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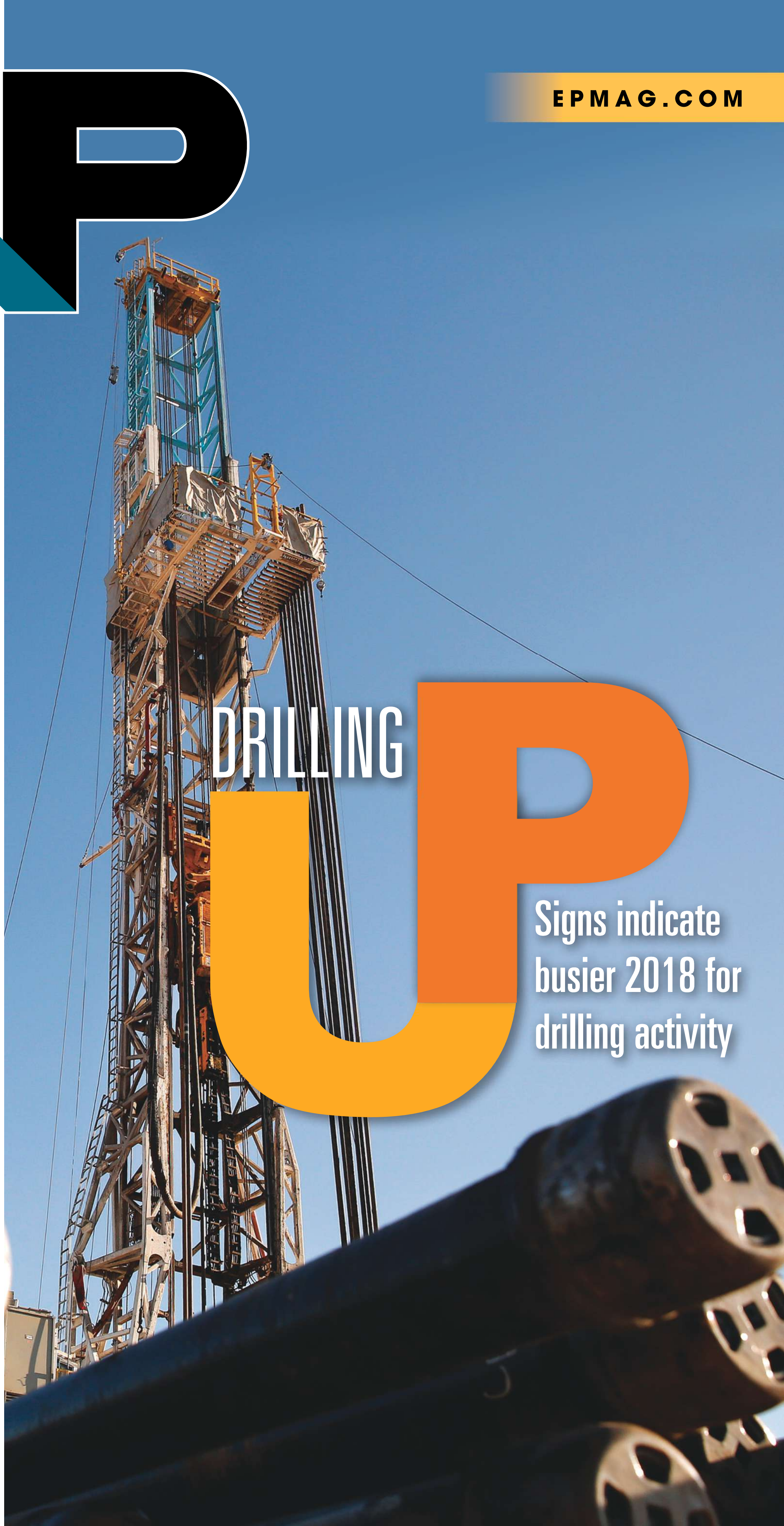

DRILLING UP

Signs indicate busier 2018 for drilling activity

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Coiled Tubing Drilling

Plugs

Onshore Well Intervention

Deepwater Production Facilities

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EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE

MARCH 2018
VOLUME 91 ISSUE 03

A HART ENERGY PUBLICATION

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ZIP technologies optimize safety, improve wellsite efficiency and maximize total available pumping time for fracture stimulation.

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The April issue of ***E&P*** will focus on digital innovations. Other features will cover land seismic, MPD/UBD, perforating systems, artificial lift, and subsea trees and controls. The unconventional report will focus on Argentina. 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 The demand for bits, pipe, rigs and more is on the rise as drilling activity increases across the U.S. Left, this 3-D rendering illustrates the past, present and future (top to bottom) of FPSO topsides. *(Cover photo by Tom Fox, courtesy of* Oil and Gas Investor; *Left photo courtesy of SBM Offshore; Cover design by Felicia Hammons)*

E&P (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX, and additional mailing offices. Subscription rates: 1 year (12 issues), US $149; 2 years (24 issues), US $279. Single copies are US $18 (prepayment required). Advertising rates furnished upon request. **POSTMASTER: Send address changes to E&P, P.O. Box 3001, Northbrook, IL 60065-9977.** Address all non-subscriber correspondence to E&P, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442 Fax: 713-840-1449; custserv@hartenergy.com.

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ACTIVITY HIGHLIGHTS

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Offshore Equatorial Guinea exploration planned

Clontarf Energy Plc was awarded Block 18 (EG-18) offshore Equatorial Guinea and has begun to identify and analyze the geological plays in the Northern Rio Muni Basin.

Hilcorp receives permit for directional delineation test on Kenai Peninsula

IHS Markit reported that Alaska Division of Oil & Gas has approved a unit plan of operations for Texas-based Hilcorp Energy Co. for a directional delineation test to be drilled from the Pearl pad on the Kenai Peninsula off of southern Alaska.

Permian Coconino sandstone ventures permitted in Apache County, Ariz.

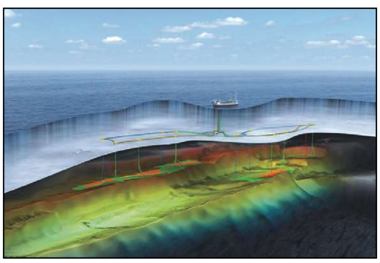
Three exploratory drilling permits have been issued to Arizona Energy Partners LLC for wells in Apache County, Ariz. According to IHS Markit, they are most likely helium projects targeting the Permian Coconino sandstone. The permits do not list objectives or differentiate between oil, gas or helium.

AVAILABLE ONLY ONLINE

Hess sees gains in Bakken with new completion design

By Velda Addison, Senior Editor, Digital News Group

The company plans to add rigs in the Bakken this year as it continues studying completion techniques.



Statoil shares insight on driving efficiency in oil, gas operations

By Mark Venables, Contributing Editor

Torger Rød, senior vice president of projects for Statoil, discusses how the company is driving efficiencies with its E&P activities.

India's state oil companies plan to spend $13.82 billion in FY 2018-19

By Tara Chand Malhotra, Contributing Editor

Half of the spending will go toward E&P activities as the country aims to increase domestic oil and gas production.

Editors' note: The charts included in the article "Haynesville continues its climb," which appeared on pages 80-81 in February *E&P*, contain inaccuracies that were discovered after the issue went to print. We regret the error.

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Latin America shines on

Falling breakevens, access to new acreage and sizeable reserves are keeping Latin America front and center.

Latin America has long captivated the world. From the beaches of Cancún to Copacabana and all points in between, near and far, the region provides the rhythm that moves us all. Nowhere is this more visible than in Brazil, home to Samba music and Carnival. The discovery there in 2007 of the Tupi oil field in the Santos Basin presalt elevated the profile of the country and its people even higher.

With an estimated 5 Bbbl to 7 Bbbl of recoverable reserves, the deepwater field renamed Lula in 2010 was the first of many in the Santos Basin. Subsequent discoveries offshore Brazil further secured the country's role as a global energy producer. While the world marveled at the Carnival-like parade of glamorous presalt discoveries made by Petróleo Brasileiro, other explorers quietly worked the edges of the continent that was once attached to Africa's hip. In 2008 Exxon Mobil began its exploration activities north of Brazil in the waters offshore Guyana. Jump forward not quite a decade and the supermajor has, along with its partners Hess and CNOOC, announced six significant Guyanese discoveries. All located on the Stabroek Block, five of the discoveries—Liza, Payara, Snoek, Liza Deep and Turbot—are estimated to have total recoverable resources of more than 3.2 Bbbl. The sixth discovery at Ranger was announced in January with appraisal drilling a possibility this year, according to an Exxon Mobil press release.

The discoveries illustrate what analysts at Wood Mackenzie believe the petroleum industry will see more of this year in the Latin America upstream. Portfolio high-grading is steering companies to the region's deepwater licensing, with exploration prospectivity and access to previously unavailable acreage and reserves driving interest, according to a Wood Mackenzie report. Licensing rounds in Brazil and Mexico are expected to draw strong bidding from majors and Asian national oil companies.

Adding to that interest is the decline in deepwater breakevens as compared to U.S. shale plays, the report noted. Hess, for example, cited in its presentation at the 2017 Bank of America Merrill Lynch Global Energy Conference that the Liza Phase 1 development offers superior economics to premier U.S. shale plays, with a $35/bbl breakeven as compared to a $45/bbl breakeven for a Delaware Basin development.

Presidential elections in Brazil, Colombia, Mexico and Venezuela are potential dark clouds on the horizon that might impact exploration and development in the region. But as time has shown, the parade may slow down but it never completely stops. E&P

Jennifer

Middle East opportunities, challenges

The workforce could be the deciding factor.

Andy Ryan, Airswift

If America can claim the title of the world's breadbasket, the Middle East is surely its oil well. Of the 19 countries that topped 1 MMbbl/d in 2016, seven are Middle Eastern (five on the Arabian Peninsula), eclipsing any other region for total output or concentration of major players.

It is a region that offers rich opportunity to the upstream oil and gas sector, but it has its challenges, too. The geopolitical situation, the low oil price—despite OPEC's production cuts—and drives by various states to diversify their economies and energy sectors are all headwinds.

However, some of the most pressing structural challenges have to do with the industry's workforce. The time to act is now, but concerted efforts are difficult, not least because tomorrow's challenge often masquerades as today's opportunity.

Headwinds

Ultimately, it all boils down to cost per barrel and price. The most obvious challenge is the persistent low oil price environment.

Taken in isolation, the low price is a storm that the region's upstream industry could ride out without too much discomfort. But nothing happens in isolation. Though not catastrophic in itself, the oil price is the rough undercurrent to a host of other challenges.

Take, for example, the ongoing diplomatic tensions between Qatar and its neighbors, including Saudi Arabia and the United Arab Emirates (UAE). Accusations of foul play and supporting terrorism have led to Qatar's larger neighbors imposing sanctions and all but closing the borders.

However, things are more difficult in the region as a result of the dispute. Sanctions and border restrictions make everything more expensive, from the food eaten by the crews onsite to the construction materials required for asset development and maintenance.

It also causes problems for suppliers to the upstream industry. Multinationals typically set up a central regional office and serve the region from there. If that office is in Dubai and there is work to be done in Doha, then a short direct flight is now a circuitous trek of about 7 hours. Though aimed at Qatar, in this way the restrictions hamper ease of doing business throughout the region.

There are other less direct challenges, too. The energy sector is changing in the Middle East, and renewables are making inroads. The UAE, for example, is investing $163 billion in renewables aiming to meet half of its power requirements sustainably by 2050. Similar projects have been planned and ambitions stated across the region. This is unlikely to spell disaster for upstream operators anytime soon, but it does reduce domestic demand and begin to chip away ever so slightly at oil's privileged position as the centerpiece of national economies.

Not all the challenges are external, either. The ease of extraction in the Middle East has led to underinvestment in efficiency and technology compared to more demanding regions around the world. As reserves gradually reduce, operators may come to regret the underinvestment.

The sleeping giant

The greatest challenge that Arabian upstream operators face does not have to do with geopolitics or tech; it has to do with people.

From March 2015 to October 2016 it is estimated more than 300,000 oil and gas jobs were lost worldwide, with the Middle East certainly seeing its share. Now, having made the painful adjustments, operators are *prima facie* in a great position. There is a lot of very skilled talent available and eager for work; to some it may look like a buyer's market. However, that situation cannot last.

Many of those people went out and made new careers for themselves. These are skilled workers with highly transferable experience that can open doors in many industrial or infrastructure sectors. The burgeoning renewables market has been a willing recipient of veteran engineering and managerial talent.

In the 2016 Global Energy Talent Index conducted by Airswift and Energy Jobline, it was revealed that 67% of oil and gas professionals worldwide were interested in working in other energy sectors, particularly renewables. One of the biggest motivations was job security (cited by 42%), and, shockingly, nearly half (49%) would take a pay cut to do so.

The oil and gas industry can't assume it will easily tempt them back. People who have been let go are not quick to forget. In the Middle East 50% of surveyed hiring managers had not rehired any of their laid-off employees, with a further 33% having rehired less than 10%. They might find that some of the skilled talent they seek to rehire have left the job market entirely. The aging workforce is a well-publicized phenomenon in the upstream sector. Almost three-fourths of hiring managers cited an overall talent deficit as a challenge to the industry, with nearly half (46%) believing the aging workforce to be the main reason for this challenge.

If the industry tries to ratchet up hiring again in the near-medium future, it might find a significant number of skilled energy workers are happily settled in other sectors and others have opted to retire. So, while it might feel like a buyer's market with regard to talent now, upstream operators should have one eye on the future.

Room for optimism?

Luckily for operators in the Middle East, many of the figures cited above are global ones, representative of the oil and gas sector as a whole. For regional operators there are some nuggets of good news in the more granular data. For example, 46% of hiring managers thought that the Middle East would be a hot spot for the industry over the next 12 months, with only 13% saying the same of Europe. When the professionals surveyed were asked for their top places to work, the Middle East came in second behind only North America.

Professionals in the Middle East were also optimistic about pay. Almost 50% believed it would increase in the next 12 months, far more than people who thought it would stay the same (33%) or decrease (14%). An important caveat, though, is that hiring managers were less bullish, with figures of 25%, 58% and 17%, respectively.

Overall, this is a broadly optimistic outlook for the Middle Eastern workforce. Global talent sees it as an attractive place to work and expresses cautious optimism about remuneration in the region. One of the biggest battles for the sector in the Middle East has been to counter false narratives in Western media about the quality of life in the region, so that is quite encouraging.

These reasons for optimism, however, don't make the looming workforce challenges disappear. The skills and talent shortages are very real, and it is up to the industry to act now to avoid or mitigate the issue. E&P

Have a story idea for Industry Pulse? This feature looks at big-picture trends that are likely to affect the upstream oil and gas industry. Submit story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

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Unraveling the Bakken's EOR complexity

With a well test underway, one independent energy company works to decipher the Bakken's EOR secrets.

Jennifer Presley, Executive Editor

The Bakken Shale that spreads approximately 520,000 sq km (200,000 sq miles) beneath Montana and North Dakota holds an estimated 7.6 Bbbl of undiscovered, technically recoverable oil, according to the U.S. Geological Survey. It is but a fraction of the total 167 Bbbl of original oil in place that the North Dakota Department of Natural Resources estimated in 2008.

With decline rates as high as 70% over the first three years of production and a primary recovery rate of about 7.5% of original oil in place, finding ways to recover more oil using EOR techniques in the maturing unconventional play is key.

Widespread interest has lead to numerous R&D efforts, with reservoir modeling and testing in a laboratory setting serving as the critical first step with testing of promising theories in the field the next step.

Building on the many years of experience it built in its Permian Basin EOR operations, Hess Corp. began an EOR R&D project in 2015 in the Bakken Shale. In 2016 the company drilled a gas injection and a production well targeting the Middle Bakken at Ross Field in Mountrail County, N.D., in the company's Red Sky acreage as part of the project.

E&P recently spoke to Dougie McMichael, director of Bakken well factory planning and execution, at Hess Corp. about the company's EOR efforts.

***E&P*: What are the primary challenges of EOR in the Bakken Shale?**

McMichael: The team has identified three major challenges that will affect the success of the project. First, [the challenge is] whether the injectant fluid-rock interaction will yield incremental production—will EOR work in the Bakken? Secondly, conformance of the injected fluid to create optimized contact with the oil with the least amount of injectant needed in the reservoir [is a challenge]. Finally, how to control the injectant on a drilling spacing unit and/or work with offset operators to maximize the recovery [is another challenge].


Dougie McMichael

***E&P*: How do these challenges compare to other unconventional resource plays?**

McMichael: EOR has yet to find wide application in unconventional resource plays, but it does appear that several companies are looking at it seriously. Most are handling their information confidentially, as you can imagine for a technique that might have a competitive advantage, so we don't know for sure how the challenges in the Bakken compare with other plays.

Our best assessment is based on publicly available information, which suggests the challenges are similar. For example, it will be important to have completions that enable gas to be injected efficiently, and it will be important to find areas where the formation is able to contain injected gas. We will also need to have access to infrastructure to supply, inject and then process the gas being used for the EOR scheme.

***E&P*: How has Hess applied its Permian Basin EOR expertise in the Bakken?**

McMichael: Hess had many years of EOR experience in the Permian, where we operated a CO_2 injection scheme. The Permian assets were divested by Hess in mid-2017, but we managed to retain knowledge and skills from that work. In particular, the type of skills the company has as a result of our work in the Permian include reservoir modeling of EOR schemes and designing lab studies to support and optimize the CO_2 injection. Bakken Formation characteristics are quite different to Hess' former Permian development, so we are working on some issues for EOR application in the Bakken Formation that are different from the Permian.

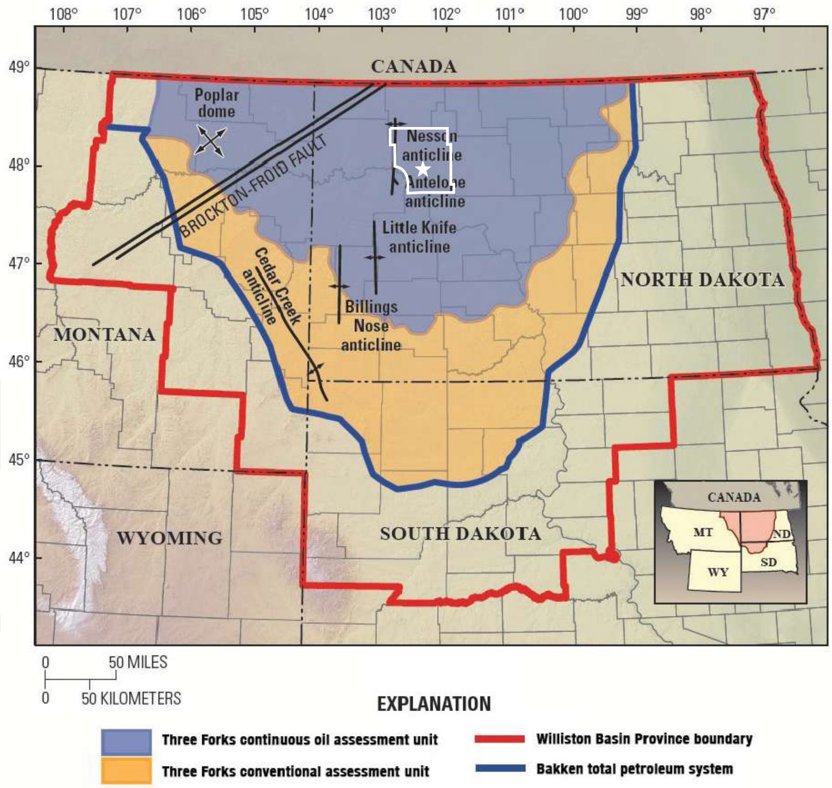
***E&P*: EOR requires a formation that can accommodate the pressuring up of the reservoir and can contain the gas long enough for it to soak into the formation. The Bakken Shale is a highly fractured, complex formation with a dense rock matrix. How will the gas penetrate the nearly impenetrable rock?**

McMichael: You are correct that we need the formation to contain the injected gas long enough to contact oil-bearing rock and increase the displacement of oil from the rock. It also is the case that the Bakken Formation is complex with a dense rock matrix.

The formation is variable across the basin, however, and Hess has a large acreage position. We can look at the characteristics of the rock across the formation to decide on where we think the application has the best chance of success.

We think the gas will migrate through the formation and contact oil-bearing rock using the same flow paths that are used for production. That includes hydraulic fractures that we initiate during well completion, natural fractures in the rock and the rock matrix. We know the formation produces oil, lots of oil, so we have high confidence we can get gas in, providing we have sufficient pressure to inject.

***E&P*: How is the gas floating the oil molecules out of the microscopic pores, into the fractures and then to the surface?**



Mountrail County, N.D., is indicated by a white star and outline on this map of the Bakken and Three Forks formations within the Williston Basin of North Dakota, Montana and South Dakota. (Source: U.S. Geological Survey)

McMichael: We believe there are a few possible mechanisms at play. Our current thinking is that potential mechanisms include oil and gas mixing, which results in the volume of oil swelling and then expelled out of the pore space, into the fracture and then produced.

There also is potential for oil to vaporize into the gas phase and then flow into the fracture and recondensate back to oil downstream of the fracture. We don't know for sure the relative impact of each and there are other mechanisms that would be at play. We are actively trying to improve our understanding of the specific processes that are leading to increased oil recovery through lab work and other studies.

***E&P*: How was the testing site selected?**

McMichael: Parameters for selection were established and various areas evaluated. Among the factors that underpinned the selection of Red Sky was an assessment of the reservoir fluids that were suitable for an EOR test, and there were no significant horizontal well development activities in this area of the field during the time frame of the planned test. This allowed for a controlled test environment for this part of the project.

***E&P*: It has been said that to successfully apply EOR in an unconventional resource play like the Bakken that it will take an 'unconventional' approach. Are you finding this to be true? How far 'out of the box' is Hess' approach to solving the Bakken EOR puzzle?**

McMichael: Interesting statement and it has its merit. I would say we are on the edge of the box, the general theories are the same for EOR in conventional and unconventional—improve sweep area/matrix contact and improve recovery.

Our approach has been to understand how EOR works in a conventional play, identify the key factors for improved recovery, capture differences between play types and apply lean methodologies to problem solve to reach a solution.

I also would add that with technology that is still in a testing phase in our industry (unconventional EOR) we must also be willing to learn from other operators. We also feel that there will be variance from play to play that has to be understood and adjustments made to be successful. E&P

Shell Brazil CEO is optimistic about Brazil's E&P future

André Araújo talks about the company's plans and expectations for its future in Brazil.

Brunno Braga, Contributing Editor

For Royal Dutch Shell, 2017 was a good year in terms of E&P activities in Brazil. Ranking as the second largest oil-producing company in Brazil, after acquiring BG Group's assets in the country, the British-Dutch major increased its oil output by 12% to 330,000 boe/d compared to 2016.

Also, Shell Brazil made important moves to take advantage of opportunities in the country's upstream segment. In 2017 Shell Brazil acquired three promising presalt fields in the Santos Basin—South Gato do Mato, Sapinhoá and West Alto Cabo Frio. Shell plans to begin drilling in the South Gato do Mato Field, where the company will work as operator, in 2019.

The company has a stake in 13 offshore blocks and four onshore blocks but intends to expand its operations in Brazil over the next few years. In an exclusive interview with Hart Energy, Shell Brazil CEO André Araújo shared his thoughts, which have been edited for clarity, about the company's plans and expectations for its future in Brazil's oil and gas segment.

André Araújo

Hart Energy: How were Shell's activities in Brazil in 2017?

Araújo: We can say that in 2017 there were some important advances created in the Brazilian oil and gas industry, especially with improvement of the regulatory framework agenda that approved important changes such as in the local content rules and in the presalt sharing regime. The three oilfield auctions and the announcement of a calendar of auctions in 2018 and 2019 also brought a great sense of predictability for the industry. We realize that Brazil's government and Brazil's oil regulator are listening to the industry's claims. They are working hard to ensure that the agenda for the upcoming year is very hot.

As for Shell, it was an important year to consolidate the company's portfolio in Brazil. We made an excellent acquisition in the presalt auction in October [2017] when we became an operator in one of the most promising regions in the world for E&P.

Hart Energy: Recently, Brazil's oil regulator said the country can reach 5 MMbbl/d of oil by 2027. Can Shell contribute to this production goal?

Araújo: Shell is Brazil's second [largest] oil-producing company after Petrobras. We expect to increase our portfolio in the country, so it is natural that our contribution will be greater. This process will take the company to a new level. It will increase our responsibility and will demand even more hard work from all of us. We have new areas to develop, explore and produce, not to mention the assets already in operation, which are very important for Shell. That will demand a large amount of investment.

Hart Energy: Talking about investments, in September 2017 it was announced that Shell will invest $2 billion in Brazil per year between 2017 and 2020. Can you elaborate?

Araújo: This is a very impressive amount of investment, and it makes us one of the largest foreign investors in Brazil. But the total investment in Brazil will be even higher since this amount of investment does not include the assets acquired in the presalt auction in October 2017.

Hart Energy: The Parque das Conchas in the Campos Basin is Shell's most important asset in Brazil. How have the company's activities in the Abalone, Argonauta, Ostra, Bijupirá and Salema fields located in the Parque das Conchas area fared?

Araújo: The Abalone, Argonauta and Ostra oil fields are part of the Parque das Conchas in the Campos Basin, where Shell performs as the operator. Those three fields began producing oil in 2009. Parque das Conchas is already in the third phase of development. Also in the Campos Basin, Bijupirá and Salema is a mature field of great importance among our assets. We have deployed

R&D projects focused on enhancing oil recovery and expanding the life of risers, which will certainly support Shell to maintain positive results on our assets.

Hart Energy: What is the contribution of these assets to Brazil's total output?

Araújo: The Parque das Conchas Field (BC-10) is a project that Shell is very proud of. It is an important milestone in the development and commercialization of deepwater oil in Brazil. Bijupirá and Salema has historical importance not only for the company but for Brazil. It was in this field that Shell became the first foreign company to produce oil on a commercial scale in the country after the opening of the domestic market [in 1997].

> In 2017 there were some important advances created in the Brazilian oil and gas industry, especially with improvement of the regulatory framework agenda.

Hart Energy: How is Shell performing in the natural gas market in Brazil? Can the former BG assets contribute to increasing natural gas production in Brazil?

Araújo: The acquisition of BG had a transformative effect for Shell in Brazil, as we incorporated important assets that enabled the company's participation in the natural gas market, with a significant increase in our production. Natural gas is a priority for the group, and we look with great interest on these assets and the integration of the energy market.

Hart Energy: Can acquisition of the South Gato do Mato, Sapinhoá and West Alto Cabo Frio southern presalt fields contribute to the company's oil and natural gas volumes?

Araújo: It is still premature to estimate their volume, but our expectation is great. These are important deepwater projects in the presalt that can put Shell in an even bigger position in Brazil's oil and gas market. We are already working to develop these two large additions to our portfolio. E&P

Engineered proppant to challenge status quo

A new suite of proprietary engineered proppant is headed to commercialization in 2018. Will it be enough to capture new share versus sand?

Richard Mason, Chief Technical Director

The instruction for customers in the old West Texas print shop was direct: good, fast, cheap. Pick two. That guideline applies to proppant selection in multistage fracturing. The majority of E&P companies are choosing "cheap" as the first option in a cost-conscious environment.

That is most evident in the gradual decline in marketshare for engineered proppants as slickwater plug-and-perf gains share in hydraulic fracturing methodology. Engineered proppants accounted for less than 16% of volume in the proppant market in 2017, according to an E&P sampling of FracFocus data.

In other words, few E&P management teams are letting the best outcome become the enemy of a good outcome. If the board is happy with the CEO, who is happy with the production managers, a "good" outcome is "good enough" in the oil patch. The question is whether improvement in engineered proppant, such as proprietary resin-coated sand, specialized fluids and rising commodity prices, will impact that "good enough" approach and increase share for engineered solutions in a global proppant market that is projected to grow financially into the early 2020s at a 7% annual compound growth rate.

- **Engineered proppant is slated for a marketshare gain in 2018.**
- **Cost remains the main obstacle for engineered proppant.**

Fairmount Santrol Co., Emerge Energy Services LP and U.S. Silica Holdings Inc. are among proppant providers who are moving proprietary engineered proppant into commercialization in 2018.

Industry emphasis is on advanced proppants that are buoyant enough to overcome duning, or settling in the wellbore, to take advantage of slickwater transportation dynamics in longer laterals. Secondly, interest is rising in a mixed proppant cocktail that ranges from channeling as an objective to customization for different sized fracture networks in the same stage.

Variations such as curable resin-coated proppant are used as a tail-in to keep proppant embedded during flowback operations. If an E&P company spends $3 million pumping a trainload of sand in the ground, the company doesn't want any of that sand back.

By region, engineered proppant is most common by volume in Appalachia, followed by the Bakken Shale, the latter of which finds the highest concentration of ceramics. Ceramics are found in HP/HT deeper plays in the Anadarko Basin and in the Gulf Coast. Appalachia and the Bakken combined represented 68% of volume for engineered proppant in the 2017 FracFocus sample.

Proppant vendors and manufacturers represented 48% of total reported volume in engineered proppant provision led by Fairmount Santrol Co. and CARBO Ceramics Inc. Well stimulation providers accounted for 34% by volume in engineered proppant provision.

There is nuance. By class, privately held E&P companies represented 60% of total count in engineered proppant use. Privately held firms using engineered proppant were most common in the Ark-La-Tex, Anadarko Basin and Delaware Basin with publicly held companies representing greater numbers in the Bakken and in Appalachia. Also, if an E&P company used engineered proppants in one play, it was likely to use engineered proppant in other geographic areas.

Expect the engineered proppant market to gain share in 2018—how much is hard to figure. Choosing "good" characterizes privately held consumers of engineered proppant, which suggests interest in boosting net present value to support eventual IPOs or an acreage sale. Choosing "good" also characterizes publicly held E&P companies seeking the most value out of reserves. Choosing "cheap and fast" characterizes everyone else. E&P

Seismic shift

Does WesternGeco's departure from seismic acquisition signal the end of an era? And if so, what's next?

RHONDA DUEY
Senior Editor, Exploration
rduey@hartenergy.com

Read more commentary at EPmag.com

It's like losing an old friend.

I remember when Western Geophysical, then owned by Baker Hughes, announced that it was merging with Geco-Prakla, then owned by Schlumberger. At the time the merger created the world's largest seismic acquisition company, only later to be eclipsed by the merger of CGG and Veritas in 2006.

WesternGeco was a powerhouse in the seismic acquisition space and introduced some eye-catching new technologies, including Q-Land and Q-Marine, coil shooting and dual-coil shooting, and later IsoMetrix, which, according to the company's website, "provid[ed] broadband data in 3-D for greater insight into real geology and efficiency without compromising on quality." I was at the product launch of IsoMetrix at a conference a few years ago, and it was not only standing room only, it was hugely packed. This was a company that was neck-and-neck with its major competition in bringing new products to the seismic market.

And now this.

While not exiting the geophysical market completely, WesternGeco is abandoning its acquisition efforts to focus on other market segments. A search on Schlumberger's website indicated that WesternGeco is very focused on the software market, and a recent article on *EPmag.com* indicated that "hardware," including expensive acquisition vessels and equipment, is now somewhat passé.

WesternGeco has decided to depart the land and marine seismic acquisition space. (Source: hkhtt hj/*Shutterstock.com*)

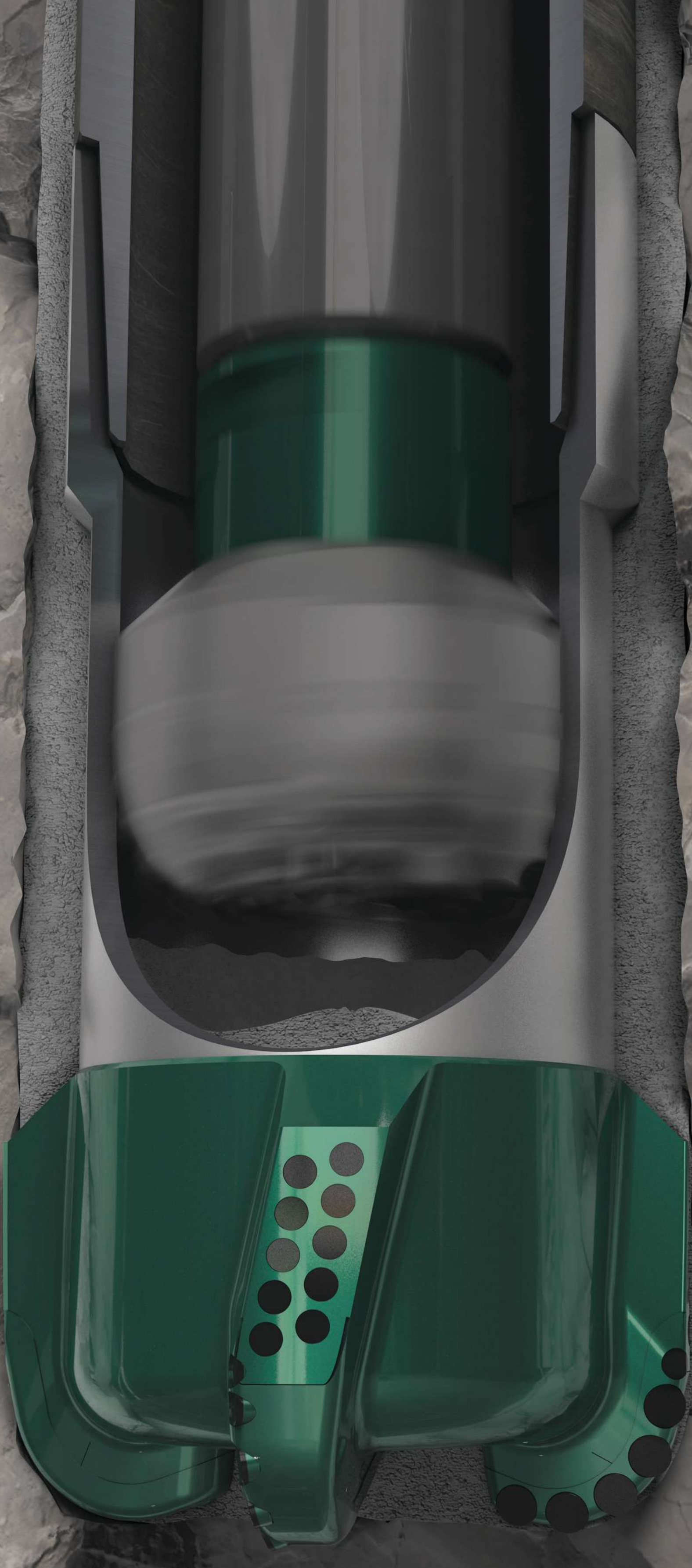
"This has not been an easy decision to make," Schlumberger CEO Paal Kibsgaard said during the company's January announcement. "But following a careful evaluation of the current market trend, our customers' buying habits and our current and projected financial return, it is an unfortunate and inevitable outcome."

Unfortunate indeed. After a year when some of WesternGeco's major competitors also had to make some stern decisions, Schlumberger's exit from the acquisition market is a difficult wake-up call. This is an industry that has introduced million-channel acquisition breakthroughs on land and developments like broadband seismic and nodal deployment at sea. But as one geophysicist said, "These things are nice to have but not necessary."

Kibsgaard added, "This challenging environment is clearly reflected in the financial statements of standalone acquisition players who are either at or close to bankruptcy, heavily burdened by weak cash flow and high debt," noting that Schlumberger has the choice to explore its other business options.

So has the seismic industry R&D'd itself out of a job? Has the shale gale refocused its efforts onto more of a reservoir characterization scale? I'm not sure. Shell, BP, Chevron, Total and others have recently announced major offshore discoveries. According to a recent article in the *Houston Chronicle*, some of these discoveries have come because companies have "found ways to cut the costs of exploration and production by winning discounts from contractors," according to Bob Fryklund, chief upstream strategist for IHS Markit's research and consulting firm. Fryklund said, "Better seismic imaging and drilling methods are bringing companies back to proven areas."

But, according to Kibsgaard, there is an absence of "a clear line of sight" in the recovery of the seismic market, adding, "We may end up selling our acquisition business to a new market entrant." I think we all will be curious to see who that might be. E&P



Midland Basin operators shift gears

A more holistic approach signals the basin's move from exploration to development.

JENNIFER PRESLEY
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Read more commentary at
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There was a time when to the untrained eye there was little above ground to indicate the stacked pay riches lying below the rusty dirt and pesky tumbleweeds of the Midland Basin. Now drilling rigs, christmas trees and pumpjacks dot the landscape. Although oil and gas activity is not new to the basin—with first oil produced not from the Santa Rita #1 well but from the T&P No. 1 well located in the Westbrook Field of Mitchell County in 1920—its pace has gone from gentle amble to full-on furious gallop thanks to ingenuity, persistence and technology.

Unconventional development activity was slow to start in the basin. However, in 2013 horizontal drilling in the basin took off and now, five years later, RS Energy Group sees signs that point to the basin's transition from exploration to development mode.

"The shift by operators from aggressively completed test wells toward a more holistic approach that optimizes spacing patterns, reservoir drainage, surface facilities and total project value signals the Midland Basin's transition to development mode," the data intelligence and market analysis company stated in a recent market news release.

Determining where to place and how to space wells so that each is "not too far away, not too close, but just right" to its neighbor is key.

Contributing to the transition in the Midland Basin is Encana Corp. with its "cube" development approach. Rather than drill a few wells to hold acreage and then return to drill infill wells, the company uses large multiwell pads to simultaneously drill all primary zones in a drilling spacing unit. This approach maximizes efficiency and utilization of equipment, crews and infrastructure above ground. The simultaneous use of multiple drilling rigs reduces cycle times and allows sharing of services, helping to keep drilling costs lower, according to the company.

Decoding the optimal well spacing for a shale play has long been like a "Goldilocks and The Three Bears" challenge. Determining where to place and how to space wells so that each is "not too far away, not too close, but just right" to its neighbor is key.

The addition of new wells to older wells creates a parent-child relationship with the child wells not being as productive as parent wells. Schlumberger shared at the 2018 SPE Hydraulic Fracturing Technical Conference in January the results of a survey it conducted of 10 shale basins that examined the production performance of infill horizontal wells versus pre-existing wells. According to the paper (SPE-189875-MS), the survey found there was a 50% chance that a child well will outperform a parent well. However, when production was normalized to include total proppant pumped and lateral length, Schlumberger found that larger volumes of proppant with longer laterals in the child well might be needed to achieve similar rates to the parent wells.

Encana CEO Mike McAllister sees a clear benefit to the company's cube approach as all are parent wells. It "minimizes the risk of communication and enhances productivity by creating a more complex fracture network," he said in the release.

The cube development and enhanced completion designs have delivered impressive results for the company's wells in the Permian. The company announced in January that fourth-quarter 2017 production exceeded 80,000 boe/d, well ahead of the company's target of 75,000 boe/d. E&P

Jennifer

Combining completions

Operations business emerges from cancelled JV.

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Operators have nearly unlimited options when choosing systems and tools for their hydraulic fracturing operations, but one major service company is looking to streamline the entire process. Schlumberger unveiled its OneStim business in January at the Hydraulic Fracturing Technology Conference in The Woodlands, Texas.

The initial iteration of OneStim was a planned joint venture (JV) between Schlumberger and Weatherford announced early last year. But in late 2017 Schlumberger opted instead to purchase Weatherford's pressure pumping assets and pump down perforating business, which Schlumberger merged with its existing hydraulic fracturing operations, multistage completions, sand mining and logistics, and coiled tubing operations.

Alejandro Peña, Schlumberger's OneStim sales and commercial director, said in an exclusive interview with *E&P* that the idea of offering the full spectrum of fracturing completions under the same business initiated in 2010 when Schlumberger began noticing inefficiencies in uniformity and coordination with its customers who utilized separate components to their completions operations.

"Each region and discrete service line had its own supply chain structure, its own maintenance structure, its own equipment and own workflow to deliver discrete services," Peña said.

By combining and centralizing coordination of the full array of services as well as offering streamlined management and operations, operators will be able to gain efficiencies and therefore enable cost savings, Peña explained.

"Completion time per well is the single most important variable when it comes to completion costs," he said. "The more you manage to reduce completion time, the more you lower costs for the operator. Everybody wins with well efficiency."

By purchasing Weatherford's pressure pumping assets, Schlumberger increased its total pressure pumping capacity to more than 3 million hp. Peña said the increase in pump down perforating capabilities means Schlumberger can now serve 100% of its fracturing fleet operations, whereas before the deal with Weatherford, Schlumberger was serving about 20%.

The automated stimulation delivery platform enables OneStim to streamline the completion-to-production cycle. (Source: Schlumberger)

Schlumberger's foray into the sand business is helping meet increased industry demands as well, Peña said. With production of the popular Northern White sands at its Wisconsin mine, and sand production soon to ramp up at a new mine in the Permian Basin, Peña said Schlumberger now will be able to meet over 70% of its customers' demand for sand with its own resources.

With so many options on the completions market, operators have increasingly engaged on piecemealing the components of their completions operations. But with OneStim, which Peña said is available and operating in every major unconventional basin in North America, the company is hoping to entice operators to go to one place for everything under commercial models tailored for each operator need—from discrete services to joint capital investments on completion programs. He said such an option ultimately results in cost savings—up to 10% per boe.

"Operators take on the task of managing more discrete workflows, which creates additional burden and creates additional liability in terms of overall risk," he said. "If one of those services goes down, then all of the other services are on standby." E&P

Re-examining Arctic potential

When some operating companies decided to abandon the Arctic three years ago, others joined forces to open what could be the largest undeveloped oil and gas province in the world.

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A few years ago Arctic drilling was a hot topic. Countries with Arctic borders were jockeying for position, and money was pouring into developing harsh environment capabilities. Many will remember the dramatic Russian move to stake a claim, planting a Russian flag on the underwater Lomonosov Ridge.

There was good reason for the heightened interest. Statistics from the U.S. Geological Survey (USGS) indicated the Arctic could hold more than 87% of the earth's oil and natural gas resource. USGS assessments estimated that the area north of the Arctic Circle holds approximately 30% of the world's undiscovered gas and 13% of its undiscovered oil, most of it offshore in less than 500 m (1,640 ft) water depth.

With oil prices above $100/bbl, a host of companies were looking at Arctic opportunities, but when prices dropped, many looked elsewhere for easier plays. Among these was Shell, which announced in September 2015 that it was halting its Arctic campaign.

With oil prices above $100/bbl, a host of companies were looking at Arctic opportunities, but when prices dropped, many looked elsewhere for easier plays.

But not everyone called it quits. The Russians, having declared interest, were very much still in the game, and their work has paid off.

In April 2017 Rosneft began drilling the northernmost well on the Russian Arctic shelf in the Khatangsky license in the Laptev Sea, hitting oil in June. According to information from analysts at Divergente LLC, Rosneft plans to resume drilling in the Barents Sea this year and in the Kara Sea within two years in a work commitment that covers the entire Russian Arctic.

Meanwhile, Gazprom subsidiary Gazpromneft-Sakhalin is looking for fields of its own. Gazprom is operator of the Dolginskoye oil field and the North-West Block in the Pechora Sea, the Kheisovsky Block in the Barents Sea, the Severo-Vrangelevsky Block in the East Siberian and Chukhchi seas, and the Ayashsky Block in the Okhotsk Sea. Last October the operator completed an appraisal well on the Ayashsky Block, discovering a new hydrocarbon field with initial in-place reserves estimated at 255 million metric tons of oil equivalent. A detailed assessment of the block, which lies on the eastern part of Sakhalin Island's continental shelf and forms part of the Sakhalin-3 project, will be prepared by mid-2018.

The Norwegians also are part of the vanguard in Arctic development. About five months before Shell's Arctic departure, a group of operators offshore Norway established the Barents Sea Exploration Collaboration (BaSEC). Initial participants Statoil, Eni Norge, Engie (GDF Suez), Lundin and OMV eventually were joined by 13 additional members.

Approximately 130 wells have been drilled to date in the Barents Sea with mixed results. In January 2017 Statoil discovered oil and gas with the Cape Vulture well, followed by two more finds in July. The Kayak well on the Johan Castberg license discovered between 25 Mboe and 50 Mboe of recoverable reserves, for the first time proving resources in this type of play in the Barents Sea. Statoil also discovered gas between the Snøhvit and Goliat fields with the Blåmann well, and Lundin Norway saw success on the Filicudi prospect.

With new acreage available, positive results and a stronger oil price, other operators might soon consider getting back in the game. E&P

Judy

The future is now

The industry needs to rethink operational processes and use new technologies that boost operational efforts.

Nick Candito, Progressly

Over the past several years the oil and gas industry has struggled with diminishing demand, evolving regulations, political uncertainty and even natural disasters. All of these challenges have forced companies to adopt new strategies to sustain profits.

Many, of course, are looking to cut costs in the areas of production and delivery. But innovations in process management and communications are enabling companies to increase their efficiency and even boost their bottom line.

Among these innovations two stand out as being the most effective: going paperless and embracing data mobility.

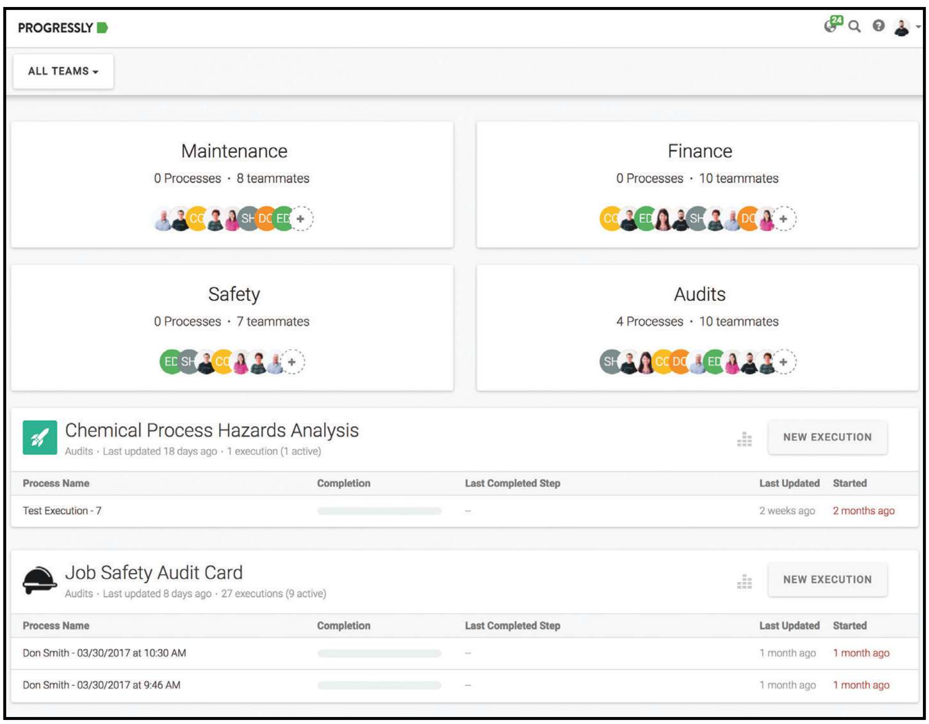
Breaking free of paperwork

As in other large well-established industries such as health care and banking, the shift to go paperless in the oil and gas industry has been slow but steady, while the benefits of embracing digital technology have become increasingly significant.

Companies continuing to rely on processes that require extensive amounts of paperwork are often unable to compete in an industry experiencing rapid changes and shrinking profit margins.

From general operations including human resources management and accounting to industry-specific tasks such as recording drilling measurements or maintaining safety records, the need to digitize files, reports and data has never been greater. In fact, process automation and having a digitally "connected" workforce are now necessary to meet many of the regulatory requirements mandated by law.

Oil and gas companies that are lagging in going digital are now feeling the impact by not being able to maintain efficient and compliant operations. This is causing some companies to move to a centralized platform to align processes and people, foster collaboration and transparency, and ensure greater consistency among divisions. This unified approach simplifies reporting and makes information available anywhere and at any time.



HSE professionals can cut time by managing safety and inspection audits in an electronic format. (Source: Progressly)

Data mobility

Back in the boom times oil and gas companies didn't have to really dig into the data and scrutinize the numbers. Companies grew rapidly and purchased different technology systems for each department and function.

However, as the data started rolling in, companies began to hire analysts to research each siloed system and come up with potentially conflicting insights. This left operations with siloed guesswork and made it nearly impossible for operators, engineers and managers to make knowledgeable, tailored and goal-oriented decisions.

Over the last 10 years, companies have spent billions of dollars implementing enterprisewide systems, but these systems don't speak to each other, and companies aren't receiving value out of their investments.

Companies need to invest in software that delivers consistent, trustable data and insights across the entire organization, from corporate to the field, and allows them to boost production and optimize capex and opex.

A system that integrates and un-siloes data helps on many levels. These include

- Omnichannel communication so that exploration, drilling, distribution and production divisions can seamlessly and transparently communicate with vendors, sales teams, partners, the corporate office and customers;
- Streamlining of operations via real-time visibility into activities at the local level and the elimination of guesswork. HSE professionals can cut more than 30 hours per month by managing safety and inspection audits in an electronic format; and
- Supply chain efficiency via real-time communication so that suppliers and contractors can be better utilized across work streams and communicate with context.

Thanks to the latest technological advancements, the industry is poised for a second digital age that will slash costs, unleash unparalleled productivity and skyrocket performance—but only if executives can harness the right technologies to support their business strategies.

What's next

While there is undoubtedly a need to continually improve extraction and production processes, there is also a continual need to rethink operational processes and use new technologies that boost operational efforts.

With the current oil and gas market, companies need to reinvent themselves to improve productivity. Investing in digital technologies is a no-regrets move that boosts production from existing operations and revolutionizes operational frameworks. E&P

Data are this century's oil

Bits and bytes provide the fuel as data and AI propel the petroleum industry into the future.

Jennifer Presley, Executive Editor

From fitness trackers that fit perfectly on a wrist to intelligent virtual personal assistants listening at the ready to answer random questions and make grocery shopping lists, the presence of artificial intelligence (AI) is rapidly increasing. AI is pushing human and machine closer together, and businesses are looking to it to help increase productivity and improve profitability while enabling a safer workspace for employees.

AI is the next step for the oil and gas industry to take as it walks deeper into the forest of alarms, monitors and sensors. Data are this century's oil. *E&P* recently spoke to Philippe Herve, vice president for oil and gas solutions at SparkCognition, about the future of data, cybersecurity and AI.

Philippe Herve

***E&P*: How does one ensure that the data being used for analytics are good, accurate and being used for the right purpose?**

Herve: Generally speaking, we work with the data delivered to us by our clients, which means the quality of data is up to the client. A machine learning algorithm is only as good as the data it's been given. If the only data available are of poor quality, the model will not be any better.

While we cannot change the quality of data, we can and do work closely with our clients to make sure this problem does not come up. If we find that there is an issue with data quality, we alert the client so they can take corrective action, allowing us to ensure that the solution we deliver is always of the highest caliber.

Of course, even the best dataset will never be without its flaws. With any data, the first step in building a model is cleaning the data, inputing missing values, scaling datapoints, converting all data to the same format and a single scale, and rebalancing if there are any issues with sample size. At the end of the day, though, our most important role in terms of data quality is keeping our clients informed of the base level of quality necessary to deliver good machine learning software.

***E&P*: What safeguards are in place to protect data in terms of cybersecurity?**

Herve: It's true that making use of collected data involves a great deal of transferring data between different assets and different levels of informational technology and operational technology. But machine learning also offers powerful protection against hacking and cyberattacks.

Cognitive endpoint protection can safeguard every endpoint in a network, shielding systems against malware, viruses, worms, trojans, ransomware and more. This includes protecting the commercial off-the-shelf systems that are otherwise a critical weak point that can be exploited to gain access to industrial systems.

Our own cloud-based cognitive engine, DeepArmor, uses a multilayer filtering process to detect threats. The first layer of protection includes file reputation analysis and application control, thereby quickly identifying known malicious and anomalous files. Once known files have been filtered, DeepArmor examines the DNA of unknown files to develop a threat confidence score for each file. A machine learning solution like it could have caught even the infamous Stuxnet worm that sabotaged Iran's nuclear program.

DeepArmor can operate out-of-band, meaning it does not go through programmable logic controllers [PLC] to access the rest of the system. This is critical to protecting industrial systems, as it allows DeepArmor to detect anomalous operations occurring, regardless of any false information being transmitted by PLCs.

***E&P*: How can a company convert the data it has collected/continues to collect into meaningful operational outcomes? How is AI helping convert data into dollars?**

Herve: Oil and gas operators would be able to record everything in an ideal world. In practice, rigs only have so many sensors and those sensors cannot catch every single datapoint. Still, there are far more data generated by the sensors on an oil rig than humans can meaningfully use and understand. The scale of data and operations is beyond human capabilities.

This problem is only further complicated by the interconnected nature of oil and gas assets. A failure in one asset can have far-reaching consequences across the entire rig. A change in the state of shale shakers will affect the mud pumps. Separating out these streams of data and achieving a meaningful understanding of events and causality on the rig is no easy feat. Cyberattacks also are increasingly taking advantage of this confusion as subtler attacks often camouflage themselves as normal machine failure.

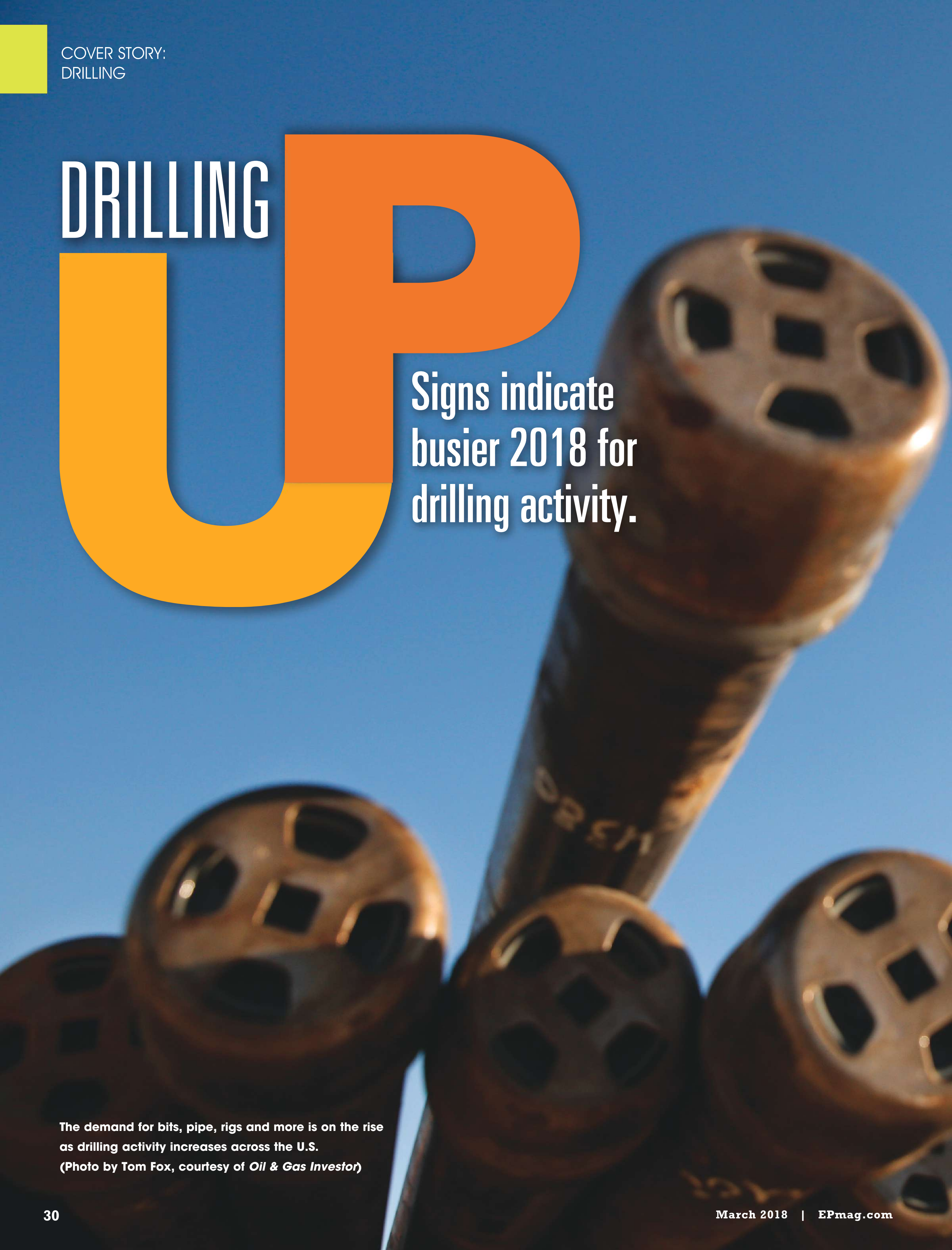
Data fill in the gaps in understandings of assets and systems, and provide technicians with a bigger picture of operations as a whole, allowing them to infer new insights. But this can only happen if a company has the right tools to interpret the data. Cognitive analytics provide a systematic way to make sense of the massive volumes of data collected across the entire oil and gas value chain.

This greater understanding of data has a measurable value for oil and gas companies. Data that have been analyzed and interpreted by AI solutions can predict when an asset will fail or ensure that resources and personnel are in a place where needed. Data can provide a window into safety issues on a rig and how to prevent them. When combined with natural language processing, AI can present its findings to human operators using a naturalistic communication interface. AI uses data to significantly reduce operating costs, increase worker and equipment safety, and optimize all processes on a rig.

In essence, what we do is take data collected from a rig, remove the clutter and extract the value. That value has a massive impact on a drilling operation and on the industry as a whole. E&P

DRILLING UP

Signs indicate busier 2018 for drilling activity.



The demand for bits, pipe, rigs and more is on the rise as drilling activity increases across the U.S. (Photo by Tom Fox, courtesy of *Oil & Gas Investor*)

Jennifer Presley, Executive Editor

After enduring the four-year roller coaster ride that has kept oil prices inching up, there are signs of acceleration in drilling activity as Brent and West Texas Intermediate (WTI) crude oil prices have settled in the high $50 to low $60 range. It is a range forecasted to remain throughout the year. The U.S. Energy Information Administration in its Short-term Energy Outlook from January indicated the Brent crude oil spot price will average $60/bbl this year and $61/bbl in 2019 and WTI crude oil will be $4/bbl lower than Brent prices in 2018 and 2019.

Although the days of $100/bbl oil may never return, the higher prices have triggered a rapid increase in U.S. drilling activity. Baker Hughes, a GE company, reported on Feb. 2 that the number of active U.S. rigs drilling for oil increased by 6 to 765, which is 182 rigs more than last year's 583. Texas' Permian Basin holds the lion's share of the count with 427 rigs and Oklahoma's Cana Woodford comes in second with 68.

There is wide concern that further price increases could lead to additional increases in drilling activity and production from the U.S. shale plays, potentially upsetting the oil supply scale from "just right" to "too much." It is a delicate balance struck between non-OPEC and OPEC entities.

Westwood Energy Group reported in its recently released "World Drilling and Production Market Forecast for 2018-2024" that OPEC exceeded its output reduction targets in 2017, eroding excess crude oil stockpiles. The market analysis firm estimated that with the extension of the cuts to the end of the year, the market will be pushed into a deeper 0.9 MMbbl/d deficit. The glut is expected to clear before the end of the year, providing the agreement participants stick to their quotas this year to offset gains from Brazil, Canada, the U.S. and the U.K.

This month *E&P* reviews how land drillers prepared in 2017 for the year ahead. Other stories include an explanation on the application of artificial intelligence in cybersecurity to keep drilling rigs safe and a review of a system that helps reduce waste and cuttings from drilling fluids. The section wraps up with an overview of the impacts drilling waste management has on the social license to operate.

As an amusement park operator would say before cranking the coaster, "Buckle up and keep all arms and legs inside the car," as the year ahead is certainly shaping up to be another interesting ride. E&P

Land drillers reload

Complex wells with longer laterals are keeping demand high for super-specification land rigs.

Jennifer Presley, Executive Editor

The increase in crude oil prices, up more than 23% since last January, is testing the resolve of E&P companies looking to maintain the increased capital discipline they developed since the mid-2014 market decline. By taking a measured response to the price increase, these companies are returning to the field and the drilling market is showing signs of this return. As well complexities and lateral lengths increase, so do the demands placed on drilling contractors to provide capable rigs and technologies to make hole in an affordable, efficient and safe manner.

Calgary-based AKITA Drilling announced in January its plans to redeploy Rig 90, an ultrahigh-specification drilling rig, from the Western Canada to West Texas' Permian Basin where it will drill deep lateral wells for a major U.S. operator. (Source: AKITA Drilling)

Brighter expectations

Domestically, the U.S. Energy Information Administration (EIA) estimated in its February 2018 Short-term Energy Outlook that U.S. crude oil production averaged 10.2 MMbbl/d in January, up 100,000 bbl/d from the December level. In addition, the EIA forecasted the total U.S. crude oil production will average 10.6 MMbbl/d in 2018. If it were to happen, it would surpass the previous record of 9.6 MMbbl/d set in 1970 as the highest annual average U.S. crude oil production level.

The increase in the U.S. rig count, up more than 27% since last January, sheds some light on how it is possible to break 48-year-old records. The average U.S. land rig count for January 2018 was 937, up 254 from last year's count at 683, according to Baker Hughes, a GE company.

Westwood Energy Group reported in its recent "World Drilling and Production Market Forecast for 2018-2024" that the U.S. onshore drilling activity is expected to rise at a cumulative annual growth rate of 11% over the forecast period, with onshore production growing 3% year-on-year over the same period.

Land drilling contractors prepared during the market downturn for a new future by working with customers to ensure, both through newbuilds or upgrades, that the right rig for the job would be available and by embracing the digital revolution. Patterson-UTI, Helmerich & Payne (H&P) and Nabors Industries—the big three land drillers—hold more than a combined one-third of the overall market share in the U.S.

"Despite widespread concerns for lower industry drilling activity, our rig count rebounded through the quarter," Patterson-UTI CEO Andy Hendricks said during the company's fourth-quarter 2017 earnings call on Feb. 8. "Our average rig count for the fourth quarter was unchanged relative to the third quarter at 161 rigs. For the month of January 2018, our average rig count was 165."

The company completed upgrading seven of its APEX 1000 rigs to its super-specification APEX XK rigs and has customer contracts to support upgrading five additional APEX rigs, with two to become APEX XK and three to become APEX PK rigs, Hendricks said, adding that all five are expected to be delivered in first-half 2018.

"Based on contracts currently in place, we expect an average of 96 rigs operating under term contracts

during the first quarter and an average of 67 rigs operating under term contracts during 2018," he said.

Super specification for longer laterals

John Lindsay, president, CEO and director for H&P, said during the company's first-quarter 2018 earnings call on Jan. 25 that the downturn has been a challenging three-year journey but that the company has spent the time preparing for the future. These preparations included upgrading its FlexRig fleet to super-specification to provide the right rig for the job and the acquisitions of MOTIVE Drilling Technologies and MagVAR in 2017.

Lindsay cites the increased length of laterals as the primary reason customers want super-specification rigs.

"Lateral lengths have increased to the extent that this is pushing the limits of the standard AC drive rig fleet," he said. "In 2017 the average lateral increased another 15% to approximately 8,000 ft [2.4 km], and we expect this trend of longer laterals to continue. As a reference point, the average lateral in 2015 was approximately 6,000 ft [1.8 km]."

H&P defines its super-specification rigs as having an AC drive, 1,500-hp drawworks, 750,000-lb hookload rating, 7,500-psi mud systems and multiwell pad drilling systems.

"H&P currently has 171 super-specification rigs operating at approximately 98% utilization," Lindsay said. "We believe there are another 200 to 250 rigs in the industry where upgrades to super-spec capacity would be economically feasible, and H&P owns roughly half of those."

The company has approximately 30 FlexRigs that are active and can be upgraded to super-specification status in the field with a $2 million to $3 million investment, he said, adding that the design of the FlexRig allows the company to reinvest in its fleet to enhance rig capabilities for more challenging and complex well designs.

"Since the first fiscal quarter of 2017, we have upgraded 107 FlexRigs to super-spec capacity," he said. "If customer demand remains and we are able to achieve reasonable pricing, our upgrade cadence could average 12 or more FlexRig upgrades per quarter."

The MOTIVE Drilling Technologies and MagVAR acquisitions in 2017 deliver technologies that deliver real-time actionable results and enable enhanced collaboration for onsite and offsite rig teams.

"MOTIVE and MagVAR are technology leaders in their respective space," Lindsay said. "These technologies provide additional value for our customers through improved wellbore quality in placement while offering the flexibility to utilize these services regardless of the drilling contractor or directional drilling company."

> Land drilling contractors prepared during the market downturn for a new future by working with customers to ensure the right rig for the job would be available and by embracing the digital revolution.

Quads and robots

In 2017 Nabors launched its first PACE-X rig featuring the quad drilling design capable of handling stands of four drillpipes versus a stand with three drillpipes. The design features an additional 9.4-m (31-ft) section of mast, decreasing the number of connections by 33%. The design also enables running double joints of casing and offline casing-stand building. For example, during operations for a customer's three-well pad, there were about 900 fewer connections made, saving about 43 hours, according to the company's third-quarter 2017 earnings presentation.

On the rig automation front, in September 2017 Nabors announced its acquisition of Stavanger-based Robotic Drilling Systems AS (RDS), a provider of automated tubular and tool handling equipment for the onshore and offshore drilling markets.

The RDS modular system is a key component to the company's PACE-R800 fully automated drilling rig. Featuring an electric rack and pinion hoisting system with a capacity of 800 kips and push capability of 66 kips, the eight pinions are driven by permanent magnet motors to provide the redundancy and precise control needed for automation, according to the company.

The robotic electric pipehandler is designed to handle drillpipe and casing from 3½ in. to 13⅜ in. without changing grippers. The tong and slip can handle 2⅞-in. to 15-in. tubulars without changing dies. The two-level rig floor design keeps personnel out of harm's way in that all operating equipment is located on the lower deck with personnel operating from the second level, according to the company.

The "brains" of the PACE-R800 rig is the company's Rigtelligent operating system and an integrated suite of drilling software, equipment and services, including ROCKit for directional steering control that oscillates the drillpipe to reduce friction and increase penetration rate and REVit to mitigate stick/slip issues through the constant application of more torque to the bit. E&P

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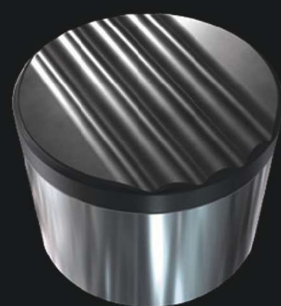

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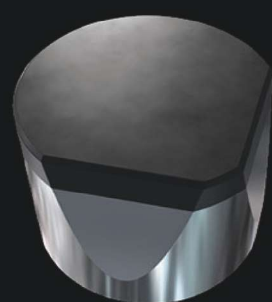

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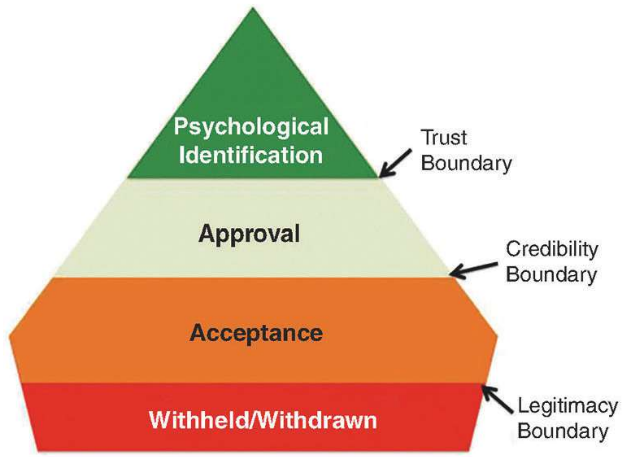
Proactive strategies could positively affect the bottom line.

P. Rodger Keller, Scott Energy Technologies LLC

Communities in oil and gas plays wrestle with the economic, social and environmental impacts of E&P operations, often for generations. Naturally, citizens have a vested interest in the sustainable development of their communities. A social license to operate (SLO) can be viewed as the ability of a company to conduct operations based on expectations by society that it will operate in a reasonable and responsible manner, according to the New Zealand Sustainable Business Council. Obtaining and maintaining an SLO is often seen as having a positive impact on an oil and gas operator's bottom line. Consequently, operators face increasingly elevated expectations as to how they manage their drilling waste and its impacts. Consideration of SLO factors is essential when evaluating drilling waste management options.

As noted in the 2014 paper, "Oil and Gas Exploration and Production Research Brief," by the Sustainability Accounting Standards Board (SASB), drilling waste has environmental, social and economic impacts on communities in oil and gas plays. These are directly related to the sustainability of the waste management practices employed by the operator. Citizen concerns about drilling waste directly affect an operator's SLO. Environmental concerns frequently include protecting the quality of groundwater, surface water and air, land area consumed by drilling waste disposal, degradation of soil quality, and potential destruction of habitats, wildlife and biodiversity. In some areas seismic impacts from deep injection well disposal of drilling waste are a primary concern.

The sheer volume of drilling waste generated drives an increase in truck traffic and land consumption for management and disposal. Increased truck traffic accelerates roadway deterioration, especially for local roads not designed for the demands of oil and gas operations. Truck traffic and drilling waste disposal practices impact quality of life, generating noise and impacting air quality. The environmental and social impacts of drilling waste can affect community health and health services, as noted in the 2014 SASB paper.



Consultants Ian Thomson and Robert Boutlilier identified four levels of the SLO, with the level of SLO granted to a company being inversely related to the level of sociopolitical risk a company faces. A lower SLO indicates a higher risk. (Source: Thomson and Boutlilier)

Opposition increases costs, delays

Company-community conflict or industry-community conflict can erode or destroy an SLO. According to the 2014 Harvard Kennedy School report, "Costs of Company-Community Conflict in the Extractive Sector," environmental issues typically ignite a company-community conflict. Waste management practices are often at the core of such conflicts. Drilling waste is no exception. The construction of drilling waste disposal facilities often precipitates conflict, as concerns over air quality, water quality and truck traffic spur opposition.

Sham recycling, which is usually a dirty disposal method under the guise of recycling, can precipitate this conflict. A proposal in Pennsylvania, for example, to use a large volume of drill cuttings as fill to extend a runway next to Pennsylvania's Grand Canyon sparked widespread public outrage, according to a 2015 NPR Pennsylvania *State Impact* article. Another example of sham recycling is "road spreading," in which drill cuttings—even oil-based cuttings—are spread on a local road and covered with rock. Landfarming, in which drilling waste is spread across land, also can provoke citizen opposition.

Community opposition can result in permitting delays, increased regulatory oversight, drilling bans, lawsuits, protests or boycotts. In 2012 the town of Erie, Colo., passed a moratorium on drilling in response to public outcry, as noted in a 2016 article in the *Journal of Energy and Natural Resources Law*. In May 2016 seven environmental groups filed a lawsuit against the Environmental Protection Agency (EPA) to increase regulation of oil and gas wastes, including drilling waste. A settlement agreement was finalized in a consent decree in December 2016, requiring the EPA to review and possibly revise oil and gas waste regulations.

Protests caused a temporary shutdown at a drilling waste facility in Ohio in 2013, according to a 2013 *Tribune Chronicle* article. Pennsylvania recently revised its oil and gas waste regulations, which included a new prohibition on waste fluid pits at the drilling site. The Arkansas Department of Environmental Quality toughened regulations on landfarms in 2009 after inspecting 11 landfarms and finding them all out of compliance, as reported in a 2012 NPR Texas *State Impact* article. Several were shut down.

Socially conscious companies fare better

According to the 2014 Harvard Kennedy School report, losing all or part of an SLO can result in significant material costs to a company. Tighter regulations result in higher costs for conventional drilling waste management. Legal fees related to lawsuits can be substantial. A company can suffer opportunity costs and lost revenue due to the inability to pursue projects, expansions or sales.

A 2012 Credit Suisse study found that the hydrocarbon industry averaged a 1.5% negative impact on target share price related to SLO conflicts. One international oil major calculated $6 billion in costs over a two-year period due to nontechnical stakeholder risks, according to the 2014 Harvard Kennedy School report. Environmental or social concerns may result in more onerous loan conditions. One lender rejected approximately 10% of transactions on environmental or social risk grounds on the basis that companies lacking sound stakeholder relations tend to financially underperform versus peers who are more proactive. Socially conscious investors are increasingly evaluating the environmental and social performance of oil and gas companies.

SLO-related costs can be significantly reduced by employing sustainable drilling waste management practices that address stakeholders' key concerns of protecting water resources, soil, air, habitats, wildlife and biodiversity. Reducing truck traffic, which is frequently a contentious issue, also strengthens the SLO. When stakeholders are confident their concerns will be taken seriously, they are more likely to grant an SLO. For example, in 2012 when the moratorium on drilling was passed in Erie, Colo., over concerns about environmental and health impacts, two oil and gas operators negotiated a memorandum of understanding with the town. This required the operators to employ best management practices that exceeded the required regulatory thresholds. As a result, the moratorium was lifted, as noted in the 2016 *Journal of Energy and Natural Resources Law* article.

Innovation can reduce friction

Social license pressures may generate opportunities to sustainably manage drilling waste by spurring innovation and evaluation of win-win options. For example, drilling waste volumes can be reduced with innovations that increase the efficiency of drilling and solids control. Drill cuttings can be sustainably recycled into engineered drilling pads, production pads or lease roads using proven repurposing technologies. Increasing the number of wells drilled from a single pad reduces the area of land disturbed, which reduces impacts to soil, water, vegetation and wildlife.

Multiple innovative, sustainable practices can be combined to achieve a significant reduction in drilling waste impact, thus directly addressing particular citizen concerns. As an example, drilling multiple wells from a single pad requires a durable pad that will withstand the loads applied to it. Constructing an engineered pad with drill cuttings provides a durable pad designed for the additional loading.

This turns a waste stream into an asset, significantly reducing environmental impacts from solid drilling waste and pad construction, reducing the area of land consumed and lessening the volume of drilling waste-related truck traffic in the community. This innovation creates a win-win scenario for the operator and the community.

Sustainable drilling waste management can benefit an operator's bottom line by reducing the risk of incurring SLO-related costs from lawsuits, delays in operations, regulatory penalties and lost opportunities. As noted in the 2014 SASB paper, financing can be more effectively leveraged from socially conscious lenders and investors. An increasing number of oil and gas lenders and investors are evaluating environmental and social sustainability criteria as part of an operator's core business.

By reducing environmental and social impacts of operations, an operator enhances its reputation, and, by extension, its SLO. E&P

Drilling rigs and cognitive security

Overcoming resistance to AI can help implement better cybersecurity.

Philippe Herve, **Rick Pither** and
Marla Rosner, SparkCognition

Although the oil industry may be hesitant to admit vulnerability, drilling rigs in the modern era need better cybersecurity. Complacency about security runs rampant through the industry, where critical assets using out-of-date operating systems are falsely believed to be safe due to air gapping. The truth is that previously isolated assets are increasingly connected to larger networks due to the proliferation of Internet of Things (IoT) devices. Even for assets without IoT endpoints, network isolation has never been a foolproof defense; there are too many other ways for malware to slip through the cracks.

Oil and gas operators are realizing their most important systems may be vulnerable. They are also increasingly aware that artificial intelligence (AI) provides a powerful way to keep their operations safe. But too often, they immediately give in to the fear and uncertainty surrounding the new cybersecurity landscape. Hastily purchasing a security solution from the first vendor that claims to sell AI protection, without understanding what that solution actually does and without a plan for moving forward, will not guard a rig against cyber threats.

AI is revolutionizing business processes across the board, and this includes cybersecurity in the oil and gas space. But operators need to be aware of the challenges to proper implementation and how best to surmount them.

Overcoming internal resistance

To make a large project like an AI implementation work, it is important to get buy-in throughout the company. Unfortunately, there will always be people within a company who still believe that device security is unnecessary for industrial assets.

The best way to overcome this resistance is with internal education. Industrial control systems cannot be kept safe through just isolation and network security. One-third of industrial sites are connected to the internet. Even on isolated systems, there have always been ways for assets to be compromised, from infected USB drives to engineers connecting to the system with corrupted devices. These attack vectors also completely bypass network security, leaving any asset without device security defenseless.

When implementing AI cybersecurity in drilling operations, spreading awareness of these dangers is the best way to ensure the whole organization is onboard. Make sure everyone in the company understands that AI cybersecurity is not being installed as a trendy new toy but a vital part of protecting the whole rig.

Studies indicate a lack of cybersecurity in the industrial sector. (Source: CyberX Labs)

Choosing an AI solution

This can be one of the most daunting steps in implementing an AI solution, cybersecurity or otherwise. AI has become a marketing buzzword, and it can be difficult to determine which software vendors are actually making use of the technology. How do you separate the real deal from the vendors just looking to get on the bandwagon of the next big trend?

Too many oil and gas companies looking to integrate AI into their operations fail to understand the massive range in scale of the complexity and effectiveness of machine learning models and algorithms. Vendors have overused the phrase "AI" to the point that making it a requirement is like walking into a car dealership, asking for any car at all, and then being surprised to find that a Honda Civic doesn't run the same as a Ferrari.

The best way to get a sense of whether an AI vendor is offering the genuine article or just another knock-off is by asking them questions that require informed answers. Which precise components of the product use machine learning, and how? How does the product deal with messy or incomplete data? Does it use deep learning, or can they even explain what exactly deep learning is? A quality vendor will be able to answer all of these questions and more in detail. Anyone who can't is trying to sell you a lemon.

Identifying value in AI

Imagine someone was concerned with air quality in their house and decided the best solution was to install a Geiger counter. Not only would this not actually prevent contaminants from getting into the house, it would only alert on one specific (and uncommon) contaminant after the home already was irradiated. It would be more useful to prevent contaminants that are likely to occur than to simply detect them.

Unfortunately, this is essentially what many operators do with cybersecurity in oil and gas. An AI cybersecurity solution will not protect a rig if it is not placed in the best vector or not looking for the right kinds of threats. Many operators implement AI to detect infections that have already made their way into the network. Although this is certainly useful, it's better to start with AI that can prevent infections from occurring in the first place.

In addition, operators often focus on the wrong threats. Hacking from, say, a foreign threat is a frightening prospect that has inspired many headlines, but drilling rigs are far more likely to be targeted by ordinary criminal groups or even pranksters. Again, protection against uncommon threats is useful as well, but it's better to guard against the most likely sources of malware first.

Testing a model's efficiency

Once the model has been selected, it needs to be tested as well—it is unwise to trust a vendor's self-reported efficacy. There are a few important best practices to follow when testing a cybersecurity product. The first is to create a safe environment for testing—tests require the use of real malware, and users do not want to infect their machine if something goes wrong. The best way to do this is by using a virtual machine, which is a fully operational computer system that runs from within another system.

To get a comprehensive picture of a solution's capabilities, it should be tested against at least three types of malware: prevalent, polymorphic and zero-day. For any file tested, a cybersecurity solution should be able to identify whether the file is a threat, what type of threat it is, what actions can be taken to protect the system and further details about the threat and threat type. At the most basic level, it must be able to alert the user and block execution of the file.

Properly identifying threats

A cognitive solution that can actually protect a rig needs to be able to catch novel threats, not just known malicious software. New malware is proliferating faster than ever before. According to Verizon's 2016 Data Breach Investigations report, 99% of malware hashes are seen for no more than 58 seconds. Hackers have automated the process of creating new malware variants and can produce novel infections at an unprecedented rate.

A solution can only protect against these threats if it is capable of correctly classifying new malware it has never seen before. There is a plethora of endpoint protection software on the market claiming to use AI and machine learning, but most of them drop substantially in efficacy against malware that is less than 24 hours old. What this indicates is that many commercial solutions offer subpar protection against new threats. Given the sheer percentage of malware that is "new" at any given time, this weakness is a major problem. When testing a solution, make sure to test it against novel threats—not the threats it already knows.

Conclusion

Of course, these are hardly the only challenges that must be planned for in implementing AI for cybersecurity on a rig. Beyond basic matters such as budgeting for the cost of the project, there is the time needed for the often lengthy certification to place new software on mission-critical assets. There are also further decisions to be made, such as whether to host the cybersecurity solution in the cloud versus on-premises.

The challenges listed here are some of the most prominent barriers to implementing a cognitive security solution in drilling operations. Critically, these are all challenges that can be overcome with the right knowledge. And the end result—drilling rigs that are protected against threats like Petya, Stuxnet and more—is well worth the effort. E&P

Reducing waste and cuttings from drilling fluids

System could lead to drilling cost efficiencies while also meeting environmental compliance.

Brandon Buzarde, Cubility

With the current industry focus on increasing efficiencies, reducing costs and meeting ambitious production targets, the drilling fluids market remains one of the most buoyant in the upstream oil and gas industry. According to industry analysts Research and Markets, the global drilling fluids market is expected to be worth more than $10 billion by 2025, up from a valuation of $7.6 billion in 2016.

Drilling fluids have a crucial role to play in ongoing drilling operations—facilitating the drilling process by suspending cuttings, cooling and lubricating the drillbit, providing buoyancy and carrying drill cuttings to the surface.

Effective fluids also can lead to increased ROP, a reduction in equivalent circulating density and the ability to keep the cuttings in suspension when circulation is stopped, all vital to preventing cuttings from accumulating at the bottom of the hole leading to pipe sticking.

Cubility's MudCube is installed on an offshore rig. The system provides lower fluid consumption and reduced waste volumes. (Source: Cubility)

Yet, just as their importance to upstream operations has increased, so have the challenges that surround them.

New environmental guidelines

With the rise in borehole complexity, stringent waste discharge guidelines also emerged. Operators must balance drilling fluid efficiencies against the amount of cuttings created and their disposal and environmental impact. Such regulatory bodies include the OSPAR Commission in the U.K., which focuses on protecting the environment and resources of the northeast Atlantic through to the National Oceanic and Atmospheric Administration and Canadian Association of Petroleum Producers, which has strict guidelines for the disposal of waste drilling fluids and cuttings in North America.

There is also an economic case for reducing the amount of drilling fluids lost, with significant potential savings around waste disposal. On the Norwegian Continental Shelf (NCS), for example, the treatment and disposal of drilling waste is conservatively estimated at $1,580 to $1,750 per ton, with onshore costs for waste disposal also significant.

It is against this industry context that the quality of drilling fluids and cuttings and the accompanying amount of drilling waste represent major issues for operators.

Available technologies

For many years shale shakers have been the pre-eminent technology offshore and onshore for maintaining drilling fluids and the separation of solids. The vibration and high g-forces lead to solids being filtered out for discharge or treatment and the cleaned fluid then incorporated back into the system.

Yet, despite being used in the industry for decades, shale shakers are often in a way too efficient. They break down the drilled solids into extremely fine particles, but at the same time reduce the ability to remove them, thereby increasing solids content in the drilling fluids and reducing their efficiency.

Secondly, vibrating shale shakers often lead to high volumes of fluid being lost with large amounts of drilling waste—drilling fluids and cuttings—generated and less fluid able to be reused within the system.

It is an alternative to shale shakers that Cubility's enclosed solids control system, the MudCube, has been effective in improving solids removal efficiencies, reducing the volume of drilling fluids lost, minimizing the tonnage of waste generated and raising drilling fluid integrity performance.

The system vacuums drilling fluids through a rotating filter belt—rather than relying on high g-forces—with a high airflow being used to separate the cuttings from the fluid. The cleaned drilling fluids are then returned to the fluid system and the drilled solids carried forward on the filter belt for discharge or removal.

The improved separation capabilities lead to better quality fluid and fewer chemicals required to maintain its properties as well as enhanced drilling efficiencies through stable fluid properties, higher ROP and reduced stuck-pipe incidents. The solids removal efficiencies also ensure that 80% more fluid is recovered than competing technologies—a substantial benefit when multiplied by about 200 rigs.

With more fluid recycled back to the fluid system, there is also reduced and "cleaner" waste to dispose of. The system generates substantially drier cuttings with fluid on cuttings being reduced to less than 30% of drilled solids and oil on cuttings as low as 5%. These drier cuttings and lower oil content mean that disposal is cheaper with less environmental requirements.

Finally, for rig contractors, the system brings with it the benefits of leaner and more cost-effective rigs.

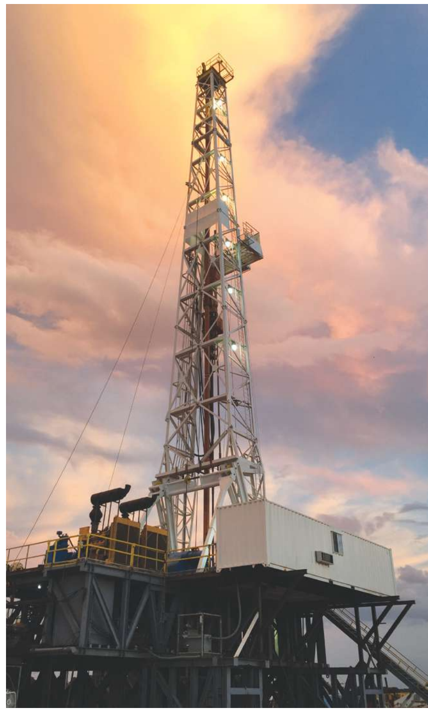
Offshore applications

There have been several recent MudCube applications in Europe and North America. One such example is on the deepest well ever drilled on the NCS. Three MudCubes are in operation on the *Maersk Gallant* jackup drilling rig operated by Total E&P Norge, which in July 2016 drilled the Solaris ultra-HP/HT well to a true vertical depth of 5,941 m (19,491 ft).

Benefits to Total E&P Norge of the MudCubes' use during drilling included improved drilling efficiencies with less drilling fluid being lost and more returned to the fluid tanks for reuse and the cuttings having a low fluid content made for easier and cheaper disposal.

Four MudCubes also are being installed on the Johan Sverdrup Field, where production startup is scheduled for year-end 2019. In this case, the MudCubes will provide the operator, Statoil, with drilling efficiencies, lower fluid consumption, reduced waste volumes and improved HSE. Noble Denton also is implementing the system on the North Sea.

The success of the MudCube offshore also is allowing Cubility to focus on R&D and explore ways to further accommodate the entire solids control cycle globally, with new technologies on offshore platforms that further reduce oil on cuttings and bring transportation benefits.



The MudCube supported the Catoosa testing facility in Tulsa, Okla. (Source: Cubility)

Onshore applications

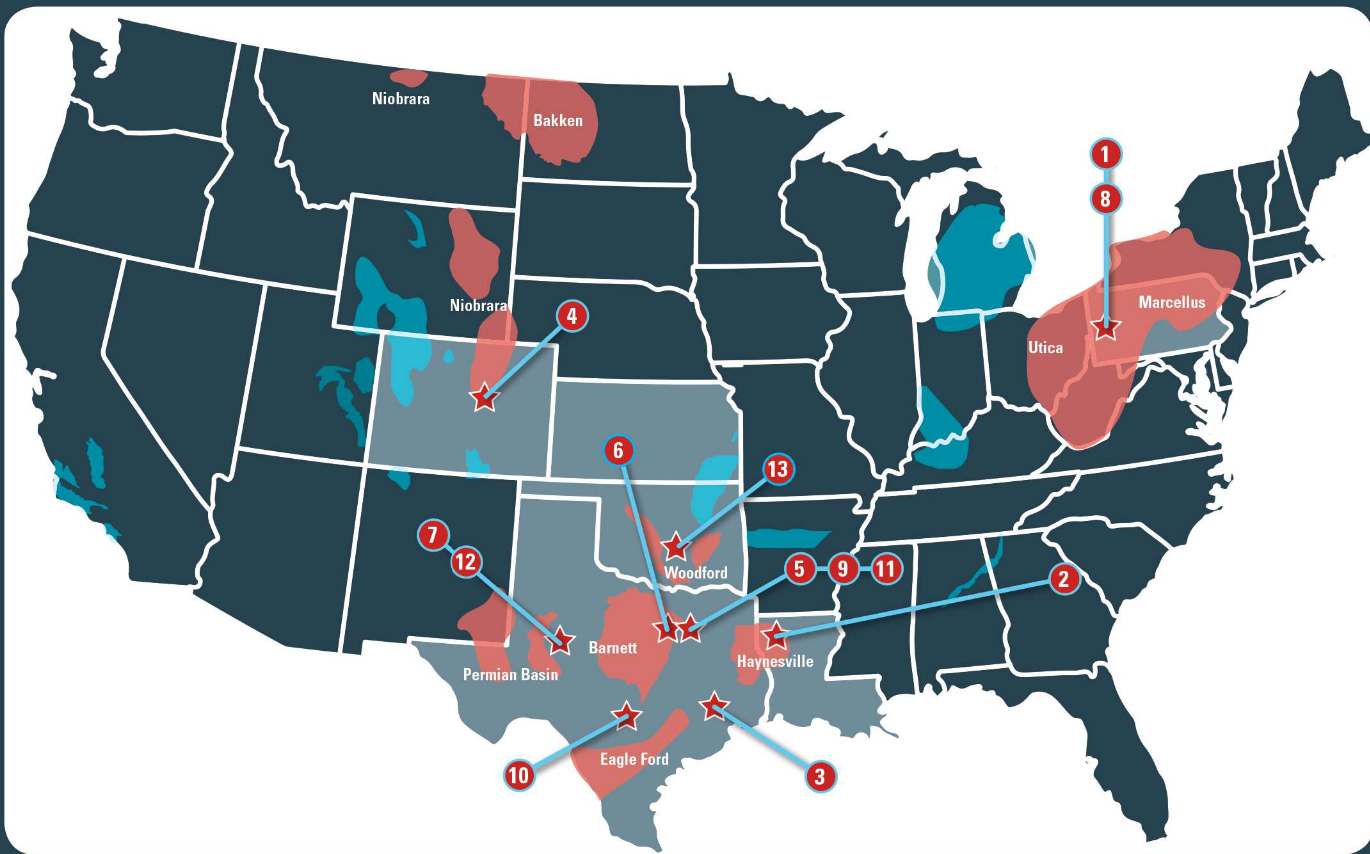
Cubility's system also provides onshore operators and drilling contractors with improved operational efficiencies, more efficient drilling fluids and reduced waste discharge. Recent applications were initiated in the Marcellus Shale. In this case, the operator tasked Cubility to find a more efficient way of processing and disposing of cuttings and reducing waste to the landfill.

In drilling applications in which large amounts of fines are not prevalent and cuttings can easily be lifted out of the wellbore (such as different formations, vertical wells, shorter to medium laterals or S-shaped wells), the MudCubes proved to be an effective solution in minimizing/eliminating backyard requirements and achieving top-tier solids control and waste disposal results. Cubility also is playing a role in taking the pressure off contractors who are faced with providing solids control equipment with little financial upside to them but maximum upside to the operator.

Through partnering with specialized service companies such as New Tech Solids in Canada and Stage 3 Separation in Houston, Cubility is enabling the cost-effective deployment of MudCubes—where an operator can rent the service per well or well pad—as part of a complete solids control solution in one of the world's most cost-conscious markets. Cubility is expanding this relationship model to other major markets in the Middle East and Asia.

As the drilling fluids market continues to grow, it has never been more important to ensure that the right waste reduction and cuttings separation technologies as well as the right business models are in place. The result will be greater efficiencies, reduced costs and environmental compliance across the drilling process. E&P

2018 Hart Energy Conferences:



1. MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION
Jan. 30 – Feb. 1
Pittsburgh, PA

2. DUG HAYNESVILLE
Feb. 20 – 21
Shreveport, LA
NEW IN 2018

3. DUG EXECUTIVE
Feb. 26
Houston, TX
NEW IN 2018

4. DUG ROCKIES
April 24 – 25
Denver, CO

5. energycapital CONFERENCE
May 7
Dallas, TX

6. DUG PERMIAN BASIN
May 21 – 23
Fort Worth, TX

7. MIDSTREAM TEXAS
June 5 – 6
Midland, TX

8. DUG EAST
June 19 – 21
Pittsburgh, PA

9. A&D STRATEGIES AND OPPORTUNITIES Conference & Workshop
Sept. 5 – 6
Dallas, TX

10. DUG EAGLE FORD
Sept. 19 – 21
San Antonio, TX

11. MIDSTREAM FINANCE CONFERENCE
Oct. 22 – 23
Dallas, TX
NEW IN 2018

12. EXECUTIVE OIL CONFERENCE
Nov. 5 – 7
Midland, TX

13. DUG MIDCONTINENT
Nov. 13 – 15
Oklahoma City, OK

The world depends on energy, and energy professionals depend on us.

Improving efficiency with near real-time diversion design evaluation

System enhances fracturing fluid stimulations.

Sudhendu Kashikar, Reveal Energy Services

If there is a word that describes the U.S. energy industry, "resiliency"—the ability to spring back or rebound quickly—certainly comes to mind. Since early 2016 at one of the industry's lowest points to today's footprint, oil and gas professionals have figured out how to do more with less.

The industry's never-give-up mindset that is shifting the country from a net energy importer to a net energy exporter by 2026 or earlier, according to the U.S. Energy Information Administration, is writing a new chapter in the industry's history. This mindset is directed at producing a greater percentage of hydrocarbon using new methods that decrease geologic and financial risks in the greater efficiency scenario throughout the major U.S. shale plays.

As part of this scenario, a new, faster method of diversion design evaluation has been commercialized. DiverterSCAN technology offers near real-time evaluation to ensure hydraulic fracturing fluid stimulates multiple perforation clusters. LINN Energy, working in the Scoop/Stack, received the first near real-time results, increasing hydraulic fracturing efficiency.

Pressure-based fracture maps

LINN Energy called on Reveal Energy Services, founded as a spin-out from Statoil Technology Invest in 2016, whose suite of five services is powered by pressure-based fracture maps. These fracture maps help operators better understand fracture geometry, proppant distribution, perforation clusters, depletion boundaries and diversion.

In this context, there is a treatment well that has been hydraulically fractured and is full of fluid, and an adja-

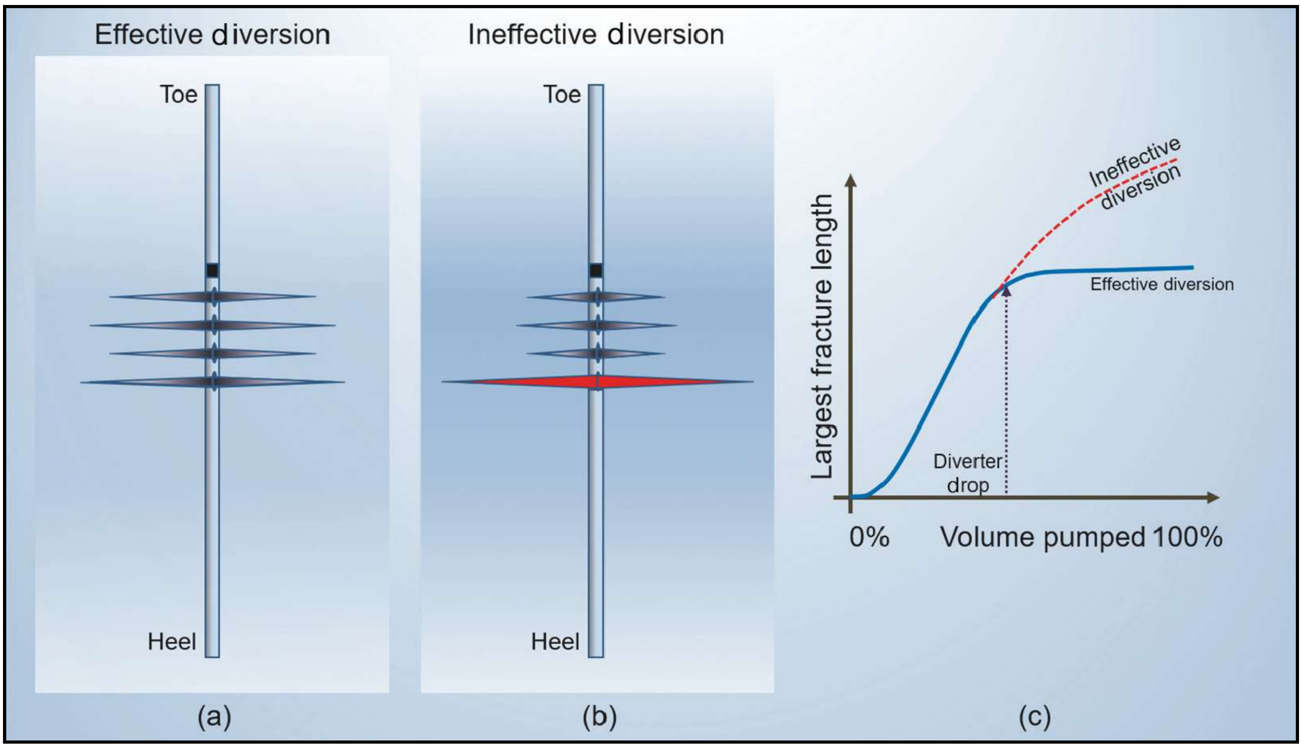


FIGURE 1. An ineffective diversion is compared to an effective diversions utilizing DiverterSCAN technology. (Source: Reveal Energy Services)

cent well, known as the monitor well, that has a pressure gauge placed at the wellhead. Because new fractures with the fluid leak-off generate a stress field pressure response in the monitor well, Reveal Energy Services was able to compute a pressure-based fracture map. The map is computed using a fully coupled 3-D model that compares the modeled pressure response with the observed pressure response in the monitor well.

The operator was interested in quickly knowing what the maps would show about its diversion designs in the Scoop/Stack. Diverter material, which is typically a combination of chemicals, fibers and particles that create a temporary plug, diverts fluid from one cluster to another with the goal of improving the cluster effectiveness and the number and geometry of fractures created in a given stage.

Before hydraulic fracturing operations, a completion engineer designs the volume, rate, concentration and timing of the diverter drops. Because there is limited knowledge about fracture width and complexity, experience with the geographic area is vital. If the treatment does not enable adequate diversion, the engineer could iterate a different design. The iterative process, typically spread out over multiple wells or pads, could take a few months to determine the optimal design. This delay in identifying the optimal diversion design is the key reason Reveal Energy Services created DiverterSCAN technology.

"What is interesting is that with DiverterSCAN technology you can see the result of a correctly engineered diversion design by watching the fracture growth rate stop in near real time, providing the completion engineer with a tool to very quickly determine the success or failure of a given diversion design," said Erica Coenen, vice president of operations and chief scientist at Reveal Energy Services.

Faster evaluation method

This new diversion diagnostic tool offers much faster diagnosis than several older methods that have been applied to monitor hydraulic fracture stimulations, such as temperature and production logging, radioactive tracers, borehole imaging, tiltmeter mapping and microseismic monitoring. Most of these methods, applied or analyzed after the stimulation operation, can take from several weeks to a few months to get the results.

DiverterSCAN technology looks at the growth rate of the largest fracture in the well using the pressure response measured in the offset monitor well as the treatment well is being fractured.

As shown in images (a) and (c) in Figure 1, a successful diverter drop results in stopping the growth of the largest fracture, while an unsuccessful diverter drop allows the largest, dominant fracture to continue growing, as shown in images (b) and (c) in Figure 1.

The purpose is for the diverter drop to force the fluid into all of the clusters to stimulate the entire stage. Unfortunately, in a typical stimulation treatment only 40% to 50% of the clusters are treated effectively and contribute to production. There is a significant opportunity to improve completion and cluster effectiveness.

LINN Energy was looking into testing several diversion designs and evaluating the effectiveness of each one for fieldwide implementation. Before LINN Energy began fracturing the well, Reveal Energy Services worked with the operator's completion engineers to develop a comprehensive data acquisition plan that accounted for the planned fracturing sequence and any field operations constraints, such as zipper fracturing manifold and reach of overhead cranes. The data acquisition plan was included in the file operating guidelines. A real-time data stream was set up to transmit pumping data (pressure, rate and proppant concentration) and offset wellhead pressure to the Reveal Energy Services' office.

Once fracturing had concluded on a given stage, an internal team of geoscientists and engineers completed the data processing and evaluated the effectiveness of individual diverter drops. The team communicated the results to the operator, usually within 2 hours of completing a stage. Valuable insight was obtained on specific diversion techniques that were successful in stopping growth of the largest fracture. Using these results, the operator adjusted and modified the diversion scheme for the subsequent wells and pads completed in that area.

"Within 2 hours, we received analysis that allowed us to evaluate the effectiveness of our diversion implementation while completing wells on one of our Stack/Scoop pads," Byron Cottingham, senior engineer for LINN Energy, said. "With these quick results, we determined the most effective diversion design on the remaining stages, instead of relying on one unverified design for the entire completion."

Conclusion

An intrastage diversion design is applicable to almost every multistage or multiperforation completion. The right design supports greater cluster efficiency with a more robust fracture network that has greater access points to the wellbore. E&P

Have a story idea for Shale Solutions? This feature highlights technologies and techniques that are helping shale players overcome their operating challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

A new economic and ecological concept for offshore decommissioning

The IR2R model offers a system to address the issue of the high cost of oil and gas asset decommissioning as well as reverses the reduction in fish habitats.

Enrico Salardi, Xodus Group, and
Matthew Allen, Subcon International

Fish stocks worldwide are under increasing stress due to raised levels of habitat degradation. State fisheries departments in many countries are undertaking habitat restoration projects to combat this phenomenon.

In conjunction, numerous offshore oil and gas installations, after many years of operation, are reaching the end of their productive lives, and the owners are required to decommission them in compliance with the rigorous decommissioning regulations that, as a base case, require removing everything from the seabed.

In the U.K. the international obligation on decommissioning is governed by the OSPAR Convention, which under the terms of Decision 98/3 prohibits leaving wholly or partly *in situ* the offshore installations.

However, during their time in operation, which can last several decades, the submerged structures of these offshore installations have created effective and productive habitats for marine life, which would otherwise be destroyed once they were removed and taken out of service as requested by the rules.

Complete removal of offshore installations also has a significant impact on the decommissioning costs, which are estimated to be as high as tens of billions of dollars worldwide. The typical removal practice is to use a large crane vessel to lift the structure out of the water onto a barge after which it is then transported to a port, transferred ashore and scrapped.

This is a very expensive process that also poses significant safety and environmental challenges to operators and their contractors executing the decommissioning works.

In addition, the decommissioning activities are effectively subsidized by governments and local communities as the cost of removal is deemed to be a sunk cost, resulting in tax liability write-offs and reduced royalties to stakeholders.

The high cost is not the only issue when it comes to decommissioning old assets. Oil and gas operators' reputations are at risk as certain cost-effective solutions may be perceived as shortcuts or attempts to pass liabilities onto taxpayers as well as causing environmental impacts that will affect future generations.

The cost factors are often used by operators to justify the "leave *in situ*" option. This is a decommissioning solution that is contemplated by industry regulators in some countries only when the operator has demonstrated, through extensive assessments, the adequacy of the site and structure. Other factors that are assessed include the future impact on

The submerged structures of offshore installations have created productive habitats for marine life. (Source: Xodus Group and Subcon International)

the environment, whether disruptions to other users of the sea have been minimized, whether alternative options are feasible or too challenging and if a solution has been proposed with respect to the ownership and responsibility for future residual liabilities. Typically, a "sea-dumping permit" would then be lodged with the regulator, answering all the above questions and requiring approval from relevant government agencies.

Given that the decommissioning of redundant oil and gas assets affects many stakeholders, the solutions to all these challenges cannot be considered the dilemma of only the oil and gas operators or governments. A solution must be found collectively and with the cooperation of all the involved parties reaching a compromise that delivers value to all stakeholders, including the affected communities and the environment.

A new partnership between Xodus Group and Subcon International will deliver Integrated Rigs to Reef (IR2R) decommissioning solutions globally. The IR2R model offers a solution to the issue of the high cost of oil and gas asset decommissioning as well as reverses the reduction in fish habitats. The partnership combines Xodus' decommissioning capabilities with Subcon's extensive track record in the design and construction of purpose-built marine habitats.

IR2R versus the traditional R2R concept

Rigs-to-Reefs (R2R) is the practice of converting decommissioned offshore oil and gas facilities into artificial reefs.

R2R originally started in the U.S. as a nationwide program developed by the former Minerals Management Service (now the Bureau of Safety and Environmental Enforcement) of the U.S. Department of the Interior. The program has been popular with fishermen, the oil and gas industry and government regulators in the Gulf of Mexico with approximately 10% of decommissioned platforms being converted into reefs. However, this has not been the case on the West Coast of the U.S. where there has been significant opposition from environmental groups, especially in California. Similar opposition has prevented implementation of R2R programs in the North Sea.

While traditional R2R has a proven track record of delivering decommissioning cost savings and an effective fish habitat, it often leaves the question as to who is enduring liability for the retired structure. It also is not specifically designed to optimize the ecological benefit.

IR2R overcame these shortcomings by augmenting the obsolete oil and gas structures with purpose-built reef modules. The modules are installed around the platform structure on the seabed to enhance the new habitat and convert it into a more productive purpose-built artificial reef.

The integrated artificial reefs become a new asset whose ownership and liability can be transferred to the relevant government agency in charge of habitat restoration or to another stakeholder exploiting it for commercial purposes.

The IR2R concept provides an opportunity to turn the decommissioned structures into a new habitat construction project that is carried out with the involvement of all interested stakeholders in predetermined sites. It changes the conversation from a sea-dumping exercise (perceived only to be driven by cost reduction) to a habitat restoration project. Habitat restoration has broad community support as science, fishing, diving and environmental conservation communities all recognize that the earth's seabed has been degraded and consequently fish stocks have plummeted.

Oil and gas operators have an opportunity to actively invest in these new purpose-built enhanced reef structures and to be part of a project that has significant social relevance. This is not only because IR2R allows the reduction of decommissioning cost liabilities (whose burden is on taxpayers for approximately 30% to 40%) but also because distressed fishing industries can be reinvigorated by the increased fish numbers from reconstituted habitats.

The U.S. government as well as the governments of Malaysia and Indonesia, where fish is one of the most important sources of protein for the inhabitants, have understood the potential of these ideas and the enormity of the associated social return. These governments have placed R2R programs as a solution that must be considered when discussing the decommissioning of offshore oil and gas structures.

The IR2R model can provide a cost reduction for the decommissioning of offshore structures between 10% and 20%; however, reducing cost represents only one of the many benefits that the IR2R concept can provide.

IR2R can also significantly improve the marine environment to the benefit of recreational and commercial fishing industries (too frequently in distress in many areas of the world due to overfishing), improve tourism, benefit the local and international communities, reduce the environmental footprint of decommissioning projects and improve the reputation of oil and gas operators. It truly is a win-win for all stakeholders. E&P

Have a story idea for Offshore Solutions? This feature highlights technologies and techniques that are helping offshore players overcome their operating challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Maximizing equipment and component life in extreme oil and gas environments

CVD coatings add value to components and reduce operational costs by saving downtime and increasing productivity.

Dr. Yuri Zhuk, Hardide Coatings

Over the last decade, a lack of material traditional hydrocarbon discoveries coupled with declining reserves has incentivized the oil and gas industry to develop new economically viable techniques to optimize extraction from increasingly challenging geologies and geographies.

In such hostile environments, and bearing the brunt of shock loads and high pressures, components can become deformed, causing fractures, chipping and catastrophic equipment malfunction. In addition, seawater, sour oil and gas containing aggressive H_2S, other grades of crude containing CO_2, and acidic fluids can quickly cause corrosive attacks which, especially when combined with abrasion or erosion, can significantly accelerate corrosion and lead to premature part failure.

Existing coating alternatives range from high-velocity oxy-fuel (HVOF), hard chrome plating (HCP) and physical vapor deposition to emerging processes such as electroless nickel composite plating and explosive bonding. However, although successful in some applications, each has its limitations.

The Hardide-T chemical vapor deposition (CVD) coating, which is typically used in the oil and gas industry, outperforms these alternatives in a number of critical areas. It belongs to a novel family of nanostructured tungsten/tungsten carbide coatings that are used on components subjected to high levels of wear, erosion, corrosion, galling and shock loading.

The coating can be used in applications calling for smooth external and internal surfaces, and on many complex shapes, including downhole tools, fracturing tools, retrievable packers, actuators, control valves and subsea pumps.

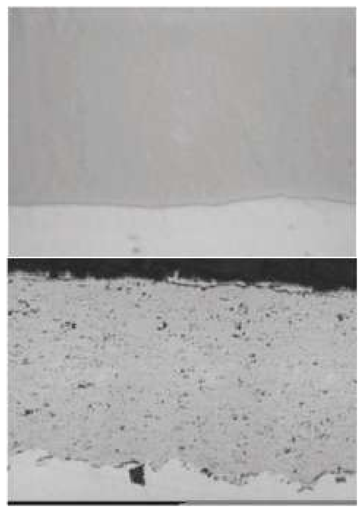
It is crystallized atom by atom from low-pressure gas media, producing a uniform, pore-free coating—a result of the highly mobile reaction products filling micropores and defects as it grows—which does not need to be sealed.

The dispersed tungsten carbide nanoparticles give the material enhanced hardness, which can be controlled and tailored to give a typical range of between 800 Vickers and 1,600 Vickers hardness for different coating types. The CVD coating is typically applied at a thickness of 50 µm.

Testing

In testing the CVD coating provided enhanced protection against corrosion, wear, erosion, acids and other chemically aggressive media. It also displayed improved fatigue life and toughness.

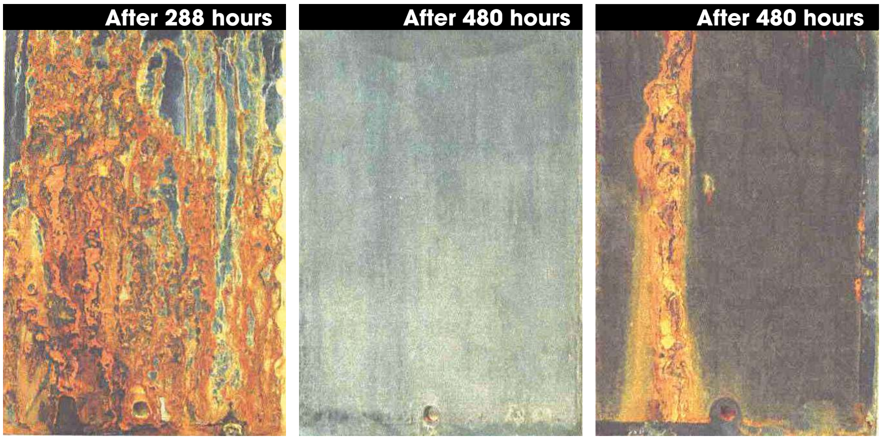
Traditionally used coatings such as HCP, thermal spray and electroplating have micropores and microcracks that can widen under load, allowing media to attack the substrate. Sealing can improve the corrosion resistance, but there are several limitations including—in the case of organic sealants—maximum use temperature.



The HVOF tungsten carbide-cobalt (bottom) has 2.55% porosity, and the CVD tungsten carbide coating (top) has 0% porosity. (Source: Hardide Coatings)

Plus, as the coating wears, deeper, previously concealed, unsealed pores will eventually open.

The pore-free CVD coating's performance was confirmed in accordance with the ASTM B117-07a standard. Mild steel plates were coated with HCP, HVOF and CVD coatings and were subjected to 480-hour neutral salt spray tests. The HCP samples were badly corroded and were removed from the test after just 288 hours of exposure. The HVOF-coated samples showed heavy rust stains and the coating blistered due to intensive corrosion of the steel plate beneath. CVD samples showed only light staining.



Samples of three different coatings after salt spray corrosion tests are shown: hard chrome (left) after 288 hours, CVD tungsten carbide coating (middle) after 480 hours and HVOF (right) after 480 hours. (Source: Hardide Coatings)

Galling prevention

The CVD tungsten carbide coating's galling resistance was tested using a Phoenix TE77 high-frequency reciprocating test rig. The test uses the reciprocating dry sliding movement of a cylinder on a flat plate with loads gradually increasing from 10 N up to 800 N—equivalent to 810.2 mega Pascal contact pressure—and monitors the coefficient of friction (CoF), where above 1.0 indicates severe galling.

In comparison with a baseline control test using a stainless steel pin, which was stopped due to sample seizure after reaching critical 1.0 CoF quickly with just a 65 N load, when a CVD-coated pin was tested against a coated plate, the dry friction coefficient remained low: stabilizing at about 0.2.

Importantly, no galling was observed even under the test rig's maximum load.

In contrast, the steady-state dry friction coefficient of HCP was reported at 0.70+/-0.1, more than three times higher, with spray coatings' dry friction range stated as 0.56 to 0.61.

Sulfide stress cracking

The CVD coating was tested by Bodycote Materials Testing for resistance to aggressive media in accordance with the NACE standard (TM0177-2005/ASTM G39) 30-day sulfide stress cracking test. This test is performed in a solution of 5 wt% sodium chloride and 0.5 wt% acetic acid saturated with H_2S. Samples were tested in deformed conditions with coating elongation up to 3,000 microstrains. During the test, the uncoated sample cracked across the full 20-mm width and experienced extensive microcracking and pitting, while the CVD-coated substrate showed no micro- or macrocracking or degradation.

Resistance to deformations, impact and wear

During micro and nano-scale testing, the coating sample did not fracture after 100 nano-impacts, and a diamond cube corner indentation failed to induce cracks. In neither test did the coating exhibit brittle behavior, thus its fracture toughness exceeded the level that can be measured using commonly used methods.

Wear resistance tests performed in accordance with the ASTM G65 standard showed the coating wear rate is 40 times lower than abrasion resistant steel, 12 times lower than hard chrome and four times lower than thermal spray.

Real world capability, potential for growth

In September 2017 Hardide Coatings announced a collaboration with Master Flo Valve Inc. (MFV) to protect HP/HT subsea choke valves.

The flow management company needed a new coating solution for its choke valves' stem assemblies. The coating needed to be rated to temperatures as high as 204 C (400 F)—a requirement that eliminated all standard coating options—and be capable of withstanding pressures up to 20,000 psi. Resistance to wear, corrosion and erosion were all critical. Plus, the coating needed to be durable and be able to be polished to an extremely smooth finish.

All these properties were crucial to preserving the tool's metal-to-metal seal, which needed to operate reliably over hundreds of cycles in subsea environments, such as single or multiphase production as well as water, chemical or gas injection.

Now the CVD coating is used to hardface stems on the MFV P4-15k and P4-20K subsea bolted bonnet choke valves as well as on an application for a capping stack, for deployment in a blowout situation. E&P

Have a story idea for Operator Solutions? This feature highlights technologies and techniques that are helping upstream operators overcome their challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Cutting plugging costs

The development of a new method will significantly reduce the cost and environmental footprint when plugging hydrocarbon wells.

Mark Sørheim, HydraWell

A wave of oil and gas wells drilled in the last 50 years are reaching the end of their useful life. These wells require attention to be plugged and abandoned in a safe manner to avoid costly liabilities for oil companies. However, plugging and abandonment represent an unwanted but necessary cost to the industry. Any improvements in efficiency and reduction of cost in this activity would deliver significant financial benefits to the oil companies and the tax payers, since in many cases these activities are subsidized through government fiscal regimes.

Since the 1970s section milling has been the preferred method of oil companies for plugging an oil and gas well where the annulus integrity is lacking. However, it is a method that can be time-consuming and difficult to execute safely and effectively.

Briefly explained, section milling incorporates the removal of a section of casing by milling operations enabling the installation of a rock-to-rock plug for hydraulic isolation purposes. After the section of casing is milled, the well needs to be properly cleaned out by removing the swarf cuttings and other debris. After the new formation is exposed, a balanced cement plug is placed in the section.

Section milling challenges

A traditional section milling job is time-consuming. Typically, it takes 10 days to 14 days to perform a 50-m (164-ft) section milling operation using an expensive drilling rig.

Proper hole cleaning is a challenge, and the fluids designed for section milling must have sufficient viscosity to suspend and transport swarf and debris to the surface. In the worst case, poorly transported swarf and debris can build up downhole and result in stuck pipe.

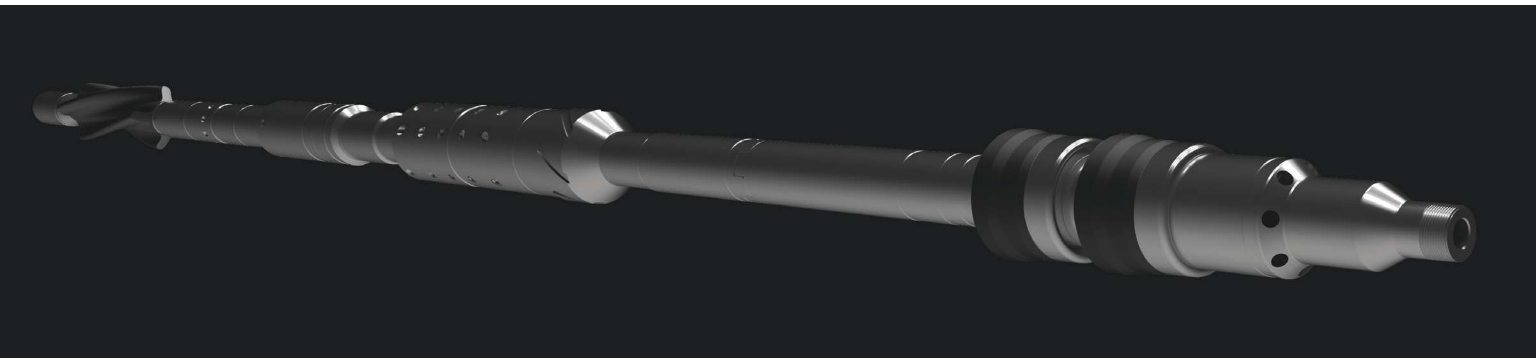
Section milling also presents HSE challenges when the swarf cuttings from the well are brought to surface as these cuttings require specialized material handling and disposal. The cuttings are razor sharp and require protective equipment when handling. On average, milling a 50-m section of an offshore well generates about 4 tonnes of swarf cuttings.

Difficult challenge, new approach

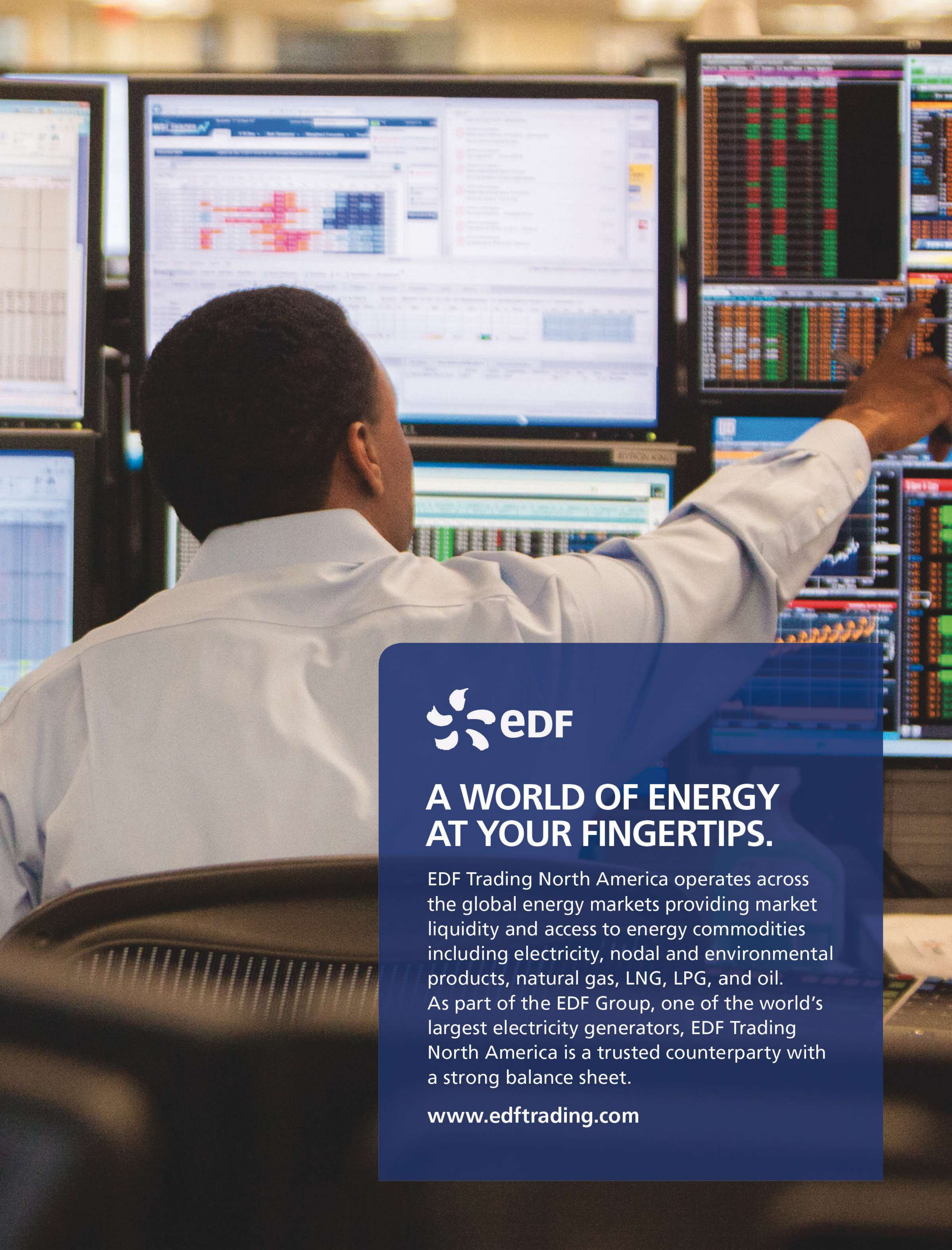
HydraWell worked to create a technology that could improve operational efficiency of plugging through multi-activity tool combinations. From this came the proprietary single-trip perforate, wash, cement (PWC) technology.

The company's HydraHemera system consists of three parts. Placed at the bottom of the assembly are third-party-supplied perforation guns. Sitting above the perforation guns is a jetting tool and then a cementing tool.

The jetting tool washes and cleans out debris in the annuli behind the perforated casings. The tool features jet nozzles configured at irregular angles and engineered for optimum fluid velocity and annuli cleaning efficiency. The jets penetrate and clean thoroughly



The HydraHemera PWC tool provides an alternative to section milling in P&A operations. (Source: HydraWell)



behind single or multiple perforated casings. In this process, debris, old mud and cement traces are replaced by clean fluid. The jetting tool ensures clean conditions in the casing annuli prior to placing the plugging material in the cross section.

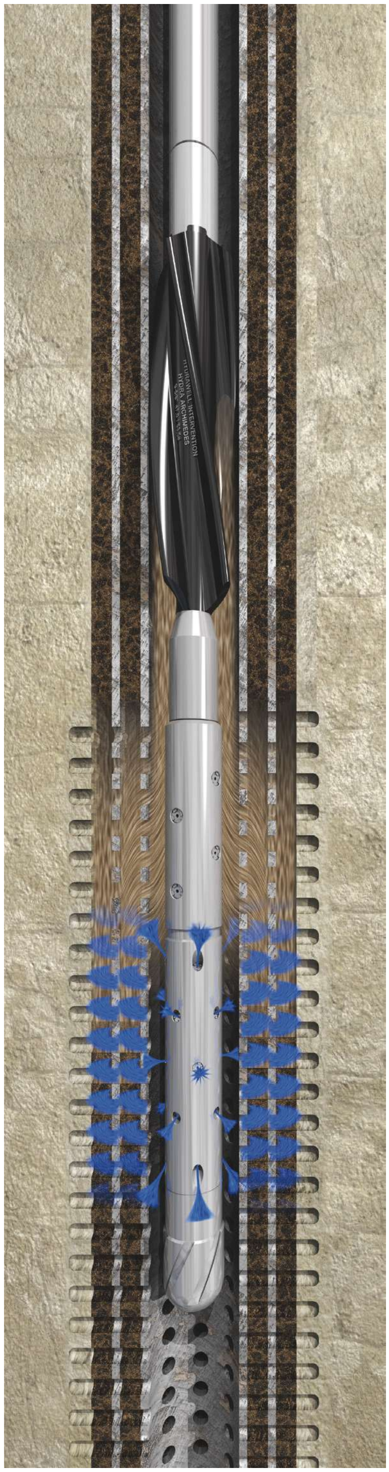
After jetting is complete, the cementing tool is then activated using a ball drop mechanism. This enables the placement of barrier material in the entire cross section of multiple annuli and establishes a proper rock-to-rock barrier in the well.

As in section milling, the mud weight must be sufficient to maintain the stability of the exposed formation. However, high-viscosity fluids are not required to lift metal debris from the wellbore. In addition, the PWC system creates an abandonment plug that can be verified. After placing barrier material, it is possible to drill out the plug and perform a cement bond log to provide verification of integrity.

Time and cost saving

ConocoPhillips was the first company to use the technology on its Ekofisk Field in the North Sea in 2010. At a presentation during the 2016 Norwegian Plug and Abandonment Forum, ConocoPhillips stated it had achieved a 70% improvement in plug and abandonment (P&A) performance at the Ekofisk Alpha Field based on the number of days saved per well, thereby concluding the P&A campaign almost one year ahead of schedule. This delivered significant cost savings to the operator with the PWC technology playing a major part.

Since introducing the PWC system, 16 operators, including supermajors, national and independent oil companies, have accepted and utilized the technology, installing more than 220 plugs worldwide. The PWC system has repeatedly demonstrated that it is capable of plugging offshore wells in two to three days instead of the 10 to 14 days it takes with traditional plugging methods such as section milling.



In this cross section of a well, the HydraHemera jetting tool is shown washing and cleaning out debris in the annuli behind perforated casings. (Source: HydraWell)

BP (now AkerBP) also stated at 2016 forum that it reduced the average days per well P&A process by 45% at the Valhall Field in the North Sea. It also reduced the average cost per well by an average of 35% and plugged and abandoned 13 wells during a rig contract period that was originally planned for six wells. HydraWell supported BP in these operations.

The PWC technology has saved more than 1,500 rig days for oil companies, with the additional benefit of a significantly smaller environmental footprint as no swarf cuttings have been brought to surface for further disposal.

Rigless P&A operations

Plugging offshore wells without removing the production tubing is the next development in the company's technology portfolio. The new proposed solution, HydraArtemis, enables plugging of wells from the existing infrastructure by use of well intervention equipment such as coiled tubing and wireline.

Typically, thousands of meters of production tubing are brought to surface in the current P&A activity. Today, oil companies often have to upgrade the drilling unit on their platforms or hire a drilling rig to execute P&A operations to retrieve this production tubing to surface. Performing this type of P&A work without a drilling rig will significantly reduce oil companies' costs.

Avoiding tubing retrieval eliminates costs and risks associated with heavy-lift vessels, transport of material onshore and disposal of the tubulars recovered from the well. E&P

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SPONSORED CONTENT

Engineers Will Lead the Way Forward

New technology programs add value to key DUG conferences

The birth of America's shale revolution is behind us – and its future promises relentless focus on efficiency. All the data, tools, analyses and operating practices in the engineers' kit will be needed to produce sustainable commercial advantages.

Everyone knows the story: It was a near-miracle shale gas wells produced at all. Results from repeated horizontal drilling and multi-zone completions in the Barnett and nearby shale basins ignited a brushfire of enthusiasm. Land rushes ensued across North America as this novel combination proved effective virtually everywhere it was applied.

Natural gas supplies boomed, commodity prices fell, commodity markets shifted – and drillers turned toward oilier basins. It worked there, too. What followed was a true oilfield boom with aftershocks. It left a new industry landscape in which the United States is becoming the world's lead producer.

Engineering-based recovery

Incentives to become the low-cost producer have sharpened. Investors demand returns, earnings that depend on both capital efficiency and operational efficiency. Engineered value is in high demand.

That's why Hart Energy is bringing a full day of technology-focused presentations, panels and roundtables to its four biggest **DUG**™ conferences in 2018. Uniquely integrated **DUG *Technology*** programs will fill the second day(s) of programming at featured DUG events in Fort Worth (May 23), Pittsburgh (June 21), San Antonio (September 21), and Oklahoma City (November 15).

Full-conference **DUG** registrants get technology-rich content as added value. Engineers, technical personnel and others most interested in the second day's agenda can take advantage of reduced rates. As always, producer and operator personnel can get open, complimentary access to the exhibit floor throughout the conference. That includes a line-up of concise presentations in the Technology Showcase, a highlight of larger **DUG** exhibitions.

Each region faces unique challenges

No doubt those with the best rocks get better chances to win, but how the rocks are played matters. Tactics and best practices vary within each major play and across all the major basins. Regionally oriented **DUG** conferences have covered investment, business and development strategies for each major shale play starting with Hart Energy's original **DUG** conference (2006) in Fort Worth.

Regional variations will be in sharp focus in the **DUG *Technology*** sessions that debut on Wednesday, May 23, during the **DUG *Permian Basin*** conference and exhibition (May 21-23 at the Fort Worth Convention Center). Technology speakers in the main room at DUG Permian Basin will address:

- New Permian sand mines
- Water logistics and water midstream services
- Last-Mile Solutions for proppant transport
- What's working now in the Permian Basin
- Common practices employed by Permian operators (and why)
- State-of-the-art technologies and products in the region

All of these topics, plus updates on key full-field development plans, will be explored on the **DUG *Permian Basin*** main stage and in the uniquely straightforward Q&A exchanges that mark all of Hart Energy's **DUG**

Tech Showcases are popular on the exhibit floor at select DUG Conferences. In response to DUG attendee requests, in-depth technical content moves to the main stage at the four largest 2018 DUG conferences.

DUG PERMIAN BASIN
May 23
Fort Worth

DUG EAST
June 21
Pittsburgh

DUG EAGLE FORD
Sept. 21
San Antonio

DUG MIDCONTINENT
Nov. 15
Oklahoma City

Don't miss the full-day technical programs in FOUR REGIONS!

events. Subsequent DUG Technology programs will be tailored to region-specific technical challenges and best practices. Expert speakers will explain and debate the most effective, efficient and profitable approaches in an open and candid environment.

Far-reaching topical programs

Typical second-day **DUG *Technology*** programs will involve 12 to 15 subject-matter experts. Each agenda will explore three or four main themes over the course of 5 to 7 hours with panels, keynotes, roundtables and case studies.

Completion and production optimization (e.g., well construction, flowback, enhanced recovery, artificial lift) and logistics (sourcing well inputs, well-site operations) will be core subjects. Many other topics will be addressed:

- Engineered drilling and completion
- Smart rigs and smart wells
- Parent-child well relationships (interference/communication)
- Directional drilling and geo-steering
- Downhole tools/motors/bits/BHAs
- Why slickwater? Plug-and-perf? Sliding Sleeves? Dissolvables?
- Proppant quality: Why 100 mesh, or 40/70 mesh?
- Last Mile delivery, transload facilities and new sources (sand mines)
- Upgrading proppant (resin-coated sands, ceramics, additives)
- Artificial lift in extended lateral wellbores
- Longer laterals effects on coiled tubing applications
- Refracs, well remediation and EOR in unconventionals

Technology-focused programs from industry leaders Hart Energy covers "the wellhead to the steering wheel," with special emphasis on financing, exploration, drilling, completion and infrastructure required to develop and produce crude oil and natural gas resources. The company's "of the industry" perspective is reflected in its media (online, print and live events), data and research services.

Programming at the four largest DUG conferences expands to two full days in 2018, with the second day "in the main room" dedicated to DUG Technology content in keynotes, moderated roundtables and panel presentations.

That point-of-view is most evident in its **DUG** speaker slates – virtual "All-Star" lineups of leaders and experts from producers, midstream operators, technology providers and the financial community – and in the many industry professionals who permeate **DUG** conference audiences. E&P

For more information about **DUG *Technology*** *programs, or any of the four 2018 DUG conferences providing this value-added content, please visit* HartEnergyConferences.com.

DUG TECHNOLOGY

HartEnergyConferences.com

Keys to establishing success in reservoir characterization

An automated approach ensures the best possible model for the reservoir simulator and better-informed field development decisions.

Julie Vonnet, Emerson Automation Solutions

Uncertainties can be incorporated into the workflow from the static domain to full dynamic reservoir simulation. Central to this has been the Big Loop automated workflow that tightly integrates the static and dynamic domains so they are synchronized throughout the field's lifetime and so that risks are quantified in the model.

This synchronization takes place at the outset of the workflow, and some of the crucial reservoir characterization stages that occur prior to the dynamic phase can determine the success or failure of the simulation.

Data preparation

One of the drawbacks of many reservoir characterization workflows today is the lack of data integration and data and knowledge and associated uncertainties getting lost, a particular challenge when dealing with multiscale data and multisource information.

Key requirements are that models should be easily updateable through an automated, repeatable workflow; should be fully integrated and consistent with available data; should operate from seismic interpretation through to flow simulation; and should propagate and manage uncertainties throughout the characterization chain.

Another important factor influencing dynamic simulation is the need to have robust and consistent data integration in the 3-D models; for example, the ability to correctly represent wells, including horizontal sections, seismic (including 4-D) and production data.

It also is necessary to have quality control tools and to understand what information needs to come from the data. Questions that should be addressed include

- Will the model be a foundation for the complete field life cycle;
- Will the model be flexible enough to expand areas of investigation; and
- Based on production data, will existing layers be able to be modified and new layers and faults incorporated easily?

Seismic interpretation

The ability to quantify geologic risk early in the interpretation process will have a strong impact on the future accuracy and effectiveness of the model. That is why the seismic interpretation stage and the need to closely link seismic with the geological model and make use of all available data are so important.

Today seismic interpretation is a crucial stage, whereas in the past the seismic stage often was characterized by inherent ambiguity in the data due to limited seismic resolution, constraints on velocity for depth conversion and the issue of scale.

One reason for this new stage is Emerson's Model Driven interpretation methodology, where users not only create the geological model while conducting seismic interpretation but also capture uncertainty during the interpretation phase. Rather than creating one model with thousands of individual measurements, users can create thousands of models by estimating uncertainty in their interpretations.

In this way uncertainty maps can be used to investigate key risks in the prospect, and other areas can be quickly identified for further study. Interpreters also can create models more representative of the limitations of the data and uncertainty distribution while still respecting the hard data and can condition these models to the seismic data.

Structural modeling

The next stage is to use the uncertainties captured during seismic interpretation to create a robust 3-D structural framework. This includes all the faults in the reservoir, fault-to-fault relations and fault-to-surface relations, as well as the heterogeneities formed as a result of the way rocks are distributed. Fault modeling often is proven to be critical to achieving a correct history match and can have a major impact on dynamic simulation farther down the line.

Within this structural modeling workflow faults are represented as "free point" intersecting surfaces with hierarchical truncation rules, providing a correct geometric representation of fault geometries. Fault surfaces closely honor the input data while users retain detailed control, and the fault surfaces honor well picks and can be truncated by unconformity surfaces.

The fault modeling process also is highly automated, and algorithms are data-driven with input data filtered, edited or smoothed. In some cases, a horizon model can be built as an intermediate step between the fault model and the grid.

Additional modeling functionalities also include the ability to build intrusion objects into the structural modeling process (e.g., to better model salt) along with enhanced seismic resolution on horizons and faults for more accurate interpretation.

This ability to handle thousands of faults, edit the fault relationships and ultimately build the reservoir grid means that all members of the asset team can easily update a model, test different interpretations and use the model for specific applications.

The repeatable workflows and easy updating also overcome any restrictions of having seismic interpretation and depth conversions locked in before any updates. With this workflow updates can take place throughout the process.

Populating the grid

The 3-D grid must be populated with physical parameters such as porosity and permeability to describe the quality of the rock in the reservoir.

The modeling of these facies or rock types in a realistic way while at the same time honoring the observations from a large number of wells requires 3-D advanced facies and petrophysical modeling tools.

Emerson's reservoir characterization workflow includes both object-based facies modeling tools originated from established geological features and more data-driven model-based tools, all incorporating seismic data information into the models.

The object models will allow data extracted from seismic to be blended with geostatistical tools such as guidelines, trends and variograms to generate well-constrained sedimentary bodies that give a more realistic property model—acknowledging well data, volumetric constraints and the sedimentological environment.

The key to a combined workflow is to support the overall characterization goal and have a model that represents the dynamic behavior in the reservoir that is predictive to the future dynamic flow pattern. Next-generation object modeling tools will be better at respecting geological features and multiwell data scenarios. The ability to quickly update any model as new data come along is also in line with the Big Loop strategy of easy model updates.

Reservoir simulator links

At this stage it also is essential to facilitate the transition between the static and dynamic domains. One such area is that of time-dependent data such as reservoir parameters (e.g., pressure and flow production data). To this end the workflow includes an events management utility that fully supports these data and facilitates the building and maintenance of simulation-ready flow models.

Figure 1 shows a simultaneous visualization of a static model and time-dependent data (based on injector and producer wells and their respective flow rates and perforation intervals) within the workflow. The workflow also can integrate dynamic and static domains by respecting multiple versions of one static model, with stochastic realizations also being taken into account at the history-matching stage through the creation of a "stochastic proxy."

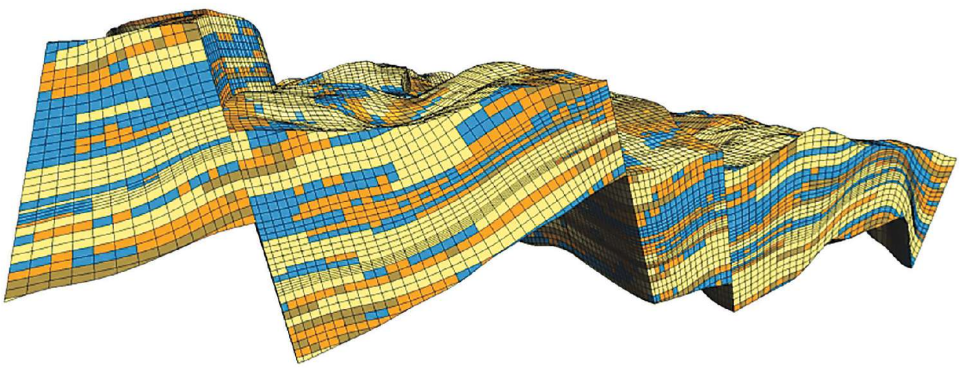


FIGURE 1. Emerson's Big Loop workflow tightly integrates static and dynamic domains and ensures a smooth, repeatable and consistent workflow. (Source: Emerson Automation Solutions)

Workflow

The Big Loop workflow remains the cornerstone of the Emerson reservoir characterization process, tightly integrating static and dynamic domains and ensuring a smooth, repeatable and consistent workflow.

It is this automated approach, supported by new innovative tools, that ensures the best possible model for the reservoir simulator and better-informed field development decisions. E&P

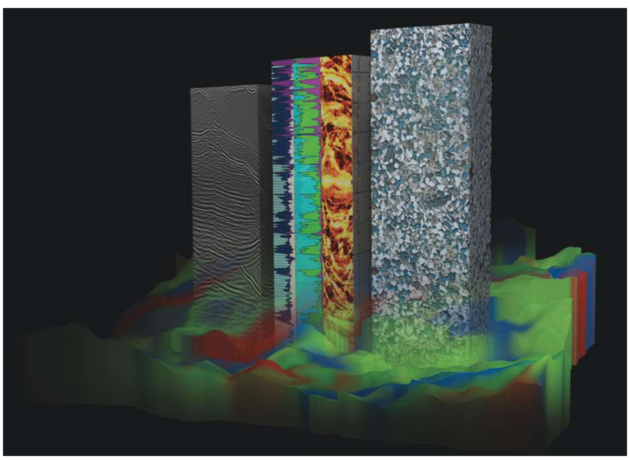
Taking reservoir characterization to the next level

An expanded laboratory integrates physical and digital information from downhole rock and fluid analysis to modeling and simulation.

Belgin Baser and **John Nighswander**, Schlumberger

Reservoir characterization, the process operators undertake to understand rock and fluid properties, is arguably the most critical component of field development planning because it is key to ensuring optimal production and recovery over the lifetime of the well. As operators have ventured into more complex fields, the service industry has responded by developing increasingly sophisticated tools and technologies for conducting the full spectrum of seismic surveys, wireline logging, fluid and core sampling and analysis, modeling, and well performance simulation to reduce uncertainties concerning the subsurface and reservoir producibility.

To meet the characterization challenges of increasingly intricate operating environments, Schlumberger recently expanded its Reservoir Laboratory in Houston to strengthen the integration of rock and fluid analysis services by bringing together the company's portfolio of reservoir characterization tools under one roof. The services span the entire reservoir characterization process across the hydrocarbon life cycle, from digitally enabled field sampling to measurement and modeling. In addition to an optimized set of measurements and analysis, customers have access to innovative solutions, digital models and geoscience expertise.



The Schlumberger Reservoir Laboratory provides a range of physical and digital rock and fluid analysis services for the life of the reservoir. (Source: Schlumberger)

Digital, integrated approach

Despite numerous advances in the industry, the ability to easily access, understand and synthesize the various data sources into a representative picture of the reservoir to make more meaningful decisions remains a challenge.

Schlumberger is replacing this piecemeal procedure with an integrated reservoir characterization strategy that provides the capability to combine field data and laboratory measurements in the DELFI cognitive E&P environment, a secure, cloud-based space that harnesses data, scientific knowledge and expertise to facilitate collaboration among E&P teams. The digital applications being implemented for data integration in turn facilitate comprehensive rock and fluid modeling and interpretation for greater reservoir insight that enhances field development from pore to pipeline.

This approach was successfully applied in a complex deepwater field in the Gulf of Mexico (GoM), reducing uncertainty and risk for the operator. The field comprises upper and lower sands separated by a significant shale layer, which presented connectivity and completion design challenges.

The integrated reservoir evaluation solution brought together multiple disciplines and technologies including seismic surveys, wireline logging data and a fluid geodynamic workflow incorporating precise laboratory measurements of fluid and geochemical properties to derive the geologic model for reservoir simulation. The model was calibrated to achieve a match between the simulated and historical production and pressure data. Reservoir simulation confirmed connectivity between the upper and lower sands, which aided the operator in optimizing wellbore placement and designing an effective completion, resulting in savings of more than $50 million.

Sampling for complete fluid characterization

Fluid analysis begins with sampling reservoir fluids. The Saturn 3-D radial probe establishes and maintains 3-D circumferential flow in the formation around the borehole. This enables accurate pressure measurements, downhole fluid analysis, sampling and permeability estimates, especially in challenging formations where the use of conventional wireline testing techniques is not possible. In an unconsolidated laminated GoM reservoir, a 9-in. Saturn probe collected clean single-phase hydrocarbon samples with very little contamination while taking only 2.5 hours for cleanup and sample acquisition.

In addition to openhole sampling, while-drilling analysis and sampling capabilities have been developed for the integrated reservoir characterization strategy. SpectraSphere fluid mapping-while-drilling service, which provides downhole fluid composition and pressure measurements in real time while drilling, provides operators with the earliest possible insight to reservoir fluids. Deployed in the Mississippi Canyon to enhance formation pressure testing and sampling, the service collected and analyzed six samples downhole in real time. This was an industry first for the transmission of detailed *in situ* fluid properties, saving the operator from waiting for two to three months to receive conventional fluid analysis.

Optimized measurement sets

Paralleling the growth of the portfolio of downhole rock and fluid measurements, technologies and workflows are similarly being implemented in the laboratory with the goal of increasing reservoir knowledge through enhanced measurement efficiency and data reliability.

For example, while new workflows decrease the number of physical laboratory tests required by the incorporation of *in situ* measurements, they also provide compositional information that increases confidence in the equation-of-state models the data are input into. The growing use of automation not only helps improve efficiency and thus accelerates access to information, but it also increases reliability and, more importantly, implements the process of digitization.

Further expanding the integrated reservoir characterization portfolio is expertise provided by Fluid Inclusion Technologies (FIT), a Schlumberger company specializing in laboratory analysis of trapped fluids in rock material. FIT uses a technique specifically suited for resolving the small concentrations of oil and gas species that are represented in the fluid inclusions, which enables documenting and mapping petroleum migration and charge events. In unconventional reservoirs in particular the information gained helps to guide completion decisions based on anticipated production. The overall workflow is fully automated and includes elemental analysis and high-resolution imaging for a complete overview.

The laboratory is staffed by scientists, engineers and technicians working across the spectrum of reservoir rock and fluid analysis. (Source: Schlumberger)

Comprehensive 3-D modeling

The reservoir characterization portfolio also includes CoreFlow digital rock and fluid analytics services, which integrate physical and digital rock and fluid analyses to create a holistic 3-D rock model that facilitates dynamic flow simulation for evaluating multiple hydrocarbon release scenarios to enable faster and better-informed decisions. The technology provides input such as relative permeabilities and capillary pressures for reservoir simulators. The pore-scale compositional simulator extends the envelope of analysis beyond the scope of physical analysis. This is particularly impressive in unconventional EOR applications, where traditional laboratory analysis reaches its current limits. Recent projects in the Eagle Ford provided operators with revised theoretical hydrocarbon release limits and an optimized approach for gas injection.

Despite the importance of fluid properties in design calculations, operators have often experienced difficulties modeling these properties because of poor software usability, deficient interchangeability between models and a lack of standardized and consistent workflows. For accurate fluid modeling throughout the reservoir life cycle, Schlumberger has released the FluidModeler application in the DELFI environment. In addition to consistent fluid analysis and modeling that combines downhole measurements, laboratory fluid analysis, software solutions and consulting services, this environment provides a new way of working for teams, enabling cross-collaboration among the geology, geophysics, reservoir engineering, drilling and production domains while leveraging the full potential of available data to optimize E&P assets. E&P

Automated compensation system increases accuracy, safety

A real-time monitoring system enhances operations in tidal conditions.

Trey Miller and **Claire Kennedy Platt**,
National Oilwell Varco

Current passive compensation systems require manual stroke and compensation adjustments associated with tide cycles and sea state variations, which depend on geographic locations and time of year. Operators must maintain constant communication with coiled tubing (CT) operators to understand real-time weight introduced to the wellbore, manually dialing in to safely compensate as intervention continues and weight increases and decreases. Stroke readjustment requires feeding nitrogen or hydraulic fluid to the compensator or bleeding nitrogen or hydraulic fluid out of the compensator system.

Manual manipulation of the block in the derrick or of the compensator within modular well intervention towers is necessary to correct stroke preparation errors and enable adequate compensation requirements. New technology, such as the motion compensation mode of operation implemented into the new compensating CT lift frame (CCTLF) from National Oilwell Varco (NOV), offers operators automatic control with manual override capabilities, eliminating the need for manual stroke and compensation adjustments, and therefore preventing human error and increasing safety.

The lift frame features an automatic tide adjustment, bleeding and feeding using pressure variance recognition in compression and tension as well as real-time weight monitoring. All hydraulic functions are wireless, contributing to a safer, more user-friendly system. Real-time monitoring shows the exact stroke and fluid levels, detecting leaks and low fluids. An alarm system notifies users when parameters are outside of scope, affording efficient troubleshooting methodologies when applicable. With even weight distribution across the upper frame assembly, down the two main beam structures and back to center at the lower frame assembly with a hydraulic elevator door, the system allows well-center rigup of CT, wireline and slickline.

NOV's CCTLF's manual override capabilities eliminate the need for manual stroke and compensation adjustments. (Source: NOV)

NOV implemented the new motion compensation mode of operation into the CCTLF based on past global completion and post-completion intervention projects throughout more than a decade, designing the system to enhance safety, increase weather working window capabilities, overcome crane limitations, improve well integrity and withstand aggressive sea state conditions. The new operation mode also is implemented into all existing inline and modular compensating well intervention towers from NOV.

P&A case study

From early 2006 through January 2008, a customer in the Gulf of Mexico (GoM) required a compensation system to perform CT and wireline services onboard a floating intervention vessel. The system needed to provide a rigless, modular, compensating well intervention tower for CT and wireline operations. Devin, part of NOV's intervention and stimulation equipment business unit, provided a cost-effective modular compensating well intervention tower system for the accommodation vessel.

The system used the dual Devin Inline Motion Eliminator (DIME) traveling head compensation system. Configuring the inline compensators outboard of the well intervention tower afforded a greater work window within the tower and reduced overall tower height requirements to accommodate well control and lubricator stack-up needs. The installation resulted in successful plugging and abandonment of multiple wells over a three-phase program with minimal downtime.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The compensation systems provided a safe, economic solution that resulted in minimal downtime during inclement weather or tidal conditions.

Subsea CT and wireline P&A campaign case study

From 2010 to 2011, an operator in the GoM required a compensation system to perform CT and wireline subsea plug and abandonment (P&A) operations. Using DIME systems, the operator compensated for slickline and e-line riserless subsea operations in nearly 91 m (300 ft) of water. The system accounted for tidal variations, inclement weather, surface winds as well as 3.6-m (12-ft) swells by ensuring downhole precision tool placement.

The DIME system provided primary means of compensation and independent well intervention support for subsea CT operations by ensuring the injector head and well control stack-up maintained relativity to the seafloor. Allowing the crane to work independently for added diver assistance and day-to-day logistical support enabled simultaneous operating capabilities. The combination of products enabled a savings of $300,000 per day of simultaneous operations. In addition, the systems contributed to a 38% cost savings compared to semisubmersible options and up to 78% cost savings compared to drillship options. The operator successfully completed P&A operations on nine subsea wells. The system increased the weather working window each time winds exceeded 30 mph because of crane boom limitations.

The CCTLF was used in four well completions offshore Nigeria. (Source: NOV)

Motion CCTLF case study

A company performing offshore operations in Nigeria from May 2013 through January 2014 had a CCTLF stored in original shipping crates. The company needed a rigup option to meet requirements regarding its immediate upcoming operations and requested a location inventory, assembly and system integration test of the CCTLF. With four wells to complete, the operator required specialized offshore motion compensation technicians to successfully rig up and operate the CCTLF throughout the duration of the operations. A team of offshore technicians from NOV rigged up the CCTLF in multiple stages to meet the rig crane capacity of 86,000 lb and performed a complete system integration test in the derrick of the rig.

They operated the CCTLF during the landing of the completion and compensated over well-center while working in up to 4.2-m (14-ft) heave conditions. As a result, the company saved significant time and money by eliminating the need to source a CCTLF externally or from another rig. They minimized downtime to 30 minutes with more than 1,000 hours of operation compensating over well-center during the four-well campaign.

Floating spar case study

From December 2015 through February 2016, an operator on a floating spar in the GoM had an objective to clean up paraffin and scale in two wells. The operation required compensation and intervention equipment rigged up from well to well that would account for high and low tide cycle variations, enabling safe working operations. The ability to increase, decrease and maintain preset levels of drillstring weight by controlling the direct line compensator (DLC) pressure was needed to safely meet the objective.

Devin installed the DLC equipment package within the rigup window and provided a nitrogen compensation skid, which accounted for all tidal movements and inclement weather by maintaining a constant hook height during vessel movement. The package minimized the weight of added intervention equipment and completion string in the existing completion, providing redundant safety measures in the event of a nitrogen failure and during normal well intervention operations.

The team safely transferred the DLC/CCTLF package and other well intervention equipment while skidding the spar 16.7 m (55 ft) to the next well location in the field. Transferring the CCTLF intervention equipment from well A-6 to well A-7 reduced rigup and rig downtime by 36 hours, saving the operator 1.5 days of rig costs. They safely flowed back well A-7 and helped bring well A-10 online to the production facility. The DLC provided the primary means of compensation support for the entire spar on both well operations. The operator successfully compensated the spar for 40 days latched to the seabottom. E&P

Automation and prognostics transform CT drilling performance

An integrated system expands the potential of underbalanced CT drilling to solve complex challenges.

Doug Pipchuk, **Eduardo Saenz** and **Greg Bowen**, Schlumberger

Since emerging onto the oil field a half-century ago, coiled tubing (CT) has more than proved its worth as a highly reliable and robust well servicing and intervention method, continually reinventing itself to meet the rigors of increasingly complex reservoirs and wellbores.

While CT has been a game changer for many applications, its use as a drilling method has been slower to develop due to technological obstacles that have impeded adoption of the approach since it was introduced in the mid- to late 1990s. Deployed with a small diameter continuous-length tubing from a spooling reel and equipped with a mud motor for rotation, a CT drilling (CTD) system requires quick reactions to constantly changing downhole and surface conditions such as kicks, formation changes, well control issues, well placement decisions and drilling speed.

The technique is suited for challenging drilling conditions, including thru-tubing re-entry drilling applications and reservoirs where underbalanced drilling (UBD) is necessary to keep wellbore pressures lower than the formation pressure. A CTD rig typically requires less personnel and leaves a significantly smaller footprint than a conventional rig. Despite these advantages, a lack of coordination and integration has been problematic in consistently overcoming those operational complexities.

The XTD4 CTD rig is an all-electric fully connected integrated system. (Source: Schlumberger)

With recent technological advances, driven by automation and prognostics, CTD performance is being transformed through integration into a single, all-electric system with an all-electric automated CTD rig, a real-time directional bottomhole assembly (BHA) and an engineered underbalanced surface separation package.

Underbalanced CT drilling (UBCTD) is increasingly being recognized as the key to unlocking the potential of fractured carbonate and geologically complex sandstone reservoirs, often in live well conditions. The process delivers such benefits as producing the well throughout the drilling and completion processes and eliminating wellbore damage and, in many cases, reducing the need for subsequent well stimulation.

Currently, the Middle East leads the UBCTD market, but global expansion is on the horizon with development of the integrated system. Recently deployed for a large, multiwell project in the Middle East, the Schlumberger integrated CTD system incorporates advances in data communication, automation and functionality to deliver a fully connected and self-sustaining operation featuring digital telemetry and automated subsystems that enhance real-time decision-making.

The all-electric system is designed to deliver high rates of data that enable fast-reaction subsystems to improve drilling efficiency and reduce risk by automating measurement of multiple downhole parameters, which include

- Torque and weight-on-bit to drill faster, increase tripping speeds and prevent stalls;
- Bottomhole pressure and pump rates to enhance well control and protect the formation from drilling damage; and
- Bottomhole and surface pressure and temperatures to prevent slugs and kicks.

Eliminating risk, inefficiency

A key driver of the new integrated system was the need to move beyond the traditional fragmented approach to CTD that relies on deployment of separate services, often supplied by multiple vendors, and human decision-making, all of which lead to inefficiencies, interface risk, nonproductive time and inaccuracies. The result is technology that integrates all the aspects of the CTD operation to work synergistically to optimize operations, increase efficiency, reduce wellsite personnel and minimize overall HSE and operational risk.

The technology's initial deployment is in a multiwell gas field in the Middle East, a region characterized by fractured carbonate reservoirs that must be drilled underbalanced to avoid fluid loss and formation damage in conjunction with the drilling process.

These formations often feature deep, hard and abrasive sandstones interbedded with shale and siltstone. With unconfined compressive strength of up to 35,000 psi and internal friction angles ranging from 25 degrees to 60 degrees, these fields are challenging to drill and reach desired lateral lengths. Openhole sidetracks in these conditions also are difficult to perform.

UBCTD has been undertaken successfully in the area since 2010. However, the integrated approach, with its capability of monitoring downhole measurements that can be connected to the surface in a continuous loop, will optimize the process by improving ROP, reducing risk and increasing formation contact, enabling quicker decision-making than conventional UBCTD applications.

The centerpiece of the technology is the automated XTD4 CTD rig, which captures data and provides command and control of the entire CTD operation. The rig design builds on the success of the AC-powered, high-capacity CT injector, which has been the foundation of the XTD rigs that have drilled 201,168 m (660,000 ft) since 2010 without a major shutdown. The injector utilizes an AC drive and control systems and a drilling-specific, heavy-duty design, specifically for desert conditions, that can provide 200,000 lb of pull with high-definition control coupled to downhole sensors.

The redesigned XTD4 rig is engineered to efficiently and safely deploy drilling BHA and optimize loads and service interfaces for efficient rig moves, reducing rigup and rigdown operations by 20%. All services are integrated through the plug-and-play digital hub and command center. Automated operations reduce workloads and protect personnel through safety interlocks on systems.

The underbalanced surface separation package, introduced in 2016, was engineered to prevent, detect and mitigate potential well control events and optimize wellbore stability during UBD operations. The system's fully automated operating system and durable control and safety protocols provide remote real-time control and monitoring. The modular, trailer-mounted equipment ensures compact and efficient rigup and safely controls, separates, measures and redirects the drilling and produced hydrocarbon fluids with a minimal footprint, while the plug-and-play instrumentation and hub facilitate integration with all services.

The surface separation package features customized applications of the Diligens mobile production testing technology, designed for quick rigup and rigdown so multiple wells can be tested per day. The mobile production testing unit receives and processes effluents to support workover operations during well cleanout. Further expanding the operational envelope is a multiphase production testing unit, which contains two multiphase flowmeters on the same skid to provide repeatable flow-rate measurements in any multiphase scenario.

Increasing reservoir exposure, minimizing damage

The platform also incorporates the Schlumberger CTDirect CT directional drilling system, a continuously oriented BHA that minimizes reservoir damage in underbalanced operations.

Integrating in real time with the rig and the underbalanced surface separation package, the CTDirect system provides measurements of downhole drilling mechanics data, shock and vibration, inclination, gamma ray, azimuth and toolface, seamlessly transmitting the data to surface where it is continuously monitored at the wellsite for precise directional control and immediate drilling performance decision-making.

This builds on more than four years of continuous operations in which the system drilled more than 100 lateral sections and 47,853.6 m (157,000 ft), reaching build rates of up to 40 degrees per 30 m (100 ft). The system achieved a 200% increase in ROP versus the field average using a conventional BHA, resulting in earlier payout and lower well stimulation costs. It has been instrumental in delivering 300% to 700% more production from re-entry wells when compared to directional drilling.

The fully integrated solution overcomes the operational limitations that have hindered mainstream adoption of the technique. By enhancing efficiency while reducing risk and nonproductive time, this approach is expected to expand potential of underbalanced CT drilling in challenging formations. E&P

Long-range fracture plugs offer customized completions

Plugs offer improved drill-out times and options in stage spacing.

Andy Mook, Magnum Oil Tools

The genesis of Magnum Oil Tools International Ltd.'s Long Range fracture plug was in the late summer of 2010, which in unconventional oilfield years is a lifetime ago.

The initial plug application—as covered in detail in the Society of Petroleum Engineers paper 146559, "A Unique Plug for a Restricted Wellbore"—was used in a West Texas well to provide zonal isolation for stages three through eight. After sticking three 3.92-in. fracture plugs in the hole (including one run on coiled tubing), a caliper run showed no signs of a restricted inside diameter (ID). The issue was a combination of a pin connection that could potentially cause a plug and tool string to be hung up, the wellbore's P-trap-like trajectory, and a dogleg severity would prevent anything greater than 1.8 m (6 ft) with an outer diameter (OD) of 3.65 in. from getting past 1,981 m (6,500 ft) of measured depth (MD).

Magnum developed a 3.25-in. OD slimhole plug that would set and hold 7,500 psi in 5-in. 18-lb/ft P-110 casing. Not only was the first plug deployment successful, all subsequent runs were made without issue, allowing the operator to complete the well.

Development

Since its release, Magnum's Long Range fracture plug has been run more than 9,800 times worldwide, saving operators time and opex. Prior to a reliable slimhole plug being on the market, completions teams were left with subpar options once casing had been repaired or a highly deviated well was handed over. This was the case especially if either or both of these restrictions were above a portion or all of the zones to be completed.

In some cases, the successful application of a sand "plug" has been documented. Rather than flushing the end of each stage, the zone is pumped with an excess amount of sand to plug off the newly fractured formation. The cost effectiveness of this practice, as well as the reliability of a nonmechanical barrier to truly isolate zones, is debatable. Although slimhole plugs were around for a decade or more prior to Magnum's Long Range, they were lacking several fundamental features that prevented the products from being economical—even in the days of $70/bbl to $100/bbl oil.

In many cases, the plugs designed for vertical wells were found to be inadequate for horizontal plug-and-perf operations. Getting pumped to bottom through a casing restriction and the plug set were a roll of the dice. The initial slimhole plugs used were typically made from cast iron, or even in some cases stainless steel, which all but prevented them from being drilled out without costly delays.

With Magnum's Long Range, there is a customizable and reliable way to complete wells with casing restrictions, casing parts and severe doglegs. Furthermore, since the Generation One Long Range was made from composite material, aluminum and utilized cast iron slips, multiple plugs could be drilled out in a single trip, with an average mill-out time of 45 minutes per plug.

The caveat of any restricted wellbore plug drillout is that one must use an undersized, drill-out, bottomhole assembly (BHA) to fit through the restriction. This limitation is the largest contributor to the lengthy drill-out times. To combat this limitation, careful consideration should be taken in the selection of the BHA used. Experience dictates the best option for drilling out an aluminum and composite plug is a five-blade reverse clutch junk

Magnum Oil Tools' Long Range fracture plugs have been run more than 9,800 times in wells worldwide. (Source: Magnum Oil Tools)

Five-blade reverse clutch junk mills are an option for drilling out aluminum and composite plugs. (Source: Magnum Oil Tools)

mill. Using a reverse clutch prevents the mill from locking up, and the mill face allows the plug to be broken up into manageable pieces.

Second-generation plug

Looking to improve upon the drill-out times per plug of the Generation One Long Range, Magnum prototyped and began field trials in early 2014 of the Long Range Generation Two plug. This plug provided the same pressure and temperature capabilities of the Generation One but also utilized 75% less aluminum. By accomplishing this, Magnum was able to reduce the drill-out times per plug by half.

As described in Case Study LR-16 on the Magnum Oil Tools website, the eight stages that were completed below the casing patch not only incurred zero plug failures during the completion, the plugs were drilled out in an average of 22 minutes each. This millout also utilized the recommended five-blade reverse clutch junk mill.

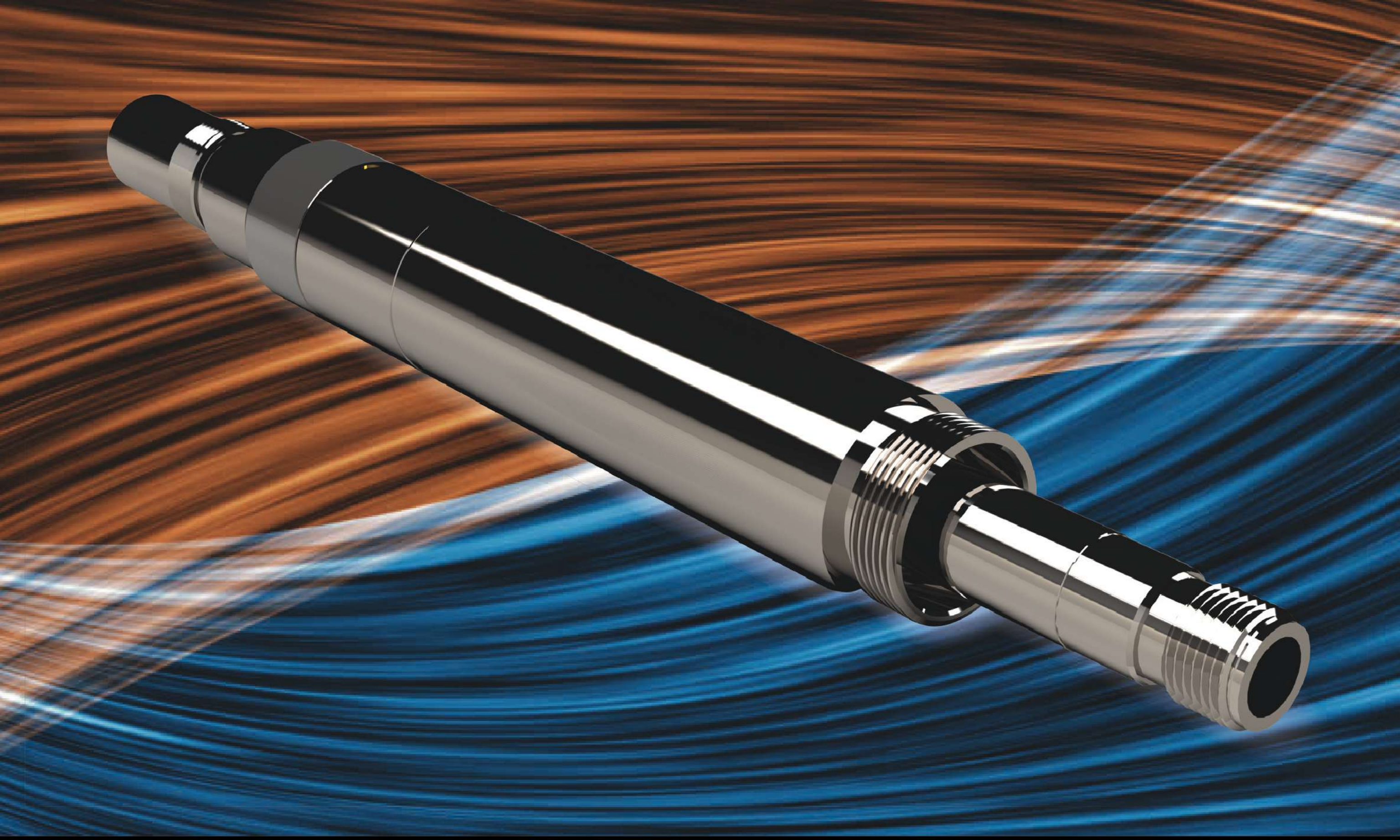
In more recent cases, likely due to the advancements in bit technology, Magnum Canada has seen success with drillouts that utilize a tri-cone bit. In May 2017 Magnum Canada was on a 37 Long Range plug drillout. The depths of the 3.75-in. OD Long Range Generation Two plugs ranged from 2,999 m (9,842 ft) to 5,499 m (18,044 ft) of MD in 5.5-in. 26-lb/ft casing.

The casing ID was 4.548 in. and had a 3.996-in. ID liner. The liner was set at 718 m (2,357 ft) and was 6 m (20 ft) long. The first 13 plugs were milled out with a five-blade reverse clutch junk mill and averaged 68 minutes per plug. The mill was pulled out of the hole and replaced with a 3.976-in. OD tri-cone bit. The remaining 24 plugs were drilled out with an average time of 28 minutes per plug.

In addition to reducing the average drill-out time per plug, the Long Range Generation Two plug has been run in challenging wellbores. With sizes ranging from a 3.06-in. to 3.92-in. OD, the plug successfully holds at 10,000 psi and 148 C (300 F).

In the spring of 2016, an operator in the Rocky Mountains was having an issue with a completions system that required casing restrictions that were pre-installed with the casing. Rather than rerun casing, the operator called on Magnum to run 153 Long Range Generation Two plugs in the 3.06-in. OD size. The operator was able to salvage its completions and simultaneously create more options for stage spacing. All plugs were run through the aforementioned casing restrictions with no issue.

The E&P sector continues to be driven by engineering, specifically within completions departments. With that, the applications for solid expandable liners and casing patches will continue to become more creative and cost effective. Wells that were once left to be plugged and abandoned are regularly completed to their full potential because of this technology and ingenuity of the end users. Advancements in zonal isolation are no different. E&P



Establishing KPIs to monitor well control events

Determining indicators can help avoid downtime and event severity.

Richard Leturno, Wild Well Control

Well control incidents can involve a highly complex series of events leading up to a prolonged period of nonproductive time. To limit the duration of downtime, operators strive to continuously improve the ability to identify uncontrolled flows, along with their causes, well before they occur.

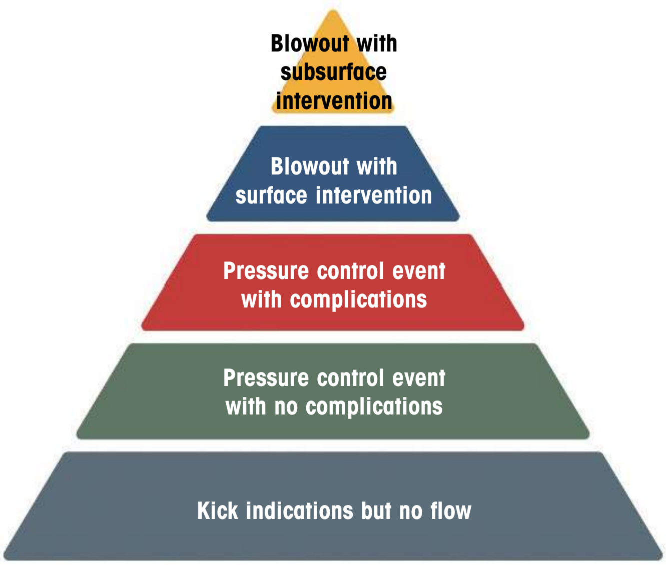
No single key performance indicator (KPI) provides the clarity for measuring and monitoring well control events. Instead, due to the intricate nature of well control events, a KPI set allows a better recognition of their multidimensional complexity. Determining these factors establishes boundaries that can be used to categorize, classify and develop a deeper understanding of well control incidents.

Well control KPIs

What are the most important well control KPIs? The answer varies with each individual using the data and their role in organization. The C-level executives' focus might be more strategic than the operations engineers who would likely be focused on tactical metrics.

For senior management, the most important well control KPIs might be frequency, duration and severity/intensity. These will need to be built to specifically address the organization's well portfolio. Under each of these high-level KPIs, there will be several lower-level KPIs that can be used to further develop the understanding and target specific preventative actions. For the operations personnel, there can be a wide range of KPIs, which may be leading indicators, while most will be lagging indicators.

When discussing well control event severity, one approach is to develop a well control event hierarchy similar to what the HSE industry has constructed. For this to be meaningful there would need to be a significant dataset and accurate reporting.



A well control event hierarchy helps determine which KPIs are the most important. (Source: Wild Well Control)

KPI management

It is important to set up a process to effectively track and manage the defined KPI set to yield continuous improvements. This requires a common understanding and clear focus across the organization.

After identifying and establishing the specific KPI set, a system must be put into place to measure and track the data. It is important that all data be incorporated. All incidents must be included. Repeat incidents in the same formation, outliers and special circumstances can be footnoted but must be included for consistency. Having additional data will allow several different perspectives to be examined, including

- Onshore versus offshore;
- Geographic areas or fields;
- Rig contractors;
- Hole sections;
- Specific formations;
- Activity when kick occurred;
- Time when kick occurred; and
- Cause of underbalance.

As the dataset develops, the findings should be incorporated into the basis of design, detailed well design process and lessons learned. Additionally, during the well construction phase, these data will be useful for fingerprinting problematic zones.

Depending on the activity level, periodic reviews should be held to examine the data and trends. This will highlight key areas of concern and identify specific actions that can be taken to positively influence the operations.

Influencing KPI frequency

Once an event has occurred, focus turns from prevention to resolution. Therefore to impact well control frequency, the team must take a proactive stance.

Drilling and completion phase. There are several components that should be considered to implement a successful well control plan. These components include well design and personnel competence.

A robust design is the first layer of defense to prevent a well control event. Typically, during the design stage, a pore pressure and fracture gradient plot is first developed and then used as the basis for selecting casing points and drilling parameters. For each section, the kick tolerance, maximum allowable annulus surface pressure and other design criteria must be determined to validate the design. In some areas, it may be appropriate to investigate shallow broaching to validate the well's integrity.

A risk assessment should be conducted. The depth of investigation should be commensurate with the complexity of the well and the overall project. This should address, but not be limited to, known hazards, well control, equipment, personnel competencies, well life-cycle issues, simultaneous operations and emergency situations.

Prior to operations commencement, an exercise may be conducted to drill the well on paper. This is typically done with all internal and external stakeholders to review the well construction and ensure alignment on the path forward. During the completion phase, an exercise to complete the well on paper might also be conducted.

Once the well is spudded and well construction begins, the human factor and personnel competence at the wellsite become key. This concern can be compounded if the entire rig site team does not have an established working relationship, communications plan and understanding of others' capabilities built over time. Providing key personnel with industry well control certification training prepares the personnel to identify a well control kick and provides a methodology to shut in the well in a timely fashion.

Production phase. Key components that can impact well control frequency during the production phase of a well's life cycle include completion design with regard to barrier envelopes and equipment condition.

The final completion design will define the barrier envelope and elements. This will also allow review of potential leak paths that might ultimately manifest themselves in pressure on one of the annuli. In the event the well has known or questionable zonal isolation, the chance for sustained casing pressure will be increased.

Many of the well control events involving producing wells are related to concerns over equipment conditions. These can be downhole conditions related to corrosion, erosion and wear on oil country tubular goods, or surface wellhead and tree components conditions related also to corrosion or maintenance practices. These conditions combined with sustained casing pressure issues can result in lowering a well's maximum allowable working pressure. Periodic wellhead surveys identify potential problems that typically can be addressed in a programmed fashion while downhole surveillance programs provide data about downhole conditions.

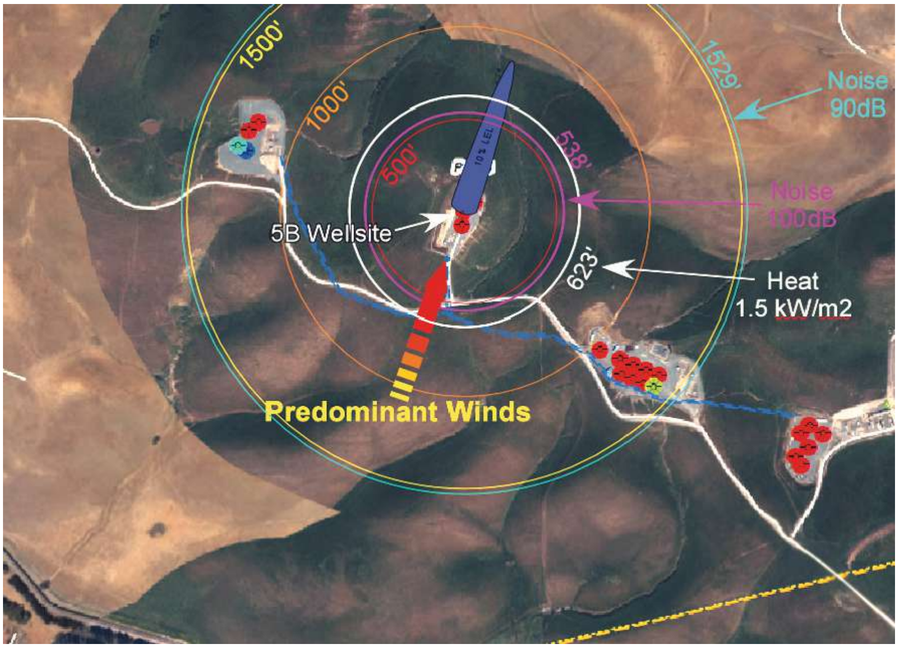
Influencing KPI duration

Once an event has occurred, primary focus is to regain control of the well as quickly and safely as possible and return to normal operations. During the drilling, completion and intervention phases, there are several factors that can influence the event's duration. These include emergency preparedness; location design; well control equipment design, sizing and layout; initial shut-in; and well control procedures.

Emergency preparedness. As an event escalates, the initial actions of everyone are driven by the company-specific well control emergency response plan. For deepwater operations, a source control emergency response plan may be developed. This document outlines the actions to be taken by the person in charge and the key team members. The plan details the roles and responsibilities that allow the team to proceed in a logical and coordinated matter. It is vital that all personnel are familiar with this document and have participated in drills to understand their role.

For some operations the emergency preparedness might also include relief well contingency plans. These plans review and investigate all areas of the relief well operations from site selection, equipment requirements, drilling, intercept and kill plan. Depending on the well's projected blowout rates, two relief wells may be required. These plans allow the operator to move quickly with a general plan in hand as they develop well specifics for the incident.

Location design. If the well control event has escalated beyond normal well control practices, and cold, warm and hot work zones have been established, well access can be a determining factor. For land wells, this may be impacted by well density, cellar design, location and equipment layout, and the proximity to



Location design uncertainty can be addressed during planning phases with the latest modeling technology. (Source: Wild Well Control)

other structures. With respect to location access on land operations, the number and condition of access roads must be reviewed along with land use, bridge and tunnel restrictions. It is not uncommon to find a site with a single usable road entering the location. This, coupled with restrictions on clearing additional land for equipment lay-down/assembly, extends the response time. For offshore locations, the entire logistical chain needs to be considered, including staging areas, shore bases, aviation and marine support.

Well control equipment design, sizing and layout. It is important to ensure the well control equipment is evaluated and determined to be fit for purpose. Once the well's design is known and the anticipated pressure, temperature, hydrocarbon types, H_2S percentage and other aspects are determined, the equipment can be properly evaluated. This should include pressure rating, elastomer type, lines sizing, accumulators, mud gas separators and flare stacks.

Initial shut-in. The first action taken in a well control event will be kick/flow identification and shutting in the well. Early detection and immediate action will result in a smaller kick volume. This responsibility is shared by the drilling crew, mud loggers and others who are actively monitoring the well. These activities are addressed in the International Association of Drilling Contractors/International Well Control Forum well control training completed by personnel individually but are critical when on the job working as a team. Kick drills should be performed with crews until they demonstrate competence. Thereafter, the drill frequency is typically reduced to regular intervals that meet operator and regulatory requirements. It might also be beneficial to have a third party or impartial observer conduct kick drills to identify areas for improvement.

Well control procedures. Once the well is shut in, the actions taken by the onsite team during the well kill operations can impact the event duration. For example, if a constant bottomhole pressure is not maintained, there is a likelihood that a second influx can enter the wellbore, extending and complicating the kill operations or creating an underground blowout. This can be addressed through continued training or, in some cases, having a well control specialist onsite to assist with pressure control.

Influencing KPI intensity/severity

As previously noted, the larger the kick, the more complex the operations to regain hydrostatic control of the well. This can be further complicated when a kick is masked by other factors such as gas in oil-based mud. Multiple influxes also will lead to longer event resolution.

If there is hydrocarbon released from the well, the severity of the incident has significantly elevated. Radiant heat modeling can be used to determine the heat at the wellbore and as it emanates outward. This can be used to help establish zones to protect personnel and equipment, particularly nearby wells on a pad or platform. Dispersion modeling is used to understand how a gas cloud will travel out from the well. This can be used to better understand the dispersion of vapor levels lower explosive limit, poisonous gas such as H_2S and where safe zones need to be placed. If the location is near a populated area, it will provide information that may indicate when evacuations need to be considered.

Considered as a secondary well control, it is critical that all components of the well control equipment are maintained and installed to operate as designed and within their operational limits. Surveys of this equipment help ensure its readiness and can give insights into the specific rig's planned maintenance program. E&P

Deepwater production advances

A fresh take on production systems introduces expanded capabilities and new applications.

Judy Murray, Senior Contributing Editor, Offshore

A low oil- and gas-price environment encourages efficiencies. Spurred by the need to deliver more value at a lower cost, designers of deepwater production systems are examining ways to modify current designs and existing assets. The goal is to create systems with a broader range of capabilities and applications in a bid to provide units that offer unique value.

Increased activity in the fixed and floating systems sector has given operators enough confidence to move forward with programs that have been tabled for the last couple of years. January 2017 saw the first signs of resurgence, with the oil price hitting $55 for the first time in 18 months. The price stayed above $50 for the first quarter, and as the industry turned the page to 2018, things still appeared to be improving. Brent crude futures held above $70/bbl and West Texas Intermediate crude futures were at $66.24/bbl at the end of January, achieving a level analysts say has resulted in the strongest oil price in five years.

Across the board, analysts and investors are predicting a resurgence in deep water. And that means the time is ripe for reevaluating some of the novel concepts designed for deepwater production and examining some new ideas that are in development.

Something old, something new

Several of the production units that are preparing to go to work now are moving out of the inactive fleet. One of these is the *BW Adolo* FPSO vessel, which will work on the BW Energy-operated Dussafu project offshore Gabon following modifications at the Keppel FELS shipyard.

The interesting thing about the *BW Adolo* is that it began life as a very large crude carrier (VLCC) called *Fina Europe*, which was built in the Hyundai Heavy Industries (HHI) yard in South Korea in 1988. The VLCC went through several names over the ensuing years, eventually being converted and renamed yet again in 2009 to become the *Azurite*, the first floating, drilling, production, storage and offloading (FDPSO) unit in the world.

The vessel made history when it began production on the Murphy West Africa Ltd. Azurite deepwater field in the Mer Profonde Sud Block offshore Republic of Congo. With a storage capacity of 1.3 MMbbl of oil and processing capacity of 40 Mbbl/d, its unique design allowed it to be used for drilling and completing production and injection wells.

Unfortunately, Murphy shut down the Azurite Field in fourth-quarter 2013 and abandoned it the following year, which left the FDPSO unit without a contract. It has not had a contract since that time.

Making its most recent debut as the newly updated and renamed *BW Adolo*, the vessel, now an FPSO unit, is going back to work. Following modifications at

Industry needs are advancing, and topsides size and weight are increasing. This 3-D rendering illustrates the past, present and future (top to bottom) using the F4W hull, showing second-generation topsides (past), third-generation topsides similar to those on Brazil presalt FPSO units in operation now by SBM (present) and heavier fourth-generation topsides anticipated in the coming years (future). (Source: SBM Offshore)

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the Keppel yard in Singapore, the vessel features large riser and storage capacity, excess processing and heating capacity and large accommodations and deck space for future field expansion. The newly modified FPSO unit will soon begin production on the Dussafu Field, which, though not a deepwater development, will be produced using this deepwater production system. First oil is planned for second-half 2018.

First to float LNG

Another of the assets entering service is Golar LNG's *Hilli Episeyo*. Golar was a first mover in the floating LNG (FLNG) space, building the world's first converted FLNG unit using the Moss LNG carrier, *Hilli*, originally built in 1975. The conversion was carried out by Keppel FELS in Singapore.

While the vessel was still in the Keppel yard, it was part of another first as the recipient of the first commercial LNG bunker transfer in Singapore when FueLNG, a Keppel FELS/Shell Eastern Petroleum Pte Ltd. joint venture, completed truck-to-ship bunkering for the vessel.

In late 2017 Golar reported that conversion and precommissioning work on the vessel were complete. The FPSO unit left Singapore in mid-October and arrived in Cameroon toward the end of November, where it will begin work on the Kribi Field for Société Nationale des Hydrocarbures and Perenco Cameroon.

Innovative concepts

In addition to units about to take the field, concepts are on the design table. R&D efforts are delivering more technologies with the potential to improve drilling and production, and more designs are targeting greater efficiencies.

One of the ways designers move novel ideas from concepts to the field is by getting third-party approval from classification societies. Class societies provide a third-party assessment of the design and award Approval in Principle (AIP) for those that are deemed feasible—defined as having no significant obstacles that would prevent the concept from being realized. Normally, this assessment takes place in the early stages of a project to confirm feasibility for the project team, company management and regulators. Recently, a number of AIPs were granted for designs that introduce some impressive new capabilities and efficiencies.

Last year HHI was awarded AIP for an FLNG design that the company said can be constructed for about half the cost of a standard FLNG hull. The design introduces a vessel with a length of 320 m (1,050 ft), a breadth of 60 m (197 ft) and a 12-m (39-ft) draft with LNG storage capacity of 200 Mcm (7 MMcf) using the GTT MARK III membrane technology. According to HHI, the near-shore FLNG hull concept design delivers an estimated one-third cost reduction compared to a standard FLNG hull.

HHI applied the same thinking to a newbuild conversion FPSO hull concept that was awarded AIP in January 2018. The company's *Newbuilding Conversion* FPSO hull also introduces economies, according to HHI. The company said the hull can be built for about half the cost of a conventional FPSO hull. The unit, which features structural reinforcement for topside structure installation, has a barge-shaped hull and is intended to store 2 MMbbl of oil.

Late in December 2017, Dalian Shipbuilding Industry Co. was awarded AIP for its *DSTLP500* deepwater tension-leg platform. The unit, which features four pontoons, four columns and eight tendons, is designed to work in 500 m (1,600 ft) water depth, primarily in the South China Sea.

Fast, flexible construction

Meanwhile SBM Offshore is moving forward with what it calls the Fast4Ward (F4W) hull concept, motivated by the belief that reduced complexity and shorter schedules are the key to achieving better safety and economics. The company, which has been developing F4W since 2014, introduced the concept in August 2017 as a faster, cheaper and safer way to reach first oil. The design focuses on standardization, modularization and flexibility. The intent is to deliver what SBM calls maximum interchangeability.

F4W is based on a generic hull designed such that it is ready to receive and integrate topsides modules and a mooring system. It has large capacity storage, deck space to accommodate complex topsides and construction that requires a single quay. According to SBM, a unit can be completed six to 12 months faster than the typical three-year schedule for a third-generation FPSO unit and at a lower cost.

In June 2017 the company signed a contract for the first standard newbuild, multipurpose hull with China Shipbuilding Trading Co. and the Shanghai Waigaoqiao Shipbuilding shipyard.

Challenges bring opportunities

While the oil and gas industry has struggled through an extended downturn, many companies have looked for ways to deliver new designs that deliver economies and capabilities to sustain oil and gas E&P. Innovative thinking has led to designs that could significantly impact economics, and even more inspired designs are still on the drawing board. E&P

Risk brings rewards

Statoil's Aasta Hansteen development put a range of technologies to work for the first time, illustrating the vital role innovation plays in breaking new ground offshore.

Judy Murray, Senior Contributing Editor, Offshore

The Aasta Hansteen Field was named after a Norwegian painter, writer and early feminist, who lived in the late 19th and early 20th centuries. She was a pioneer and trailblazer, much like the eponymous production system, which, when it comes onstream later this year, will be the first spar to work offshore Norway.

When the *Aasta Hansteen* spar begins production, it will be the largest producing spar platform in the world.

The Aasta Hansteen development, which lies in the Norwegian Sea approximately 300 km (185 miles) offshore in 1,300 m (4,265 ft) water depth, comprises three gas discoveries—Luva, Haklang and Snefrid South—with combined recoverable reserves estimated at 47 Bcm (1.7 Tcf). Field operator Statoil made the decision to develop the field six years ago, submitting its development plan to the Norwegian Ministry of Petroleum and Energy in December 2012 outlining the scheme that would employ a spar for the first time in Norwegian waters. The ministry granted approval in June 2013, and work immediately got underway.

From concept to construction

Statoil awarded the contract for engineering, procurement, construction and transportation of the hull and mooring systems to a TechnipFMC and Hyundai Heavy Industries (HHI) consortium. Unlike the majority of spars, which were designed for Gulf of Mexico conditions, the *Aasta Hansteen* spar design had to accommodate more extreme environments and have significantly higher structural fatigue resistance. This was the first time a spar hull was designed and built to NORSOK and other Norwegian requirements. The platform had to be built to survive 10,000-year storm conditions and to be operational in 100-year storms.

The new design also includes an elevator in the moonpool access shaft, 25 Mcm (883 Mcf) of storage for condensate and an offloading system, which places the *Aasta Hansteen* spar as the first to function as an FPSO vessel. The space requirement for storage combined with the 24,000-ton topside makes the *Aasta Hansteen* platform the world's largest truss spar hull at

The *Dockwise Vanguard* transports the *Aasta Hansteen* spar from HHI in Ulsan, South Korea, to Ølensvåg, Norway. (Photo by Eva Sleire, courtesy of Statoil)

200 m long (656 ft) and 50 m (164 ft) in diameter, with total displacement of 146,000 mt.

The field development layout comprises a spar platform and two subsea templates with eight well slots. EMAS AMC was awarded the contract to transport and install the two four-slot subsea templates and one single-slot template on the field, all of which were shipped from Aker Solutions' facility in Sandnessjøen, Norway, on EMAS' *Boa Sub C* construction vessel. Another first was achieved with the subsea template installation, which is the deepest on the Norwegian Continental Shelf (NCS).

The subsea templates are tied back to the spar platform through pipelines and steel catenary risers (SCRs). Made feasible by the stable motions of the spar, SCRs are being used for the first time offshore Norway.

Subea 7 was awarded a contract for procurement, fabrication and installation of 18 km (11 miles) of 12-in. mechanically lined pipe flowlines and four SCR systems. Three 2-km-long (1.2-mile) SCRs connect three subsea templates to the spar, with another 2-km-long SCR exporting to the export pipeline system.

The spar hull will be moored onsite using a taut mooring system comprising 17 polyester lines made of Gama 98 polyester supplied by Lankhorst Ropes. The mooring lines are in three clusters—two made up of six lines each and a third with five lines. In yet another first, the lines are being wet stored on the seabed and will be attached to the hull when it arrives on the field.

While the site was being prepared, construction of the spar and topsides was proceeding at the HHI yard

in Ulsan, South Korea. Large segments of the spar were constructed on the site in modules that were subsequently lifted as "mega blocks" and mated quayside to the horizontal spar structure using a 10,000-mt crane in an advanced heavy-lift operation that achieved precise mating in five mega-lifts. This was the first time HHI had executed lifting and placement of a mega block of this size.

Moving a mega structure

With the hull and topsides completed, the next challenge was to convey them from Korea to Norway, a distance of 14,500 nautical miles, equivalent to nearly 26,900 km (16,715 miles).

The spar hull made the journey aboard the world's largest heavy transport vessel, *Dockwise Vanguard*, owned by Boskalis subsidiary Dockwise. The vessel measures 275 m long (900 ft) and 79 m wide (260 ft) and can carry cargo up to 110,000 mt. When the hull arrived in Norway in June 2017, it was floated off the transport vessel and towed to Klosterfjord, where it was upended and anchored, awaiting the arrival of the topsides.

The platform deck, weighing 24,000 mt, followed the hull to Norway, making the trip aboard the Dockwise *White Marlin*, the newest and second largest vessel in the company's fleet. When the topsides arrived at the end of November, it was transferred from the *White Marlin* to two S-class vessels, which are the smallest in the Dockwise fleet. These units worked as a sort of catamaran, with the topsides balancing across the two hulls as the vessels moved the unit to the hull, where the two massive components were mated. With construction finished, the spar is ready to be moved to the Vøring area of the Norwegian Sea to begin production.

The *Aasta Hansteen* topside is balanced across the hulls of two S-class vessels as it is mated to the spar offshore Norway. (Photo by Espen Rønnevik/Worldcam, courtesy of Statoil)

First production from Aasta Hansteen is scheduled for September 2018.

Moving gas to shore

Completed in September 2015, the 480-km (300-mile) Polarled pipeline connects the Aasta Hansteen development to a processing facility on the Nyhamna peninsula, originally constructed to process gas from the Ormen Lange Field, which produces 70 Mcm/d (2.4 Bcf/d) of natural gas. Nyhamna is one of Northern Europe's largest gas terminals and is getting bigger, having received sanctioning from the Norwegian Petroleum Directorate in February 2017 for expansion. Greater capacity—80 Mcm/d (2.8 Bcf/d)—will allow additional volumes from currently producing fields like Ormen Lange and from future discoveries, which can be tied into Polarled via the six connection points installed along the line.

Embracing innovation

The number of technology advances that were part of the Aasta Hansteen development is impressive. They illustrate how enabling new technologies pushes the boundaries of what is technically possible and changes the status quo. The technologies proven on this development will be the foundation on which the industry builds forward. Projects like this that focus on investing in ideas with the potential to extend capabilities and improve operations will continue to transform the oil and gas industry. E&P

Aasta Hansteen firsts

- Largest spar in the world
- First spar offshore Norway
- First spar with condensate storage
- First use of SCRs offshore Norway
- First synthetic rope mooring offshore Norway
- First time a lift and placement of a mega block of this size were executed at the HHI yard
- First use of mechanically lined pipe installed using reel-lay offshore Norway
- First pipeline on the NCS that crosses the Arctic Circle
- Deepest pipeline on the NCS, reaching 1,260 m (4,100 ft) at the Aasta Hansteen Field
- First time a 36-in. diameter pipe has been laid at this depth

Also noteworthy are the roles vessels played in the Aasta Hansteen development. The *Dockwise Vanguard*, the largest heavy transport vessel in the world, carried the spar hull 26,900 km from Korea to Norway, while the *White Marlin*, the second largest heavy transport vessel in the fleet, moved the topsides. The Allseas pipelayer *Solitaire*, one of the largest vessels of its type in the world, laid the Polarled pipeline, which connects the Aasta Hansteen Field to facilities at Nyhamna 480 km (300 miles) away. ■

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New tubing anchor frees up downhole space

The cone/slip shape design enables the use of more capillary lines and monitoring cables downhole.

Jennifer Presley, Executive Editor

The downhole environment of an oil and gas well is highly dynamic and cramped. Unable to physically see and measure in person what is happening downhole, the petroleum industry must rely on the next best thing: digital technologies.

The push for more and better data is dependent on the space made available for the sensors to measure, record and transmit without impeding the flow of oil and gas. As wells become increasingly more complex, more space downhole is needed to accommodate that digital footprint.

After learning of the need for more space around the tubing anchors from a client attending a tradeshow, the designers at D&L Oil Tools began development on what would become the company's line of Trilobite Anchor tools.

The Trilobite product name was inspired by the combination of "tri" for the three slips, "lob" for it being a lobe tool and "bite" for it being a way for things to bypass as well as the tool's literal bite, which keeps it in place, according to Heath Bringham (pictured), the original developer of the tool. (Source: D&L Oil Tools)

Slim design

Officially released in late 2017, the patent-pending design of the anchors features three heat-treated steel alloy slips to maximize holding in tension and compression. The spacing of the anchor components creates additional space to allow increased annular flow and capillary tube bypassing without compromising a 5½-in.-by-2⅞-in. tubing size.

"With a slimline bypass style design, we were able to eliminate extra material while making the slips a little bit bigger than the rest of the tool body," said Heath Bringham, senior sales engineer for D&L Oil Tools and original designer of the tool. "The body is no bigger than the tubing couplings that run up to the surface of the well."

The area around the tool has been maximized to accommodate the need to run multiple capillary lines or monitoring cables past the tubing couplings while also providing space for gas/debris bypass around the slips.

"We have customers who make downhole gauges that require a quarter-inch or smaller fiber-optic or electrical cable be run alongside the tool for operation," he said. "With our anchor tool, there is plenty of space to run one or multiple cables. We recommend anything up to ⅜ in. or smaller diameter line. You can place them right along the outside of the tool between the slips, and the line will be protected and not take up any extra room."

He noted the added space also is beneficial to production in that gas in the well is able to rise naturally beyond the anchor, allowing downhole pumps to work efficiently.

"The unique thing about our tool is that not only does it have that maximum reduction on the outside diameter [OD] of the tool," Bringham said, "we were able to keep the maximum inner diameter [ID] through it as well. In 5½-in. casing, a 2⅞-in. tubing connection with a 2.44-in. ID is known as a big bore tool. Most operators aren't really looking for much bigger than that.

"Not only do they have the area for gas to rise and to run whatever they want along the outside of the tool, they also can run larger pumps down through their tubing because the Trilobite tool has a fullbore ID. Most tools that have an OD reduction like the Trilobite tool require smaller ID tubing through the tool to accommodate that reduction," he said.

Another feature of the anchor tool is that it also serves as "catcher," Bringham said.

"If part of the tubing happens to part, the tool prevents the tubing from dropping to the bottom of the well," he said.

Hydraulic or mechanical?

There are two tool-activation options. One is the Trilobite Hydro Anchor that is hydraulically set. Pressuring up the plugged tubing activates internal hydraulics to actuate and set the slips into the casing. Releasing the slip is accomplished by pulling the tool straight up, according to Bringham. The anchor is available for 5½-in. and 7-in. casing sizes.

The other option is the Trilobite Quarter Turn Anchor that is mechanically set from the surface.

"With it, the slips are set by manipulating the tubing at the surface," he said. "A quarter turn to the right sets the slips and another quarter turn to the right releases them."

The mechanical anchor is available for 5½-in. casing. The company is in the process of filling out the product line with additional sizes of tools.

"We started with those sizes initially to help familiarize people with the tool and to start using it," he said. "We are working on tools in sizes of 4½ in.-by-2⅜ in., 7 in.-by-2⅞ in., and 7 in.-by-3½ in. in both product lines that we hope to roll out in 2018."

The decision to use one versus the other depends on an operator's preference and well design.

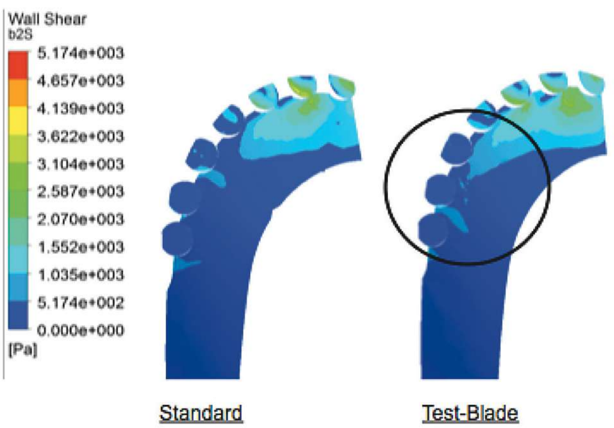
"It is hard to make a one-size-fits-all kind of tool," Bringham said. "We had a design that lent itself well to both styles so we made both to accommodate our customers."

The Trilobite Hydro and Trilobite Quarter Turn Anchor designs were filed with the U.S. Provisional Patent Office in June 2017 and will undergo a full patent process this year. E&P

Have a story idea for Tech Watch? This feature highlights leading-edge technology that has the potential to eventually address real-life upstream challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

New system addresses challenges of bit balling

Varel Oil & Gas Drill Bits' HYDRA hydraulics optimization system is designed to improve ROP and footage in softer clays and shales using a blend of curved nozzles and straight blades with webbed features. Compared to conventional bits with straight nozzles, and curved, open blade designs, the bits achieve better cooling and cleaning without placing new demands on rig hydraulics, according to the company. Bits based on the HYDRA system have turned in impressive results in a wide range of traditionally sticky formations, Varel reported. In interbedded clays in New Mexico, where polycrystalline-diamond-compact penetration rates typically suffer, HYDRA-optimized bits have increased ROP to 40 m/hr (133 ft/hr) versus a 32 m/hr (106 ft/hr) average for offsets, resulting in the operators' fastest one-bottomhole assembly run to total depth. Drilling the Permian Basin's Wolfcamp, HYDRA optimization cut the number of bits in half with just two Varel bits required to drill a lateral section, resulting in 8% more footage at an 8.5% higher ROP. In another Wolfcamp well, a single bit drilled a total 2,354 m (7,724 ft) in 65.75 hours at 36 m/hr (117.5 ft/hr) for a 58% increase in ROP and a 96% increase in footage drilled. *varelintl.com*



Shear stress modeled in light blue reaches more of the HYDRA optimized blade to enhance cleaning and cooling. (Source: Varel International)

Platform enables real-time drilling optimization in challenging applications

National Oilwell Varco (NOV) has introduced the iSeries NXT platform to its portfolio of Tolteq MWD/LWD directional systems and tools. The NXT platform enhances the function of the iSeries platform with improved capabilities that support additional measurement types, enabling real-time drilling optimization in challenging applications, according to the company. Legacy compatible, the NXT platform is available with a directional module that provides inclination and azimuth information together with increased directional measurement accuracy, a top-mounted pulser that increases data transmission speeds while increasing shock and vibration resistance, and a pressure-while-drilling sensor that complements the top-mounted pulser to enable real-time annular and internal bore pressure measurements while drilling. *nov.com*

NOV's new Tolteq iSeries NXT platform delivers expanded measurement capabilities and high-speed data transmission, which are critical in today's performance drilling applications. (Source: NOV)

System captures EM signals rapidly in a range of pipe materials

TGT Oilfield Services successfully validated its electromagnetic (EM) EmPulse well inspection system in high chromium tubulars, a press release stated. In three Middle East deployments—one an operator-witnessed "yard test" and the other in two live wells—TGT engineers demonstrated that the EmPulse system can quantitatively determine the individual tubular thickness of up to four concentric barriers, even when there are high amounts of chrome in the tubulars. The increase in chrome and the resulting decrease in ferrous content causes EM signals to decay too quickly for ordinary EM inspection systems. Designed and manufactured completely in-house by TGT scientists and engineers, the EmPulse system combines ultrafast sensor technology with "time-domain" measurement techniques to capture EM signals rapidly and accurately in a wide range of pipe materials, including those with high chrome content. This enables operators to evaluate pipe thickness and metal loss in multiple casing strings simultaneously, ensuring long-term well performance even in the most challenging production environments. *tgtoil.com*

New design improves cuttings evacuation from PDC bit

Drillbits designed with standard hydraulics can accumulate cuttings, balling up locally around the cutters and

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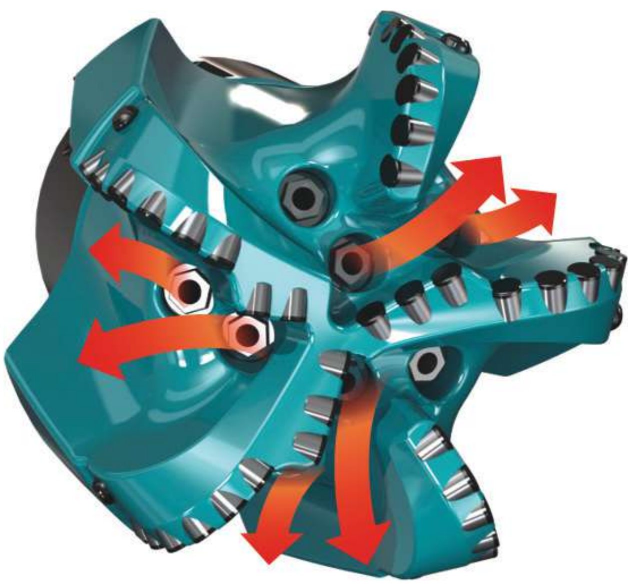

The SplitBlade design provides more area for cuttings evacuation. (Source: Ulterra)

Packer enables multizone production

Zonal isolation is a challenge in openhole completions, and swell packers can take days to set. Schlumberger's OptiPac service mechanical packer (OSMP) overcomes this problem with a mechanically activated, hydrostatic-set-on-demand feature, enabling users to achieve zonal isolation in openhole, conventional or extended-reach gravel-pack wells, a company announcement stated. A customer in Angola saved $160 million using the OSMP to access multiple reservoirs with a single well using zonal isolation instead of drilling a well for each reservoir. *slb.com*

Access live ship management, track data via web-based tool

ChartCo's FleetManager enables shore-based customers to access live ship management and tracking data. (Source: ChartCo)

ChartCo, a global supplier of maritime digital data and compliance services, has released its new easy-to-use FleetManager software, a press release stated. As a web-based tool, FleetManager enables shore-based customers to access live ship management and tracking data in one place at any time and on any popular browser as well as via smartphones and tablets. FleetManager offers a range of highly effective environmental, piracy and regulatory overlays that can highlight potential sources of delay or hazard. It also provides the ability to link with ChartCo's e-navigation platform PassageManager. This enables shore-based staff to view an active passage plan so that any deviations from the expected track can be interrogated in real time. FleetManager helps managers ensure fleet compliance with the ability to inspect any vessel remotely and to view and instantly audit its navigation and compliance status. Managers can check software versions installed, connection history and data download volumes. They also can authorize, approve or reject electronic and paper chart and publication orders placed through PassageManager. *chartco.com*

Fall detection from offshore rigs

SecuraTrac has released the Mobile Defender-Model S (MD-S), a mobile personal emergency response pendant equipped with location technologies and a built-in fall advisory capability, according to a product annoucement. The pendant can detect horizontal and vertical movement and can be used to detect trips or falls from equipment on offshore rigs with cellular signal. The MD-S can trigger a call for help automatically or an SOS button on the pendant can be used. Wake-on SOS gives the device the ability to last over 30 days on a single charge. SecuraTrac devices work in more than 120 countries across North and South America, Europe, Asia, Africa, the Middle East and Australia, and are compatible with every major U.S. cellular service provider in addition to foreign carriers. *securatrac.com/products*

The MD-S provides global GPS services and is able to withstand extreme conditions and uses. (Source: SecuraTrac)

Technology eliminates requirement for heavy-lift installation vessels

Capitalizing on their strategic alliance agreement announced last year, Trelleborg's offshore operation and Safe Marine Transfer LLC (SMT) are working to develop a technology for the offshore installation and subsea operation arena, a press release stated. With U.S. patents issued and additional ones pending, the new technology enables subsea deployment of equipment and chemical storage using SMT's Subsea Shuttle powered via jointly developed Pumpable Buoyancy technology. To continue to move this project forward, SMT, under contract with a major international oil company, has completed Subsea Shuttle design testing and validation of performance at Seanic Ocean Systems' onshore test tank facility in Katy, Texas. The scale model performed as predicted from computational fluid dynamics and dynamic simulation studies. Successful model tests of the Subsea Shuttle design performed with static buoyancy to lay the foundation for qualification of dynamically adjustable Pumpable Buoyancy. *trelleborg.com/offshore*

New tools for 3-D fracture modeling

FracGeo has released StimPredictor, a desktop module of its FracPredictor software platform, and GMXFrac, a cloud-based web service for real-time optimization of perforation and fracture treatment design of unconventional and tight reservoir wells that adapts to the lithologic and stress variability using surface drilling data, a press release stated. StimPredictor represents the next generation in fracture design and analysis software, deploying novel complex physics able to account for current operational realities combined with advanced algorithms for real-time results. StimPredictor captures the actual geologic and geomechanical data along each studied well by leveraging commonly available surface drilling data instead of constant properties from pilot or nearby wells. *fracgeo.com*

New 2-D flow visualization technology

NEL, a flow measurement R&D specialist, has the first laboratory in the world to invest in 2-D flow visualization technology, a press release stated. The new technology uses 2-D X-ray tomography to produce high-definition images of complex multiphase flows, which cannot be captured with conventional instruments. This more precise reproduction of flow patterns will optimize meter design against specific operating conditions, ensuring greater measurement accuracy, reducing uncertainty and minimizing operators' financial exposure. Dr. Bruno Pinguet, multiphase domain senior adviser at NEL, said, "This new technology will allow us to look in unprecedented detail at meter performance versus flow dynamic structures. This will help us to advance our understanding of how complex multiphase fluids behave, so that the quality of factory acceptance testing for multiphase meters will improve significantly." NEL's system is designed primarily for measuring multiphase flows in horizontal and vertical pipes and will be capable of determining the 2-D phase fractions within a multiphase pipe flow in real time. It also offers extremely high-frequency data capture of over 150 frames per second, delivering detailed tomographic reproduction of the cross-sectional phase distribution (oil, gas, water) within the flow regime. *tuvnel.com* E&P

Please submit your company's updates related to new technology products and services to Ariana Benavidez at abenavidez@hartenergy.com.

The Oil Industry's 2018 IOR Challenge: Cutting Costs, Producing More

The oil industry's resurgence has operating and service/supply companies laser-focused on containing costs. Revolutionary breakthroughs in IOR technologies—hydraulic fracturing and horizontal drilling—have unleashed vast new supplies of oil and gas that have transformed and even overwhelmed existing markets. Companies that survive and thrive while transitioning from boom to a lower-for-longer commodity price environment must now become laser-focused on cost-effective IOR and EOR in today's dominant unconventional plays.

Challenges include:

- Optimizing batch drilling of horizontal wells from pads.
- Minimizing water handling/treating/disposal/reuse costs.
- New frontiers in fracture delineation and rock physics.
- Well placement demands at an unprecedented level of precision.
- Understanding basic flow characteristics in unconventional reservoirs.
- Identifying the most cost-effective EOR processes to deploy in tight oil and gas plays.
- Determining if climate change push helps prospects for CO_2 EOR/sequestration.

Get answers to these questions and learn even more about all the cutting-edge IOR and EOR technologies at the 21st Improved Oil Recovery Conference, April 14–18, 2016, in downtown Tulsa, Okla. Sponsored by the Mid-Continent Section of SPE since 1978, this biennial conference of the world's leading experts in improved oil recovery and enhanced oil recovery is the largest gathering of its kind anywhere in the world.

IOR 2018 HIGHLIGHTS

Technical Program	Other IOR 2018 Offerings
>125 Paper Presentations/Poster Sessions	Special plenary sessions on IOR/EOR case studies
Best of 2016 EAGE IOR Symposium	Eight accredited short courses, including a special AAPG course on Development Geology offered for the first time ever at the conference
EOR/IOR for Unconventional/Shale Reservoirs	
Water Quality	
Gas Injection Processes	IOR Pioneer Awards Luncheon
Chemical EOR	Beer 'n Brats night with door prizes, entertainment
Conformance	Dozens of industry exhibits
CO_2 EOR/Sequestration	Catered food & refreshments on exhibit floor
Polymer	New mobile app to track conference details, events
Novel & Nanotech	Proceedings available to attendees via the cloud
Field Case Histories	Best networking opportunities for EOR/IOR specialists
Viscous/Heavy Oil Recovery	Regional geology field trip
Foams in EOR	A unique, first-ever coordinated program combining entertainment, dining, tours, group travel, and just plain fun in the rejuvenated Tulsa downtown area. We guarantee this will be an extracurricular experience attendees have never had before at an IOR conference—and won't soon forget.
Low Salinity	
Reservoir Characterization/Management	
Smart Wells	

Join us at the 21st IOR Conference in Tulsa on April 14–18, 2018, to learn about the latest advances and network with the top experts in IOR and EOR technology and best practices

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1 US

IHS Markit announced that Marathon Oil Co. has completed a Middle Bakken and a Three Forks well from a drill pad in Section 15-146n-93w of Dunn County, N.D. The #31-15H Chapman well flowed 5.072 Mbbl/d of 40-degree-gravity oil, 67.7 Mcm/d (2.391 MMcf/d) of gas and 6.422 Mbbl/d of water. Production is from a lateral extending 3,323 m (10,902 ft) southward to 6,366 m (20,886 ft), has a 3,226-m (10,584-ft) true vertical depth and bottomed in Section 22-146n-93w. It was tested on a 46/64-in. choke following 45-stage fracturing, and the flowing casing pressure was 1,500 psi. The #31-15TFH French flowed 2.282 Mbbl/d of 41-degree-gravity oil, 28.3 Mcm/d (1 MMcf/d) of gas and 4.587 Mbbl/d of water. Production is from a horizontal Upper Three Forks interval at 3,325 m to 6,176 m (10,910 ft to 20,626 ft) after 45-stage fracturing. The lateral extends 3,303 m (10,837 ft) southward to 6,367 m (20,890 ft), and it bottomed in Section 22-146n-93w with a true vertical depth of 3,246 m (10,651 ft). Gauged on a 64/64-in. choke, the casing pressure was 790 psi.

2 Colombia

Canacol Energy Ltd. announced the results of appraisal well #2-Pandereta in the VIM 5 Block in Colombia's Lower Magdalena Valley Basin. The #2-Pandereta well encountered 40 m (130 ft) of net gas pay in Cienaga de Oro and confirmed a previous completion on the block at #1-Pandereta. The #2-Pandereta had an absolute open flow rate of 3.9 MMcm/d (140 MMcf/d). The appraisal well was drilled to 2,939 m (9,641 ft) and had an average porosity of 23% within the Cienaga de Oro sandstone reservoir target. The upper part of Cienaga de Oro was perforated between 2,592 m and 2,625 m (8,505 ft and 8,612 ft) and flowed 991 Mcm/d (35 MMcf/d) during testing on a 57/64-in. choke. The flowing tubing head pressure was 1,438 psi. The lower part of Cienaga de Oro was perforated between 2,644 m and 2,647 m (8,674 ft and 8,684 ft) and was tested on a 32/64-in. choke with a flowing tubing head pressure of 2,446 psi.

3 Chile

GeoPark announced results from an exploration well in the Fell Block in Chile's Magallanes Basin. The #1-Uaken well was drilled to 1,115 m (3,658 ft). A production test of El Salto flowed 22.66 Mcm/d (800 Mcf/d) of gas with a wellhead pressure of 158 psi. According to GeoPark, the Uaken gas field creates a new gas play in the Fell Block that can be tested in identified leads and prospects. In addition, there are multiple wells in already discovered oil and gas fields within the Fell Block that can be re-entered to test this formation.

4 Guyana

Exxon Mobil completed its sixth discovery in offshore Guyana's Stabroek Block. The #1-Ranger well hit a 70-m (230-ft) oil-bearing reservoir with high-quality oil. The well was drilled to 6,450 m (21,161 ft) and had an area water depth of 2,735 m (8,973 ft). According to Exxon Mobil, the recoverable resource estimate for the block is 3.2 Bboe. When #1-Ranger is complete, the drillship will be moved to the Pacora prospect.

5 Morocco

SDX Energy announced results from a completion in Morocco's Sebou permit area. The #16-KSR well was tested flowing at a restricted average rate of 238 Mcm/d (8.43 MMcf/d), and it has been placed on production. Additional completion information is not available.

6 UK

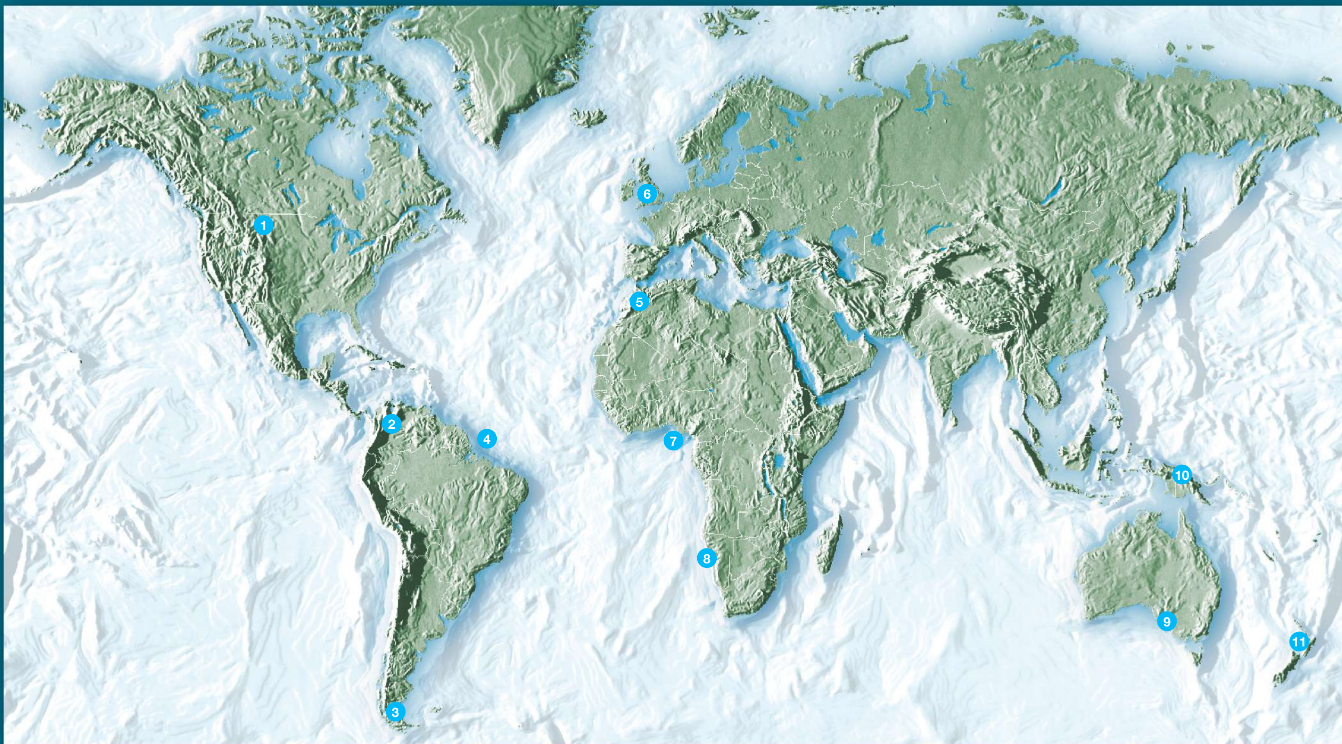
According to Cuadrilla Resources Ltd., it has discovered gas in the Borough of Flyde in Lancashire, U.K. A horizontal shale well, the first in the country, is planned. Cuadrilla analyzed data from 114 m (375 ft) of core samples from a well at Preston New Road. The samples indicated excellent rock quality and high gas content in several of the shale zones. Up to four wells could be drilled at the site in second-quarter 2018.

7 Equatorial Guinea

An oil discovery was reported by Exxon Mobil offshore Equatorial Guinea in Block EG-06. The #1-Avestruz well is adjacent to the Zafiro Field. The company is assessing the commercial viability of the find. The government of Equatorial Guinea has partnered with Exxon Mobil in Block EG-06 through a 20% stake held by the national oil company.

8 Namibia

An offshore Namibia test is planned by Africa Oil Corp. at the Cormorant Prospect in petroleum exploration license 37. The prospect is located in the Walvis Basin and area water depth is 550 m (1,804 ft). According to the company, the prospect is one in a series of extensive base-of-slope turbidite fan prospects with significant combined resource potential. The fans directly overlie a mature oil-prone source rock of Aptian age that was recently proven by nearby wells #1-Murombe and #1-Wingat.



9 Australia

A new gas field discovery in South Australia's Otway Basin was announced by Beach Energy Ltd. The #3-Haselgrove ST1 was drilled as a deviated well to 4,331 m (14,209 ft) and intersected with an estimated gross gas column of 104 m (341 ft) in Sawpit Sandstone, with an estimated net pay of 25.6 m (84 ft). An estimated gross gas column of 11.6 m (38 ft) was also intersected in the shallower Pretty Hill Sandstone, with an estimated net pay of 8.5 m (28 ft). The well is in petroleum prospecting license 62 on state forestry land. The well initially produced 708 Mcm/d (25 MMcf/d) of gas from perforations at 4,023 m to 4,185 m (13,199 ft to 13,730 ft) and was tested on a 36/64-in. choke with a wellhead pressure of 2,700 psi. Flow rates were constrained due to the size of completion tubing. The well is shut-in and more testing is planned.

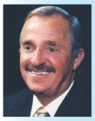
10 Papua New Guinea

The results from an appraisal well testing at Papua New Guinea's Western Highlands Province were announced by Oil Search Ltd. The #2ST 1 P'nyang South is in petroleum retention license 3/application petroleum development license 13. According to the company, the objective was to migrate 2C (proven and probable) gas resource volumes to the 1C (proven) category as well as appraise 2C resource upside potential identified in the southeastern part of the field. The well was drilled to 2,275 m (7,464 ft) with 9$\frac{5}{8}$-in. casing set at 1,981 m (6,499 ft). It was cored and then drilled through the objective Toro, Digimu and Emuk, and cores indicate saturated gas with good reservoir quality. Additional testing is planned.

11 New Zealand

TAG Oil Ltd.'s drilling is underway is underway at exploration well #1-Pukatea in onshore New Zealand's North Island on the Puka Permit PEP51153. The primary objective of the #1-Pukatea well is the deep Tikorangi Limestone. The well will be drilled to 3,170 m (10,401 ft). The well site is adjacent to the Waihapa oil field, which has produced more than 23 MMbbl from Tikorangi Limestone. According to the company, individual wells produced up to 5 Mbbl/d of oil. In addition to the drilling of Tikorangi Limestone, the venture will also test the shallower Mount Messenger. E&P

PEOPLE



James D. Woods, 86, former chairman, president and CEO of Baker Hughes Inc. and noted philanthropist, passed away in Houston on Feb. 4. He retired from the company in 1997, after joining Baker Oil Tools in 1955 and spending his entire career there. Woods was a past president of the Petroleum Equipment and Suppliers Association and the National Ocean Industries Association.

Respected oil and gas veteran **Ted Collins Jr.**, 79, unexpectedly passed away in January. Throughout a 50-year career, he served as director at several large energy companies, including RSP Permian Inc. and Oasis Petroleum Inc.

David Williams retired as chairman, president and CEO of Noble Corp. Plc in January. **Julie Robertson** was named his successor.

Jack Gerard, the American Petroleum Institute's president and CEO, will step down in August. As of press time, the association had not yet named a successor.

Pat Lawless of EM&I Group was promoted to CEO.

Wentworth Resources Ltd. promoted **Eskil Jersing** to CEO, commencing second-quarter 2018.

J. Blair Goertzen resigned as a director of Zedcor Energy Inc. due to other work commitments. **Andy Purves** was named a director of the company and **Ian H. McKinnon** was named president, CEO and a board member.

Michael Watford, chairman and CEO of Ultra Petroleum Corp., retired, and **Brad Johnson** was named interim CEO.

Vanguard Natural Resources Inc. appointed **Richard Scott Sloan** president and CEO, succeeding **Scott W. Smith**. In addition, **Ryan Midgett** was elected CFO and **Patty Avila-Eady** chief accounting officer.

Dave T. Ho of Sixty Six Oilfield Services Inc. was elected president and CEO. He also serves on the board of directors. In addition, **Jim Frazier** stepped down as president to focus solely on the development of the oilfield service sector. He is now executive vice president.


Lifting Equipment Engineers Association appointed **Dr. Ross Moloney** (left) CEO, and **Paul Fulcher** (right) was elected chairman on the board of directors.

Michael Ciskowski, executive vice president and CFO of Valero Energy Corp., will retire in May. **Donna Titzman** will be his successor.

Bengal Energy Ltd. welcomed **Matthew Moorman** as its new CFO.

Rex Energy Corp. promoted **Curt Walker** to CFO.

Ikkuma Resources Corp. named **John Van de Pol** senior vice president and CFO.

NXT Energy Solutions Inc. appointed **Jakub Brogowski** vice president of finance and CFO.

Targa Resources Corp. named **Matthew J. Meloy** president, **Patrick J. McDonie** president of gathering and processing, **D. Scott Pryor** president of logistics and marketing, **Robert M. Muraro** chief commercial officer and **Jennifer R. Kneale** CFO.

Gen III Oil Corp.'s **Gordon Driedger** was promoted to COO.

Randy Steele of Pengrowth Energy Corp. was named COO, and **Steve De Maio** resigned as senior vice president of thermal operations.

Starlee Sykes was appointed BP's regional president for the Gulf of Mexico and Canada, succeeding retiree **Richard Morrison**.


Marathon Petroleum Corp. appointed **Brian K. Partee** (left) vice president of business development and **Rick Linhardt** (right) vice president of tax.

Chevron Corp. promoted **Bruce Niemeyer**, vice president of Chevron's Mid-Continent business unit, to corporate vice president of strategic planning. Niemeyer was succeeded by **Jeff Gustavson**, Chevron Canada Ltd.'s president. In addition, **Jim Umpleby** was elected to Chevron's board of directors.

UTEC selected **Bill Hickie** as business unit director of its Middle East and Caspian operations.

Rovco selected **Liam Warren** as operations manager.

Galtway Industries LLC promoted **Greg Gilbert** to vice president of sales.

Matador Resources Co. appointed **Timothy E. Parker** to the company's board of directors.

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on the MOVE

Exxon Mobil Corp. elected **Steven A. Kandarian** to its board of directors.

Europa Oil & Gas Plc's board of directors elected **Simon Oddie** non-executive chairman, succeeding **Colin Bousfield**. In addition, **Brian O'Cathain** was appointed nonexecutive director.

Tap Oil Ltd. elected **Blaine Ulmer** nonexecutive director of the company, and **Chris Newton** and **Govert van Ek** were appointed directors.

TORC Oil & Gas Ltd. appointed **Mary-Jo Case** to its board of directors.

Hugh Saville of the Energy Industries Council was elected board chairman.

SRC Energy Inc.'s board of directors appointed **Jennifer S. Zucker** independent director.

COMPANIES

Total signed an agreement to acquire **Samson Offshore Anchor LLC**.

Transocean Ltd.'s acquisition of **Songa Offshore SE** is expected to close by the end of first-quarter 2018.

Beach Energy Ltd. acquired **Lattice Energy Ltd.** from **Origin Energy Ltd.**

FairfieldNodal finalized its agreement to purchase **WGP Group Ltd.**, a provider of marine geophysical services.

Vermilion Energy Inc. entered into an agreement to purchase **Privateco**. The $90.8-million deal was expected to close Feb. 15.

Blackstone Industrial Services acquired **Nuovo Parts Inc.**, a distributor and authorized service and sales channel of **Baker Hughes, GE company**. E&P

ADVERTISER INDEX

Improving contractor-management processes

An increasing reliance on contractors is making risk mitigation a growing concern.

Joe Eastin, ISN

Contractor companies have a lot to look forward to in the year ahead. In a contractor-management strategy survey that ISN recently conducted, 60% of the 34 organizations in the upstream oil and gas industry reported that they expect to see an increase in their outsourcing of work to third-party contractors over the next 12 to 18 months.

Although a trend toward increased outsourcing is great news for contractor companies, it is not without risk to them. An increased workload for contractors in capital-intensive industries might lead to greater risk exposure for contractors and their employees. Since ISN started in 2000, it has observed that the increase in outsourcing work to third-party contractors has been driven primarily by increased specialization of work and the desire of companies to streamline efficiencies and free company resources. Contractors accounted for 65% of total work hours in 2000, increasing to 77% in 2016, with contractors having a 30% higher total recordable incident rate than company employees in 2016.

Challenges

Even with progress, there continues to be challenges in finding qualified contractor companies and ensuring that work conditions remain safe—two top priorities, according to the upstream oil and gas decision-makers surveyed. Additionally, 100% of those who reported having mature contractor-management processes also reported having a documented strategic plan for their contractor-management goals. By comparison, only 50% of the responding organizations that described themselves in the survey as having less mature processes reported having a documented strategic plan for their contractor-management goals.

One of the primary concerns identified in the ISN survey is ensuring the competency and compliance of second- and third-tier subcontractors hired by prime contractors. A hiring organization's contractor management process needs to ensure that subcontractors are included along with the prequalification of contractor companies.

Other risk factors identified by survey respondents included distracted driving and the presence of temporary workers. The U.S. Occupational Safety and Health Administration estimated that motor vehicle crashes cost employers $60 billion annually in medical care, legal expenses, property damage and lost productivity.

The increase in outsourcing is great news for contractors.

Critical advice

With the new year in full swing, it's a good time for hiring organizations to review and look for ways to improve their current contractor-management processes. Hiring organizations should implement new initiatives aimed at engaging the workforce and driving continual improvement plus alignment with the organizational values and goals. As president and CEO of ISN, whenever anyone asks me where to begin, I like to share three pieces of advice:

1. Clearly define and, if necessary, reiterate expectations to reduce confusion on the job site;
2. Better integrate internal processes and systems (i.e., health and safety management, procurement, etc.) so you have an end-to-end risk management process for outsourced work; and
3. Implement the "Five Times Rule" by communicating your points at least five times and in five different directions within the organization.

Better measurement equals better management

During the past 17 years, we have often said, "You can't manage what you can't measure" when speaking of mitigating the risk of outsourcing work. Using objective data to measure contractor performance is critical to improving the management and overall performance and compliance of contractors. A lot has changed in the industry during the past 17 years, and organizations and contractors alike must stay ahead of the risks associated with the changes. E&P

References available.

CONTROLLED INTENSITY™

Pinpoint fracturing delivers aggressive infill completions one frac at a time, with less risk of well bashing.

Multistage Unlimited® pinpoint fracturing delivers maximum SRV with far less risk of frac hits and well bashing during infill field development, compared with plug-and-perf. You put fracs where you want them, and you control how much sand you pump into each one, preventing "super clusters" that can hurt production from offset wells. With repeatable frac placement from well to well plus recorded downhole pressure/temperature data, you can truly optimize stage count and spacing in a given formation with just a few wells.

More stages per well

NCS pinpoint fracturing delivers more individual entry points with far higher frac efficiency than plug-and-perf. For example:

- 165 stages (Montney
- 155 stages (Bakken)
- 147 stages (Permian)
- 145 stages (Montney)
- 135 stages (Cardium)
- 125 stages (Duvernay)

More sand per well

More intensity means pumping a lot more sand, and NCS Multistage pinpoint fracturing handles it:

- 18.2 million lb @1,870 lb/lateral ft (Montney)
- 16.2 million lb @2,190 lb/lateral ft (Montney)
- 15.0 million lb @1,711 lb/lateral ft (Duvernay)
- 14.2 million lb @1,973 lb/lateral ft (Permian)

Faster execution

NCS Multistage pinpoint completions are being executed faster than ever. Here's why:

Higher rates. Technology and design advances have boosted Multistage Unlimited frac rates through the coiled tubing/casing annulus to nearly 80 bbl/min in 5.5-in. casing, far higher "per cluster" than plug-and-perf and more than enough to transport sand (>12 ppg) with slickwater.

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