology]."

Cogen is valued in Alberta's highly industrialized economy, where, according to Evan Bahry, executive director of the Independent Power Producers Society of Alberta (IPPSA), 65 per cent of electricity demand comes from the industrial sector, the highest percentage in North America.

"With cogen the steam is the driver, plus it gives you on-site, reliable power," he says.

In their report EDC says one of the largest forces leading to the need for more cogen is the shift to SAGD technology in the oilsands, which the firm calls "the perfect environment" for the technology.

"With cogen, natural gas is burned directly at the blades of a gas combustion turbine, which spins a generator to make electricity," the consultants explained. "The extremely hot exhaust gasses are passed through a heat recovery steam generator (HRSG), which extracts the waste heat to boil steam. The steam is then put to work in its host's process, replacing steam otherwise produced by a traditional stand-alone steam boiler."

They went on to explain that the simultaneous creation of electrical energy and steam energy is much more efficient than creating the two separately, achieving up to 90 per cent efficiency.

EDC, which also offers a course in cogen economics, believes the technology is massively underutilized in the province.

> ***"Cogen produces half to two-thirds of the GHG emissions of a combined cycle gas plant and one-quarter to one-half of those from a coal-fired plant [equipped with $CO_2$ reduction technology]."***
>
> ***— Duane Reid-Carlson, president, EDC Associates***

However, it is a growing source of generation capacity as part of Alberta's total generation of about 16,224 MW (it also imports 1,250 MW). Coal-fired electricity is still the largest source of generation, supplying 6,271 MW of electricity, or about 39 per cent of in-province generation. Cogen is next, with 4,431 MW of generation, or 27 per cent of the in-province total. Combined cycle is next, providing 11 per cent, while simple cycle gas provides seven per cent. Wind provides about nine per cent of the total, with hydro and biomass providing the rest.

EDC forecasts that the cogen fleet will grow to almost 5,500 MW in the next seven years, with about 2,300 MW being sent to the grid.

While most of the other generation sources contribute as much to the power grid as they produce, cogen only delivers about 1,850 MW, about one-third of its total output. The reason for that, of course, is that much of the electricity cogen units produce is consumed "in-house" by those entities producing it.

While the SAGD sector has been a popular and logical area for the adoption of the technology, it's not the only area where cogen has >

been deployed. For instance, the University of Alberta, the University of Calgary and SAIT Polytechnic all have smaller cogen units. In addition, there is a 474 MW cogen plant at the Nova Chemicals petrochemical plant at Joffre and another 326 MW cogen unit at the Dow Chemical plant near Edmonton. There are also cogeneration units at forestry plants near Grande Prairie and Lac La Biche and at heavy oil upgraders.

Oilsands producers Suncor Energy and Syncrude Canada are large cogen users, with Suncor having a total of 901 MW of generation (with smaller units scattered at various mining and SAGD sites), and Syncrude deploying 510 MW of cogen, also scattered at various sites.

Reid-Carlson argues that that the potential for cogen utilization is much greater than has been realized, particularly in the SAGD sector, but with potential in urban centres as well, particularly at manufacturing facilities.

"It's a logical technology because there are so many advantages, including environmental, offering great efficiency and reliability," he says.

So why isn't more cogen being developed?

There are several reasons, he says, one of them being that the logical builders, those SAGD plant operators, are facing capital constraints now. At current low oil prices, investing in a cogeneration plant is unlikely, especially for mid-size companies involved in the oilsands.

Although costs can vary, the U.S.-based Centre for Climate and Energy Solutions, which is a proponent of the technology, estimates the cost of a 50 MW gas turbine cogen facility would be about $45 million U.S. It estimates cogen, which is deployed at about 3,300 sites in the U.S., provides about 12 per cent of the country's electricity.

The other factor is that SAGD plant operators are focused on bitumen production and building a cogen plant means "they're entering a world they're not familiar with," he says.

Larger operators, such as Suncor, Syncrude and Imperial Oil, can afford to retain employees who are familiar with and dedicated to operating cogen plants, he says. In fact, when Syncrude and Suncor first got involved in cogen they partnered with major utilities, but now they operate the plants themselves.

One of the impediments in recent years was the spike in natural gas prices, which challenged the economics of cogen, he says. That tended to discourage new investment in the plants in the early part of this decade. However, with gas prices low and likely to stay there, that is another incentive to use the technology, says Reid-Carlson. "These are 40- or 50-year assets," he says, which means even if gas prices rise the technology still makes sense.

Because of the efficiency of cogen, he says they have a 25 per cent cost advantage over combined-cycle gas plants, "but combined-cycle is what the utilities are building." An example of that is Enmax Energy's new Shepard Energy Centre in Calgary, the province's largest natural gas–fuelled power facility, generating 800 MW of power.

There are now some third party proponents of cogen hoping to work with SAGD operators and others to build and operate cogen plants, he says.

In addition to the environmental, efficiency and other arguments in favour of cogen, he says "behind-the-fence" consumption offers users yet another advantage of utilizing cogen: greater reliability, with no need to tap the power grid. Given new provincial legislation mandating the development of costly new transmission lines, he says the future cost of tapping the grid for power is sure to rise.

Although his firm has not conducted a thorough economic analysis, Reid-Carlson believes a shift to cogen from combined-cycle power units, which are considered very efficient, could lead to a 25 per cent cost savings.

In any case, the province's coal-reliant power fleet will see a significant shift in the next few decades to cleaner, gas-fired power, says Bahry. "We expect an orderly replacement of our province's coal fleet by natural gas supply, as it represents the most cost-effective baseload supply that can be built in a timely manner," he says.

By 2050, IPPSA sees just 929 MW of coal power remaining, even though it forecasts power generation will double to 30,000 MW by then.

IPPSA, which champions Alberta's deregulated power system, the only one in Canada, argues that it has produced a competitive marketplace that has made power rates some of the lowest in North America.

It will also be a system that will have a much lower environmental footprint, thanks to the shift to gas. "By 2030 our emissions intensity is forecast to fall in half," Bahry says.

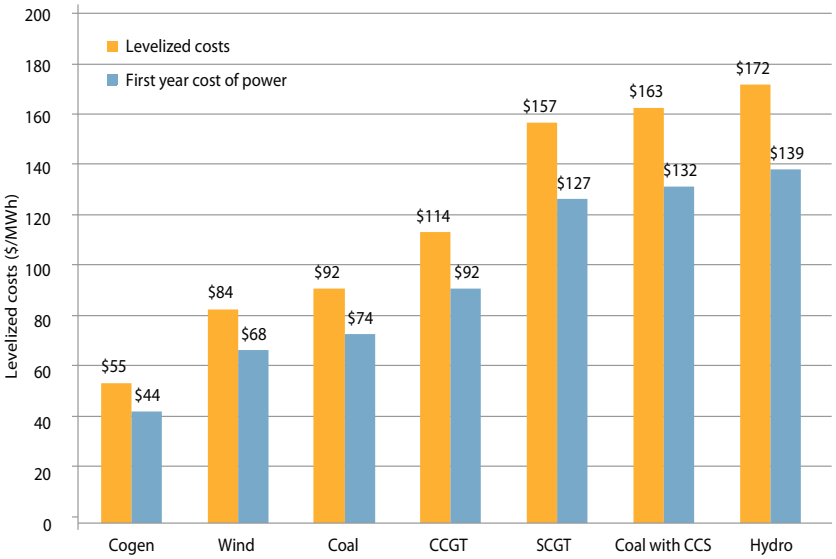
That will occur while gas-fired power provides about 80 per cent of the province's generation, with wind providing about 15 per cent. In 2013 EDC produced a study for IPPSA, Trends in GHG Emissions in the Alberta Electricity Market, which forecast that outcome. However, new policy directions suggested by Alberta's new government, such as a speed-up of coal power plant retirements and an increased emphasis on renewable power, could change those estimates.

Reid-Carlson thinks it's quite possible higher carbon levies will lead to a retirement of the entire coal-fired fleet prior to 2050, leaving room for more cogen and other gas-fired alternatives, and possibly more wind.

Imperial Oil is one of the province's largest users of cogen at its Cold Lake Project, an in situ oilsands operation, where vast amounts of steam are used, as well as at its Kearl oilsands mining project, north of Fort McMurray.

"We like cogen because it gives you a higher degree of reliability because your power is provided on site, rather than relying on the

Levelized cost of electricity generation in Alberta

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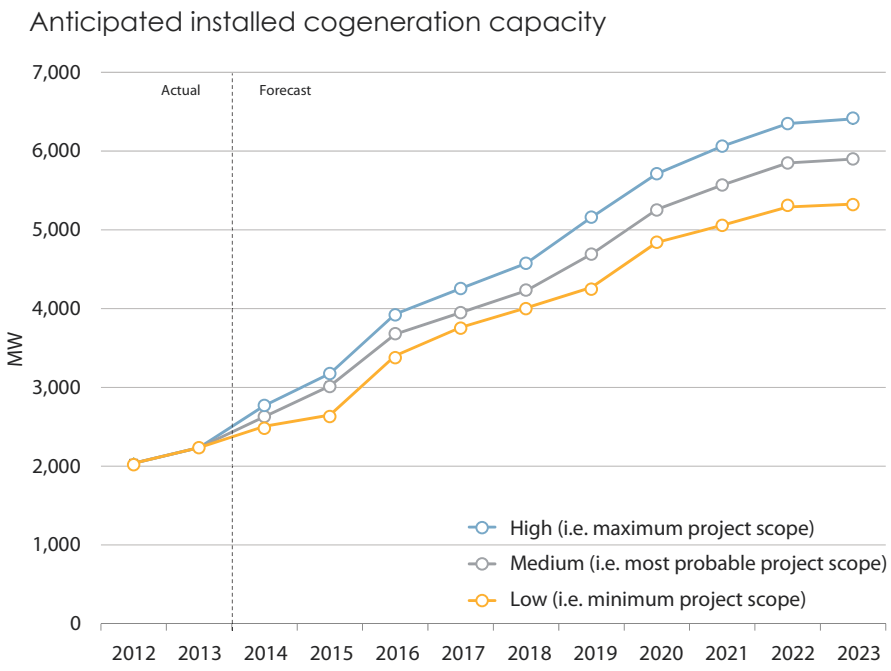



SOURCE dESIDERATA ENERGY CONSULTING

transmission grid," says Imperial spokesperson Pius Rolheiser.

It first used cogen at its 40,000-bbl/d Mahkeses plant, which went into operation in 2004 at Cold Lake. It built a 170 MW unit there. It was so happy with the results of that move, it included a similar-sized cogen unit in the 40,000-bbl/d Nabiye phased expansion, which went into operation late last year.

It won't reveal what it spent on the cogen units themselves, but the entire cost of the Nabiye plant was $2 billion. It spent $650 million on Mahkeses. It now produces about 160,000 bbls/d of bitumen at Cold Lake.

At Kearl, where it has spent about $21.8 billion on two phases, which eventually will produce 345,000 bbls/d, it built an 85 MW cogen plant.

The Cold Lake plant, which was described by the late Howard Dingle, an Imperial Oil executive who managed the project in the 1980s, as "a massive water recycling operation that also produces bitumen," involves the injection of 500,000 barrels of water per day, in the form of steam, to produce bitumen. Ninety per cent of the water is recycled.

Rolheiser says using cogen has led to a 40 per cent reduction in GHGs compared to using electricity from the grid and having conventional boilers.

It uses about 190 MW of the total cogen power it produces at Cold Lake now and sells about 150 MW to the grid. However, Imperial has long-term plans to expand the plant, which would require more of that power to be used on site.

At Kearl, where large volumes of steam are also used, similar GHG reductions are expected, he says. The company has applied to the Alberta Utilities Commission to "build future cogen capacity at Kearl, based on our needs," he says. ■

# *Flying* High

## *Leveraging jet engine technology to compress gas, cut emissions*

By Jim Bentein

At least one of the LNG plants being proposed for coastal British Columbia is off to a flying start, with power for the huge project being supplied by the offspring of a jet engine.

Last December, LNG Canada Development, which is proposing a new LNG plant for the Kitimat area, announced it had selected a high-efficiency General Electric LMS100-PB aeroderivative gas turbine to provide power for the proposed new multi-billion dollar LNG facility.

Manufactured in Houston, the aeroderivative gas turbine is the largest unit GE manufactures, with a capacity to produce 100 megawatts (MW) of power.

GE, which makes the world's largest and most powerful jet engines, has developed a family of jet turbines based on its aviation technology, which it fittingly calls "aeroderivatives."

The company now has more than 2,100 aeroderivative gas turbines generating electricity in 73 countries. In 2012, MIT's *Technology Review* recognized aeroderivatives as a "key innovation…for building flexible and efficient natural gas power plants."

The Texas Medical Center, the world's largest healthcare complex, which serves seven million patients per year with an operating budget of US$15 billion, announced last year it would be using GE's LM6000 aeroderivative turbine, which can generate 48 MW of power. The system also traps exhaust heat to generate steam for the health care complex's heating and air conditioning systems. >

GE manufactures units capable of generating from 18 to 100 MW of power.

LNG Canada, a partnership of Shell Canada Energy (50 per cent), an affiliate of Royal Dutch Shell plc, and affiliates of PetroChina (20 per cent), Korea Gas (15 per cent) and Mitsubishi (15 per cent), is proposing to build two LNG processing units, referred to as trains, with an option to expand it in the future to four trains. Each of the first two trains would produce 6.5 million tonnes per annum of LNG.

In June, the project received environmental assessment approval from the provincial and federal governments, though its backers must still comply with several conditions.

At the time Andy Calitz, chief executive officer of LNG Canada, said the partners had "made significant progress to advance our project over the past year." He said the company had taken several steps to reduce the environmental impact of the project, including locating it adjacent to an existing port facility, and choosing a power solution that will greatly reduce its $CO_2$ footprint.

Bill Garvin, Calgary-based sales director for Canada with GE Oil & Gas, says the LMS100-PB dry low emissions aeroderivative gas turbine his company sold to LNG Canada will also include vertically and horizontally split centrifugal compressor technologies. The introduction of intercooling technology makes the unit ideal for LNG use, the company said.

"The aerodynamically coupled free power turbine provides speed, flexibility and high torque for typical LNG compressor loads, especially during start sequencing with pressurized conditions in the refrigeration loop, avoiding the need for starter/helper motors," GE said in its press release.

Garvin says it's the first time the turbines will be used in an LNG plant, but it probably won't be the last. "It's ideal for LNG use because [users] can bring compressors on line more quickly, without the need for a 25 MW starter motor," he says. "Also, because the aeroderivative units are lighter than [conventional] technologies, they can do a plant overhaul in two or three days, instead of weeks."

The units can be transported on a flatbed truck, as opposed to turbines now in use, which would require 10 or 15 semis to carry them. "It will be much cheaper to operate the units [because down time is so minimal]," Garvin says. He would not disclose the capital cost of the unit, except to say it is in the millions.

Garvin says GE expects to sell more of the units to LNG plant developers in Canada. There are more than a dozen LNG plants proposed for the West Coast. "We're already talking to other potential customers," he says.

The large output of the units means they are unlikely to be used in the oilsands, even though they could be used both to generate power and capture steam. For the most part, lower-generating cogeneration units are preferred solutions, says Garvin.

"It's a similar concept to cogen, but with these units you're generating more power," he says. "A lot of SAGD plants don't need 100 MW." The units can generate up to 105 MW.

> ***"It's ideal for LNG use because [users] can bring compressors on line more quickly, without the need for a 25 MW starter motor."***
>
> ***— Bill Garvin, Calgary-based sales director for Canada with GE Oil & Gas***

LNG Canada has selected the GE natural gas turbines for the natural gas liquefaction process to minimize fuel use and GHG emissions because of the greater efficiency of the technology. In addition, LNG Canada recently signed a power agreement with BC Hydro to use renewable electricity for a portion of the electricity needed in the plant.

As a result, it estimates the proposed facility would have a GHG emission intensity of about 0.15 tonne of $CO_2$ for every tonne of LNG produced, which would make it among the lowest-emitting LNG plants in the world.

GE has previously sold two LMS100 units, without the intercooling capacity, to Edmonton-based utility Capital Power. Michael Sheehan, media relations manager for the utility, says it selected a GE LM 6000 turbine, similar to the one used in the Texas Medical Center, along with two of the GE 100 MW LMS turbines, for its Clover Bar Energy Centre, located in the Edmonton area.

"The simple cycle natural gas technology has the unique ability to deliver power on demand within 10 minutes," he says. "This gives Capital Power the flexibility to respond to sudden changes in Alberta's supply and demand, including demand peaks that occur during hot and cold weather."

Sheehan says the units provide extremely quick cold start times, high-efficiency generation and low emission levels per megawatt generated.

"The simple cycle configuration allows the units to respond quickly to peak electricity demand with quick ramp-up and synchronization capabilities. In comparison, a combined cycle configuration that relies on steam to generate power requires a substantially longer time to ramp up, thus making it incapable of being effectively used to meet peak demand."

He says the units use 85 per cent less water and produce 70 per cent less nitrogen oxides per megawatt hour than the four older turbines at the old Clover Bar Generating Station, which was decommissioned in 2007. Each LMS 100 unit can reduce $CO_2$ emissions by more than 30,000 tonnes per year, which is equivalent to taking 5,000 passenger cars off the road, he says. ■


FRACTURING

# PRESSURE PLAY

Frac pumping system offers cost savings, access to more efficient pumps

When high-pressure hydraulic fracturing pumps are pushing what amounts to peanut butter and sand downhole, it's not surprising that they often fail. The entire operation is forced to shut down until the pump can be replaced.

A California-based company has developed a technology that it says will significantly reduce pump repair and maintenance costs, saving both time and money during hydraulic fracturing operations while opening the door for more energy-efficient pumps.

The VorTeq hydraulic pumping system is based on Energy Recovery's proprietary PX Pressure Exchanger technology, which was initially developed to increase the energy efficiency of water desalinization plants, says Joel Gay, president and chief executive officer.

"The Pressure Exchanger is an energy recovery device, taking a column of fluid and slamming it into another and imparting up to 98 per cent of the energy," he says. With access to hydraulic power, it can also be used as a pump.

"Our concept is very simple," says Gay. "The VorTeq is a sacrificial barrier between the existing pumping technology and the frac fluid."

With the installation of the VorTeq manifold (missile), an aggregation of 12–14 special pressure exchangers (VorTeq cartridges), there is no longer a need to process the highly viscous, highly abrasive frac fluid through the positive displacement (PD) pumps. Instead, the pumps are now pressurizing clean water, and within VorTeq, that high-pressure energy is transferred to the low-pressure frac fluid coming in from the blender, pressurizing the frac fluid that is then pumped downhole.

Having transferred its energy to the frac fluid, the low-pressure water exits the VorTeq and flows back into the water pipes where it is filtered and recirculated. >

**^ PUMP PROTECTION**
Manufactured as a complete manifold trailer, Energy Recovery's VorTeq hydraulic pumping system allows companies to replace plunger pumps with more efficient pumping solutions.

PHOTO: VORTEQ

The VorTeq operates at a pressure of up to 15,000 psi and 110 bbls/min and is multi-phase capable, so it can process a multi-phase fluid, including both solids and liquids.

To help it withstand the abrasive frac fluid, the VorTeq cartridge is manufactured out of tungsten carbide, one of the hardest compounds on the planet and more than 1,000 times more abrasion-resistant than steel. "Tungsten carbide is used to crush sand, so clearly we believe in the durability, reliability and life expectancy of this unit," says Gay.

Energy Recovery has achieved proof of concept for one VorTeq cartridge in the context of the missile and has amalgamated 12–14 cartridges on a 100,000-pound trailer with several tonnes of high-pressure iron. "Now it's a question of seeing how this works in the context of a frac ecosystem when you have multiple Pressure Exchangers in a very complex environment," he says.

Denver-based Liberty Oilfield Services, which operates its own wells, has undertaken a six- to nine-month field trial process to achieve proof of concept in the field.

"The field tests, which include testing at a live wellsite, are not only the culmination of months of collaboration with Energy Recovery, but for me, the solution to a critical problem in our work that has challenged the industry for years," says Ron Gusek, Liberty's vice-president of technology and development.

In the first phase of field trials, Energy Recovery has eight to 10 pumps rigged up to the missile at one of Liberty's yards in western Colorado where VorTeq is being put through a battery of tests in simulating a hydraulic fracture.

The technology will then be deployed to a Liberty wellsite in either Wyoming or North Dakota. "Our objective is very simple: we want to frac one well," says Gay.

Energy Recovery believes that its technology has the potential to reduce repair and maintenance costs, as the PD pumps will no longer be pumping frac fluid, and to reduce exploration and production (E&P) company requirements for additional pumps. Most significant, though, will be that pumping companies will be able to replace the existing pumps with a more efficient pumping technology, says Gay.

"At the wellhead, the No. 1 failure mode is pumps breaking down because you are processing and pressurizing a viscous, multi-phase fluid that consists of water, chemicals and [ceramic or silica] proppant," he says. "Depending upon the basin, depending upon the frac chemistry, depending upon the well, these pumps can be rebuilt as frequently as every 20 hours."

As a result, E&P companies that contract pumpers to complete a well require that the service providers carry an inordinate amount of excess capacity—upward of 50 per cent, says Gay. If a well requires 12 PD pumps to generate 110 bbls/min of flow to fracture a well, the E&P is going to require that they carry 18. "Theoretically, six of those pumps are sitting idle, waiting to be deployed upon the failure of one the pumps that has already been rigged in."

Pumping companies will be able to lease the VorTeq, which can be incorporated into their existing spread using their PD pumps. It will be priced so that companies will be able to save an estimated $1 million per year per fleet simply on repair and maintenance, says Gay.

"If you are no longer pumping frac fluid, you are going to rebuild your pumps on a much less frequent basis, you are going to increase the mean time to failure, and therefore you are going to decrease your expenditures on valves, valve seat plungers, well service packing, labour costs, etc."

If pumps are lasting longer, E&Ps will recognize that there is less risk to capacity utilization and will require lower levels of excess capacity, according to Gay. The service companies will be able to either use those excess pumps to generate revenue elsewhere or can forego future capital expenditures. And at $1.5 million to $3 million per pump, "it's not an insignificant amount."

However, Energy Recovery is most excited about the potential of VorTeq to enable the use of other pumping technologies. At present, PD pumps are used because they can withstand the abrasive wear and tear of frac fluid better than any other pumping technology, according to Gay. However, other technologies provide a higher rate of mechanical efficiency and better overall performance characteristics that would allow service providers to decrease their footprint by several orders of magnitude, he says.

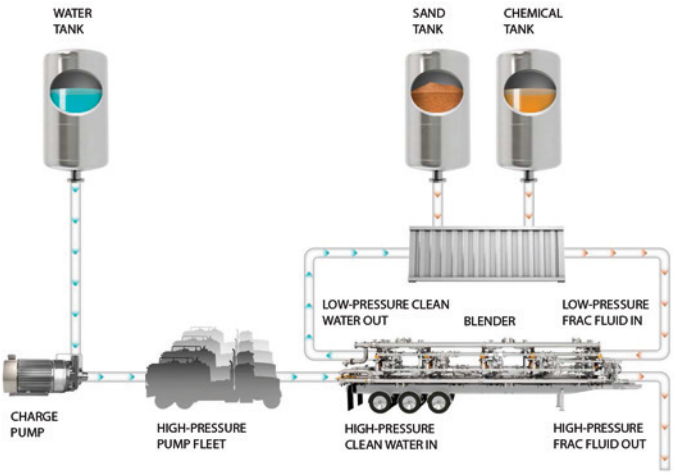
VorTeq is the gateway technology to the massive natural gas–powered centrifugal pumps, the same as those found on the most advanced offshore rigs, that could be powered by natural gas turbine generators. "We are already seeing migration away from diesel" on about 10 per cent of frac spreads in North America, Gay notes.

And while positive displacement pumps can operate for 6,000–8,000 hours before being scrapped or needing to be totally rebuilt, centrifugal pumps can operate for 60,000 hours—representing one-tenth the average depreciable or equipment expense over time.

"That is a massive piece of value creation, and we believe it will materially impact the cost per barrel to frac a well," he says. "It will move the needle."

■ *Elsie Ross*

## HYDRAULIC FRACTURING WITH VORTEQ




SOURCE: VORTEQ

**< FLUID PRESSURE RECYCLING**
The VorTeq hydraulic pumping system uses Energy Recovery's PX Pressure Exchanger technology to reroute abrasive frac proppants away from high-pressure pumps, ensuring that only pure water comes in contact with the pumps and significantly extending their lifespan.

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OILSANDS

# CATCHING THE WAVE

Microwave heating offers cheaper, cleaner way of separating water from bitumen

The easiest way to melt bitumen so it will flow to production wells is to inject steam into the reservoir, but the problem with mixing hot water with bitumen is that microscopic water bubbles stay suspended in the oil.

There are three established ways to break up this water-in-oil emulsion, which can be used separately or in combination, but none are ideal.

One is mechanical—flow the oil through separators with enough velocity that the microscopic water bubbles combine into droplets big enough to separate by gravity. Another is to add chemicals to coalesce the water droplets until they get heavy enough to fall out of the oil. And the third is to heat the emulsion, which is energy intensive. All are costly.

Researchers at Texas A&M University believe there is a cheaper, faster, cleaner way to break water-in-bitumen emulsion: microwave heating.

Separating water from emulsions through microwave heating isn't new—it's been tested in the lab and even in the field. However, these tests didn't investigate the effect of the asphaltene and resin content of the oil on microwave efficiency. The assumption was that microwaving was effective because of the water content of the emulsion.

The recent project at Texas A&M University's department of petroleum engineering tested bitumen samples from northern Alberta. The tests consisted of lab simulations of both straight SAGD and SAGD with solvent injection.

The results are described in a paper published by the American Chemical Society's *Energy & Fuels* journal on May 29. Researchers Taniya Kar and Berna Hascakir concluded microwave heating worked well on the simulated SAGD emulsion, but might be less effective if solvents (especially asphaltene-insoluble solvents) are added to the injected steam. The researchers found it was the asphaltene and resin content—not the water content—that controls the emulsion-breaking efficiency of microwave heating.

To understand the role of asphaltenes and resins in emulsion breaking, it helps to understand how microwave heating works.

Microwave heating depends on the polarity of molecules. When food is placed in a plastic container in a microwave oven, the microwave heats the water molecules in the food, but not the plastic. The plastic container may be warmed by contact with the hot food, but not by the microwaves. Microwaves are a type of electromagnetic wave, and plastic is microwave transparent whereas water absorbs microwaves.

**BITUMEN BREAKDOWN**
Texas A&M University researchers Taniya Kar and Berna Hascakir found that it is the asphaltene and resin content in SAGD-produced bitumen, rather than the water content, that controls the emulsion-breaking efficiency of microwave heating.

PHOTO: TEXAS A&M UNIVERSITY

That's because the water molecules in the food are polar, but the molecules in plastic are non-polar. Whether a molecule can be heated by microwaving depends on its polarity. Polar molecules have both geometric asymmetry and asymmetric electron distribution.

Polar molecules (such as water) are agitated by microwaves, which are essentially very short, high-frequency radio waves. So as the water molecules in food are exposed to microwaves, they begin to oscillate at the atomic level and generate heat.

But all polar molecules aren't created equal. A molecule's polar component is measured in debye units. For example, carbon dioxide, which is non-polar, is zero debye. Water, which is polar, is 1.85 debye. But that's puny compared to asphaltenes, which are about 40 debye; resins can be somewhere around 30.

Due to the asphaltene and resin content, the polarity of the tested bitumen was actually higher than the water polarity. Hence, asphaltenes and resins are your friends if you're using microwave heat to break water-in-bitumen emulsion since these components greatly accelerate heating.

"The emulsion breaking occurs by the heat transfer caused by conduction or convection," the Texas A&M researchers wrote in their *Energy & Fuels* paper. "First, heat is generated by the oscillation of the polar fractions; then heat is transferred to water. If a sufficient amount of heat is transferred to water by the oscillation of polar molecules, then water could be effectively removed from emulsions."

The bottom line: the higher the ratio of asphaltenes and resins in the emulsion, the faster the heating time. Unlike in refining, the presence of asphaltenes and resins would be an advantage in emulsion breaking by microwave heating. The more there are, the faster the fluid will heat, allowing the water and oil to separate faster.

And the faster the heating, the less energy is consumed by burning fuel to heat the emulsion. Burning less fuel lowers fuel costs and reduces $CO_2$ emissions.

The Texas A&M group also studied the effectiveness of microwave heating to break water-in-oil emulsions from >

expanding solvent SAGD (ES-SAGD), where a solvent is co-injected with steam to mobilize bitumen by diluting as well as heating it.

In one ES-SAGD lab test, the solvent used was n-hexane; the other tests used n-hexane and toluene. The researchers found that emulsion samples with solvent were less amenable to emulsion breaking by microwave heating.

Another factor is the interaction of the solvents with the bitumen components. For example, n-hexane is asphaltene insoluble.

"Those solvents' solubility to asphaltenes is very important. Some solvents are soluble in asphaltenes; some of them are not soluble. And when we [added] the asphaltene-insoluble solvent, which is n-hexane ... we got less water production coming with the oil when compared to other cases," says Hascakir, an assistant professor of petroleum engineering who holds a doctorate in petroleum and natural gas engineering.

The pure SAGD emulsion microwaved by the Texas A&M researchers contained 54 per cent water while an ES-SAGD sample had about 20 per cent water. And how much of that water was removed by microwave heating?

"We removed almost all the water inside the SAGD sample. And the total time we spent with microwave was just one minute," Hascakir told *New Technology Magazine*. "So it's extremely energy efficient. You are just consuming one minute. [But] if you are applying conventional heating, it will take a lot of time to reach a similar temperature.... With microwave heating, you are removing almost all water in just one minute," she stressed.

This underscores the difference between microwave heating and conventional heating. Cooking food in a microwave oven, for example, uses about 80 per cent less energy than cooking in a conventional electric oven.

The produced oil samples were heated at a microwave frequency of 2,450 megahertz and 900 watts of microwave power. All bitumen samples tested were 8.65 degrees API gravity and 54,000 centipoise viscosity. The lab experiments were conducted on 50-millilitre samples.

So what needs to be done next?

Hascakir said industrial-scale microwave generators, called klystrons, are commercially available, so it's already possible for a thermal bitumen producer to build what amounts to a big microwave oven for emulsion breaking.

But first more lab-scale research is needed on how asphaltenes, resins and water interact during microwave heating, she said. "We need to understand the physics behind emulsion formation and we need to avoid its formation first… because the consequences can be really detrimental and can cost a lot of money if you [don't] understand the fundamentals."

***Pat Roche***

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PRODUCTION

# MEAN MACHINES

## New artificial lift technologies pump longer for less

Artificial lift technologies are likely to get more attention today than they have over the last few years, when oil prices were roughly double today's level. That's because the latest technologies reduce costs by boosting efficiency, improving equipment runtimes and consuming less fuel. In recent years, producers were often too busy increasing output to carefully weigh all their options—now the question is, can they afford not to?

Pump providers across the continent are introducing new technologies, from Weatherford International's Sand-Tolerant Pump to Liberty Lift Solutions' high-efficiency and enhanced-geometry pumping units, General Magnetic International's permanent magnet motor progressive cavity pump top drive and AccessESP's rigless electrical submersible pump conveyance system.

The most common type of onshore artificial lift uses a beam pumping system, and includes a sucker rod string, downhole rod pump and the familiar rocking pumpjack at surface. But a high percentage of rod pump wells globally encounter problems, often resulting in shortened pump life, because of produced sand and other solids.

"Wear of plungers, barrels and stuck pumps are some of the failure modes caused by production of solids," notes a paper by experts at Weatherford presented at an SPE Production Operations Symposium in Oklahoma City in March.

As the pumping action occurs, a seal is formed between the barrel's inner diameter and the plunger's outer diameter, but a small amount of produced fluid, called slippage, flows in the annular gap and aids in lubrication. Solid particles can abrade the surfaces of both barrel and plunger with long grooves, known as "sand cut," providing space for more slippage, which reduces the efficiency of the pump.

The industry tried various methods to solve the problem. "For a 100 years, we said we must filter out sand," says Doug Hebert, a business development manager for artificial lift systems at Weatherford. "Then one day we said, 'We only need to screen out three barrels [per 100] for lubricant.' We had been trying to clear all the fluid of sand, not just the three barrels needed for lubrication. By filtering out that amount of sand, it builds up down hole. We had been trying to stop all the sand from entering the wellbore for 100 years."

Based on data from dozens of problem, sand-laden wells and ongoing tests, Weatherford developed its Sand-Tolerant Pump (STP), which can increase pump runtime by up to 450 per cent in highly abrasive conditions. It does this by keeping sand or other particles away from the barrel-plunger interface with the help of two key components: a wiper assembly and a filter coupling.

The outside of the wiper assembly creates a barrier that keeps sand out of the plunger-barrel interface by continuously pushing the sand upward, while the internal parts of the assembly prevent sand from falling back into the plunger. Various


**ENERGY MISER**
In a partnership with National Oilwell Varco, General Magnetic is marketing its power-saving permanent magnetic top drive motor for low-speed progressive cavity pump applications.

PHOTO: NATIONAL OILWELL VARCO

assembly configurations are available for specific well conditions.

The wiper prevents sandy produced fluid from entering the critical area between the plunger and the barrel. The filter coupling, which has an internal screen, ensures that produced fluid, minus sand or other abrasive solids, reaches the plunger-barrel interface to enable lubrication. The coupling's filters move with the plunger so that the sweeping action of the fluid on the downstroke cleans the filters and keeps sand suspended within the production fluid, which travels up the plunger's centre to the surface.

"The focus [of the new design] is on increasing runtime and reducing workover costs," says Hebert, who owns a couple of pump patents and was involved in developing and testing the STP.

Well over 2,000 STP units have been installed in a dozen U.S. states since testing first began in 2012, he says. The official product rollout is scheduled for September.

The field testing discussed in the SPE paper was based on 56 problem wells in Kern County, Calif., where pump runs were curtailed due to sand damage, and where at least one of a well's two previous pump runs had lasted less than a year. Across the 56 wells, the STP, with its integral screen system, showed an average percentage increase in runtime of 450 per cent, compared to that of the two previous installations of conventional pumps.

"Any well that doesn't get a one-year runtime for the pump is a perfect candidate for this," Hebert says.

Conventional pumps can be retrofitted with STP technology, he says, "with the caveat that we can add to the total barrel length in order to retain existing stroke length."

The STP has been deployed on wells ranging in daily production from 15–20 barrels up to around 500 barrels. The STP is rated for temperatures up to 182 degrees Celsius (360 degrees Fahrenheit) and to depths of 2,743 metres (9,000 feet). There are plans to test for higher temperatures in a possible thermal application, Hebert says. He sees an application potential for the STP in recently fractured wells in the shale oil sector.

## LESS HORSEPOWER, MORE LIFT

If the STP benefits from a paradigm shift in the approach to a problem, the product offer from Liberty Lift Solutions targets better performance and durability for beam pumping units, providing its clients with something they have been demanding.

Noting that his company has been in business for barely two-and-a-half years, Don Crow, Liberty's vice-president of sales, says, "We've improved on technology that's been around for decades. We put all the bells and whistles on a pumping unit that clients had to pay extra for in the past. We've also built this company around service. As a manufacturer, we understand the business as well as anybody else. People wanted a lower-cost quality unit. So that's what we designed and built."

Liberty's executive team includes people like Crow—who was with Texas-based Lufkin Industries (purchased by GE Oil & Gas in 2013) for 26 years—with plenty of experience in the artificial lift sector.

The company's high-efficiency (HE) pumping unit can be operated in clockwise and counter-clockwise rotation and has 186 degrees of upstroke instead of the 180 degrees typical of many units when run in the clockwise direction. This enables more production than similarly sized conventional pumps. The amount of incremental production can vary somewhat depending on several factors, Crow says.

Liberty's EG (enhanced geometry) is designed for optimal mechanical efficiency and provides 192 degrees of crank rotation. Crow says the EG's design and phase angle extend the permissible load range, with more lifting capacity, using less horsepower. Its reduced acceleration during the upstroke cycle lowers sucker rod forces and peak torque requirements.

Both HE and EG units exceed American Petroleum Institute (API) structure design specifications, and the API Monogram licence indicating they meet API quality program and product specifications.

The proliferation of horizontal wells has increased the need for gas lift and jet pumping, Crow says. To meet the demand, Liberty designs and sells gas lift valves and mandrels and distributes and services the Ultra-Flo hydraulic jet pump >

**RIGLESS CONVEYANCE**
AccessESP integrated a side pocket downhole wet connect system, above, and a permanent magnet motor to create a patented solution consisting of a tubing-mounted permanent completion and a slickline retrievable assembly.

system from Louisiana-based artificial lift company JJ-Tech. The pump has recently had a design makeover, which included combining JJ-Tech's Select-Jet downhole pump with the T-Series hydracell diaphragm pump from Wanner Engineering.

## POWER CONSUMPTION SAVINGS

In today's lower-commodity-price environment, technologies that reduce power costs are welcome. In the past, manufacturers achieved what were regarded as mixed results from their efforts to develop a permanent magnet motor (PMM) progressive cavity pump (PCP) top drive, which flourished under field conditions and consumed less power.

Now, Calgary-based General Magnetic has developed a PMM top drive specifically for low-speed PCP applications. Payback for the incremental cost of a 100-horsepower unit, based on about $10,000 savings in electricity costs, is about a year. Thanks to a partnership between General Magnetic and National Oilwell Varco (NOV) Mono, the PMM top drive is now part of NOV Mono's global artificial lift offering.

Besides cutting power consumption costs, the PMM top drives from NOV, which are currently available in two horsepower ratings with further ratings and configurations in the pipe for later this year, could attract interest on other counts.

"A true direct top drive with no speed reduction equipment has always been the sweet spot that developers have wanted to exploit," says Dan Wowchuk, Calgary-based product line director for PCP systems at NOV. "The reasons for this are twofold. First, traditional motors require speed reduction equipment to operate top drives. Virtually all conventional top drives use some form of speed reduction equipment, be it belts or sheaves or gearboxes. The moment you introduce speed reduction equipment, you reduce system efficiencies, as this equipment consumes energy as it functions. This equipment also adds numerous additional moving parts that create maintenance issues."

He adds that because of their reliance on traditional induction motors and not a PMM, conventional systems are less efficient. Besides lower power costs, "The PMM's reduced maintenance delivers sustainable reduced long-term operating costs [that] conventional systems can't compete with. The other key attribute is the integrated resistive electronic breaking system, which makes the PMM top drive inherently far safer than conventional counterparts with mechanical braking systems."

## RIGLESS CONVEYANCE

The benefits of a PMM also show up in the latest generation of a rigless electrical submersible pump (ESP) conveyance system from AccessESP, formerly Artificial Lift Company. "Access375 is the fourth-generation, state-of-the-art, single-section permanent magnet motor and is one-fifth the length and weight of a conventional induction motor," according to a company press release. The single-section design eliminates the need for tandem and triple motors and reduces system complexity.

The company began work on its first rigless ESP after ConocoPhillips selected its proposal around 2006, says Greg Nutter, vice-president of operations at AccessESP.

By late 2010, a design that had evolved from prototype testing was deployed in Alaska. The rigless ESP has also been used in the Middle East and Europe. "Where we see this system used is where there is constrained rig supply. For today, that means fixed platforms offshore, remote [onshore] areas, Latin American countries like Ecuador and Colombia, the far north. The new version has better durability and is easier to assemble at the wellsite," Nutter says.

Thermal-based oilsands operations where high temperatures reduce a system's run-life are a potential venue for rigless ESP. "We can replace a pump and motor with a live well. We see SAGD as a possibility," Nutter says.

■ *Godfrey Budd*

PHOTOS: ACCESSESP