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COMING NEXT MONTH The September issue of ***E&P*** examines the challenges associated with HP/HT production technology. Other features will include unconventional exploration technology, multilaterals and extended-reach wells, production testing, and floating production, and regional reports will highlight the Utica Shale and Southeast Asia. As always, while you're waiting for your next copy of ***E&P***, be sure to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER Apache's Forties Field is shown in the UKCS. The North Sea is celebrating 50 years of production this year. Left, EOR technologies continue to be refined to produce residual oil. (Cover image courtesy of Apache Corp.; cover design by Felicia Hammons)

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Kuwait Oil taps Petrofac for EPC project

The engineering, procurement and construction (EPC) project, valued at about $780 million, is integral to Kuwait's plans to increase and maintain crude production over the next five years.

Brazil's 13th oil round could fetch $870 million

Large and small E&P companies will compete for 182 onshore and 84 offshore blocks—including land basins near natural gas discoveries and deepwater areas.

Ophir awards Fortuna FLNG FEED contracts

Key focus areas for the FEED process will be to define the number of wells required at first gas; the cost of the development; and the delivery time of the long-lead subsea items, such as subsea trees, that are on the critical path to first gas.

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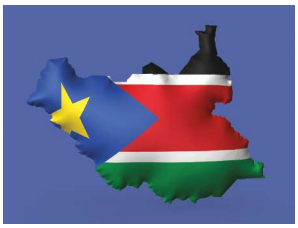


South Sudan's struggles continue following independence

By Velda Addison, Associate Online Editor

A civil war that has left thousands of people dead and damaged infrastructure and the threat of rebel forces have kept potential oil and gas investors at bay.

Surging oil production has nowhere to go

By Kristie Sotolongo, Hart Energy

The release of floating oil volumes will introduce additional supply into an already saturated market and exacerbate the number of unsold Mediterranean, North Sea and West African cargoes in the Atlantic Basin.

BP reaches $18.7 billion deal to settle 2010 oil spill claims

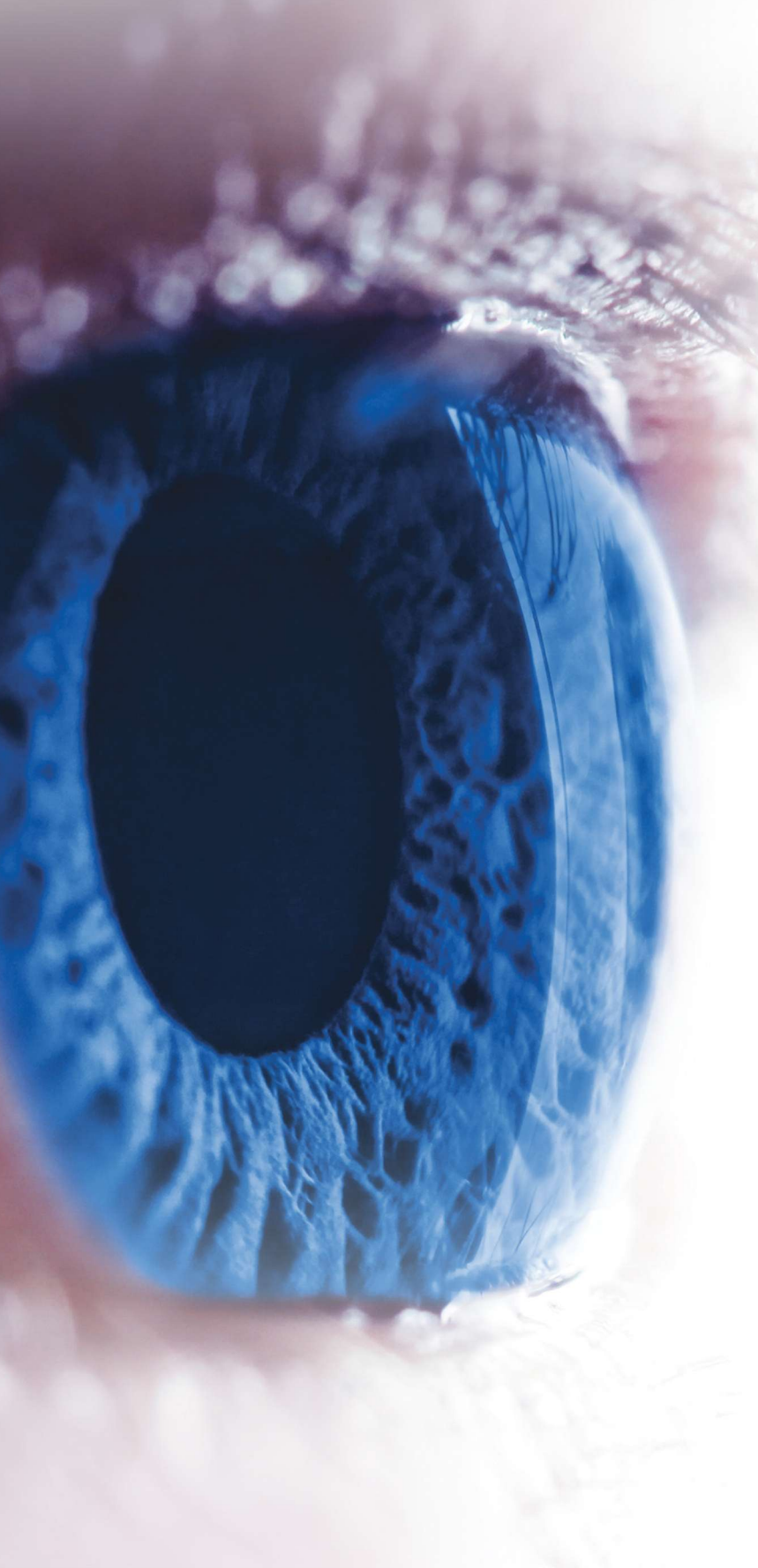
By Velda Addison, Associate Online Editor

As part of the agreements between BP, the U.S. government and five states, $18.7 billion in payments would be made over 18 years, settling economic and other claims. The settlement is, however, still subject to court approval.

DUG East: Energy business is 'living dangerously' in a changing world

By Paul Hart, Hart Energy

Multiple political and military trends, along with the rise in U.S. crude oil and natural gas production, are occurring at the same time. And that makes for an uneasy situation, Tom Petrie said.



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Papal comments highlight global 'trilemma'

Holy smoke! It's not often that an individual representing more than 1.2 billion people—that's one in seven of the world's population—starts commenting on the future of oil and gas.

So when a spiritual leader as influential to so many Roman Catholics as Pope Francis discusses climate change, backed by peer-reviewed science and environmental analysis, the E&P industry needs to show its mettle because otherwise it will once again be labeled as the chief culprit.

The industry needs to demonstrate it also is part of the solution.

When Pope Francis addressed the environment issue in late June via his papal encyclical, he described it as one of the "principal challenges facing humanity." That encyclical is now part of the church's teaching. Ironically, he did not discuss population growth, a driver of soaring energy demand.

This is to be expected leading up to the United Nations' Conference on Climate Change, COP21, taking place in Paris at the end of the year.

Michael Engell-Jensen, executive director for the International Association of Oil & Gas Producers (IOGP), did a great job in highlighting three factors governing the world's energy future:

- The need to respond to climate change, i.e. burning less carbon;
- The need for affordable energy for all; and
- The need for secure energy supplies.

"While each of these factors is essential, they form a trilemma," Engell-Jensen said. "The fundamental challenge is how to balance these three elements. IOGP needs to add discussion of this trilemma to the climate change debate."

He added that IOGP is committed to communicating the role the industry can play in solving the challenge while simultaneously meeting growing energy demand. "Natural gas, in particular, will be crucial in limiting CO2 emissions," he said in a prepared response. "For example, switching from coal to gas in power production can halve that sector's carbon footprint."

He couldn't resist pointing out some energy truths, namely that oil and gas provide abundant, affordable and reliable energy to billions of people and that, according to the International Energy Agency, demand will double by 2050, with oil and gas forecast to meet up to 60% of it.

The E&P sector has long recognized and acknowledged the risks of climate change due to rising emissions, resulting from fast-growing energy requirements.

The long-term objective of climate change policy, IOGP said, should be to reduce the risk of serious impacts on society and ecosystems, while recognizing the importance of reliable affordable energy.

With comments on the oil and gas industry coming from such influential individuals as Pope Francis, this is an objective we ourselves need to preach like our own gospel as widely as we can or else accept the consequences. E&P

Business development in low oil-price environment: international export strategies

Upstream oil and gas exports offer an important and often untapped customer base for many U.S. companies.

Julius Svoboda, International Trade Administration, U.S. Department of Commerce

Oil companies' competitors are increasing their global market share, and so should they. As oil and gas equipment manufacturers and service providers in the U.S. adjust their business model because of the low price of oil, it's time to pivot to global markets. The benefits to exporting are manifold: risk mitigation, competitive advantage, increased demand and improved profitability.

Companies that export have an easier time riding out fluctuations in the U.S. economy and are more likely to remain profitable during difficult economic periods.

On average, companies that export see faster sales growth and support more jobs than nonexporting firms. And this makes sense—more than 80% of the world's purchasing power is located outside the U.S., offering an important and often untapped customer base for many American companies.

Additionally, when U.S. firms export, they often find buyers that respect the quality of American goods and services. Foreign firms also routinely cite the outstanding customer service they receive from American companies as well as the sound business practices that U.S. firms bring to the market.

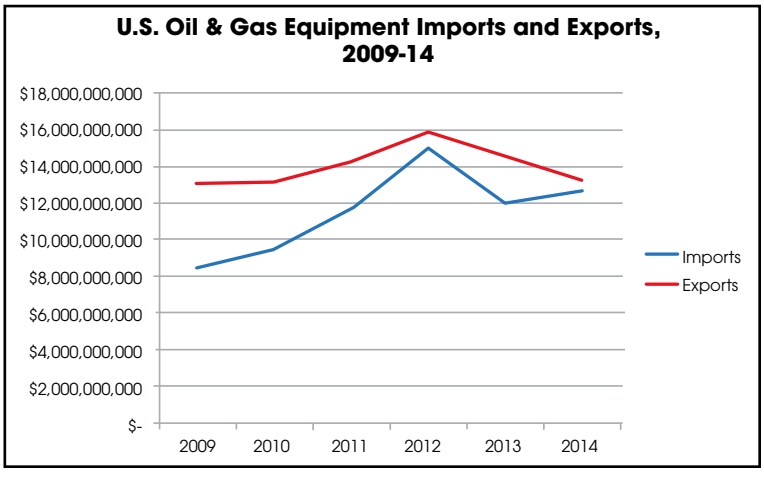
Exporting is not just for large companies; it can benefit businesses of all sizes. In fact, small and medium-sized companies account for 98% of U.S. exporters. Most of these firms, however, export to only one market—usually Canada or Mexico. Expanding the export profile beyond these two regional markets is easier today than ever before. Technology and improved logistics allow companies to reach markets quicker and provide the nuanced solutions to customers' demands.

Oil, gas export trends

The fundamental transformation in the oil and gas sector during the last seven years and the significant drop in the price of oil since October 2014 have altered the economics of carefully planned business development strategies for many companies. The headlines in the oil and gas sector talk about downsizing work forces, reigning in investments and focusing on less capital-intensive and low-cost production. For those companies that were banking on continued investment in the U.S. shale gas sector, the impacts have been particularly acute and painful.

Trade in oil and gas equipment reflects overall trends in the U.S. export profile: Equipment manufacturers, and by extension service providers, need to find new sources of demand growth in a low oil price environment. Looking at what is exported and where it is going is one way to prioritize business development destinations.

The U.S. is overall a net exporter of oil and gas equipment, but the gap between imports and exports is narrowing. This means that the U.S. is using more foreign-made equipment and sending less equipment to foreign countries. This is in large part due to the increase in oil and gas E&P activity in the U.S., but this trend is changing.



The U.S. overall is a net exporter of oil and gas equipment; however, it is using more foreign-made equipment due in large part to the increase in oil and gas E&P activity in the U.S. (Source: International Trade Administration)

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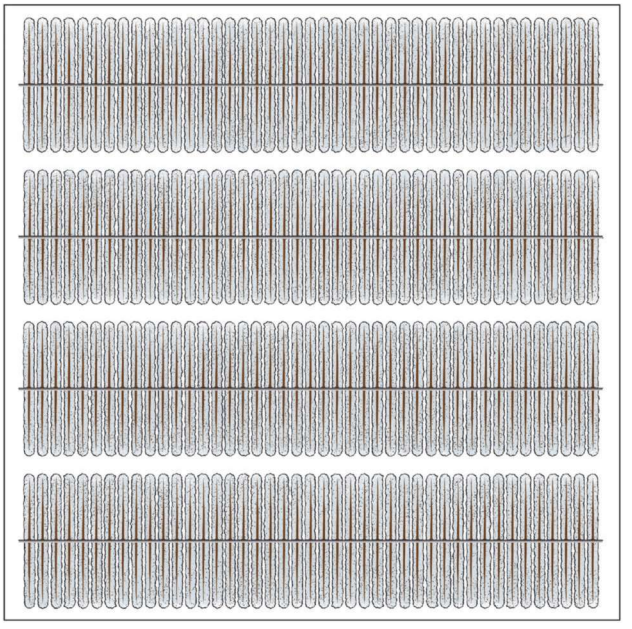

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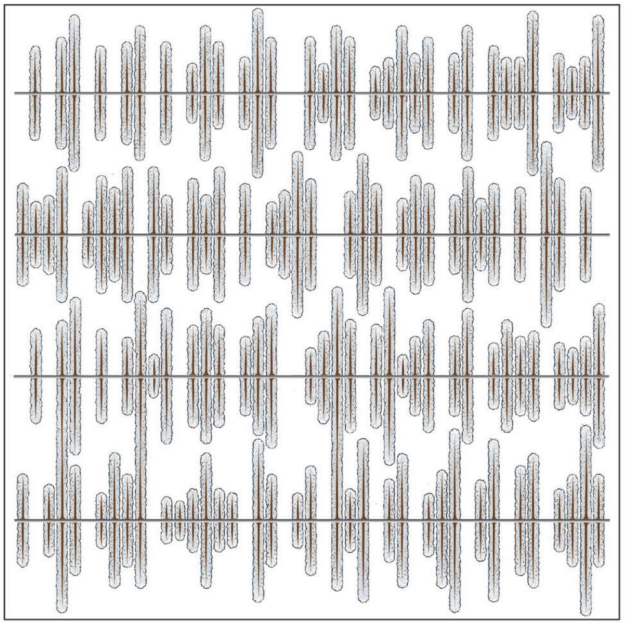

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What is being exported and where

South Korea and China are the two main exporters of oil and gas equipment to the world by value. South Korea is a major manufacturer of oceangoing vessels; semisubmersible drilling and production platforms; and other equipment such as casing, line pipe and containers. China is a major exporter of parts for derricks, tankers and light oceangoing vessels as well as offshore drilling and production platforms. The U.S. ranks third among major exporters of high-end drilling equipment and derricks, most of which go to Canada and Mexico (two of the nation's largest trading partners).

Major U.S. competitors for equipment in the global market tend to produce low-tech components and commoditized equipment. U.S. firms are known for cutting-edge technologies with high R&D costs with very few competitors. Those countries with developing shale gas operations, ultradeepwater plays and needs for EOR technology would benefit most from the types of equipment and services in which many U.S. companies specialize. South Korea and China may export more, but they cannot compete with what U.S. companies have to offer.

Recent trade statistics indicate that Saudi Arabia and Argentina are two major growth markets for U.S. sales of oil and gas equipment. Both Saudi Arabia and Argentina have significant shale resources that are in the formative stages of development. The shale gas and shale oil boom in the U.S. has given a significant head start to U.S. companies in the subsector.

Three of the largest overall importers of oil and gas equipment are Singapore, Colombia and Norway. Singapore is a major hub for oil and gas equipment sales to Southeast Asia and is consistently ranked as one of the top places in the world to conduct business.

The government of Colombia also is looking to have private firms develop its shale resources in addition to its expanding offshore sector. Norway is a well-established destination for oil and gas equipment, particularly for companies with harsh-environment oil rigs, LNG technology for transportation from remote locations and advanced environmental technology to reduce emissions.

Prioritizing top destinations for business development

The U.S. Department of Commerce's International Trade Administration is committed to using its data analytics as well as its industry expertise and Foreign Commercial Service staff to provide exporters an honest assessment of opportunities in global markets.

To help meet this objective, the International Trade Administration released its "2015 Top Markets Report for Upstream Oil and Gas Equipment," which evaluates 75 different markets using seven indicators and ranks each country's oil and gas market to gauge U.S. export potential.

The top markets report methodology consists of both quantitative and qualitative factors, including a country's distance from the U.S., the amount of equipment the country has historically imported from the U.S., the amount of equipment the country imports from other countries, the country's resources, its planned upstream investments, its business climate and overall market access.

This assessment provides a list of top export destinations for U.S. upstream oil and gas equipment firms along with researched market intelligence and country facts.

The report includes detailed case studies on 10 different markets that can help U.S. exporters better understand market dynamics, challenges to export competitiveness and opportunities. The report this year highlights Australia, Brazil, Canada, China, Colombia, Ghana, Israel, Mexico, Norway and the United Arab Emirates.

The report also includes two countries to watch that were not captured in the methodology: Burma and Mozambique. Burma is added because of the change in sanctions and its focus on oil and gas development, and Mozambique because of the large offshore gas development occurring in the northern part of the country. The countries to watch are in transition because these are developing markets. U.S. companies should look into business opportunities in these countries to gain the first mover advantage.

Advantages of exporting

During a difficult 2015, U.S. oil and gas equipment and service suppliers may find advantages through diversification into foreign markets. But what businesses do in this price environment is a challenge to be met, and U.S. companies have a global reputation second to none. Foreign firms seek U.S. cutting-edge technology, rugged equipment, reliable services and on-time deliveries, and this reputation can be leveraged when working with foreign buyers.

Hopefully the top markets report becomes a tool for exporters to use when considering foreign markets as a means to expand business operations. While 2015 has been a challenging year for the upstream oil and gas sector, it also can be a year to think about selling a company's products or services in new places. The International Trade Administration stands ready to assist companies in this effort. E&P

Q&A

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Big Data gives operators advantages in hotly contested plays

The industry can benefit quickly by approaching Big Data from the place of maximizing value by minimizing complexity.

Scott Weeden, Senior Editor, Drilling

Given the amount of seismic shot and number of wells drilled since the mid-1950s, the oil and gas industry has amassed tremendous amounts of data. Long before the concept of Big Data was popular, the E&P industry was searching for ways to tap into that data resource.

Now with all of the microseismic, geochemical, geomechanical and production information coming out of the wellbore, there is increased focus on getting the most value out of those data.

The complexity of unconventional development, for example, is much greater than conventional development. Along with that there is much more data from 3-D and 4-D seismic and microseismic technology. Computing capacity doubles every two years, adding to the complexity.

The data available to oil and gas companies are not limited to private datasets. Information is available from public and regulatory sources as well. But how much data can an operator actually use?

A roundtable on "Big Data Solutions" at the DUG Permian Conference May 20 in Fort Worth, Texas, with Luther Birdzell, CEO of OAG Analytics; Ben Shattuck, upstream analyst for Wood Mackenzie; Alan Lindsey, founder and CEO of PetroDE; and James Yockey, president of Oseberg; delved into how the industry can find value in Big Data.

Alan Lindsey, founder and CEO of PetroDE (Source: Hart Energy; photo by Tom Fox)

Ben Shattuck, left, upstream analyst of Wood Mackenzie (Source: Hart Energy; photo by Tom Fox)

E&P: What is the definition of Big Data?

Birdzell: Fundamentally, Big Data is about transforming data from a cost- into a revenue-generating asset. It can be measured as incremental barrels of oil per dollar deployed. I think Big Data would be broadly defined as data stored for data requirements that exceeded commercially available technology.

The industry can benefit most quickly and with the greatest magnitude by approaching this problem from the place of maximizing value to the user by minimizing complexity.

Yockey: When we think about Big Data, we think about huge amounts of disparate data that have different formats and shapes that are really messy and complex to deal with. But if you can get it right, you can get tremendous value.

Lindsey: The important thing to keep in mind is how the current view of Big Data differs from the way we looked at data in the past. In the past we dealt with a lot of well-structured datasets that were pretty easy to analyze with the systems we have today. The tools of Big Data allow us to get a handle on much more complicated and less structured data so that we can make sense of information that used to be next to valueless.

Shattuck: The oil and gas industry has been thirsting for data from Day 1. Typically, on the technical side of the

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business the engineers and geologists want the data. Later, for example with Facebook, there was this huge acceleration of the transformation of data into assets. That caused a particular acceleration of these technologies outside oil and gas. There's a lot of value to be had by operators and financial services by harnessing the leading edge of that technology.

With the new style of oil and gas drilling, there are hundreds of thousands of wells drilled with associated data at each point along the way. It is wrapping your mind around what that dataset means, what are the components of those data and understanding—particularly as we roll this out to people who are not very technically minded—what the capabilities and the limitations of those datasets are.

Fundamentally, our company changed the way we look at things like forecasting. It is really due to the advent of Big Data. How do you take 4 million wells, separate the noise and distraction from what really matters and roll that up into a meaningful industry-level view?

James Yockey, president of Oseberg (Source: Hart Energy; photo by Tom Fox)

Luther Birdzell, CEO of OAG Analytics (Source: Hart Energy; photo by Tom Fox)

companies have been capturing for years. To put into context how this fits in the industry, I was at an investment conference in Houston on May 19. One of the speakers was a managing director and head of the Houston office for McKinsey & Co.

He was talking about innovation and technology across the entire oil and gas industry. In a study that McKinsey published recently, its view was that data and data analytics are going to be the fastest growing segment of technology in the oil and gas industry with the highest margins, which is pretty interesting.

The second datapoint was about a $1 billion contract that a major oil company signed this year with Palantir Technologies. This is a rumor and not confirmed. Palantir is known for helping the U.S. Department of Defense and intelligence agencies deal with insurgents and terrorists by aggregating a bunch of disparate information and helping them analyze it, normalize it and visualize patterns and trends, with all the data being collected from around the world. The contract was said to be for helping the oil company make sense of the data that it was sitting on.

E&P: How can an operator maximize data analysis?

Lindsey: What you need to do essentially is preprocess that old data to understand what that means. The ultimate is to take us from these expensive well-spacing tests where we're drilling physical wells to determining that spacing from our microseismic, geochemical and geomechanical measurements so we can get very close to the correct answer right out of the starting gate. That will end up saving millions of dollars.

Most companies take the information on a well-by-well basis and analyze it, put it under a lot of intense scrutiny and then put it on a shelf. What is available now through the Cloud and data technologies is the ability to keep these data alive and on low-cost systems for instant access. Our industry is always worrying about how to optimize these completions, and someone will come up with a new technique.

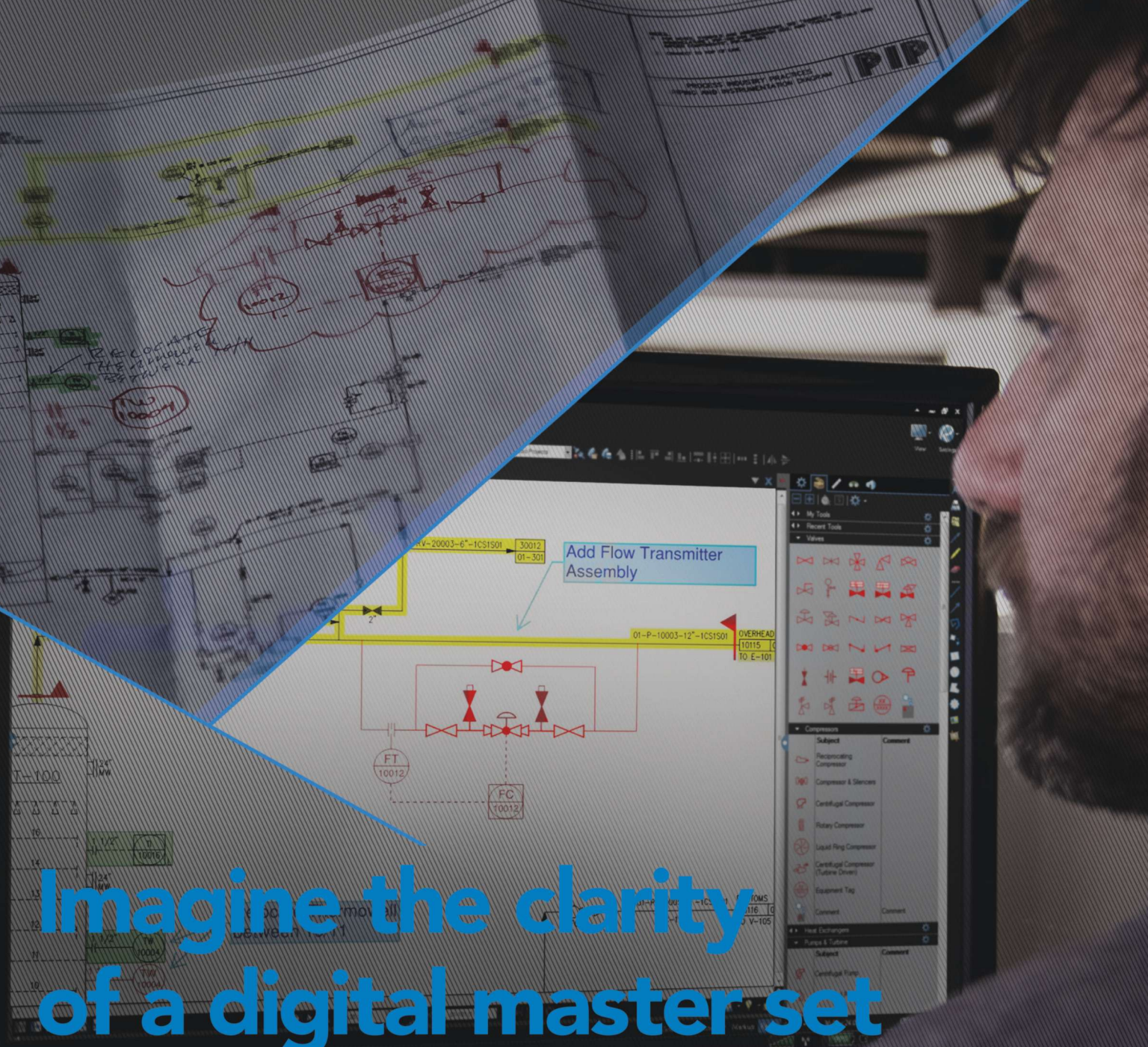
E&P: What is the future for Big Data analysis?

Yockey: There are tons of great information that oil

Lindsey: There are mountains of public data out there, and each company carries with that their own mountains of more detailed information. Frankly, it is the integration of those pieces that brings a lot of added value. One of the things we do at PetroDE is allow companies to integrate all of their public information that they know from their competitors with their own operation-generated data so that they can get competitive analysis and understand where the various plays are going.

E&P: Given all of the data being collected by the oil and gas industry, the task of analyzing those data can be overwhelming. How much collaboration do you think will have to occur to maximize the value?

Birdzell: We're able to materially reduce the uncertainty of key reservoir and completion practices using advanced statistical methods from public data. We are able to do even more with proprietary data. One way to cost-effectively



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Members of the Big Data Solutions panel at the DUG Permian Conference agreed that companies can quickly add value to their assets by integrating public and private data. (Source: Hart Energy; photo by Tom Fox)

reduce the uncertainty is to contribute to pools at the same level of data that is required to be disclosed publicly in North Dakota. Operators that are willing to do that in those other plays will very quickly enjoy that value proposition. Ultimately, the most value comes from combining public and proprietary data with even more value for every company involved in pooling those data. Being able to make more decisions more quickly and accelerate beyond the primary process as part of getting our heads around optimized infill wells or wellbore density programs are some of the many areas that we are working on and (that are) contributing to add more value more quickly.

Shattuck: From publically available data sources we roll it into a dataset that [includes] essentially every well across the Lower 48. We found that if we wanted to do meaningful commercial analysis across the Lower 48, we needed to have granular, flow-level data. We found two things when we started to get into the data. First was that the data were overwhelming to begin with, and we needed to make the effort to manage them and pull out what was important. The second was that through the various reporting conventions the data have a lot of different pitfalls.

What we have to do is go back to the drawing board and spend a really tremendous amount of time cleaning up the data. When we talk about Big Data, we've got hundreds of data categories, standardizing and sourcing from numerous locations. We've got to make sure we have a good dataset and confidence that we can get down to the analysis that we find the most valuable.

Yockey: Frankly, it is the integration of those pieces that brings a lot of added value. There are mountains of public data out there, but each company carries its own mountain of more detailed information. There are lots of opportunities on both sides of that.

There are anomalies and outliers in the data. For example, last September Continental Resources announced its next big play in the Anadarko Basin and the South Central Oklahoma Oil Play. Except for the collapse of oil prices, this would be a play that everyone would be talking about now.

What we saw at Oseberg a year out in September 2013 was that the Springer would be its next big play in the Midcontinent. We could identify that this was a new formation that Continental was going to be talking about by mining the details of the formation-specific IPs that Continental and other operators were releasing through filings with the Oklahoma Corporation Commission.

We could have leveraged a bunch of other data like spacing and increased density from filings to not just have our attention drawn to the Springer but also to delineating what the fairway was and [what] Continental's, Marathon's and Newfield's net positions [were] in the play months before this announcement. That's worth a lot to geologists, engineers and business executives in the E&P industry. E&P

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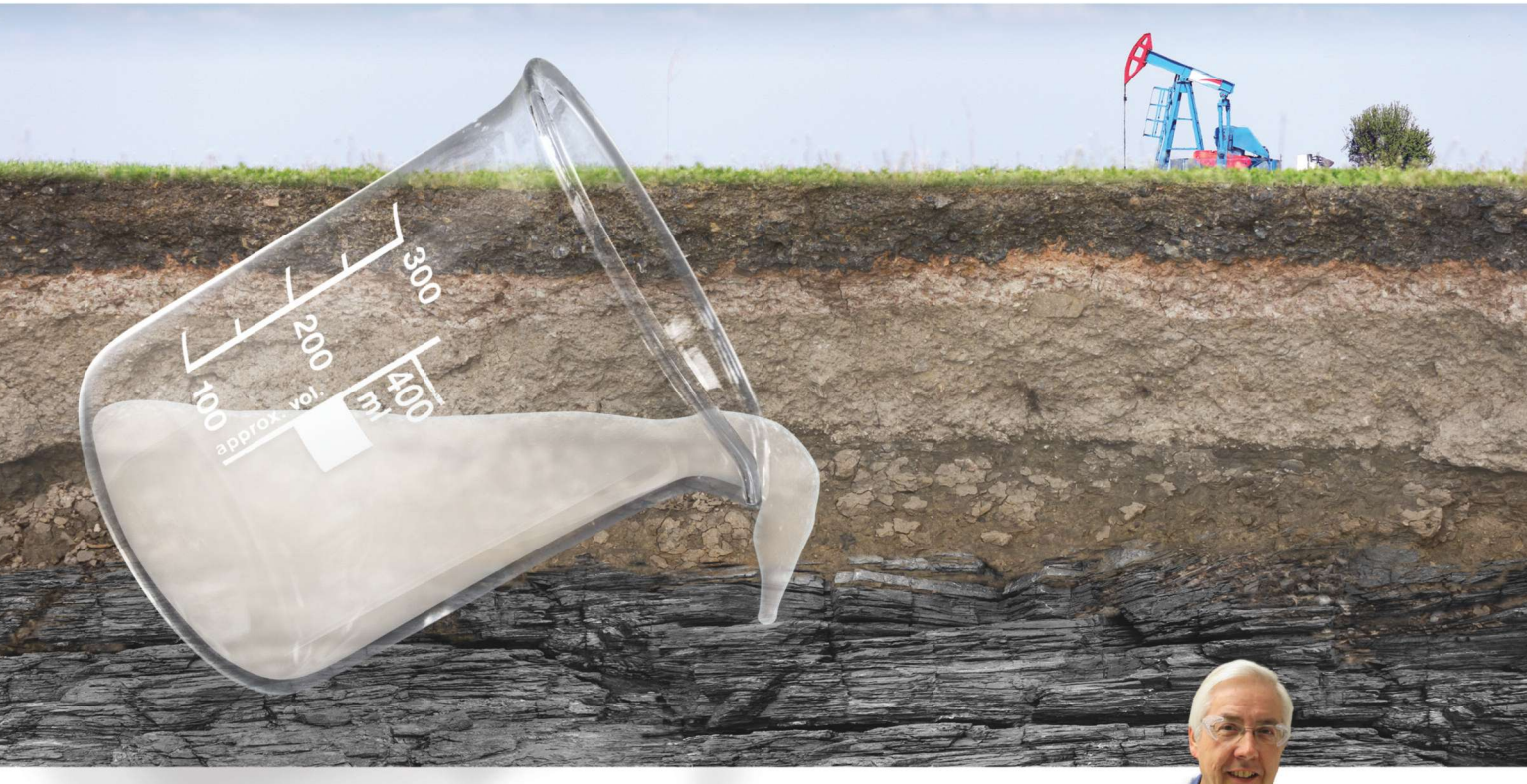

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First green shoots?

After six months of decline, demand for Permian Basin oil services—and pricing—is stabilizing.

Richard Mason, Chief Technical Director

Is it time to think about recovery in domestic oil field services?

The answer is yes—if the industry is looking for the initial green shoots, which historically have been defined by an increase in rig count. Large-scale recovery in oilfield services demand remains a 2016 event. There are various scenarios around the order of battle for how recovery progresses, typically based on how optimistic a commentator is about oil pricing. But a growing consensus suggests that the first signs of recovery should originate in the Permian Basin with the industry tackling the rising supply of drilled but uncompleted wells.

Estimates on the number of uncompleted wells, sometimes called "fracklog," exceed 4,000 units nationally. Half of those are in the Permian Basin. Reference to that backlog, and the growing role it is playing in industry conversations, has become a frequent topic in Hart Energy surveys of oilfield service firms.

- **Permian Basin oil services market stabilizes**
- **Service providers cite a slight increase in demand for oil services**
- **Operators will tackle a backlog of 2,000 uncompleted wells**
- **Pricing stabilizes for oil services, but market needs higher commodity prices for service pricing to recover**

Indeed, whether the service line is land drilling, well stimulation or workover services, sentiment has changed as service providers express confidence that the steep decline in demand for oil services has stabilized. The days of doom and gloom are over. Furthermore, contractors across all service lines note pricing also has stabilized, though at very low rates.

Per-stage pricing for plug-and-perf operations in the Permian appears to be settling in the mid-to-high $50,000 range, down about 30% to 35% from the mid-to-high $80,000 range in fourth-quarter 2014.

Similarly, average spot pricing for 1,500-hp Tier I rigs in the Permian has edged below $20,000, plus or minus $2,500 depending on contractual arrangements. New work—and contractors are reporting that a small number of rigs have gone back to work on the basis of low rig rates—is done on a well-to-well basis. Outside the spot market, contracts cover the spectrum from subsidized contracts, contracts being paid off, re-negotiated contracts and well-to-well contracts. Overall, land contractors have seen rig pricing decline 20% to 25% since the first of the year.

In the Permian, operators moved to massive slickwater fracture stimulation largely as a cost-saving measure to cope with the downturn in commodity prices. In recent months, some operators have begun using resin-coated sand as a proppant to boost recoveries as part of a strategy of lowering the per-barrel cost of new oil. This nuanced shift from an emphasis on lowering well cost to a strategy on lowering the cost per barrel represents an important shift in philosophy, particularly if the industry is in for a long workout at a lower commodity price deck going forward.

Well stimulation firms tell Hart Energy that regional capacity, as measured by crew count, is roughly half the size it was at peak in 2014. Similarly, drilling rig utilization remains at 40% of prior peak, according to contractors participating in the Hart Energy survey program.

Although rising demand has yet to materialize in a significant way, several service providers express concern that a quick demand uptick will overwhelm the depleted crew count in the Permian Basin when it comes to well stimulation.

For workover services, the job mix has shifted to routine well maintenance as operators reduce expenditures by doing only what is necessary to sustain production. Well service contractors note that nearly 80% of the job mix centers on routine well maintenance, with completions accounting for 15%. Routine maintenance accounted for less than 45% of the job mix in early 2015.

Like their counterparts on the land drilling side, workover contractors have noticed an incremental demand uptick—enough to convince them of market stabilization but not enough to engender hope for better pricing. The industry will need higher oil prices for that. E&P

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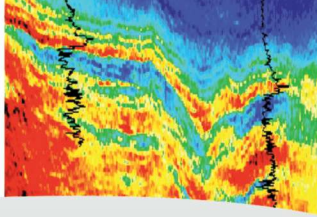

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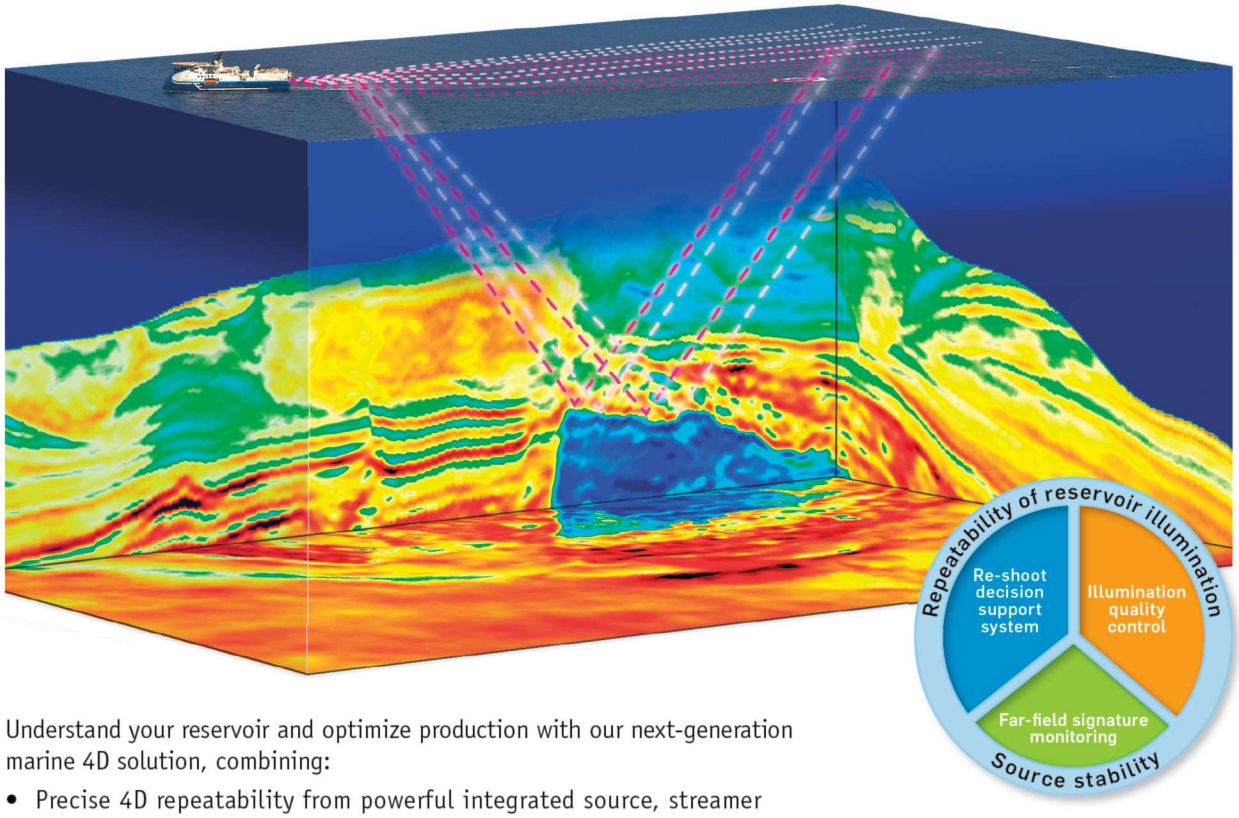

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A small processing shop evolves to hold the world's largest 2-D multiclient library.

RHONDA DUEY
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Four years ago Spectrum Geo brought in several new people at the senior management level. That decision is starting to pay serious dividends for the company.

Spectrum announced a deal July 1 that will make it the owner of the world's largest 2-D multiclient library and a major player in the 3-D multiclient space. The purchase of Fugro's multiclient library, for a total of $115 million, doubled the company's 2-D library and increased its existing 3-D library by 700%.

The 2-D library now comprises more than 3.3 million line km (2 million line miles) and contains 587 datasets spanning 67 offshore territories. Spectrum's data library now spans all of the major sedimentary basins and 3,640 oil fields worldwide. It is estimated to cover 42% of the world's known offshore hydrocarbon reserves, and as Spectrum's geoscientists begin to examine the data for reprocessing opportunities, that number could grow.

Wow. These are big numbers for what began as a small processing shop in the U.K. in 1986. When I first encountered the company, it owned one seismic vessel (which it later terminated) but mostly focused on reprocessing legacy data to define new leads for its clients. That changed in 2012 when the company acquired its first multiclient 2-D seismic survey. Since then it has continued to grow its library organically through ambitious projects like its Pelotas Basin survey offshore Brazil and Uruguay and its recently announced collaboration with Schlumberger and PGS to acquire 80,000 km to 100,000 km (50,000 miles to 62,000 miles) of long-offset 2-D data encompassing all of the major hydrocarbon provinces offshore Mexico.

Spectrum specializes in reprocessing legacy data as well as increasing the size of its multiclient library. (Source: Spectrum Geo)

"Our vision was to become a major multiclient seismic player, and that's what we are now," said CEO Rune Eng. "We're certainly in Division 1 and approaching a library that is of such a size that it's comparable to the bigger players like TGS, PGS and WesternGeco."

Like TGS, Spectrum owns no vessels, preferring to charter them from other companies. "Our business model is to focus on the projects," Eng said. "We believe in the project and not necessarily in the steel."

For Eng, the type of cooperation in the Mexico survey represents "the flavor of the industry." "If you have limited budgets from oil companies, it's better to have cooperation than competing head-to-head in typical multiclient areas like Mexico," he said. "We think this makes a lot of sense.

"We expect that the prospectivity in the Mexican part of the Gulf is probably as good as it is in the U.S. Pemex has done quite a lot, but I think it's time to move on," he said.

The timing of the purchase might seem odd given the current low-price environment, and Eng acknowledged that the multiclient market can be as vulnerable to reduced exploration spending as any other part of the seismic industry. However, he said, "The multiclient model is robust in terms of the adaptation to market fluctuations. Spectrum does not own any vessels, and we will, in a downturn, preserve cash by reducing investments that carry high risk while focusing on sales of our existing database." EP

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Greenpeace damages Seattle marine park; Shell picks up tab

Activists protesting Shell's plans for Arctic drilling caused $10,000 worth of damage in Elliot Bay, paddling off without paying.

The *People's Platform*, otherwise known as the *Solar Pioneer* barge, obviously doesn't like giant Pacific octopuses or it wouldn't be dropping 1- to 2-ton concrete-block anchors on the marine wildlife habitat in Puget Sound that the creatures call home. The barge was the base for Greenpeace protestors that were trying to stop Shell Oil from moving the semisubmersible *Polar Pioneer* to the Chukchi Sea offshore Alaska later this summer.

The marine habitat—Alki Cove 2—is a popular diving spot in the Seattle area. The habitat was damaged by the concrete anchors and mooring lines that were not deployed properly to withstand tidal movement.

According to an Associated Press article May 25, the Washington Department of Natural Resources (DNR) investigated the damage and ordered the anchors and mooring lines to be removed from Seacrest Park. A DNR spokesman said the damage to the habitat was minimal and Greenpeace would have to pay for the cleanup.

A concrete anchor is removed from a marine wildlife habitat in Puget Sound, where a Greenpeace barge dropped it. The cleanup cost $10,000. (Source: Global Underwater Explorers)

Another environmental group, Global Underwater Explorers (GUE), was upset that Greenpeace would cause environmental damage and not clean up its mess. GUE was willing to coordinate clearing up the mooring lines and anchors but didn't have the finances for the task, and Greenpeace didn't offer to fix its mess either.

It just so happened that one company was more than willing to help with the funding—Shell Oil. GUE sent an email to Shell CEO Ben van Beurden. Shortly thereafter, GUE was very surprised to get a call from Shell in Alaska saying, "We'd love to help." Koos du Preez, a Seattle-based GUE instructor, welcomed the offer.

Shell paid for the cleanup and enlisted the help of Foss Maritime, barge-owner John Sellers, and Global Diving and Salvage. Two teams of GUE scuba divers helped. Score one for the oil industry.

Shell was still condemned as the villain. In several news reports, Du Preez said, "If Shell wasn't in the area, the activists wouldn't be in the area, and none of this would have happened. I and our group consider this whole incident as collateral damage."

In other words, Greenpeace gets a free pass. Greenpeace doesn't seem to mind causing damage to the environment to protest environmental damage. As a matter of fact, the organization is making a habit of it. Just ask the Peruvian government.

At the end of 2014, 20 Greenpeace activists unfurled a banner near a hummingbird figure that was carved into the Plains of Nazca in southern Peru about 1,500 years ago. This is a UNESCO World Heritage Site, and visits are closely supervised; even presidents and ministers have to get special permission.

But Greenpeace's message of "Time for change! The future is renewable" was more important. That message could be worth up to six years in prison for the perpetrators. Greenpeace actually apologized for this publicity stunt, but Peruvian authorities were not impressed.

The end justifies the means for Greenpeace even to the detriment of safety and the environment. EP

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Up to a challenge?

New initiative seeks fresh ideas to reduce and reuse water in onshore shale development.

JENNIFER PRESLEY
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Read more commentary at
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Collaboration is not a new concept, but it is one that can be swept aside in the rush to be the first to market or shelved when inconvenient due to humankind's competitive spirit. However, it is a concept that has of late been rediscovered, thanks to a variety of factors like rising costs and declining profits. Finding lower cost alternatives that are easier on the environment while maintaining or increasing oil and gas production is one of the industry's tougher challenges. Realizing that the possible solutions to the challenge may require the casting of a much larger net, GE and Statoil teamed up earlier this year in their "Powering Collaboration" joint technology program.

The collaboration was launched in January as an ambitious joint technology-focused program to drive industrial solutions to some of the biggest challenges facing global oil and gas production. The initiative seeks to reduce the environmental impact of oil and gas development and production by accelerating the development of environmentally and economically sustainable energy solutions, a GE-issued press release said.

In addition to the collaboration initiative, the companies launched a global open innovation challenge. The first challenge aimed to address the use of sand in unconventional resources. The call for entries for the second challenge was announced in July. The focus of the second challenge is on water usage in the development of unconventional oil and gas reservoirs.

"This collaboration with Statoil is centered on both our companies' commitment to continued investment in technology and innovation to help develop low-cost and more efficient energy solutions. We recognize that great ideas transcend any one company or geography, which is why we've launched this open innovation challenge," said Eric Gebhardt, CTO at GE Oil and Gas, in the press release. "We invite individual innovators, institutions and companies large and small from around the world to co-develop potential solutions to make energy production more sustainable by improving the use of water in unconventional operations."

This second challenge seeks to find innovative solutions to both reducing freshwater usage and treating and reusing water from development activities while maintaining or improving productivity, the press release said.

"Ideas at any scale are welcome," said Lars Høier, senior vice president of R&D and innovation for Statoil ASA. "Even incremental strides in improving water management can add up to significant conservation gains. Wherever possible we try to reduce freshwater usage; for example, we recently successfully fractured two wells with 100% produced water, saving 3.5 million gallons of freshwater per well—and we are eager to do more to help move the industry toward better water conservation."

In this challenge, up to five winning entries will win a prize of $25,000 each and the opportunity to be eligible to receive additional funding from an available discretionary prize pool of $375,000 in development funds. In addition, the two companies will leverage their joint assets and resources to support the commercialization of the winning submissions. EP

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Standardization just innovation by another name

Things can move slowly in the offshore world, and we're not talking about the leviathans of the deep here.

JOHN SHEEHAN
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jsheehan@hartenergy.com

Read more commentary at EPmag.com

Take the subsea industry, for example. The average time taken from an initial idea—that "eureka" moment—to implementation in the field is 30 years.

That's according to Pål Helsing, president and executive vice president of Kongsberg Oil and Gas Technologies, speaking at a recent industry conference.

Thirty years is a long time in anyone's books. Understandably, the subsea industry is looking to speed things up a bit and, at the same time, cut costs in the low oil-price environment.

The way to achieve this is through innovation—not necessarily through technological advances but by thinking outside the box.

Helsing told the Underwater Technology Conference in Bergen, Norway, "Innovation is about creating something new that is valuable and can be implemented. Innovation can be many things. It can be technical, organizational, in how we write technical requirements, the whole process."

> "To achieve standardization, collaboration between operators and technology suppliers at the earliest stage of the cycle is essential."
> —Mike Garding, OneSubsea

And this brings us back to the old chestnut of standardization, which, let's face it, has been around as a discussion topic for a few years now. Per Sandberg, chief of innovation at Statoil, said, "I'm very happy that standardization is talked about as an innovation. The success of subsea has been driven by technological magic—one technological piece of magic after another. But innovation can be many things; it doesn't have to be a technological solution."

"We are addressing the fact that we have probably made things too complicated. We have tailor-made too much. The solution is simplification and standardization of the interfaces of the module types, etc. It is not about technology; it is about collaborating, cooperating and agreeing."

Helsing highlighted BP's Well Advisor digital solution, developed in collaboration with Kongsberg. The technology uses sensors on the drillstring to detect friction as the well is completed and alerts the drilling team before it becomes a problem.

According to Helsing, it is being used globally on 26 of the operator's rigs and has been 100% successful in avoiding stuck pipe in hundreds of runs of well casing, saving an estimated $200 million in reduced nonproductive time.

Another speaker, Herve Valla, CTO at Aker Solutions, highlighted the fast-track development of the riserLOCK system, which has been developed to enable the quicker connection of risers. "It makes the connection faster and avoids having people in the rig zone, which is a huge health and safety advantage for the operator," he said.

Both of these examples were achieved with cross-industry collaboration, something OneSubsea's CEO Mike Garding sees as going to the heart of the matter. "To achieve standardization, collaboration between operators and technology suppliers at the earliest stage of the cycle is essential," he said.

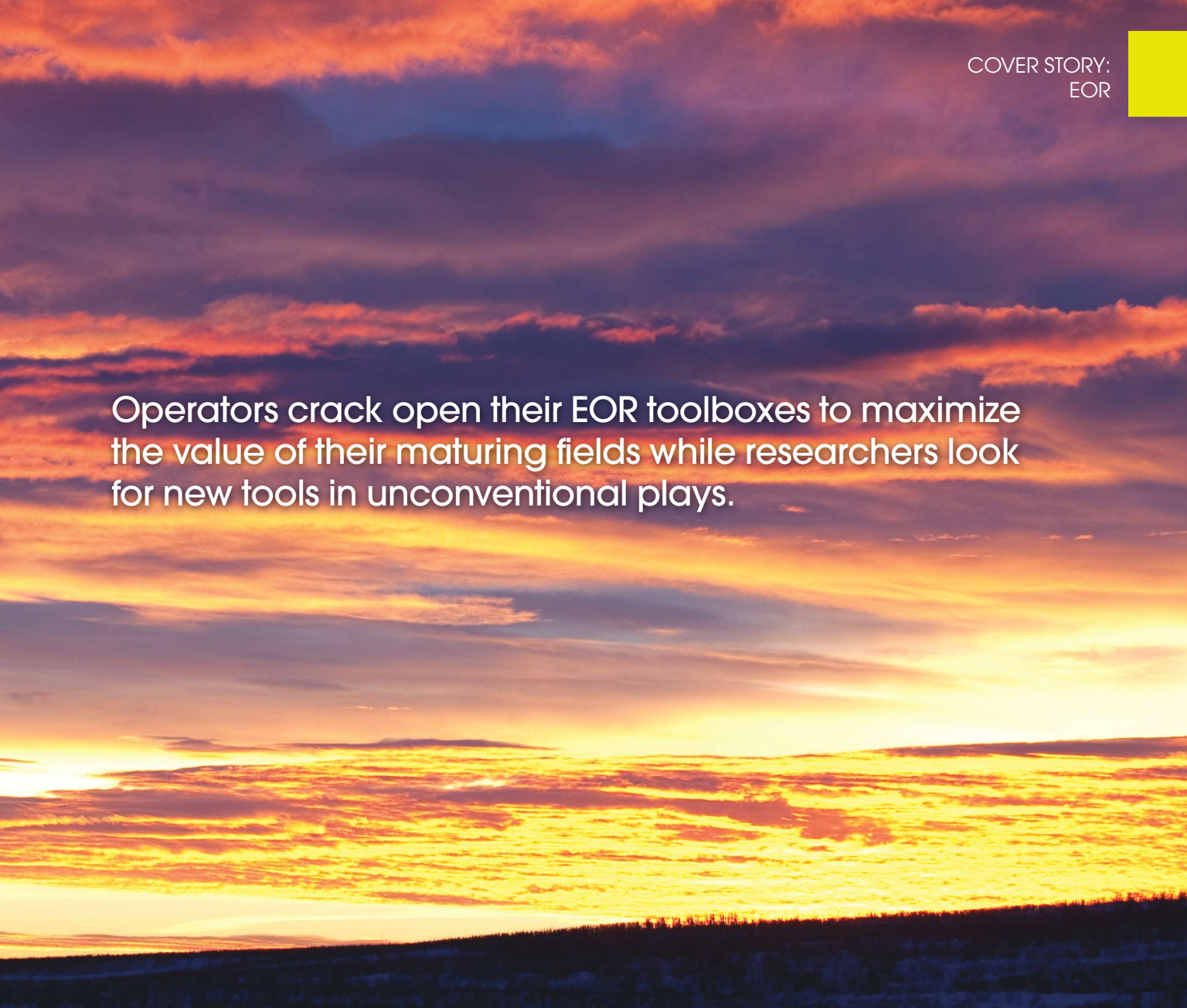
"In addition, reusing field-proven designs is a standardization strategy that would reduce capex and shorten cycle times by eliminating reengineering, qualification and documentation."

Looks like standardization is just innovation by another name. EP

Open FOR BUSINESS

Extracting maximum oil from mature fields in a cost-efficient and safe manner is a puzzle that operators have long toiled over. Once the easy-to-produce oil has been recovered, out comes the EOR toolbox. When the extension of a reservoir's natural drive through waterflooding or gas flooding comes to an end, operators can utilize a variety of tools to squeeze out the last recoverable drops of oil. And like the TV infomercials of old, the call of "but wait, there's more" rings with a fourth option from the reservoir's residual oil zones (ROZ).

Fields like the North Sea's Forties—nearing its 40th anniversary of first production—or the Permian Basin's Scurry Area Canyon Reef Operators Committee (SACROC) unit—with 67 years of operation—are producing today due to continued evolution and application of EOR technologies.



Operators crack open their EOR toolboxes to maximize the value of their maturing fields while researchers look for new tools in unconventional plays.

What does the future hold for EOR? According to a Markets and Markets report published earlier this year, the EOR technology market is expected to grow at a healthy rate of 18.2% between 2014 and 2019, with the chemical EOR market estimated to be one of the fastest growing markets.

The EOR toolbox is large, and for one operator, pre-screening chemical EOR methods helped determine the best EOR strategy to apply in its deep-water reservoirs. Operators in the Middle East are looking for new techniques to enhance recovery in carbonate reservoirs. The challenge of increasing recovery in the tight Bakken Shale with the aid of CO_2 is under the microscope as researchers at the University of North Dakota look to bump up the play's recovery factor. Meanwhile, studies in the Permian Basin are uncovering methods to produce the once unproducible ROZ. ■

Middle East bucking the trend in drive for new EOR technology

New techniques will play a major role in enhancing carbonate recovery.

Dr. Patrick O'Brien, Denike Onyia and **Giuseppe Astarita**, ITF

The majority of daily oil production in today's market comes from mature or maturing fields. New discoveries of recoverable reserves are failing to match the pace set by the growing global demand for energy.

This, in turn, increases the requirement for new technologies that can enhance recovery from both active fields and future discoveries.

The hydrocarbon resources found within carbonate reservoirs are in particular need of innovative new technologies to facilitate their economic exploitation. Carbonates are of critical importance to the oil and gas industry, with more than 60% of the world's oil and 40% of its gas reserves trapped in such carbonates. Despite this, recovery factors using primary, secondary and tertiary methods from carbonates are significantly lower than that of sandstones.

The high oil price period of recent years resulted in both an increased interest in EOR R&D and a willing-

EOR advances are in the pipeline. According to ITF, carbonates are of critical importance, with more than 60% of the world's oil and 40% of its gas reserves trapped in such reservoirs. Carbonate fields dominate the Middle East region, and NOCs there are continuing to invest substantially in developing new EOR technologies despite a relative downturn in investment elsewhere in the world, as depicted by an artist's conceptual rendering. (Source: ITF)

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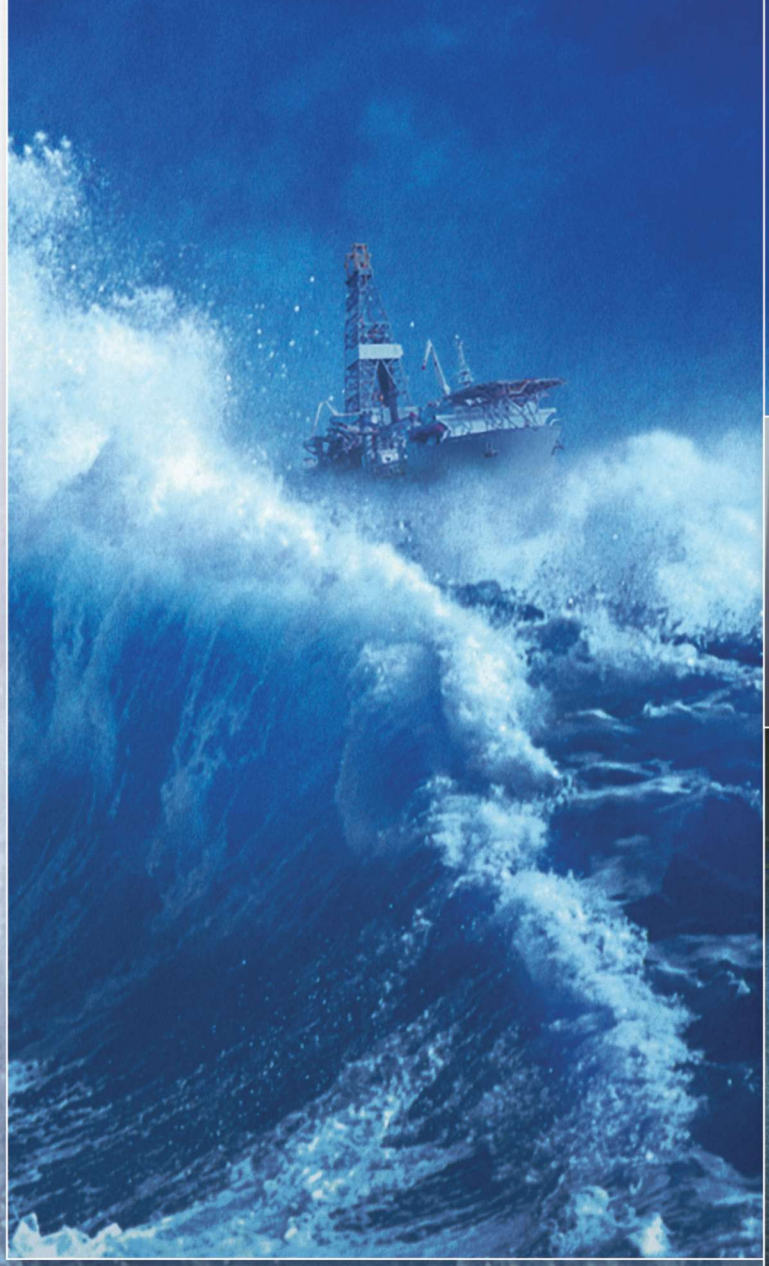

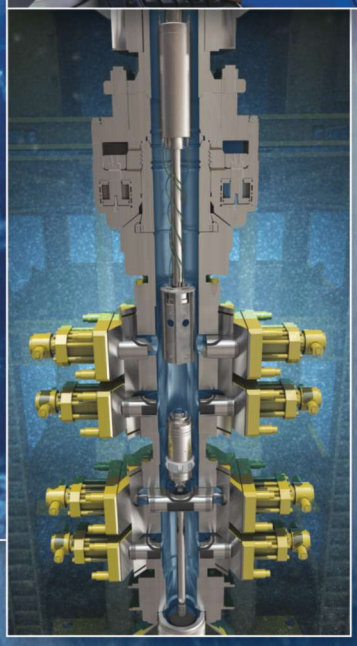

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ness to invest substantially in a wide range of techniques and approaches. There is concern that this enthusiasm is now diminishing due to last year's fall in the oil price and its sustained lower level at the current time, with companies sticking to the less-costly tried and tested waterflooding technique as the preferred method of enhancing oil production.

Middle East drive

Carbonate fields dominate the Middle East region, with approximately 70% of oil and 90% of gas reserves held within carbonate reservoirs. The upstream industry in this region is, however, still reasonably buoyant compared to elsewhere in the world, despite the slump in the oil price. In addition, companies are continuing to invest in developing potential fields while other regions have and still are cutting back.

The Industry Technology Facilitator (ITF)'s Middle East-based members in particular are showing significant appetite for developing new technologies that can help them maximize their returns from carbonates. The organization's EOR/carbonates workshop in Kuwait in January 2015 was the first such initiative and focused solely on its Gulf Cooperation Council (GCC) members. These include major players such as Petroleum Development Oman (PDO), Qatar Petroleum, Kuwait Oil Co. and ADMA-OPCO.

ITF has been active in the Middle East for a number of years and has done a great deal of work to build up trust, promoting and spearheading collaborative activity in the region. The workshop was the first time member companies had collectively shared ideas and, following discussions with world-leading experts and academics, the group agreed on three main EOR techniques in carbonate reservoirs for further development:

- Low salinity;
- Miscible and near-miscible gas injection; and
- Foam flooding.

EOR remains high on the agenda for operators in the Middle East given the large amount of onshore reserves contained in the region, with the expectation that much more can be extracted by improving the extraction rate. The costs are relatively low in comparison to the North Sea, for example, with the complications that come with working offshore.

EOR methods

Currently there are several methods that are most commonly used in increasing and/or enhancing oil recovery, including CO_2 injection, steam injection, waterflood injection and reservoir stimulation.

There have been successful deployments of some of these methods in carbonates, but there remains much room for improvement. This presents an opportunity for the development of advanced secondary and tertiary technologies that may mitigate the current low recovery rates from carbonates as well as enhance current recovery rates from sandstone reservoirs.

Principally, the factors behind the low recovery rates in carbonates are low wettability, natural fractures, and highly heterogeneous and seemingly unpredictable static and dynamic reservoir properties. Hence, further research is necessary to improve understanding of these factors and their impact on various EOR techniques.

Stepping stone

A drive toward low-salinity injection, miscible and near-miscible gas injection, foam flooding, and nano-surfactant enhancement technologies could prove to be a vital stepping stone in improving recovery from carbonates.

In maturing basins worldwide any such improvement in recovery rates could prove to be the vital boost needed in order for them to remain economically viable and to ensure that future issues of supply and demand are better managed and controlled.

Studies estimate that a mere 1% increase in the global efficiency of hydrocarbon recovery could raise conventional oil reserves by up to 88 Bbbl, the equivalent of three years of annual production at today's levels.

Collaboration

ITF's role in the Middle East is evolving from initially instigating collaborative ventures into facilitating project work and technology development.

U.S.-based ProSep, for example, last December launched a 12-month joint industry project (JIP) with Qatar Petroleum and PDO, with the contractor and the two national oil companies (NOCs) collaborating on an offshore-capable unit for oil-in-water removal and media regeneration. This project marked the first truly collaborative ITF-sponsored JIP between two NOCs in the region.

By working with its GCC members, ITF is looking to develop a collaborative technology roadmap that has been pivotal in bringing the Middle Eastern companies together to share ideas. The results of the workshop earlier this year suggested that there were two further areas of interest—not only EOR but also the reduction of the environmental impact of the activities of the oil and gas industry.

ITF is working with its Middle East members to collaborate with developers on innovative projects. One such proj-

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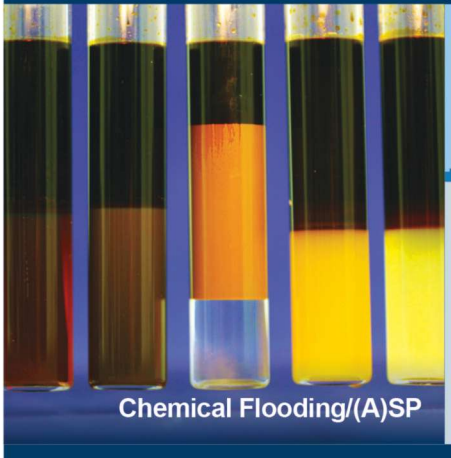
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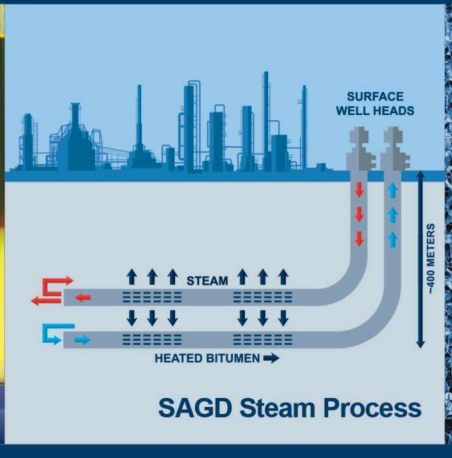

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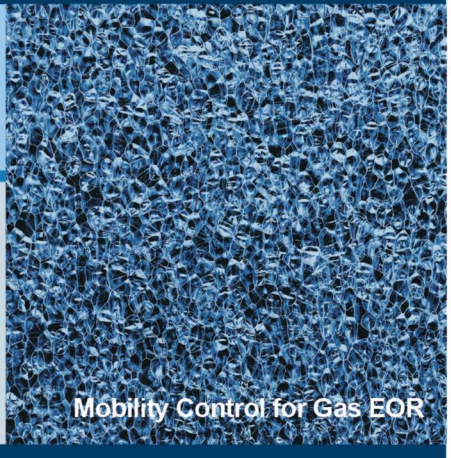
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ect is Cyclone, an initiative centered on real-time production logging, while another is the Imperial College London's Waterfront Imaging Using Self–Potential, which could allow imaging of waterfronts several tens to hundreds of meters away from an instrumented well. Both of these could initiate a new approach among the GCC members.

The vision for ITF is to see local collaboration tapped into a global agenda as has been achieved by the organization in Brazil, which has a similar interest to the Middle East in carbonate reservoirs.

Recovery rise of 30% to 60%

The overall contribution from EOR techniques has remained relatively stagnant over the long-term at around 3.5% of daily global production, and it is primarily used to target immobile oil that cannot be produced from primary and secondary methods.

Commonly, an increase in production of between 30% and 60% of a reservoir's original oil-in-place is expected, with the global average recovery rate from hydrocarbons currently somewhere around the mid-30s percentage range.

This emphasizes the need for new technologies capable of increasing recovery trends in oil production, particularly for carbonates. If the large quantities of resources found within these reservoirs can be exploited to a similar level as clastic reservoirs currently exploited by EOR techniques, it may go some way toward alleviating the plethora of issues related to rising global energy demand. EP

EOR remains high on the agenda for operators in the Middle East, with an opportunity to further develop advanced secondary and tertiary technologies to mitigate current low recovery rates from carbonates there. (Source: ITF)

PDO undertakes ambitious EOR project

By **Rhonda Duey,** Executive Editor

Solar energy and fossil fuels don't have to compete. GlassPoint Solar and Petroleum Development Oman (PDO) recently announced plans to build one of the world's largest solar plants to provide steam for thermal EOR. When complete, the plant will generate up to 1 GW of energy.

Miraah (meaning "mirror" in Arabic) will be located in South Oman near the Amal Field, which requires steam injection to produce heavy and viscous oil. The steam is currently generated by burning natural gas, and the two companies anticipate that applying solar power will save 5.6 TBtu/y, an amount that could provide residential electricity to 209,000 people.

Already the two companies have built a pilot facility at Amal to test the commercial viability of solar steam. The facility has produced 50 t/d of steam and is capable of producing 7 MW/d. The pilot facility will continue to operate alongside the full-scale development.

When complete, the new facility will generate 6,000 t/d of steam and will comprise 36 glasshouse modules covering 3 sq km (1.2 sq miles). It will use GlassPoint's concentrating solar power technology, which uses large, curved mirrors to focus sunlight on a boiler tube containing water. The concentrated energy boils the water to produce high-quality steam, which is fed to the field's existing steam distribution network.

A self-cleaning glasshouse encloses and protects the solar collectors from wind, sand and dust storms. The wind-free environment allows the mirrors and other components to be thin and lightweight. This produces significant savings over exposed solar thermal systems.

"This is one tiny step for the oil and gas industry, but it will be one of the largest solar projects in the world," said John O'Donnell, vice president of business development for GlassPoint. "It's all available technology, and it's completely automatic. It operates itself." ■

Recognition, exploitation of ROZs coming of age

EOR projects are producing formerly immobile oil.

L. Stephen Melzer, Melzer Consulting; and
Robert C. Trentham, University of Texas of the Permian Basin

Studies sponsored by the Research Partnership to Secure Energy for America (RPSEA) and the U.S. Department of Energy (DOE) have opened the door to a whole new set of opportunities for commercial development of residual oil zones (ROZs) throughout the world. The historical understanding of the zones beneath the oil/water contacts in reservoirs had been relegated to the category of transition zones wherein capillary pressure and surface tension controlled the bottom of a reservoir, where there exists a mixed oil-and-water zone of several meters to tens of meters.

Recent research has shown that the zones below many oil fields are not only hundreds of meters thick but often possess an interval of nearly constant residual oil saturation sandwiched between the upward transition to mobile oil (main pay zone) and a lower transition to zero oil saturation below (Figure 1). These ROZs also are commonly observed to possess 20% to 50% oil saturation but with only mobile water. The research shows that they are present in extensive regions between oil fields.

With these ROZ observations as the basis, three types or origins of ROZs have been identified. All of these can be thought of as natural waterflood of a paleo oil entrapment. All come after the subsidence, oil generation and oil migration stage of a basin. They owe their presence to a post-entrapment tilt of the paleo trap, which can be a local or basinwide event; leakage or breach of the seal above the reservoir; or tectonic event on one side of a basin that creates an outcrop of the reservoir formation(s) and causes a lateral movement of meteorologically derived water through the basin to outcrops on the downdip side of the basin. This last type is being studied extensively today in the Permian Basin's San Andres Formation and in the Tensleep Formation in the Bighorn Basin of Wyoming.

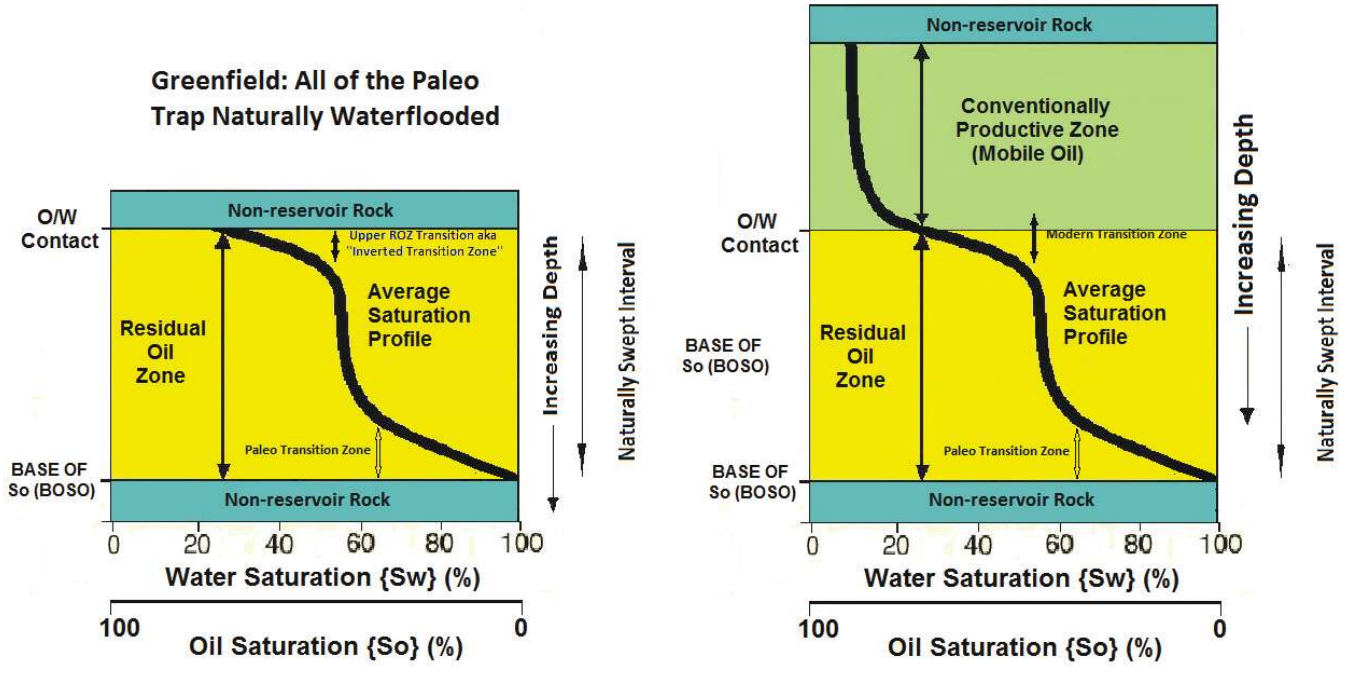

FIGURE 1. This figure shows greenfield and brownfield ROZs illustrating upper and lower transition zones. (Source: RPSEA)

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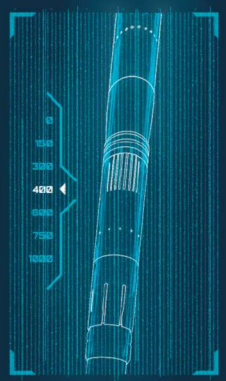

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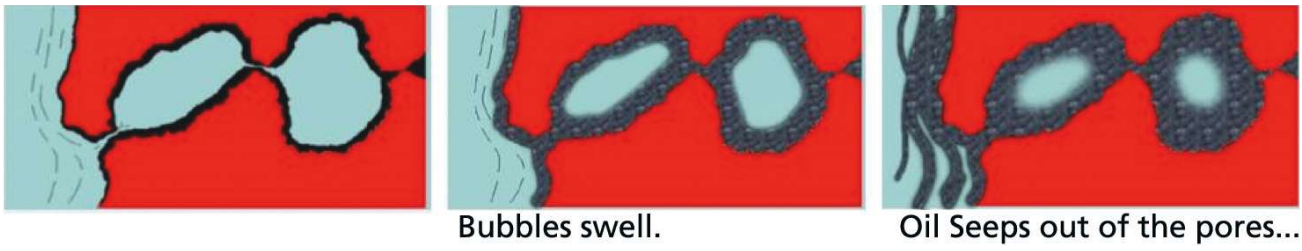


FIGURE 2. ROZs have oil affixed to the rock surfaces. If that oil has gas in it, depressurizing releases some of the oil and entrained gas into the flowstream of the well. (Source: RPSEA)

Permian study

The Permian Basin work sponsored by RPSEA has just completed a four-county study of the area between oil fields in what has been dubbed greenfields (Figure 1). The areas have no well infrastructure in place since all of the wells drilled there were dry holes. The RPSEA-sponsored work has identified 76 Bbbl of high-quality target ROZ reservoirs where the oil saturations exceed 25% and the formation porosity exceeds 8%. ROZ resources have to be produced by processes that alter the properties of the oil to render it mobile. The four-county region encompasses approximately 10,620 sq km (4,100 sq miles) and includes 12 ROZ CO_2 EOR projects.

Today the Permian Basin plays host to a total of 15 individual CO_2 EOR projects exploiting the ROZ. By conservative measures, these newly implemented projects are producing more than 12,000 bbl/d of formerly immobile ROZ oil. Most of these projects involve deepening the wells in an oil field into the ROZ (brownfields), but two have recently been completed in greenfield areas. The Tall Cotton project in Gaines County, put into operation late last year by Kinder Morgan CO_2 Co., is especially notable in its potential size. Today the project consists of nine injectors and 14 producers on a 40-acre five-spot configuration. While industry is leading the deployments, the ROZ work sponsored by RPSEA clearly has provided much of the scientific platform for the ongoing commercial work.

One of the characteristics of ROZs, especially the upper portions, is that when drilling through the formation, the oil and gas "shows" from those intervals of immobile oil are equally as enticing as oil shows from the main pay zones. Some drilling includes coring, but even this often gives false indicators of mobile oil. As a result, many vertical well completions have been tried, making very large volumes of sulfur water with noncommercial volumes of oil.

Very recently, some operators have utilized the evolving technologies of horizontal drilling and staged hydrofracturing completions to attempt to establish commercial production in these intervals. There are several examples of 1.6-km- (1-mile-) long laterals with peak production levels of 250 bbl/d or more of oil and projected ultimate recoveries of 250,000 bbl or more of oil. Total well costs are such that the economics are working at $60 oil prices if water disposal costs can be controlled. The typical initial water production rate is 1,500 bbl/d to 2,000 bbl/d accompanied with no oil for 30 to 40 days. After that period oil cuts rise to 10% to 25% as the well matures.

Understanding ROZs

The production concept is not yet widely recognized as the industry's grasp of ROZs and their origins is not widespread, and understanding of the mostly oil-wet ROZs is still immature. Some believe the oil is coming from the mobile portion of the fluids in the transition zone. However, time should prove that the oil is actually residual oil that has sufficient gas in solution to cause the immobile oil of the ROZ to break out as the pressures decay, analogous to the solution gas drive mechanism long witnessed and modeled in the mobile oil portions of reservoirs. Figure 2 shows the principles of this process, tentatively dubbed depressuring EOR (DEOR) or depressuring the upper ROZ (DUROZ).

The ROZ researchers are beginning to believe that such discoveries are in no way exclusive to the Permian Basin but will soon see deployment in a variety of basins throughout the world. In fact, it is highly likely that most of the so-called dewatering plays around the U.S. are not connecting up mobile oil compartments in reservoirs but are, in fact, an ROZ depressuring play, at least in part.

Finally, it is interesting to reflect on the amazing explosion of new ideas and production occurring in the U.S. today. It is clearly a product of a number of factors, but the availability of research-sponsoring organizations such as RPSEA and DOE is very significant. Just as important are private mineral ownership, the availability of capital and the wealth of entrepreneurs who are willing to experiment on new things in the oil and gas producing and service sectors. Taken collectively, they have all combined to be the accelerant for the innovation being witnessed today. Producing the ROZs by CO_2 EOR and DEOR/DUROZ are two examples. EP

EOR in the Bakken

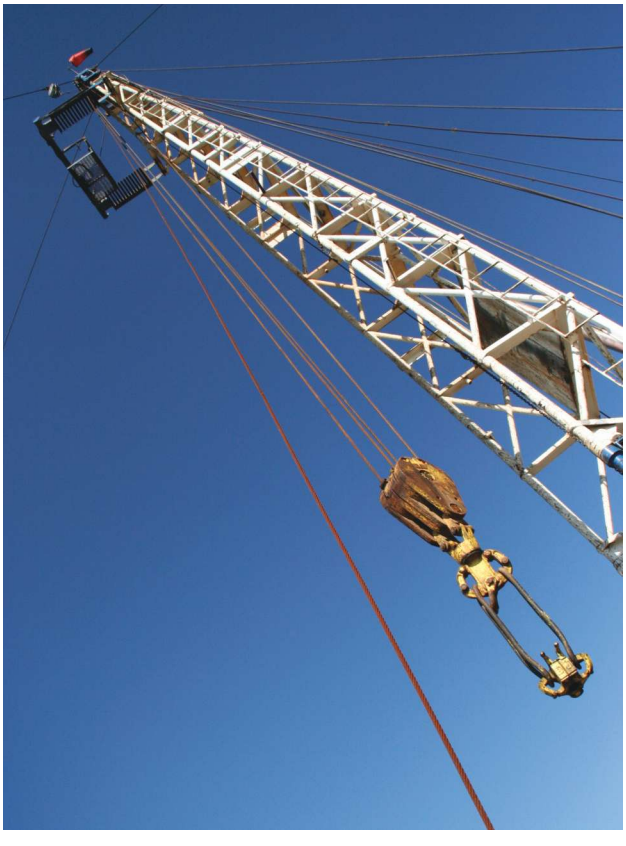
A research project is attempting to free up the vast amounts of residual oil in this world-class play.

Rhonda Duey, Executive Editor

As of April 2015, the Bakken Shale was producing 1.1 MMbbl/d of oil from almost 10,000 wells. But that's the tip of the iceberg.

At the University of North Dakota's Energy & Environmental Research Center (EERC), researchers were concerned about the low recovery factor in the play, on the order of just 4% to 6% of original oil in place. "We started looking at ways to meaningfully change that," said John Harju, associate director for research.

Standard IOR techniques like waterflooding were quickly rejected because of the oil-wet nature of the rocks. The researchers then settled on examining the utility of CO_2, and a research project was born.



The EERC is working on CO_2 injection for EOR. (Source: EERC)

Phase I

Harju said that the project was a "collision of opportunity and necessity." The U.S. Department of Energy was interested in exploring carbon capture and sequestration, and using captured CO_2 for EOR seemed like a win-win. "EERC has been busy looking at how we can take this challenge that the power sector has and try to create some economic return for the cost of capturing CO_2," Harju said. "EOR has been one of the things we've been looking at."

Early industry efforts involved several field tests. None of them can be considered a technical success, he said, but they were instructive in the EERC consortium's Phase I efforts and led to several laboratory tests and simulation work involving reservoir characterization.

Overall, Phase I led to several conclusions:

- CO_2 has the potential to remove more than 90% of the oil in the reservoir rocks (Middle Bakken and Three Forks) and more than 60% of the oil in the shales (Upper and Lower Bakken);
- The CO_2 flow will be dictated by the fractures, not the rock matrix;
- Therefore, it's important to understand the natural fracture network; and
- Modeling results indicate that CO_2 EOR is feasible.

Phase II

Harju said that the second phase actually consists of an "A" and "B" phase, but overall the goals are to select potential injection and production schemes as well as to determine whether to fracture the wells and which member to place them in. More experiments are required to improve the understanding of oil/ CO_2/natural gas phase behavior and rates of CO_2 diffusion in different rocks. And efforts to further improve reservoir characterization will include microfracture characterization, hydrocarbon extraction data on key Bakken and Three Forks lithofacies and integration of these improved data into the existing models.

Harju described Phase 2A as an attempt to marry the observations in the lab with actual field results. "We have Schlumberger, Baker Hughes and CMG all making meaningful contributions and helping us in the simulation space by providing their software platforms and

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The EERC's Plains CO_2 Reduction Partnership *(undeerc.org/pcor)* has conducted several field validation tests that confirmed the effectiveness of CO_2 storage in the Bakken. (Source: EERC)

their development teams, while Kinder Morgan's reservoir simulation team has been actively engaged as well," he said. "It's just physics, but it's poorly understood at this point. So trying to upscale and model what we observe in the lab is challenging with traditional software packages."

Phase 2B will involve the detailed field experimental work once a scheme is decided on in Phase 2A. Continental, Marathon, Hess and XTO are the "anchor" operating companies for this phase, and currently these companies are examining their portfolios to find the ideal test site for the demonstration project. This project could happen as early as late third-quarter 2015, he said.

As of press time, a site had not yet been selected. Harju said that choosing the site requires a balance between the design of the experiment and the economic constraints based on the current downturn. However, he said, with the rig count down, more staff time is available for these types of projects. "That's a little bit of a silver lining for this project from that otherwise dark cloud of depressed prices," he said.

The biggest challenge, oddly, will be sourcing the CO_2. Despite the government's incentives to capture carbon emissions, the Williston Basin has limited infrastructure. Harju said there is only one existing pipeline and two meaningful supplies of CO_2 in the basin. While new sources are coming online and new pipelines are planned in the next few years, meaningful CO_2 EOR in the Williston Basin could require as much as 200 Mt annually to achieve the estimated recovery potential. Current emissions from all of the coal-fired power plants in the state are 35 Mt/y.

Phase 3?

Phase 3 will likely take the learnings of Phase 2 to a commercial scale, Harju said. "As we contemplate Phase 2 right now, I think we're comfortable that it's a fairly limited injection volume in a very carefully designed way that will elucidate unknowns that we think we have new insights on," he said. "Let's say we answer all of the questions we had hoped to in Phase 2. Then, in my mind, Phase 3 would be a commercial-scale pilot project."

The team also has been looking into opportunities with rich gas to evaluate the utility of some of the higher Btu gas as an EOR fluid. "Our lab work in that space is very encouraging, especially the higher Btu gas with considerable ethane, propane, butane, pentane and so on," Harju said. "It tends to work really, really well in the lab work that we've seen thus far." E&P

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Unlocking reserves in deepwater fields

Pre-screening helps determine the best EOR strategy in this case study.

Álvaro Fernández, Repsol-Sinopec Brasil,
and **Sonia Embid**, Repsol Technology Center

Around 55%, or 3 Tbbl, of the world's total conventional oil resources have so far been left untouched as current technologies are not advanced enough to reach them. At the same time, the rate of replacement of the produced reserves by new discoveries has declined steadily over the last decade. As a result, optimizing mature oil fields through the use of EOR technologies presents a profitable opportunity for oil companies.

In this study, different chemical EOR techniques (such as polymers, surfactants and low-salinity waterflooding) have been tested in a turbiditic oil field offshore, with a medium-heavy gravity oil and a high formation water salinity of between 80,000 parts per million (ppm) to 90,000 ppm. Repsol is developing new technologies to increase the field recovery factor and will carry out a field pilot test to demonstrate these technologies and to extend their application to other areas of the field.

The investigations are supported by chemical screenings and lab core flood at reservoir conditions with rocks and fluids from each reservoir. The investigation is indicated clearly in the case study, and the promising techniques are low-salinity water and polymer floodings. These show an increment of the recovery factor between 15% and 25% of stock tank oil initially in place at laboratory scale above waterflooding. The case study also describes the basic methods used in numerical simulation at the lab core level and the scale-up parameters required at field scale simulation to determine the best EOR strategy.

Range of applications

The average recovery factor (RF) of light and medium crude oil deposits is around 30% to 35% after conventional recovery. Figure 1 shows that a tertiary step can be added to increase the amount of oil recovered through various EOR technologies and indicates the range of applications of EOR technologies based on viscosity, depth and lithology with more than 1,500 projects being evaluated.

In general, thermal methods apply for heavy crudes, and gas and chemical injections apply more for light and medium crudes. To increase the RF, the most appropriate EOR technology must be used. This requires a detailed evaluation of the reservoir and fluid characteristics and the identification of production mechanism. In this context, parameters such as viscosity, mobility ratio and residual oil saturation (ROS) are critical for the effectiveness of EOR.

Typically, steam and miscible gases impact viscosity and ROS, while polymers improve the mobility ratio and sweep efficiency but do not impact the ROS. Usually, the

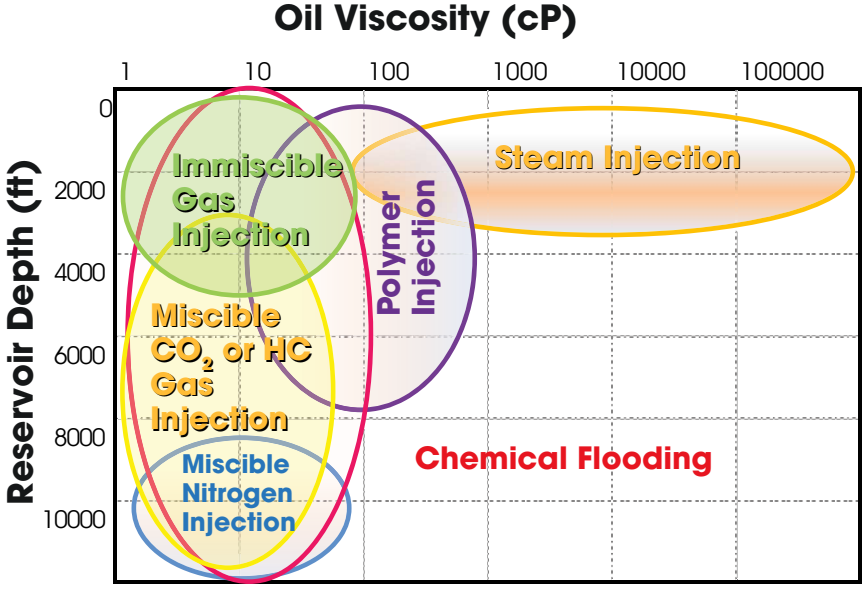

FIGURE 1. This figure shows the typical range of EOR technology applications. (Source: Repsol)

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RF increase in chemical EOR projects is between 5% and 10% for polymers and between 10% and 20% for surfactant projects. The operating costs of polymer EOR ranges between $1.50/bbl and $4/bbl of incremental oil recovered. Meanwhile, the cost of surfactant-polymer and alkaline-surfactant-polymer projects ranges from $4/bbl to $8/bbl of incremental oil recovered.

In addition, the quality of commercial chemicals such as polymers and surfactants has dramatically improved, and the ratio of chemicals/crude oil prices has drastically decreased.

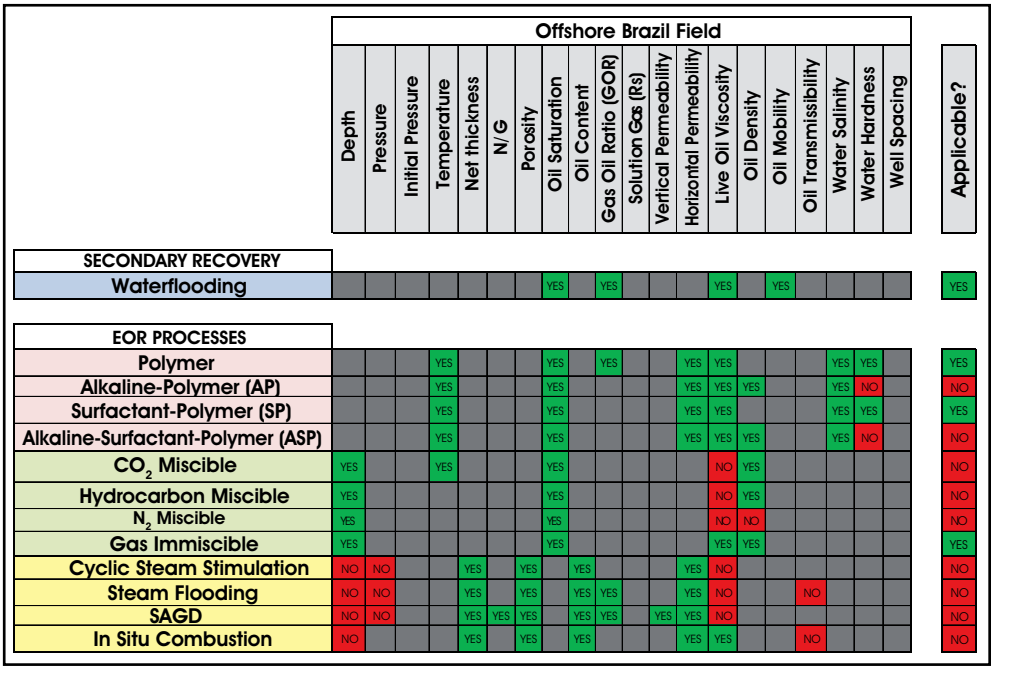

FIGURE 2. EOR case study pre-screening results indicate that polymers provide the best and most cost-effective recovery for this particular field. (Source: Repsol)

EOR technology screening

The case study explores deepwater to evaluate the feasibility of increasing production and the RF with the use of EOR technology. The aim is to determine at field scale the best EOR technology through a pilot test in a selected area of the reservoir. To assess the potential EOR technologies that may be used in this case study, a pre-screening methodology using average properties based on a pass/no-pass gate was used.

The reservoir is a turbidite at a depth of 2,300 m (7,545 ft), with a pressure of 2,650 psi, temperature of 54 C (129 F) and very high-salinity production water. The crude oil is medium-heavy from 16°API gravity to 22°API. Viscosity is between 7 centipoise (cp) and 22 cp at reservoir conditions, and the water table is between 800 m and 1,500 m (2,625 ft and 4,921 ft). The EOR pre-screening results are shown in Figure 2, where technologies that may be applied include EOR chemical processes and gas injection. However, as gas availability in the field for reinjection is limited, this option was not considered. Steam injection was not applicable because of the high pressure and depth.

The quality of commercial chemicals has dramatically improved, and the ratio of chemicals/crude oil prices has drastically decreased.

Program, field pilot modeling

EOR laboratory water and chemical core flood experiments have been conducted using core plugs and oil samples from the field to assess the feasibility of increasing its RF. Core plug samples have air permeability ranging from 2,123 millidarcy (mD) to 3,434 mD and porosity from 29% to 35.1%. All core samples selected were prepared by restoring them to their native wettability condition in the reservoir. Formation brine salinity for the plugs' restoration was 86,000 ppm of sodium chloride.

Two stacks of four plug samples each were mounted to conduct the core displacement tests. The oil from the reservoir shows 20°API, high total asset number and dead oil viscosity of 47 cp at 54 C. The injection water available in the platform is desulfide seawater. Chemical screening outside the

porous medium was performed to select the best formulation (polymer, surfactant/polymer and crosslinked polymer [CLP]) for a chemical EOR process.

Conventional polymer has been selected for working at high salinity as well as CLP that generates its properties as polymer inside the reservoir at high temperature but shows low viscosity during preparation and injection. Three different surfactants were evaluated with an interfacial surface tension close to 10-2 to 10-3 Dynes/cm at a concentration of 2,000 ppm into brine.

Polymer, CLP and low-salinity water (LSW) have demonstrated their technical feasibility as potential chemical EOR methods at field case conditions. LSW has shown very good results, increasing oil recovery by more than 15.5% when compared to the brine injection. Meanwhile, with 4 pore volume (PV) of polymer (1,000 ppm and 2,000 ppm), 14.5% incremental oil recovery has been obtained.

CLP incremental oil recovery was 8.8% but with only 1-PV CLP slug (600 ppm), resulting in a more effective chemical than the conventional polymer. CLP in brine followed by LSW recovery has been 18.7%. LSW followed by polymer shows an incremental recovery of 27.3%, which is much higher than the conventional polymer and brine. A good match of an experimental displacement test was obtained using a CMG-STARS program.

The incremental oil recovery factor of the pilot area was 7.4% for LSW, 6% for CLP, 5.4% for polymer and 6.9% for surfactant polymer for the pilot area. The cost of chemicals per incremental barrel shows the lower value with $2/bbl for CLP, $3.50/bbl for polymer and $6.50/bbl for surfactant polymer. No chemicals have been injected with the LSW due to the limited space available on the platform to install the required equipment to desalt the seawater.

Results

For the experimental program, the main results were:

- Selected surfactants were able to reduce the interfacial tension, but the additional recovery is marginal when compared with the cost of the chemical;
- CLP and conventional polymer present a promising performance in mobility control under reservoir conditions; and
- Synergy effects were observed for LSW-polymer and LSW-CLP. Additional research needs to be carried out to optimize these phenomena.

The experiments obtained key results that were used to improve the modeling and support the scale-up from the lab to the field. Field simulation results showed that the most promising techniques are the CLP, polymer and LSW. CLP has increased RF of 6% over waterflooding with an injected chemicals cost of $2/bbl of incremental oil. Polymer has incremental RF of 5.4% and a chemicals cost of $3.50/bbl of incremental oil. LSW has resulted in incremental RF of 7.4% without chemicals injected; however, additional surface facilities in production platforms and capex need to be evaluated further. EP

Automation optimizes trucking operations

A CTB approach and automation package has improved onsite safety and the bottom line for operations.

Brad Long and Gerald Price, Apache Corp.;
Ricky Strong, Vinson Process Controls; and
Joey Raskie and Al Majek, Emerson

Rapid growth of production in the U.S. oil patch has severely taxed the infrastructure necessary to transport liquids from field locations. Until pipelines can be constructed, trucking can be the only means available. The large number of trips necessary dictates that operators seek out the safest, most efficient means of handling truck load-outs. Consolidation of storage facilities combined with automation techniques can solve the problem and offer other substantive benefits to field operations.

FIGURE 1. The area is characterized by widespread wells over hilly terrain. (Source: Emerson Process Management)

Manual operation

In the northern section of the Texas Panhandle, Apache Corp. has an active drilling program in the Canyon Wash Formation. Largely dominated by conventional vertical single well sites, liquid removal meant a great deal of truck movements within a field (Figure 1). Drivers performed a manual gauging operation that required climbing to the top of a crude oil tank. A sample was taken to determine the water content and the beginning tank level measured. Fluid loading would be executed using a pump mounted on the truck along with a sight glass or flowmeter.

At the end of the load-out operation, the driver would make a second trip to the top of the tank top to gauge the haul closing level. A load ticket would be manually created, with a copy left for the operating company. Field pumper personnel would pick up the tickets within a 24-hour to 48-hour period during their normal rounds.

Centralized operations

To streamline operations, the field configuration was changed to use a central delivery point, or central tank battery (CTB), approach.

The CTB design supports a loading facility intended to handle up to three trucks at a time for crude oil transfer (Figure 2). Central to the concept is a lease automatic custody transfer (LACT) unit implemented with an automation package. Electronics managing the process have to be suitable for harsh outdoor environments. In particular, the human-machine interface (HMI) at each loading spot needs to be easy to read, viewable under strong sunlight and able to hold up to occasional wind-driven rain and hail.

The control package has to accept different styles of inputs from various end devices and execute complex algorithms. The ability to offer custody transfer grade measurement functionality for both gas and liquid streams is preferred so that a common equipment platform can be utilized fieldwide. For this task Apache selected a complete packaged solution supplied by Vinson Process Controls based upon Emerson's remote operations controller (ROC) series of equipment. Included was Tank Manager, a software application specifically designed to handle the demands of onshore production inventory management.

Automated loading

The process begins with level measurement of the storage tanks. Each tank level is monitored by an individual guided wave radar gauge. The tanks are treated as an equalized group all connected to a central header. Based upon the level readings, operations personnel manually select which tanks are to be opened or closed, assuring enough crude is always available for the truck drivers. Level totals are forwarded to a central logistics call center over the company's SCADA computer network. Office personnel track the totals and execute truck call-outs as required.

Upon arrival, a driver parks in one of the three loading areas and connects a vehicle grounding cable. This is a safety practice to prevent sparks from occurring while loading the truck. Lack of a grounding connection will be detected by the controller, and no loading will be permitted to occur. The driver then proceeds to the controller panel. Using the touch screen, passwords such as company identifier and driver IDs are entered to grant loading access. Finally, the driver enters an amount of gross barrels to load—a preset value—and the loading sequence is initiated.

The header from the tanks is piped to two pumps and then to an automated three-way valve. When the sequence begins, product is initially routed to a diverter tank. The ROC monitors the output of a basic sediment and water (BS&W) meter placed on the incoming flowline. Once the reading is within contractual limits, the controller will automatically adjust the valve to route the liquid away from the diverter tank and move it through a Coriolis meter to the truck (Figure 3).

In combination with the Coriolis mass flow data, by monitoring temperature, pressure and BS&W transmitter readings, the Tank Manager program can determine gross barrels, gross standard barrels and net standard barrels (Figure 4). Once the volume preset value is met, the valve is automatically closed and the pump shut off, thereby completing the load. A ticket can be locally printed for the operator and truck hauling company records. Or the driver may input the data from the HMI screen into a trucking company computer and print a copy to be left for the operator records. In either case, an electronic version is sent via the Apache SCADA communications network to the enterprise accounting system.

Should any condition arise requiring a rapid end to the process, an emergency shut-down switch is supplied on the LACT panel, which will immediately stop the pump and cease the load-out operation.

Practical benefits

The CTB approach and its associated automation were chosen to improve both operation efficiency and HSE elements. In practice, the concept proved to meet all expectations.

Of most prominence is the elimination of routine trips to the tops of tanks by personnel. Rain and snow were obvious conditions that increased physical hazards. But even on clear days winds in the Texas Panhandle area can pose a problem. In addition, opening the tanks for manual gauging work always carried with it a risk of excessive exposure to undesirable, possibly even deadly, vapors. With automation in place, these operations are performed infrequently only on an as-needed basis. Concerns over exposure to hazardous gases and inclement weather conditions are significantly reduced.

FIGURE 2. The loading facility handles up to three trucks at the same time. (Source: Emerson Process Management)

FIGURE 3. An Emerson Elite Coriolis meter is at the core of each load-out point. (Source: Emerson Process Management)

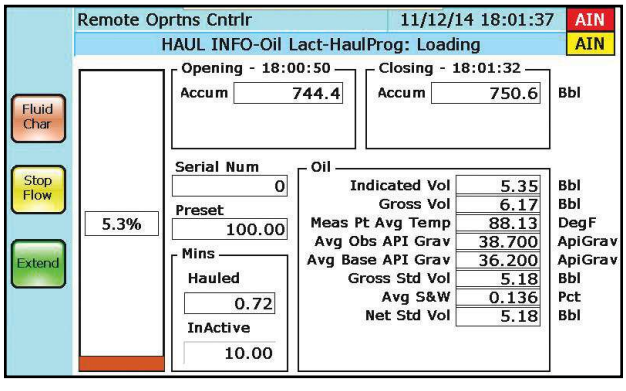

FIGURE 4. The local display shows all necessary information. (Source: Emerson Process Management)

Daily Lease Production Bbl/day	Crude $/Bbl	1% Manual Gauging Loss/ Year	0.1% Coriolis Based LACT Alternative	Annual Revenue Savings
2,500	$60	$547,500	$54,750	$492,750
2,500	$70	$638,750	$63,875	$574,875
2,500	$80	$730,000	$73,000	$657,000
2,500	$90	$821,250	$82,125	$739,125

Figure 5. This figure shows LACT implementation savings. (Source: Emerson Process Management)

From an environmental standpoint, emissions were greatly diminished. Prior to the CTB approach, tanks had to sit for a 24-hour period, venting valuable hydrocarbon vapors to a flare system to make the liquid acceptable for truck hauling. Up to 8% shrinkage was observed in tank volumes. The centralized nature of the CTB method allows crude to be processed by stabilizers, resulting in capture of virtually the entire hydrocarbon spectrum.

The original method required a driver to spend close to two hours at locations widely spread over the field. Loading operations had to be carried out during all hours of the day to keep pace with production. There was constant fear that wells would be shut in should trucks not appear in a timely fashion. In the automated CTB case, this time drops to an average of 20 minutes. Most operations can now be conducted during daylight hours. Furthermore, the CTB location was chosen to maximize access to a paved road; therefore, weather conditions rarely impact operations. Finally, damage to lease roads and the associated maintenance costs dramatically dropped as most heavy truck traffic was eliminated.

Accuracy increases revenues

Consistency of liquid measurement has greatly improved, since the effects of different people with different levels of training and capability are no longer an issue. The meter device characteristics, especially device accuracies, are established by Apache criteria. A driver can still enter manual values if deemed necessary. However, all parameters determined electronically are maintained by the system, allowing comparison to any manual modifications. In nearly all cases, drivers accept the values presented by the automation package.

The potential gross revenue savings at various crude prices is demonstrated in Figure 5.

Quick accounting reconciliation

Manually generated tickets used to be left on site for later pickup by company personnel. Depending upon timing and weather conditions, such pickups would occur within a 48-hour span. Tickets would then be manually entered into the company enterprise system, adding perhaps another day. Since an average day supports around 13 load-outs, by the time tickets were reviewed there could be almost 40 loads performed.

Challenging the result from any particular load was a difficult task. Under the current system, haul logs are retrieved in electronic form via the company's SCADA system. The ticket information is available literally before the truck has left the site. The elimination of the time spent on manual entry is a clear savings. But from an accounting standpoint, another plus to the electronic system is the disappearance of transcription errors and lost or damaged tickets that are inherit in any manual technique.

Overall, the CTB approach coupled with its associated automation package has crafted a formidable solution for improving onsite safety as well as the financial bottom line for operations. E&P

Making balanced connections to reduce rig time

Pressure-balanced connection system for offshore ESP systems eliminates the weaknesses of conventional ESP cable connectors.

John Hirsekorn and Eli Wilson, ITT Corp.

As the terrestrial search for oil reservoirs winds down, bold exploration efforts beneath the sea are bearing fruit. These oil reserves are now being discovered below the surface at depths greater than 3,048 m (10,000 ft). Reservoirs at these depths, such as the Gulf of Mexico's Lower Tertiary, experience pressures as high as 25,000 psi and temperatures of 149 C (300 F).

Electric submersible pump (ESP) lift systems often are used to reach offshore depths and deliver pumping power capable of overcoming ambient pressure. Pumping the heavy bitumen in these deep and ultradeepwater reservoirs requires a delicate control scheme to protect the pump, including regularly stopping and restarting the system. Some oil production companies cite thousands of such stop-and-start cycles throughout the life of one downhole ESP system. Every time a pump is stopped and restarted, it represents a decompression cycle experienced by all the downhole equipment, a major source of material stress.

Adding to the challenges of these production environments, ESP cables must be spliced to reach the depths needed for deep and ultradeepwater plays. This splicing balances the electrical phases but introduces more components that can fail, potentially compromising the ESP string.

Offshore rig time for repairs and installation typically costs in the range of $200,000/d to $400,000/d. Costs for ultradeepwater rigs can exceed $1 million/d. This is in addition to opportunity costs for lost production time, which mount steadily as waiting periods for available equipment can reach weeks or even months.

Typically, rigging needs take shape under two different scenarios: planned installations and unplanned repairs. Both scenarios are more challenging in the ultradeep conditions of modern offshore wells. Technological innovations can help mitigate these challenges. Rig installations, for example, can be made more efficient by improving ease of assembly of equipment, while unplanned repairs can be avoided by using reliable components designed for modern offshore completions.

ESP electrical cable penetrating systems

Conventional ESP cable feed-through system technologies that ensure safe passage of electricity through well safety barriers were not designed for the sort of deepwater conditions in which production is becoming more prevalent. Most ESP cable connections rely on elastomeric seals to hold out the pressure. These seals fatigue and plastically deform as the well pressure and temperature are cycled. When tightly constrained to withstand the pressures in deepwater conditions, the seals are more susceptible to failure by extrusion driven by thermal expansion.

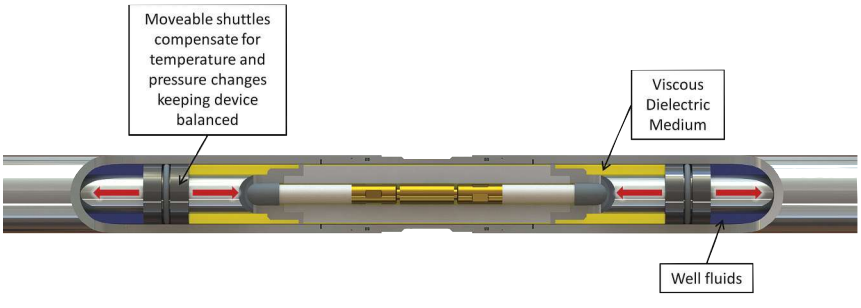

FIGURE 1. Key features of k-PaC Technology's pressure-balancing concept are the movable barriers that encapsulate a viscous dielectric medium that can accommodate well pressure without creating a large pressure differential across the connector. (Source: ITT Corp.)

Pressure-balanced connection system

A connector technology to address the challenges presented by deepwater conditions was developed by the BIW Connector Systems group within ITT Corp. The k-PaC Technology was designed to eliminate the weaknesses of conventional ESP cable connectors that are often exposed in offshore environments.

Connectors with this technology employ a pressure-balancing function

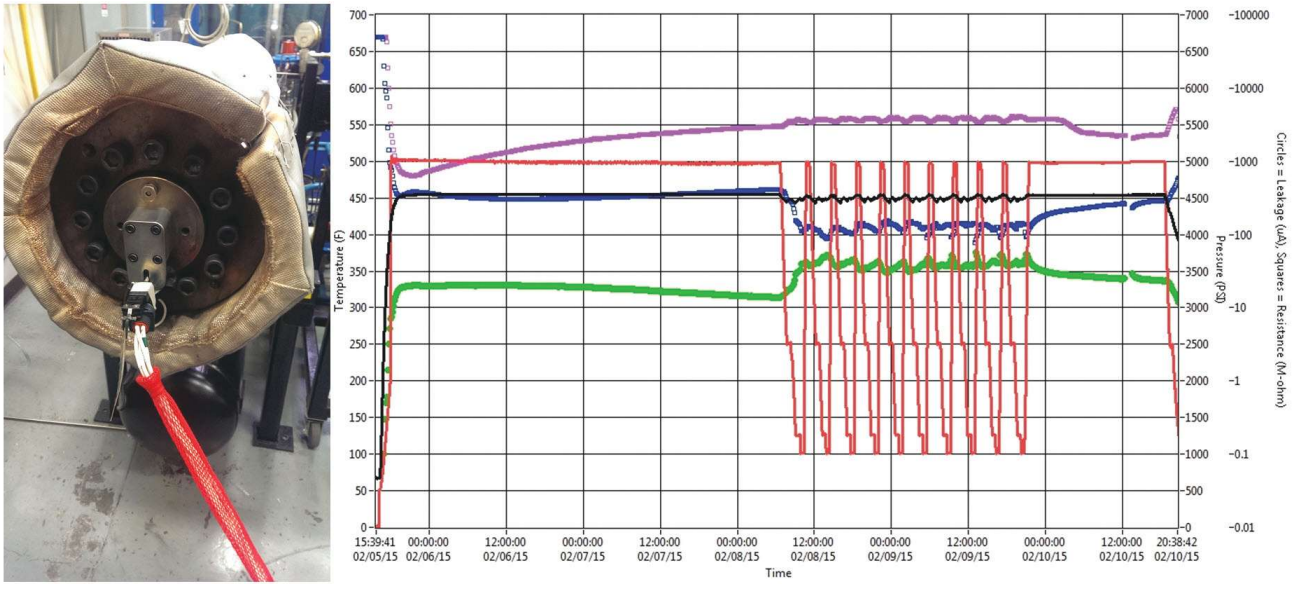

FIGURE 2. The *in situ* chamber penetration and parametric overlay plot shows the electrical feed-through on the environmental autoclave and the electrical performance at temperature as the connecter underwent pressure cycling. (Source: ITT Corp.)

that does not rely on elastomeric material to seal out well pressure. Rather, the pressure-balancing system works with the pressure to create a resilient sealing mechanism capable of functioning under higher pressures and temperatures than conventional technologies that employ elastomeric seals. The resilient seal accommodates stop-and-start cycles, and the improved temperature and pressure ratings extend the application of the connectors.

Figure 1 shows the key features of k-PaC Technology's pressure balancing concept. Movable barriers encapsulate a viscous dielectric medium (VDM) and accommodate well pressure without creating a large pressure differential across the connector.

Failure mechanisms apparent in conventional elastomeric seals, including damage to the cable and connector insulation, were designed with k-PaC Technology. Specifically, the benefits of pressure-balancing over conventional elastomeric technologies include:

- Elimination of tensile stresses on both the conductor insulation and the connector's insulating components;
- Reduction, by the movable barriers, of the pressure difference across seals, preventing extrusion;
- Self-regulation by the barriers of the buildup of internal forces due to thermal expansion;
- The VDM acting as an extension of the leaded barrier by restricting gas absorption, which reduces decompression damage and preserves the conductor insulation; and
- Encapsulated VDM conforming to various cable geometries, allowing for quick assembly without error and the use of mix-matched cable splices.

Testing, field trials

After the technology concept was established, the physical development of the k-PaC Technology occurred in two main phases: prototyping and product qualification, and field trials.

During prototyping and qualification, the connectors were subjected to more than 1,500 hours of downhole environmental simulation in ITT BIW's HP/HT autoclaves. Significant lab upgrades were required to stress and monitor the new technology. Material qualification and system design required the use of a 1,200-C (2,192-F) oven and a 19,000-psi heated hydrostatic chamber, complete access to a multimillion-dollar material science laboratory, and, most prominently, development of an *in situ* electrical monitoring capability outfitted to an autoclave capable of 7,000 psi and 277 C (530 F).

Figure 2 shows the electrical feed-through on the environmental autoclave as well as an output plot demonstrating the electrical performance at temperature as the connecter underwent pressure cycling. Insights gained from the *in situ* electrical data were crucial to the successful development of the connectors.

The first qualified product with k-PaC Technology was the HT connector used in the Metal-Lok Ultra Wellhead Penetrator System. Designed for steam-assisted gravity

FIGURE 3. The Presta Deep Water Mechanical Splice is shown with a protector system. (Source: ITT Corp.)

drainage (SAGD) wells, the application involves a cyclic steaming process with the ESP string installed, directly exposing the connector to 260 C (500 F). Field trials for the SAGD connector commenced with Suncor Energy in August 2014 and have continued without any failure through May 2015.

The second qualified k-PaC Technology product is called the Presta Deep Water Mechanical Splice. This splice was designed specifically to meet the needs of offshore deepwater completions. The mechanical splice has undergone full qualification testing for broad applications up to 177 C (350 F) and greater than 15,000 psi and is currently being readied for trial in several deepwater applications.

Reduced rig time

Both products with k-PaC Technology were designed for simple, reliable and fast assembly. Functional tests were performed to measure the time needed for each product to be assembled. Assembly time for the three-phase SAGD connector was less than 30 minutes. The assembly time for three mechanical splices, including breakouts, was less than 90 minutes, representing a major improvement over legacy technologies.

To demonstrate the cost savings of rig time, compare the mechanical splice assembly time to an industry average of four to eight hours needed to complete a hand splice for deepwater offshore conditions. For a rig cost of $300,000/d ($12,500/hr), the mechanical splice saves an average of $31,333 per splice when compared to the fastest hand splice. The mechanical splice requires minimal training, enabling nonspecialized personnel to complete the splice and allowing multiple technicians to work together. No time is spent coordinating the arrival of a specialized hand-splicing technician, and no hours are wasted while the rig fee clock is ticking. E&P

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Surge reduction while running casing can improve well integrity

Specially designed equipment can reduce the surge pressure attributable to running casing and liners. An optimized casing running solution may be required.

Tim Dunn, Weatherford

The well-known adage "time is money" is applicable to every oilfield operation. For drilling operations in particular, the cost associated with drilling a well is directly related to the time to complete it. Operators, drilling contractors and service companies are constantly looking for better ways to improve the efficiency and safety of drilling and completions operations.

Casing- or liner-running operations are areas that promise major time-saving opportunities. Each string of casing must be run into the hole as quickly as possible but without compromising the integrity of the formation that the casing is designed to isolate. Running too quickly may threaten well integrity in the form of excessive incremental surge or swab pressures. These pressures arise as the pipe runs inside the previous casing string already cemented into place, creating a restrictive annular space and displacing the mud column around the outside of the casing.

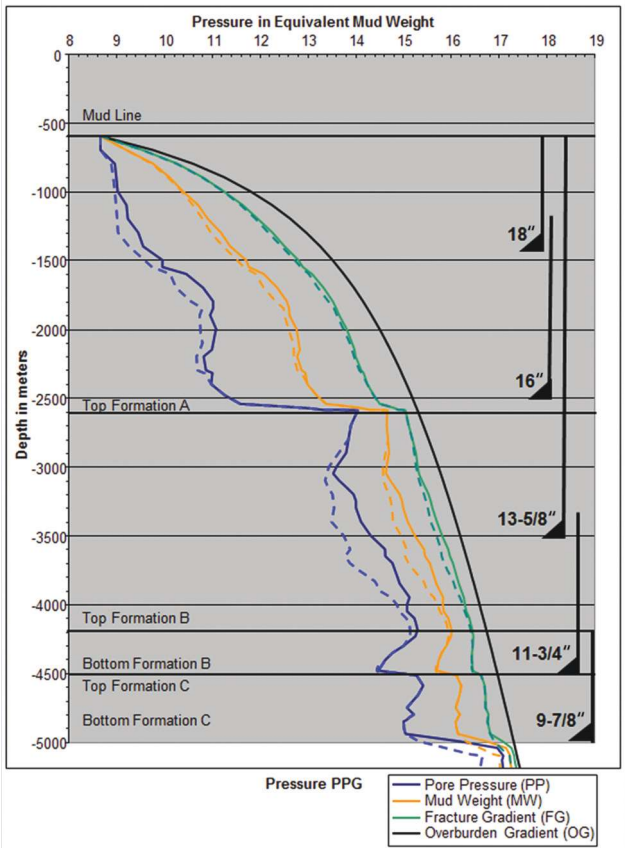
If the pressure buildup is too great in this annulus, the mud often has nowhere to go but into the formation. Induced mud losses as a result of exceeding fracture pressures while running casing compromise the success of the primary cement job and contribute to well integrity issues that may require remediation. Losing mud into productive zones can jeopardize future production and limit the reservoir's full production potential.

In many circumstances, the combined effect of the hydrostatic pressure exerted by the mud column and any additional surge pressure created when tripping casing in the well does not exceed the formation's fracture gradient. In these cases, conventional float shoes and float collars are installed in the casing string, which divert the displaced mud around the outside of the casing back to surface.

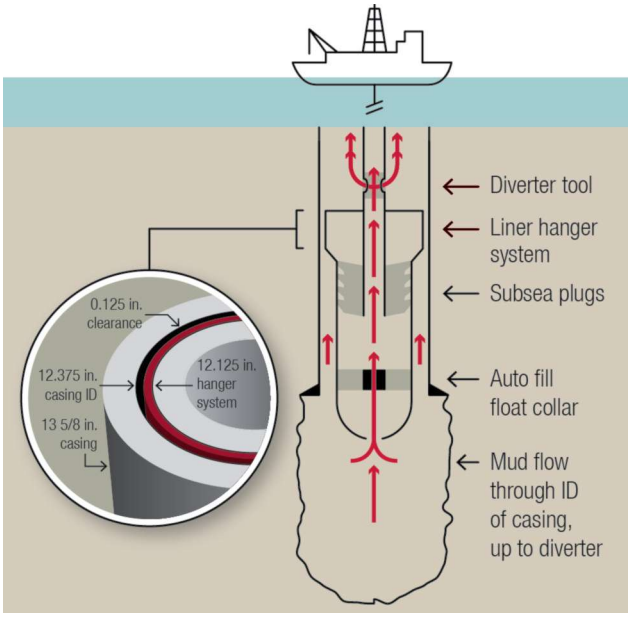
Managing surge in tight windows

In narrow pore-pressure/fracture-gradient margin wells with tight-tolerance annular clearances, however, a more technically advanced solution may be required to maintain well integrity. An optimized casing running solution—one that ensures both successful deployment of the casing or liner to total depth and a high-integrity primary cement job—should begin with a thorough assessment of any potential well issues before the casing enters the hole.

Software modeling can simulate and predict the potential combined impact of surge pressures and the hydrostatic pressure of the mud column for a given well's geometry, fluid properties and geomechanics. And



A typical deepwater subsurface pressure profile exemplifies the challenges of tight-tolerance casing design. (Source: Weatherford)



Surge management and tight tolerance are realized by running a diverter tool in conjunction with auto-fill float equipment to divert displaced fluids from the casing running string into the annulus. (Source: Weatherford)

specially designed equipment can reduce the surge pressure attributable to running casing and liners on drillpipe by taking returns through the inside of the casing.

Such a design begins at the bottom of the casing string, where a free-rotating guide shoe allows the casing string to move past wellbore ledges without getting hung up or stuck, a particular risk in highly deviated hole sections. The guide shoe should have an opening with an adequate cross-sectional area to freely permit mud flow into the casing, where an auto-fill float collar is positioned to allow the mud to flow up the inside of the casing string.

Once the low-margin window section of the formation has been bypassed, the flowing mud will then pass out the top of the casing string through a set of large-bore subsea plugs and a diverter tool, which directs the fluid back up the annular space to the surface.

This casing running scenario efficiently moves 60% to 75% of the mud up the interior of the casing string, reducing the annular pressure and lowering the risk of formation damage and mud losses. Running speeds also can be dramatically improved. Without surge reduction, the operator might elect to run casing at a rate of 1.5 m/min (5 ft/min) or less to reduce the stress to the wellbore, but with surge reduction, running speeds of 6 m/min (20 ft/min) or higher are common.

Surge-reduction success in offshore well

An operator drilling a deepwater exploration well in the U.S. Gulf of Mexico needed a surge reduction solution while running casing strings that were 11¾ in., 14 in., 16 in. and 18 in. in diameter. Such a solution would prevent mud losses while running the casing to its setting depth, circulating the well and cementing the casing in place.

Without it, the operator ran the risk of exceeding the downhole formation fracture gradient. Mud weights ranging from 10.6 parts per gallon (ppg) for the 18-in. casing to 14 ppg for the 11¾-in. casing were within 0.4 ppg to 0.6 ppg of the fracture gradients, while the equivalent static density and equivalent circulating density were within a 0.05 ppg to 0.1 ppg margin of exceeding the fracture gradient. Poorly executed surge reduction also raised the risks of an inadequate cement job in the well and an inability to get the casing string deployed to its required setting depth.

Weatherford was tasked with delivering a comprehensive surge-reduction solution for a casing running operation in the GoM. (Source: Weatherford)

Weatherford was tasked with delivering a comprehensive surge-reduction solution for the casing running operation. For each casing size, the solution comprised large-bore auto-fill float collars, large-bore subsea release (SSR) casing wiper plugs and a multi-opening diverter tool. The 16-in., 14-in. and 11¾-in. casing strings also used a plug locator collar and SSR casing wiper plugs with a locator ring on the top plug.

The diverter tool enabled the operator to break circulation without conversion of the auto-fill float equipment while tripping into the well with casing on the landing string, thus reducing mud gel strengths and lowering annular friction pressures at the casing setting depth.

This solution allowed the operator to run thousands of feet of casing without creating surge-induced stresses and without compromising formation integrity. For each casing size deployed, casing-running speeds averaged 7.6 m/min to 10.7 m/min (25 ft/min to 35 ft/min) and eliminated thousands of barrels of potential mud losses while running casing to the planned setting depth.

All casing strings that utilized the SSR plug system and the plug locator collar successfully displaced the entire casing volume and bumped the SSR top wiper plug on the respective float collars. Ultimately, the surge-reduction technology provided the operator with the necessary openhole formation integrity to circulate, condition and execute successfully its primary cementing operations on four close-tolerance casing sizes in narrow margin openhole formations, eliminating the need for subsequent primary cementing remediation.

Effectively managing well integrity includes but is not limited to running casing without losses, being able to circulate full mud returns prior to cementing the well, achieving the required zonal isolation, maximizing reservoir productivity and eliminating the need for remedial cement work later in the life of the well as a result of an inadequate primary cement job. E&P

A business case for borehole geophysics

When surveys go from science projects to value builders, the prize will be in reach.

Rhonda Duey, Executive Editor

In the world of borehole geophysics, Brian Hornby claims to be both the biggest champion and the biggest skeptic. After all, this type of technology is not meant to be used for exploration geophysics but rather as a calibration tool for surface seismic in complex environments. When the resulting data fail to provide additional information, the exercise quickly becomes one of futility.

Hornby, head of Hornby Geophysical Services LLC, spoke at a recent Geophysical Society of Houston luncheon about the technical challenges of achieving a truly useful 3-D vertical seismic profile (VSP) as well as some of the newer technologies on the market. While the talk was highly technical at times, it boiled down to a rather basic theme, as evidenced by the title, "Beyond time-to-depth: Achieving business value using high-end borehole geophysics."

Borehole Seismic Traffic Lights
Beyond time-to-depth

		Now	1-5 yr	5 yr+
VSP imaging and inversion	VSP, Offset VSP/			
	Walkaway VSP			
	3D VSP			
	DAS: Multi-well imaging/ reservoir monitoring			
	AVA and anisotropy			
Passive borehole seismic	Microseismic frac monitoring -			
	Microseismic frac monitoring - source mechanisms			
	Passive reservoir monitoring			
Cross-well	Cross-well imaging			
Salt-proximity	Salt flank location			

Routine business value achieved | Some business value achieved, more development required | No real business value achieved

A simple 'traffic light' system ranks available technologies and their maturity. (Source: Brian Hornby)

He laid out his case by asking luncheon participants to pretend that they were subsurface managers for a project. "You're drilling wells, and you hold the checkbook to decide which technologies you'll use in these wells," he said. "What does it take for you to say, 'This adds value?'"

Although focus of the talk was on "beyond time-to-depth," Hornby made some initial comments on the more standard time-to-depth VSP application. The time-to-depth aspect, Hornby said, accounts for probably 70% to 80% of all of the borehole surveys. "This is the area we have to get right," he said. "There's no simple borehole seismic survey. Even in vertical wells getting time to depth can be troublesome."

Complex overburdens, dipping beds and salt can complicate surface seismic surveys, and this is where VSPs can come in handy. But they don't always provide the additional information needed for informed decisions.

Business barriers

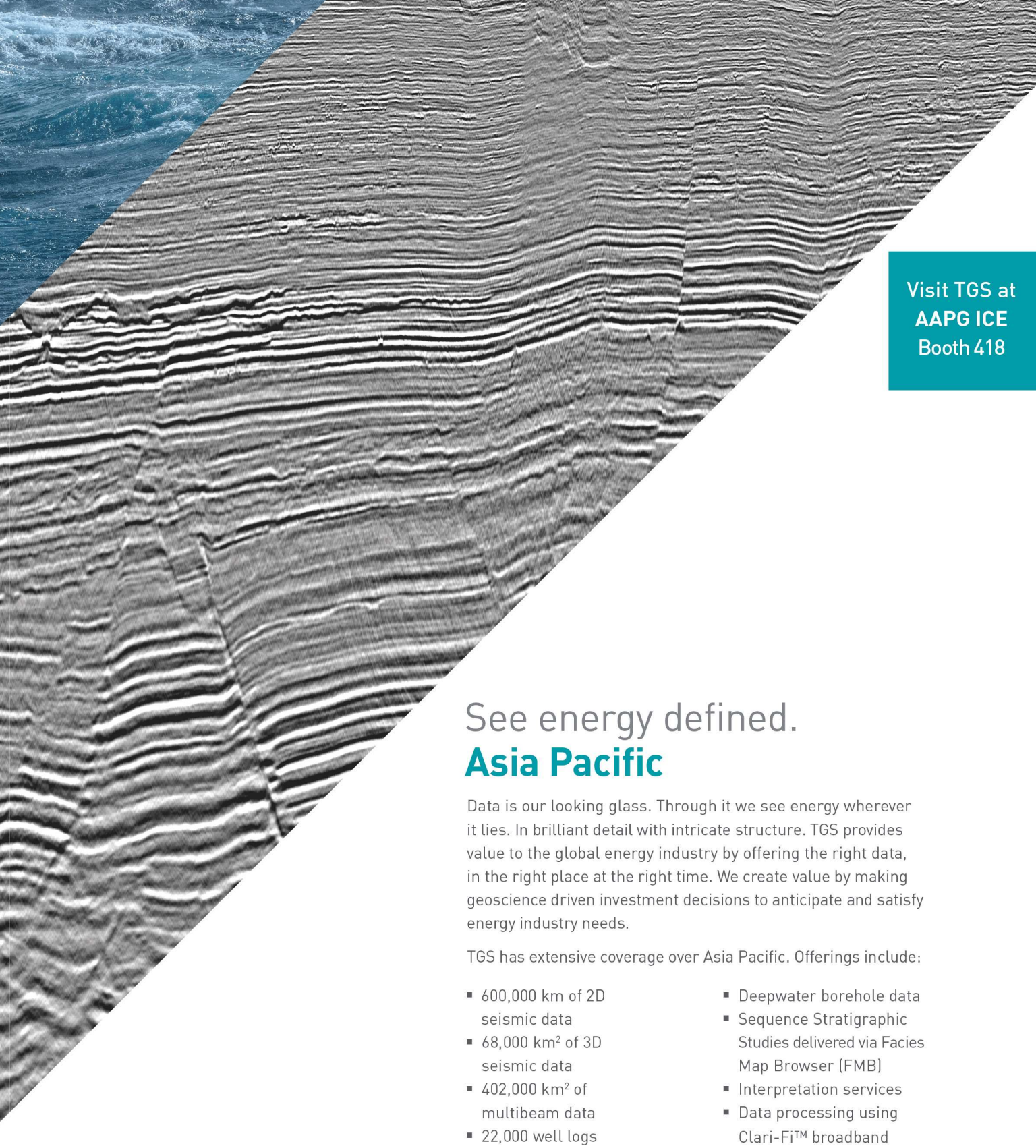
Because of the nature of the oil and gas business, new technologies often get overhyped before the kinks have really been worked out. "New technology advances create excitement in the industry that can lead to a bandwagon mentality," he said. "The cooler sounding the technology, the more the excitement, and it becomes sort of like a boom or bust in the stock market. The oil company's goal is to achieve value, and the vendors rush to commercialization, resulting in overselling.

"This may not be intentional; they're trying to fulfill the demand they're seeing. But the technology may be too immature to actually achieve something that will affect a particular project."

3-D VSPs also have suffered from being shown to be "just as good as surface seismic." "So what?" Hornby asked. "You already have the seismic; you're drilling wells on it. If the VSP image looks something like it, academically that's great. But does it add anything to the project?"

3-D VSP imaging

The objective of a 3-D VSP is to provide a 3-D image volume that delivers crisper resolution than surface seismic and will image areas, such as beneath salt, which are poorly imaged on the surface seismic.



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3-D VSP imaging has been a development process, Hornby said. Early examples showed promise but delivered poor image quality, mostly because of inadequate tools and imaging solutions. They also suffered some of the over-hyped fate due to over-optimistic feasibility modeling.

Hornby is a huge proponent of instrumenting the wellbore as much as possible. While earlier tools might have been a few hundred meters in length, he promotes tools that are 2,438 m to 3,050 m (8,000 ft to 10,000 ft) in length. He also promotes 3-D finite modeling prior to the survey and the use of the latest imaging algorithms and anisotropic velocity models during processing.

For instance, at its Wamsutter Field in Wyoming, BP used a 160-level tool to perform a VSP survey. Hornby said the well was full of receivers with a large, dense shot pattern. "A lot of modeling went into that," he said. Results from the survey were very promising.

Given these types of findings, companies are developing both wireline-conveyed and tubing/drillpipe-conveyed land systems, one of which will have 1,000 levels of capability when its development is complete.

Offshore, the size of the prize is enough to spur companies to action. Hornby said that 1,220-m (4,000-ft) arrays are possible, but the tools will still need near-term development to get to the 2,438-m tool he envisions. Simulations, meanwhile, indicate that fully instrumented wells will provide the best data. Again, vendors are working to develop tools, mostly wireline-conveyed, to meet these goals.

Permanent arrays

This is one of the areas of greatest interest in borehole geophysics. Permanently installed sensors can deliver larger-scale 3-D VSP imaging using multiple instrumented wells with a surface source vessel and can deliver low-cost and effective reservoir monitoring capability. Costs can be greatly reduced over conventional 3-D VSP due to removal of the rig time cost and lack of requirement to deploy surface or seabed seismic sensors for reservoir monitoring. For the downhole technology there are two main options:

- Dedicated 3-D fiber-optic sensors. These provide high-quality three-component data but are expensive and of limited array size; and
- Distributed acoustic sensing (DAS). This technology uses an existing fiber-optic cable and pulses light down the cable. The light is backscattered by impurities in the fiber, and the phase and amplitude effects are changed by any strain in the fiber caused by seismic waves or acoustic waves hitting the fiber. A surface box translates the received laser signal into seismic signals.

The big and potentially game-changing advantage of DAS is delivery of a very large borehole seismic array (fully instrumenting the well as essentially the array of sensors is everywhere an optic fiber is instrumented in the well) at very low cost and with minimal or no change to well completion procedures. The downhole sensor is simply plain optic fiber, which could easily be included in the standard well completion cabling bundle (e.g. for downhole pressure/temperature [P/T] measurement). The "low-hanging fruit" for DAS is that many wells are already instrumented with fiber for downhole optic P/T gauges or distributed temperature sensing (DTS). So by adding a surface box while a seabed node survey is being acquired near a well, a full 3-D VSP survey can be acquired at very little cost and with no impact or intervention in the well.

However, Hornby said, there are some issues with data quality. First, signal-to-noise (S/N) is an issue with current DAS systems and is seen to be 20 db or more below high-quality dedicated seismic sensors. The impact of this is that the higher frequencies that 3-D VSP targets may not be received with the DAS system, and the high noise floor can limit the useful depth the system can be used at. Hornby said that all of the companies that manufacture these systems are working to get the noise floor down.

Another issue is that the amplitude in DAS surveys falls off very quickly. "If your source is oriented along the fiber, you get a good signal," he said. "If it's orthogonal to the fiber, it's horrible." As shown by recent field trials, special installation procedures for newly completed wells such as helix-winding the fiber can potentially deliver a more angle-independent result and better imaging.

Traffic lights

Hornby rated the different borehole geophysics systems with a simple traffic light system. Green means the technology brings business value now. Yellow is some business value but more work needed; red is no business value. The traffic lights look at the potential now, in one to five years and in five years plus.

None of these high-end technologies gets the green light today, but 3-D VSP, amplitude vs. azimuth and anisotropy, microseismic hydraulic fracture monitoring for event location, and salt proximity get green lights within five years. DAS, microseismic hydraulic fracture monitoring for source mechanisms and crosswell imaging get green lights five years or more out.

In the case of 3-D VSPs, Hornby said he's looking for "the definitive survey. The interpreter says, 'Wow, now I can take this to the bank,'" he said. "Once that happens, we move to do business as usual." E&P

Trends in well testing

The size of hydraulic fracturing jobs as well as environmental and safety expectations will only continue to increase.

Mitchell Shauf, Select Energy Services

Vast technological advances have been made in the oil and gas arena, particularly with horizontal drilling and hydraulic fracturing. The well testing industry that supports it has evolved as well, becoming much more sophisticated and regulated.

In the not-too-distant past, becoming a "well tester" required little training, and a well tester's responsibility consisted primarily of counting the number of barrels that a well produced. The job description might read, "Check the tanks, call the trucking company and don't let the water hit the ground." Gone are the days of barrel counters, single well pads and open pits.

Today well testing is much more complicated. Three notable trends have occurred in testing across the numerous shale plays:

- Fracking operations are larger, and that has implications for well testing;
- Green completions indicate the expectation that the industry become more environmentally responsible; and
- Advances in safety have been made due to an expectation of stringent safety standards and a good safety record.

Each of these trends has a unique set of challenges, equipment requirements and skill sets.

Bigger operations

The size and scope of hydraulic fracturing operations continues to increase with technological advances in horizontal drilling and completions. Frack jobs call for more resources—water, sand and horsepower—as energy producers operate multiple wells on a single pad. Larger operations require specialized equipment for handling flowback fluids, such as test separators.

Test separators are able to efficiently separate oil, water, gas and solids from flowback fluids. The oil and water are moved into isolated tanks while the gas is flared off or, ideally, redirected to a sales pipeline. Separators vary in size based on the unique requirements of the operation. Larger separators add efficiency and reduce completion costs. A larger separator can handle fluids from multiple wells at one time, a process called comingling. In addition, retention times are greater in a larger vessel, so more oil is recovered from the fluids and returned to the energy producer rather than disposed of in an injection well.

Test separators efficiently remove oil and gas from flowback and produced water. (Source: Select Energy Services)

These requirements have led to large and varied equipment demand. Select Energy Services, for example, owns and operates 125 full sets of equipment across the U.S. shale plays. This equipment includes 2-in. to 4-in. 1502 iron 15,000-psi frack stands; 15,000-psi manifolds; 15,000-psi plug catchers; and sand separators, flare stacks, incinerators, combustors and multiphase test separators with working pressure ratings ranging from 3,000 psi to 15,000 psi.

Green completions

Regulatory agencies continue to influence the industry, directing energy producers to be more environmentally responsible. One movement, known as Green Completions, is reducing the amount of methane and

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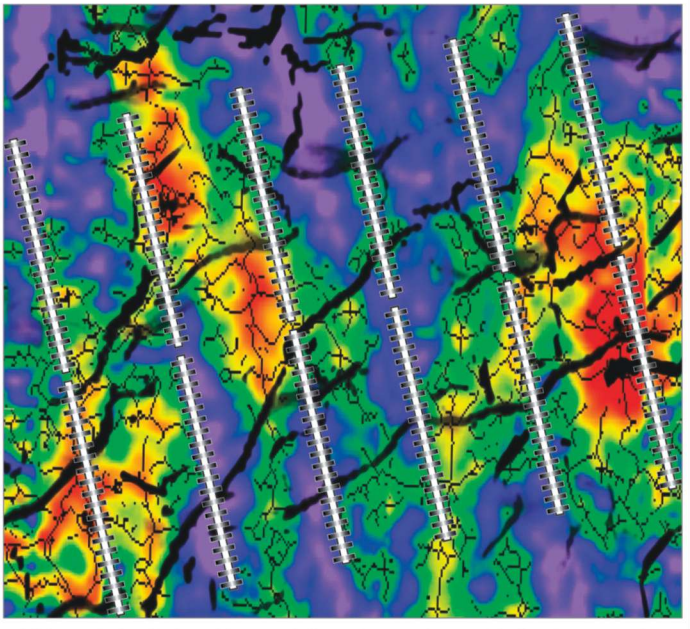
3D design to image 12 planned Utica wells from a pad in Eastern Ohio. Vibroseis source positions are confined to roads to optimize acquisition efficiency. Receiver positions are evenly distributed in a hex array using AutoSeis® recording nodes.



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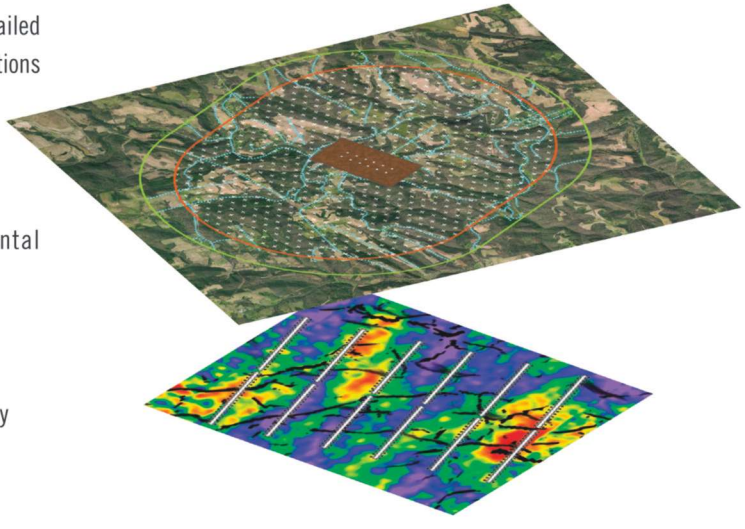

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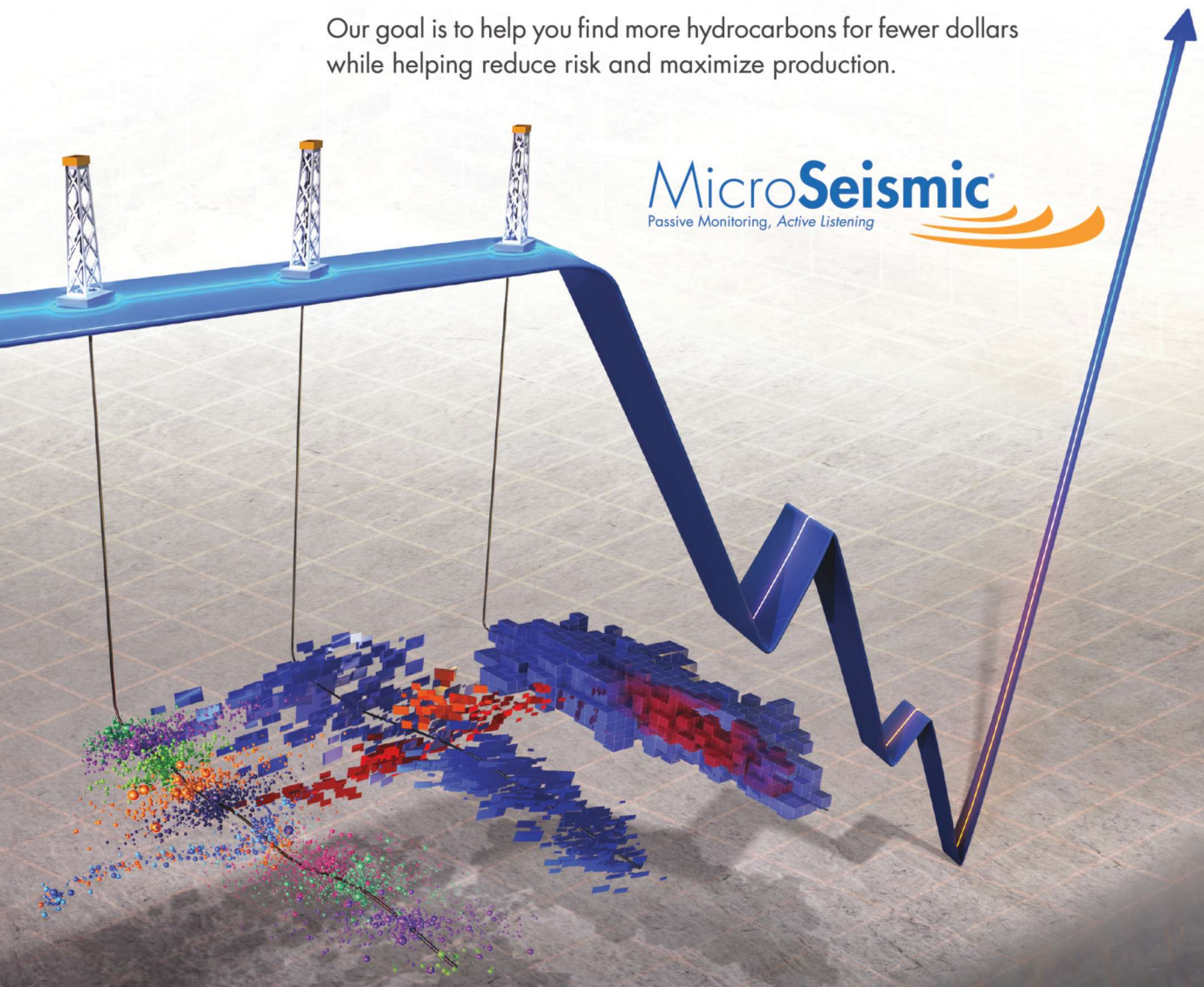

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vapor emissions released into the air around oil and gas well sites. This process safely contains and combusts flare gas, reducing the amount of wellsite emissions.

Well testers utilize specialized closed-loop tank ventilation combustion units to prevent the release of methane and vapors into the air during operations. Benefits include optimized project efficiency—the system has been tested and proven, with established standard operating procedures and rigup procedures. They also manage and coordinate interaction with community and regulatory bodies and consider this an integral part of the process.

A closed-loop tank ventilation and combustion system replaces conventional methods of flaring excess methane and vapors on hydraulic fracturing sites. (Source: Select Energy Services)

Safety

Onshore well testing and flowback operations are among the most dangerous in the industry, and strict safety standards are necessary. Employees are constantly at risk of exposure to high temperatures, high pressures and high concentrations of dangerous gases. And since well testers work closest to the well, many times they are in charge of not only their own activities but also of third-party activities on location that are happening concurrently.

Credible oilfield services companies make safety a priority, not only to protect the wellbeing of their workers but also because it is an expectation by operators, which actively review the safety records of their contractors. Specialized equipment coupled with rigorous employee training programs are the keys to a successful operation.

Trends in employee safety measures

In the oil and gas industry rapid growth and high turnover rates can make it hard to keep highly trained staff members. Safety training for front-line well testing employees is critical to developing specific skill sets. This typically includes mandatory classroom training and hands-on field training. Mentorship programs also effectively enhance safety performance; looking out for the "other guy" can make people more mindful of safety issues.

Select Energy Services has a designated training facility in Brighton, Colo., where employees complete classroom sessions. The company also has a hands-on training center where employees can get experience with equipment and trainers can simulate flow, as if an employee were on a job site but without the risks. Additionally, the company has an ongoing campaign that serves as a daily reminder that safety is a core value at the company. The slogan, "It starts with me," empowers employees with a message of ownership and accountability for safety.

An employee monitors and records well testing and flowback data on a four-well pad in Colorado. (Source: Select Energy Services)

Trends in equipment

Specialized equipment also contributes to safer work environments, and technology has created significant advancements. Kevlar restraints now replace metal stakes that once stabilized high-pressure flowlines. Electronic, pneumatic and hydraulic valves have become commonplace and allow for quick control of the well in the event of a problem. Personal lower explosive limit meters alert workers of the presence of toxic and corrosive gas emissions, and forward-looking

09

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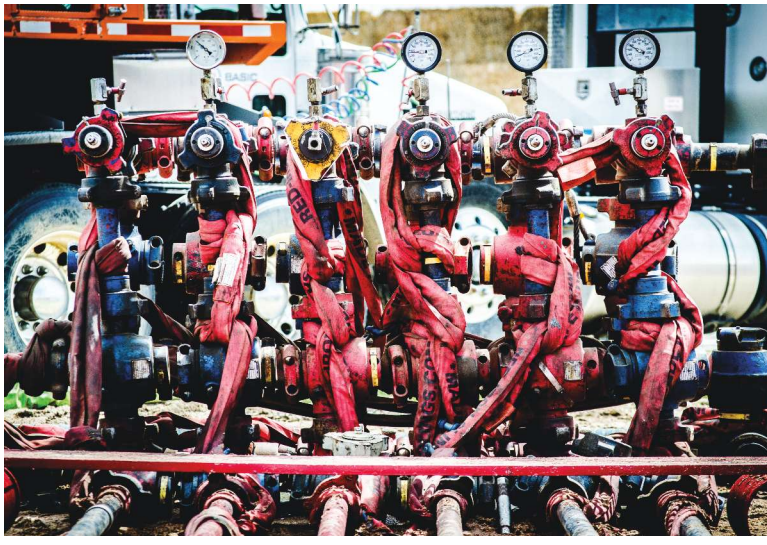
infrared (FLIR) cameras allow them to identify and measure the source of the emissions. FLIR cameras also allow workers to identify ice plugs or "hydrates" within the equipment. To reduce the risk of flash fire injuries, electronic ignition systems are now equipped on indirect line heaters, combustors, incinerators and flare stacks.

Leading well testing companies offer state-of-the-art inventory of equipment that meets API standards to safely deliver all of the operators' well testing requirements. They provide experienced team members who can safely and effectively operate in all testing environments, including high-risk environments such as those with high temperatures, high pressures and/or high concentrations of sour gas.

As oilfield technologies evolve, so do the requirements for well testing. The trends in size of hydraulic fracturing jobs, environmental expectations and safety demand will only continue to increase. Operators have high expectations, and oilfield services companies must deliver to remain relevant in this industry. EP



Kevlar restraints stabilize high-pressure flowlines. (Source: Select Energy Services)

Companies can't overemphasize well integrity

Cement job integrity can be improved with a rotating mandrel hanger that allows the casing to be rotated through the heel of the lateral while installing and cementing.

Diane Langley and **Moises Nava,** Cameron

Cement jobs in the oil and gas industry are getting a bad rap. Cementing work has been identified as the possible culprit in many onshore fracking disputes. The U.S. Bureau of Land Management reports provide evidence of the role bad cement work has played in accidents.

Production optimization begins with a good completion, and a good completion depends on the integrity of the primary cement job. Every year poor cement jobs cause tremendous costs to the oil and gas industry. Poor cement jobs demand additional cementing operations such as squeeze jobs. These operations are time-consuming and rig-demanding, which in turn leads to economic loss. If a poor cement job is left unattended, the result can be catastrophic.

Clearly, there is room for improvement in cementing technologies to withstand the rigors of well operations and any disruptions that might occur. The integrity of the cement job can use all the help it can get. The manner in which the cement is placed inside the annulus assists with the integrity aspect of the cementing operation, and the wellhead can actually help improve efficiency of the cement placement.

A good primary cement job can prevent remedial work. Successful isolation of the hole and formation is extremely important in preventing the migration of gas and fluid and limiting the environmental impact.

Gaining efficiency in horizontal drilling

The achievement of desired technical objectives via horizontal drilling comes at a price: A horizontal well may be anywhere from 25% to 300% more costly to drill and complete for production than a vertical well directed to the same target horizon. But there are advantages: Operators often are able to develop a reservoir with a sufficiently smaller number of horizontal wells since each well can drain a larger rock volume around its bore than a vertical well could.

The nested design of the MN-DS wellhead allows the whole system to easily fit under most skidded drilling rigs. The system can be installed along with all subsequent strings through the diverter riser/BOP. (Source: Cameron)

An added advantage relative to the environmental costs or land use problems that may pertain in some situations is that the aggregate surface footprint of an oil or gas recovery operation can be reduced by use of horizontal wells. The second key benefit is that a horizontal well may produce at rates several times greater than a vertical well due to the increased wellbore surface area within the producing interval.

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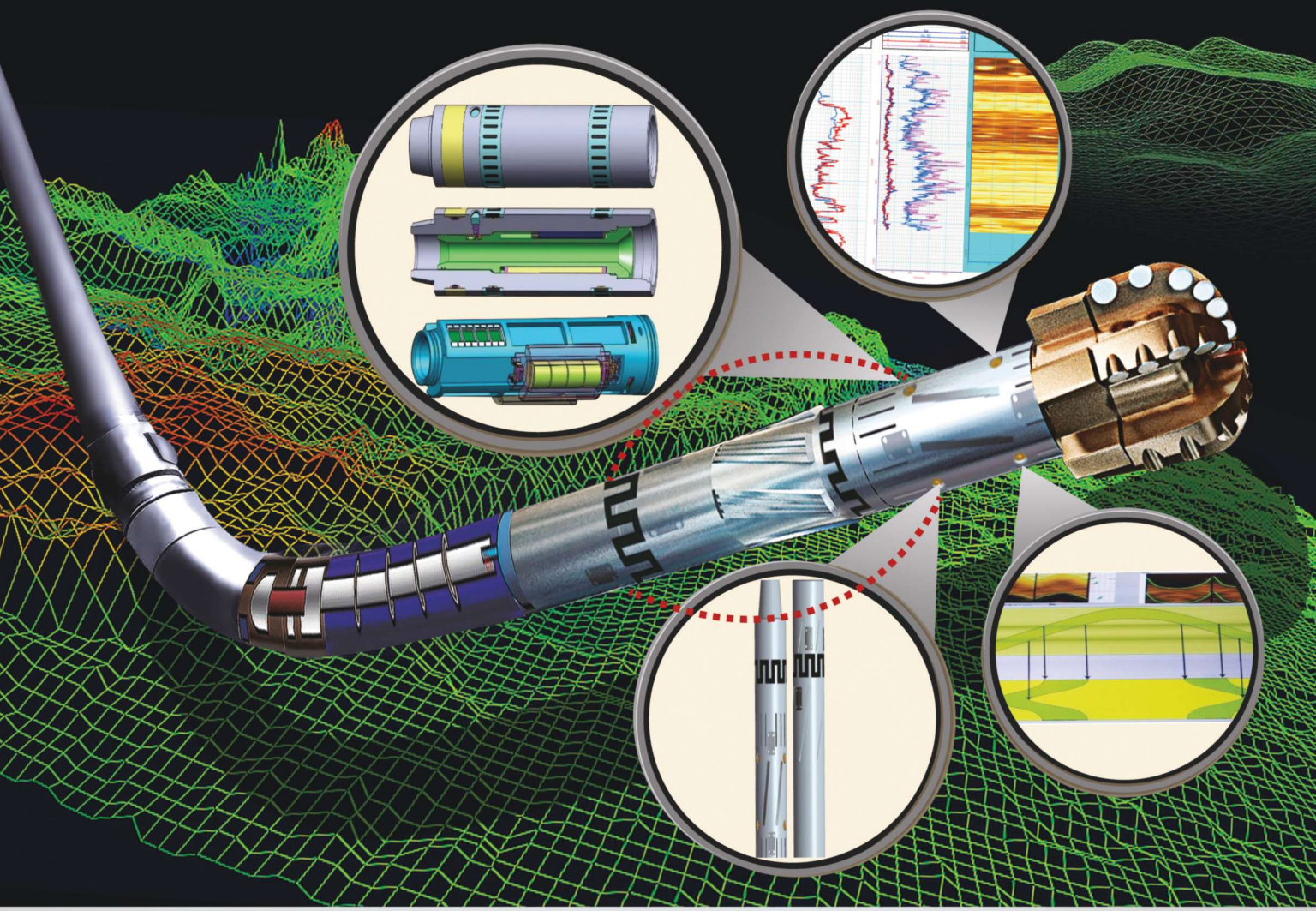

The GW-NB system consists of measurement transmission motors, a wireless receiving system, a positive pulse of wireless LWD system, and surface processors and geosteering decision software. It is designed to improve the discovery rate for exploratory wells, drilling encounter rates and oil recovery for development wells.

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This approach offers multiple advantages, including better drainage, lower drawdown and a reduced footprint. Its sole purpose is to help operators develop more of the wellbore. The initial linear portion of a horizontal well, unless very short, is typically drilled using the same rotary drilling technique that is used to drill most vertical wells, wherein the entire drillstring is rotated at the surface.

Setting the packer and optimal placement of fluids and cement represent areas of challenge in horizontal wellbores. Suspension of the hanger represents a major challenge. The parent hanger body has a tendency to spin before latching once the child is landed, causing a less-than-safe condition and potential rod wear. Also, by nature, horizontal wellbores are deviated, causing fluids and cement to migrate to the low side of the hole, resulting in a less-than-optimal distribution downhole.

Choice of wellhead matters

Because cement integrity is one of the most critical steps in well completion, Cameron has studied the need for enhancing cement jobs. Movement of the pipe during cementing is one of the best methods of improving mud displacement and reducing the number of mud channels remaining after cementing. Rotation of casing helps force the mud from the pipe and formation contact areas and ensures a more even distribution of cement. Special rotating heads are required to allow pumping while turning.

The wellhead is a vital pressure-containing component at surface that can make operational processes more efficient and flexible and enhance the integrity of the well. Internal components such as a rotating mandrel hanger will allow the casing to be rotated through the heel of the lateral while installing and cementing.

Such a rotating feature can help operators ensure the production casing runs the full length of the lateral to achieve a proper cement job. Once the casing mandrel is landed in the wellhead, slotted mandrel shoulders permit cement circulation, removing the necessity to wait on cement with casing slips.

Multibowl nested diverter snap-ring wellhead system

One such wellhead is Cameron's multibowl nested diverter snap-ring (MN-DS) wellhead system. It incorporates a unique rotating mandrel casing hanger designed to improve cement job integrity and wellbore stability for vertical and horizontal gas wells. The hanger enables the operator to rotate the production casing during installation, promoting better displacement efficiencies, effective zonal isolation and less eccentricity in the pipe during cementing jobs.

The ability to rotate the hanger addresses the deviations inherent in horizontal wells. By rotating the hanger, slurries can be more evenly distributed inside the wellbore. On a recent trial with a major South Texas operator, it was deemed that the rotating hanger saved an estimated eight to 10 hours rig time as compared to using a regular slip-style hanger. This time is traditionally spent waiting on cement to reach an acceptable compressive strength before breaking the BOP stack.

A nested design is new methodology for industry wellhead systems. This design, employed in the MN-DS system, reduces the overall height of the wellhead system, making it ideal for use with today's high-performance horizontal skidded drilling rigs.

Rather than the typical design of the hanger on top of the pack-off, the nested design consists of a hanger that fits within the pack-off, reducing system height. This hanger can be either a production casing hanger or a tubing hanger, providing the option to complete as a one-stage system if intermediate casing is not required.

Because the system uses a spin-on flange design, no special tubing head or tree adapter is required. The system enables the wellhead and all subsequent casing strings to be installed through the diverter riser/BOP without having to nipple down, providing considerable cost and time savings. The wellhead has the ability, depending on the string configuration, to be installed prior to the rig moving to the pad; the only action required is to nipple up the BOP to the wellhead.

The MN-DS system also offers a higher degree of safety resulting from an internally locked system, which eliminates penetrations from lock screws in the housing. The system is particularly applicable in highly deviated horizontal wells because it offers a secure method of protecting the wellbore during drilling operations. Also, the potential for rod wear is diminished because tension is maintained throughout the packer-setting process.

Other examples of equipment helping to ensure well integrity are back-pressure valves and pack-off systems. These can be installed into the rotating mandrel to provide a barrier for both the bore and the annulus to secure the well at surface.

In artificial lift applications, the system's tubing hanger keeps the tubing string in tension to better endure the sucker rods' constant up-and-down motion, thereby maximizing the life of the tubing. About 200 MN-DS wellheads have been installed and are operating successfully in the field. EP

Ultrahigh-concentrated point load fractures high-compressive-strength rocks

Conical diamond elements with very high-impact resistance provide flexibility in designing the numbers and placement of elements for special applications.

Allen White, **Jordan Self**, **Steven Noble**, **Chance Copeland** and **Frederick Mihal**, Smith Bits, a Schlumberger company

There is a familiar story about a customer who walks into a hardware store looking for a ½-in.-diameter drillbit. However, what the customer really wants is a ½-in.-diameter hole; the bit just helps construct it.

The same analogy can be applied to oil and gas wells. Operators want smooth trajectory boreholes drilled quickly and landed precisely in the target reservoir. But because of wide variation in geology, mineralogy and mechanical properties, some bits drill more efficiently.

In addition, some bits last longer than others, and this enables drillers to construct precisely drilled boreholes with fewer replacement trips to change out worn or broken bits. In every basin, rig rates form a significant portion of well costs, so elimination of just one bit replacement trip amounts to a major savings. Accordingly, longevity is perhaps the greatest benefit a bit can offer because savings go directly to the bottom line.

FIGURE 1. Strategically placed conical diamond elements deliver both extended life and higher ROP with StingBlade bits. (Source Schlumberger)

Based on these challenges, Smith Bits created a new drillbit technology called StingBlade, a conical diamond-element bit that offers both longevity and efficiency benefits. The chief characteristic is the implementation of conical diamond elements with very high impact resistance (Figure 1).

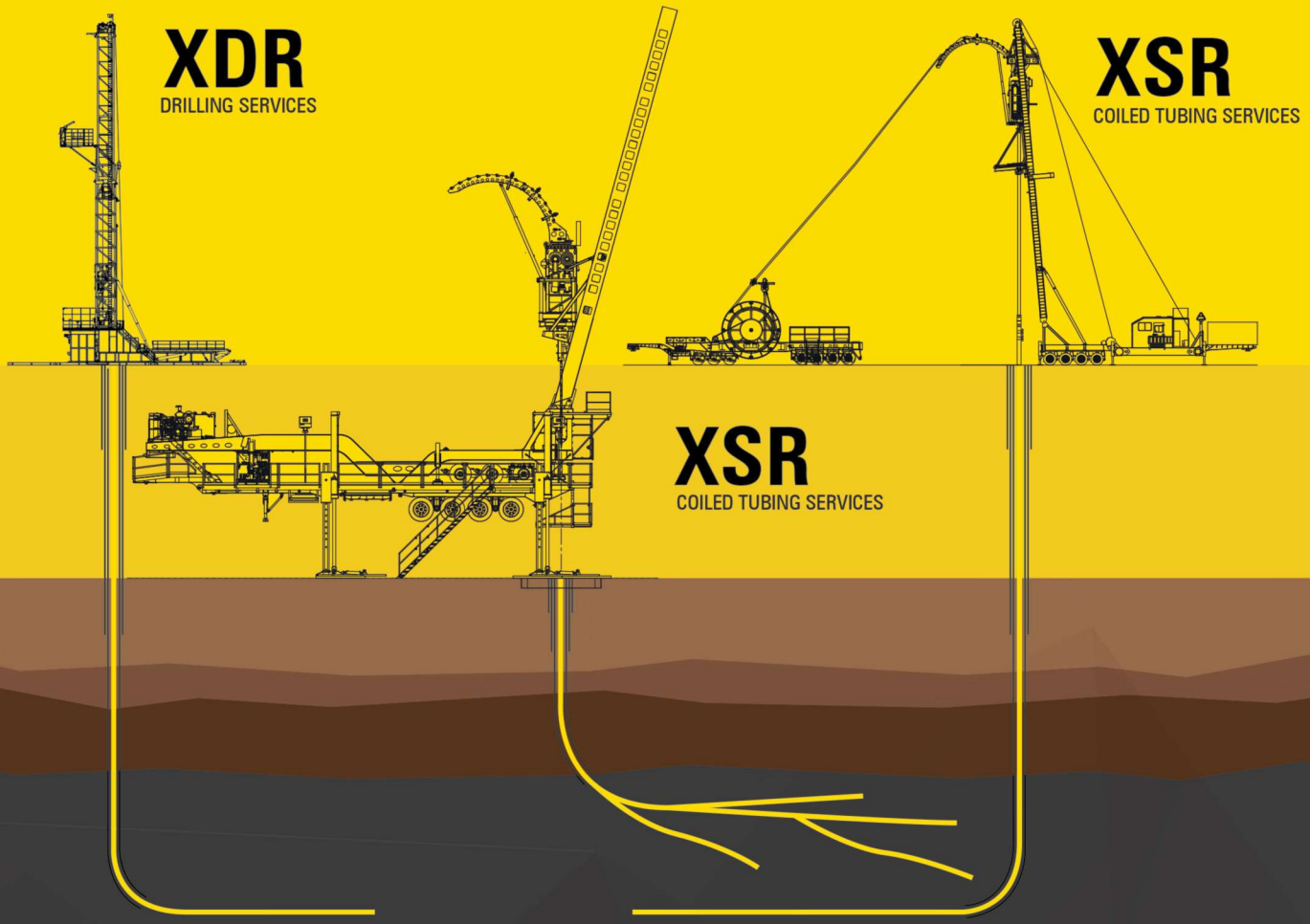
The elements have been strategically inserted across the blade of a fixed-cutter bit design. Smith Bits design engineers used the IDEAS integrated drillbit design platform to simulate drilling conditions and determine the optimal number and placement of the Stinger elements.

How does it work?

The key factor behind the new bit's performance is its conical diamond element. The shape of the element creates an ultrahigh concentrated point load on the formation to fracture high-compressive-strength rocks more efficiently. Also, the element has a thicker diamond table compared with standard cylindrical cutters, which gives it superior impact strength.

In a direct comparison, two cutters—a standard polycrystalline diamond compact (PDC) cutter and a conical diamond element—were smashed with 18,000 lbf onto a steel plate to simulate instantaneous impact loads typically seen while drilling downhole. The standard PDC cutter failed on first impact, but the new element continued for 100 impacts without any damage (Figure 2).

In addition, the elements generate less torque than cylindrical cutters. This, in turn, yields better directional response (steerability) and smoother toolface control. Because cutting force is applied to the symmetrical point of the new diamond element, drilling proceeds with less shock and vibration.



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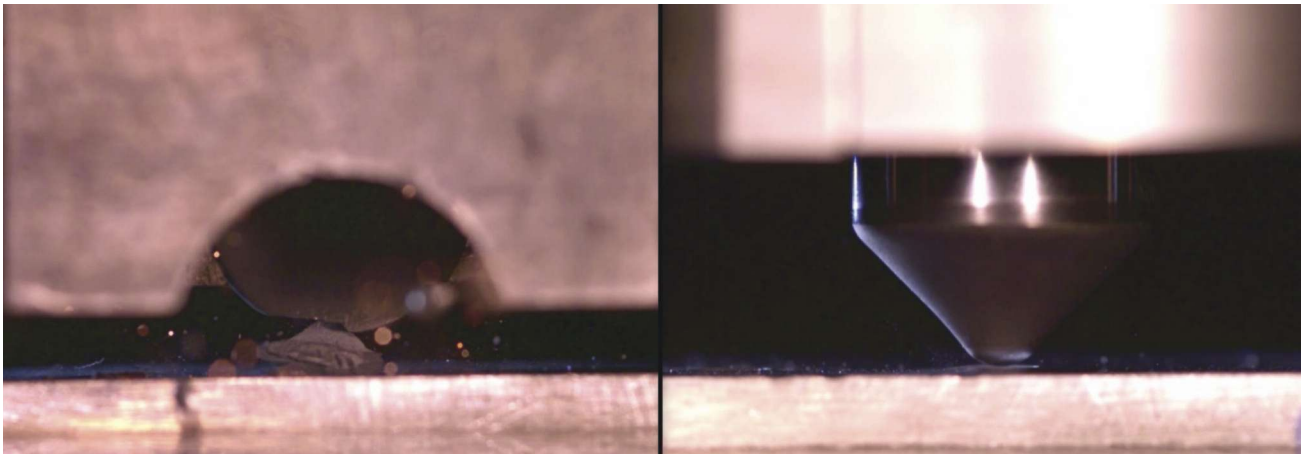

FIGURE 2. A comparison shows a Stinger element (right) vs. a conventional PDC cutter (left) after impacting a hardened steel block at 18,000 lbf to simulate drilling into a hard limestone at 60 ft/hr. (Source: Schlumberger)

The new technology also chips off larger pieces of rock, which are swept away up the junk slot by strategically placed nozzles and circulated to surface, compared to typical cutters that can waste energy regrinding cuttings. Currently, the conical diamond elements can be inserted in all bit sizes from 5⅞-in. diameter to as large as 36-in. diameter.

Williston Basin breakthrough

In the prolific Williston Basin play of northwestern U.S. and southwestern Canada, operators are striving to reduce drilling costs, especially on wells designed with long lateral sections. Oasis Petroleum achieved immediate results by switching to StingBlade (Z613) bits in the Three Forks First Bench laterals.

To effectively produce the formation, the company drilled long, precise laterals. On the first lateral utilizing the Z613, there was a 50% increase in ROP compared to the rig's average conventional PDC bit runs. One factor leading to the increase in ROP was that the bit provided sliding ROP twice that of conventional PDC bits. In addition to the increase in ROP, the biggest advantage Oasis observed with the bits was the ability to drill the entire lateral with a single bit.

The company realized a substantial drop in tripping time and number of bits used on wells. When adding up trip time saved, increase in single-bit laterals and an increase in ROP, Oasis achieved considerable cost savings on wells where the bits were used.

Tough test

In the Permian Basin, another operator chose a typical Wolfcamp well plan to test the StingBlade bit for ROP, impact resistance and overall longevity. The test required drilling the lateral section first with a Z516 five-blade bit design. After drilling 762 m to 915 m (2,500 ft to 3,000 ft) a motor failure required a pipe trip.

While the motor was being changed out, the bit was inspected and showed minimal wear. Continuing the comparison test, a standard MDSi516 bit with an identical diameter, blade and cutter arrangement but without any conical diamond elements was run into the hole. It only drilled 113 m (375 ft) before it was damaged beyond repair while drilling a transition zone. A Z516 bit of the same configuration was then run to drill the remaining 762 m of lateral, which it accomplished with minimum wear. In each case the new bit averaged higher ROP, greater longevity and superior impact resistance. It stayed sharper longer.

Vibration plays role

In both of the examples a third factor played a significant role in quality and safety. Destructive bottomhole assembly (BHA) vibration slows ROP, affects borehole quality and can severely damage downhole tools. Precise measurements have confirmed that vibration levels on BHAs utilizing bits with Stinger elements on the blade remain between zero and two for 99% of the time. Records for competitor bits where vibration was measured in the same area varied between a high of 74% and a low of 64%, respectively, with two cases where destructive level 5 to level 7 vibration was experienced.

In general, the new technology has higher steerability that allows it to kick off from vertical at a greater depth and still land in target zones. The conical diamond elements chip off much larger cuttings that allow better geological analysis when circulated to surface. Design flexibility comes from the ability to change the numbers and placement of elements according to the design program to create a customized bit for special applications. EP


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Advanced diversion technology boosts stimulation effectiveness, economics in new and rejuvenated wells

Unrestricted long-term production flow paths improve production results and reduce hydraulic fracturing costs.

Elizabeth McCartney, Baker Hughes

Since the beginning of the U.S. shale revolution, operators have been frustrated by rapid production decline rates, nonproductive frack stages, extremely low recovery factors and high opex.

Ironically, the underlying causes of these frustrations can be traced back to hydraulic fracturing, which has been cited, along with horizontal drilling, as a key enabler of the shale revolution. Like all liquids, hydraulic fracturing fluids tend to follow the path of least resistance. This frequently leads to erratic fluid and proppant placement, which can result in overtreated zones, fractures growing into undesired zones, untreated perforation clusters within a stage, suboptimal reservoir contact and the inability to create the desired level of complexity in the fracture network.

Diverter technology

In the past, commodity diverter materials such as gilsonite, rock salt, benzoic acid flakes and bio-sealers often were deployed to block the path of least resistance and redirect fracturing fluids to the perforation clusters where they are needed for maximum stimulation performance. To perform effectively, these diverter materials must remain intact throughout the fracturing operation to create the desired "barrier," then dissolve after the operation is completed to permit production flowback to the well.

More recently, specially engineered solid particulate diverter systems have been developed with optimal particle size distribution and longer dissolution times. In addition, these newer diverters help enable far-field diversion, which creates more complex fracture networks by temporarily plugging the main fracture to allow the fluid and proppant to extend into the far—and smaller—reaches of the fracture network. However, one challenge that has remained is that the dissolving diverters create voids in the proppant pack that can close or "choke" the fracture in the near-wellbore area and restrict production.

Newest advancement

The latest advancement in diverter technology is a solid particulate diverter and ultralightweight proppant combination known as REAL Divert Complete that is engineered to deliver effective, efficient diversion without risking collapsed or choked hydrocarbon pathways. Superior conductivity is enabled by premixing an engineered solid particulate diverter with a specially engineered strong but lightweight proppant and placing it into the fracture area.

The system's diversion materials are fully degradable and soluble, so they clean up completely after the stimulation treatment. The ultralightweight bimodal proppant is engineered to have large particle size distribution, which makes the diverter more efficient. Once the diverter particulates dissolve, the proppant particles keep the fracture open to maintain a permanent connection between the near-wellbore and far-field areas of the fracture network and to allow unrestricted hydrocarbon flow throughout the life of the well.

Improving production

With increased reservoir contact and more effective stimulation of perforation clusters, production and ultimate recovery are improved. For example, an operator in the Bone Spring Shale in New Mexico significantly improved production over offset wells using the new family of diverter technologies.

The operator was dissatisfied with initial production rates and recoveries from multistage hydraulic fracturing of offset horizontal wells in the field. Information gathered from production logging, microseismic and other monitoring methods showed that not all frack stages were contributing to total production. A key reason was that some perforation clusters in each stage had been either ineffectively stimulated or not stimulated at all. It is believed that there were two primary contributors to the inconsistent fracture pattern and the resulting poor performance along horizontal laterals. First was the heterogeneous nature of shales. Sec-

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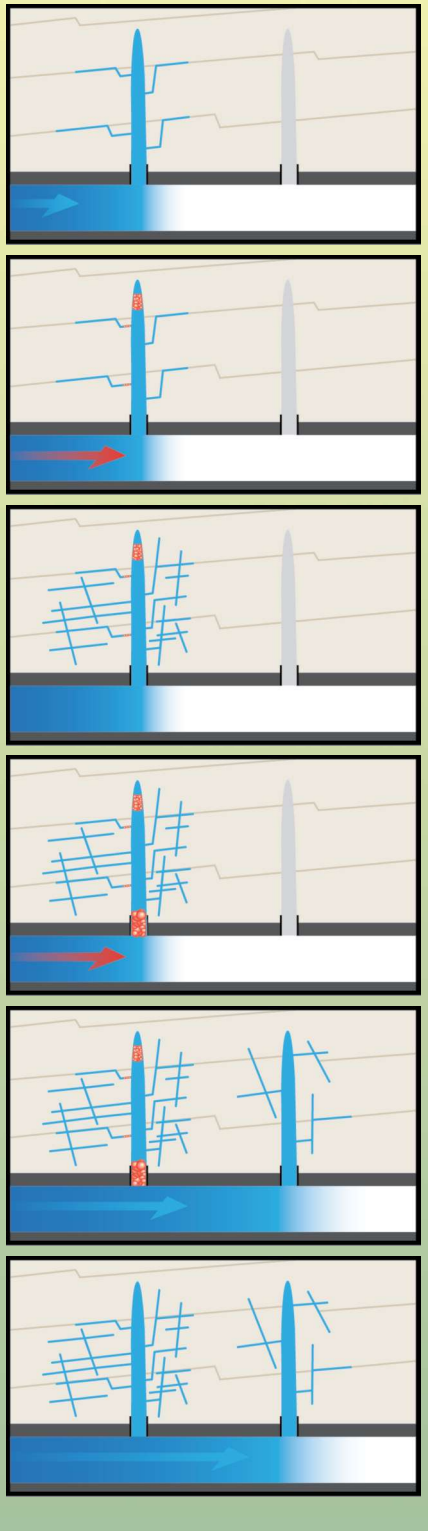
New Diversion Technology Sequence

(Source: Baker Hughes)



1. **First, a portion of the scheduled fracturing fluid and proppant is pumped, creating a fracture with minimal complexity.**
2. **A fine-mesh-size particulate diverter system is pumped far into the formation to bridge within the created fracture network. This is referred to as far-field diversion.**
3. **Additional fracturing fluid and proppant are then pumped and redirected to the smaller fracture systems to create a more complex fracture.**
4. **A larger-mesh-size diverter system is then pumped to bridge off the main fracture within the near-wellbore and perforation area. This is referred to as near-wellbore diversion.**
5. **Fluid and proppant are redirected to another perforation set that was not previously accepting any fluid, and a new fracture is created.**
6. **With time, temperature, and an aqueous- or oil-based carrier fluid, the diverter will dissolve, leaving a more conductive fracture geometry.**

ond was a phenomenon known as imparted stress shadowing. This phenomenon occurs when two hydraulic fractures are placed adjacent to one another and the presence of one frack impacts the stress experienced by the other.

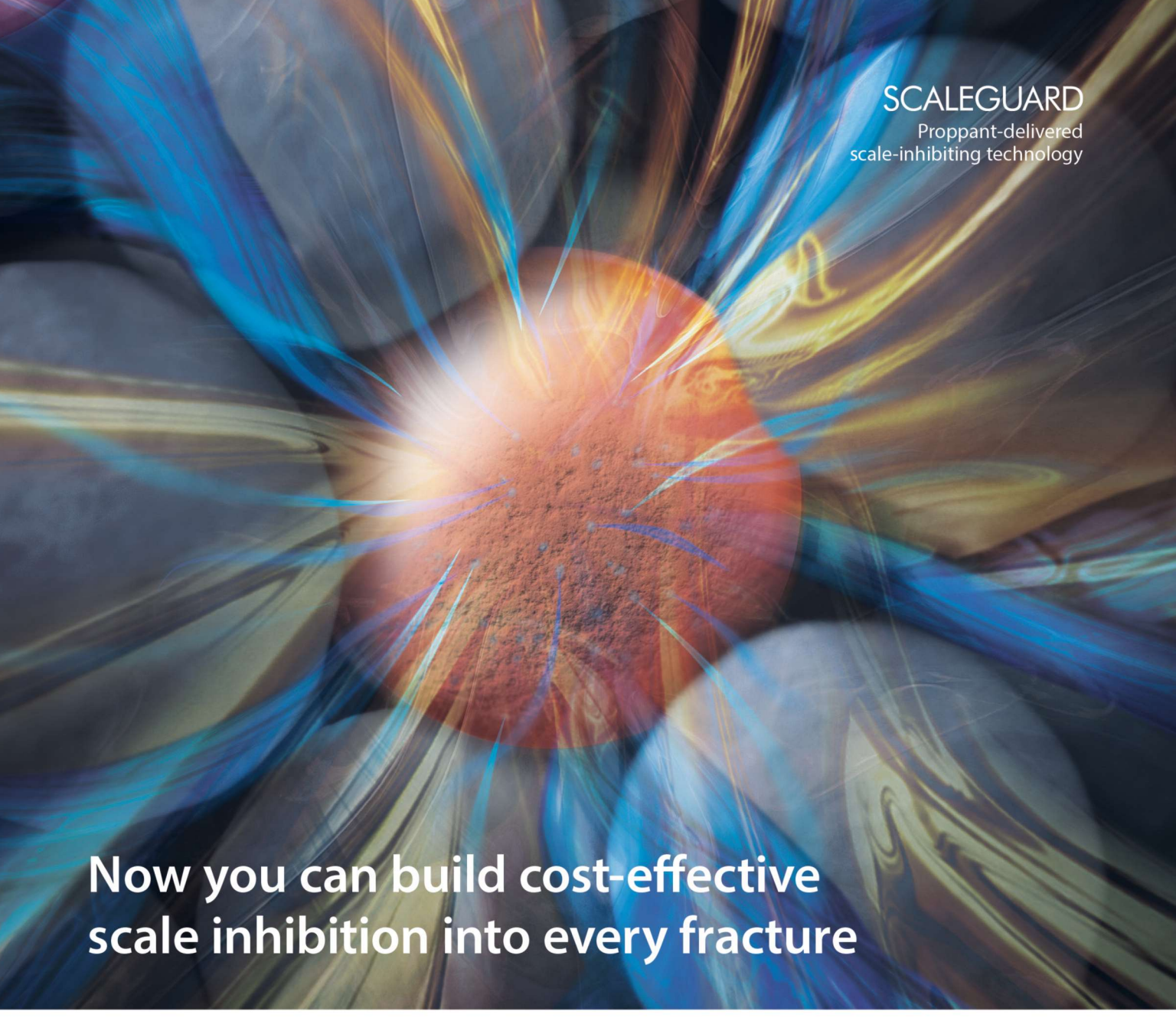
The new solid particulate diverter was used to treat a new well with 10 planned frack stages and five perf clusters per stage. The treatment effectively stimulated the perf clusters by providing more even distribution of the fracturing fluid and proppant. During the first six months of production, the treated well's cumulative production was 54% greater than the offset wells.

Economic benefits

Diverter systems such as the one described in this article help accelerate stimulation operations by enabling the placement of more perforation sets per stage, combining stages and reducing the number of plugs required for isolation. In addition to improving initial production rates in new conventional and unconventional wells, these diversion technologies can help rejuvenate mature wells through effective refracturing treatments.

The economic benefits of the latest diverter technology in this application are illustrated by a case study in De Soto Parish, La., where production from six wells increased between 8% and 2,271% following the restimulation treatment. An operator in this section of the Haynesville Shale had a large inventory of previously drilled unconventional wells that were reaching the low end of the production curve. The operator wanted to refracture the existing wells to avoid the cost of drilling and completing new wells.

It was determined that the diverter for the restimulation would need to be stable enough to withstand the 150 C (300 F) bottomhole temperatures found in the Haynesville for up to 16 hours—the estimated amount of time needed to complete retreatment. To treat underperforming intervals and reestablish wellbore connectivity through pre-existing fractures, a specially formulated high-temperature diversion agent was pumped between frack stages. Engineers on location closely monitored the job and adjusted the volume of diverter as needed to control the pressure responses for each treatment stage. The constant monitoring and adjusting of pump rates and fluid selection kept pressure, fluid and diverter responses under control. Restimulating with diversion technology resulted in savings of $7 million per well by eliminating the need for drilling and completing replacement wells. It also enabled the operator to effectively restimulate more of the lateral section, increasing EUR. Based on these results, the rejuvenation program has grown from a six-well pilot to a 15-well program, with 70 additional wells in line for rejuvenation. E&P



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Improving hydraulic fracturing efficiency with better proppant transport

New proppant transport technology simplifies completions while reducing water consumption.

Brian Goldstein, Fairmount Santrol

A proppant transport technology, which is a proppant and fluid system in one, was designed to make completions simpler by reducing pumping time and water consumption in addition to eliminating extraneous chemicals. The Propel SSP hydrogel polymer wrapped around a proppant rapidly swells and suspends the proppant by just adding to water. The hydrated polymer reduces a proppant's effective specific gravity (SG), enabling uniform proppant distribution throughout a thin frack fluid. Once in the fracture, the polymer is cleanly broken with a traditional breaker. This more efficient hydraulic fracturing system expands the reservoir drainage radius from a longer effective fracture half-length.

This new technology simplifies downhole chemistry, eliminating compromises faced by the industry for decades. Because traditional proppant falls out of the frack fluid before reaching the fracture tip, engineers have increased frack fluid viscosity and/or pumping rates. Frack fluid additives that increase viscosity can be costly, and the chemistry can damage the formation and proppant pack. Engineers have chosen finer-mesh, lower-conductivity proppant to achieve enhanced transport.

The required mesh size can be pumped, and proppant is evenly transported throughout the fracture length and height. Engineers can plan pumping designs without certain frack fluid additives, including guar, crosslinkers and friction-reducers. The Propel SSP technology maximizes the reservoir contact area.

Propel SSP proppant transport technology swells upon contact with water to go farther and higher into the formation, expanding the reservoir drainage radius from a longer effective fracture half-length. (Source: Fairmount Santrol)

Technology design, fluid systems

The hydrogel polymer is wrapped around a proppant substrate of frack sand or ceramic. The substrate's characteristics are not altered. When mixed with water, the hydrogel polymer expands, reducing the substrate's effective SG to resist settling and enabling the proppant to stack higher in fractures.

The hydrogel, which remains wrapped around the proppant during fluid transport, reduces friction while pumping and imparts minimal viscosity of approximately 5 centipoise (cp) to 7 cp per parts per gallon (ppg) of proppant. This low-viscosity fluid remains in the pay zone. Proppant travels farther into the formation and throughout the fracture half-length.

Slick water, one of the most common fracturing fluids, reduces the friction generated as fluid is pumped down the wellbore. Although perceived to be low-cost, slick water offers poor proppant transport, requires a high pumping rate and excessive water, damages formation permeability, and results in reduced effective fracture half-lengths.

Linear gel reduces treating pressure, allows lower pump rates and increases the frack fluid's proppant-carrying capacity. Crosslinked gel generates higher viscosity in the range of 200 cp to 1,000 cp, further improving proppant-carrying capacity and increasing the fracture width and height compared with linear gel and slick water. Despite the improved proppant transport and fracture geometry, linear gel and crosslinked gel can place fluid and proppant out of zone while leaving behind damaging residue. A comparison

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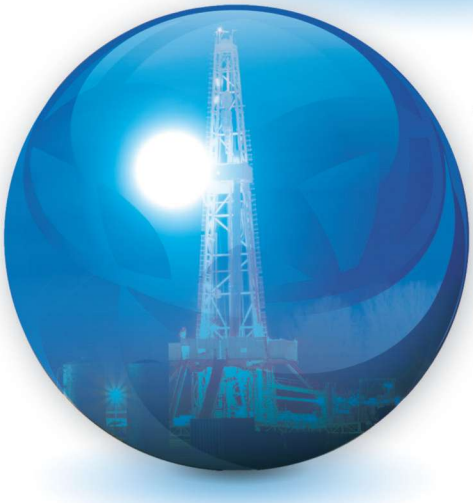

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Attributes	Slick Water	Crosslinked Gel	Propel SSP Technology
Method of proppant transport	High fluid rate	High viscosity	Any fluid rate; low viscosity
Carrying capacity	Low concentration	Any concentration	Improves at higher proppant concentration
Residual damage	Formation permeability	Proppant pack conductivity	None
Created frack geometry	Length	Width and height	Length and height

A comparison of fluid system attributes shows their effects on completion performance.

of the technology against slick water and crosslinked gel systems is shown in the table.

Surface handling

Prior to pumping, the technology must not stick together in the high heat and humidity of a South Texas summer. This is the benchmark climate condition for moisture resistance to ensure product integrity using traditional shipping methods from proppant terminal to well. Fairmount Santrol R&D developed and refined this important attribute based on close monitoring of initial field trials.

Even in cold weather, the technology swells without using a hydration unit. Unlike conventional gel-based fluids, this robust technology achieves 190% expansion within 30 seconds of pumping when stored at subzero temperature and added to 4.4-C (40-F) water. Additional water heating is unnecessary when pumping in cold climates.

Oilfield services companies are pumping the system without modifying surface equipment or changing equipment controls, regardless of climate conditions.

Pressure pumping

As the technology rapidly hydrates in water, maintaining shear stability is important. Shear stability is the polymer-coating capacity to remain attached to the proppant from the frack blender through the pumps, perforations and fracture network. Shear stability ensures the coated proppant uniformly distributes and stacks throughout the fracture. If the polymer were to detach, there could be two negative effects. First, the fluid viscosity would increase, potentially resulting in fracking out of zone. Second, the technology's unique stacking effect that increases propped fracture height would be absent.

The swollen, shear-stable polymer coating lowers the proppant substrate's effective SG. When pumping proppant at a concentration of less than 3 ppg, lower SG enables efficient proppant transport. This transport is accomplished by reducing the fluid velocity needed to keep proppant flowing. As proppant concentration increases above 3 ppg, SG plays a less important role with this technology. Typically, at or above this concentration, the technology consumes all free water in a fluid column, resulting in uniform suspension in the frack fluid and ideal proppant transport.

Polymer breaking

The technology is pumped with traditional oxidizing breakers. The breaker is absorbed within the hydrogel and carried downhole as the technology hydrates. Once at bottomhole conditions, the breaker causes the hydrogel to unwrap from the proppant and break down to a low molecular-weight fluid that can flow back easily. After fluid flowback, there is no residue left in the fractures or around the proppant pack as with traditional fluid systems.

Breaker testing was conducted with commercially available breakers, including ammonium persulfate and magnesium peroxide. More than 10 oilfield services companies have used their proprietary chemistry to do the same. Test conditions comprised various technology concentrations, temperature, breaker loading rates and time.

Prior to pumping, polymer breaking should be verified by testing the fluid viscosity and proppant pack attributes. The polymer will flow back when the viscosity reduces to near that of water. The proppant pack should appear identical to an uncoated substrate, feel gritty and visually fill the same volumetric space as a sand sample of equal mass.

More detailed analytical and performance tests also confirm a clean break. Analytical tests, including loss on ignition and spectra analysis, have validated no residue remains on the proppant's surface. Long-term regain proppant pack conductivity and retained core permeability performance tests also validate exceptional polymer cleanup compared with slickwater and gelled frack fluids that can reduce hydrocarbon flow by more than 50%.

Compelling production

Thirteen E&P companies have pumped the technology in more than 40 wells throughout the U.S. and Canada plays. When compared with the offset wells completed with different fluid systems and the same pump schedule, the technology typically has increased hydrocarbon production by more than 30% within six months. In several cases, operators have achieved greater than 50% production gains within two months simply by achieving a higher proppant concentration. In addition to enhanced production with higher proppant concentrations, the technology has enabled operators to reduce water, chemical and energy consumption. E&P

Hybrid tree solutions take root

When it comes to the latest generation of tree designs available for new field developments, the answer increasingly looks like it might not be just 'horizontal' or 'vertical' but something in between.

Mark Thomas, Editor-in-Chief, and
John Sheehan, International Editor

Hybrid solutions look even more attractive to operators since this emerging new breed of tree designs, combined with long-overdue standardization initiatives being undertaken by all the main subsea contractors, also is demonstrably capable of offering substantial savings in development costs.

This emerging subsea technology trend could not have come soon enough. "I have seen a number of crises, but this one looks more like the perfect storm than anything I've seen before," said Per Arne Nilsen, head of subsea technology for Total.

Speaking during a panel session at the Underwater Technology Conference (UTC) in Bergen, Norway, he also bemoaned the lack of standardization over time that had driven up costs. "Every time we have a new project it is a bespoke design. We like to bash ourselves these days to show that we are serious and changing. If you look at Total and our history, we have been very good at one thing, and that is never repeating anything twice."

Increased efficiency

Nilsen commented that the subsea industry has created an "extremely inefficient" business during the last 10 to 15 years with negative productivity.

"If you look at a [christmas] tree today compared to a [christmas] tree 10 years ago, it's the same. It has got some more whistles and bells, but today we spend three times the man-hours to engineer and manufacture it compared to 10 years ago, for no obvious reason. We need to increase efficiency," he said.

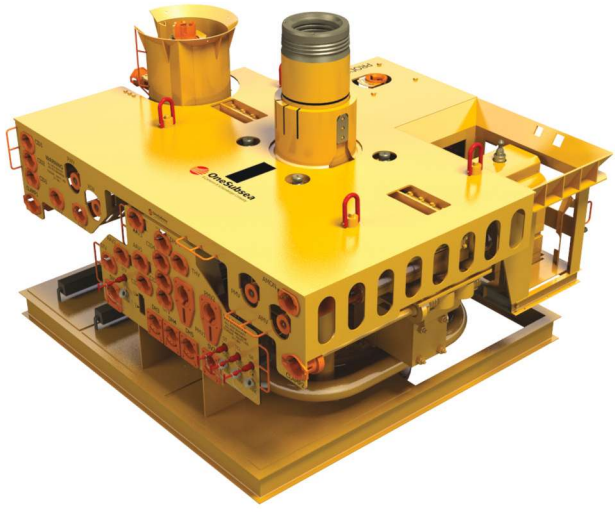
Roald Sirevaag, Statoil's vice president for subsea and diving, at the same event called for greater cooperation on subsea trees. "We are operating with non-standard specifications. For 5-in. deepwater trees we asked for four completely different solutions doing exactly the same job. I think we should agree on one type of tree."

HyFleX highlighted

The industry, however, appears to be already heeding the operators' pleas. A growing number of the main hardware manufacturers are expanding or are planning to expand upon the traditional vertical and horizontal subsea tree designs. OneSubsea recently unveiled its HyFleX tree, which it said offers the benefits of both types.

The HyFleX system has the tree and the tubing hanger as two separate units in parallel rather than in series, meaning the tree and tubing hanger are completely independent in their installation and recovery. "The benefit of that is that all that equipment would be more easily recoverable if required," said James Stewart, OneSubsea's tree product manager. "The HyFleX tree system offers greater benefits, more flexibility and reduced cost. It gives greater and optimized installation and recovery options by having the tree and the tubing hanger as independent units in parallel rather than in series. Because these units are separate, you have a lower lift weight, and they can be lifted individually rather than in one large assembly."

The tree system comprises three major components that are integrated. The tubing head spool consists of



OneSubsea recently unveiled its HyFleX hybrid subsea tree. (Source: OneSubsea)

the wellhead connector main body and valves and forms the barrier on the wellhead.

The system also is designed to be standardized. The tree module integrates onto the tubing head spool, with the tree module designed to be configurable. This is where the project-specific requirements can be accommodated. The module would contain hydraulically actuated valves, chokes, control systems, chemical injection metering, any monitoring and sensors—essentially everything that would be in the tree.

Field-proven

All of the components of the HyFleX tree already exist, including the wellhead connector, the valves and the connection systems, according to Stewart. "It is all field-proven and already existing technology."

It is not entirely surprising that the first "visible" hybrid tree has emerged from OneSubsea. Its joint founder parent company Cameron was responsible for two highly significant tree advances: the SpoolTree, otherwise known as the horizontal tree, which came onto the market in the early 1990s; and all-electric trees, which appeared in the mid-2000s.

OneSubsea's own figures suggest that the HyFleX tree could offer savings of $10 million per well, which on a 10-well field can add up to savings of $100 million achieved simply by tree selection alone.

During the Offshore Technology Conference in Houston, the company outlined a case study based on an operator in Malaysia that had a four-well development consisting of four trees, four in-line sleds, jumpers connected to the sleds, jumper connections and pressure caps. The development featured a flowline in a daisy chain arrangement linking each one of these together so the flowline can be installed independently of the tree with four in-line tees.

"Essentially, we can link the flowline into the tubing head spool on the HyFleX tree, and the flowlines can therefore be installed completely independently of the trees," Stewart said. "We have four trees as before, but now we only have eight jumper connectors and eight pressure caps. We have saved four in-line tee-sleds, four jumpers, eight jumper connectors and four pressure packs. For this field that was a 20% saving just in capital expenditure [capex]. That doesn't include installation cost savings. That often can be the difference between a field being viable or not."

Fast-track trees

Mike Garding, OneSubsea's CEO, also spoke at the UTC event in Norway, where he focused on aspects of tree standardization.

He highlighted the success of a fast-track tree program developed several years ago to meet the requirements for a flexible well solution with reduced lead time and reduced capex. "The uptake of this solution has been particularly successful in the Gulf of Mexico, and we're expanding this to other regions globally. The pre-engineering components provide a common tree core that can then be configured with key components."

Garding said the fast-track program, compared with conventional procedures, led to delivery times being shortened by six months and costs being reduced by between 20% and 30%. "This is a successful example of standardization of design and manufacturing processes. Bespoke engineering and man-hour costs are down. The reuse of proven solutions reduces risk, costs and lead times," he said.

New design debut on Sverdrup

Statoil and its subsea contractors also have been working hard to reduce tree costs and time, putting their heads together to develop a new 7-in. vertical christmas tree that will make its debut on the giant Johan Sverdrup Field project offshore Norway.

The tree has been developed as part of a companywide cost initiative that was actually implemented by Statoil before the oil price crash.

Kristoffer Dahl, a subsea engineer with Statoil, described the VXT Initiative's 7-in. christmas tree as a cooperation between Statoil and its four main subsea contractors, Aker Solutions, FMC, GE Oil & Gas and OneSubsea.

"The main intention for developing a new christmas tree at Statoil was to reduce the rig time, especially the maintenance costs of the rig," Dahl said during UTC. "It is more a cost reduction on the operational side and the life-cycle total cost."

Hybrid vertical tree

The vertical tree consists of a 7-in. vertical bore that is unlike the horizontal 7-in. unit. "The tree is put on top of the completion," Dahl said. "The tubing hanger is installed directly in the wellhead and not through the tree, as it is on the horizontal tree. It is not a true vertical tree. It is more of a hybrid [since] the valves are on the horizontal side, but we still call it a 7-in. vertical [christmas] tree."

He said the main challenge had been to qualify an annulus barrier valve. "As a 7-in. vertical [christmas] tree you don't have any direct access in the tube on the annulus side, so some sort of plug-in mechanism is needed in the tubing hanger. The Johan Castberg project has been leading the development, but Sverdrup has joined in the financing. Johan Sverdrup will be the first user of this tree," he said. E&P

Looking to the long term

With the nervous offshore industry likely to produce only modest growth in the subsea tree market over the short to medium term, the expectation is that the eventual rebound will be largely driven by the E&P sector's continued and necessary push into deeper waters.

Diego Lorenzo, Infield Systems

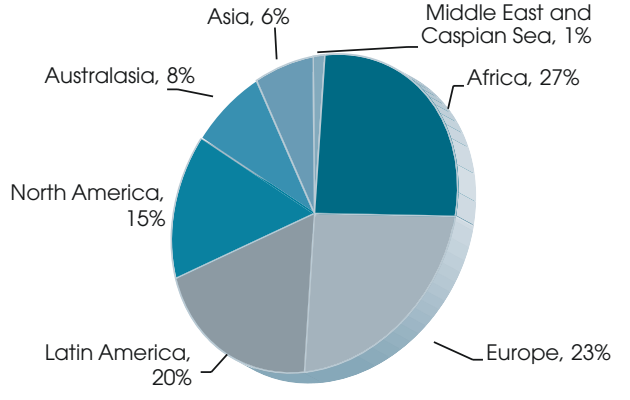
The ongoing cuts in capex and the continuing lower level of crude prices have led to considerable caution across the industry, with modest market growth in the short to medium term now expected.

Over the longer term, however, with world energy demand increasing and crude prices expected to recover, Infield Systems anticipates growth potential. Indeed, while Infield expects significantly lower levels of subsea tree installations during 2015 and 2016 compared to the previous two years, the likely increase in deep and ultradeepwater developments means the subsea tree market is expected to rebound from 2017 onward.

Africa is expected to lead the market in terms of subsea tree installations between 2015 and 2018 with 27% of the period's installations, followed by Europe and Latin America holding 23% and 20% of global installations, respectively.

The remainder are split between North America, Australasia, Asia, and the Middle East and Caspian Sea region, which are expected to comprise a combined 30% of tree installations throughout the period to 2018.

Subsea Tree Installation 2015-18—By Region



(Source: Infield Systems)

Africa

The African market is expected to be driven mainly by the deepwater developments off West Africa, with Total leading the way on projects including Kaombo offshore Angola, Egina offshore Nigeria and Moho Nord Marine offshore Congo (Brazzaville). Offshore Ghana, Tullow's Tweneboa (TEN) project and Eni's Sankofa East project and developments within its Angolan East Hub in Block 15/06 also are expected to require a high number of tree installations during the 2015 to 2018 time frame.

In terms of capex, Africa is projected to form a 27% share of the global subsea trees installation expenditure during the 2015 to 2018 time frame, with the most capital-intensive subsea development expected to be the Egina development, with a peak subsea spend expected in 2017.

Europe

Subsea activity in Europe will continue to be driven by the North Sea, accounting for more than 90% of the region's tree installations. The majority of such installations (205) are expected to be located within U.K. waters, where the average water depth of such installations is expected to be 162 m (532 ft).

The single largest project within the region in terms of installations is expected to be Kraken, east of Shetland. BP's Quad 204 Schiehallion redevelopment and Statoil's Gullfaks satellites also are expected to see a significant number of installations during the forecast period.

In terms of capex, Europe is expected to represent 6% of total global demand for tree installations over the next four years, with Kraken expected to be the most capital-intensive project taking place.

Latin America

Latin America's subsea tree market will continue to be predominantly driven by Brazil, with the country comprising about 90% of future installations in the region. Brazil's deep and ultradeepwater presalt and post-salt developments, such as Petrobras' multifield Lula, Buzios and Iracema developments, are the main drivers of the

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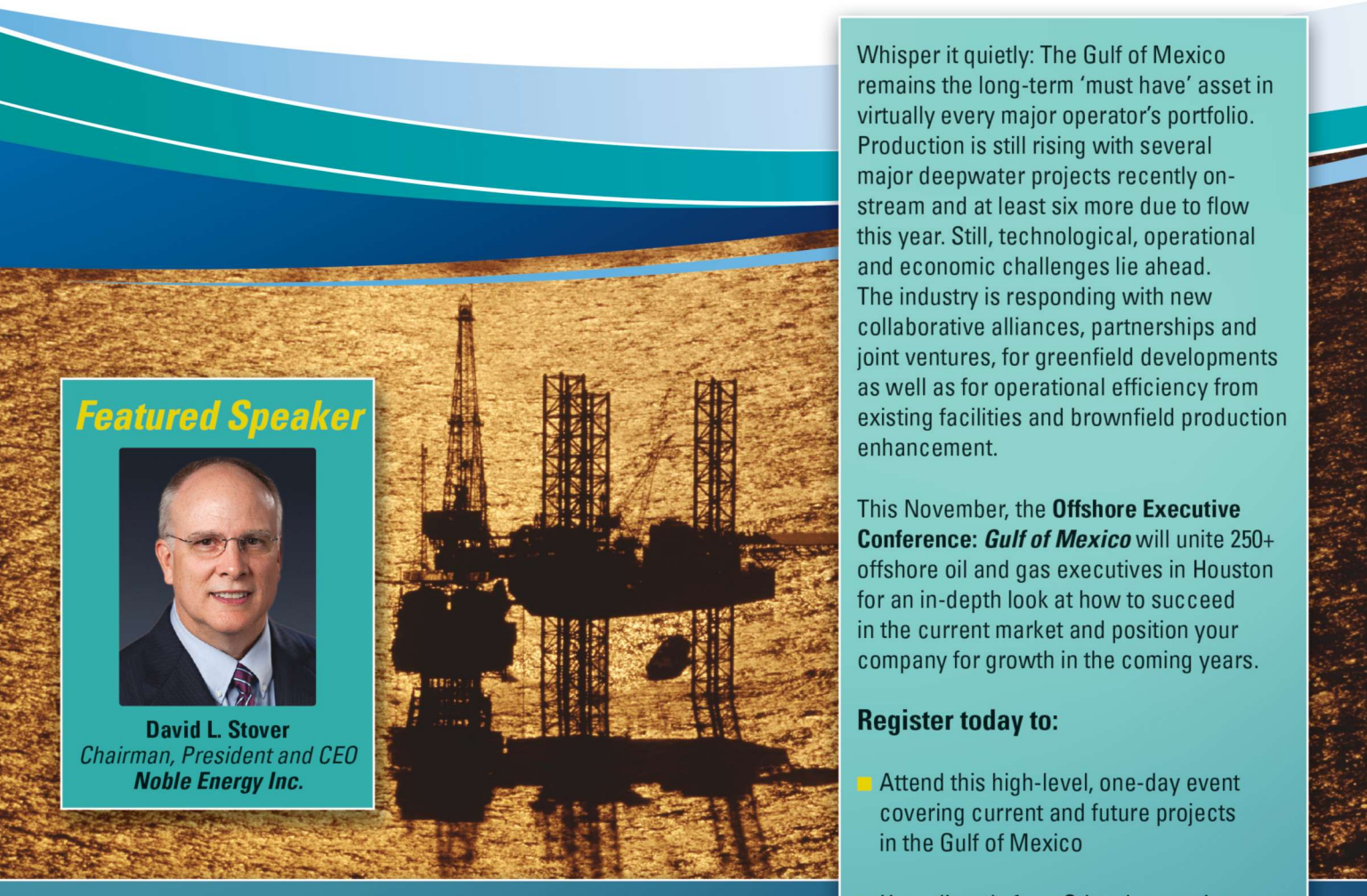

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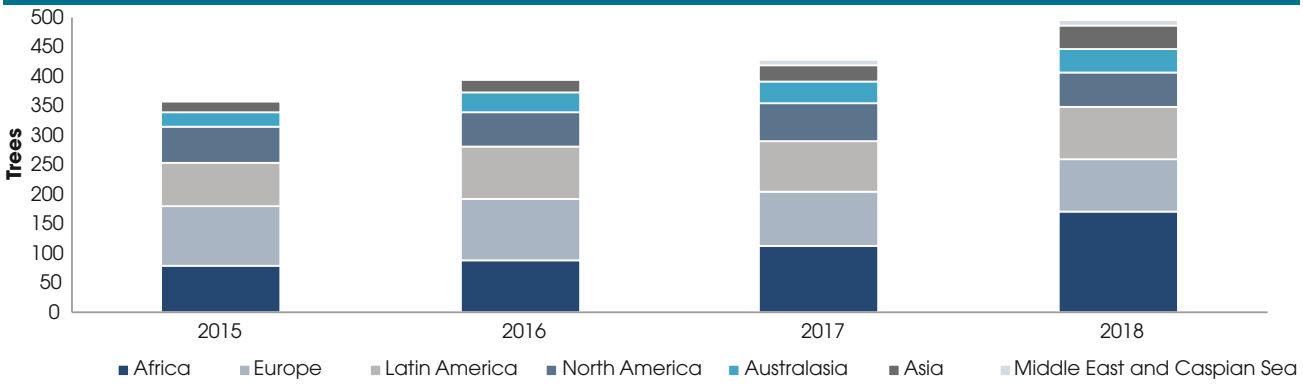
Subsea Tree Installation 2015-18—By Region



(Source: Infield Systems)

sector. However, following the company's corruption scandal, some contracts have been suspended and deliveries delayed, which in turn could affect Petrobras' production targets.

For instance, in May a Brazilian federal court ordered the temporary suspension of the contract for 29 locally built presalt drillships. The potential cancellation of rig orders would force Petrobras to look outside Brazil for its future rig requirements, resulting in a knock-on effect as the installation of subsea trees might be delayed.

With respect to capex, Latin America is projected to hold the largest share of global tree installation, with a 35% share. The most capital-intensive development is expected to be the giant Lula Central Field, where tree installations are forecast to take place in up to 2,200 m (7,218 ft) of water.

North America

Influenced largely by a continuous focus on deepwater activity in the U.S. Gulf of Mexico (GoM), North America is expected to see around 15% of global subsea trees installations between 2015 and 2018. The U.S. is set to account for 87% of these awards, while Canada is anticipated to account for the remaining 13%.

Activity is expected to peak in 2017, driven by major projects such as Heidelberg and Chevron's Jack-St. Malo in the GoM and Exxon Mobil's Hibernia extensions offshore eastern Canada. With regards to capex, North America's spending is anticipated to represent 25% of global tree installation capex over the forecast period, which will be driven by operators such as Shell, with a 24% share of the region's subsea tree expenditure during those years.

Asia-Pacific

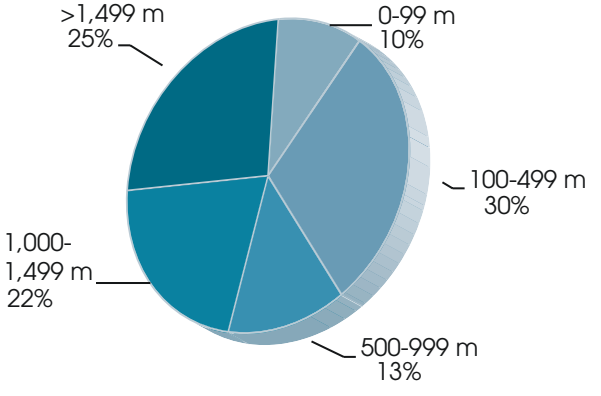
In the Asia-Pacific region, Australia is likely to be a major focus for subsea expenditure, driven by the country's determination to become a major LNG exporting nation. Australasia (comprising Australia and New Zealand) is expected to account for 8% of global subsea tree installations and 3% of capex over the next four years.

Key megaprojects are the Chevron-led Greater Gorgon, Shell's Prelude and Inpex's Ichthys, the latter of which is Japan's largest-ever investment in Australia. In May it was announced that the Ichthys project was on track to deliver first LNG cargoes by year-end 2016.

Projects in Malaysia, China and India will drive subsea tree installations, with the region expected to account for 6% and 3% shares of global installations and global expenditure, respectively, for the 2015 to 2018 period.

A peak in tree installations is expected in 2017, bolstered by developments in India such as ONGC's projects in the Krishna Godavari Basin. So far, India's major offshore developments have been in the shallow waters off the west coast due to the country's limited exposure to subsea technology.

Subsea Tree Installation 2015-18—By Water Depth



(Source: Infield Systems)

Middle East, Caspian

The Middle East and Caspian region, with 1% of global subsea tree installations as well as a 1% share of global subsea tree expenditure over the forecast period, is expected to remain a marginal market. Substantial growth in the number of installations from 2017 onward is forecast to be driven by Azerbaijan and Israel, with BP's Shah Deniz Stage 2 project in Azerbaijan and Noble's Leviathan project in Israel holding the potential to become key gas developments in the region.

Water depths

Breaking the market down further in terms of water depth, shallow-water developments (at depths up to 499 m [1,637 ft]) are expected to account for 40% of subsea tree installations over the forecast period, which is mostly focused within Europe. Installations in depths from 500 m to 999 m (1,640 ft to 3,278 ft) are expected to account for just 13% of installations taking place, mostly centered upon developments offshore West Africa.

Projects in water depths of 1,000 m (3,281 ft) and greater are likely to account for the remaining 47% of subsea tree installations, with Brazil, the U.S. and Angola anticipated to be key countries driving demand. Indeed, together these three countries are expected to hold a combined 36% share of global tree installations in depths of more than 1,000 m during the 2015 to 2018 time frame.

Outside the Middle East and Europe the offshore oil and gas market will focus significantly on deeper waters, with 78% of subsea tree installations over the 2015 to 2018 time frame expected to be located in water depths of 1,000 m or more, with 64% of installations in ultradeep water of more than 1,499 m (4,918 ft).

Indeed, while capex demand is likely to fall this year and next as installations are pushed to the latter half of the four-year forecast period and operators continue to trim their spending budgets given the low oil price outlook, over the long term substantial growth will be driven by both an increase in volume and the overall cost of subsea tree installations as projects move into deeper waters. E&P

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Formation Evaluation: wireline logging, core analysis, cuttings analysis and well testing hardware and software

HSE: hardware, software, and methodologies related to health, safety and the environment

Drillbits: natural diamond, impregnated, PDC, bi-center, milled tooth, hybrid, insert and hammer

Drilling Fluids/Stimulation: chemicals, drilling mud, additives, flow enhancers and green systems

Drilling Systems: LWD/MWD, motors, coring, tool joints, fishing tools, drillpipe, whipstocks, subs, packers and rotary steerable systems

Hydraulic Fracturing/Completions: surface equipment, frack trees, hhp, plug-and-perf, sliding sleeves, cementing, perforating, horizontal drilling, stages, frack balls, zipper fracks and microseismic

E&P

Argentina goes against the grain by increasing spending

A 14% budget increase by YPF for 2015 is mainly aimed at unconventional shale plays and tight gas sands.

Scott Weeden, Senior Editor, Drilling

Oil and natural gas were flowing from the Vaca Muerta Shale at the rate of 22,900 bbl/d of oil and 1.9 MMcm/d (67 MMcf/d) of natural gas for YPF at the end of the first-quarter 2015. Argentina, the U.S., Canada and China are the only four countries in the world producing commercial volumes of oil and gas from shale plays.

YPF sees a significant upside in the unconventional resource base in Argentina—an estimated 27 Bbbl of oil resources and 22.7 Tcm (802 Tcf) of natural gas.

As the largest shale operator in the country, YPF has three joint ventures in the Vaca Muerta play in the Neuquén Basin: with Chevron at the Loma Campana concession, Dow Chemical at the El Orejano concession and Petronas at the La Amarga Chica concession. In addition, Sinopec and Gazprom recently signed memoranda of understanding with YPF to jointly develop shale in the basin, according to the U.S. Energy Information Administration.

Loma Campana development

As the sixth largest producer in Argentina, Chevron Argentina has several interests in the Vaca Muerta Shale. The most active work is on the Loma Campana concession with YPF as the operator. During 2014 there were 19 rigs active drilling vertical and horizontal wells. A total of 166 wells were drilled in 2014. Plans call for drilling another 150 wells. At year-end 2014, 290 wells were connected to production facilities.

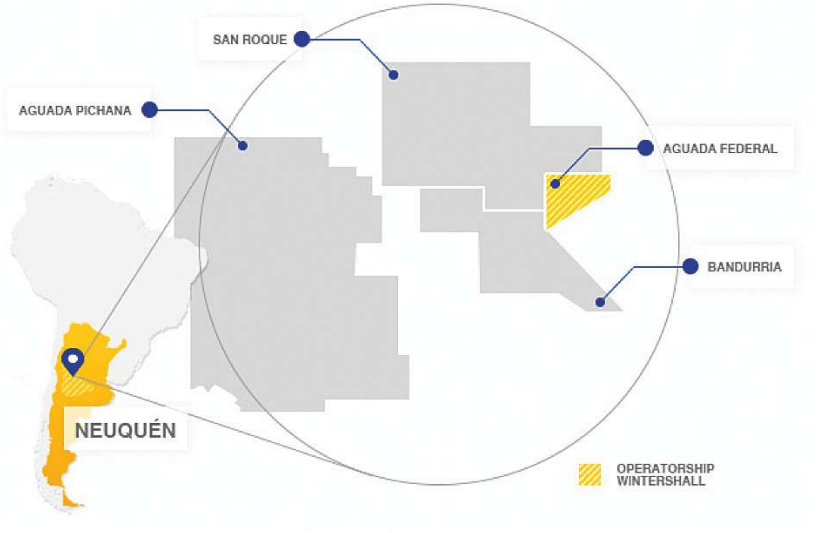
According to an April 2015 shareholders presentation, YPF expected the complete development to include 1,400 wells at a cost of $15 billion.

This follows agreements that were signed by Chevron and YPF in early 2014. The agreements called for continued investment toward large-scale drilling and production in the 96,000-acre Loma Campana concession, according to Chevron.

The agreements also call for exploration of shale oil and gas resources in the 49,400-acre Narambuena area located about 100 km (60 miles) north of Loma Campana in the Chihuido de la Sierra Negra concession, which is one of the main producing areas in the Neuquén Basin of west-central Argentina. The exploration plan for Narambuena includes a total of nine wells to be drilled in two phases, according to the 2014 supplement to the annual report.

On March 18, 2015, a Chevron press release noted that YPF was making impressive progress as the first development project in Argentina's Vaca Muerta Formation. Since January 2014 production has doubled, and Loma Campana has become the second-largest oil producer in Argentina. The project area has an estimated recoverable resource of 1 Bboe.

To achieve the Loma Campana development plan, the project team draws on shale experience gained in Chevron's Appalachian/Michigan and Midcontinent



Wintershall has interests in four blocks in the Vaca Muerta play. (Source: Wintershall)

operations. The Loma Campana team uses walking rigs to drill up to eight wells on one well pad.

Chevron subsidiary General Manager Kevin Maneffa credits YPF for forging the path at Loma Campana after drilling 120 wells during a pilot phase in 2012 and 2013. "The lessons learned from the pilot wells are enabling us to standardize operations and drive costs down, which is key to shale development," he said.

YPF has been able to reduce the cost per well from $11 million in 2011 to $7.6 million in 2014. Through the first four months of 2015, the company has averaged $7 million per well.

In its joint venture with Petronas, YPF was scheduled to begin drilling in the La Amarga Chica concession in second-quarter 2015. The first stage involves 30 vertical and horizontal wells at a cost of $550 million. The entire development will include more than 1,000 wells at a cost of $9 billion.

The first stage of its work at the El Orejano concession with Dow called for 16 wells at a cost of $180 million. The complete development will include 12 vertical and 172 horizontal producing wells.

Other activity in Argentina

Total has been involved in a large-scale drilling campaign in the Vaca Muerta Formation in Neuquén Province to assess shale gas and oil potential in its operated Neuquén licenses, including Aguada Pichana, San Roque, Rincón la Ceniza and La Escalonada (85% interest in each) along with Aguada de Castro and Pampa de las Yeguas II (42.5% interest in each).

Total has nonoperated interests in Cerro Las Minas (40%), Cerro Partido (45%), Rincón de Aranda (45%) and Veta Escondida (45%).

Wintershall Energía sees the potential of unconventional reservoirs in Argentina as huge, especially in the Vaca Muerta Formation. The company has interests in the San Roque, Aguada Pichana, Bandurria and Aguada Federal concessions.

In March 2015 Wintershall as operator launched its first vertical exploration well in the Aguada Federal concession. The company plans to drill a second well in 2015. Depending on the results, the company will drill six horizontal wells to optimize the development concept. The block, which includes the Vaca Muerta Shale, is in the eastern part of Neuquén Province. The reservoir is situated between 2,700 m and 3,000 m (8,856 ft and 9,840 ft) deep.

In early 2012 Wintershall Energía was awarded two exploration permits for the blocks CN-V and Ranquil Norte in Mendoza Province. In spring 2013 a 3-D seismic survey was run in the CN-V block. The companies investigated the Ranquil Norte area in 2014.

YPF has 19 rigs drilling vertical and horizontal wells in the Loma Campana concession. The company drilled 166 wells in 2014. (Source: YPF)

Hydraulic fracturing has boosted production from the Vaca Meurta Formation to nearly 45,000 boe/d. (Source: Pan American Energy)

In the Aguada Pichana block more than 270 wells have been drilled. For 2015 around 10 new wells are planned, most of them targeting tight gas reservoirs.

In 2014 a shale gas pilot project consisting of 12 horizontal wells with horizontal sections ranging from 1.5 km to 2 km (0.9 miles to 1.2 miles) started drilling the Vaca Muerta Formation.

GeoPark noted in its 2014 annual report that it "relinquished two nonproductive blocks in Mendoza Province and also participated in the Mendoza bidding round to acquire a nonoperated 18% interest in two blocks with our partner Pluspetrol. In 2015 we will carry out a seismic survey in an effort to delineate an attractive new shallow oil play [20 MMbbl to 30 MMbbl potential]."

In Fortín de Piedra, Tecpetrol is currently drilling development wells in the Vaca Muerta Formation. EP

New alternative to flaring

Power oxidation process turns 'waste gases' into clean, usable energy.

Rhonda Duey, Executive Editor

There has been a lot of buzz about dual-fuel engines and other machines that can use field gas as a fuel to save on diesel costs and emissions. But not all gas produced in oil and gas fields is usable.

So-called "waste gases" with very low Btu counts exist in many industries and are often released as pollutants since they can't be burned. A company called Ener-Core has devised a unique solution to accelerate the natural oxidation of those gases so that they can be used to power machinery.

Making gases rust

The concept was started in the late 1990s by an engineer named Edan Prabhu, head of R&D for So Cal Edison, according to Alain Castro, CEO of Ener-Core. Prabhu was interested in examining alternative ways of using waste gases. "The challenge was getting energy out of gases that are very weak from a Btu perspective," Castro said. "Sometimes these are gases that have lots of contaminants and impurities that wreak havoc on any kind of combustion device."

Prabhu started experimenting with catalysts, but due to the impurities in the gases, the catalysts kept getting poisoned. But, over time, the engineering team at Ener-Core learned how to anchor an accelerated oxidation reaction without the need for any catalysts at all.

"We all know oxidation happens to virtually everything, including our own skin," Castro said. "But, unfortunately, when it comes to greenhouse gases, our natural atmosphere simply takes way too long to oxidize them, and they linger in our atmosphere for 10 to 20 years before being fully oxidized.

"With Ener-Core's technology, we create an environmental condition or atmospheric condition where the natural oxidation reaction happens in two to three seconds instead of 10 to 20 years. By doing so, we can use the heat energy that's created by our accelerated oxidation reaction. One thing that many people, even engineers, don't realize is that oxidation is exothermic—it gives off heat. But normally it's such a slow chemical reaction that you really can't tell," he continued.

Ener-Core's test rig is shown at the company's facility in Irvine, Calif. (Source: Ener-Core)

By 2007 Prabhu had obtained venture capital funding, and between 2007 and 2013 he put some engineering resources behind his concept, built prototypes and developed what is now called the "Power Oxidizer," which takes low-quality gas, causes an oxidation reaction and releases energy in the form of heat.

"At the right pressure and temperature, we can optimize the speed of an oxidation reaction," Castro said. "Oxidation takes forever in the atmosphere. If we go to higher pressure—4 atmospheres or so—and higher temperatures, we can get that reaction to happen at its optimal speed."

Not only does the process prevent approximately 99.9% of the greenhouse gas from going to the atmosphere, but the energy released from the reaction can be used to power a turbine or boiler, he added.

Industry uptake

The company recently announced a partnership with Hofstetter B.V., a specialist in flaring technology and degassing systems, providing Ener-Core, through its distributor, Holland Renewable Energy Technologies, access to significant European markets. Hofstetter has installed more than 1,600 flaring systems around the world.

"The Ener-Core Power Oxidizer is a revolutionary technology that greatly expands our offering for customers," Andre Schoute, managing director at Hoftstetter, said in a press release.

If we go to higher pressure—4 atmospheres or so—and higher temperatures, we can get that reaction to happen at its optimal speed.

Castro added that the company has gone "way beyond field trials" in other industries, outfitting old landfills, for instance. "For every active landfill, there are probably two inactive ones. The inactive ones have very poor gas quality because they're not getting replenished with municipal waste. But one of the environmental issues is related to the fact that an inactive landfill continues to emit poor-quality greenhouse gases for another 50 to 60 years after it ceases to receive any more municipal waste. Despite these ongoing emissions of waste gases, the common thought is that once a landfill becomes inactive, you can't run any kind of power generation on it because the gas quality goes way down.

"We're actually operating on a landfill in The Netherlands that has been inactive for more than two decades, and we're enabling that landfill to generate power (and revenues) for decades to come," he explained.

The company is also in the process of installing a system in Orange County, Calif., on an inactive landfill that has been closed since 1996 but has needed to continue flaring its waste gases.

It has been a bit slower for Ener-Core to successfully enter the oil and gas industry, but it has partnered with Dresser-Rand to visit with "just a handful of first-tier oil and gas companies" to discuss possible applications, Castro said. "We're entering into evaluation phases where the enthusiasm is very high, but what they want to do is deploy a few of these units on drill sites, in oil and gas refineries and potentially at various stages throughout the pipelines."

One customer is a large oil producer. Like many upstream oil companies, it has to supplement its low-methane waste gases with high-quality natural gas to be able to flare it. The company approached Ener-Core to find a better solution.

"Phase 1 was to complete a test at our facility at the University of California-Irvine," said Mike Leone, market development manager for Ener-Core. "We trucked in large volumes of low-quality gases to simulate the gas composition from the drilling sites. That allowed us to prove that we can generate power from a very low-energy gas while also achieving the highest known emissions curtailment in the market.

"A typical gas engine needs a gas that is least 30% methane to operate properly, and we proved in that particular case that we can run our power station down to 7% methane. That's a lot lower than anyone else has been able to generate electricity from," he added.

Oil companies currently spend money to flare their waste gases, and they can now use their waste gases to produce clean electricity for their own site operations, he said. "For them it's pretty much a no-brainer."

Currently Ener-Core is structuring a plan to install one or two units in northern Alberta to prove that the units are rugged enough to withstand the region's tough winters. Then it's basically off to the races. "Virtually every drill site could one day have one of these power station units operating on it," Castro said. "We've just been in shock to learn how common it is for oil and gas companies all over the world to be purchasing natural gas solely so that they can enrich the energy density of their waste gas, just to be able to burn it and comply with environmental regulations on emissions."

Financial payback

The benefits are numerous. Not only do the systems monetize waste gases, but they also help operators comply with environmental regulations, which are becoming increasingly stringent in terms of flaring. "It's an environmental solution with a real financial payback," Castro said.

Dresser-Rand is the first licensee of this technology in the oil and gas industry, and the ultimate goal is to commercialize the technology through large, established companies that make turbines and steam boilers, he said.

"If you think about a gas turbine or a steam boiler, the first phase of both of those pieces of equipment is a combustor," he said. "Combustors have been around for hundreds of years, and they've improved tremendously. However, the combustors limit the turbines, boilers and other energy equipment from being able to run on poor-quality fuels. Now we can retrofit our Power Oxidizer into these boilers or turbines to replace those combustors. We can then work with these license partners as our commercial front end as our Power Oxidizer equipment is getting embedded into their turbines and boilers."

Early conversations with Dresser-Rand customers have been very positive. "In every single meeting we've had with the operations directors who have authority over the entire supply chain, the typical response has been, 'There are so many applications for this across our infrastructure!' And their jaws drop," Castro said. "We just think it's a matter of time before this will become mainstream news."

And given the current environment of low-priced oil, making operations more efficient and reducing operational costs becomes the name of the game. "Yes, we're making their operations cleaner, and there's a great public benefit for oil companies being able to report that they're being more environmentally sustainable," he said. "But just as importantly, we're enabling them to get their costs down, thereby gaining a competitive edge within their industries." E&P

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Data-driven model advances completions in Eagle Ford

Neural network modeling indicates best strategies.

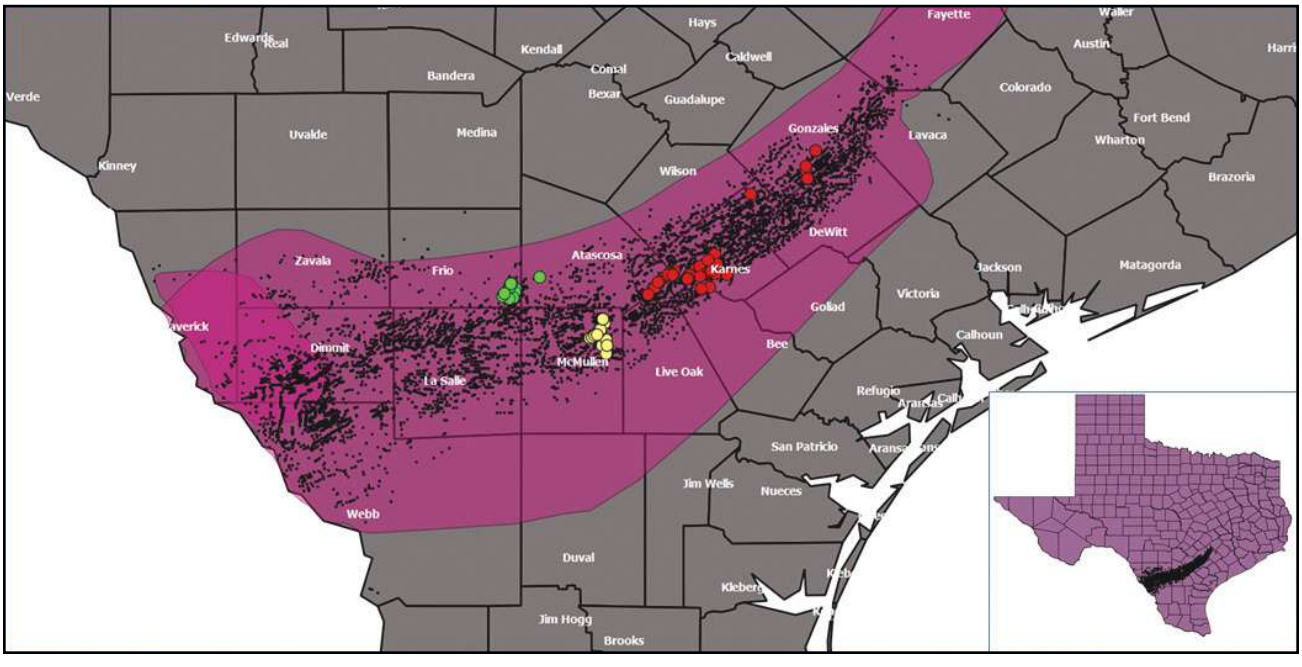
Robert F. Shelley, P.E., Amir M. Nejad, Ph.D., and **Stanislav Sheludko,** StrataGen; and **Trey Hodgson** and **Riley McFall**, Sundance Energy

A data-driven neural network model, built upon an evaluation of integrated, multi-operator datasets, yields deeper insight for optimizing area-specific completion and fracture treatment designs aimed at maximizing production and reducing costs throughout the multiple-hydrocarbon-window Eagle Ford Shale.

The validated model addresses the unique challenges in designing fracture stimulation jobs in a play, which along with localized variations in thickness, thermal maturity and pore pressure features diverse reservoir fluid types. The indexed well performance analysis can be used to identify key production drivers specific to the heterogeneous geological and petrophysical characteristics of the Eagle Ford. The proppant-centric data are correlated into the most effective completion and stimulation strategies for maximizing return on investment (ROI), from the sweet spot to the more marginal areas within the South Texas play.

Trained on a comprehensive database, the artificial neural network (ANN) model identifies the cause-and-effect relationships of various completion- and fracture-related inputs as well as readily obtainable drilling and mud data used to indicate pressure, fluid saturation, permeability and other geological and reservoir-related parameters. The model outputs, comprising normalized oil and gas production to account for pressure management differences, on the whole delivered predicted and observed best 30-day well productivity values greater than 0.9 for boe/psi, 0.8 for bbl/psi and 0.85 for Mcf/psi.

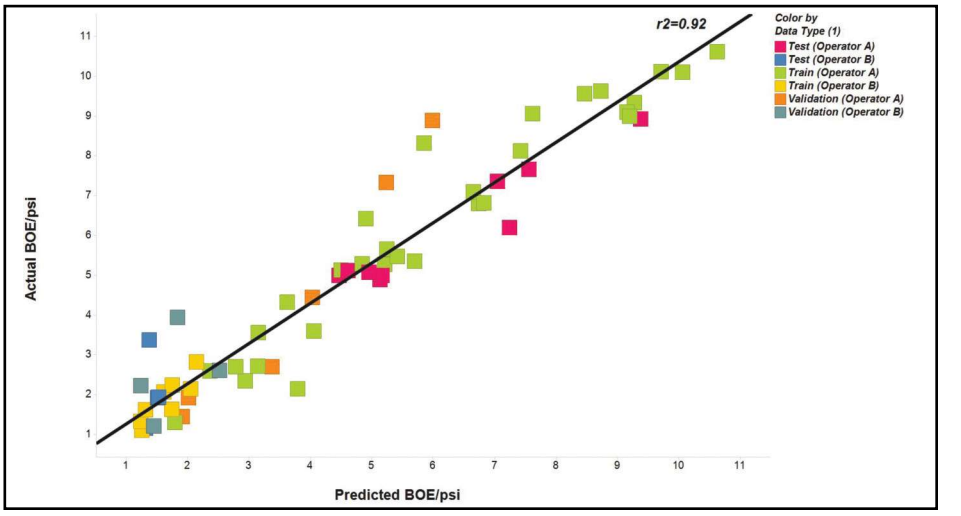
Specifically, sensitivity analysis of the ANN model isolated the top of the Eagle Ford from sea level as the most important noncontrollable reservoir-related parameter, followed by the butane and pentane fraction measured during horizontal drilling. Further, the model holds that deeper wells, with their comparatively better reservoir characteristics and higher thermal maturity,



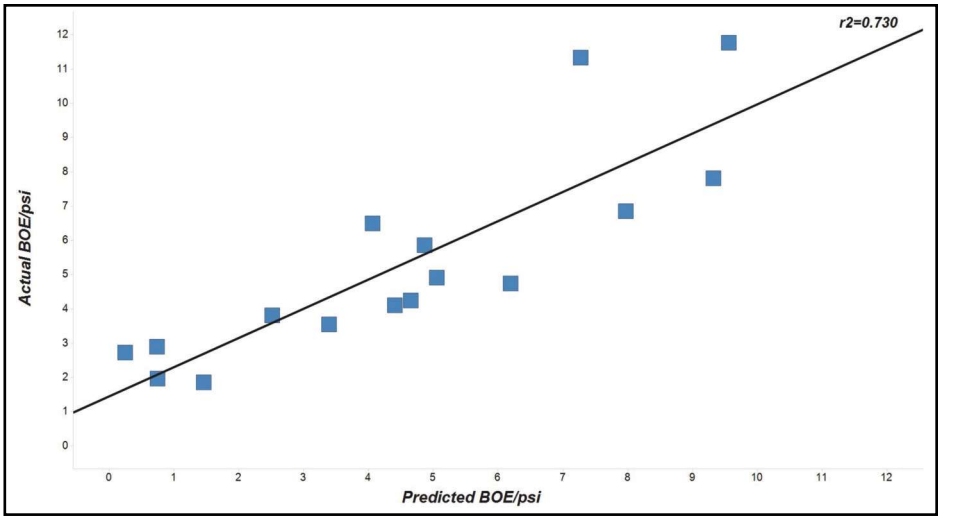
The locations of the wells used in this study (red, Operator A; green, Operator B; and yellow, Operator C), are compared to those of other wells drilled since 2008 (black dots). (Source: Carbo Ceramics)

tend to produce more hydrocarbons. The model also holds that those completed with optimized fracture stimulation programs, which couple additional frack stages to enhance reservoir contact with high-conductivity frack designs, also produce more hydrocarbons.

The model, while reinforcing the compelling correlation between pounds of proppant pumped and 90-day oil production, supports the dual hypothesis that large-volume sand treatments generally increase costs and inefficiencies and that the contribution of 100-mesh sand proppant to oil production is negligible.



The ANN model compares predicted boe/psi vs. actual boe/psi for operators A and B of Eagle Ford Shale wells (train, test and validation data). (Source: Carbo Ceramics)



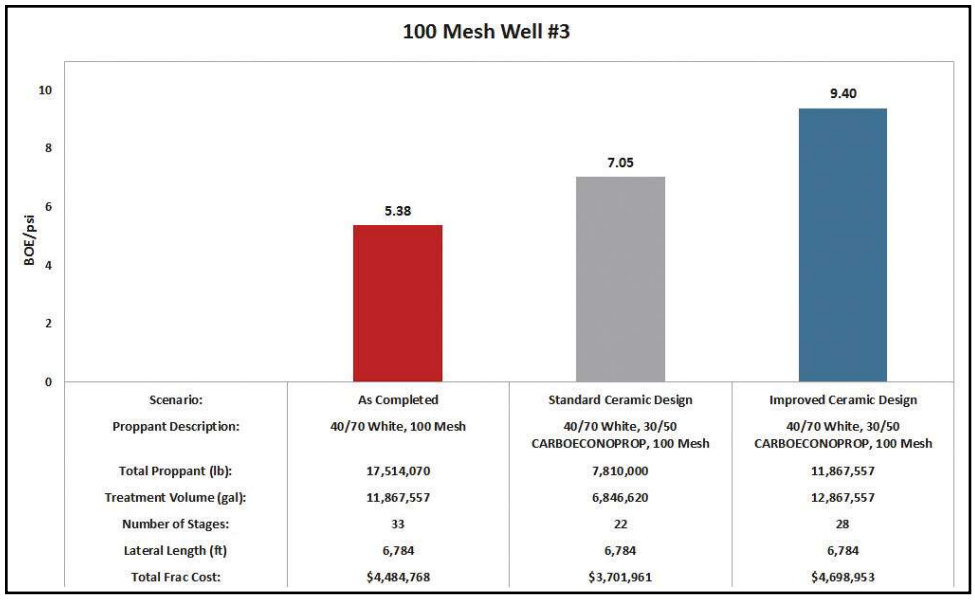
The ANN model compares predicted boe/psi vs. actual boe/psi for Operator C of Eagle Ford Shale wells (validation data). (Source: Carbo Ceramics)

Building the model

Typically, in comparatively homogeneous reservoirs, a discrete single-well modeling approach in which numerical reservoir models are constructed based on available data is used to evaluate the productive capacity of completions and stimulations. However, the extreme geological complexities of most unconventional plays like the Eagle Ford usually prevent this conventional methodology from analyzing a wide range of wells and, in turn, produce both general and field-specific recommendations on completion effectiveness.

By definition, the neural network modeling technique used in the Eagle Ford evaluation analyzed diverse well datasets to identify connections between the system input and output variables. The technique sought to do so without requiring explicit knowledge of the physical behavior of the system. Owing to its flexibility, neural network modeling can handle a large number of datasets to produce high-level analysis. Therefore, it offers an inherent advantage in that models are built based on available data, making prior assumptions and/or knowledge of input data unnecessary.

The Eagle Ford study utilized a database comprising 81 wells completed by three operators (A, B and C) from 2011 to 2014 in different areas of the oil, gas and condensate windows. In building the neural network, a cumulative 39 wells completed by operators A and B were randomly selected from the database for model training as they exhibited wide production variability, from 1 boe/psi to 11 boe/psi (best 30-day cumulative equivalent barrel of oil production per psi of average drawdown). An additional 23 wells were held back from model training as test sets for model selection and validation purposes. After the neural network model was developed and tested, Operator C's 19-well dataset was used for final model validation.



The chart shows the predicted impact of alternative completion and frack designs on Operator C's underperforming, all-white sand well. (Source: Carbo Ceramics)

Within the database, 45 wells were attributed to Operator A, all drilled in the sweet spot fairway in Gonzales, Karnes and Atascosa counties. Excluding two wells using ceramic proppant tail-in, these wells were completed mainly with white sand proppant in a hybrid fluid system with 16 stages.

Operator C, meanwhile, contributed 17 wells to the database, which were drilled and completed in less favorable areas of Frio and Atascosa counties. On average, these wells consisted of 17 treatment stages using crosslinked gel and 30/50 white sand proppant, with two completed wells with ceramic proppant.

Operator C's wells were all drilled in a more marginally productive area in McMullen County. Unlike its two counterparts, this operator experimented with different proppant types, with various combinations of 30/50 ceramic, 100-mesh sand and 40/70-mesh sand in a hybrid fluid system, thereby generating an average sand-to-ceramic ratio of 70% to 30%, referred to as the standard ceramic completion. Operator C completed 10 wells with 40% of the total treatment program using ceramic proppant; three wells were completed with more than 60% of the treatment proppant comprising in excess of 8 million lb of 100-mesh white sand. Since this operator's wells were located in a less productive area compared to those of Operator A, 50% more proppant was required to achieve the same well productivity.

Comparative frack analysis

Evaluation of Operator C's validation wells bolstered the productivity advantages of combining high-conductivity frack designs with increased reservoir contact. The evaluation showed wells stimulated entirely with white sand proppant are cost-neutral compared with those stimulated with the standard ceramic completion design, even with more proppant and additional stages. The proposed improved ceramic completion design implies performing more individual hydraulic fracture treatments per well as compared to the standard ceramic design with an estimated fracture treatment cost increase of 25% per well. Further modeling suggested that the improved ceramic proppant frack design could have provided up to 75% more productivity compared to the large volume all-white-sand completion design.

The productivity ramifications were clearly illustrated in an evaluation of one well completed in 27 stages with a combination of more than 14 million lb of 100-mesh and 40/70 sand proppant placed in 11 million gal of fracturing fluid. This well achieved actual productivity of 6.7 boe/psi, while the predictive data-driven model estimated that if the well had been completed with the standard ceramic completion design, the productivity value would have remained about the same, at 6.6 boe/psi with fewer stages and smaller volume jobs. Taking it further, if this well had been completed using an enhanced completion strategy with 28 frack stages, 5.5 million lb of sand and 4 million lb of ceramic proppant, the neural network model forecasted its productivity value increasing more than 40% to 9.6 boe/psi.

Additional reinforcement of the model output was reflected in a comparative analysis of another Operator C well completed in 26 fracture stages with 14 million lb of 100-mesh and 40/70 sand, resulting in a well productivity of 7.2 boe/psi. The neural network model estimates that employing the standard 22-stage ceramic completion design would result in a well productivity of 6.4 boe/psi. However, the improved 28-stage ceramic completion design would yield a forecasted 8.6 boe/psi productivity for this particular well.

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A third well evaluated was completed with 33 stages and also used large-volume (17 million lb) 100-mesh and 40/70 mesh sand frack designs. This well produced a below-average 5.48 boe/psi, and the neural network model estimated that a standard ceramic completion design would have boosted productivity to 7.1 boe/psi while the improved high-conductivity ceramic proppant completion design would have yielded well productivity of 9.4 boe/psi.

Hence, the neural network model, while identifying under-producing wells, provides operators with data-driven recommendations for alternate and fracture stimulation designs that will elevate productivity and improve economics. This type of modeling approach can be performed with limited or vast amounts of data; the results are equally useful for emerging and more mature plays like the Eagle Ford. E&P

> The neural network model provides operators with data-driven recommendations.

Acknowledgment

This article was adapted from SPE paper 173336, "A Case History: Evaluating Well Completions in the Eagle Ford Shale Using a Data-Driven Approach," by Amir M. Nejad, Ph.D., Stanislav Sheludko and Robert F. Shelly, P.E., of StrataGen; and Trey Hodgson and Riley McFall of Sundance Energy. The paper was presented at the 2015 SPE Hydraulic Fracturing Technology Conference in The Woodlands, Texas, from Feb. 3 to 5.

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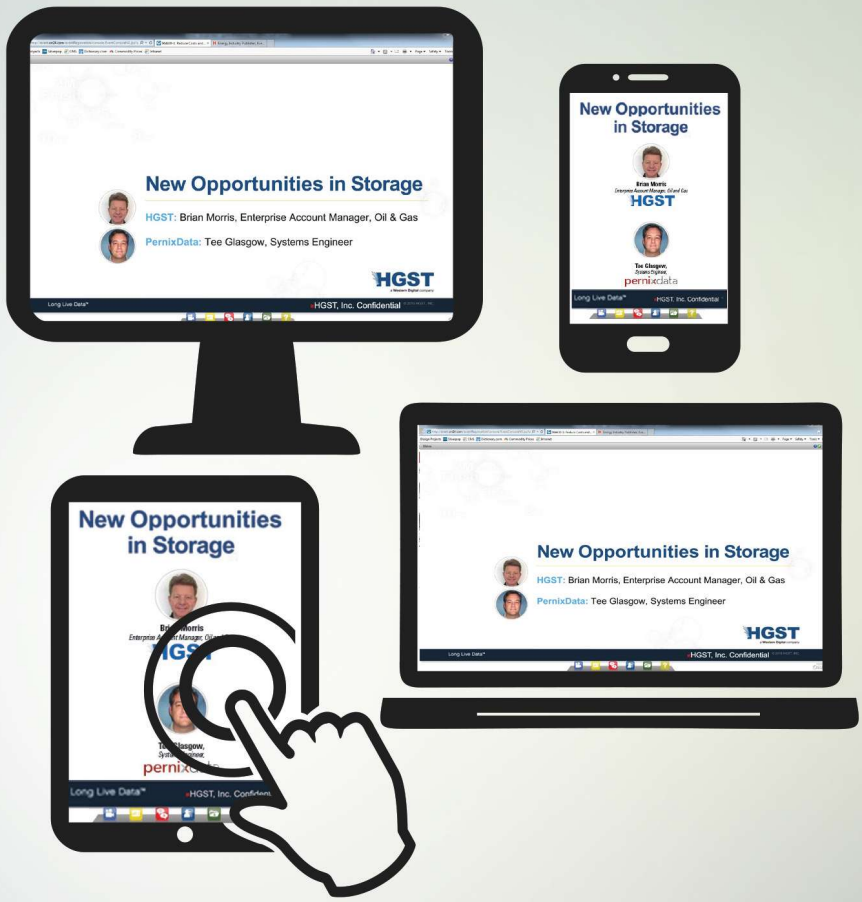

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HARTENERGY

Hydrostatic pressure vessels offer pressure capacity up to 10,007 psi

MacArtney introduced its new range of in-house-developed hydrostatic pressure vessels for companies that require setting up their own facilities capable of putting almost any type of underwater equipment to the test. MacArtney now offers a range of four standard pressure vessels, according to a product announcement. With a pressure capacity up to about 10,007 psi, the company's standard pressure vessels can simulate the hydrostatic operating conditions at 7,000 m (22,965.9 ft) of ocean depth. The entire testing process is computer-controlled with real-time electric and optical measurements. Control software developed in-house enables plug-and-play testing, bespoke test programs and repeated pressure cycling. Other pressure vessel benefits include lid integrated penetrators and the user-friendly "clamp-lock" system, which allows swift test mobilization and turnaround. Optional features include live video monitoring and in-vessel temperature control. *macartney.com*

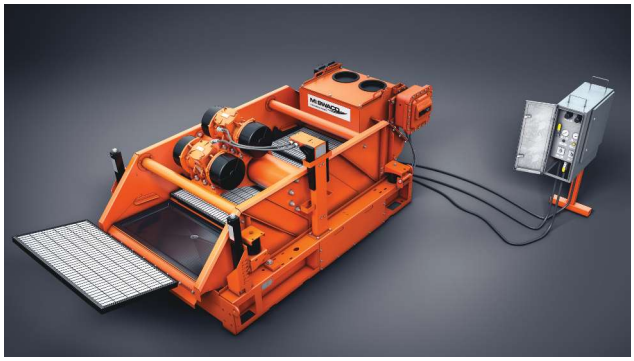
A MacArtney hydrostatic pressure vessel has been installed within a new test environment. (Source: MacArtney)

Corrosion inhibitor protects pipelines

GE introduced the GE ProSolv Corrosion Inhibitor to help protect crude oil and gas pipelines against the corrosive nature of acid gases. The hydrocarbon-soluble corrosion inhibitor is a cost-effective chemistry that protects against corrosion in a wide variety of operating conditions including sweet, sour, wet and dry gases, the company said. Using locally sourced solvents leading to improved logistics and shorter lead times, the corrosion inhibitor is applicable in upstream and downstream process streams. It is compatible with injection packages' most commonly used metallurgies and is safe to handle and store in hot climates. *geoilandgas.com*

Fluid, cuttings separator can operate up to four shakers

M-I SWACO, a Schlumberger company, released the SCREEN PULSE fluid and cuttings separator. Easily installed onto new or existing shale shakers, the fully pneumatic system delivers drilling fluid recovery of up to 30 bbl/d and an average drill cuttings waste reduction of 20%, according to a press release. Operators drilling on land, in shallow waters and in deepwater are looking for ways to optimize the efficiency of the solids control process and lower the total cost of drilling, the release said. Combined with M-I SWACO's shaker technology and lightweight composite screens, the new SCREEN PULSE separator can maximize drilling fluid recovery and can generate drier cuttings, which can reduce waste handling and disposal and overall drilling costs. The separator is a retrofitted fully pneumatic system equipped to operate up to four shakers simultaneously. A carbon-fiber pan fitted with an air valve mechanism that provides a pulsing air supply pulls drilling fluid from the cuttings as they travel toward the discharge end of the shaker. The new separator was field-tested in the Middle East; South America; and North America, including in Oklahoma, Pennsylvania, Texas and Louisiana. *miswaco.com/screenpulse*



The SCREEN PULSE separator recovers drilling fluid and can generate a drier cuttings discharge from the shale shaker. (Source: Schlumberger)

Subsea flowline inspection technology locates blockage issues

Tracerco has released Explorer, a technology able to screen subsea pipelines for content and deposit buildup at speeds of up to 100 m (328 ft) per hour, meaning many kilometers of pipeline can be surveyed per day, according to the company. Explorer has been developed for use in conjunction with Discovery, which is the technology for pipeline inspection that gives detailed high-resolution computed tomography scans of subsea pipelines, distinguishing between wax, hydrate, asphaltene or scale

deposition at density differences of 0.05 g/cu. m. Once Explorer has located the area of the suspected blockage, Discovery can be deployed to accurately characterize its precise nature. Both devices are nonintrusive, scanning content from outside the pipeline. There is no need to remove protective coatings or interrupt production to carry out the inspection, making it a cost-effective solution to flow assurance problems. Explorer can operate at depths of up to 3,000 m (10,000 ft) and can cover pipe diameters from 2 in. to 60 in. It has the ability to screen a variety of different piping systems, including standard rigid pipe (coated or uncoated), pipe-in-pipe, bundle systems and flexibles. *tracerco.com/subsea/explorer*

System designed to move rigs over drill pad sites safer, more efficiently

Integrated Drive Systems (IDS) has developed the patent-pending ReelRig distributed power and control system, designed to enhance walking rig mobilization and operations. The system replaces a traditional centralized power network with a clean, streamlined power and control cable-handling system designed for moving rigs over drill pad sites safer and more efficiently, the company said. The system locates variable-frequency drives (VFDs) and programmable logic controllers near the driven equipment. This process involves eliminating multiple power and control cables and connectors by adding a transformer to the backyard power house area, "stepping up" the power from 600 v to 4,160 v, sending that power through a single medium-voltage cable, "stepping down" the voltage at the rig via another transformer and then distributing the power closer to where it is needed on the rig. The entire ReelRig system consists of the power control house with mud system VFDs, transformers, cable and cable-handling system/skid, local equipment room VFDs, driller's cabin with integrated driller's controls, AC drawworks controls, and AC top drive controls. *ids-oilfield.com*

Iron sulfide scale inhibitor requires lower dosage rates

Clariant Oil Services introduced its SCALETREAT FeS iron sulfide scale inhibitor. SCALETREAT FeS prevents scale formation and any resultant damage at considerably lower dosages than existing chemistries such as tetrakis hydroxymethyl phosphonium sulfate (THPS) and Acrolein, according to the company. The low-dose continuous injection iron sulfide scale inhibitor also targets and prevents sulfide scales of zinc and lead. The field-proven inhibitor slowly dissolves existing iron sulfide deposits at threshold concentrations levels as much as 50% lower than the market's benchmark THPS product. In addition, the scale inhibitor is effective over a broad range of temperature, pressure and salinity conditions. *clariant.com*

System handles issue of corroded bolts

Equalizer Flange Integrity Systems, part of the Equalizer Group, designed the Xtegrity system, which provides a solution for dealing with heavily corroded or degraded bolts in flange joints on offshore and onshore installations, according to the company. The system takes away the need to remove corroded bolts by replacing them with a new set of bolts that clamp around the outside of the flange and are held in place with a floating frame. Xtegrity can reduce the time required to carry out work from days to hours, the company said. *equalizerifs.com* E&P

The IDS ReelRig power and communication cable spooling skid is shown attached to the substructure of Orion Drilling's new Aries Rig #18. (Source: Integrated Drive Systems)

The Xtegrity system won the Grampian Award for Innovation at the Elevator Awards in the U.K. (Source: Equalizer Flange Integrity Systems)

UKCS regeneration game

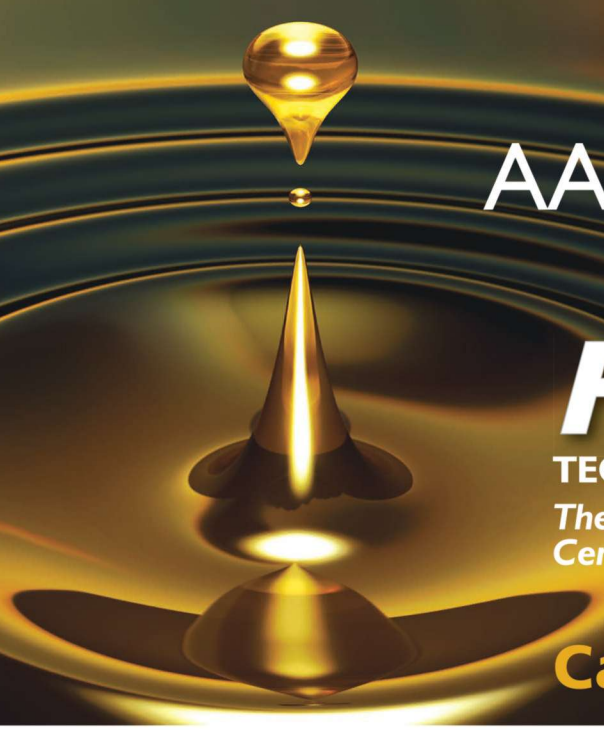
The year 2015 is playing host to several milestone anniversaries for the UKCS, but it may also eventually be viewed as a crucial inflection point in its remarkable history as it battles to remain economically viable in its later years.

Mark Thomas, Editor-in-Chief

It is impossible to outline the significance of the milestone anniversaries for the venerable U.K. Continental Shelf (UKCS) offshore region—the whole of *E&P* would have to be dedicated to them to do the region justice. In a nutshell, though, 2015 is of particular historical note because of the following events:

- The UKCS has now seen half a century of activity, since BP's Sea Gem jackup rig struck gas on the West Sole Field in September 1965;
- Tragically, it also represents 50 years since the sector's first offshore disaster, when two of the same rig's legs collapsed on Dec. 27 as it was being lowered to move onto its next job, resulting in the loss of 13 lives;
- About 45 years have passed since BP discovered the giant—and still producing (thanks to Apache Corp.)—Forties Field in October 1970, just 10 months after the U.K. sector's first oil field (Montrose) was found by Amoco and the year before Shell discovered the Brent Field; and
- It has been 40 years since the U.K.'s first offshore oil began flowing from the Hamilton Brothers' Argyll and Duncan fields in June 1975, followed in November by the Forties Field when it started piping crude to Scotland's Grangemouth refinery.

The original producing Forties Alpha platform (left) is shown with the bridge-linked Forties Alpha Satellite Platform (FASP). The Forties project has the best U.K. North Sea production efficiency rate, averaging between 93% and 96%. Also alongside is the Rowan Gorilla VII jackup rig, used to drill additional FASP producer wells. (Source: Apache Corp.)



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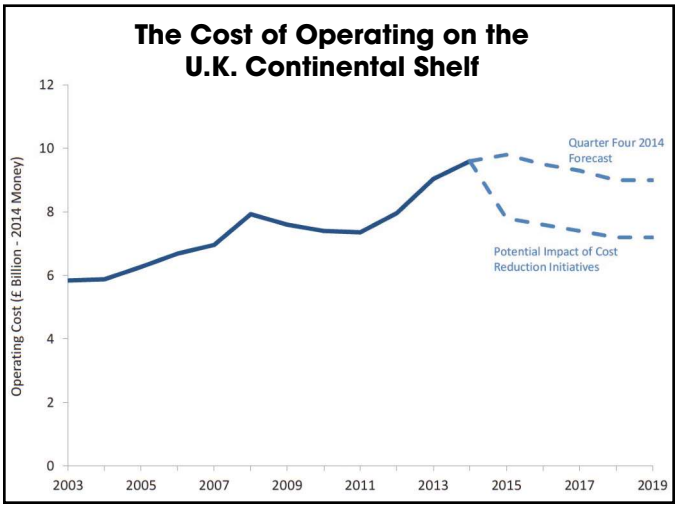
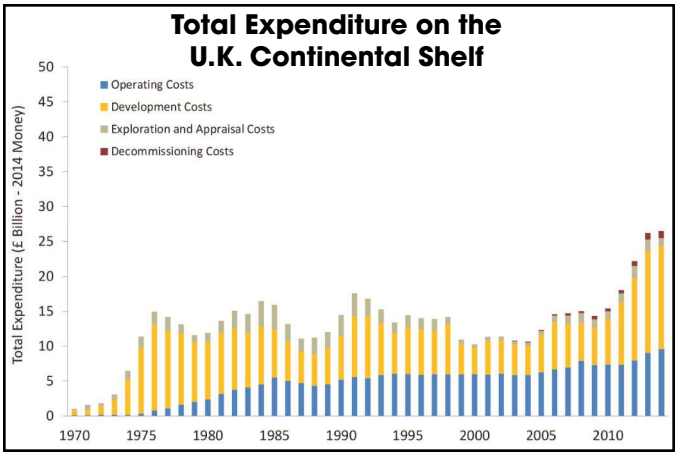


(Source: Oil and Gas UK)



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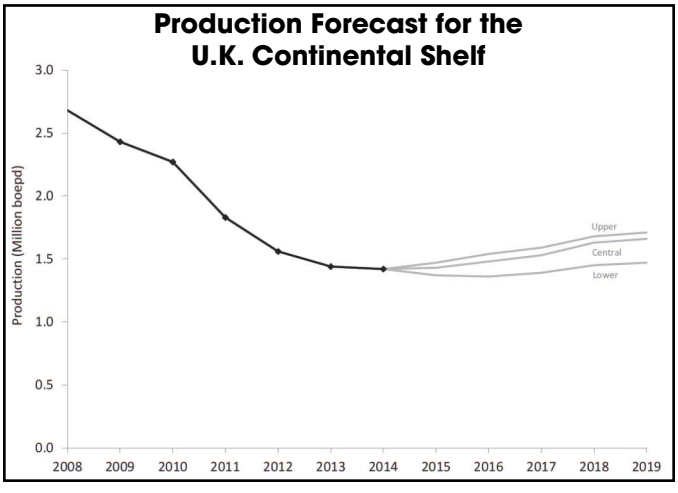

(Source: Oil and Gas UK)

Just to put that into some wider perspective, 1965 also was the year that the Hollywood flick "The Sound of Music" topped the U.S. box office, with the James Bond movie "Thunderball" No. 1 on the U.K. film charts. On the music front, meanwhile, "Day Tripper" by the Beatles ended the year at No. 1 on the U.K. charts, while the Dave Clark Five topped the U.S. charts with "Over and Over."

Current status

Fast-forward to today, and those heady days are indeed long gone. So what is the current condition of the U.K. offshore sector?

First readings are not encouraging—exploration drilling activity is at virtually an all-time low, with just 14 exploration wells drilled last year and 18 appraisal wells, including sidetracks. Possibly only between eight and 13 exploration wells are expected to be drilled this year (with seven drilled as of July), and just a handful of appraisals are anticipated. The number of development wells drilled last year was 126 including sidetracks, which is slightly higher than in 2013.

Production last year was 1.42 MMboe/d, which, according to the industry's representative body Oil & Gas UK, was the best year-on-year performance in 15 years. However, it still is a declining production profile, being 1.1% less than the prior year.

Of greater concern is the fact that only 50 MMboe of potentially commercial reserves were found in 2014, which is far lower than the annual average of about 250 MMboe during the previous decade. Only eight new fields were sanctioned for development.

Most concerning, however, in light of today's lower oil-price environment, are the running costs. According to Oil & Gas UK's figures, unit operating costs had risen in 2014 to US$28.90/boe (£18.50/boe), up from US$26.50/boe (£17.00/boe) in 2013. That was at a time when the oil price was still averaging nearly US$100/bbl but beginning its plunge toward US$55/bbl by the end of December 2014.

Changing tide

The U.K. sector is, however, working hard to change this grim outlook, and the early signs are giving strong cause for long-term optimism.

According to analyst Wood Mackenzie, capital and operating costs in the U.K. upstream sector will fall steadily this year as operators continue to respond to the lower oil price. The biggest reductions will come in drilling costs, which could fall by one-third by year-end 2016.

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Near-term pre-final investment decision (FID) field developments are expected to be best placed to benefit from these reductions, with development costs potentially falling by up to 20%, according to the analyst.

Operating costs will decrease by up to 15% in the U.K., with Wood Mackenzie asserting that upstream cost deflation is inevitable for the region as it exits a period of more intense development activity over the past five years. That has been the root cause of severe cost inflation as operators competed for already-expensive access to offshore services.

In one of Wood Mackenzie's latest reports, Malcolm Dickson, principal North Sea analyst, said, "High capital and operating costs are the single biggest issue for companies in the U.K. and Norwegian sectors of the North Sea today. Even before the oil price crash, [being able to] develop and operate fields while making a profit was challenging, and we expected some cost deflation in the sector as activity cooled.

"The drop in oil prices has accelerated the need for lower costs as companies adjust to protect their cash flows, and changes are now required to correct the industry's cost base."

According to Dickson, rig rates already have dropped significantly, with reductions of up to 20% for new contracts agreed to in 2015. Of mobile rigs in the U.K., 40% (and 23% of mobile rigs in Norway) are either currently without contract or are due to come off by year-end 2015, giving scope for high reductions in future contract renewals, he said.

Upstream capital investment is continuing to fall this year in the U.K., with competition within the supply chain increasing as operators scrutinize costs and project execution. "As well as looking internally for efficiency gains, North Sea operators are now negotiating with contractors," Dickson added. "This is because the opportunity for cost reductions is highest in uncontracted spend such as pre-FID projects and new brownfield developments."

Dickson went on to add that in general Wood Mackenzie expects to see costs fall a little further and quicker in the U.K.—for instance, lower rig utilization will mean cheaper drilling. However, he added, many of the U.K.'s new projects "are technically challenging, and standardized solutions are not an option, meaning there are few contractors capable of supporting them."

According to Wood Mackenzie the remaining pre-FID projects are smaller (averaging just US$375 million in capex) and are generally operated by independent E&P companies, so economies of scale within the supply chain are harder to achieve.

Knowing that so much remains dependent on the level of the oil price, Dickson summed up his view going forward, saying, "Assuming the oil price rises as we think it will, the lower cost base achieved over this year and next can only be sustained through fundamental changes in practice and increased collaboration between the operators and the service sector."

The bridge-linked FASP (left) was installed in 2014 by operator Apache to work in tandem with the original Forties Alpha Platform. (Source: Apache Corp.)

Rampant inflation

Such changes cannot come soon enough for some, with the rampant cost inflation that U.K. North Sea producers have been battling against for years being starkly highlighted at a recent industry event in Aberdeen, Scotland.

Dan Cole of McKinsey & Co.'s London-based oil and gas practice described offshore inflation as "way out of line" compared to the general economy. The annual rise in inflation in the U.K. during the period from 2000 to 2014 was 2.5%, but the cost of operating an offshore installation went up by 12% per annum in

that period. Meanwhile, the development cost per barrel rose by 21% annually between 2004 and 2013.

Cole told a recent Oil & Gas UK business breakfast that with an oil price of US$55/bbl, nearly half of all North Sea fields were uneconomic. To paraphrase this, he pointed out that if the fast-food industry had faced the same inflation rate, a burger in the U.K. that cost £2 (US$3.10) in the year 2000 would cost a staggering £13 (US$20.17) today. For those who don't eat fast food too often, the price of a 2015 burger is still priced at less than £3 (US$4.66) in the U.K.

Cole added that cost inflation in the oil and gas industry was not due to increased activity or the supply chain becoming more profitable but rather was due to higher wages and greater inefficiencies.

A way forward, he continued, was to consult with the aerospace and automotive industries, where cost inflation since the start of the century has averaged just 1% a year. Aerospace manufacturing has kept costs down by parts standardization and by more collaboration with the supply chain, while the automotive sector has benefited from standardization and increased collaboration between rivals.

Sustainable at $60/bbl

According to Oil & Gas UK's recently-installed CEO Deirdre Michie, the U.K. offshore sector simply has to become sustainable in a US$60 world. Speaking at the association's annual conference in Aberdeen, she said that at US$60 oil, 10% of the U.K.'s production "is struggling to make money. There is a shortage of capital and a shortage of investors willing to place their money here.

"We need to think about this from an investor's point of view," she continued. "Given that we compete for investment dollars on a global basis, we must ensure the U.K. is a commercially attractive and predictable place in which to invest. Learning from our mistakes, we know that our focus cannot merely be on 'cutting costs' but must more fundamentally address the efficiency of the basin. Focusing on efficiency means that, if or when the oil price bounces back, we will be best placed to seize new opportunities."

20 Bbbl prize

The prize to be won remains substantial, she added. "With over 20 Bbbl of oil and gas still to play for, there's plenty of opportunity to ensure an indigenous supply for the country. On a global scale we might be a small player, but we're also a world leader. Our technical expertise is unsurpassed and is reflected in the quality, the capability and the success story that is our supply chain.

"I'm pleased to be able to say that we have come together, aligned as to the prize our industry still offers. In keeping together, we have already made progress with the [new regulatory body] Oil and Gas Authority being set up, positive fiscal change being delivered and the industry working hard to improve its competitiveness."

Some initial steps undertaken this year already include a consultancy being commissioned by Oil & Gas UK to carry out a survey of daily rates paid to independent contractors, allowing companies to benchmark their rates against the market. It also has established a database of spare parts held in inventories across the sector, which will allow replacement equipment to be sourced quickly and efficiently with the aim of reducing production downtime.

Michie said there was "increasing evidence that big strides are being made to improve the efficiency and reduce the cost of operations. Lifting costs are anticipated to fall as a result over the next 12 months."

The end target is an ambitious 40% improvement in unit operating costs. Wood Mackenzie has estimated that 1.3 Bboe of development opportunities will become available if the industry can achieve the targeted cost and efficiency improvements.

U.K. government support

The U.K. government has finally appeared to acknowledge the very real threat to the industry's existence and is playing its part with tax reforms confirmed in the latest budget along with more direct support to help improve competitiveness.

Chancellor George Osborne cut tax rates on North Sea production, saying that this would help boost oil production by 15% by the end of the decade.

Tax rates on production from older fields will be reduced from 80% to 75% immediately and are backdated to January, while the rate on newer fields will be cut from 60% to 50%. The corporation tax also is being cut by 2% over the next five years.

The government will fund new seismic surveys via the OGA to the tune of US$31 million (£20 million) to assess the potential in underexplored areas of the U.K. sector. The two immediate priority areas chosen are the frontier region of the mid-North Sea High and the Rockall Trough basins, for which only sparse seismic information currently exists.

Modern 2-D seismic technology will be used to secure more detailed images of subsurface geology and geophysical properties to improve understanding of these areas. Invitations to tender for the work were posted earlier this year with the aim of beginning acquisition this

Small Fish, Big Prize

The U.K. is targeting the development of approximately 287 "small pools" of hydrocarbons on the U.K. Continental Shelf (UKCS) as a means of maximizing the recovery of oil and gas left in the ground as well as acting as a trigger for further technology innovation and development.

Gordon Drummond, project director at the National Subsea Research Initiative (NSRI), told delegates at a recent conference in northeast England that this would help sustain the U.K. subsea industry in particular. He sees the pursuit of small pools as the next step, defining them as reservoirs of between 3 MMboe and 15 MMboe. He added that to achieve production from these assets, the industry must create new technology.

Operators Centrica and EnQuest are acting as technology champions for this "small pool" push, with workshops to be held in Aberdeen, Newcastle and London to pursue such projects.

"Small pools are a positive story about chasing new reserves and not the start of the decommissioning process for the U.K.," he said.

Paddy O'Brien, CEO of the Industry Technology Facilitator (ITF), added that the Centrica- and EnQuest-backed project is looking to develop reserve pools of either 10 MMboe of gas or 30 MMboe for less than US$156 million (£100 million). "How technology can reduce costs will figure highly in the current climate," he said.

Jeremy Cutler, Total E&P U.K.'s head of technology innovation, said his company's target for small pools in the U.K. is to develop 15 MMboe for less than US$234 million (£150 million).

Total has three main U.K. technology focus areas: long-distance subsea tiebacks (small pools), effective drilling and completions (lower costs/increase productivity), and intelligent operating and maintenance (including the use of robotics for unmanned platforms).

Others include subsurface imaging, decommissioning and onshore shale gas, Cutler added.

Analyst Wood Mackenzie has estimated that there are currently more than 300 discoveries without development plans containing nearly 3.9 Bboe offshore the U.K. The last time a discovery larger than 100 MMboe was made in traditional sandstone reservoirs was in 2008 when the Culzean Field was found. ■

summer and delivering the final processed datasets by the end of March 2016.

Collaboration is key

One example of how the industry is reacting to the call for collaboration is a forum that has been set up to address challenges in subsea integrity management.

The subsea-focused SURF IM Network is now in its second phase and has been extended for a further three years. Led by Wood Group Kenny with support from the U.K.-based Industry Technology Facilitator (ITF), Phase 1 was launched last year and was supported by a group of 14 operators.

The network facilitates face-to-face and virtual forums for knowledge sharing and delivering solutions to subsea integrity and reliability challenges, focusing particularly on subsea hardware. The first phase saw progress made in understanding the issue of control system module reliability, and the findings of a comprehensive participant survey were presented to subsea suppliers to highlight integrity challenges and find ways to enhance future reliability.

"Taking a standardized approach to complex subsea integrity issues that are common across the industry can help to drive efficiencies while creating a safer operating environment, so the network is a win-win for all involved," said Dr. Patrick O'Brien, CEO for ITF. "It is a great example in the current climate of operators collaborating to support the development of effective and cost-efficient means to inspect subsea facilities that are being installed in continually increasing water depths and with longer step-out distances."

Well intervention focus

Another area flagged for further work is well intervention. According to Martha Vasquez, a manager with consulting firm McKinsey & Co. who spoke at the Offshore Well Intervention event in Aberdeen recently, oil and gas operators in the North Sea simply don't do enough such work and also don't get the most out of their existing intervention work.

Vasquez pointed out that with $50/bbl oil having resulted in operators becoming significantly cash-constrained and with reduced budgets, production and ultimate recovery targets still remain. Well intervention will simply help lower operating expenses per barrel. "It also is usually cheaper, quicker and less risky—and yields higher returns per barrel than drilling a new well," she said. "The incremental volume and recovery opportunity is significant; most active operators realize over 10% incremental production and 5% barrels protection from

well intervention. However, operators don't do enough intervention and fail to get the most from their intervention efforts." The 5% barrels protection involves insuring a well's production level within 5% of its present level to protect against rapid decline.

Vasquez questioned why not enough well intervention work is being carried out, concluding that asset managers tend to put a lower priority on well integrity and production optimization tasks to protect production levels. "The belief is that drilling brings higher value. Asset teams lack the information to be certain that intervention will bring higher value than drilling."

Vasquez added that there also was a failure to get the most from intervention activity, for reasons including a shortage of good opportunities, companies preferring not to take a risk and also companies simply not knowing whether an intervention had worked by not fully understanding intervention performance.

The *EnQuest Producer* FPSO vessel at OGN Group's yard in Tyneside, England, before moving to its present location on the Alma Field in the central North Sea, is sited over what was in June 1975 the U.K.'s first producing offshore oil field, Argyll.

Back to the future

The above actions are early evidence that the U.K. industry is tackling the daunting task of raising its game operationally and economically with its usual application.

Although too soon to be able to predict success with any certainty, its track record earned during the past five decades of offshore achievement would infer that it is capable of once more rising to the challenge.

Perhaps one of the most significant illustrations of the U.K. offshore sector's undoubtedly innovative culture—and its ability to leave no stone unturned—during such a historic anniversary year is one that features the very first producing field that started it all.

Argyll reborn—again

The Argyll Field is due to start flowing oil again this year, 40 years after producing its first pioneering barrels.

EnQuest is redeveloping the field, now known as Alma, located in the central North Sea in U.K. blocks 30/24 and 30/25. Lying in a water depth of 80 m (262 ft), this redevelopment project is expected to see production flow for up to 10 years. With estimated recoverable reserves of more than 20 MMbbl of oil, and possibly up to 32 MMbbl, the field is expected to produce around 4.5 MMbbl of oil during its first year.

As Argyll, it produced more than 72 MMbbl of light sweet crude during a 17-year period before being decommissioned in the early 1990s.

Incredibly, this is not the first time Argyll has been redeveloped but the second, having been produced under the name Ardmore via two wells for two years using the modified Rowan Gorilla VII jackup rig by operator Tuscan Energy. It produced more than 5 MMbbl of oil before being decommissioned again in 2008, having been deemed uncommercial at that time.

EnQuest decided to redevelop the marginal field in late 2011, along with the nearby Galia satellite discovery, with water injection and electric submersible pumps to be used to help produce the now-low-pressure reservoir.

The wells will be connected to an FPSO vessel, Bluewater's upgraded floater formerly known as *Uisge Gorm* and now called the *EnQuest Producer*, through 10-in. flowlines. Moored on location over the field in May, the preparation process is almost complete, with first oil expected imminently via five wells.

In many ways Argyll—or Alma, as it is called now—is truly representative of the U.K. offshore scene. Discovered more than four decades ago, it produced, peaked, matured, declined and was then written off. A decade later it went through a smaller-scale revival, produced at a lower level and was then written off once more.

But here we are, in the next decade, and there's still apparently plenty of life (and dollars) in the old girl yet. A shining microcosm, perhaps, for the UKCS as a whole. EP

End of an era on Brent

The iconic North Sea field is nearing the end of its productive life after pumping oil and gas for close to four decades.

John Sheehan, International Editor

When the Brent Field was discovered in 1971, the U.K. North Sea oil and gas industry was in its relative infancy. Brent was to become the heartbeat of the region and the country's most famous offshore field, with its blend becoming a global benchmark for the price of a barrel of crude.

One of the most significant oil and gas finds ever made in the U.K. sector, at the time of its discovery in U.K. license Block 211/29 in the East Shetland Basin its expected lifespan was put at 25 years at the most.

But continuous investment and a $2 billion redevelopment in the 1990s by the field partners Shell and Esso to unlock large quantities of low-pressure gas extended its life well beyond original expectations.

Brent, located 180 km (112 miles) northeast of Lerwick in the Shetland Islands, lies in a water depth of 141 m (463 ft) and had four platforms installed.

1971 discovery

The discovery well drilled in 1971 hit an oil column of 60 m (197 ft), while the second found 53 m (174 ft) of gas overlying 114 m (374 ft) of net oil sand.

Brent is typical of many of the fields in the area, consisting of a tilted fault block exposing the Brent Formation next to bounding faults. This allowed migration from deeper adjacent "kitchen" areas where the Kimmeridge Clay Formation becomes fully mature and releases hydrocarbons.

Production started up on Nov. 11, 1976, and on Dec. 13, 1976 the first tanker was loaded.

The Brent Field consists of Alpha (a steel jacket structure), Bravo (a gravity base structure with 16 storage tanks), Charlie (another gravity base structure with 32 storage tanks) and Delta (a third gravity base structure with 16 storage tanks).

A fifth installation, the now-infamous floating Brent Spar, served as a storage and tanker-loading buoy after being installed early in the field's construction.

Since production began, two-thirds of the revenue generated from the field has been paid to the U.K. government as tax—amounting to more than $31 billion.

Four Bboe produced so far

To date the field has produced around 4 Bboe, which is almost 10% of all the oil and gas produced from the U.K. sector of the North Sea. In its pomp, the field helped the U.K. to become an oil exporter.

At its peak in 1982 the field was producing more than 500,000 bbl/d—its production that year would have met the annual energy needs of around half of all the homes in Britain.

The field, which has mainly produced gas since the mid-1990s, has now almost exhausted its recoverable reserves and is in the process of being decommissioned.

Brent Delta reached cessation of production (CoP) on Dec. 31, 2011, while Alpha and Bravo reached CoP on Nov. 1, 2014. Charlie is still producing with no designated shut-down date at this time.

The Brent Delta platform produced for 34 years until 2011. Its topsides will be the first to be removed in the field's 10-year decommissioning schedule. (Source: Shell)

Alpha and Bravo had not produced since May 2014 when they were shut down for inspection and maintenance work, at which point it became clear that the platforms were no longer economical.

'Iconic platforms'

A Shell spokeswoman told *E&P*, "We recognize the major contribution of Alpha and Bravo and the efforts of the many people associated with the platforms over the last 40 years. From a technically innovative installation phase through to a long period of operation and production, these iconic platforms have helped to sustain vital North Sea oil and gas supplies. We will now focus on safely decommissioning these assets."

The decommissioning process will be a complex and major engineering project, with Shell saying it will take more than 10 years to complete.

The operator said that when the Brent platforms and infrastructure were built in the 1970s during a period of global energy shortages, decommissioning did not feature highly in the design considerations. "The technology, expertise and environmental standards we rely on today were only in their infancy in the 1970s. Since then, society's expectations, legislation and technology have moved on, and all offshore installations in the northeast Atlantic built after 1999 are designed to be completely removed [at the end of their useful life.]"

Allseas' *Pioneering Spirit* heavy lift vessel will first remove Brent Delta's topsides, which weigh 24,000 tonnes and will be lifted in approximately 10 seconds, said Shell. (Source: Allseas)

Decommissioning challenges

Elements of the Brent Field infrastructure present particular decommissioning challenges and have been the focus of detailed research.

Three of the platforms (Bravo, Charlie and Delta) have giant concrete legs that support the topsides and clusters of large concrete oil storage cells at their base. These storage tanks contain large quantities of gravel ballast, used to anchor the structure to the seabed. Many cells were originally used for oil storage and therefore contain some oily sediment.

Accessing the cells to remove this sediment presents a significant technological challenge, due not only to their location deep beneath the water's surface but also their size and the thickness of the cell walls.

Appropriately reflecting the pioneering nature of the original Brent platforms, the operator will individually remove the cells, which will be transported from the field to the Tees onboard Allseas' newly-constructed *Pioneering Spirit* vessel. The vessel has been specially designed to carry out heavy single-lift installation and removal works.

The *Pioneering Spirit* is the world's largest vessel in terms of gross tonnage, and has a 25,000-tonne jacket lift capacity and a 48,000-tonne topside lift capacity. The vessel cost an estimated $2 billion to build.

Heaviest offshore lift

At 382 m (1,253 ft) long, *Pioneering Spirit* will first remove Delta's 24,000-tonne topsides—one of the heaviest offshore lifts yet attempted.

According to a Shell inventory, the 44-m (144-ft) tall topsides includes 10 tonnes of asbestos (used for insulation and gaskets), 899 tonnes of paint, 31 tonnes of batteries, 6 tonnes of cotton for bedding and 3,446 fluorescent lighting tubes.

The lifting process is expected to take only a matter of seconds, with the topsides to be moved to Able Seaton Port in Hartlepool in northeast England, where Able U.K. has been awarded the contract for the disposal of the four offshore structures. One of Europe's heaviest load-bearing quays is being built at the port to receive the structures.

About 100 jobs will be created during the 18-month construction of the new quay, with the six-year recycling contract itself generating a further 100 new jobs. It is anticipated that more than 97% of the structures will be reused or recycled.

It has not yet been decided how to deal with the approximate 300,000 tonnes of subsea structure that make up the concrete gravity base structure.

Shell is quick to point out that, while this may be the end of an era for Brent, it is far from the end of the line for the U.K. North Sea as a producing region.

Oil and Gas UK estimates that one-third of the U.K. Continental Shelf's total reserves still remain—some 15 Bboe to 24 Bboe. But the days of finding supergiant fields in the U.K. North Sea such as Brent appear to now be just a happy but distant memory. E&P

Pioneering FPSO vessel gets new lease on life

Many of the vessels featured in this section tend to be newbuilds and new designs, but the spotlight this month falls deservedly on a ship that undeniably changed the way the E&P industry approached floating production as the solution for exploiting small- to medium-sized fields.

The venerable *Petrojarl 1* recently entered drydock at Damen Shiprepair's yard in Rotterdam, the Netherlands, for a yearlong $175 million facelift after clocking up nearly three decades of almost faultless operations.

Originally known as the Production Test Ship, the FPSO vessel's first outing was on Norsk Hydro's Oseberg Field in 1986, quickly demonstrating to the industry the value and inherent flexibility of this type of production facility.

Historically, the *Petrojarl 1* has achieved an outstanding average production reliability rate on varied projects of between 96% and 99%, all of which have been in the harsh-environment North Sea. Its ability to act essentially as a vacuum cleaner to tap what would otherwise be marginal fields, incurring low upfront costs and avoiding decommissioning issues, enabled the exploitation of reservoirs that may otherwise never have been produced.

The list of fields on which the FPSO vessel has been stationed is impressive: Oseberg, Troll, Lyell, Fulmar, Balder, Fife, Fergus, Flora, Angus, Hudson, Blenheim, Kyle and Glitne.

Current owner Teekay Offshore is now having this grand old lady upgraded for her next charter across the Atlantic in warmer climes on a five-year contract as an early production system for Queiroz Galvão Exploração e Produção. It will produce the post-salt Atlanta heavy oil field in Brazil's deepwater Santos Basin.

Having first undergone four months of preliminary work alongside the yard, the vessel was then moved in April into Damen's 307-m- (1,007-ft-) long by 47-m- (154-ft-) wide drydock No. 8, where it is now receiving comprehensive upgrade and modification work on its hull and topsides. The process systems (ie. the separation train and produced water topsides) also are being converted, and the vessel is being prepared for full Brazilian compliance.

Although long in the tooth, the *Petrojarl 1* remains impressively productive. The current upgrade will extend its useful life by at least 15 years, and it is expected to generate an annual cash flow from operations of $55 million to $60 million per year. EP

Vessel Facts	
Sector:	Floating production
Owner:	Teekay Offshore
Vessel Design:	Tentech 685
Built:	NKK Japan
Size (length, breadth):	215 m (705 ft), 32 m (105 ft)
Deadweight:	31,473 tons
Transit Speed:	10 knots
Mooring Type:	Nondisconnectable internal turret
Riser Slots:	Nine
Storage Capacity	180,000 bbl
Operating Arena:	Worldwide
Classification:	Dnv+A1
Accommodation:	68 persons
Next Location:	Atlanta Field, Brazil (1H 2016)

The *Petrojarl 1* FPSO vessel first produced oil back in 1986 offshore Norway. In 2016 it will still be working, with a planned startup by mid-year on the Atlanta Field in Brazil's deepwater Santos Basin. (Source: Teekay Offshore)

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AFRICA

Wentworth strikes gas in southern Tanzania

The MB-4 development well in southern Tanzania's Mnazi Bay concession has encountered Miocene gas reservoirs with net pay of 24 m (79 ft) in the Upper Mnazi Bay and 43 m (141 ft) in the Lower Mnazi Bay, Wentworth Resources Ltd. said. The well, drilled to a total depth of 2,788 m (9,147 ft), is located about 800 m (2,625 ft) from the MB-2 and MB-3 wells in the Mnazi Bay gas field. Wentworth has ranked the recent discoveries as being among the best of the five wells drilled in this field to date. Within this well, two reservoirs were tested at different two-hour stabilized flows, with the Upper Mnazi Bay achieving a constrained flow rate of up to 532,356 cm/d (18.8 MMcf/d) and the Lower Mnazi Bay of up to 628,633 cm/d (22.2 MMcf/d). The well will be connected to the production facilities, which currently are being installed in the field, for startup in third-quarter 2015.

Expro receives contracts for Ghana work

Expro received new three-year contracts from Tullow Oil Plc for work in Ghana, Expro said. The contracts are worth more than $100 million and will support work on the Jubilee Field, the Tweneboa-Enyenra-Ntomme (TEN) Field project and other Tullow projects in the country. Expro has another Phase 1 contract for Jubilee for more than 10 completions; now, services can continue for Phase 1 A, which covers new well interventions and remedial work. Jubilee's Phase 1 A will use large-bore subsea completion landing strings, subsea exploration and appraisal landing strings, high flow-rate surface well testing, and sampling services. The TEN project also will involve subsea completion work in all planned wells.

ASIA

KrisEnergy sees first oil at Nong Yao Field

Oil production from three wells at the Nong Yao Field in the Gulf of Thailand has started, KrisEnergy Ltd. said. The field is in the G11/48 license. The company is working on another four oil developments in the Gulf of Thailand, including the KrisEnergy-operated Wassana oil field in the adjacent G10/48 concession, which KrisEnergy expects to go into production soon. The Nong Yao development will comprise up to 23 wells, a wellhead processing platform and a minimum-facility wellhead platform with the export of crude via a floating storage and offloading vessel. The facilities have a production capacity of up to 15 Mbbl/d and a processing capacity of 30 Mbbl/d of fluids. G11/48 covers 3,374 sq km (1,303 sq miles) over the southern margin of the Pattani Basin and the northwest margin of the Malay Basin in water depths of up to 75 m (246 ft).

AUSTRALIA

Dolphin starts 3-D seismic work in Australia

Dolphin Group ASA has initiated a 3-D SHarp broadband multiclient survey covering about 15,000 sq km (5,791 sq miles) on Australia's North West Shelf, the company said. In cooperation with TGS and supported by major oil companies, Dolphin mobilized its high-capacity 3-D *Sanco Swift* vessel to acquire the North Carnarvon Basin survey, covering both newly-awarded licensed and open acreage. Dolphin will perform full broadband seismic processing of the survey data to produce a high-quality onboard post-stack time-migrated fast-track volume followed by the prestack time-migrated dataset. All processing will be performed with input from supporting clients. Prior to this survey, Dolphin and TGS planned to complete Phase 1 of about 2,500 sq km (965 sq miles) of the Monuments MC 3-D survey with the same vessel. This was scheduled to be completed around June 25. These surveys use 10 streamers with 150-m (492-ft) separations and 8,100-m (26,575-ft) offsets.

Dolphin's high-capacity 3-D vessel, the *Sanco Swift*, will carry out a survey over the North West Shelf of Australia. (Source: Dolphin Geophysical)

EUROPE

Energean plans 3-D seismic survey in Gulf of Kavala

Energean Oil & Gas will conduct a new 3-D seismic

INTRODUCING

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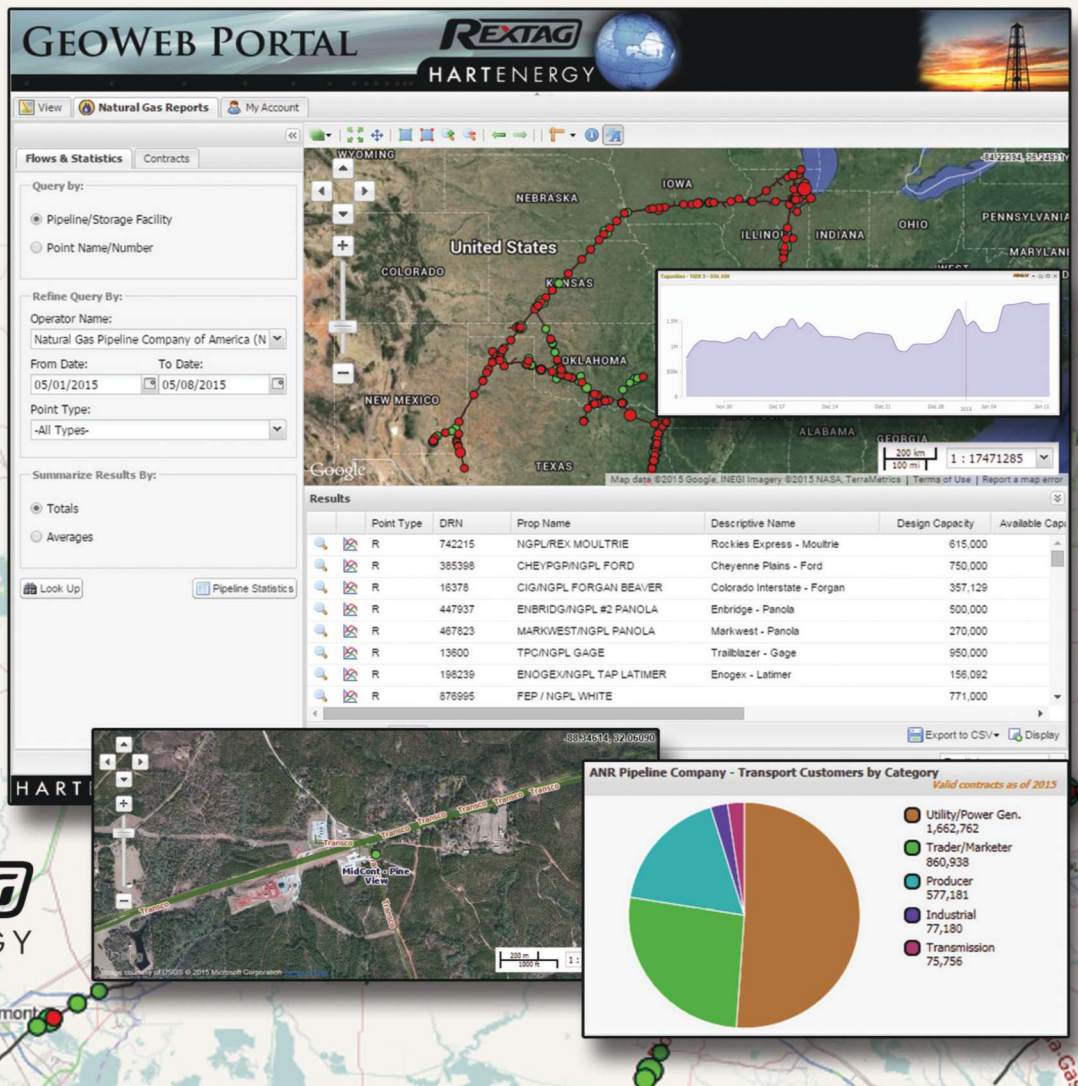

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survey over the Prinos oil field and its surrounding licenses in the Gulf of Kavala offshore Greece, the company said. Through the new 3-D acquisition, Energean said it aims to improve the seismic imaging of the Prinos Field and the satellite oil fields Prinos North and Epsilon. Energean has appointed Dolphin Geophysical to carry out the project. In the Gulf of Kavala, Energean will use the *Polar Marquis* 3-D vessel and the *Artemis Arctic* source vessel. Coverage will be further enhanced by an undershooting operation. The 3-D survey was scheduled to cover an area of 400 sq km (154 sq miles) and to last about three weeks.

Energean aims to improve the seismic imaging of the Prinos complex in the Gulf of Kavala offshore Greece. (Source: Energean Oil & Gas)

MIDDLE EAST

Wood Group secures Saudi Aramco offshore contract

Wood Group has been awarded an offshore maintain potential program contract by Saudi Aramco for greenfield and brownfield engineering services, procurement, and construction management support for new facilities in the Arabian Gulf, according to a news release. The six-year contract, which includes options for two three-year renewals, includes the establishment of an offshore engineering center of excellence in Al Khobar, Saudi Arabia. Work will be performed by Wood Group Mustang in the U.S. The in-kingdom work scope will be executed by Mustang-HDP.

RUSSIA CIS

OneSubsea wins subsea trees contract for Shah Deniz Stage 2

OneSubsea has been awarded a contract totaling more than $60 million for the BP-operated Shah Deniz Stage 2 development offshore Azerbaijan, according to a news release. The scope of the new contract includes the supply of the second of three planned batches of subsea production trees and ancillaries. Deliveries are expected to commence in 2016.

Data reveal Russia as China's top oil supplier

Russia surpassed Saudi Arabia to become China's top crude supplier as the fight for market share in the world's second-largest oil consumer intensifies, Bloomberg reported. China imported a record 3.92 million metric tons from its northern neighbor in May, according to data emailed by the General Administration of Customs in June. That's equivalent to 927 Mbbl/d, a 20% increase from April. Saudi sales slumped 42% from April to 3.05 million tons. China is becoming a key market for global oil exporters as surging output from shale fields allows the U.S., the biggest crude consumer, to rely less on overseas supplies. China will account for more than 11% of world demand in 2015, the International Energy Agency predicted in June.

SOUTH AMERICA

Premier strikes oil at Isobel Deep

Premier Oil has struck oil in its Isobel Deep exploration well 14/20-1 in the North Falkland Basin, about 30 km (19 miles) south of the Sea Lion Field, the company said. The Isobel Deep exploration well has been drilled to a depth of 2,528 m (8,294 ft), reaching top reservoir on prognosis. The bottom 23 m (75 ft) of the well consists of oil-bearing F3 sands. The sands were at a higher reservoir pressure than expected, and this resulted in an influx into the well. As part of the operations to remove the influx, oil was recovered from the well and appears similar in nature to Sea Lion crude. As a result of the new geological information, the company has decided to suspend operations on the well and release the rig to drill in the South Falkland Basin. The *Eirik Raude* rig is expected to return to continue operations in the North Falklands Basin in August.

Poço Verde 4 well hits new oil in Sergipe-Alagoas Basin

The Poço Verde 4 well hit a new oil accumulation in the Poço Verde area in the ultradeepwater Sergipe-Alagoas Basin offshore Brazil, Petrobras said. The well is in the BM-SEAL-4 concession. The well, formally known as Well 3 SES 189, is 23.5 km (15 miles) from the discovery well in 2,480 m (8,133 ft) of water. Poço Verde ran 5,350 m (17,552 ft) deep. The area's light oil reservoirs are 85 m (279 ft) thick with good porosity and permeability. This well was the third drilled in the Poço Verde area. Poço Verde is part of the exploratory project in the basin. There are five other evaluation plans. E&P

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PEOPLE

Andrew Way will lead as CEO and president of Exterran Holding's upcoming international and fabrication services spin-off company to be launched in third-quarter 2015.

Rockwater Energy Solutions Inc. has promoted **Holli Ladhani** to president and CEO as well as to board member of the board of directors.

Energistics appointed **Ross Philo** as its new president and CEO.

AFGlobal Corp. has promoted **Curtis Samford** to president and CEO, succeeding **Gean Stalcup**. Stalcup has been named chairman of the board for AFGlobal.

Ceona has appointed **Mark Preece** as CEO.

Effective Oct. 1, **Alex Schneiter** is the new president and CEO of Lundin Petroleum AB, following the decision of **Ashley Heppenstall** to step down.

DNV GL Group has appointed **Tor Svensen** as group executive vice president. **Knut Ørbeck-Nilssen** will succeed Svensen as CEO of its maritime business area.

The International Well Control Forum selected **David Conroy** as its first CTO.

President and CEO **Steven L. Bietz** retired on July 17 from MDU Resources Group's pipeline and energy services business.

Strategic Marine has appointed **Rob Osborn** as general manager for fabrication and engineering.

Cimarex CFO **Paul Korus** plans to retire on or before Sept. 1, and the company has appointed **Mark Burford** as the new CFO, effective as of Korus' retirement.

Peter Jenkins has been selected as the new CEO of 4Subsea.

BHP Billiton has selected **Dean Dalla Valle** as the new COO.

Rodney J. Eichler, Apache Corp.'s executive vice president and executive adviser to the CEO, retired at the end of June.

RigNet Inc. promoted **Keith Stewart** to vice president of global operations of RigNet TSI.

The Society of Petroleum Engineers has selected **Janeen Judah** as the 2017 president of the international professional society.

Xodus Group has promoted **Andrew Sewell** to the role of global subsurface lead.

Hatch has appointed **John Russell Baird P.C.** as global strategic adviser.

Trelleborg Sealing Solutions has promoted **David Brown** to global lead group director of oil and gas.

Umberto Vergine has been appointed chief midstream gas and power officer at Eni, and a new position of chief retail market gas and power officer has been assigned to **Marco Alverà**.

Petroplan has named **Lindsay Sher** the new regional recruitment manager for Sub-Saharan Africa.

2H Offshore, an Acteon company, has appointed **Prahlad Enuganti** as technical manager in its Aberdeen of, Scotland, office.

Ahmed Al-Dadah has been appointed to the role of business development director for engineering and property management at Penspen, and **Na'el Barghouthi** joins as director of asset integrity for the Middle East and Asia-Pacific regions. **Michael Simm** has been newly appointed to the role of regional director for Penspen's Middle East business.

Allen "Al" Ferguson has been selected as Clariant's oil services manager for Canada.

Henrik Lundin will join the board of directors of TAG Oil Ltd.

Øystein Løseth was elected as new chair and **Roy Franklin** was selected as a new member and deputy chair of Statoil's board of directors.

National Fuel Gas Co. has elected **Joseph N. Jaggers** as a new director for the corporate board of directors.

Goodrich Petroleum Corp. appointed **Walter G. "Gil" Goodrich** to chairman of the board of directors, replacing **Patrick E. Makkoy III**, who retired May 11.

Darra Comyn resigned as group finance director of Afren. **David Thomas** is the new COO and executive director of the board of directors. **David C. L. Frauman** will join the board as nonexecutive chairman.

A. Glenn Patterson, one of the original founders of Patterson-UTI Energy Inc., has passed away. He served as president and COO from 1978 to 2006.

Sembcorp Marine has appointed **Ong Poh Kwee** as COO, **Wang Zijian** as head of Singapore yard operations, **Ho Nee Sin** as head of offshore platforms, **Wong Lee Lin** as head of repairs and upgrades, **William Gu** as head of rigs and floaters, and **Freddie Woo** as head of specialized shipbuilding.

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on the MOVE

Rainer Seele has been selected as OMV CEO and chairman of the executive board.

Sir John Hood has been appointed chairman of BMT Group Ltd. following the retirement of Dr. Neil Cross.

John Hogg assumed the presidency of the American Association of Petroleum Geologists.

COMPANIES

Santos GLNG's three major natural gas compression hubs are now operational, marking the end of the first phase of gas field construction. The achievement comes after testing of the third and final hub, near Roma, was completed and handed over to the long-term operations team, according to a press release.

Technical University of Varna opened a new maritime simulator wing that features a NAUTIS Class B dynamic positioning simulator as well as a NAUTIS Class A full-mission bridge simulator and a new ECDIS Simulator classroom.

J2 Subsea, an Acteon company, has opened a new subsea tooling facility at Seatronics' subsea electronics location in Houston. The facility includes a workshop for tool preparation, servicing and support.

Tenaris has expanded its service center in Esbjerg, Denmark. In June, the company inaugurated its newly constructed pipe yard, which has a storage capacity of 14,000 tons. The facility offers technical assistance for offshore and onshore oil country tubular goods and operational and administrative support as well as an onsite machine shop. E&P

ADVERTISER INDEX

Hitting the payload the first time

Successful ERP deployment for the oil and gas supply chain requires a bridge between consultants, operators and major suppliers.

Chris Welsh, OFS Portal

Oil and gas companies are facing increasingly complex issues that are disrupting the normal course of business at an accelerated rate, issues like integration of mergers and acquisitions, intricate joint venture arrangements, regulations from multiple jurisdictions and the emergence of breakthrough technologies. The pace of change is such that what once were considered disruptions are now becoming part of business as usual.

To keep up with, understand and process this evolution of the industry, all major oil and gas companies are in the process of implementing enterprise resource planning (ERP) landscapes. Unfortunately, the requirements of these landscapes grow more complicated over time, and the industry is littered with false starts and restarts. Some companies have spent upwards of $50 million, are on their third or fourth iteration and still are not fully deployed.

While most companies have taken appropriate steps hiring top-tier consultants who are considered among the best at major ERP implementations, the incomplete track record across the industry speaks for itself. The missing ingredient is a partner that can bridge the gap between pure ERP consultants and the industry and that understands key processes in the oil field and correct implementation of ERP for operators.

Not only should all aspects of the oil field be thoroughly understood in an ERP implementation, it is critical for success that the parties doing the implementation also possess a deep understanding of both operators and service companies and their integrated supply chains.

The oil and gas industry continues to hire the very best engineers and geoscientists to develop and manage its downhole investments, yet the attention directed at the back office and supply chain pales in comparison. Although not nearly as high-profile, shouldn't the industry apply the same attention to these areas? After all, they also are critical in the success of overall business goals.

ERP implementation occupies a relatively low priority when the industry is booming; companies direct financial and human capital to business growth. However, given the current market, timing couldn't be better to put ERP implementation at the forefront. For example, digitizing the supply chain is a key component of successful ERP implementation, and the industry increasingly finds itself buried in paper. In this downturn, internal resources are available to take on this huge digitization process as well as to implement practical e-commerce standards, create best practices and be fully ready to take advantage of the next upturn. As a result, these efforts will create significant value and long-term sustainability.

Operators shouldn't shoulder the entire load! Service companies must step up and be more engaged with customers' needs in this digitization initiative. After all, they are partners in the oil field and should be partners throughout the entire supply chain for both to achieve long-term success.

> Working smarter at the front end of the ERP process is similar to planning a well.

Ideally, collaboration occurs at the onset of the implementation, similar to a major capital project, which can save tens and perhaps hundreds of millions of dollars in false starts and rework. Think of tackling ERP implementation on the front end as cost avoidance vs. cost reduction—a company could be going down the wrong path but not realize it until it is two years in and has to start over. The companies that will get it right, whether it be the first or third time, will engage the correct subject-matter experts in the planning process of ERP implementation.

Working smarter at the front end of the ERP process is similar to planning a well—bringing the right partners to the table and making sure to take full advantage of the investment. One missing ingredient or partner can mean the difference of an investment's success and return on that investment. Think of a successful ERP implementation the same way: The missing ingredient has been the bridge between consultants, operators and the major suppliers, and filling that gap can mean hitting the payload the first time. EP

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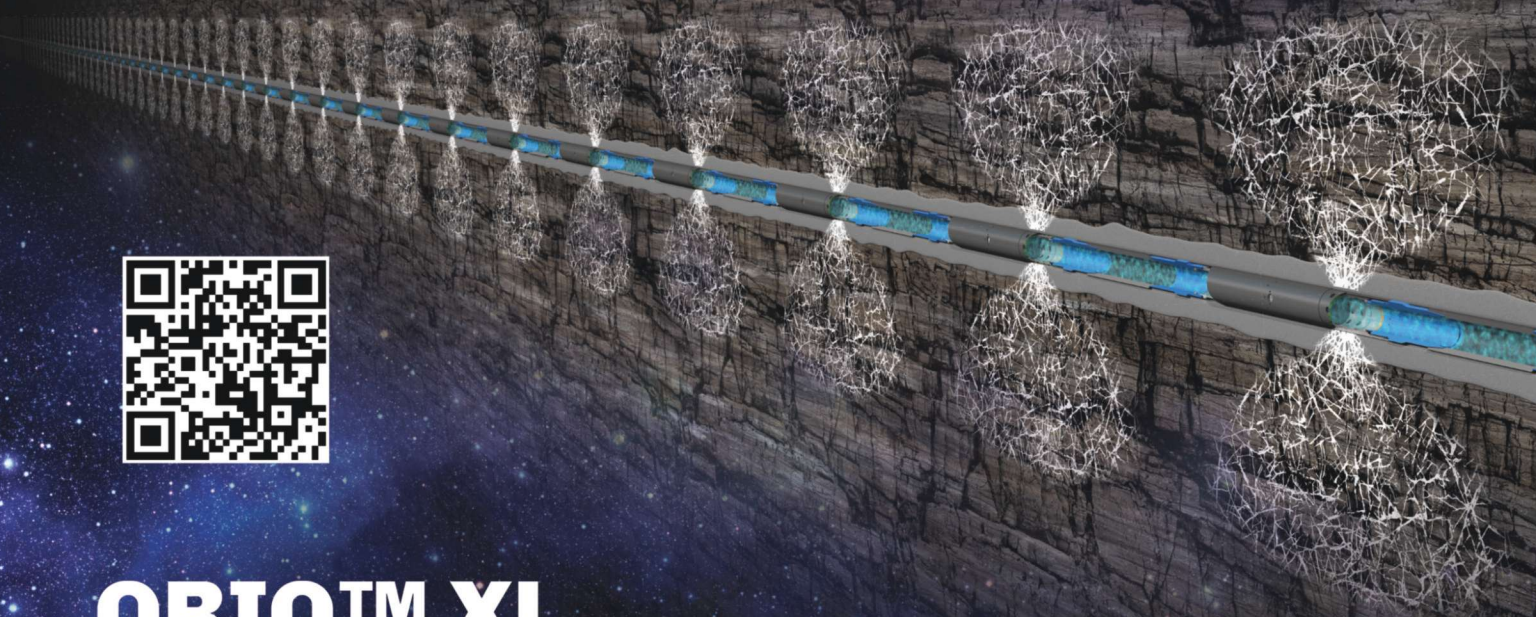

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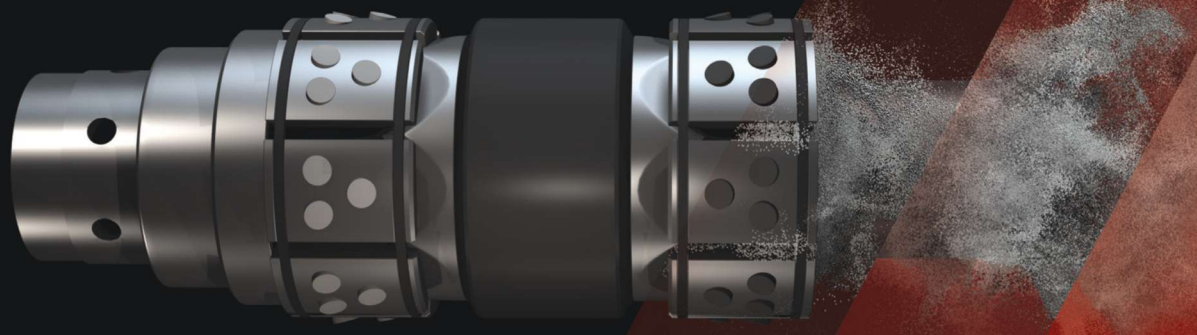

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