APRIL 2015

New Technology magazine

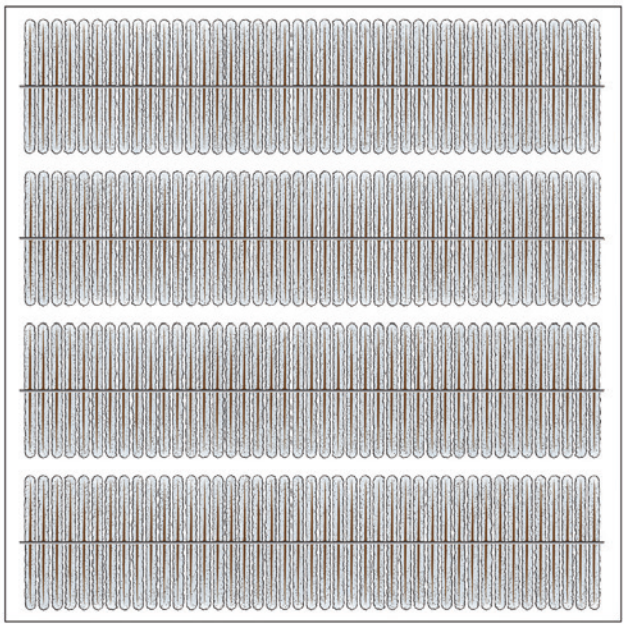
THE FIRST WORD ON OILPATCH INNOVATION

Perfecting the PIPELINE

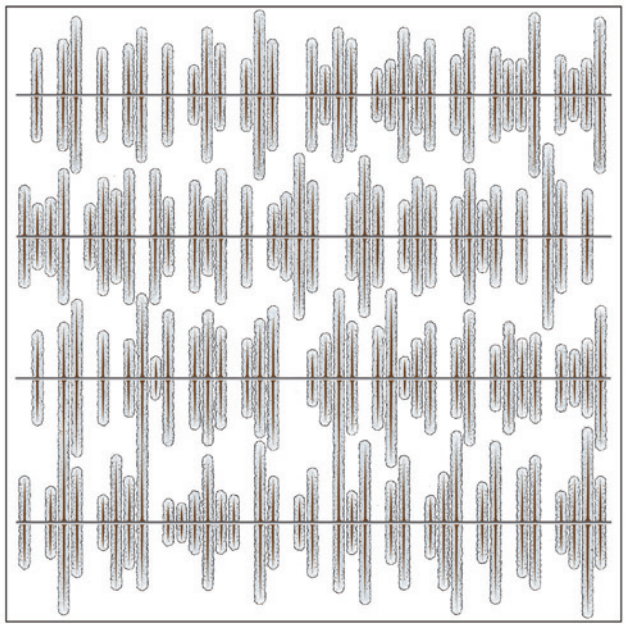
New inspection, construction technologies making pipelines SAFER

Consistent frac placement makes optimization possible.

The most efficient field frac network starts with predictable frac spacing and predictable propped volume.



Predictable: Multistage Unlimited casing sleeves



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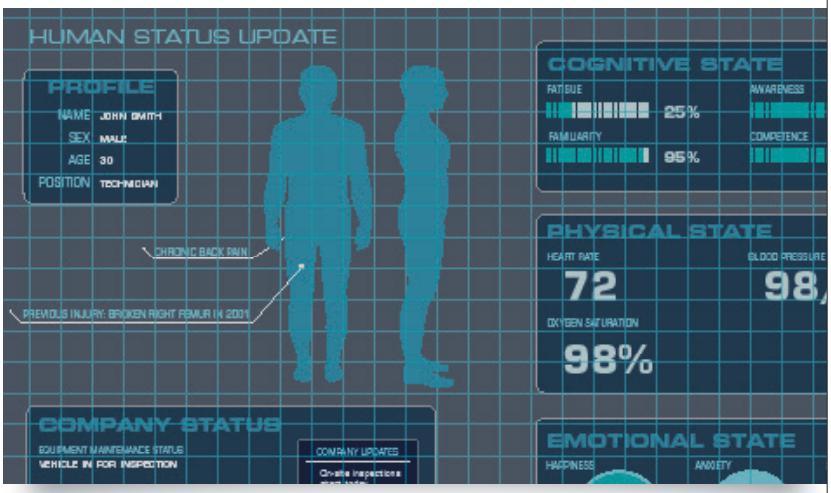

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In today's dramatically lower oil and gas price environment—amid oil prices half what they were last spring and natural gas prices mired in a multi-year slump—it is tempting to focus on prices as the main and perhaps only real challenge facing the industry today.

New technologies have solved many of the most pressing issues, like solving the oilsands and shale gas and tight oil production challenges, which together have put North America on top when it comes to production but have also contributed greatly to the overabundance of oil and gas that have caused today's languishing prices.

Those who have lived through a few boom and bust cycles know that as surely as night follows day, prices will eventually recover, and the industry will return to a prosperous state. But technology hasn't solved all of the industry's shortcomings, and a return to higher prices won't entirely solve them either. The bigger challenge is the social licence to operate, which threatens industry growth, recruiting, investment and perhaps even its future existence. And social licence rests largely on the industry's performance in the areas of environmental responsibility and health and safety.

For both the oilsands and shale and tight oil and gas production, gaining social licence has become just about as big a barrier to growth as technology once was. Moratoriums barring hydraulic fracturing limit growth in prospective areas, while access to markets is stymied by concerns about potential pipeline leaks and spills and the increased production—with commensurate emissions—market access will facilitate.

Despite tremendous strides, the oilsands are still stigmatized by images of massive tailings ponds and the sector's growing greenhouse gas emissions, while the tight oil and gas sector continues to battle a reputation its operations endanger groundwater, leak methane and trigger earthquakes. Both are perceived to endanger worker and public health and safety, due to aspects like increased highway traffic, release of pollutants and rail tanker derailments and explosions.

In this issue of *New Technology Magazine*, we focus in on many of these challenges, collectively falling under the rubric of environment, health and safety. We examine technology that both makes pipelines safer and helps to clean up spills when they do occur. We look at the human factor in causing accidents and breakdowns and at how to prevent them. We examine ways to improve workplace safety in inherently hazardous environments and ways to rein in emissions even as production grows.

In recognition of the increased focus on these issues today and in the future, *New Technology Magazine* is creating a new channel both in the magazine and on the website for stories devoted to them, titled Environment, Health & Safety (EHS).

Increasingly, the solutions to the challenges faced in gaining social licence to operate come in the form of advanced software solutions, the use of big data and analytics, and the merging of bytes and industrial equipment—the emerging Internet of Things (IoT). Enabled by advances in areas such as computing power and data storage, data mining and predictive analytics, wireless and machine-to-machine communications technology, and sensors and micro-electromechanical systems, the IoT holds vast potential to enhance efficiency, prevent breakdowns and accidents, reduce emissions and improve the bottom line.

Given the growing value of the IoT to the energy industry, *New Technology Magazine* has also created a channel for all articles related to IoT and the oilpatch.

A third main channel is devoted to the mainstay of *New Technology Magazine*, its coverage of the latest and greatest new technologies devoted to drilling and completions. As with IoT and EHS, technological advances in drilling and completions are occurring at a rapid pace, even in the downturn, as companies race to increase efficiencies and do more with less.

Categorizing our coverage in these three main channels within the magazine and online will enable readers to more readily find the information they need to move their business forward in a rapidly changing industry. Through innovation and technological advancement, the energy industry has proven to be resilient through good times and bad. With a more refined focus, *New Technology Magazine* will continue to provide insight into those emerging technologies that are vital to the continued growth and prosperity of the industry in the years ahead.

■ ***Maurice Smith***

New Technology magazine

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GST Registration Number 8265 26554RT.

 Publications mail agreement No. 40069240. Return undeliverable Canadian addresses to our circulation department, 2nd Flr-816 55 Avenue NE, Calgary, AB, T2E 6Y4.

You may also send information on address changes by email to NewTechnology@junewarren-nickles.com. Please quote the code that begins with the prefix NTM.

For members of the Society of Petroleum Engineers, please contact the SPE office directly with your address change.

New Technology Magazine is owned by JuneWarren-Nickle's Energy Group, a subsidiary of Glacier Media Inc., and is published 10 times per year. Printed in Canada by PrintWest. ISSN 1480-2147.

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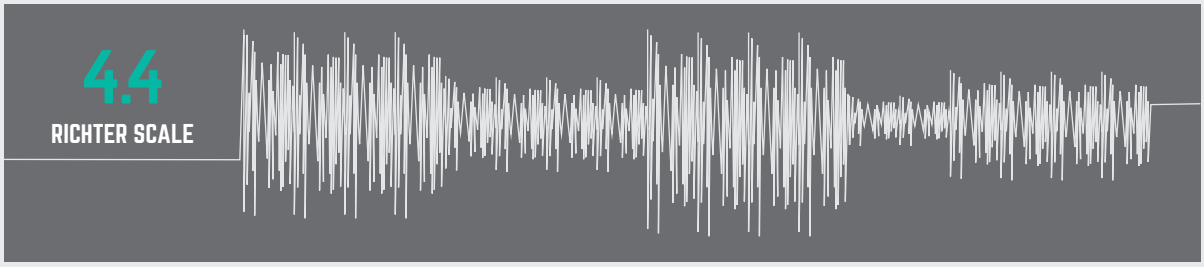


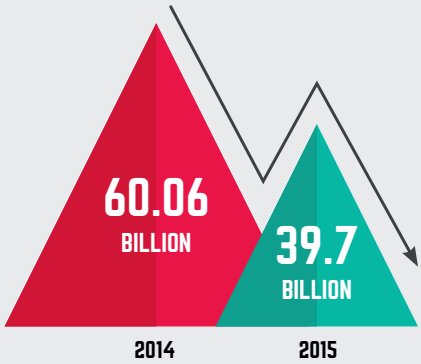
According to Earthquakes Canada, a seismic event measuring 4.4 on the Richter scale occurred 33 kilometres west of Fox Creek, Alta., on January 22, one in a sequence of seismic events in the area from early January. The events, possibly related to hydraulic fracturing, triggered an order from the Alberta Energy Regulator that operators in the Duvernay Formation monitor and report seismic activity in accordance with a "traffic light" process with staged thresholds.

U.S. IMPORTS OF CANADIAN NATURAL GAS ARE EXPECTED TO FALL

30%

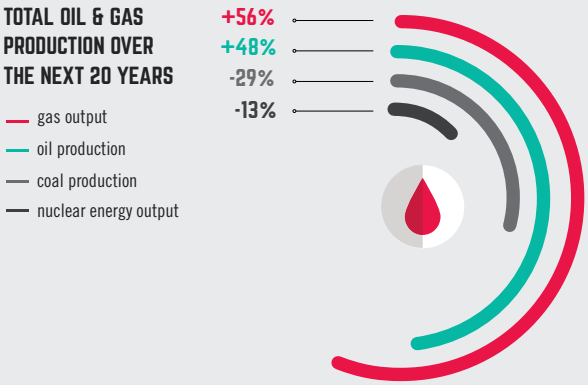
BY 2040.

As shale gas production continues to surge, more Canadian natural gas will be displaced from its traditional U.S. market, Angelina LaRose, head of the natural gas markets team at the U.S. Energy Information Administration, predicted at the Canadian Energy Research Institute's 2015 gas conference. U.S. imports of Canadian gas are expected to fall by 30 per cent by 2040 from 2012 levels, while exports of U.S. gas into Canada will grow by about one or two per cent a year to 2040.



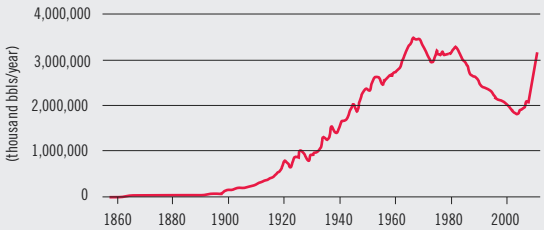
Two months into 2015, producer spending plans were down about $20 billion from 2014, a *Daily Oil Bulletin* tally shows. Capital budget announcements totalled $39.7 billion, down from estimated 2014 spending of $60.06 billion. The figures include the capital budgets of Canadian-based producers as well as the Canadian spending plans of non-Canadian producers who broke out their Canadian allocations. Excluded are companies that declined to disclose their Canadian spending plans, such as Royal Dutch Shell and Progress Energy Canada.

TOTAL OIL & GAS PRODUCTION OVER THE NEXT 20 YEARS



Total North American oil production will rise 48 per cent and gas output will climb 56 per cent over the next 20 years, while coal production will fall 29 per cent and nuclear energy output will decline 13 per cent, BP predicted in its annual energy outlook in February. Growth in shale gas production will remain strong in North America, but that growth won't be duplicated elsewhere in the world, it forecast, suggesting the fact that prospective areas elsewhere are heavily populated and the mineral rights are government owned will prevent a shale gas revolution during that time frame.

U.S. FIELD PRODUCTION OF CRUDE OIL



U.S. crude oil production will approach all-time record levels in 2016, the U.S. Energy Information Administration said in February. It expects average production of 9.3 million bbls/d in 2015 and 9.5 million bbls/d in 2016, falling just short of the record level of 9.6 million bbls/d set in 1970. Last year, tight oil production grew U.S. oil output by 1.5 million bbls/d, its largest ever single-year rise. Production averaged 9.2 million bbls/d of oil in January.

COMPLETIONS

TRILLION-DOLLAR FRAC PLAY

Optimum development of Montney will require collaborative research, improved methods

Too much of the Montney's enormous prize will be left behind unless the industry gets better at extracting the hydrocarbons—both in the technical and non-technical sense.

That's the message Jim Reimer, vice-president of geoscience and technology at Painted Pony Petroleum, delivered during a Canadian Society for Unconventional Resources (CSUR) technical lunch presentation in February. Painted Pony, which had average third-quarter production of more than 14,000 boe/d, operates exclusively in the Montney formation of northeastern B.C.

According to the CSUR abstract on Reimer's talk, the initial gas in place across the entire Montney may exceed 3,500 tcf. This supply is to anchor proposed LNG exports from the West Coast.

"The problem is we're going to leave a lot of this gas behind if we don't get better at extracting it," Reimer told a sold-out audience of more than 225 people.

Putting the Montney into perspective, the Painted Pony executive said the tight over-pressured fairway is about 560 kilometres long and 120 kilometres wide. That works out to more than 25,000 sections of gas-charged Montney.

He noted there are a number of different well spacing and hydrocarbon extraction ideas for the Montney. "But if you were to develop three layers in the Montney and to develop them on four wells per section, that's 12 wells per section. And if you say we're just going to develop 50 per cent of that available area, we would drill, as an industry, 150,000 wells," Reimer said.

"If you look at current data sets, people are doing anywhere from 15 to 20 fracs per well. So [hypothetically] we're going to do two to three million fracs to get that done. And if your costs are $300,000–$500,000 per frac stage, which is not an unrealistic number, we're going to spend—as an industry to develop this—somewhere north of $1 trillion [to] $1.5 trillion."

To put that in context, Reimer said, "Canada's entire GDP last year was $1.8 trillion. So we're going to spend the equivalent of Canada's GDP to develop this Montney. That's just to frac it."

> **"THE PROBLEM IS WE'RE GOING TO LEAVE A LOT OF THIS GAS BEHIND IF WE DON'T GET BETTER AT EXTRACTING IT.**
>
> ***— Jim Reimer, vice-president of geoscience and technology, Painted Pony Petroleum***

This will involve both social and technical challenges.

"I think it's important to get the right message out about [fracturing] operations from a social licence perspective," said Reimer. "But it's also important to work on the recovery optimization because there's so much gas, and we don't want to leave gas behind [that could be recovered]."

On the technical side, Montney producers are still working to optimize recoveries. Challenges include wellbore parameters such as total length, azimuth, the number of frac stages, length per stage, proppant tonnage and fluid volumes per stage, pumping rates, interwell spacing and frac heights and half-widths.

At this point, Reimer said, it's too soon to predict ultimate recovery rates from the Montney. "I hear numbers that vary between 20 per cent recovery efficiency and 50 or 60 per cent recovery efficiency. Can we get better than 50 or 60? I hope so. But a lot of it just has to do with putting enough drainage pathways, enough wellbores, in to properly drain the formation. That's part of the technical challenge—the recovery challenge."

Reimer said the ultimate goal is to develop a high-probability model of the stimulated reservoir volume geometry to ensure minimum spoilage in gas recovery. The optimal models are expected to vary regionally across the play fairway and also locally within the upper, middle and lower Montney.

One technique some companies, including Painted Pony, are trying is drilling wells in parallel pairs. "I think we were probably one of the first in the Northern Montney, but I think many other operators are trying it," Reimer said.

Two gas wells are drilled at the same landing depth, reasonably close together (about 300–350 metres apart). The wells are completed sequentially and flowed back together.

"The idea is that some of the pressure that we induce into the formation from the completion stimulation is a constructive pressure interference and helps us get a better frac off, a better stimulation network and therefore higher gas rates," Reimer explained.

The working premise is that a producer would get more from two wells combined than if it did two wells in isolation. "It's still early in applying this kind of a pattern, this kind of technology. We'll see over time whether that holds up. We're pretty excited about it so far."

Asked about further technical improvements that need to happen, Reimer said one of the big challenges in the Montney is minimizing the surface footprint by learning to drill more wells from a small pad area. "And I think it's going to require a lot of different thinking in rig technology.... I think we have to think outside the box and think about some new ideas there."

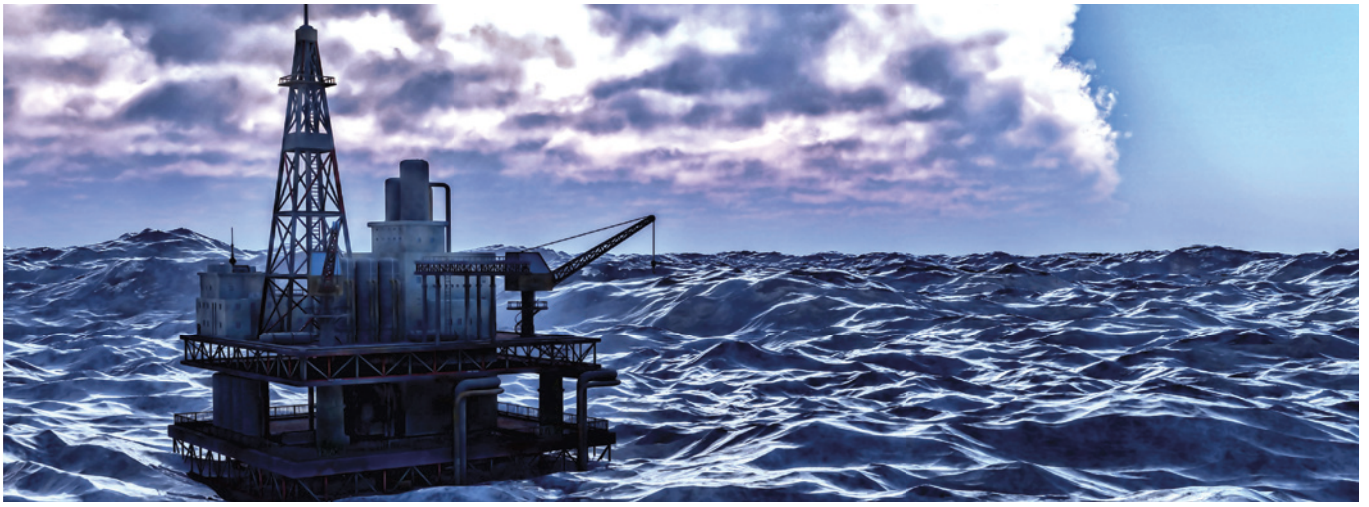
Wells per pad varies by operator in the Montney. "Our pads are typically set up for between 12 and 18 wells, typically. But we're not doing that full drilling at this point. We're drilling a couple of those at a time, and then moving to another pad, and then coming back later on," the Painted Pony executive said. "But as we move into full-development phase down the road, then I would see us doing a larger number from one pad before we move the rig to a subsequent pad."

Pat Roche

OFFSHORE

FACILITATING ARCTIC DRILLING

New well-kill technology could eliminate need for second rig



ARCTIC OPENING
With only limited ice-free conditions occurring during the Arctic summer, drillers are proposing new technologies to control a blowout that would not require a second rig to drill a same-season relief well.

Although Chevron Corporation has put its plans for deepwater offshore Beaufort Sea exploration on indefinite hold, it has offered to make a new well-kill technology it has developed available to other operators.

The company has been working on the Alternative Well-Kill System (AWKS) with Houston-based Cameron for the past eight years, Bill Scott, general manager of the Chevron Arctic Center in Calgary, said in March at the CI Energy Group Arctic oil and gas symposium.

While Cameron has the worldwide rights, Chevron has an exclusive arrangement for use in the Arctic. But it is willing to allow other operators to use it, he told reporters. "From Chevron's point of view, it's a piece of safety equipment."

The AWKS safety package is a fully independent emergency blowout preventer (BOP) that simultaneously shears and seals over a wide range of drilling tubulars and large-diameter casing with a single ram. To achieve the same effect, a conventional BOP requires two—one to shear and one to seal.

The package can be remotely activated from the rig or from a standby vessel.

Although AWKS has successfully completed its shear and seal testing, it is not yet in use anywhere in the world, according to Scott.

After the BP Macondo blowout in the Gulf of Mexico, the National Energy Board (NEB) undertook a review of its Same Season Relief Well policy that had been approved in the 1970s. Under the policy, an applicant must demonstrate in its contingency plan the capability to drill a relief well to kill an out-of-control well during the same drilling season. Following extensive consultations with northern residents on future requirements for Arctic drilling, the board reaffirmed that policy.

However, it also said that any company wishing to depart from the policy in a future application for a well would have to demonstrate how it would meet or exceed the intended outcome, which is to kill an out-of-control well in the same season in order to minimize harmful impacts on the environment.

Chevron had planned to submit an application for an alternative to the same-season relief well. But in December it announced it was putting a plan to drill a well in the deepwater Beaufort Sea on indefinite hold because of what it called "economic uncertainty in the industry" with falling oil prices.

Imperial Oil, operator of a joint venture with ExxonMobil and BP, which hopes to drill a deepwater well in the Beaufort Sea in the summer of 2020, has indicated to the NEB that it plans to file an application for an equivalency to a same-season relief well by the end of this year.

Chevron believes that a ship-based cap along with the AWKS would provide the greatest protection for the environment in the event of the loss of control of a well as it would provide the most rapid response, reducing the duration of the release, said Scott. "Anything that dramatically impacts the ability to shut off that flow is the best way to go because you are talking about millions of barrels of oil."

The rules for a same-season relief well require an operator to consider a worst-case scenario, which would include the cost of a relief well, the cost of cleanup and any impact on the Inuvialuit, he said. "If you add all those together, it's a huge number."

In his presentation, Scott suggested that for development to proceed in the Arctic, trade-offs would be required by both industry and local stakeholders. An acceptable alternative to a same-season relief well would make developm ent drilling more economic by significantly increasing the length of the drilling season, resulting in longer-term employment for local residents along with addressing the issues of environmental sustainability and human health, he says.

■ *Elsie Ross*

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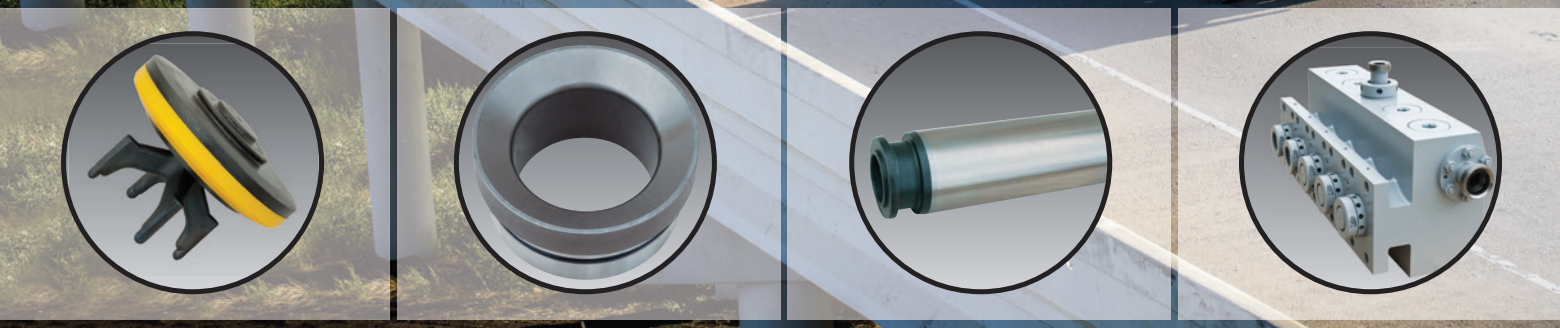

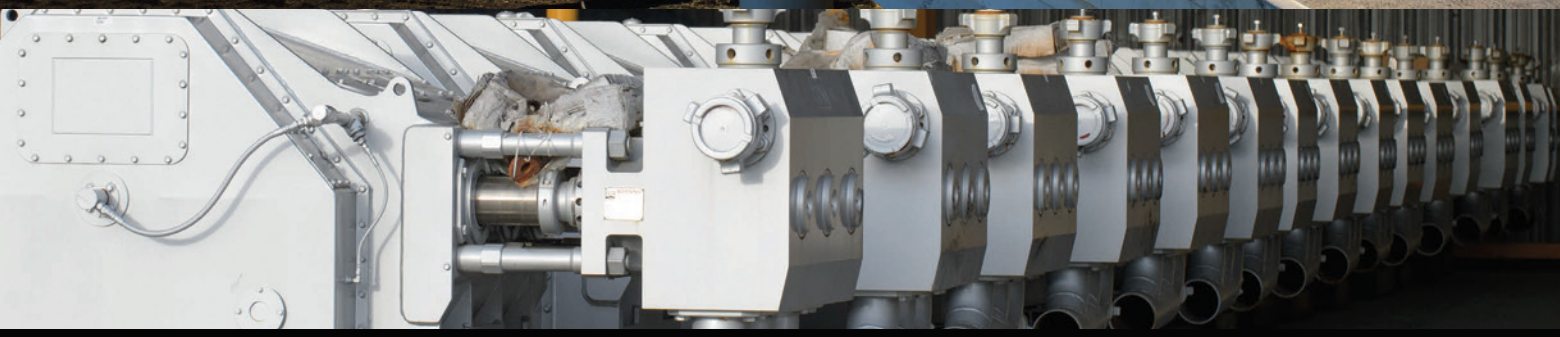

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SOFTWARE

AN ANALYTIC APPROACH

Using data management and predictive analytics to cut costs, avoid breakdowns

If you've searched a travel site on the Internet, booked a hotel room or bought a book on Amazon's website, it's likely your search has been analyzed by a data mining technology called analytics; a powerful tool that lets companies trying to sell you their products and services determine what your future tastes and desires will be in order to better target you.

Search engine Google, which offers its web-based Google Analytics service, typifies the trend, with a data analysis tool that lets companies and others provide an easier way for potential customers to search for their sites and to better design their websites so they can quickly find the information they're seeking, while also being able to gather information about those customers' tastes and desires.

And while the oil and gas industry has been slow in adopting the technology, a Calgary-based executive with SAS Canada Institute, one of the leaders in analytics, says he's convinced virtually all areas of the industry could benefit from its use, potentially saving hundreds of millions of dollars by better deploying its assets and its workforce.

"I'm an old oil and gas engineer," says Doug Crawford, 60, who is the executive lead, oil and gas Americas, with SAS. "A lot of the people who run the [oil and gas] companies [in Canada] are my age. But if you can show someone where you can save them money and make their operations more efficient for $500,000 or $1 million, I think they would be interested."

SAS, an acronym for Statistical Analysis System, is a software suite developed by the SAS Institute for advanced analytics, first developed at North Carolina State University in the late 1960s; it remains headquartered in that state. The Institute, now a privately >

^ VISUALIZING ROOT CAUSE
One area for deeper analytic utilization is in health, safety and environment. SAS Visual Analytics can deploy mobile scorecards of specific business areas.

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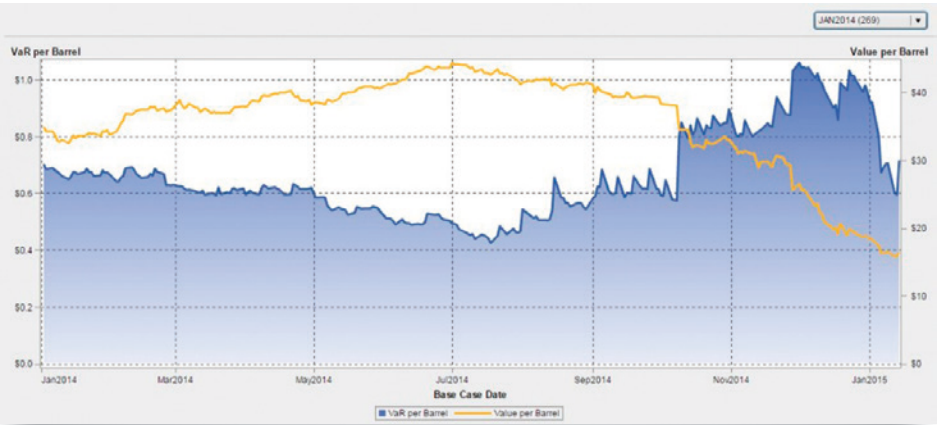

ENERGY RISK MANAGEMENT
Examples of SAS BookRunner data surfaced in SAS Visual Analytics using a fictitious energy production portfolio, VirtualOil, showing a five-year rolling portfolio, top, and a January 2014 start date portfolio, bottom. SAS posts the recurring simulation exercise, with charts representing mark-to-market and value-at-risk at the barrel level, as a generic benchmark that readers can compare against their own physical oil commodity book's performance.

owned corporation with thousands of employees worldwide, is the leader in the use of advanced analytics, business intelligence, data management and predictive analytics.

The technology has steadily advanced since then, with the development of computer power that has seen laptops exceed what mainframes could achieve when they were first developed. SAS data can be published in a variety of software formats and is now available in the cloud as well.

While it is used in virtually all industries, one of its best-known products is its enterprise financial crimes for banking technology, which involves the use of SAS technology to detect fraud, money laundering and other fraudulent transactions.

"Every time you use your credit card, you're using an SAS code, which is part of our fraud detection framework," Crawford says.

Crawford is a chemical engineering graduate of the University of Calgary with 32 years of industry experience, including in the offshore and oilsands with the former Gulf Canada as well as with North Dakota fracking pioneer Mission Oil and Gas, now owned by Calgary-based Crescent Point Energy. While SAS analytics is used by the oil and gas industry, Crawford says it has not adopted the SAS analytics approach as rapidly as he believes it should.

"I'm a bit surprised the folks [in the industry] in Canada aren't more quickly adopting it," he says. "When I joined SAS [last fall], I was astounded with the things people [at the Institute] were doing with big data."

Shell Upstream Americas has already learned what can be done with its data, deploying SAS tools called SAS Predictive Asset Management and SAS Visual Analytics in its offshore operations.

The Predictive Asset Management technology analyses real-time data to predict possible downtime caused by defects, preventing prolonged shutdowns and optimizing maintenance cycles.

The company's Visual Analytics technology uses advanced visualization technology to provide engineers and operations personnel with an event-based surveillance capability across all of Shell's deepwater assets in the Gulf of Mexico and Brazil.

Tom Moroney, Shell's deepwater technology deployment manager, described in an article posted on the SAS corporate website how the approach can help the company manage its assets. "We're beginning to use some fairly intense statistics and we don't want just to be looking at events but patterns and the emergence of patterns in real time," he says.

Crawford says there are numerous other examples of the use of analytics in the oil and gas industry. One notable use was in the Netherlands' massive Groningen gas field, the largest natural gas field in Europe, where the technology has been used to detect maintenance issues, reducing downtimes there from 28 days to just a few days, he says.

As an engineer by training, Crawford says learning how the technology works has been eye opening. "Using algorithms, [SAS computer scientists and data managers] can look at all the data and figure out the most important variable," he says. "The more historical data you have, the more predictive you can be."

SAS technology is already in widespread use in one aspect of the oil and gas industry, in the area of hedging, he says. "We have a number of clients in Calgary who use our BookRunner [Advanced Analytics] technology," he says.

BookRunner uses advanced modelling functions to measure and monitor risk metrics associated with physical or financial energy assets and contracts, including value-at-risk, cash-flow-at-risk, potential future exposure, run-risk sensitivity and other factors.

Crawford says the value of hedging is obvious in today's volatile commodity price environment. He says there are many other examples of how the company's technology has been used to squeeze more profits out of producing oil and gas assets.

IMAGES: SAS CANADA INSTITUTE

"There's an operator in the U.S. [that he could not identify] that has thousands of wells in California," he says. "If they can get [an additional] one-half a barrel a day from each well, it could be worth millions of dollars to them," he says. The company put controllers on all its wells and brought that information into a central point where it can use analytics to better manage the asset.

The use of the technology has allowed the company to maximize production, reduce maintenance costs and better prevent rod failure and other equipment problems. "They also saved 30 per cent on chemical costs while increasing production by 10 per cent," he says.

Another area where SAS technology was used was in the Early Warning project on the Ekofisk 2/4 (EKOJ) oil platform operated by ConocoPhillips in the North Sea. The EKOJ receives streams of information from multiple platforms, which is analyzed using SAS technology to form predictive rules to diagnose possible performance issues before they occur. In that case, he says maintenance costs were cut dramatically and there was a five per cent improvement in production.

Crawford is convinced that the use of his firm's technology in the Canadian oilpatch, particularly in the oilsands, could save companies hundreds of millions of dollars. He provides one recent example of how analytics could have saved an oilsands producer millions of dollars.

"There was the [Imperial Oil] Kearl oilsands mining project, where a problem with a crusher caused a plant shutdown, preventing the production of 92,000 bbls/d and causing the company's share price to decline," he says. "Predictive maintenance technology would have helped Imperial avoid that."

The problem with the ore crusher occurred last fall, shortly after the start-up of the first phase of the project. Production was shut down due to mechanical issues that caused vibrations in the ore crusher unit. It took several weeks to repair the malfunction.

The ore crusher is part of a process to remove clay particles and water from bitumen so an upgrader isn't required to produce marketable bitumen. Imperial, which has completed the second phase of the Kearl project, tried to assure nervous investors it had learned its lesson, and the same problem would not be encountered with the newest phase.

Crawford says some producers in Canada are starting to embrace his firm's technology. "I think the opportunity in the oil and gas space is extraordinary."

He says one existing opportunity is in the steam assisted gravity drainage (SAGD) area.

SAS is already working with some SAGD operators, though the company could not yet reveal which ones, and Crawford says he can see a number of areas where analytics can be used. One is in better determining where core holes need to be drilled. "If you input all of the data and analyze it, you can better map where to drill the wells," he says.

The technology can also be used to optimize steam injection, he says. "We hope to create a surrogate reservoir model, working with our computer modelling group. Because there are 150 different models and they are complex, it can take months now. But we're trying to compress that, using the SAS approach."

Another area in the oilsands and in the downstream sector where Crawford sees great potential is in the maintenance, repair and operations (MRO) space—also known as shutdowns and turnarounds.

"We believe operators could better schedule MRO work by using analytics to create critical pathways," he says. This could sharply reduce maintenance and upkeep costs.

Crawford argues that manufacturers of critical equipment are "ultra-conservative" when they suggest maintenance schedules, which can drive up costs. Using analytics would create a more realistic MRO regimen.

"Preventive maintenance is what everyone does, but our technology can help them do predictive maintenance," he says.

Crawford notes an independent study by the U.S. Department of Energy in its *Operations and Maintenance Best Practices Guide* showed that predictive analytics can "virtually eliminate catastrophic failures" and can reduce unplanned downtime to three to four per cent, as opposed to 10–18 per cent without its use.

That same study showed that in industrial settings there is a 25–30 per cent reduction in maintenance costs, a 70–75 per cent elimination of breakdowns, a 35–40 per cent reduction in downtime and a 20–25 per cent increase in production.

■ ***Jim Bentein***

IMPROVING PERFORMANCE

SAS Asset Performance Analytics integrates sensor data and historical asset/process data to model and optimize the maintenance and performance of an asset and related processes.

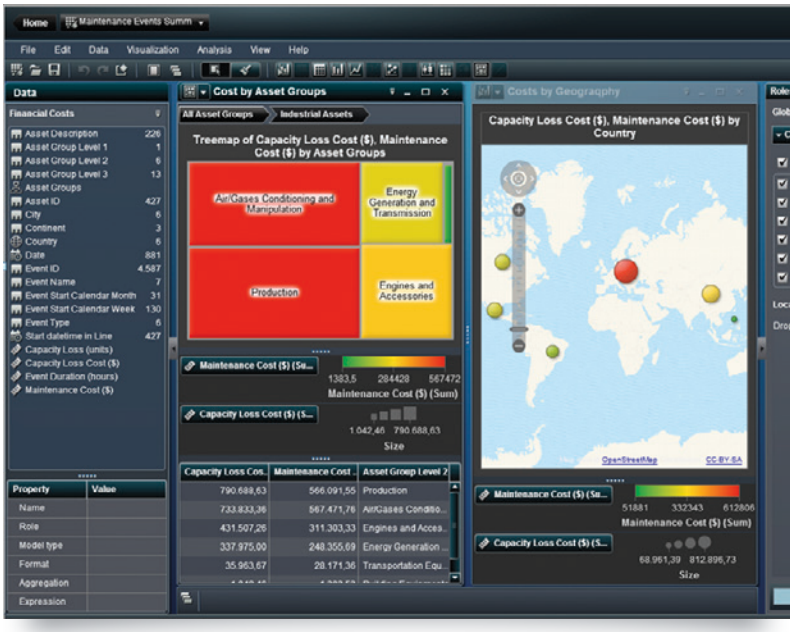

IMAGE: SAS CANADA INSTITUTE

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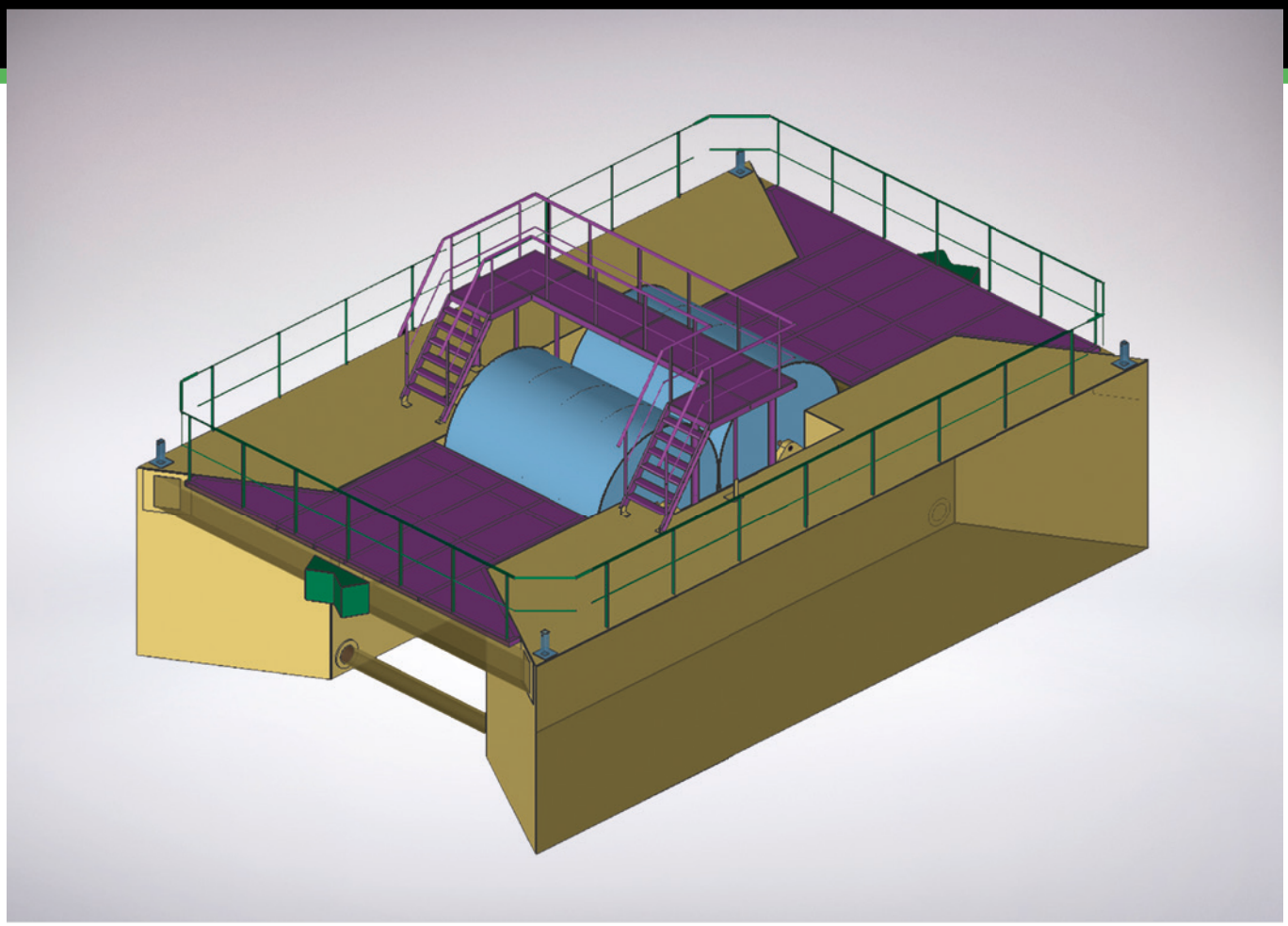

SPILLS

RESURRECTING AN INNOVATIVE OIL SPILL RESPONSE

Vessel designed to recover oil in rough seas, lakes, rivers—and tailings ponds

A popular American reality show pits treasure hunters against each other as they bid on the contents of abandoned storage lockers based on a five-minute, flashlight-aided peek of what they can see from the door when it is open. Part detectives, part gamblers, *Storage Wars*' stars hope to strike it rich on the repossessed storage units' items, and sometimes they do. One collector bought a unit for $800 and sold its contents for a $40,000 profit. Another has reportedly found items ranging from a plastic-wrapped corpse to Pablo Picasso drawings.

Similarly, Nathan Hansen believes he found a treasure in the patent for an ocean-going oil skimmer hidden within a company he bought several years ago.

Hansen buys corporate shells. "For all intents and purposes, their charter is alive, they have lots of shareholders, they just don't have a management team. It all fell apart at one time. This patent was inside one of those kinds of companies."

Hansen is president and chief executive officer of Lethbridge, Alta.–based Robix Alternative Fuels, which owns the rights to the Clean Ocean Vessel (COV), a catamaran-hulled barge designed to recover oil from water in virtually any conditions, including rough seas and possibly oilsands tailings ponds.

The COV's rotating drums lift oil and water from the surface of the ocean (or tailings pond) and scavenger blades scrape the oil/water fluid off the drums into storage tanks within the hulls.

Hansen uses this analogy: "I'm in the storage locker business and I just found a very, very interesting thing in the back corner of a storage locker. Like on the TV show *Storage Wars*."

First, Robix will showcase the vessel, take it through the certification process and then bring it >

^ CONTRA-ROTATION INNOVATION
Robix's Clean Ocean Vessel uses contra-rotating drums to lift oil and water from the surface of the ocean and scavenger blades to "scrape" the fluid off the drums into storage tanks in the catamaran hulls.

PHOTO: ROBIX ALTERNATIVE FUELS

< VERSATILE OIL SKIMMER
Under construction in Sparwood, B.C., Robix's COV low draft oil spill recovery vessel is designed to recover oil on both rough seas and in lakes and rivers.

> **THIS IS TO DO WITH A COMBINATION OF TECHNOLOGIES THAT ARE CURRENTLY BEING TESTED BY VARIOUS OIL COMPANIES. WE CALL OURS "THE HARVESTER."**
>
> ***— Nathan Hansen, president and chief executive officer, Robix Alternative Fuels***

back to Canada, fully certified as an ocean-spill vessel, says the resident of Revelstoke, B.C.

At press time, the COV was scheduled to be demonstrated on March 19 in Vancouver at the Canada Place east-side dock, though that display will be limited to a spinning of the drums in the water, since Hansen is not allowed to spill oil in the ocean.

To demonstrate its effectiveness, he plans to have the 40-foot prototype tested and certified soon at an authorized testing facility.

The COV's technology works on two basic principles of physics: the oleophilic principle—that oil sticks to metals—and the Bernoulli effect, which refers to contra-rotating drums that cause a pumping action that helps collect the oil more effectively than it would with just one rotating drum.

"If you just turned one drum, you would have an oleophilic skimmer," says Hansen. "Those are a dime a dozen. They're everywhere. The norm of the mechanical oil-spill response industry is a skimmer."

But two drums turning in opposite directions draws oil up with the whipping action of the spinning drum, he says.

According to tests done in 1996, the 40-foot vessel can pick up 90 per cent of spilled oil at 4,000 gallons a minute, he says, adding that only a few competitors have those kinds of rates, and he expects these rates to improve in the next round of tests because the drums have been balanced in the ensuing years.

Where the vessel really stands out, though, is in its stability, says Hansen.

According to Robix, the 40-foot vessel can withstand waves up to eight feet high—the competition's limit is 18-inch waves, he says—thanks to the ballast in its 33,000-litre-capacity hulls where buoyancy tanks are interspersed with ballast tanks filled with water that is dispersed by the recovered oil.

Each ballast and oil-holding tank has two seacocks—gates that open and close—to allow oil and water in. Sensors at the bottom of the drums indicate when they are full and the seacocks close until the oil is ready to be offloaded, ideally for recycling.

The COV's creators plan to offer the vessels in sizes of 10, 20, 40 and 80 feet in length. The 40-foot version is 26 feet wide, 12 feet deep and 60 tonnes of steel.

It was invented by a retired Navy captain, the late James Steele, who "chugged around the Burrard Inlet around Vancouver, British Columbia, picking up oil and testimonials" in the mid-1970s—long before the Exxon Valdez oil tanker ran aground in 1989, spilling millions of gallons of crude oil off the coast of Alaska and creating a need for his technology.

In 1993, a group of Victoria, B.C., entrepreneurs redesigned and improved the vessel. The technology was validated in 1996, but then through various poor management decisions, the years following were stagnant in commercial progress of the COV, says Hansen.

He purchased the technology in an estate sale in 2008. Now, the COV's primary market is the pipeline industry, followed by oil companies with offshore production platforms, says Hansen. Oilsands companies are another target.

Robix reckons pipeline companies such as Enbridge, which is proposing the Northern Gateway Pipeline to Canada's west coast, will be keen to adopt the COV to prove to regulators that it is prepared to handle oil spills.

OILSANDS APPLICATION

An oilsands version is being built in the tiny coal-mining town of Sparwood, B.C. "This is to do with a combination of technologies that are currently being tested by various oil companies," says Hansen. "We call ours 'The Harvester.'"

The Harvester would remove oil from tailings ponds and work with complementary technologies that would remove

PHOTO: ROBIX ALTERNATIVE FUELS

WAVE TAMER
Utilizing a catamaran-hull barge design with water-filled ballast tanks, Robix's COV can continue to operate in waves as high as eight feet.

the ponds' water "and in essence make that waste oil dry and able to be processed," says Hansen. "The pond would have less mixed waste. It would have more, if I can call it this, clean waste—drier oil and water knocked out of it before it gets to the bottom."

Robix is now consulting oilsands companies and according to Hansen, so far they like what they see.

"I think it's an awesome innovation," says Maggie Hanna, a Calgary-based innovation and technology scout for the oilsands.

One of the issues with oilsands tailings ponds is the bitumen that floats on them, and she's been working to solve this. She has discussed the COV with Robix's principles, seen photographs of the COV design and witnessed a bench-scale COV model pick up hydraulic oil from water in Brooks, Alta.

"Man, it worked well," she tells *New Technology Magazine*. "It just worked like a hot darn. I think they're really on to something there."

She especially likes that the 10-foot vessel has a 1.5-foot draft, enabling it to get close to ponds' shores.

But before oilsands companies invest, they want to see the technology working for a period of time "to match the flow rates that they have in their existing systems with our ability to keep up with those flow rates," ays Hansen.

In other words, they want more than a peek at it before they buy.

Lynda Harrison

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PHOTO: ROBIX ALTERNATIVE FUELS

GAS DETECTON

GAINING PEACE OF MIND

Laser-based gas detector technology eliminates false alarms, improves worker safety

BUILT FOR EXTREMES
One of the largest FPSO vessels ever built, the double-hulled, ice-reinforced Terra Nova can accommodate up to 120 personnel and store 960,000 barrels of oil, which is offloaded from the FPSO onto large shuttle tankers for shipment.

Thirteen years into operations at its massive offshore Terra Nova oil production facility, Suncor Energy was running into two big problems. The oil was unexpectedly souring, creating a potential safety problem since the facility's gas detection system was not set up to detect hydrogen sulphide (H_2S). And its existing monitoring system was proving unreliable partly due to the harsh environment in which the platform operates, leading to false alarms and unnecessary shutdowns that were costing the consortium that owns the facility $5 million to $10 million a year.

Suncor is the operator of the Terra Nova floating production, storage and offloading (FPSO) vessel, located on the Grand Banks about 350 kilometres from St. John's. It is jointly owned by Suncor (37.675 per cent), ExxonMobil (19 per cent), Statoil (15 per cent), Husky Energy (13 per cent), Murphy Oil (10.475 per cent), Mosbacher Operating (3.85 per cent) and Chevron Canada (one per cent).

The FPSO is one of the largest ever built—at 292 metres long approximately the size of three football fields laid end to end and standing 18 storeys high from the keel to the helideck. The oilfield, in the Jeanne d'Arc Basin, is the second largest producing oilfield off the East Coast. Its produced gases are separated from the oil and re-injected into the reservoir for production support and possible future extraction. The vessel can store 960,000 barrels of oil and accommodates up to 120 personnel.

Short of the Arctic, it's hard to imagine a more remote and inhospitable location for oil extraction. Terra Nova is in iceberg alley, necessitating measures to avoid damage from icebergs—it is a double-hulled, ice-reinforced vessel with a dynamic positioning system that enables it to change to more favourable headings in high winds and storms. It is situated in one of the foggiest areas of the planet, shrouded in fog more than 200 days a year, and is hit by snow squalls, freezing rain, gale-force winds and storm waves exceeding 25 metres in height.

Such conditions created numerous challenges for the vessel's original gas detection system—based on both infrared line-of-sight (LOS) detectors and point detectors—including malfunctions, the need for frequent maintenance and false alarms that caused numerous production shutdowns.

In a recent paper detailing the switchover to a new laser-based system by representatives of Suncor, Senscient and GexCon US, the authors report that during periods of fog or snow many LOS detectors would report a blocked beam fault condition and, depending on the situation, some would falsely detect gas. A high level of maintenance was required, temporary portable detectors were often deployed and three to four production trips per year were experienced due to false gas detection.

"During a trip initiated by gas detection, emergency shutdown valves are closed quickly, equipment is tripped and gas inventory is sent to the flare system. Shutting down the plant in this manner has potential damaging effects on plant equipment such as generators and gas compressors. The FPSO experienced damage to process equipment during emergency shutdowns several times prior to the installation of the laser-based gas detectors, resulting in prolonged outages and significant repair costs," says the paper. The trips resulted in production deferments of approximately 50,000–100,000 barrels of oil per year.

In 2010, the field began producing toxic H_2S, forcing an upgrade from the existing gas detection system that did not

PHOTO: SUNCOR ENERGY

incorporate dedicated H_2S detection. A multi-disciplinary team with representation from safety, risk analysis, operations, instrumentation and controls engineering was tasked to come up with a new gas detection solution.

SOLUTION SEARCH

Suncor began to investigate and trial various gas detection technologies while simultaneously building a gas dispersion model for the FPSO and using this analysis to complete a comprehensive gas detection evaluation and optimization study. A detailed analysis of the facility based on computational fluid dynamics (CFD) modelling was performed, and more than 1,400 gas leak scenarios were simulated and used in the evaluation, detector selection process, optimization and overall design of the upgrade to the gas detection system.

Among the aspects analyzed were the simulation of a range of realistic gas leak cases, simulating explosions to establish dangerous cloud sizes for each module of the FPSO, benchmarking a range of detector designs and layouts, arriving at a recommended optimum system for each module, and ensuring sufficient performance for both toxic and hydrocarbon gas detection.

The Suncor team's extensive search led it to the selection of Senscient's Enhanced Laser Diode Spectroscopy (ELDS) technology, which combines toxic and flammable gas detection in a single LOS detector while minimizing maintenance and increasing reliability, as a replacement system.

"The main advantage is that we can detect both flammable and toxic gases using open path technology, and the existing technology they were using couldn't detect sour gas, and their reservoir was souring," says Rajat Barua, Senscient chief executive officer and one of the authors of the paper.

"And secondly, the existing technology was giving them tremendous problems in adverse weather conditions, when they had fog, sleet, snow, mist, rain, because the existing technology they had relied on [used] infrared radiation, which is absorbed by water. Hence in those conditions, first of all they would lose their detection coverage, and secondly they were getting false alarms, which was very costly to them because it was causing the shutdown to their platform—that was a huge detrimental impact they were having to their operations in lost time and lost production."

> **"THE MAIN ADVANTAGE IS THAT WE CAN DETECT BOTH FLAMMABLE AND TOXIC GASES USING OPEN PATH TECHNOLOGY, AND THE EXISTING TECHNOLOGY THEY WERE USING COULDN'T DETECT SOUR GAS AND THEIR RESERVOIR WAS SOURING.**
>
> ***— Rajat Barua, chief executive officer, Senscient***

ELDS uses a transmitter-receiver configuration to detect and measure gas concentrations at specific target gas absorption wavelengths over distances of up to 200 metres. The transmitter uses highly reliable, solid-state laser diode sources similar to those used in telecommunications applications to generate a laser beam. The receiver measures absorbance changes when a combustible or toxic gas passes through the laser beam, according to Senscient. It uses harmonic fingerprinting to detect small fractional absorbances and eliminate false alarms.

"A harmonic fingerprint is a specific set of harmonic components introduced by target gas absorption where the relative amplitudes and phases of the components are known and specific to the target gas absorption line that is being scanned," states the paper. "Using a small retained sample of target gas inside the transmitter, the temperature and wavelength modulation currents applied to the transmitter's laser diodes are actively controlled to lock the lasers such that absorption by target gas produces specific harmonic fingerprints. The relative amplitudes and phases of the harmonic components in a harmonic fingerprint are so specific and unique that only absorption by the specified target gas produces a signal with the desired harmonic fingerprint."

Noise, absorption by atmospheric gases and coherent interference effects don't produce signals with the harmonic fingerprint, enabling the system to eliminate false alarms. The gas reference cell also enables remote, on command, electronic functional testing of the gas detector either locally or from a control room under any conditions. ELDS units are programmed to conduct a validity test every 24 hours and the results are automatically logged. "The presence of a gas reference cell is an innovation that improves reliability and reduces maintenance, which eliminates the need for technicians to carry cylinders of hazardous gases through the FPSO in order to test gas detectors," it states.

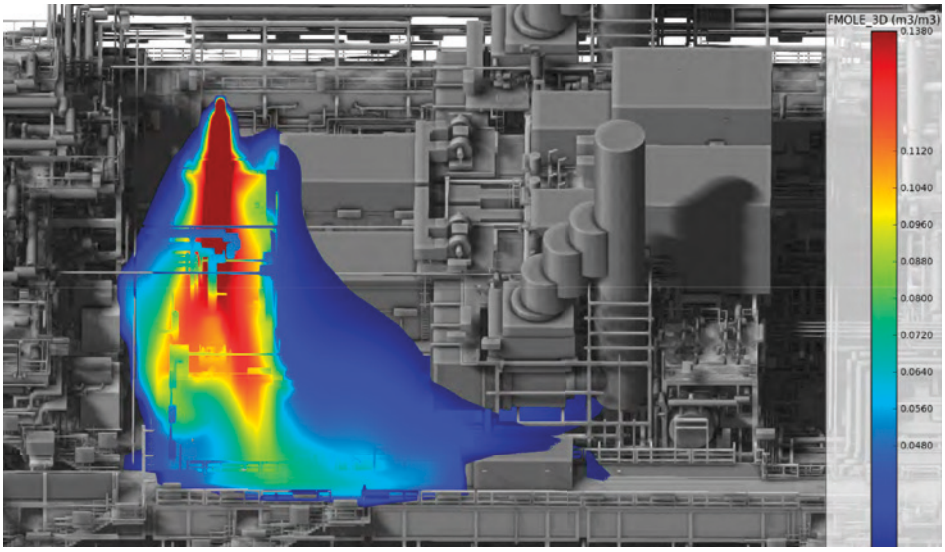
The laser-based sensors also have a minimum detection threshold that is much lower than the older infrared-based detectors, providing up to a fivefold increase in sensitivity without experiencing any drifting and related false alarms. This increases the detectable volume and makes it more likely that any given detector will be exposed to detectable gas before the flammable volume reaches a dangerous size.

Stringent performance testing of the ELDS system began in 2011 at the Terra Nova onshore distributed control system (DCS) simulator. Tested in simulated fog using water mist, in direct water spray on the device lenses, with plastic of various types placed in the beam path and with snow placed over the lens to approximately one-inch thickness, the system performed without issue.

A dual methane and H_2S ELDS detector was installed on the FPSO in May 2011 for a 24-month trial period and, other than a loose mounting bracket, performed without incident and created no spurious trips. The decision was made in 2013 to replace, over two years, all 141 infrared LOS detectors with 158 ELDS detectors, with the extra units to provide additional coverage as recommended by a GexCon assessment.

Prior to the upgrade, the Terra Nova FPSO experienced three to five plant trips, more than 100,000 fault indications and 20–25 unrevealed failures per year. Afterward, "the performance of the upgraded system has been exceptional," the paper states.

The number of faults/blocked beam indications fell from 3.82 per day to 0.14 per day. Not counting two ELDS detectors >



EXPLOSIVE RELEASE
A gas release simulation resulting in a hazardous flammable cloud scenario in the FPSO's power generation module shows concentration contours from 50 per cent lower explosive limit, depicted in deep blue, to upper explosive limit, depicted in dark red.

with alignment issues that caused most of the faults, and one faulty infrared detector that accounted for almost half of that system's failures, the overall fault rate was 1.1 per detector day with the infrared system (due mainly to weather, dirty optics and alignment), compared to 0.025 for the laser system.

"Some things are harder to quantify, like improved safety, but certainly the most apparent saving is in production. By eliminating the false alarms, which was costing them $5 [million] to $10 million a year, by simply eliminating the false alarms, we have increased the production and hence the revenue for Terra Nova by $5 [million] to $10 million a year," Barua says.

The requirements for technical response and troubleshooting also fell dramatically, from 234 maintenance work orders per year from 2009 to 2013 (not including unrecorded callouts to clean detectors due to snow, rain and mist) to just 13 maintenance work orders from June 2013 to July 2014 for issues related to the laser-based devices.

ONSHORE USE

Founded in 2004, Senscient developed and commercialized the ELDS technology over a period of almost 10 years. "The technology itself was developed between 2004 and 2008, when the [research and development] was done, and between 2008 and 2011 the company received all of the approvals and certifications—with safety devices there are a lot of approvals required—and we have been in commercial mode since 2011," says Barua.

There are now over 1,300 sensors in operation around the world, in 30 countries, with several installed in facilities in the Gulf of Mexico and the North Sea, he says. (While Barua is based in Houston, the company's headquarters and research and development team are in the U.K.)

In addition to the oil and gas sector, which represents about 75 per cent of the company's business, the sensors are also used in other industries, including the semiconductor, agriculture and environmental monitoring industries.

Onshore oil and gas facilities are also moving to laser-based gas detectors. In western Canada, Calgary-based Spartan Controls is distributor of Senscient sensors. "Within oil and gas, one of the big gases of interest tends to be hydrogen sulphide, and western Canada has a lot of sour gas production, so there is a lot of interest there," Barua says.

Jim Hueston, Spartan Controls manager, fire and safety, says the company has been selling Senscient gas detectors for just over a year. "I would say we have sold over 100 in the first year," he says. "And we have pretty solid orders for the next couple of years." A couple of major heavy oil and oilsands producers are adopting the technology as is an agricultural company.

"The big benefit is that there are no false alarms, there is no calibration required and there are no sensor changes, which are some of the biggest costs for our customers. And it's an industrialized packaged device, so it's meant for cold, nasty, windy, dirty environments. If it is delicate, it's not going to last.

"Another benefit is it's really quick to install. One of the most difficult parts of setting up an open path detector is alignment, and I was recently able to align one in under two minutes. Some of the older ones from different manufacturers have taken an hour to do the full alignment," Hueston says.

While it is more costly upfront, the system is cheaper over the long run, he says. "These cover a large area—they can replace a number of point detectors, and since they don't require maintenance, the cost of ownership is actually quite small versus looking at a number of point detectors."

But one of the greatest values is less quantifiable, he says—worker safety and peace of mind. "One of my customers actually had a leak, and they had a lost-time incident because of it, and the workers—and probably the management—had lost faith in the gas detection that was there. They replaced it with the Senscient laser-based open path, and they extensively tested it for the first six or eight months, and they were very happy. So at the end of the day not only were the workers happy with it, but I think the management was happy that they had found a solution. They are responsible for those workers, and you want to make sure that you are providing an environment that is safe, and so I think peace of mind for all the stakeholders was one of the big things they got out of it."

Going forward, Hueston says point detectors will continue to have a place, but new technologies like laser-based detectors will gain ground. "I truly believe that in a couple of years from now, we are going to see a step-change in gas detection. We are going to see a whole lot more open path detection, intermingled with point detection and ultrasonic detection, because I think that combination is what is going to provide the best coverage for customers. Both the open path detection and ultrasonic detection are gaining traction, and I think the use of point detection is going to decline."

Maurice Smith

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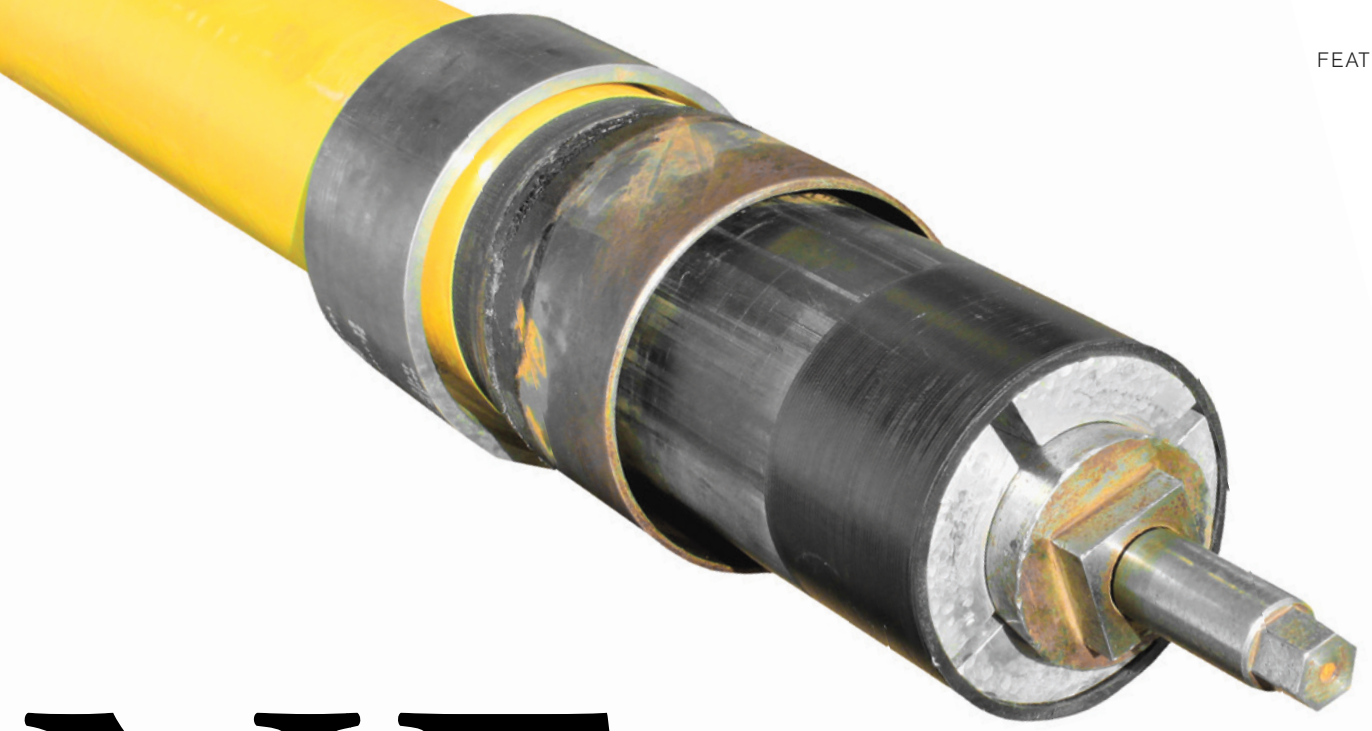
PHOTO: SENSCIENT

Perfecting the PIPELI

PHOTO: CORE LINEPIPE



NE

New inspection, construction technologies making pipelines safer

BY CARTER HAYDU

The long-running saga surrounding U.S. State Department approval of the 800,000-bbls/d Keystone XL Pipeline has, if nothing else, made the general public acutely aware of pipeline integrity issues. Fortunately for that public, the vice-president of pipeline safety and compliance at TransCanada, which is building the 1,900-kilometre line, believes the capability exists right now to install and operate a pipeline with zero leaks or defects.

"If everything is perfectly done, then it is possible, using all of today's technologies on a brand new pipeline, to achieve this," says Vern Meier. For existing pipelines, he notes, huge gains with in-line inspection tools over the past decade means the industry can detect defects half the size of a human fingernail, as well as corrosion features smaller than the tip of a pencil.

Meier says, "There are now high-resolution magnetic flux leakage in-line inspection tools, along with an electro-magnetic acoustic transducer tool that TransCanada has been on the front end of research and development for gas pipelines that are highly accurate and reliable in detecting pipeline defects." >

ZERO-LEAK TARGET
New pipeline leak detection and prevention technologies, like CORE Linepipe's ClickWeld and CORE Liner, are moving the industry toward the construction of pipelines with zero leaks and defects.

"We will go in and repair or replace a segment of pipe well before it comes close to reaching the point where it could potentially leak."

— Vern Meier, vice-president, pipeline safety and compliance, TransCanada

One of the great things about the advances in in-line inspection technology, Meier says, is that companies can now inspect existing lines with these tools as frequently as every couple of years, allowing them to calculate defect growth rates to determine subsequent intervals and to predict when a defect might cause a leak or a break in the pipeline.

"We will go in and repair or replace a segment of pipe well before it comes close to reaching the point where it could potentially leak."

However, Meier says, there is still a need within the industry for better inspection and leak detection tools to effectively monitor buried pipelines not easily inspected using current technologies. "Some older lines are telescoping or have fittings that these in-line inspection tools cannot navigate or are in some cases too small for the current technology to be able to be used in them."

TransCanada continues to work with in-line inspection tool vendors to refine gas pipeline crack-detection capabilities, investing about $100 million over the last 15 years to improve the ability to detect crack-like faults. The tools are now very effective on pipelines with standard-line pipe wall thicknesses and improvements are now focusing on thicker-wall pipelines.

For leak detection, Meier says, the industry is layering several complementary monitoring techniques on top of one another to provide comprehensive leak-detection capabilities.

His company uses a computational pipeline monitoring system on its liquid pipelines to model flows, pressures, densities and temperatures. But that system alone is still not a 100 per cent solution, so it is supplemented by a mass balancing system, frequent aerial surveillance, ground patrols, facility inspections and a public education program that enlists the support of nearby residents in keeping an eye open for possible leaks.

"There is not a 'silver bullet' piece of equipment yet," Meiers says. "These systems altogether work extremely well to virtually detect any leak that is out there, but not all of the emerging technologies have been proven out yet, and we still have not found the best tool out there that can do everything we want."

In its efforts to find that perfect detection method, last year TransCanada, along with Enbridge and the governments of Alberta and Canada, celebrated the official opening of a new $14-million research and testing facility in Edmonton, dedicated to advancing pipeline safety and efficiency through C-FER Technologies' External Leak Detection Experimental Research (ELDER) test apparatus.

"It is really the first facility of its type that has really been able to offer an environment where we could throw as many real life–type situations and conditions at these technologies in order to get a pretty robust idea of how they are going to perform," Meier says, adding TransCanada will assess four independent sensing technologies at ELDER.

A Job "Weld" Done

Better building, assembly techniques create more reliable pipelines

THE PIPELINE INDUSTRY IS INCREASINGLY short on labour, grappling with a deficit of welders at the same time more public scrutiny hovers over the safe construction and implementation of pipelines, says Aethan Sakell, sales and marketing manager for CORE Linepipe.

"We need to be more efficient with less manpower and less equipment. We need to build better pipelines, and we need to do it for less money."

Addressing both concerns, CORE offers a unique solution—the combination of CORE Liner and ClickWeld, which allows pipeline installation at more than 30 per cent savings compared to traditional methods, reducing the number of welders required on site and enabling a means of laying pipe while increasing performance through engineering design of critical internal corrosion-protection lining.

At TransCanada, the advent of mechanized welding over the last 15 years addresses the human factor in welding quality. Vern Meier, vice-president of pipeline safety and compliance, says automated welding ensures much higher quality of the welds and much more repeatability, and it can be done in the field using enclosed portables with welding shacks that provide a controlled, factory-style environment.

"Basically, robotics is what it is. It is the bringing of robotic technology to bear, and there are constant improvements with that technology. TransCanada has a technology project underway now where we are using a phased array ultrasonic-testing methodology to further improve on the mechanized-welding performance."

When it comes to reducing construction and manufacturing defects, Meier says TransCanada's pipe mills use non-destructive testing methods such as ultrasonic inspections. An applied fusion bond epoxy coating mitigates the corrosion threat over time, which is inspected at the pipe mills—and re-inspected as the pipe is lowered into the ditch—using high-voltage holiday detectors, which identify even the minutest failings within the coating.

"Once the pipeline is joined with welding, we use two forms of inspection on 100 per cent of the construction welds. We use a radiographic imaging that is taken of each and every single weld and then visually inspect it on site before it is buried so as to ensure it meets all the quality requirements."

However, as steal pipe is welded together the valuable coatings therein can burn off, Sakell notes, and the industry either uses modified weld procedures that do not work very well or expensive coated spool pieces with buried fittings. Fortunately for the pipeline industry, he adds, CORE offers a solution that not only reduces personnel challenges placed on the sector, but also protects coatings or additional liners.

"These are cable-based technologies that function on an acoustic-sensing principle, picking up sounds of escaping product from a particular line. Then there are vapour-sensing technologies we are assessing as well that will sense the different types of chemicals released from the hydrocarbons. Then there is the actual hydrocarbon-sensing cable technology we are assessing, and finally there is temperature-sensing technology."

Shining Laser Light On Pinhole Leaks

Identifying pinhole leaks is a concern for pipeline companies, Meier says, which is why industry is investing considerable research time and money to find an in-line inspection technology that could detect very tiny weld defects. These are particularly challenging to locate without using labour-intensive processes such as hydrostatic tests that involve filling the pipeline with water and increasing the pressure.

"To the extent there might be a small pinhole leak in a circumferential weld joining the pipes together, those are the ones we are really trying to focus the industry's attention on and the in-line inspection vendors' capabilities to find."

One potential solution is Illusense's laser-based optical technique, which Brad Bycraft, chief executive officer, describes as a "colonoscopy for pipelines"—detecting those elusive, tiny corrosion or leak features measuring >

PHOTO: INTELLIVIEW

< HIGH-LEVEL VIEW
IntelliView's automated fluid leak-detection system uses thermal cameras mounted on a mast or pump station shelter combined with advanced analytics to detect temperature differences that could indicate a leak.

ClickWeld is an enabling technology, Sakell says. By removing welding, the company avoids traditional field installations, and instead factory-installs liners and coatings in a controlled setting. Welding, he notes, "is the bottleneck in the manufacturing and installing of material."

For a typical job, according to Sakell, CORE Linepipe products and the ClickWeld joining system can potentially eliminate about 12 people from an otherwise 20-person crew, not only making the work less expensive by reducing workers and equipment, but also making it safer while simultaneously softening the environmental impact.

"If you are going to build a three- or four-kilometre pipeline, where a lot of the time companies will put five or six welders out to build [a conventional-method pipeline], depending on the size of the job, we come out with three or maybe four people. There is a huge reduction in manpower equipment, and that brings improvements in the carbon footprint, the time for construction as we can do it almost twice as fast."

According to Sakell, this mechanical pipe-joining system tests stronger than conventional steel pipelines and provides an improved level of product reliability, as field activities such as welding are eliminated. In the field, a small three-person CORE team fully completes a link—both mechanically and to conduct the internal fusions of the liner—in about seven minutes.

"We have this awesome joining system that is more modular than anything. We assemble a pipeline in the field. It has liners pre-installed and coating pre-installed. By doing all of this in a factory, we take [care of] basically everything that leads to operational failures and performance issues in conventional products, and those happen to be the same things that drive costs up and see people blowing their budgets."

CORE Liner uses an outer steel pipe for structural strength and an inner polymer liner pipe for corrosion resistance, which is implemented with an electro-fusion coupling by the ClickWeld system. Sakell says, "The idea of a mechanical joint is not new, but our execution certainly is. A lot of what has come before uses an epoxy system, where a lot of the strength comes from the epoxy that breaks down over time. Our system, however, is a permanent change in the steel."

CORE recently designed and completed 6,000 metres of corrosion-resistant pipeline for Edge Resources' water and natural gas Eye Hill East facility, using CORE Liner and ClickWeld. About half the time, according to Edge management, CORE enables pipeline installation at more than 30 per cent savings compared to traditional methods.

Given the benefits it offers over older technologies, the producer would not hesitate to use this technology solution on any pipelines it constructs in the future, Monty McNeil, vice-president of operations at Edge, stated in a recent facility update. "In this environment when pipelines are coming under increased public and regulatory scrutiny, we wanted a system that we wouldn't have to even think about for generations," he says. ■

> CORE SERVICE
Using proprietary installation equipment, a four-person CORE Linepipe crew can field assemble a pipeline and energize ClickWeld joints significantly faster than could be accomplished using traditional welding crews.

five millimetres in diameter or less, and that other sensors have difficulty seeing.

"Our main focus currently would be oil pipelines, but the technology would be transferable to water and gas pipelines as well. There are some slight variances that would have to happen, but the technology is applicable to all those types of pipelines."

With no disruption in the way service is currently run, the laser-based technology deploys as an add-on section to an in-line inspection device, providing an additional layer of integrity information to the operator and providing valuable data analysis and interpretation.

"We have shown the technology works, and we are currently in the process of doing a pilot inspection with industry members and the Canadian Energy Pipeline Association [CEPA]," Bycraft says. He adds that while pinhole leaks are a major pipeline sector concern, current technologies do not necessarily deliver high enough resolution to detect holes smaller than one centimetre in diameter.

"We got our engineers together, and we figured out what sort of solution we would be able to build that would find pinhole-sized leaks," he notes. "We're starting with the smallest leaks, and we are building a technology based on what the industry wants."

According to Elaine Pacheco, director of safety at CEPA, Illusense and the innovative technology project came highly recommended by the association's Pipeline Integrity Work Group and its members, believing the technology could potentially become a valuable instrument in the "pipeline integrity tool box."

The pilot itself will develop an innovative pipeline inspection solution to deliver over 10,000-times higher resolution compared to current technologies, providing operators with an unprecedented level of integrity data. This sort of information helps operators create a more proactive level of integrity management, enabling them to not only sustain their licence to operate but also save dollars and protect the environment, Pacheco says.

Research into the Illusense technology began three years ago, and the company formed in 2013. The pilot project will be complete in 2016.

Keeping An Eye On Pump Stations

During start-up of the liquids pipeline operation on the U.S. portion of the Keystone XL line, TransCanada experienced a few equipment-related leaks at its pump stations, mostly associated with initial installation—things such as small fittings not threaded or entirely tightened, or the seals and flanges not installed properly.

Fortunately, according to Meier, the company's control centre monitors its pump stations 24 hours a day, seven days a week, and has been successful in picking up any indications of small leaks. Furthermore, he says, TransCanada's pump stations are designed to largely contain on site any leakage from equipment.

"We have a membrane that covers the site and protects and prevents leaks from getting into the ground and migrating down into groundwater. As well, the sites are graded and bermed to contain larger amounts of oil that might be captured on site in the event of a bit bigger leak, which we have not had of that sort."

But systems are not perfect. As such, TransCanada is working with IntelliView Technologies, which offers another potential layer of protection and assurance, Meier says. "We are piloting the infrared camera technology on one pump station, and we will put it through a series of simulated tests and environments to see how reliably it performs."

Using a thermal and colour camera, IntelliView mounts its automated fluid leak-detection system to a mast or pump station shelter. The technology learns background temperature and can detect any temperature differences indicating possible leakage.

"If there is a fluid or an oil leak, we see fluid that is a different temperature than the outdoor ambient temperature," says Chris Beadle, vice-president of sales and marketing at IntelliView.

"The camera sees that and relays it back to our rack-mount computer or HRV where we have analytics that look at every frame. When they see a new object in that frame, they analyze it to see if it is a leak. Is it moving? What is the size of it? What is happening to it? Typically, we will see it, characterize it and alarm it in six seconds, sending a picture or video clip of the event to a control centre."

The leak detection system is based on thermal cameras and advanced analytics that detect small leaks involving a

PHOTO: CORE LINEPIPE

wide range of fluid products in above ground pipeline applications, which if left undetected could cause significant environmental damage.

While thermal cameras are nothing new, IntelliView offers analytics—algorithms determining whether a leak is actually occurring, or if thermal detection is due to some other benign factor such as a bird flying by the camera.

Beadle says, "Every analytic we use we have written ourselves. Many of these are patented, and what we did is fine-tune it to ensure there are very, very few false alarms, because within a pipeline scenario you want to make sure you do not have false alarms. That is our secret sauce—being able to analyze a video stream and determine what is going on."

According to Beadle, IntelliView works well at a pump station, where vibrations and ageing asset seals and gaskets could cause leaks. He says the majority of leaks occur in a pump station environment, and these are typically very small drips or sprays that are difficult to confirm without sensitive technology such as what IntelliView offers.

IntelliView is demonstrating its technology at a selected TransCanada pump station as part of a one-year field trial, incorporating intrusion detection using proprietary thermal cameras and a suite of security analytics. An Alberta Innovates – Technology Futures Product Demonstration Program award will partially fund the installation.

"It will be installed probably in the spring, and TransCanada is finalizing where that location will be. We will find out shortly," Beadle says. "They are looking for the most appropriate site that will provide the best data."

Meier adds, "Depending on how those tests work out, and how the equipment works from an operability and maintainability perspective, we will make some decisions on whether to deploy that across the rest of our facilities."

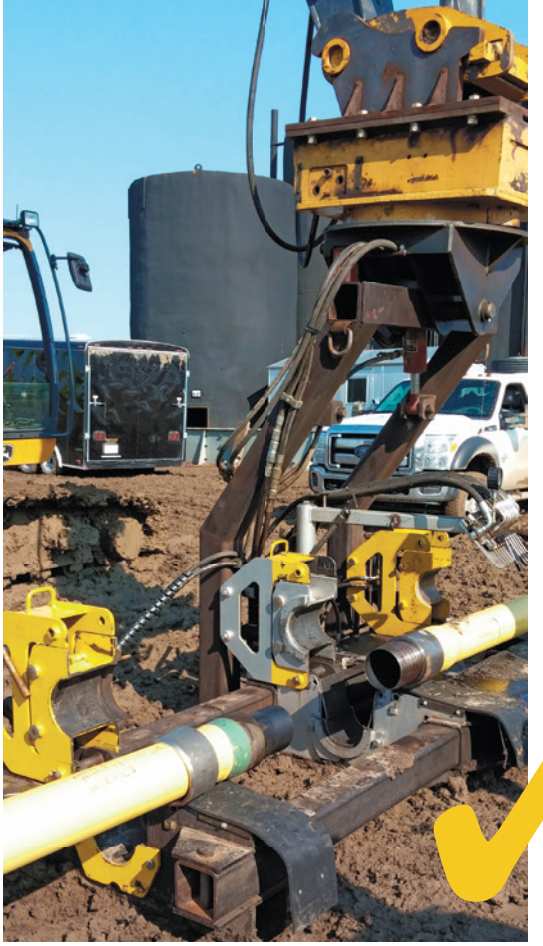
The Future Of Pipeline Integrity

The use of horizontal directional drilling is one of the most significant developments toward pipeline safety in recent years, says Meier, as it enables companies to bury pipelines much deeper, and far below the threat of any third-party damages or disruption from flood or other naturally occurring events at surface.

"We can use the directional-drilling capability, and it is really the same technology they are using now to develop a lot of the oilfields, basically to drill a trench or hole for the pipeline big enough to put a large-diameter, high-pressure pipe through it. It really does allow us to get way below, for example, a riverbed that could have the potential to scour or wash out over time because of a seasonal or one-time storm event."

As he considers TransCanada's future, Meier says he is excited by the ability to take seemingly unrelated technologies into his industry and find ways of adopting them to make pipeline systems even safer.

"It was not too many years ago when fibre optics became a broadly-used technology within the telecommunications industry. For that to find its way within our industry now as a potential application to be used for leak detection, I think, has been a fairly important development."



< SEAL OF APPROVAL
Using CORE Linepipe's mechanical pipe joining system allows a company to eliminate field activities such as welding, radiography and secondary hydrostatic testing, while producing a fluid tight joint that is stronger than the base pipe.

PHOTO: CORE LINEPIPE

He adds, "The global positioning system has provided the capability now to pinpoint the exact location of a corrosion feature the size of your fingernail on a 2,000-mile long pipeline, which is something that has just presented itself within the last one or two decades and has been embraced by the pipeline industry, and really leveraged to create a bit of a step-change in terms of our ability to operate the pipelines more safely."

For the future of IntelliView, Beadle says the company is making its sensors even more powerful, and plans to introduce the ability to pinpoint specific temperatures.

"If we know the temperature of the product, we can exclude any heat above or below that, which further reduces false alarms," he says, adding the company is also looking to develop a system that reduces the infrastructure costs of implementation, as the main application for the automated fluid leak-detection system is the pump stations.

"With existing pump stations, if you have to do a lot of trenching or wiring, then that can become quite expensive. We are looking at developing systems that avoid those costs."

Illusense began out of the University of British Columbia by founders with backgrounds varying from image processing to nanotechnology to thin-film optics. Bycraft says it is important to the company that it helps tackle the pipeline safety concerns of British Columbians, as pipeline expansion projects appear increasingly to be a likely part of the province's future.

"We really want to improve the technology of the world in any way we can, and therefore we want to make sure we are working with our customers to develop the best solution for the market." ■

HUMAN STATUS UPDATE

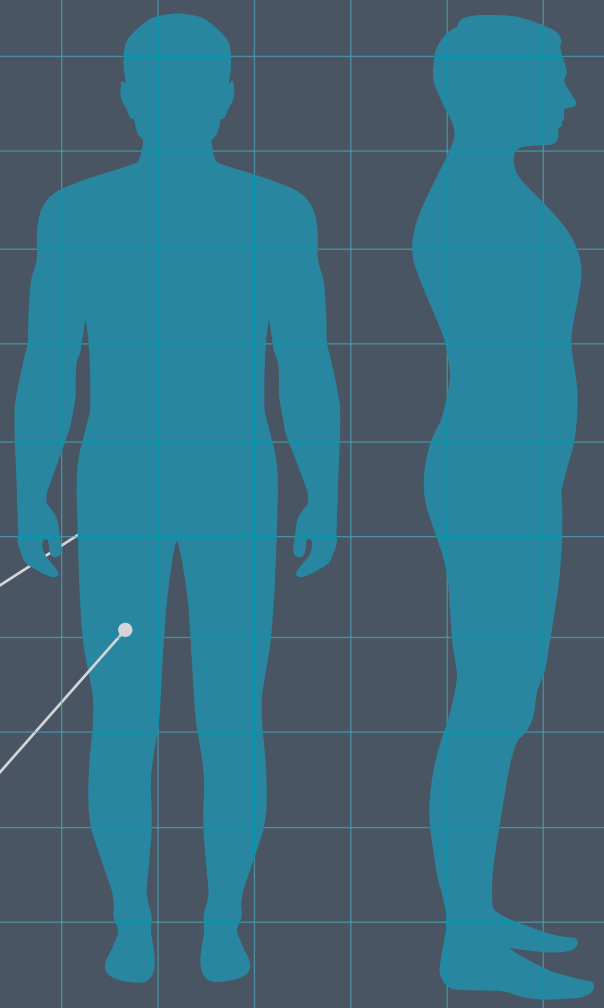
PROFILE

NAME JOHN SMITH

SEX MALE

AGE 30

POSITION TECHNICIAN



COMPANY STATUS

EQUIPMENT MAINTENANCE STATUS

VEHICLE IN FOR INSPECTION

REPORTING TO

GEORGE

COMPANY UPDATES

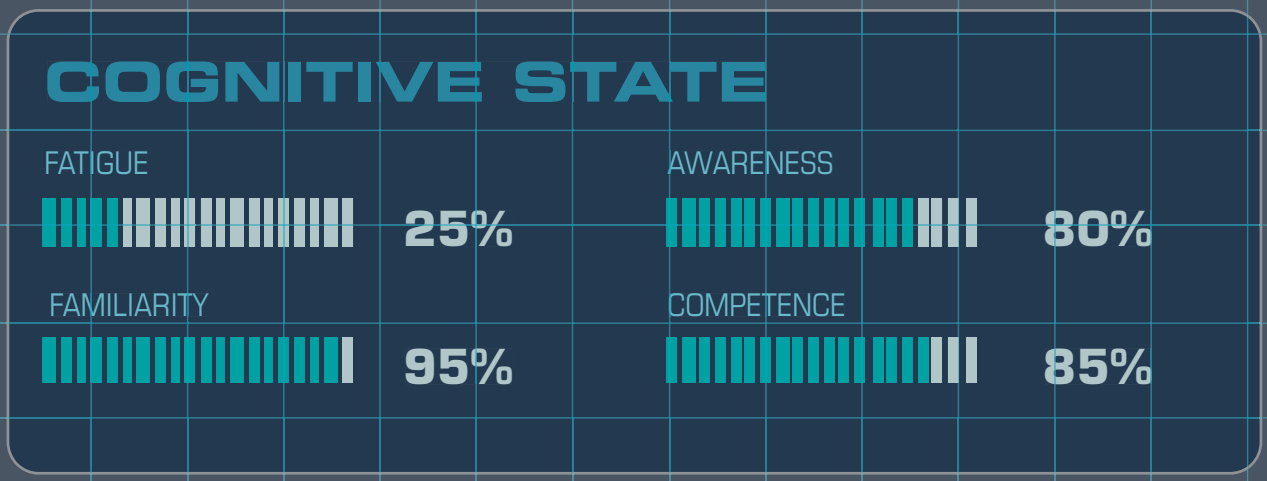
On-site inspections start today.

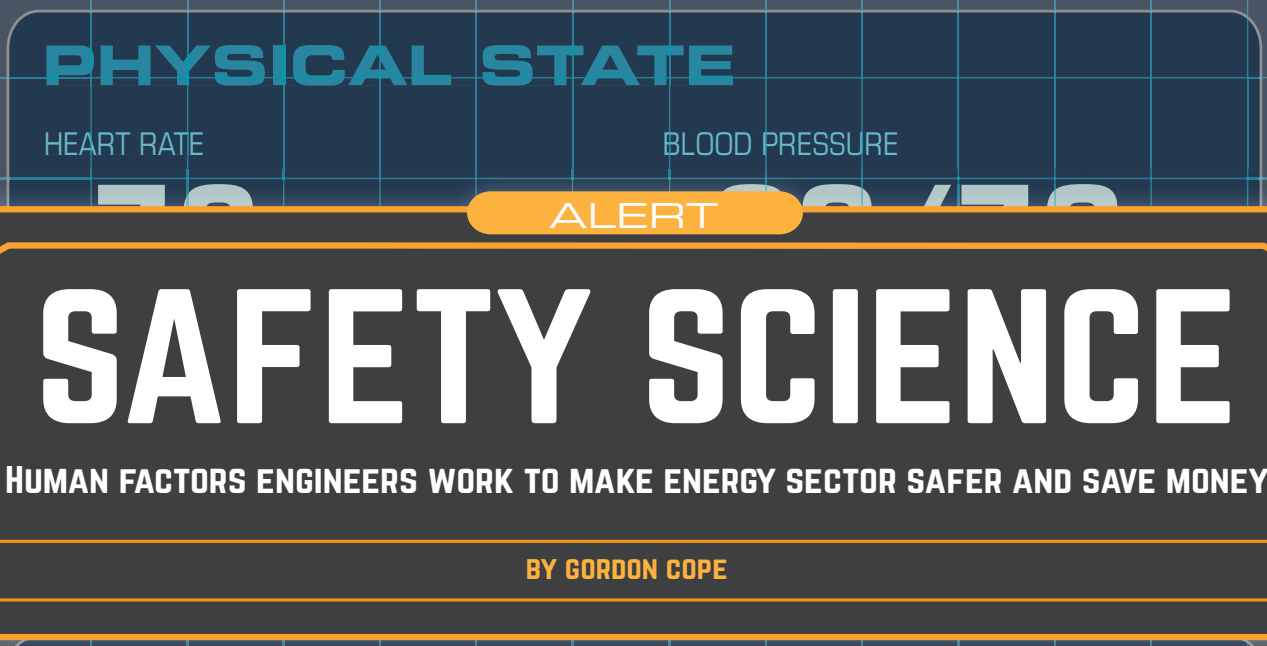
8:45 am on 04/01/2015

Peter is away till end of the week.

8:45 am on 04/01/2015

ILLUSTRATION: CELIA HUI

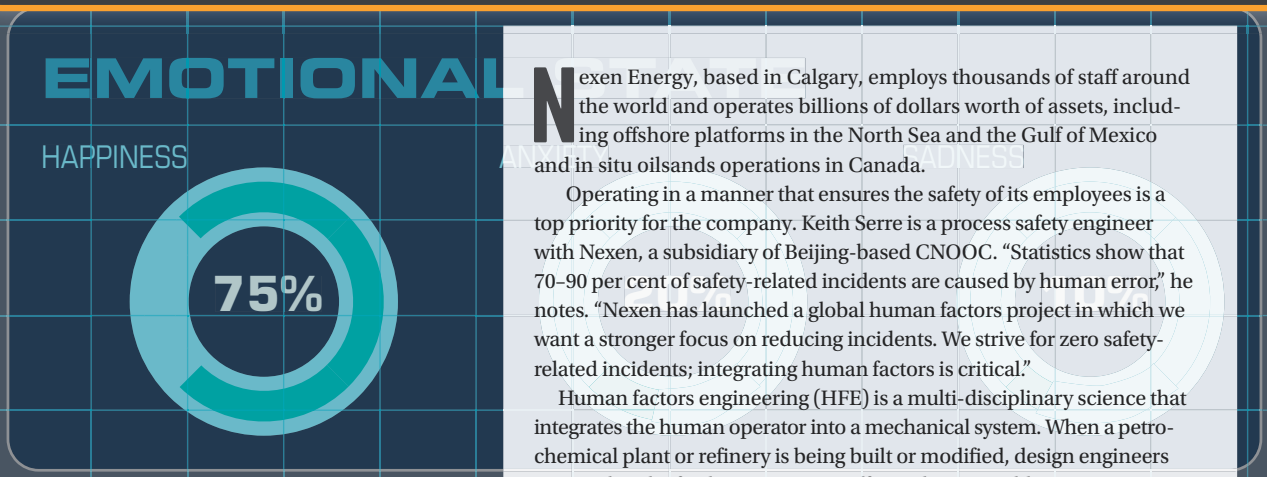




SAFETY SCIENCE

Human factors engineers work to make energy sector safer and save money

BY GORDON COPE



Nexen Energy, based in Calgary, employs thousands of staff around the world and operates billions of dollars worth of assets, including offshore platforms in the North Sea and the Gulf of Mexico and in situ oilsands operations in Canada.

Operating in a manner that ensures the safety of its employees is a top priority for the company. Keith Serre is a process safety engineer with Nexen, a subsidiary of Beijing-based CNOOC. "Statistics show that 70–90 per cent of safety-related incidents are caused by human error," he notes. "Nexen has launched a global human factors project in which we want a stronger focus on reducing incidents. We strive for zero safety-related incidents; integrating human factors is critical."

Human factors engineering (HFE) is a multi-disciplinary science that integrates the human operator into a mechanical system. When a petrochemical plant or refinery is being built or modified, design engineers ensure that the facility operates as efficiently as possible; HF engineers are plant safety experts who determine potential danger spots. >

"An HF engineer works to establish a socio-technical system so that when an emergency happens, you can address it," says Jeff Caird, a professor of human factors in the psychology department at the University of Calgary. Caird has an academic and working background in engineering, psychology and kinesiology. "You need to be a generalist that understands how the human body works and thinks and be able to communicate that knowledge in a manner that engineers can relate to."

The origins of HFE date back almost a century to the early 1920s. At the time, biplanes began carrying mail around North America; in the space of five years, over 100 pilots were killed in the line of duty. Cognitive scientists were brought in to investigate the situation, and they learned that pilots would fly into bad weather and not know which way was up. They would suffer gravitational illusions and think they were flying level when they weren't. Airplane manufacturers began to put gauges into the planes so pilots would know altitude, direction and orientation. This resulted in improved safety that exists today; the same basic layout of instruments in a plane in 1930 still exists in a Boeing 737.

> **YOU NEED TO BE A GENERALIST THAT UNDERSTANDS HOW THE HUMAN BODY WORKS AND THINKS AND BE ABLE TO COMMUNICATE THAT KNOWLEDGE IN A MANNER THAT ENGINEERS CAN RELATE TO.**
>
> ***— Jeff Caird, professor of human factors, University of Calgary***

Currently, there are about 10,000 HF engineers worldwide. Most of them are usability engineers; they work with a software company, for instance, to see how a client would navigate through their applications. Ergonomics engineering consultants, on the other hand, work to address how the human element interacts with equipment and processes to ensure that a facility functions in the safest, most efficient manner possible. As technology increases in complexity, their role becomes increasingly critical.

Atkins Group is a global design, engineering and project management consultancy with 18,000 employees worldwide. As part of its operations, Atkins has one of the world's leading HF consultancy businesses.

Ben Woodcock is the Calgary operations manager for Atkins Energy. He has consulted in the oilsands, offering advice on control rooms, occupational health and safety, and mine transportation. "There are three general parts to human factors," he notes. "The first is the immediate interface: access to valves, pumps, switches and the working environment. The second is human reliability: the ability to remain aware and be able to take in data and make decisions in an error-free manner. The third is the safety culture: looking to influence the corporate culture to behave in a safer manner."

Immediate interface, also referred to as human-machine interface, is a major HF concern. "This is an area where a lot of thought and research has gone into how to identify the most critical areas," says Woodcock. "Alarms are the number one area."

Proper alarm management strategy is key when an emergency arises. Accident investigators have delineated it as a factor in numerous tragedies including the Three Mile Island nuclear meltdown in 1979 and the Air France crash in the Atlantic Ocean near Brazil in 2009. "There is what we refer to as the 'Christmas-tree phenomenon,' where all the alarms light up at once," says Caird. "If the alarm system is designed poorly, you can't tell what is minor and what is potentially catastrophic."

Studies show that people generally react to the Christmas-tree phenomenon in one of two ways: they either freeze due to cognitive overload or they react to the alarm that's easiest to address instead of the most critical. "One solution is to design an alarm system so that the problems are identified in a descending order of criticality," says Caird. "You have to design the system so that you deal with the most serious issues first."

Human reliability is also a major issue. "There are always opportunities for error and consequences," says Woodcock. "Are you looking at the system in a way that minimizes errors, or are you creating an environment where the likelihood of human error and consequences increases?"

According to Woodcock, there is a common set of error-producing conditions: fatigue, unfamiliarity, competence of task and awareness. "Take familiarity—doing the same thing day in and day out. You would think that there would be less opportunity for error, but if you are performing a task 11 hours into a shift as opposed to the first three hours, then fatigue is going to be a factor."

When an accident occurs, HF engineers are called in to help ascertain the cause. If a catastrophic incident is caused by a technological failure, then the malfunctioning equipment can be repaired and new devices re-engineered. Historically, however, if the cause is due to human failure, very few proactive steps beyond training are commonly taken to avoid future repetitions. "It is easy to say, 'It was just human error, there's not much we can do about that,'" says Woodcock.

HF engineers have developed categorizations that break down human error in such a way as to allow the targeting of specific improvements. "There are four basic types of errors: slips, lapses, mistakes and violations," says Woodcock. "Slips are physical errors, something as simple as pushing the wrong button. It can be because the operator is wearing gloves or that the buttons are too close together—who hasn't pushed the letter *y* instead of the letter *t* on their cellphone because of that?"

Improved design can mitigate slips or provide recovery steps. "For example, in the case of pushing the wrong button, you can have a prompt," says Woodcock. "If I close a Word document without saving it first, I get a prompt asking if I want to save it. The same with a control system; it can ask you if you want to close a valve before turning off a pump."

A lapse is when an operator is intent on performing task A, but does task B because of fatigue or distraction. "Perhaps you're driving down the road and fussing with the radio and you miss your turn," says Woodcock. "Or you have been driving too long, and you drive right past your turn because you're in robot mode. Mitigation in the workplace might take the form of fatigue management or looking at task organization to see that you have enough people and time to perform a task properly."

Mistakes happen when, instead of performing task Y, the operator performs task X because they firmly believe that was the correct thing to do. "In this case, mitigation might include training in the correct procedures and an awareness of what is incorrect," says Woodcock.

Violations occur when an operator deliberately undertakes an incorrect operation knowing that it is wrong. "Most of the times, this is not done maliciously but due to prioritizing other parameters [such as time and cost] ahead of following a correct procedure," says Woodcock. "This could, of course, result in safety being compromised. In many instances, this will be down to a misaligned corporate culture. The long-term solution in this case would be to develop a corporate culture that promotes doing things right: prioritizing safety over schedule or profit."

For HF engineers, cultivating a corporate culture that focuses on safety is a strategy that forms the foundation for reducing employee injury and catastrophic events. Some sectors, such as aerospace and nuclear power generation, have strong safety cultures, but others, such as oil and gas (O&G), have lagged. "HFE has been applied inconsistently in the oil and gas sector," says Woodcock.

As in many sectors, safety can become a secondary consideration to profit. "Shutting down a pipeline can cost millions of dollars," says Caird. >

OUT OF HARM'S WAY

STANDARDIZATION, AUTOMATION AND ATTENTION TO DESIGN AMONG THE SOLUTIONS IN THE HFE TOOLBOX

Human factors (HF) engineers have a spectrum of weapons in their arsenal to increase safety and efficiency in many parts of the oil and gas sector. "A drill rig is an excellent example of a place where HF can be applied," says Ben Woodcock, Calgary operations manager for Atkins Energy. "Much has been done to incorporate advances in automation [in which certain processes are placed under computer control, such as] moving the operator away from areas where the risk to the operator is inherently higher."

But automation can be both a blessing and a curse. Positive automation bias is a circumstance in which something works too well; airplane autopilot systems have induced human pilots to drowse off and overfly their destination.

"You have to balance automation with the supervisory advantage of proximity, of having access to a broad spectrum of information, such as vibrations or feedback from an operator who is present on a platform for the entirety of his or her shift," says Woodcock.

Standardization is very important. HF engineers have a saying for valves: lefty loosey, righty tighty. It means that valves should open by turning to the left, and close by turning to the right. Rotary switches increase clockwise and decrease counter-clockwise. A lever increases when one pushes it away and decreases when one pulls it closer.

Standardizations change from region to region, however. In North America, for instance, a light switch turns on when one flicks the toggle up and off when the toggle is flicked down. In the U.K., however, the opposite is true; if a facility is to be run by British operators, HF engineers and designers must account for population stereotypes.

The design of worker access, such as scaffolding and ladders, can make a significant difference in safety. A 10-kilogram object may be relatively easy to lift if it is at one's feet, but if it is one metre beyond the edge of a scaffold, it becomes difficult to handle without risking injury. According to U.S. safety statistics, there were 128 fatalities in the offshore Gulf of Mexico from 2003-10, but there were 1,400 career-ending injuries.

HF engineers fine-tune emergency escape and rescue, an issue that first gained prominence after the 1988 Piper Alpha tragedy (in which a North Sea platform caught fire and exploded, killing 167 workers). Attention focused on the number of lifeboats and their ease of launch under severe weather conditions. Pathways were also an important consideration; not all evacuation routes led to safety.

"Span of control" is an HF term that refers to the ability to handle different tasks simultaneously. Generally, an individual can keep track of up to seven unique items. A supervisor, for instance, can oversee up to seven staff; after that, the facility needs another level of supervision to remain effective.

In addition, there is a permit-to-work (PTW) form that must be issued whenever an operator is doing a hazardous operation such as a hot-tapping or working in a confined space where oxygen supply might be limited. For a supervisor, every PTW is an additional responsibility and impedes their span of control by adding to their cognitive load; as such, PTWs need to be limited in order to maintain safety. ■

"There is always a reluctance to make a decision, or to defer responsibility. It is human nature to blame someone if something goes wrong."

One way around the roadblock is to develop a system in which employees can anonymously report problems to management, which then is accountable for addressing them. "NASA developed an anonymous reporting system years ago, and it works well," says Caird. "But it is very important that the system remains anonymous; any indication that you can identify the reporter can quickly ruin the system."

Nexen recently began incorporating HFE into its corporate structure. The first step was to categorize what had already been done within their firm. "Most companies have some form of HFE, but it may not be classified as such because it hasn't been done in a structured manner," says Serre. "Nexen has done comprehensive redesign of control rooms, improving graphical displays, performed alarm rationalization and other advances that fall under the scope of HFE but wasn't done as part of a structured process."

Nexen then audited what HFE information and training was already available to the O&G sector. "The Energy Institute [EI] and the Health and Safety Executive in the U.K. have a list of the top 10 most common HF issues including HF in design, procedures and fatigue management," says Serre. "We plan to look at their information and see which apply most to Nexen. The EI also has free online training that is very helpful. We have also brought in HF experts from industry to raise awareness about the subject."

Nexen is now contemplating initiating specific HF projects. "For instance, we have recently developed a procedure for incorporating HF in the design of our facilities, which will be used for several capital projects happening in the near future."

Valve criticality analysis during the facility-design stage is a valuable HFE procedure. Criticality level 1 involves ensuring that, in an emergency, an operator can get to a valve instantly. Criticality level 2 is for valves that must be accessed frequently, such as every day to test samples. Criticality level 3 is for valves that might be used once a year for maintenance purposes. Appropriate access can vary from being right on the main control panel to a scaffold to a ladder; HF engineers verify that the access is appropriate to the function.

THE FUTURE

At this point, only a small fraction of companies in the O&G sector consistently engage in HFE. "The oil and gas sector is lagging when compared to other sectors, but there are some companies that are moving ahead," says Serre. "Some of the majors have long lists of HF design standards that they implement from the start of a project right through to operations, and many other companies are moving this way."

According to HF practitioners, adding HFE to a project will cost around $300,000–$500,000 on a $2-billion project. "Companies are not aware of the reputational and cost savings," says Caird. "Although it's difficult to assign a value to a major catastrophe that is averted, it has been demonstrated that for every $1 invested in HFE, you get approximately $5 back in cost savings; there are not a lot of investments that can do that."

In the near future, the take-up of HFE in the O&G sector will depend a lot on the price of oil. "When prices are low, safety is one of the first casualties of cutbacks, unfortunately," says Caird. "And, during layoffs, you lose institutional knowledge, which leaves a company more vulnerable."

Industry stakeholders note that countries that mandate HFE in the workplace have greater participation. "If you look at Europe, where there are regulations to do HF analyses upfront, there is a higher percentage of HFE," says Caird. "Ideally, we should enact intelligent regulations that protect companies and workers by doing analyses before a project is built."

In the meantime, far-sighted companies are already examining HFE policies. For them, Serre has some advice. "Incorporating HF engineering globally into an oil company is a multi-year project," he notes. "You need to know where to start; the Energy Institute, IOGP, UK-HSE and the International Association of Drilling Contractors have lots of resources that can help you understand the scope of HF and help you to structure a plan.

"I would also recommend referring to a consultant specializing in HF who has supported a company's efforts in integrating HF into their operations. Secondly, you don't have to do everything at once; you can high-grade projects to give you valuable wins that help you make a business case to management. Finally, you need to have a robust plan to integrate HF engineering into both project planning and operations," says Serre.

"You also have to be pragmatic in the applications of HF fundamentals in the real world; as you show real value, then you will see greater application of HF in the oil and gas sector," adds Woodcock. "In the end, it's all about improving safety and performance."

PHOTO: CENOVUS

OILSANDS

FLAME THROWER

Duplex tile technology slashes steam generator emissions, saves fuel

Prevention is the best medicine, goes the old adage, and a Seattle-based technology firm has taken that to heart when it comes to the air pollution produced by massive industrial combustion.

"Most systems take care of pollution downstream," says Geoff Osler, chief marketing officer of ClearSign Combustion. "They put on scrubbers and expensive [selective catalytic reduction systems] and other devices to clean up pollution after they create it."

However, that's a costly process that has its own tradeoffs, such as reduced process throughput or reduced water quality.

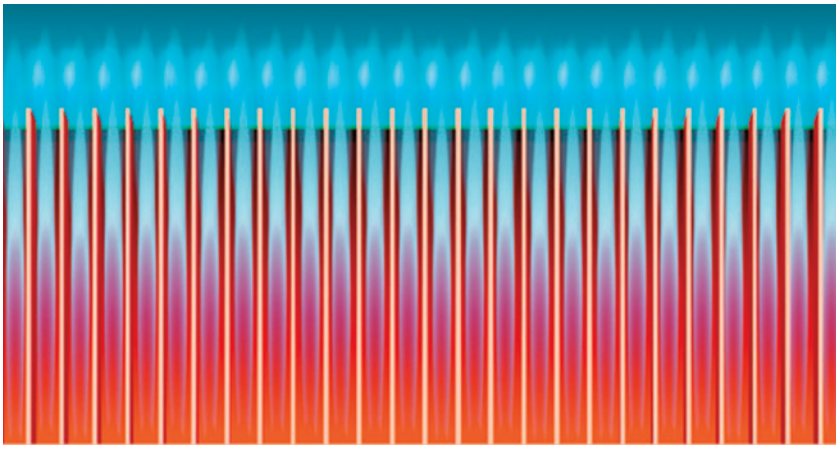
ClearSign, he says, "is founded on the idea you can do a lot more inside the combustion region itself than trying to clean it up afterwards. Prevention is always more efficient."

Started in 2008, the company spent a lot of time developing the technology and securing its intellectual property positions—it has filed about 150 patents—before bringing it to market in 2014. "It's only in the past year we have come out and started getting some major traction," says Osler.

However, he believes the technology is well placed to scale up quickly. The Canadian federal government is preparing to introduce new regulations controlling greenhouse gas emissions. With that legislation, oilsands producers will be facing further costs associated with reducing the smog-creating nitrogen oxide (NO_x) emissions produced by the massive high-temperature once-through steam generators (OTSG) used in bitumen extraction.

ClearSign's patented Duplex technology is designed to reduce NO_x, eliminate carbon monoxide >

^ PENDING REGULATIONS
With Canadian regulators planning stricter limits on smog-creating NO_x emissions, once-through steam generators commonly used for in situ oilsands production may need to incorporate new technologies, such as ClearSign's Duplex, to meet those limits.



ENHANCED COMBUSTION
ClearSign's Duplex burner technology uses a ducted ceramic tile above a standard burner, turning a single large flame into thousands of tiny, more easily controlled flames. It reduces flame length by more than 80 per cent while increasing thermal capacity and reducing air polluting emissions.

emissions and potentially reduce carbon dioxide emissions with reduced fuel consumption.

The technology consists of a proprietary high temperature porous ceramic matrix with hundreds of holes aligned in the direction of the flame. In large generators, such as those found in the Alberta oilsands, the Duplex tiles could be up to 1.5 feet thick.

"We start off the process with a conventional burner such as that found in a once-through steam generator and heat the tile to an ignition point where the tile is actually glowing an orange-white colour," says Osler. "We then detach the flame from the traditional burner and all the combustion occurs on the tile itself; there is no flame left at all."

The entire body is glowing and becomes a radiant surface from which the heat transfers to the steam tubes surrounding it. With the addition of the tile, "Duplex essentially turns a single large and unruly flame into thousands of tiny, more easily controlled flames," according to the company.

ClearSign can work with any type of burner in retrofitting a system to include the Duplex. The installation process takes only a few days.

With a successful commercial demonstration project of its Duplex technology in southern California behind it, ClearSign is confident it can be scaled up to meet the demands of larger oilsands steam units, according to Osler. "They are a bit bigger [150–200 mmBtu/hour from a single burner], but really from what we have seen so far, [Duplex] scales up in a very linear fashion," he says. "We tested the system at five mmBtu/hour and went right to 42 mmBtu."

Earlier this year, ClearSign and Aera Energy, a major California oil company, announced that they had achieved the project objectives of a field demonstration of the technology in an OTSG that had begun in the fourth quarter of 2014. The enhanced oil recovery (EOR) steam generator at Aera's Belridge field outside Bakersfield was tested at a firing rate of 42.5 mmBtu/hour.

The technology met the San Joaquin Valley air pollution control district's regulations requiring NO_x emissions of five ppm (corrected at three per cent O_2). In comparison, most industrial combustion processes produce from 60 to 100 ppm of NO_x.

"California has the most stringent regulations in the United States and possibly in the world, and to be able to meet those regulations is a very big deal for us," says Osler.

The results were achieved without major modifications to the burner or the need for costly flue gas recirculation, he notes. During testing, Aera's OTSG unit continued to supply steam at the capacity and quality required for oilfield operations.

ClearSign plans to conduct additional testing at firing rates up to 62.5 mmBtu as it continues to validate the environmental and operational benefits of its technology.

New Environment Canada regulations are going to be looking at NO_X as a major pollutant, especially in the oilsands, says Osler. Depending on the type of burner and the technology, current emissions could be as high as 60 ppm at the oilsands projects, he suggests.

ClearSign is in "advanced conversations" with most of the majors in Canada because it believes that emission reductions at oilsands projects will have the greatest impact in reducing air pollution, according to Osler. These systems are producing a great deal of NO_X, an important component of smog and one of six common air pollutants, known as criteria pollutants, for which the Environmental Protection Agency in the U.S. has set air quality standards, he notes. The emissions are also a health issue, he says.

While any combustion is going to create some level of CO_2, that can be reduced with lower fuel use. The Duplex technology will virtually eliminate carbon monoxide and reduce NO_X to the announced levels of five ppm, he says. "You are looking at reducing the only two health hazard pollutants that are created with the use of natural gas."

Although it's still too early for ClearSign to talk publicly about costs, "I can tell you it will be a fraction of any other technology used to reduce NO_X," Osler says.

On the operating cost side, if there is an energy efficiency benefit, "Duplex technology is the first air pollution system that actually has a positive payback," he says. "When companies have to add air pollution control, it's a cost of doing business—it's a cost of money. In this particular case, it may wind up making very good business sense."

When pollution control systems are added, there's usually a tradeoff, whether it's steam quality or energy efficiency or something else a company needs, he says. "In the case of our system, there is no compromise.

"The NO_X is going down, as is the carbon monoxide, and we also are going to be demonstrating some level of energy efficiency, so it actually may be that we can be producing the same amount of steam with less fuel," says Osler.

"The steam quality remains the same, the steam volume remains the same [and,] if anything, we are going to be using less fuel," he says. "Anything you can do to reduce the cost of a barrel of oil from the tarsands is a big deal."

Elsie Ross

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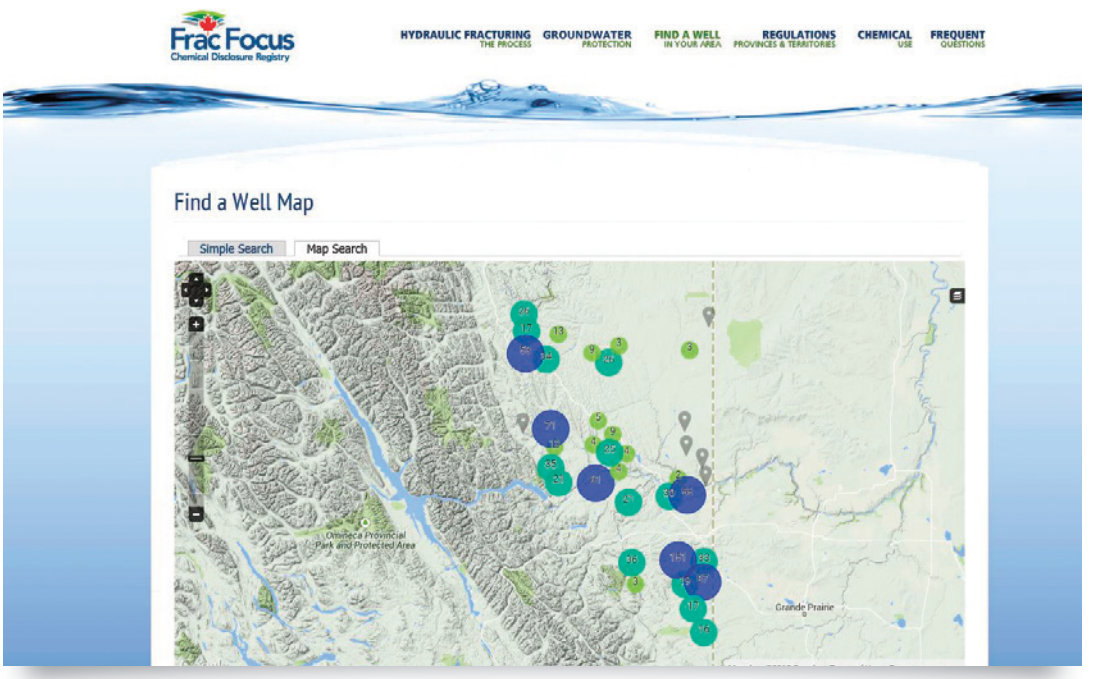
IMAGE: CLEARSIGN COMBUSTION

FRACTURING

REGULATORY TOOL WITH A BONUS

Disclosure websites for fracturing chemicals are assisting industry in cost-conscious times



< IN FOCUS
FracFocus websites in Canada and the U.S. both inform the public about hydraulic fractures performed in their region and inform industry about trends in fracking over time.

IMAGE: FRACFOCUS.CA

Besides providing transparency and reassurance about the likely quality of the local groundwater to area residents, farmers and other stakeholders, experts say the information on the websites of two publicly accessible frac chemical disclosure registries can help industry design better hydraulic fracture jobs.

That's a far cry from only five years ago, when far less data was readily available. Especially in the northeastern U.S., but also elsewhere, as drilling along with increasingly complex frac completions ramped up sharply in the Marcellus and other oil and gas shale plays, public demand for the disclosure of frac ingredients and chemicals was intensifying.

At the same time, from an industry standpoint, operators were on a steep learning curve with fast-evolving completions technologies and a still small but growing knowledge base on a host of variables that could factor into a decision on what frac chemicals to use on a specific well.

"The whole industry is [now] more knowledgeable about chemicals, compared to five or six years ago. Every major operator has significant knowledge that they didn't have five or six years ago," says Cal Cooper, director of special projects and emerging technologies at Apache Energy.

The first of the two frac chemical disclosure registries was established in the U.S. Called FracFocus, its website became active in April 2011. It is managed by the U.S. Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission. At present, more than 93,000 well sites are registered with FracFocus (U.S.), up from 55,000 a year ago. The Canadian version, launched about a year later, has the same name, but with a dot-ca domain rather than dot-org.

After the U.S. site was launched, states began passing laws requiring operators to submit their fracture fluid information to FracFocus. About 25 states require chemical disclosure of frac fluids, and the regulatory agencies of over 20 require operators to post ingredients with FracFocus.

"After about a year, the site was rebooted. It was improved and updated. Partly, this was to make it easier for industry—for uploading and increased search functionality, etc. The data for a well on the FracFocus site belongs to the state that has jurisdiction over that well," says Dan Yates, the associate executive director of GWPC.

The upgrade, called 2.0, also enabled faster data transfers to state regulatory agencies and added a customer support line.

Once a well is located, public users of the site obtain a PDF in material safety data sheet format that includes a list of chemicals used in a frac, along with their chemical abstract service numbers. "The site covers the majority of wells in the U.S. that have been fractured since we went live in 2011," Yates says.

He says the site's information, which includes water use and sand deployment metrics, can help operators as well as state regulatory agencies. "If you're an operator in a certain county, you could find all the wells with this or that particular ingredient used in their fracs."

Noting that the GWPC is a non-profit observer that acts as a data collection centre for a group of states, he says that its FracFocus service is a natural extension of its traditional role.

The Canadian FracFocus operation, however, is part of a single >

regulatory agency, the B.C. Oil and Gas Commission (BCOGC). Nonetheless it, too, is involved with other agencies, including the Alberta Energy Regulator (AER). "The AER collects all the data and then we publish that data," says Stu Venables, a senior petroleum geologist with BCOGC. Also, the National Energy Board signed an agreement in November 2013 to participate in the Canadian FracFocus.

Apart from proprietary ingredients under federal legislation dealing with trade secrets, BCOGC requires disclosure of frac chemicals. Venables says this is covered by state law in the U.S.

In both Canada and the U.S., increased participation and some improvements are expected to augment the FracFocus service for both the public and industry.

An imminent upgrade at the U.S. site, called FracFocus 3.0, will expand the public's ability to search records, improve data accuracy, provide easier extraction of data in a "machine readable" format and "upgrade educational information on chemical use, oil and gas production and potential environmental impacts," it states on its website.

Operators appear to be on board with the trend to increased disclosure—and disclosure sites getting more user-friendly. As a Calgary-based technical specialist with an oil and gas major who asked not to be identified said in an email, "There is value in looking at trends in chemical use by region [volumes, types or variety] as well as the volumes of water used in these regions. This data is not easily accessible by individual companies. However, I expect the regulator will in time be making these types of data analyses."

The FracFocus concept is saving money and improving efficiencies across the industry, says Cooper of Apache. "It's a small cost to post and it hasn't stopped innovation," he says.

For Tulsa-based ALL Consulting, which developed the U.S. FracFocus system, the new volumes of electronic frac data at a central location represent an expansion of the firm's offer to its clients. "Everybody is worried about costs. A company might be using 50 per cent more water, or a vendor is selling more chemical, but the producer isn't seeing any more production," says Dan Arthur, managing partner at ALL Consulting.

With data gathered from such sources as the U.S. Department of Energy, the U.S. Geological Survey, regulatory agencies and FracFocus, comparisons and correlations can be made that factor in well characteristics, water use, sand, number of frac stages, length of horizontal and so on. ALL gets data from FracFocus using a software program "the same as any company could," Arthur notes.

As he also notes, the amount of available information depends on the regulatory agency's regime. "You can compare service companies reporting to FracFocus—which companies use the most water or chemicals, sometimes how the frac was performed. In some areas, you can get a lot of detail," Arthur says.

Increasingly, it is possible, for instance, to benchmark the number of stages to production, amounts of water used by region and other variables, he says. "What is available now is incredible compared to 10 years ago."

■ ***Godfrey Budd***

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