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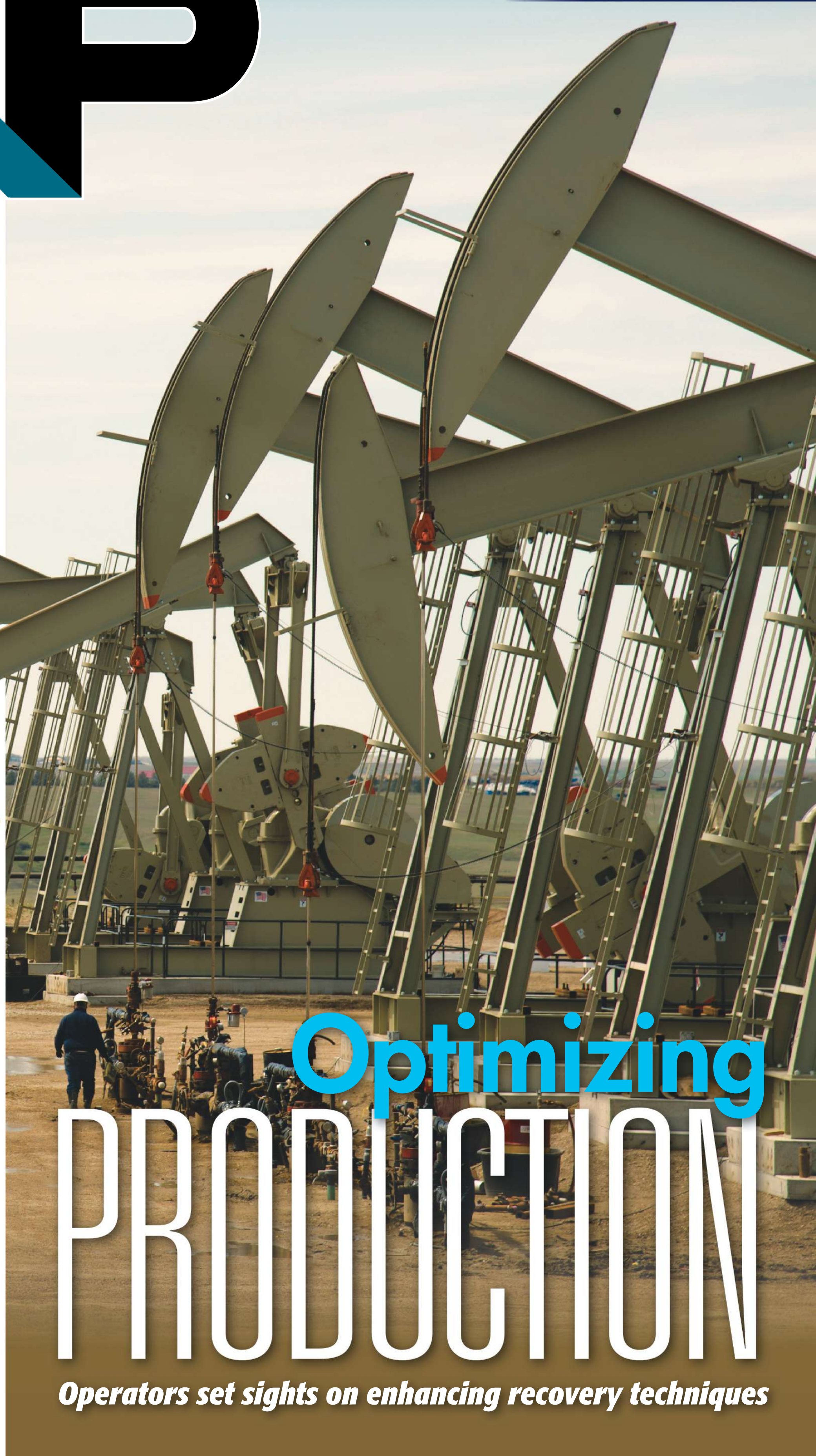

Optimizing PRODUCTION

Operators set sights on enhancing recovery techniques

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE
SEPTEMBER 2018
VOLUME 91 ISSUE 09
A HART ENERGY PUBLICATION
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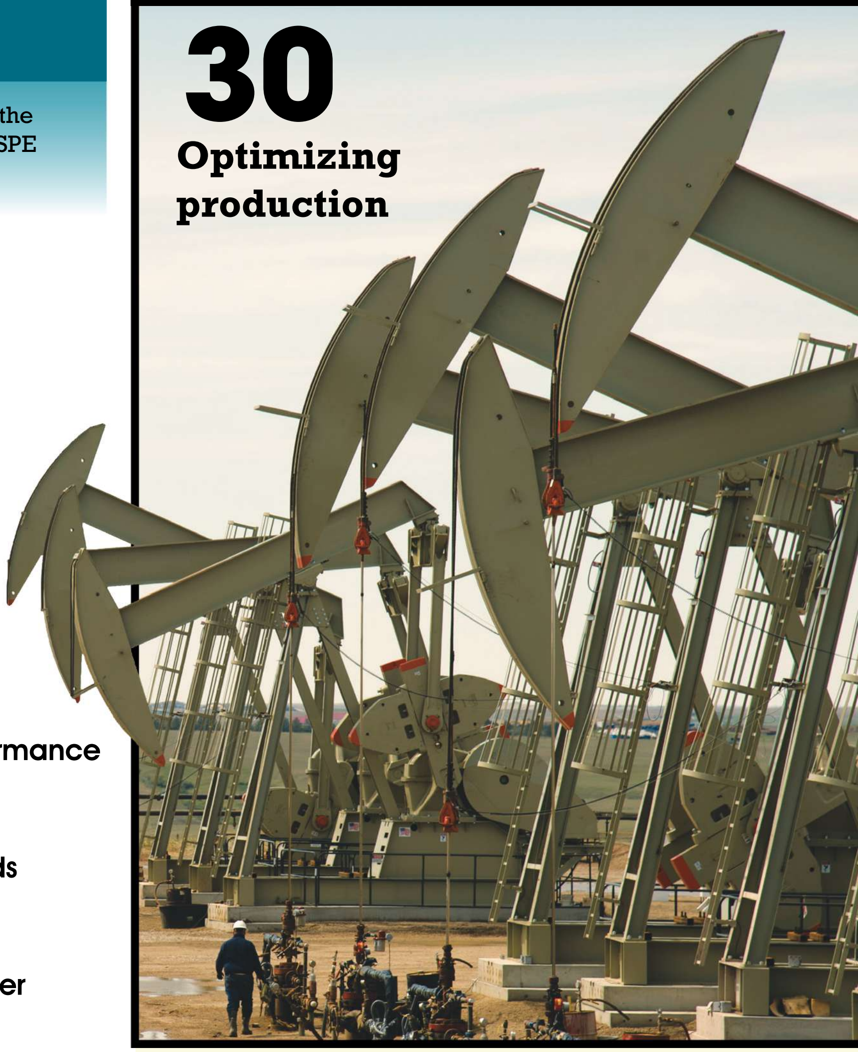
COVER STORY: PRODUCTION



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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The October issue of ***E&P*** will focus on exploration. Other features will cover marine seismic, automation/drilling efficiency, fracture fluid optimization, mature field life extension, and ROVs and AUVs. The unconventional report will focus on the Eagle Ford. 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 Equinor will deploy artificial-intelligence-powered artificial lift technology on its rod pump wells in North Dakota. Left, CNX produced 3.6 Bcm (129.5 Bcfe) in the first quarter of 2018. *(Cover photo courtesy of Ole Jørgen Bratland/Equinor; Left photo courtesy of CNX Resources; 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.

ACTIVITY HIGHLIGHTS

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Montney horizontal discovery producing 1,900 boe/d

Painted Pony Energy Ltd. has reported test results for its first Montney horizontal well on the Beg Block in northeastern British Columbia. The #1 well was drilled to 2,267 m (7,438 ft), with 1,800 m (5,906 ft) true vertical depth.

Eight Niobrara, Codell wildcats planned from drill pad

IHS Markit reported that Enerplus Resources has received drilling permits for eight horizontal wildcat wells targeting Niobrara and Codell on a common drill pad in Weld County, Colo. in the western Denver-Julesburg Basin.

Directional Miocene test scheduled in Louisiana's Breton Sound

Upstream Exploration LLC has planned another directional Miocene test in Louisiana state waters in Breton Sound. The East Cox Bay Field test, #2 State Lease 21380, will be drilled in Section 26-18s-16e.

AVAILABLE ONLY ONLINE

Sorting subsea seawater injection

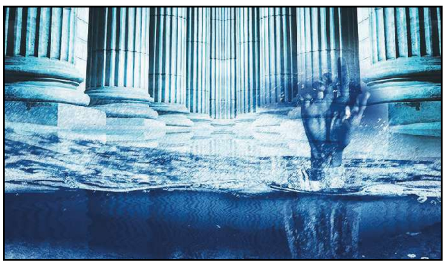
By Elaine Maslin, Contributing Editor

For mature offshore facilities, adding or even increasing water treatment and injection facilities can prove difficult due to space or weight constraints and also may be prohibitively expensive.

Service providers, regulators can help tackle water management

By Mary Holcomb, Assistant Editor, Digital News Group

With the rapid growth of produced water and infrastructure constraints, operators have to find new ways to tackle it.



Technology leads way to bigger profits in the Bakken

By Terrance Harris, Associate Editor, Digital News Group

Improved data analytics, increased cell towers and the use of drones will all serve to increase production and efficiency in the Bakken.

Pioneer gears up for more high-intensity Permian completions

By Velda Addison, Senior Editor, Digital News Group

Pioneer intends to add 60 more Version 3.0+ completions in the Permian during the second half of 2018, along with four more rigs, as it further tailors completions by well, zone and area.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The final push begins

With just four months left in 2018, operators are looking to exit the year flush with fresh production.

If there is one thing that gets a response from your industry peers, it's anything to do with oil and gas production. It is a natural topic of discussion as who doesn't like to talk about a good science experiment? Add a dash of cash to the process, and the intrigue grows incrementally as does the weight of fiscal responsibility to stakeholders. With just four months remaining in 2018, the final push is on to make the year-end numbers projected way back when in January.

It seems like a lifetime ago, but it has only been eight months. Moreover, what an impact those 32 weeks have had on the oil and gas industry. In that span of time, offshore projects like Shah Deniz 2, Icthys, Kaombo and Kaikias all saw first production while Martin Linge, Johan Sverdrup and Appomattox roll closer to the finish line.

The plans for many of the proposed offshore projects placed on the shelf during the industry downturn are now seeing life. According to a Rystad Energy press release, out of the 17 deepwater projects approved over the past 18 months, as many as 16 had previously been in the development queue but were then put on hold during the industry downcycle.

"These same projects can now pass operators' investment criteria down to $30 per barrel," the press release stated. "The 16 delayed deepwater projects that have attained FID [final investment decision] so far will collectively develop around 6 billion boe and require investments totaling $43.2 billion to reach first production."

It is the onshore side of the production coin that is the focus of this month's cover story. In it, the leading producers in many of the U.S. shale plays share insights into the current state of production technologies and how they are using those technologies to increase hydrocarbon production from their fields.

September brings with it the Society of Petroleum Engineers' Annual Technical Conference and Exhibition (SPE ATCE). The conference, to be held in Dallas this year, will feature "Translating Big Data into Business Results" for its opening general session. Panelists from Encana, Shell, Schlumberger and Google will attempt to answer the real question regarding the use of Big Data: how can it be used to improve safety and increase profitability?

In recognition of the event, *E&P* highlights new products from more than 40 companies that are exhibiting at the show in our annual SPE ATCE Technology Showcase (see page 82).

As the industry sets its sights on 2019, let's keep pushing during these last four months to ensure 2018 exits with less whimper and more bang! E&P

Jennifer

Shale's radically changing workforce

The labor force of the future will combine essential domain knowledge with digital savviness.

Paul Goydan and **Jamie Webster**,
Boston Consulting Group

If shale operators are to maintain their competitive advantage in a changing policy, technology and price environment, they will need a more skilled and flexible workforce.

The shifts in shale production growth over the course of the post-2014 oil price "swoon" and subsequent recovery have demonstrated that operators can respond quickly to price alterations. Companies have relied on remote drilling and other digitally enabled technologies to increase worker productivity.

As they plan for a future where costs will need to be kept lower for longer, shale companies will increasingly turn to technological solutions to achieve this, while keeping productivity high. Digitalization also will allow companies to maintain headcount numbers below the level seen during the oil price peak even as the industry recovers. In a bid to become leaner, many shale operators shed employees in noncore areas and squeezed asset teams during the price downturn. However, the workers they employ in the future will need to be tech-savvy and open to new ways of working.

Skills shortage

Shale operators face a looming skills shortage caused by two factors: one stemming from historical events and one that is just beginning to impact companies. The first is the retirement of a generation of talent recruited before the 1986 oil price collapse. Because of the low levels of hiring in the late '80s, there likely will be insufficient skilled personnel in subsequent generations of workers to replace these individuals. The second is the need to recruit personnel with expertise in digital tools. This is made more difficult by the intense competition for graduates with such skills. The overlapping skills needed include higher level mathematics and computer science.

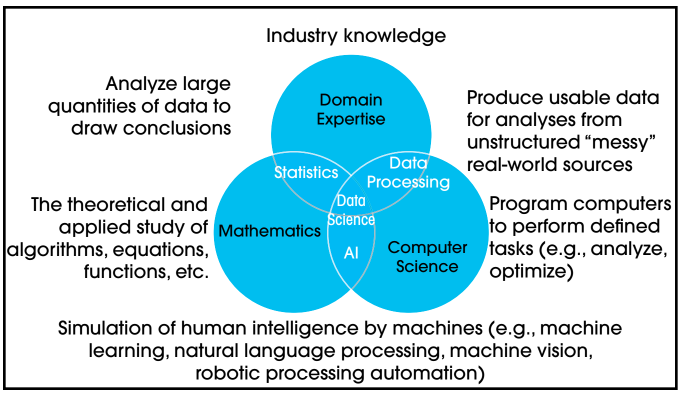

FIGURE 1. Mathematics and computer science skills, when combined with domain expertise, enable a company's access to fields such as data science and processing. (Source: Boston Consulting Group)

These challenges have prompted some shale operators to confront their human resources issues. Internal training programs are fostering more organizational learning and are facilitating knowledge transfer between generations. Companies are using programs to provide employees who already possess ample domain knowledge with digital expertise, similar to the training initiatives undertaken when desktop computers became commonplace. Combining domain expertise with mathematics and computer science skills can more easily allow companies to access needed fields such as data science, data processing and machine learning (Figure 1).

By providing more flexible work options, companies are encouraging older workers to stay on longer to minimize the industry's skills gap—mirroring a trend in the wider U.S. economy where workers over 65 make an increasingly important contribution. They also are recruiting and training workers needed to perform essential tasks such as welding and driving trucks. Companies are investing in scholarships and college partnerships to encourage students majoring in science, technology, engineering and mathematics subjects to join the industry.

Keeping costs in check

Technological advances are already enabling shale operators to reduce the number of employees they need. For example, optimizing the choke settings on a gas-lift well used to take one engineer a day working across multiple system interfaces. However, by applying robotic process automation technologies, that time can be cut to a couple of hours. Similarly, technology start-ups are developing online tender platforms for oilfield services such as sand delivery. By accepting the lowest bid for a particular job, shale operators can keep costs in check.

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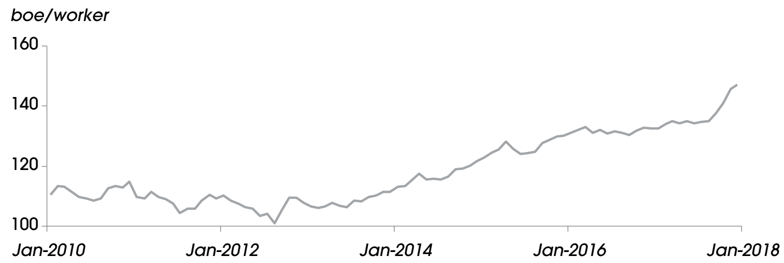

FIGURE 2. Technology advances have boosted human productivity so greatly that one person's efforts can produce nearly 150 boe, up from 110 boe a decade ago. (Source: Bureau of Labor Statistics, U.S. Energy Information Administration, Boston Consulting Group and Camber Energy Inc.)

The employment picture for shale operators has changed significantly following the slide in the oil price. U.S. employment for oil and gas extraction fell from more than 200,000 in October 2014, before the drop, to a low of 145,000 in mid-2017. Since then, employment numbers have risen by only about 5,000 and remain near 2007 levels when the shale industry was in its infancy. Various factors have contributed to the relatively muted upturn in the headcount: in particular, technology has boosted employee productivity. One person can produce nearly 150 boe, up from 110 boe a decade ago (Figure 2). A renewed focus by shale operators on their core acreage, combined with the growth in robotics and remote drilling, also has reduced the technical workforce required to develop a well.

Wages will still need to increase if the shale industry is to draw in workers. The rise of the shale industry coincided with a period of growth following the Great Recession. Economic conditions are different this time around. Today's U.S. labor market is far tighter, enabling workers in many sectors to demand pay hikes. However, while wages in the wider U.S. economy have risen by more than 5% since January 2017, when OPEC implemented its landmark supply-cutting deal, wages in oil and gas extraction have increased by less than 1%. Over the same period, oil prices have risen more than 20%. This mismatch is creating uncertainty about whether shale can compete with other industries to attract a stable supply of high-quality prospective employees.

Need for flexibility

Exacerbating the recruitment challenge for shale operators are their rapidly changing requirements. In the shale industry of the future, workers will need a far broader combination of skills than they possess today. Employees will require digitally driven skills in computer programming and new fields, such as advanced analytics, that can be deployed to solve complex engineering and technical problems on shale's frontline. Domain expertise, such as in geology and geoengineering, will still be important to employers and act as a means of entry to the industry. However, possessing such specialist knowledge won't be sufficient for workers to prosper.

In a data-driven world in which companies are aiming for greater organizational flexibility, employees also will need to work in new and more agile ways. They will need to adapt to industry trends including increased business unit autonomy, greater employee empowerment and accountability, factory-style execution and more cross-functional teams. Companies can address these challenges by adopting new approaches. For example, they can pair experienced staff with younger workers trained in emerging fields such as data science, and they can adopt continuous learning programs that allow existing workers to update their skill sets. Companies also will need to revamp the talent management and competency frameworks that define roles and govern skills development programs.

Competition between industries for candidates with these much sought-after digital skill sets is going to get fiercer. Before the oil price drop, petroleum engineering was the best paid career option for U.S. graduates and attracted the cream of the crop. Today a degree in data science is the ticket to a well-remunerated job right out of college. The difference is that graduates with strong data skills are needed in almost all industries as companies embrace the benefits of digitalization. Their skills are highly transferable, and graduates can pick and choose between competing offers.

With a shortage of data science graduates to meet the demand from U.S. companies, shale operators will have to spruce up their compensation programs and total remuneration packages, and tackle the industry's slow career progression if they want to attract digital natives. They also will have to create a more compelling value proposition in other ways. Millennials want to live in cities. So part of a viable employment solution will involve using digital technologies and processes to transmit oil and gas data to employees located in urban centers, a shift from the old model of sending workers to remote outposts close to hydrocarbon deposits. 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*.

Operators ditch 'pump and pray' mantra

Senior technology leaders at URTeC 2018 discussed how to get improved results in unconventional reservoirs and automation's effect on the workplace.

Mary Holcomb, Assistant Editor, Digital News Group

Technology has only begun to scratch the surface in the unconventional sector of the oil and gas industry, especially considering a revolution from digital analytics to automation is imminent.

A panel of senior technology leaders, comprising operators and service providers, shared this sentiment at the Unconventional Resources Technology Conference (URTeC) held in July. The panelists honed in on technologies that would make a difference in unconventional reservoirs.

Expanding on the topic, Concho Resources Inc.'s vice president of geoscience and technology, Chris Spies, said the industry has only really witnessed the top of the glacier when it comes to technology.

"From my perspective, the amazing thing about watching unconventionals grow over the last five years is that there hasn't been a real breakthrough in technology, and there hasn't been a major leap in innovation," he said. "It's just all these little tiny tweaks to the landing zone, to the perf cluster spacing, to the proppant we use [and] to the fluid volumes."

Spies went on to compare the technology revolution to a living, breathing organism that is on an "exponential learning curve and it's not stopping now," adding that the downturn a few years back was actually a positive setup for the industry.

"It's much bigger than I originally anticipated. We're learning new things every day," he said.

Adopting automation

Hege Kverneland, corporate vice president and CTO at National Oilwell Varco (NOV), agreed with Spies.

Because of the downturn, Kverneland said oil companies steered away from new technologies and systems that were introduced by service companies at that time because they were making money anyway. Service companies like NOV, she said, lost more money and workers than oil companies.

Despite not listening before, Kverneland said oil companies are more receptive now.

"Implementing new technologies is much easier to do now than it was three to four years ago, so that's the good part [about the downturn]," she explained.

Serving as the moderator for the panel, ConocoPhillips' CTO Greg Leveille asked what specific trend would carry the industry another leap forward.

Without hesitation, Kverneland said "automation in general" is the next big game changer.

Even for a driller in a drill cabin, she said, they still do very manual work such as lifting pipe, running pipe, starting pumps, connecting pipes and drilling into holes. This repetitive process, she said, could all be automated.

"[Automation] can make it into a process so that the driller can push a button [that performs these tasks] so that the drilling machine is doing it all for him and he can now pay attention to his group, and more importantly, to what's happening downhole," Kverneland said.

Despite growing up in the offshore business, she said it is important to look at how the shale sector has thrived as a result of incorporating Big Data. Kverneland specified that U.S. shale is the industry to watch because it will leave E&P companies in the dust if they do not improve just as fast.

Big Data has been a significant driving force for optimization in the U.S. shale industry, especially for the drillers. But she said it's the opposite for E&P operations because Big Data hasn't reached its full potential in the sector.

"We're just scratching the surface right now," she said. "We haven't started doing a lot. We're doing some of it, but we can do a lot more."

Although drilling has already had many advancements, she asserted that automation and data analytics will come more and more into play.

"I'm amazed that we've done so much for so long without actually having this [automation]," she said. "It's like driving a car with a blindfold, and now we're taking that off so we can drive that car much faster."

For Spies, drilling and hydraulic fracturing are still the "bread and butter" of the industry. But he noted that he has seen an emergence in gas injection EOR and chemical surfactants.

"A lot of these organic mudstones may be absorbing a lot of oil, and there are some things we can do on a chemical side to help liberate some more hydrocarbons. I think that's also at the forefront," Spies said.

Impact on workers

But with the work place being digitized, what does this mean for workers in the industry?

Chris Cheatwood, CTO and executive vice president at Pioneer Natural Resources Co., said people hate change. Since the transformation is inevitable, he said, people and company leaders will have to come onboard to avoid being left behind.

"You have to understand that and embrace it, and you have to bring the people into the process. They're a part of developing these new things," he said. "You can't just say, 'we're going to do this and here's how we're going to do it.' That won't work. You have to bring them in and make them a part of that change."

Cheatwood said bringing people into the process is actually the first step to moving into the new way of operating.

Yanni Charalambous, vice president and CIO at Occidental Petroleum Corp., agreed with Cheatwood's point, highlighting that machine technology cannot replace every worker. In fact, he said people are needed to oversee and somewhat teach machines.

"Your job's not in jeopardy," Cheatwood said. "But we can't work the old way."

Concho's Spies added that introducing tools and concepts actually inspires ingenuity from workers.

"People will blow your mind with what they are able to come up with, and being a part of that and embracing it makes the transition a little easier I think. It's not a bad thing," Spies said.

Kverneland pointed out the importance of attracting the younger crowd. From her perspective, she said she has seen many young people come into the industry.

"I'm very optimistic about the future of this industry. But that also means that we need to start introducing new technology, we need to operate autonomously and we need to monitor what's happening without necessarily going in there," Kverneland said.

"[And] we still need people that can teach machines. You cannot do everything remotely." E&P

A tiger in the tank

A Goldilocks solution can lead to greater well density and improved reservoir recovery.

Richard Mason, Chief Technical Director

You've heard of cube development. You've heard of pattern development. Now add tank development to the lexicon of terms describing full field development.

To be sure, the industry is early in the strategic evolution to completing multiple wells on a single pad, which characterizes more than 90% of wells in the Bakken and Marcellus. Other regions, such as the Midcontinent, are earlier yet in evolution along an arc of tight formation exploitation that moves from discovery to delineation, optimization and full field development.

A major issue in the traditional strategy of capturing acreage first and developing acreage later stems from drilling a parent well to retain acreage via production followed by a return to build out the lease with multiple child wells. That strategy exposes the industry to production issues associated with parent/child well interference.

- **Sequencing pad development improves stacked reservoir recovery.**
- **It is possible to both increase well density and improve individual well recovery.**

The parent well creates a pressure sink. Infill wells, added later, impact production in the parent well, often negatively, but also generate diminishing returns as energy applied to hydraulically fracture infill wells migrates toward the parent well's pressure sink. Suboptimal recovery and diminishing returns impact capital efficiency in operations and curtail access to full financial leverage in reserve-based lending.

E&P companies use strategies to subvert this phenomenon such as repressuring and shutting in the parent well before fracture stimulating a neighboring infill well. Some larger E&P companies use a factory approach by drilling dozens of wells in a section then completing those wells simultaneously.

Branding for those techniques include terms such as "cube" or "pattern" development, and entail significant upfront capital costs for drilling, completion and infrastructure development, while creating logistical challenges involving sand and water sourcing, treatment and disposal, long before generating revenue when wells are turned in-line six to nine months later.

Engineers from QEP Resources Inc. proposed a solution to these challenges by recapping field experiments in two stacked pay Spraberry drilling units in the Midland Basin at the 2018 Unconventional Resources Technology Conference summer gathering in Houston.

QEP engineers labeled the practice as "tank" development. It involves drilling, completing and turning wells in-line simultaneously for each well pad. However, think of it as a multiphase sequence that involves a drilling unit such as a four-well pad, a temporary nonactive neighboring pad as a buffer, the completion sequence, which creates a pressure wall, and the final sequence, which turns all wells into line.

Specifically, it involves drilling all wells in the initial drilling unit before the rig moves to the next pad. As the rig moves to a third pad, stimulation crews employ a top down completion sequence on the first pad, then move to the neighboring pad. As the crew reaches the third pad, wells in the first pad are brought online only after a pressure wall separates wells in completion on the third pad from wells being turned in-line on the first pad. The sequence of events is repeated along neighboring pads as rigs, stimulation crews and production transit across the reservoir.

QEP's stacked play Spraberry experiment showed the methodology eliminates parent/child well interaction and increases stimulated rock volume by adding pressure to the reservoir faster than it dissipates. The additional pressure creates a more complex fracture network.

Greater yield comes from tighter well density—up to 16 wells per mile versus 10 previously—and improved recovery for each drilling unit, which amplifies asset value. In other words, the method harvests more hydrocarbons from individual wells and more hydrocarbons in aggregate from all wells in a drilling unit. Tank development also lowers well costs by reducing surface complexity.

Stay tuned. E&P

Can AI help interpreters?

Companies are working to solve the hiccups.

RHONDA DUEY
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Artificial intelligence (AI) is not exactly new, but the oil and gas industry has struggled to find a fit for it in several sectors.

One of the issues with AI might also be one of its strengths when it comes to interpretation. Although AI systems can rapidly track through reams of data, they need to be trained to quickly find patterns that some geoscientists might miss. "Seismic interpretation and processing are very human-intensive and knowledge-intensive," said Ulisses Mello, director of the IBM Brazil Research Laboratory. "[This process] is parallel to doctors. Seismic is similar to radiology because technicians have to sift through thousands of images. The idea is to assist in a process that makes sense."

A key component of interpretation is pattern recognition, Mello said, but biases can cloud the truth. "A lot of geoscientific expertise leads to bias," he said. "If you have a geologist who's worked his whole life offshore Brazil, he can go to West Africa and be helpful. But Colombia? Not so much."

AI can speed up seismic processing and interpretation, but it is still not an exact science. (Source: Jinning Li/*Shutterstock.com*)

IBM is working with Galp to address the challenge of incorporating AI into the geoscience workflow. After a three-year project partially funded by a Brazilian agency, a prototype tool has been developed to use AI and other technologies to help geoscientists identify and evaluate exploration prospects as well as risk assessments and the interpretation of 3-D seismic images. But balancing the human element with the scientific element is as important.

"AI tools bring additional considerations—have you considered this? Have you considered that?" Mello said. "[AI] accelerates the knowledge transfer quickly."

One goal of AI is to speed up transfer between the old guard and the new guard. The prototype, Mello wrote in a blog, "automates the analysis of technical documents (including notes made by research scientists), provides advice and suggestions on possible interpretations of subsurface images and aids in risk assessments." He added that the tool integrates information from multiple sources, including published papers.

"In Brazil it takes more than three years for companies to catch up, which is why they partner with other companies to gain the domain expertise," he said. "If a tool could read every paper or report in Portuguese that Petrobras ever published, it would speed things up."

Mello said the prototype will reside on current applications that are already available to the industry, and the intention is to make it commercially available at some point.

Although the geoscience industry is gifted at many things, this has still been a learning curve for the research group, and Mello said things like learning how an interpreter actually looks at a seismic section through eye-tracking devices helped to understand how interpreters make decisions and make the product intuitive.

"Different professionals go through different paths, and that's trickier for the system to learn because geoscientists are not very linear in the way they think," he said. "It's an exciting new area." E&P

Rhonda

Staying ahead of the decline curve

Lost in the news of record-breaking production and impressive rig counts is the increasing rate of decline in production in the Permian Basin.

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Read more commentary at
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From the front porch of my grandparents' house located outside of Midland, Texas, one would be hard-pressed to miss the giant of a pumpjack painted in the school colors of Greenwood "Ranger" baby blue and red that sits on the horizon. Every time I stepped out onto the porch as a kid, I always wondered how much oil Big Jack was pumping.

It is a question that bubbled up again during a recent rig tour in the Delaware Basin. However, that one question naturally led to another. With all of the rigs drilling new wells in the area and with all of the shiny new pumpjacks lined up in multiples on well pads, how was production holding up for shale wells drilled several years ago?

To find an answer, I consulted the U. S. Energy Information Administration's (EIA) Drilling Productivity reports for the Permian Basin. According to the July 2018 report, production from new wells was projected to be 296,000 bbl/d through August while production from legacy wells was projected to drop by 223,000 bbl/d, the highest it has been in the region for the year.

The decline has steadily increased over the past year, with the July 2017 report projecting legacy production to be 154,000 bbl/d.

It is important to note that, according to the EIA report, the legacy oil production change represents total oil production from all wells other than new wells, and the "trend is dominated by well depletion rates, but that other circumstances can influence the direction of the change," according to the EIA report.

It is a decline that analysts at Wood Mackenzie also noticed. In its new study, "Everything is Accelerating in the Permian, Including Decline Rates," the inherent risks of using proxy values, based on decades-old data from vertical wells and other shale plays, to model tight-oil terminal decline rates were analyzed, according to a press release.

The industry's rich history in the area provides an equally rich set of historic data on thousands of vertical wells that have been producing for decades. However, the relative immaturity of the Wolfcamp as compared to other zones results in pure field data for horizontal tight oil wells that only goes back about eight years, according to the study. Analysts compared the older data against the actual mature Wolfcamp well results and modeled the long-term supply and cash flow implications for operators and investors.

"The challenges of modeling tight well estimated ultimate recoveries are growing and accurately selecting a representative terminal decline rate is not always straightforward," said Ryan Duman, principal analyst for Wood Mackenzie, in the press release. "It may have been historically, but using those assumptions for today's Wolfcamp wells in the Permian may contribute to inaccurate volume assessments and valuations."

The study found that, after five years of production, the most active Wolfcamp subplays have annual decline rates roughly double the proxy value of 5% to 10% that is commonly used. The most common terminal decline value observed in mature horizontal Wolfcamp wells was 14%.

Under a 14% terminal decline scenario, the near-term impact to total Permian supply is relatively minimal, but by 2040 nearly 800,000 bbl/d of Permian production is at risk, according to the press release.

It appears that for now the best way to stay ahead of the production decline curve is to "stay calm and drill on." E&P

Jennifer

The right recipe for the Rockies

Enhanced completion designs and improved economics draw investments to the D-J Basin.

BRIAN WALZEL
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Read more commentary at
EPmag.com

Right-sized completions and improving production rates are leading to improved well economics in the Denver-Julesburg (D-J) Basin. A recent report by Westwood Global Energy Group revealed that since 2015 the D-J Basin's average 90-day cumulative oil production has increased by 61%, leading some operators to increase their investments as commodity prices have similarly climbed.

Citing a study by Energent, Westwood reported the D-J Basin's average 90-day cumulative production has increased from about 25,000 bbl/d in 2015 to 40,000 bbl/d through 2017. In its July Drilling Productivity Report, the U.S. Energy Information Administration reported oil production in the Niobrara region continues to see all-time high production, climbing to 600,000 bbl/d through June, an increase of about 6,000 bbl/d through May.

Anadarko Petroleum is planning $950 million in investments in the D-J Basin. (Source: Anadarko Petroleum)

Those production gains have coincided with operators extending the basin's average well lateral length from 1,829 m (6,000 ft) in 2015 to 2,743 m (9,000 ft) this year.

Last year Anadarko reported in the first quarter of the year that in Colorado it was testing new completion designs that involved increased fluid volumes and tighter stage spacing. The new design, according to Westwood, features low-proppant slickwater fractures that use 72% less proppant. According to Energent, the new design led to 10% cumulative oil gains and a 20% increase in EURs.

And despite regulatory risks in the region due to upcoming state elections and possible regulatory and environmental restrictions, operators are committing to producing the D-J Basin. According to Westwood, Anadarko Petroleum announced a $950-million capex plan, running five drilling rigs. HighPoint Resources has allocated up to $550 million with three drilling rigs and extraction oil and gas plans expenditures of $900 million.

HighPoint's XRL enhanced well completion designs have netted the operator production gains of 47% since 2015, from about 50,000 bbl/d after 12 months to more than 80,000 bbl/d over the same period in 2017. Those completion designs feature a higher number of stages—82 in 2017 compared to 55 in 2015—and increased proppant loads of about 1,500 lb/ft. The company has ramped up its XRL program, completing 44 such wells in 2017 compared to 29 in 2015.

While producers continue to ramp up drilling and production operations, they also are being mindful of the unique environment in which they operate.

"Operators have focused on efficient operations through water infrastructure investments to recycle freshwater, box solutions to store frack sand to reduce truck traffic and quiet frack fleets to reduce noise pollution," Westwood reported.

Anadarko reported in its first-quarter investor report that its entire D-J Basin completion fleet features equipment with noise reduction technology.

The D-J Basin's propensity as both a quality gas and oil play and its geographic setting in one of the most environmentally conscious areas of North America make it unique among shale plays. Although it likely will never be an oil-producing behemoth like the Permian Basin or rival the Marcellus-Utica for gas production, its economics and right-sized completion designs are drawing more attention and more investments from operators. E&P

Brian

Predicting equipment maintenance through modeling

Platform enables operators to better optimize maintenance needs.

Philippe Herve and **Marla Rosner**, SparkCognition

In an industry like oil and gas, unexpected failures can be catastrophic for many reasons. The cost of maintenance or new parts is often exorbitant, and with how much capital is committed to wells by a company per day, the lost opportunity cost from unplanned downtime can be shocking.

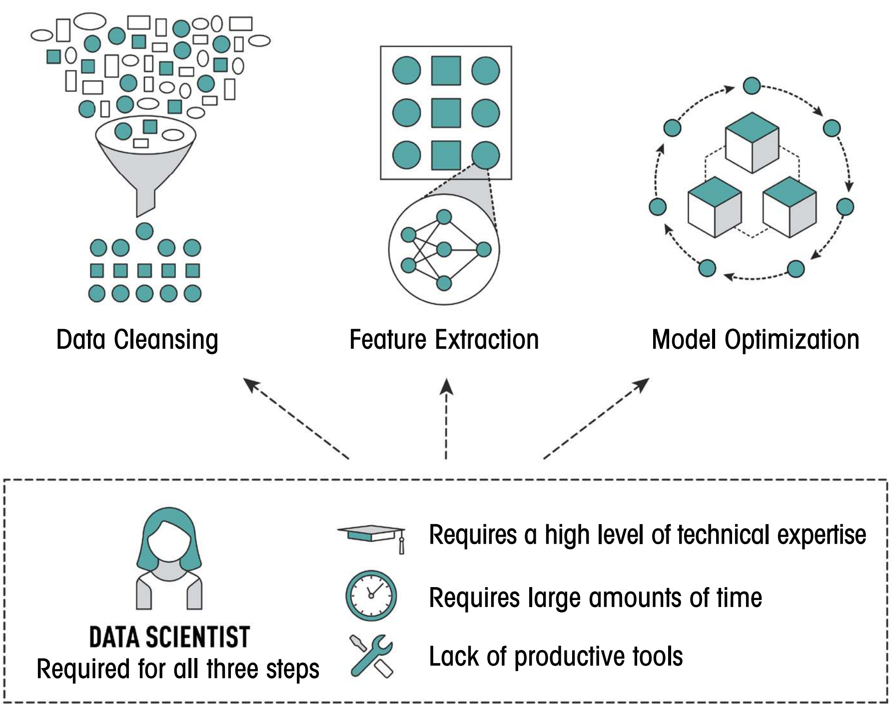
Despite this, the industry has never had particularly great methods of predicting and preventing unexpected failures before they can cause problems. Too many operators still take either a reactive or scheduled approach to maintenance, both of which have tremendous downsides for reliable production. Reactive maintenance runs the risk of creating safety hazards or large operational damage, while scheduled maintenance often halts operations unnecessarily. Enter predictive maintenance, which shows great promise as a new paradigm for monitoring operations but has been a challenge to implement efficiently and effectively. New technology is needed to enable oil and gas operators to truly enjoy the benefits of predictive maintenance and keep their rigs running safely and continuously.

That new technology is none other than automated model building (AMB), which aims to deliver artificial intelligence (AI) to the fingertips of industrial companies, hence ensuring the success of predictive maintenance programs without the need for large data science organizations. As an AI company working in the oil and gas space, SparkCognition already has helped oil and gas operators apply AMB to their operations with great success.

Current state

Predictive maintenance, which involves analyzing patterns in sensor data to forecast impending asset failures before they occur, is an invaluable tool for oil and gas operators. It allows companies to optimize their maintenance strategies, performing the needed maintenance on the asset while it is not in use or bringing in a replacement beforehand if the failure cannot be averted. This greatly reduces unscheduled downtime while eliminating many of the uncertainties from the drilling process.

According to research by the Electric Power Research Institute, the annual cost of scheduled maintenance is $24/hp. Reactive maintenance costs $17/hp per year—before considering the additional costs of the safety hazards or operational damage that may be incurred by asset failure. Predictive maintenance was



Data scientists must be skilled and require extensive lengths of time to analyze the data to determine when maintenance is needed. (Source: SparkCognition)

Predictive maintenance, which involves analyzing patterns in sensor data to forecast impending asset failures before they occur, is an invaluable tool for oil and gas operators.

found to be by far the most cost-effective method, costing only $9/hp annually and including no hidden costs or dangers.

The quantitative benefits of predictive analytics also have been well documented within the oil and gas sector. McKinsey & Co. found that advanced analytics can yield as much as 30 to 50 times the initial investment within the first few months of implementation.

In spite of this, the oil and gas industry has been slow to adopt predictive maintenance, as it comes with some barriers to entry. Predictive maintenance requires data analytics, but data science talent can be scarce. Even for operations that do have an in-house data science team, the exorbitant amount of time predictive maintenance requires from it in collecting and analyzing new sensor data is neither feasible nor scalable.

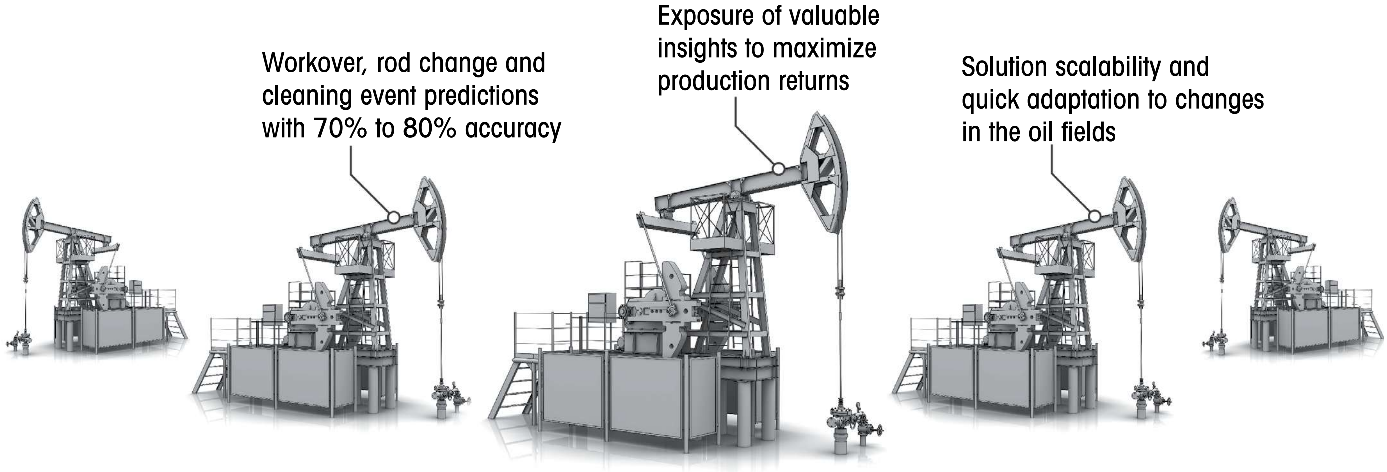
Predictive maintenance also relies on the use of models based on prior data to predict asset health and operating states. Traditionally, these models were built on predefined rules worked out by human analysts. Such models can take enormous amounts of time and human talent to build, perform poorly in extreme or unusual conditions and are subject to human bias. Additionally, they are inflexible; if a single variable of the asset changes, the model is rendered useless.

AMB is the answer

AMB opens up the full potential of predictive maintenance to the oil and gas industry. AMB platforms ingest operational, sensor and historical data, including production data (oil, gas, water, etc.), sensors from compressors, pumps and vapor recovery units. Then they automatically build machine learning models that predict the operating state and remaining useful life of a given asset. This reduces the time required for the process of model creation by orders of magnitude, bringing it down to weeks or even days.

AMB also amplifies a data scientist's work by enabling more effective model building. It gives data scientists the ability to iterate through thousands upon thousands of different models and architectures rapidly. In doing so, AMB allows data scientists and nondata scientist model builders alike to focus on their data problems rather than parameter tuning within models.

As AMB platforms leverage machine learning, models produced by AMB are continuously learning and refining themselves, allowing them to adapt to changing conditions in assets and catch the never-before-seen failures or edge cases that traditional models struggle with.



The use of AMB makes it possible for operators to reduce uncertainty in its field operations. (Source: SparkCognition)

Case study

SparkCognition proved out the utility of AMB in predictive maintenance for oil and gas for a major E&P operator looking to leverage the power of AI to predict workover needs and production in oil fields.

As oil and gas maintenance operations go, workovers do not come cheap. They require large crews, heavy equipment and the complete shutdown of production. For a fairly normal well that produces an average of 50 bbl/d priced at $60/bbl, ceasing production translates to an average of $3,000 lost income per well for each day it's not running. Add to that the costs of a workover rig with support equipment and crew at about $10,000 per day and it's a hefty price tag. All told, workover operations can cost roughly $70,000 to $100,000 for a single well.

> AMB allows data scientists and nondata scientist model builders alike to focus on their data problems rather than parameter tuning within models.

Unfortunately, workovers are a necessary evil of oil and gas production. On average, 10% of wells in a field require a full workover each year. Savvy operators are always on the lookout for ways to reduce this number while maximizing returns, and this operator decided to turn to AMB as a possible solution. Specifically, the operator wanted an automated, reliable solution to monitor the state of its wells, assist process engineers in identifying which wells needed maintenance (and what kind of maintenance), and predictive maintenance needs enough in advance to allow the operator to minimize downtime. It also wanted a solution that would help process engineers prioritize maintenance operations by assessing the potential return of a given well after a workover event.

Working together with SparkCognition's AMB Darwin platform, the operator rapidly created cognitive models to predict well maintenance needs and future well production accurately. These models were created using a limited dataset with only one input per month. This set included data on well static properties, including location, reservoir characteristics, and monthly oil, water and gas production. Darwin ingested these data, extracted the 40 most relevant features and built optimized models to identify seven types of maintenance events for wells in the field.

The models Darwin built predicted workover, rod change and cleaning operation needs in 12 out of 17 wells in the field with accuracy between 70% and 80%. These predictions were made three to six months in advance, allowing the operator to plan maintenance operations. In doing so, the operator was able to improve safety and reduce its operating costs by replacing expensive emergency repair with informed, as-needed scheduled maintenance events.

The models also provided valuable insights for process engineers on well production potential. The engineers were able to maximize their returns by focusing efforts on the most promising wells. E&P

Monitoring riser and wellhead fatigue

Systems provide field measurements of drilling riser and wellhead stress in real time.

Kenneth Bhalla and **Scott McNeill**,
Stress Engineering Services

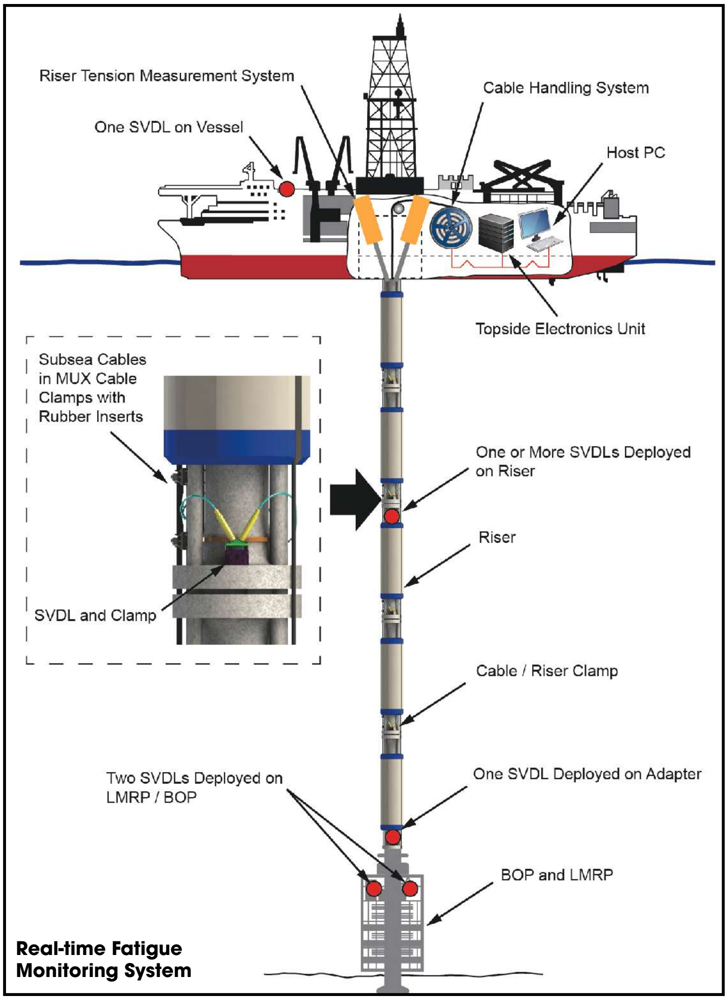
As drilling risers are deployed into deeper water, they are subjected to increasingly severe environmental loading due to ocean currents, wind and waves. Also, for drilling risers that are deployed in shallow water, the larger BOPs on sixth- or seventh-generation mobile operating drilling units (MODUs) result in higher wellhead fatigue loading, which potentially compromises the integrity of the well system.

Estimation and management of wellhead fatigue are required to ensure well integrity during offshore drilling operations. The criticality of this topic has increased recently as the fatigue demand due to loads on wellheads has increased with larger BOPs and lower marine riser package stacks, in addition to drilling operations being performed in harsher metocean environments.

The term "wellhead fatigue" refers to the fatigue damage at the hot spots in the wellhead and casing system. Cyclic loads are imparted to the wellhead by the connected riser, as the riser experiences dynamic motions from waves, vessel motions and by vortex-induced vibrations due to currents. The hot spots in the wellhead/casing system include welds, connectors and also the geometrical features in the wellhead itself.

Analytical models of these riser, wellhead and casing systems often predict premature failure due to the required safety factors and conservative modeling. As the design boundaries are extended, field measurements become necessary to assess the accuracy associated with these models. Additionally, such measurements are expected to play a prominent role as quantitative structural integrity management programs such as condition-based maintenance are formalized and mandated.

Stress Engineering Services has developed a real-time fatigue monitoring system (RFMS) and wellhead fatigue monitoring system (WFMS) to provide field measurements of drilling riser and wellhead stress and fatigue in real time.



The RFMS and WFMS calculate the stress in the riser or wellhead system from accelerometers and angular rate sensors housed inside SVDL modules located at strategic locations along the length of the riser and BOP. (Source: Stress Engineering Services)

System design

The RFMS and WFMS calculate the stress in the riser or wellhead system from accelerometers and angular rate sensors housed inside subsea vibration data logger (SVDL) modules, which are installed at strategic locations along the length of the riser and BOP. The SVDL modules are connected via fiber-optic subsea cabling to a central data acquisition system located topside.

The RFMS provides field measurements of drilling riser and wellhead stress and fatigue in real time. (Source: Stress Engineering Services)

The RFMS and WFMS are designed to provide an unprecedented level of actionable information on the health of the drilling riser, wellhead and casing system to the rig crew. By precisely recording the motion of the drilling riser, wellhead and casing system at discrete points in a time synchronous manner, fatigue damage of these components can be determined. Specialized algorithms in the software accurately compute the fatigue damage at any location, despite the complexity of the measured motions. By combining these data with past estimates, an accumulated fatigue damage history is calculated.

The primary driver is the need to acquire accurate, synchronous dynamic measurements in a subsea environment with a high degree of reliability. A secondary but important requirement is to minimize the impact of the system deployment on the riser running operations, thus driving a need for easy installation and retrieval in minimal time.

Case study

The RFMS was initially deployed at two well sites offshore Japan in water depths of 1,180 m to 1,939 m (360 ft to 591 ft). The system successfully collected and processed data from August to November 2012, recording a number of riser excitation events due to weather, vortex-induced vibration and operations while connected and disconnected from the wellhead. The system successfully recorded fatigue damage on the riser.

A comprehensive measurement campaign using the WFMS was designed and deployed on a sixth-generation semisubmersible MODU. The measurement campaign was conducted in a shallow-water region (water depth of 85 m to 95 m [26 ft to 29 ft]) and was subjected to a harsh wave environment. The campaign consisted of a real-time WFMS that measured vessel, riser and stack motions with synchronized accelerometers and angular rate sensors. Additional data including wave and current data, mud weight, slip ring tension, vessel offsets and the tensioner pressures were concurrently measured.

The objective was to quantify any possible conservatism in the riser analyses and thus in wellhead loads and fatigue estimates. In other words, the focus is to address the "load" side of the wellhead fatigue equation, the "resistance" side being out of scope. Any conservatism in loads due to the design of metocean conditions was not the focus of this work. Rather, conservatism in the computation of system response to known (measured) excitation was the focus of the investigation.

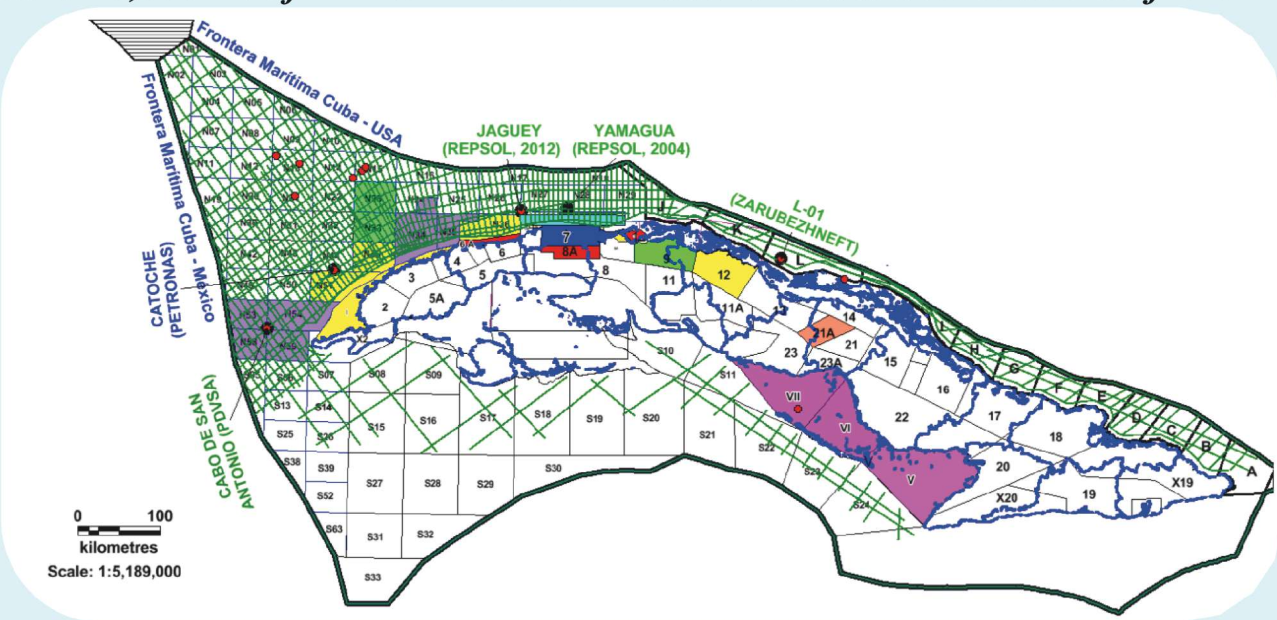
Analytical models were driven both in frequency-domain and time-domain with measured environmental excitation, and the analytical predictions of riser and stack motions were compared with motions measured in the field. Approximately six weeks of measured data were used for the data analysis and model validation. Another objective of the monitoring system was to provide real-time information to the rig crew on the riser/stack motions and on wellhead fatigue response and management.

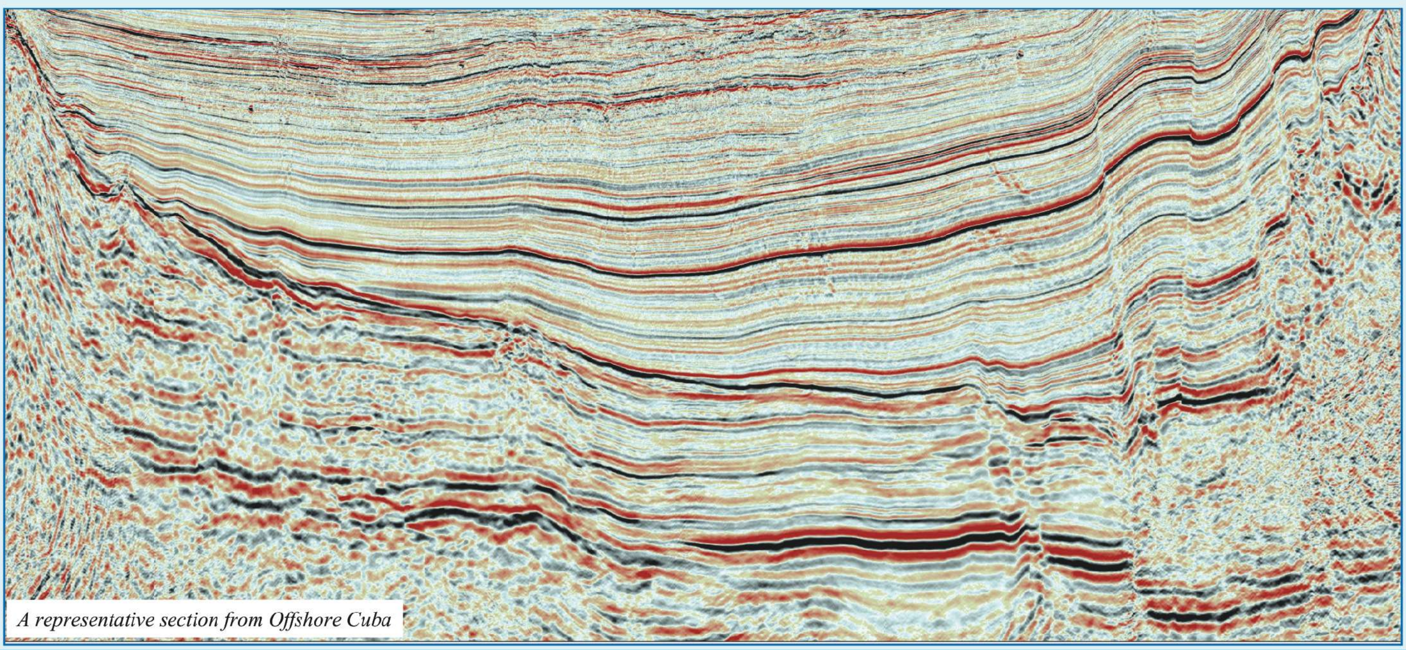
The deployment showed that the RFMS riser and stack motions predicted by analysis using existing modeling techniques match well with the measurements. By extension, the wellhead loads would be accurately estimated from analytical models. This is valid for the analyzed conditions, which correspond to the shallow-water depth (85 m to 95 m), stiff sandy soils, mild to harsh wave environment and small current speeds (no vortex-induced vibrations). With the given metocean conditions, the load side of the wellhead fatigue equation appears to be reasonably predicted by existing analytical techniques both in frequency and time domain. Valuable information was provided to the rig crew, enabling uninterrupted drilling activity despite the harsh conditions. E&P

CUBA

PRE-ANNOUNCEMENT FOR INTERNATIONAL BID ROUND, 2018

Cuba is coming out with a plan to launch a formal bid round at the Cuba Oil & Gas Summit in December, 2018. The round will run from Q4, 2018 until Q2, 2019. It will focus on around 50 exploration blocks in the Cuban sector of the Gulf of Mexico. BGP Offshore has acquired a 2D Multi-Client survey in offshore Cuba after being awarded a contract by Cupet as shown in following map. Newly released 26,880km of 2D PSTM & PSDM data are available to license from BGP.





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Optimizing PRODUCTION

Operators set sights on enhancing recovery techniques.

Brian Walzel, Associate Editor, Production Technologies

As the North American unconventional oil and gas industry continues to be a prime mover on the worldwide energy stage driven by remarkable gains in completion efficiencies, oil companies large and small might be moving into a phase in which those completion designs are reaching maximum optimization. Lease rights will ultimately dictate how far lateral lengths can be extended. There is a finite number of potential fracture stages in any given well, and there are indications that intense proppant loads might be reaching their peak in some basins.

A study issued in February by McKinsey Energy Insights reported average proppant loading in the Bakken Shale increased from about 800 lb/ft in 2016 to nearly 1,000 lb/ft by mid-2017.

"By performing a sensitivity analysis on proppant intensity, we can see that operators in the Bakken have limited growth potential from current intensity levels before the incremental pound of proppant negatively impacts NPV [net present value]—observed about approximately 1,100 pounds per foot," the McKinsey report stated.

Equinor will deploy artificial-intelligence-powered artificial lift technology on its rod pump wells in North Dakota. (Source: Ole Jørgen Bratland/Equinor)

McKinsey suggested that by this year, additional moves toward higher proppant intensities "will likely diminish the value of the well."

If operators are, in fact, nearing the limit on completion optimizations, the industry now is turning to methods to get the most out of their production operations. Opportunities abound in places like the Permian Basin to implement methodologies to draw out decline curves to ensure well production remains healthy for a longer period of time, particularly as the understanding of decline curves for unconventionals becomes more recognized. For example, a recent Wood Mackenzie report suggested unconventional wells in the Wolfcamp might have an annual decline rate closer to 12% to 14%, as compared to conventional vertical wells, which have annual decline rates of up to 10%.

This month's cover story features insights from several operators and service providers that talk about their current production strategies and how they address some of the challenges they face, including parent/child well interactions and long-term production strategies. E&P

Shifting the focus to optimized production

Operators see opportunities for production gains in legacy wells, refracturing and data analytics.

Brian Walzel, Associate Editor, Production Technologies

Producers operating in the unconventional oil and gas basins in North America have found in optimized completion designs the right recipes to make production in a post-downturn industry economic. Over the past half-decade, operators have discovered that longer laterals, higher proppant loads, tighter stage spacing and more fracture stages have led to lower breakeven costs in a $70/bbl price environment.

Now there are emerging signs indicating that the era of optimized completions might be beginning to plateau, that operators might be pumping as much proppant into the well as they can and that laterals have extended so long that it might not be economical to drill out much farther.

"We believe there is a point of diminishing returns [on completion optimizations]," said Jim Miller, senior vice president of operations for Chaparral Energy. "There are several areas in the Stack where operators over the past three years have pushed up the pounds of sand per foot. Probably within the last six months, you've seen some of them start to pull back and drop back down. When you compare those wells where they pulled back down or decreased to the EURs of the wells with a higher sand per foot concentration, you can see they reached a point of maximum returns."

Miller added that in the Meramec Formation in Oklahoma, operators likely have yet to reach maximum levels of sand loading, "but the industry is pretty close to seeing it."

If, in fact, operators are reaching the limit for optimized completions, where does the industry go from here? Where lies the next opportunity for value creation?

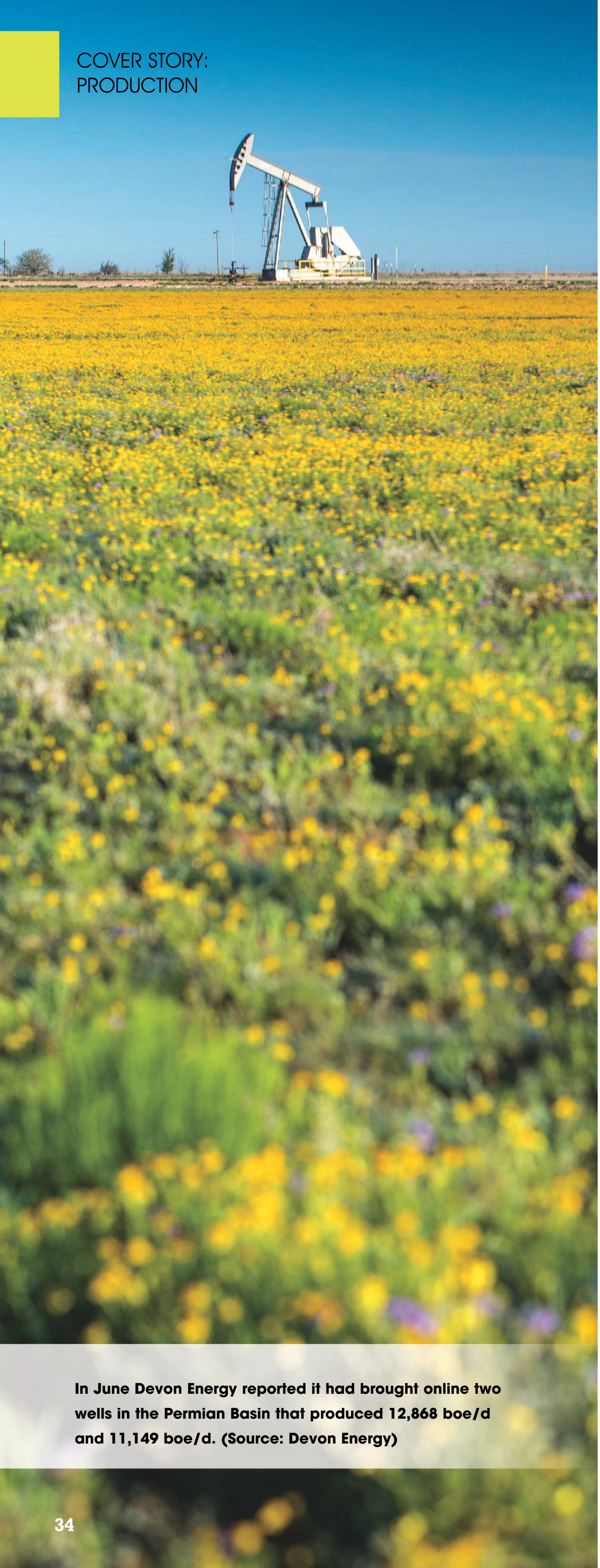
In exclusive interviews with *E&P*, several producers operating in major basins throughout North America as well as service providers specializing in production technologies said the next era in optimization could well come in enhanced production systems and tools designed to draw out decline curves and improve EURs. Recent events indicate such an evolution.

In late July Equinor announced it will deploy a rod lift technology developed by Ambyint—a company that specializes in artificial lift and production optimization equipment—on its wells in the Bakken Shale, where Equinor will expand the system to full-field development.

During pilot testing, Equinor was able to automate rod pump well optimization through the use of Ambyint's autonomous set point management functionality, according to a press release. By identifying wells that were overpumping or underpumping, controller set points were adjusted "with minimal human interference," the release stated.

Equinor said in the release that this type of proactive optimization system resulted in increased production

Chaparral Energy produced 12,289 boe/d from Oklahoma's Stack play in the first quarter of 2018. (Source: Chaparral Energy)



In June Devon Energy reported it had brought online two wells in the Permian Basin that produced 12,868 boe/d and 11,149 boe/d. (Source: Devon Energy)

rates and more efficient pumping while reducing the well volatility.

"The Ambyint technology has improved the remote data visibility and has delivered a more accurate diagnostic of downhole conditions to our rod pump wells in the Bakken," said Jack Freeman, production engineer for Equinor's Bakken asset, in the release. "The autonomous speed range management tool has leveraged the power of machine learning to optimize our wells by identifying and acting on real opportunities."

Brian Arnst, director of optimization at Ambyint, said much of the processes and systems used by oil companies even 50 years ago are still in use today and that many of those processes and systems have finally proven to be outdated and inefficient.

"Pump-off controllers were introduced in the 1960s, 1970s and [variable frequency drives] were applied on top of pump-off controllers in the early 2000s," Arnst said. "But at a very high level, companies are still deploying if-then logic. They are not doing any calculations on site.

"Companies are starting to recognize this, and they are starting to look for what that new solution is. Frankly, there are not a lot of options out there right now. You're starting to see companies trying to find a new strategy, which focuses on what technologies exist that can allow them to take their production optimization strategies to the next level."

Arnst said Ambyint identified a trend in the market in which production optimization was being neglected, with companies instead focusing their investments more on completions and advancing reservoir characterization technology.

"Now we're seeing a lot of companies turn to the production side and realize that is where their cash flow in 20 years is going to come from," he said. "They are realizing they need to figure this out and get their [lease operating expenses] in order. A lot of companies are looking to invest in production technologies that can handle the changes these horizontal wells are bringing."

Legacy well optimization

One of the principal areas that operators are turning to in their efforts to optimize production are their legacy oil and gas wells, which are older wells whose production has tapered off but also might have ample reserves remaining. Legacy wells run on aging systems and therefore are prime candidates for restoration. Among the challenges of optimizing legacy wells are pressure depletion and higher gas-liquid ratios

(GLRs), said Jimmy Turnini, production optimization manager at Devon Energy.

"We are pushing the limits of rod pump by setting the pump in the curve toward the lateral with success due to better design and equipment available to handle gas and sand migration," he said. "Drawing down the reservoir is key and getting the pump down deeper helps."

Turnini said Devon works to stretch out decline curves by combing lift methods like gas-assisted plunger lift and developing in-house algorithms to provide on-demand supplemental gas to plunger wells when needed.

Amir Gerges, Permian general manager at Shell, said the company focuses on improving the performance of its wells through its Well, Reservoir and Facilities Maintenance Program, which he explained is an integrated data-enhanced performance system designed to maximize value.

"A multidisciplinary team performs surveillance and optimization activities across the production system," Gerges said. "This process consists of gathering, managing and interpreting data that are then used to identify and execute production-enhancing opportunities throughout the field. In our Permian asset, we conduct daily, weekly, monthly and annual reviews."

According to Rocky Seale, national product line sales leader, completions and well intervention at Baker Hughes, a GE company, a common method the company implements to drive cost savings and improve production are wellbore cleanouts. Seale explained that debris accumulates in the wellbore and impacts the functionality of artificial lift systems such as electric submersible pumps (ESPs) and can cause them to fail prematurely.

"That's a big value add for the operator, where they can go clean out the well and then, instead of having to change out a pump every nine months or so, it extends the life [of the ESP] to 12, 15 months," he said.

One of many pumpjacks is at work among the rolling green hills of the Joseph H. Williams Tallgrass Prairie Preserve in northeastern Oklahoma. (Photo by Jennifer Presley, Hart Energy)

Robert Turnham, president of Goodrich Petroleum, stressed the importance of maintaining a conservative approach to choke management during production operations, particularly in overpressured wells.

"What we and others are doing is limiting our pressure drawdown on a daily basis to 30 to 50 pounds per day," Turnham said. "You restrict the flow in an effort to not pull the reservoir too hard, because if you pull it too hard, or open the choke too much, then you'll see premature depletion. So choke it back to a rate and pressure where you are very gentle on the reservoir and you flatten your decline curves."

Turnham said such a strategy would ultimately generate better recovery of the gas that is in place versus seeing a higher production rate early on, but have a much steeper decline curve, which Turnham explained as being damaging to the reservoir.

The key component to any production optimization strategy is cost, he said. Turnham identified the best correlation to determining cost efficiency in production operations is the amount of proppant per foot compared to EUR.

"So the higher proppant concentration equals better EUR up to a certain point," he said. "Then you have diminishing returns."

Turnham explained how Goodrich pumped 1,000 lb/ft to 1,100 lb/ft of proppant in the Haynesville, which led to about 141 MMcm (5 Bcf) of return on a 1,402-m (4,600-ft) lateral, or 31 MMcm (1 Bcf) per 304 m (1,000 ft) of lateral length.

"We're now pumping 3,000 to 5,000 pounds per foot and getting as much as 3 billion cubic feet [85 MMcm] per 1,000 feet [of lateral]," he said, "… so a lot more sand but a much higher EUR. The real question is, by going from 4,000 pounds per foot to 5,000 pounds per foot, is your IRR [internal rate of return] the same, better or worse? Because we know the EUR is going to be higher based on the proppant concentration being higher at 5,000 pounds per foot."

Turnham said Goodrich is finding that the optimum return might be to "dial back" proppant concentrations from 5,000 lb/ft to about 4,000 lb/ft.

"So it's not the highest EUR, but it's the highest IRR," he said.

Well refracturing

Although not all operators are implementing refracturing operations, companies often refracture some of their older wells to squeeze more hydrocarbons from their respective reservoirs, particularly if the well was initially poorly completed or understimulated.

"The biggest thing that has changed is refracking of existing wells," Turnham said. "In the Haynesville back in 2008 to 2014, we were predominantly drilling 4,600-foot laterals and pumping about 1,000 pounds of proppant per foot. The frack interval was 250 to 400 feet [76 m to 122 m] wide. Basically, we would [fracture] 10 to 12 stages with very low stimulation per foot compared to what we're doing now. So clearly the vintage wells were understimulated, which is why they are good candidates for refracks."

Turnham said a few years ago "Hail Mary fracks" were common—pumping without much direction and hoping the well stimulation fluids would get into the formation where operators needed it to get more gas back. Now, Turnham said Goodrich is revisiting its wells by introduc-

Devon Energy produced 56,000 boe/d last year in the Delaware Basin, 10% of the company's total production. (Source: Devon Energy)

ing smaller pipe, cementing in smaller casing of the existing well's casing and running plug-and-perf fractures.

"You can't pump at similar rates as a new well because the interior casing is smaller, but you're going into a wellbore that was clearly understimulated," he said.

David Elkin, senior vice president of asset optimization at EQT, said for refracturing options to be viable in the Marcellus Basin, the initial completion must have been very poorly designed. Although EQT has tested methodologies of the past, the company has yet to observe a need since its early well designs featured what Elkin called "reduced cluster spacing."

"EQT has very few understimulated wells and therefore very few refracturing candidates," he said.

Turnini said Devon is engaging in refracturing in the Barnett, focusing on opening new perforations or adding additional intervals that were not originally completed.

"The general approach is to re-perf tighter clusters between existing clusters and try to pump new completions with diversion," he said.

Oasis Petroleum has been experimenting with refracturing possibilities for about the past three years, said Taylor Reid, president and COO.

"We now have an active program where we refrack parent wells as we are fully developing each drilling spacing unit [DSU]," Reid said. "Generally, we frack the parent well first using a combination of gelled fluid, slickwater and heavy doses of diverters."

Reid said in Oasis' early wells they had challenges getting adequate distribution of the fracture across the lateral, which resulted in the toe of the well preferentially taking most of the fracture. The company looked to solve the problem by leveraging microseismic evaluation and fiber coil to confirm the fracture distribution across the lateral.

"In later jobs we adjusted by using combined liquid and particle diverters at higher loadings to much greater effect," Reid said. "In fact, the microseismic and fiber coil confirmed distribution across the lateral. Once the parent wells are fracked, we then fracked the new offset well. The result has been that wells, which were on rod pump before being fracked, generally flow and then produce at higher rates post-frack, adding unique reserves that more than justify the capital expenditure."

Reid also disclosed that Oasis is working on EOR designs in the Williston Basin. He said the evaluation is in the early days and the hopes of Oasis and other operators testing EOR in the Williston are to increase the amount of oil recovery from what is typically about 10% to 20% of oil in a reservoir.

"There are a number of options, but the most popular under evaluation currently involves the injection of natural gas and/or natural gas liquids from the reservoir to liberate incremental oil," Reid said. "As I said, it is early in the evolution of these techniques for the Bakken, but it could have a substantial impact to the production life of a well and to the overall reserves for North Dakota and Montana."

Seale said refracture design trends in the Eagle Ford and Haynesville include operators initially running a 3½-in. to 4-in. pipe inside a 5½-in. sealing and reperforating sections between the initial wellbore perforations. In the Eagle Ford, some operators are implementing larger-sized casing to plan for refractures at a later date, he said.

"For example, in the Eagle Ford you are seeing operators that instead of running 5½-in. casing, they are running 6-in. casing to give them that little bit of extra room," Seale said. "That reduces the friction pressure on the initial frack, and then they can run 5-in. flush joints through there and through their refrack if they choose to do it at some later time. So they are planning the wellbore for refrack and re-entry down the road ahead of time."

Artificial lift trends

Graham Makin, vice president of sales, marketing and investor relations at Silverwell, a service provider that specializes in digital artificial lift systems, said there is ongoing discussion among operators in unconventional plays about the cycle of artificial lift techniques through the life of the well.

Makin said current discussions are centering on how long a well should flow under its own pressure, when

EQT produced 678,208 MMcfe/d through the first six months of the year at its Marcellus and Utica operations, a 98% increase in production over the same period last year. (Source: EQT)

to implement ESPs, and when to turn to gas-lift systems and eventually to rod and plunger lift systems.

"People optimizing that process are trying to decide which lift technique to use when, and that process is being driven in different ways depending on if they want to maximize production in the early phases of a well, from an economic point of view, or if they want to go for a longer life cycle and take a reservoir management approach to the well," Makin said.

Devon has moved away from ESPs and toward gas-lift systems as a result of well flow characteristics and economic benefits because an ESP system is often costly to maintain, according to Turnini.

"IP with steep declines, increasing GLRs and sand migration played havoc on ESP reliability so we've moved to gas lift as we've developed better designs and, through the use of modeling, determined that we can draw the reservoir down farther than once thought," Turnini said. "The failure rates are much lower, making the economic benefits for gas lift superior to ESP in many of our cases."

Oasis Petroleum implements a variety of artificial lift methods in its production operations, including gas lift, ESPs, jet pumps, rod pumps, plunger lift and traditional beam pumps. Reid said selecting the right artificial lift method is dependent on the well and its time in the life cycle.

"The first phase of high-capacity lift is critical to realize the benefits of the high-intensity fracks we are employing," Reid said. "Rod lift systems simply do not have the capacity to move the volumes of fluid at this stage in the well's life. As production drops off over time, we will eventually place the wells on rod pump."

Chaparral's Miller said they primarily apply ESPs on their Stack wells, which he said have proven more productive than gas-lift systems.

"We primarily determine whether to use an ESP or gas lift by a GLR of greater than 1,000," Miller said. "If it's above 1,000, we'll typically go with gas lift. If the GLR is lower than 1,000 or closer to 500, then we'll usually move toward the ESP. But when we look at the production of wells on ESP versus gas lift, we see peak IP rates of less than 60 days on an ESP versus peak IPs on a gas lift of sometimes up to 120 days."

Digital technologies

While operators turn to refracturing and determine the optimal artificial lift strategy to enhance their production returns, Devon's Turnini said the most substantial impact on production optimization comes in the form of analytics.

"In my opinion, the biggest opportunity to enhance production operations is to leverage real-time data," he said. "This will enable us to provide the field with information to act on quicker and move us from being reactive to more proactive."

EQT is among the growing number of companies adopting data analytics and predictive technologies into its operations. Elkin said such an approach aids in extending producing well decline curves.

"We do find ourselves with a larger and larger base production made up of these later-life wells, and we have to think about how to extend and smooth out that production as best we can, even with new volumes constantly being onboarded," Elkin said. "The answer to that is, of course, getting to lower field pressures but also leveraging our current plunger systems with sensors, transducers and SCADA, and optimizing in real time through production profile algorithms, potentially getting into pattern recognition and AI [artificial intelligence] so we are predicting performance ahead of time and adjusting to it."

Predictive maintenance algorithms have proven particularly useful for companies like Devon and Chaparral, both of which have leveraged their capabilities to predict ESP failures, which are a common and costly problem in production operations.

"A key for us has been lowering the number of failures we've had on ESPs," Chaparral's Miller said. "We spent a lot of time evaluating historical data and determined how many failures have to occur before we realize better returns running a gas lift versus an ESP. It's around one-and-a-half. Typically we would want to shift an ESP to a gas lift or a rod pump sometime between six months and a year, so our ultimate goal was to determine how to keep failures below that one-and-a-half mark threshold during that time frame so that we're a lot better off economically. Thanks to the enhancements we have made with our automation systems, we've been able to do that and seen a significant reduction in ESP failures."

Josh Walker, vice president of completions and operations at Chaparral Energy, said the company widely implements data analytics, but the analytics systems only work well if the data are managed the right way and "kept clean." Walker said Chaparral can leverage the company's historic production data to determine a specific reservoir landing location from a specific well pad and what the first method of artificial lift should be for that well.

"Beyond that, our goal is to get to real-time optimization," he said. "That's where the automation comes in so that we can control things from anywhere. We can get to the point, for example, historically with a plunger lift well we might have a lease operator tweak something one day and we'll watch it for a week, and [then] we'll make another tweak and we'll watch it for a week. Where with the real-time optimization, we can see everything in real time and make immediate changes. You can have a machine make 30 changes within a day and get a result that took weeks in the past ironed out in a matter of hours or days."

Parent/child well challenges

One of the most significant challenges facing the oil and gas industry in regard to production is the relationship between producing "parent" and "child" wells, or well bashing. Well bashing is a result of drilling infill, or child, wells that interfere with existing parent wells as fractures from the new wells connect with the old ones, which can lead to a loss of fracturing fluids and underperformance in both wells.

Well bashing can significantly reduce the amount of recoverable reserves from a reservoir. Operators in every basin acknowledge the problem, but solutions are so far proving elusive.

Elkin said that although EQT does face issues with parent/child well interactions, the Marcellus Basin is relatively more "forgiving" than other plays. He said EQT manages the effect of offset depletion by managing pressure on the parent well prior to completing the child well.

"Unfortunately, there is no one-size-fits-all solution," he said. "Both produced volume and the completion design of the parent well can affect the outcome, and alterations to the spacing and completion design of the child well may also be necessary to mitigate this interaction."

Turnini said Devon is still "exploring options" but has seen some success in controlling the effects of well bashing by recharging the parent well with water ranging from small to larger jobs equivalent to the original fracturing job.

In its Permian Basin operations, Shell conducts reservoir development for the entire reservoir area, taking into consideration the optimal well spacing and completion design for each horizon, Gerges said.

"Dependencies between horizons are managed as co-development, with a focus on managing interference and minimizing parent/child depletion to maximize recovery and value," he said.

Oasis' Reid said that in North Dakota the company is applying full-field development strategies, so Oasis does not have much activity cycling in the same area, which helps allay the effects of well bashing.

"We generally have one parent well in each of our DSUs, and when we come in for development drilling we are drilling out the full DSU at all depths in the Bakken and Three Forks to minimize future interference effects," he said. "In addition, we are often refracking the parent well to improve its performance and to minimize the disruption to the new wells from a depleted parent well."

As operators turn their attention to production optimization, they will face a multitude of challenges, from implementing artificial lift techniques to addressing the interactions of parent and child wells. Both service providers and operators alike agree that as production optimization plays an increasingly important role in the industry a major step change moving forward will be the application of data analytics, predictive and optimization programs.

"The industry as a whole has always optimized production; it's just been an extremely laborious and slow process," Silverwell's Makin said. "What we are now on the cusp of being able to do is make that process immensely efficient with a much faster cycle time." E&P

Sands of time

A proppant silo system increases efficiency and storage capacity.

Tiffany Matthews, **Nathan Markert** and
Claire Kennedy Platt, NOV

Technology developments in hydraulic fracturing continue to result in smarter solutions. As increasingly longer horizontals become more common, especially in shale basins, proppant usage is higher than ever before. Drilling advancements, downhole proppant placement and zipper fracture designs are dramatically impacting the number of wells per pad, the number of stages per well and time reduction between fracture stages. As such, sand logistics are proving to be a major player in the success of fracturing operations. Conventional onsite storage systems are unequipped to handle proppant requirements in today's industry, resulting in insufficient sand volume ready to feed the fracture operation. Shortages of hot sand on site lead to increased nonproductive time (NPT), adding to operational costs and unnecessary delays in the well completion process.

Multiwell pads create additional challenges by requiring fracture equipment to be set up and operational for increasingly longer periods of time. Once set up, existing sand storage solutions take up a large footprint on location. Also, these uncontained storage systems create abundant dust volume during the pneumatic loading process, causing potential safety risks and falling short of upcoming industry regulations. The SandBank proppant silo system from National Oilwell Varco (NOV) increases sand storage capacity, creating a smaller footprint, improving efficiency in unloading sand transports and limiting dust exposure.

The SandBank loads a silo at 275 tons of proppant per hour using a bucket elevator system and feeds blenders between 700 lb/min and 20,000 lb/min of proppant using auto-controlled conveyors. (Source: NOV)

Improved storage capacity, operations

NOV engineers examined industry proppant handling needs, comparing conventional methods with silos and box-style storage systems. Selecting silos as a more optimal solution, they worked to improve storage capacity. SandBank contains six silos, each holding up to 400,000 lb for a total system volume of 2.4 MMlb of proppant. The capacity of the system is 1.6 times more than traditional fracture sanders and six times greater than competing box-style equipment. Compared to existing solutions, vertical storage creates a smaller footprint by occupying less space on site.

In addition to focusing on improving storage capacity, the engineering team sought to drastically reduce the time associated with unloading sand transports on location. This was accomplished by combining a belly dump drive-over conveyor belting system, a swiveling diverter head and silos outfitted with integral bucket elevators. The elevators are capable of moving 275 tons of proppant per hour. Using two drive-overs in a six-pack configuration with a one-time setup allows four trucks to simultaneously unload at a total rate up to 550 tons per hour.

A significant added benefit of this system is that it eliminates the need for the pneumatic conveying of sand. The SandBank proppant silo system can unload a transport more than twice as fast as pneumatically conveying into traditional fracture sanders, a 58% reduction in unload time. Compared to pneumatically filling silos, it unloads more than three times faster, a 70% reduction in unload time. Improvements such as this will have a direct impact on demurrage cost reduction incurred for sand logistics on a well site.

By increasing the amount of sand available on location and significantly reducing time to unload a sand transport, SandBank minimizes the risk of proppant shortages. This effectively drives improved uptime, reduces potential NPT and mitigates delays associated with sand logistics.

The engineering team emphasized redundancy, which served as a large driver for the system design. SandBank features bucket elevators in each silo, offering an advantage over other methods of silo loading with standalone, independent bucket systems. Pneumatic fill pipes also are included on each silo. Two drive-overs are included and can be exchanged with a simple swap out if necessary. The two bases each contain a conveyor designed with automatic or manual blender feed control capable of delivery rates between 700 lb/min and 20,000 lb/min each. All six silos can gravity feed either conveyor. The integrated six-pack configuration can supply two blenders.

Each SandBank base contains a 480-V, alternating current diesel-electric generator for system power supply and offers critical function generator backup across the bases or shore power options. Additional features include a pressurized climate-controlled operator cabin with complete system controls, automated silo overflow protection, and simultaneous loading and unloading capabilities. For ease of mobilization and setup, a complete SandBank system includes silo transport trailers with hydraulic lift cylinders and an integral lift frame. These trailers can be used to stand up silos on a base or the ground and can connect to either side of a silo, providing additional handling or positioning provisions.

Safety, regulations

As hydraulic fracturing demands have changed, so have industry regulations. The U.S. Occupational Safety and Health Administration (OSHA) is changing requirements to protect personnel from exposure to crystalline silica. Hydraulic fracturing operations in the oil and gas industry are required to implement dust controls to limit exposures to the new permissible exposure limit (PEL) by June 23, 2021. The new PEL will be 50 μg/cu. m averaged over an eight-hour day. To meet future industry regulations, NOV focused on mitigating dust exposure by designing fully enclosed conveyor systems, implementing a gravity feed protocol for the sand transport and silo unloading processes, and incorporating a pressurized operator cabin.

Compared to existing proppant storage solutions, NOV's SandBank proppant silo system enables the industry to accommodate the latest hydraulic fracturing demands. In addition to offering the ability to store significantly larger volumes of sand to feed the fracturing spread, the system offers more efficient loading and unloading of the silos.

Built-in redundancy solves common challenges associated with traditional proppant storage. The system puts the end user in the optimal position to reduce NPT on location and capitalize on cost savings. By minimizing dust, SandBank also drives safety improvements and helps the industry prepare to meet upcoming OSHA regulations. The product will undergo field trials late in the third quarter of the year. 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*.

Longer laterals push connection innovations farther

Challenging reservoirs requiring longer laterals drive demand for improved semipremium connections.

John Feuerstein, Hunting Energy Services

As the U.S. onshore unconventional oil and gas E&P effort continues to grow, the demand for connection performance increases as operators push the envelope in their quest to reach more challenging reservoirs and increase lateral reach.

"We knew from our own experience and from hearing the operators' needs that longer reach lateral wells being drilled or planning to be drilled required more out of semipremium connections," said Aaron Walsh, manager of engineering services for Hunting Energy Services. "They may have to push on it more, so compression is needed. They may have to rotate it more, so torque is an issue. We knew that a slimmer wedge-type connection that could provide the compression and performance, much like a threaded and coupled connection would, was needed."

Left, during the application of high torque, the test subject 5.500 20.00# P110 pipe body was crushed at 46,500 ft-lb. Right, after the application of maximum torque, the TEC-LOCK Wedge connection was undamaged. (Source: Hunting Energy Services)

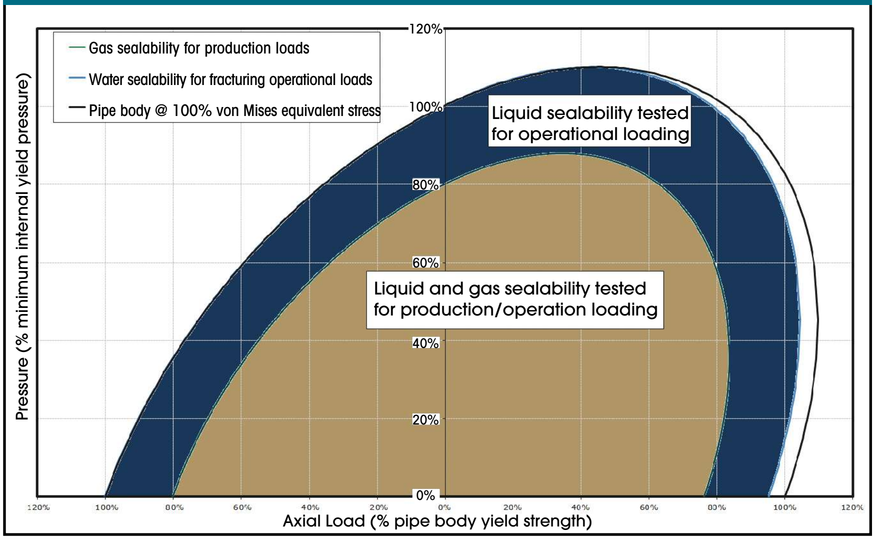
To address these requirements, Hunting developed the TEC-LOCK semipremium connection that features close-tolerance and wedge-style thread forms as an alternative offering to premium connections. This new product family consists of TEC-LOCK BTC, TEC-LOCK BTC-S and TEC-LOCK Wedge.

"We incorporated the design philosophies and characteristics of our WEDGE-LOCK semiflush premium connection that has had great success in the Gulf of Mexico into a smaller outer diameter [OD] connection size for the onshore market," Walsh said.

The BTC and BTC-S connections are close-tolerance thread forms that minimize connection stresses and eliminate the open J area, thus creating a flush inner diameter for turbulent-free flow and reduced tool hang-ups. Available in 4.5-in. to 9.625-in. sizes, the connections deliver multiple make-and-break capabilities. The TEC-LOCK Wedge features a semiflush OD and offers extremely high-torque capabilities and maximum axial efficiencies. The "wedge" thread profile provides full pipe body compression performance and increased torque ratings.

"The connection's integral connection design eliminates the need for a coupling through the use of an expanded box that is less than the standard API [American Petroleum Institute] coupling diameter," Walsh said. "This helps to improve clearance, circulation and cementing while also reducing drag, not to mention the operational and economic advantages that come with eliminating the

TEC-LOCK WEDGE WITH SEALLUBE - PRODUCT FAMILY PERFORMANCE



SealLube, when applied on the TEC-LOCK Wedge connection provides a gas-tight seal like that found in metal-to-metal premium connections. (Source: Hunting Energy Services)

coupling. To reduce running time on the rig, the Wedge connection makes up quickly, significantly reducing overall rig running time and further saving the customer money in operating costs."

When used with Hunting's SealLube thread sealant, the Wedge connection provides gas sealability on a product without a metal-to-metal seal.

Test-certified performance

Designing the connection is one thing; however, validating the connection's performance prior to bringing it to market is the primary concern. The company's engineering team performed rigorous full-scale physical testing on the TEC-LOCK Wedge. Comprehensive make-and-break and torque-to-failure tests were performed to evaluate the robust connection thread's resistance to damage at extreme torques. From there, the connection was tested for gas sealability in a combined load test to validate its use for gas wells. Finally, the connection went through cyclical fatigue testing to establish the connections survivability in applications where drilling, reaming or rotating while cementing operations are required. All tests concluded successfully, met all expectations and conclusively validated the stated performance of the connection.

TEC-LOCK Wedge provides the ability to achieve longer laterals with extreme torque and gas sealability without using costlier premium connections. Reducing operational costs by quicker makeup and run time, eliminating the issues and limitations associated with couplings while at the same time mitigating risks of overtorqueing the connection, Hunting's TEC-LOCK Wedge connection provides premium performance while maintaining the required economics of the highly competitive semipremium market. E&P

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Taking a focus on packing

A new packing system cuts maintenance time in half for fracturing operations.

Neal Spence, Gardner Denver

As well complexities, temperatures, pressures and lateral lengths increase, so do the demands placed on service companies to provide capable rigs and technologies that operate in an efficient and safe manner. With many service companies taking a measured approach to increasing operating costs, oftentimes new pressure pumping equipment is not in the budget. New pumps are an expensive investment, causing many service companies to make existing equipment work. However, money is being invested in consumables (packing, pistons, valves, plungers, etc.), allowing older pumps to continue running even in today's harsh conditions.

Until recently, consumables have not been given much consideration, and there were not any distinguishable characteristics between them, allowing service companies to choose the cheapest and/or most convenient options. As the industry exited the downturn, customers simply had to find ways to be more efficient and extend their equipment's life without breaking the bank.

Packing is the critical sealing system in the heart of the pump, which creates a barrier between the high-pressure fracturing fluid and environment. Generally, packing is the second most common reason service companies have to tear into a fluid end, resulting in costly nonproductive time (NPT). Historically, packing has to be changed out/serviced between 50 hours and 250 hours of run time, depending on the shale play. This leads to unwanted downtime, causing safety risks and costing operators money.

Frequent packing changes and shortened service intervals add additional strain on available horsepower to complete a fracturing operation. Every time field personnel have to open up a fluid end, it puts them at risk to pinch points, heavy loads and challenging working conditions (consider winter in North Dakota or August in South Texas). Packing changes also can introduce operational installation errors that can lead to costly fluid end washouts and premature fluid end failures.

Extending product life

Gardner Denver launched the first of its Redline Consumables, Redline Packing, in February after two years of R&D and extensive field testing in both Gardner

FIGURE 1. This image depicts catastrophic packing failure after 35 hours of operation. (Source: Gardner Denver)

FIGURE 2. Redline Packing demonstrates no failures after 138 hours of operation. (Source: Gardner Denver)

Denver and competitor fluid ends. The company's product development team conducted research into packing failures, product design and property makeup in an effort to improve packing performance and extend product life in fracturing operations. In preliminary field trials in the Denver-Julesburg Basin in Colorado, Redline Packing outperformed its predecessor by nearly 700 hours.

With redesigned header and pressure rings and refined material makeup, Redline Packing can withstand increased heat, friction and abrasion resistance in high-pressure environments, ultimately leading to longer product life. Redline Packing's improved performance in harsh wells extends maintenance intervals, reducing downtime and increasing margins. The increased asset utilization rate allows packing to be changed at the maintenance facility rather than at a field location, decreasing NPT.

Case studies

In December 2017 Gardner Denver teamed up with a service company to run Redline Packing in the Scoop and Stack plays in western Oklahoma, where high pressures and challenging conditions are standard.

Conditions included 9,500-psi average pressures, 100-mesh sand and 105-bbl/min flow. Upon test completion, 144 stages were completed. The incumbent averaged 50 stages with 32 failures out of 45 sets of packing (a 71.1% failure rate). Redline Packing had one failure out of 40 sets of packing (a 2.5% failure rate).

Since the conclusion of preliminary results and compilation of data into definitive results, the customer has installed Redline Packing on more of its fleets, which continue to increase asset utilization and lower its cost of ownership.

In another field test, the customer wanted to determine how long it could push Redline Packing. The incumbent packing lasted 50 stages at 2 hours per stage. After seven complete jobs, Redline Packing completed more than 280 stages with only three packing bore failures, saving the customer in excess of 55 hours of scheduled maintenance, not including all the pump downtime. These time savings equated to lower NPT, faster fleet turnarounds and increased productivity. These factors translated into the customer earning two additional days of pumping, which generated an additional $2 million in revenue. Because Redline Packing lasted well past the service company's scheduled maintenance intervals, downtime and exposure time were reduced and crews were kept safer.

In another example, a customer was interested in solving premature packing failures in South Texas and was running 200 mesh sand at over 10,000 psi. The customer's existing packing system did not last more than 35 hours before failure (Figure 1), and crews could not keep the pumps in service and were washing fluid ends. The team decided to test Redline Packing to determine if it could improve its operations. Not only did Redline Packing surpass the 35 hours, the new packing ran for the remainder of the job—more than 138 hours without failures (Figure 2). The customer decided to adopt Redline across its entire operation. E&P

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Shifting from efficient to effective field facility solutions

Modularized production systems streamline field installations.

Stefan Mullins, Tri-Point Oil & Gas Production Systems LLC

Steadily improving commodity pricing continues to drive increased rig counts across each of the prolific U.S. shale basins and, as a result, completion and production trends in each of the basins are experiencing common challenges. After years of downsizing, many operators are being pressured to deliver on ever-increasing production targets with fewer in-house resources. Coupled with the challenge of retention and recruitment of talented engineers, a "do more with less" mantra drives today's production and field facility teams. This hiatus of manpower influences field production facility development in a way that some might not be aware of.

The approach to building field production facilities has followed a rather traditional model for decades. Many operators segment field development tasks, utilize a procurement process engaging a multitude of vendors and drive their facilities to look more like a Frankenstein production monster rather than a well-designed machine made to work as one.

The challenge

Operators typically engineer their facilities leveraging either in-house resources or third-party engineering firms. Varied application conditions can exacerbate a lack of standardization on each of an operator's facility designs from site to site.

Once piping, instrumentation and flow diagrams are complete, the operator must turn to the fabricators to build the production and processing equipment. Typically, the equipment is left to be sized and designed individually by each vendor. This often requires re-engineering and coordination between multiple suppliers before each component is built and ready to be delivered to the field.

Upon delivery, a third-party installation crew is brought on site to piece together the various components, run the electrical and instrumentation, complete system integration testing and commissioning and then start up.

This approach is no longer a viable solution for the industry. It might be considered an efficient process in delivering perceived low-cost, optimized facilities to the field, but an effective system is needed to package production equipment that gets operators to first oil faster.

A MPS accommodates single-well to multiwell layouts, offering plug-and-play capabilities and life-of-well flexibility. (Source: Tri-Point Oil & Gas Production Systems)

Service providers like Tri-Point Oil & Gas Production Systems LLC are working to partner with operators to provide a new approach to the field development process. Modularized production systems (MPS) streamline facility implementation by simplifying the overall design, reducing project shareholders, expediting installation schedules and, ultimately, providing cost savings in the final installed product.

An integrated approach

The MPS is an integrated field facility designed to accommodate the production, separation, measurement, transfer and storage for single- to multiple-well arrangements installed between the wells and the sales line. The MPS approach works as a turnkey execution process and can be engineered to order, allowing operators to optimize a wider variety of applications in their field with standardized tiered offerings. With the front-end engineering of a facility settled, the MPS aims to provide a compact, scalable alternative to the inconsistency of traditional field facility layouts.

Although the production equipment used in MPS is not new technology, the system packages its various

components in a more accessible manner, allowing reduced installation time by an original equipment manufacturing service team. The system also provides flexibility through plug-and-play capabilities and generates capex savings.

Reduced installation time

Traditional field development consents for major equipment to be fabricated in a shop, then over a 45- to 60-day period each component is interconnected on site in a "stick-build" style installation. In contrast, a typical modular production system is installed on site and commissioned in a period of 10 to 15 days. At today's oil price, a 40-day average schedule improvement to first oil can be recognized at about $4 million in a four-well facility scenario producing on overage 1,500 bbl/d.

The MPS approach to field development improves installation times by reducing the amount of work required to be performed on site. During an MPS installation, completed modules are delivered to the site using standard trailers. Each standard MPS skid is no larger than 2 m by 12 m (8 ft by 40 ft), allowing the entire system to be delivered without a permitted load.

This approach to field development is designed to improve facility scheduling and implementation on a macro level. Operators can take their attention away from managing the individual tasks of engineering, fabrication, installation and startup and focus on ensuring wells and facilities come online together and without any production delay. By fabricating a standardized design in a controlled manufacturing setting, MPS facilities can be built in parallel to well completion operations and delivered when the operator is ready to begin production. Ultimately, the integrated MPS reduces the development workload and allows an operator's facility engineering team to accomplish more with less.

Plug-and-play accommodation

The design of the MPS provides operators a plug-and-play capability with their equipment that is not possible through traditional field facilities. MPS modules with standardized process connection locations allow the exchange of production equipment as the application evolves.

For example, costly high-pressure separators required to accommodate initial high volume and high pressure can be replaced later in the system's life with lower-pressure separators that can manage the conditions. These high-pressure separators can then be utilized elsewhere, either within the same facility or where new wells are coming online.

The MPS is an integrated field facility installed between the well and the pipeline for oil and gas processing applications. (Source: Tri-Point Oil & Gas Production Systems)

Capex savings

Reduced installation time generates savings on installation costs, eliminating the need for prolonged onsite field labor. Assuming an average labor force of 30 people for 45 days at 10 hours a day and a $50/hour rate, the total installation for a tradition facility would be about $675,000. By comparison, an MPS installation with an average crew size of 10 for 15 days at the same rate would cost an operator an estimated $75,000 to begin production. In this scenario, the operator saves about $600,000 in field installation and startup services alone.

Quality and safety improvements

Facilities fabricated in the field are prone to exposure to unfavorable conditions, which can lead to inconsistent quality. In a controlled shop environment, welders are more easily able to ensure a quality product.

Traditional facility construction requires more manpower in the field for longer periods of time. Extended time in the field creates a strain on resources and increases the risk of injury. If an injury in the field does occur, these locations are often fairly remote and far from medical care. All of these potential hazards are minimized by moving to a modularized system approach.

Operators recognize that creating efficiency at any stage of oil and gas production and processing is essential but never at the expense of safety or quality. The integrated modular approach eliminates inefficiencies, safety risks and other concerns that disrupt productivity, all while reducing cycle time from well completion to facility production and saving operators money. E&P

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Using CSEM in West Africa to de-risk a prospect

Seismic is not always a standalone tool in stratigraphic traps.

Lodve Berre, **Stein Fanavoll** and **Pål Gabrielsen**, EMGS

Exploration in West Africa has a rather low commercial success rate when it comes to frontier, deepwater wells, as evidenced by recent drilling campaigns. Of the nine West African frontier exploration wells drilled in 2017, only one was reported as a significant discovery. That corresponds to a disappointing success rate of 11%. The key challenge is the nature of the stratigraphic trap being chased here, where in particular seal is notoriously difficult to assess, and fluid type through quantitative interpretation using seismic data is ambiguous. This is well illustrated when viewing two of the wells drilled in 2017: one being the discovery Yakaar and the other the neighboring dry well Requin Tigre-1 (Figure 1). Both wells are tied to neighboring discoveries (Teranga and Tortue, respectively) and show large similarities in seismic definition as well as calibrated, positive amplitude-versus-offset responses. Yet, the outcome of the two wells is largely different. A similar result can be seen across the Atlantic on the South American Margin in the Guyana Basin, where the two prospects Liza and Skipjack had almost identical seismic expression and risking profile. However, the outcome of the drilling was very different—Liza came in as a discovery, while Skipjack was dry.

Controlled-source electromagnetic (CSEM) technology is a marine remote geophysical method imaging the earth resistivity. The method is proven as a technology to identify oil and gas reservoirs and to separate low-saturation noncommercial reservoirs from commercial high-saturation reservoirs. Generic CSEM sensitivity studies based on public knowledge relevant for the nine West Africa wells from 2017 show that CSEM data should give significant contributions to the de-risking of these prospects. Application of CSEM for such a target would separate false positive seismic amplitude responses from true positives, in addition to reducing uncertainty in in-place hydrocarbon estimates. CSEM data acquisition in these basins in Africa should be considered to facilitate better decision-making of the next wells.

In November 2000 the first full-scale field test of the CSEM technology was carried out in Angola over the Girasol Field. The results of this survey were encouraging, bringing a new remote geophysical method in the toolbox to detect hydrocarbons offshore. Since then the development of equipment, acquisition, imaging and interpretation tools has been enormous. EMGS

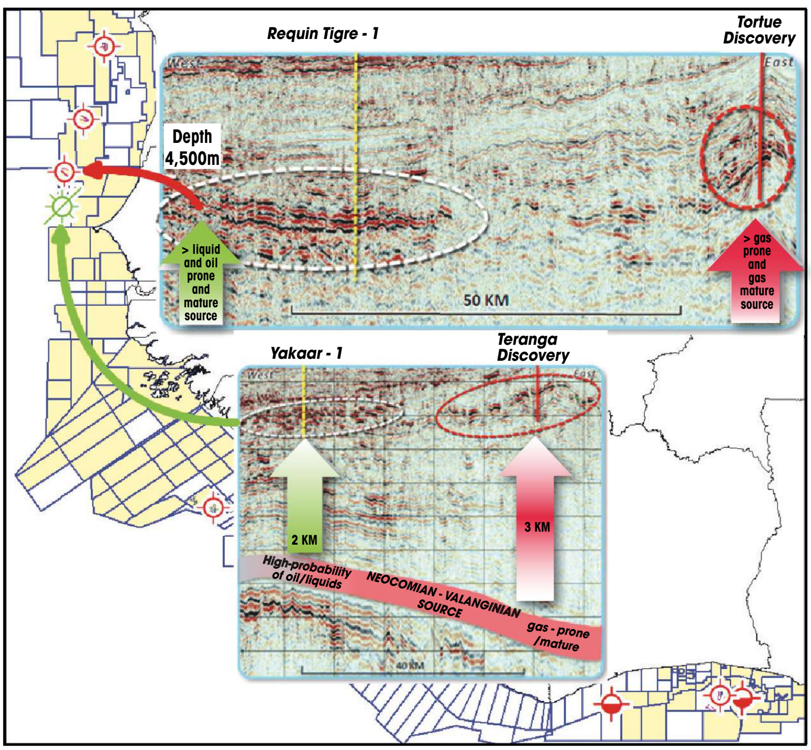


FIGURE 1. This map covers eight of the nine African frontier exploration wells drilled in 2017. Results were disappointing, with only one discovery (gas), five dry holes and two wells with shows. This strongly suggests that a seismic direct hydrocarbon indicator might say something about charge but does not properly distinguish between low- and high-saturation reservoirs. The two seismic lines show the discovery Yakaar-1 and the neighboring dry well Requin Tigre-1. Both wells are tied to nearby discoveries (Teranga and Tortue, respectively). (Source: EMGS)

has acquired a significant amount of CSEM datasets in Africa, covering, among others, known discoveries as the Fortuna discovery in Equatorial Guinea and the Jubilee discovery in Ghana.

One of the Africa CSEM case stories is from the deeper parts of a delta system. Here, reservoir sands may not be deposited over structural closures such as delta toe thrusts. The distribution of channels and basin floor fans is normally controlled by other factors, such as transform faults. Traps will be of stratigraphic type, with high risk on seal. In an African CSEM campaign in 2004, several 2-D lines targeted mapped structural closures, but none of these structures could be correlated to resistive anomalies. However, along one of the lines, a strong resistive anomaly appeared toward the end. A closer look at the seismic data in the area revealed a channel/fan system that could be correlated to the resistive anomaly. Subsequently, an extension of the original line was acquired and the resistive anomaly from the extended line had a very good lateral match to the extension of the channel/fan system identified on the seismic. A well drilled some years later confirmed the presence of gas (Figure 2). Another well was drilled on the structural high where no resistive anomaly was observed. The well turned out to be dry as predicted by the CSEM results.

The exploration history shows that there are large uncertainties in the risking of prospects on the African shelf. It is a known fact that seismic is best suited for mapping trap and reservoir and not to determine the fluid content. It is often seen that the majority of failures are due to charge or seal, which often cannot be properly de-risked by the use of seismic data when it comes to fluid prediction. Many wells are now targeting stratigraphic fan type plays and these plays are typically characterized by high seal risk and large uncertainty on in-place volume. This risk and uncertainty are worth keeping in mind, especially in light of the recent dry Fatala-1 well in Guinea on the West African Atlantic margin, drilled on exactly such a play. What if Fatala was a "Skipjack"; could the next well be a "Liza"?

Could this be a similar case as in the Yakaar-1 and Requin Tigre-1 case, as illustrated in Figure 1?

CSEM data are sensitive to the fluid content in a reservoir separating seismic prospects with residual saturation from high hydrocarbon saturations. Therefore, CSEM data act as a complementary tool to seismic data in the prospect risking process. In-house sensitivity modeling based on public knowledge has shown that the Fatala target, as well as most of the other ones, is within the sensitivity range for the CSEM methodology (Figure 3). Therefore, wise use of CSEM can cost-efficiently improve the drilling sequence toward drilling high-volume/lower-risk prospects early on in the campaign. E&P

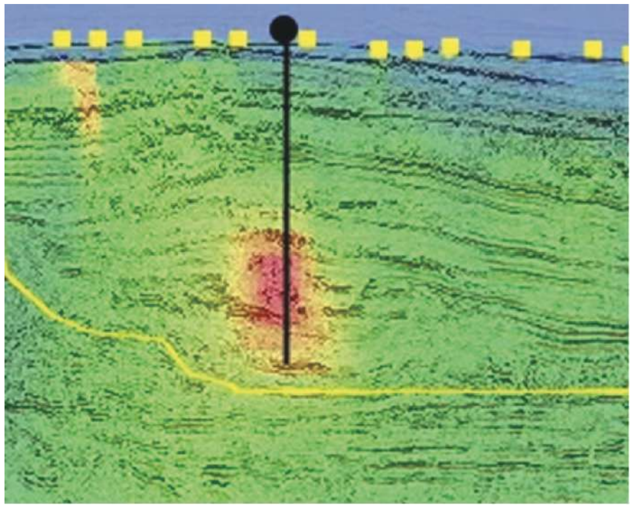


FIGURE 2. A strong resistive anomaly (red) is highlighting a channel system identified on seismic data located off a structural high. A well drilled some years later confirmed the presence of gas identified by the CSEM data. (Source: EMGS)

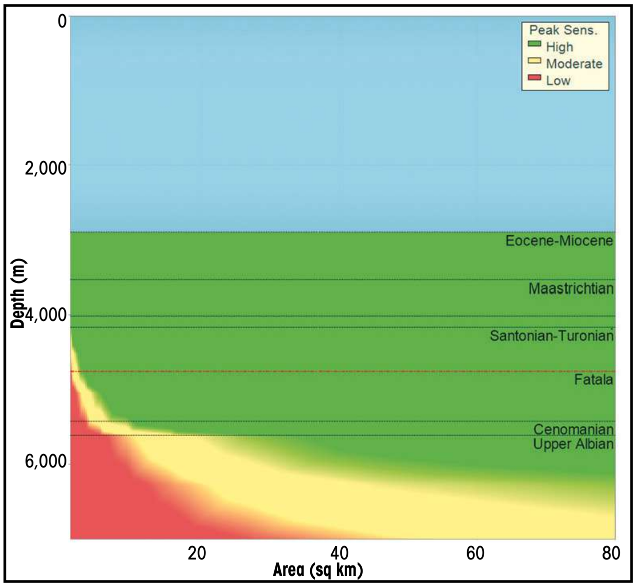


FIGURE 3. A CSEM sensitivity study used a resistivity background model relevant for the Fatala-1 well. Scanning for depth versus areal size of target clearly illustrates that CSEM data will be sensitive to a target with size and reservoir depth similar to the Fatala prospect. The green area means high sensitivity to the target, while red means low to no target sensitivity. Being within the yellow transition zone will require more detailed work. (Source: EMGS)

References available.

Clearer downhole picture emerges

An LWD service provides operators with reservoir insight before, during and after the drilling operation illuminates and maps ultradeep reservoir and fluid boundaries in the wellbore.

Tim Parker, Halliburton

E&P operators around the world are looking for ways to reduce well construction costs while optimizing well placement and increasing production to maximize their overall asset value. In new developments the main obstacle to optimal well placement is uncertainty in the reservoir position and structure because of the inherent limitations of surface seismic data. In mature fields the reservoir position and size are generally well-known; however, significant uncertainty is associated with the position of the fluids within it because of movement caused by production or waterflooding. Such fluid movement is difficult to predict and leads to well placement challenges.

Conventional resistivity-based geosteering tools are sensitive to bed boundaries up to 5 m (18 ft) from the borehole. This range is sometimes insufficient to detect important structural features in time to make appropriate steering decisions. This can result in undesired exits from a reservoir target zone, the suboptimal positioning of the well in a target zone or the failure to hit a target zone altogether. By knowing the location of hydrocarbon pockets in the reservoir, being able to correlate the geological structure with surface seismic data, identifying bypassed pay and multiple reservoir layers, and seeing more of the reservoir and its surrounding area, operators can make better drilling decisions, plan for future field development and reduce costs per barrel of oil equivalent.

The Halliburton EarthStar ultradeep resistivity service addresses these challenges using electromagnetic (EM) wave-propagation technology to illuminate and map reservoir and fluid boundaries more than 60 m (200 ft) from the wellbore—twice the depth of investigation of current industry standards. It provides operators a much clearer view of the surrounding reservoir environment. In deep water and mature fields, this technology helps operators to maximize asset value and plan for future field development through geostopping, geosteering and geomapping.

Not just a tool

The EarthStar service is more than just a tool; it is a comprehensive service that includes proprietary RoxC geosteering software and highly trained geosteering experts. The service provides operators with reservoir insight before, during and after the drilling operation. The RoxC software provides two primary functions: to process the EarthStar data using a customized inversion process and to display the results graphically on a 2-D inversion plane. It also includes various quality control functions useful for interpreting the results.

The tool is flexible and configurable. It comprises several separate collar sections. A transmitter collar is always required, but it is possible to run the tool with one or more receivers at variable spacings from the transmitter. Figure 1 shows a typical configuration with a transmitter collar toward the lower end of the bottomhole assembly (BHA), typically immediately behind the rotary steerable tool, and two receiver collars separated from the transmitter by other intervening LWD tools or spacer collars.

The BHA configuration is not fixed and might be different from that shown. The tool's modular construction allows adjustable spacings between the transmitter and receivers. Spacing adjustment is necessary to optimize the configuration for a particular application. If the objective is to detect boundaries far from the borehole (e.g., in a well-landing situation), then longer spacings are preferred because this provides a greater depth of investigation than shorter spacings. Conversely, if the target zone is relatively thin or if the detailed mapping of formation layers close to the wellbore is required, then shorter spacings are preferred.

When choosing the spacing and frequency for a particular operation, it is

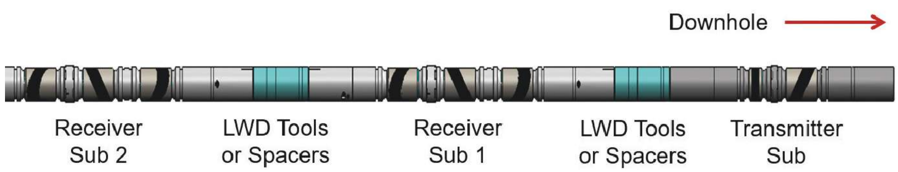


FIGURE 1. This is the basic layout of the EarthStar service tool with the transmitter collar located toward the lower end of the BHA. (Source: Halliburton)

essential to perform pre-well modeling to simulate the tool response in the planned well. Pre-well modeling determines the optimum tool spacings and firing frequencies to suit the operator's objectives for the target well. Regardless of the frequencies selected for real-time transmission, the tool records measurements from all firing frequencies in its memory.

Another differentiating feature of the EarthStar service is the tool's very low-noise electronics. The transmitter emits an EM wave at one of seven possible frequencies: 1, 2, 4, 8, 16, 32 and 64 kHz. As with the choice of spacing, the firing frequency affects the depth of investigation of the measurement and the bed resolution of the tool. Low frequencies have the greatest depth of investigation, while higher frequencies are shallower reading but tend to reveal more detail in the surrounding structure. The emitted wave travels through the formations around the tool and interacts with boundaries between rock and fluid layers. The effect that a particular boundary has on the wave depends on the contrast in resistivity from one side of the boundary to the other.

Boundaries with high contrast will tend to reflect some of the wave energy back toward the tool, while those with no contrast will not. The wave amplitude diminishes as it moves away from the transmitter. The farther the wave travels through the formation, the more attenuated it becomes. The receivers must be able to detect and measure small signals that have been highly attenuated to be sensitive to boundaries far from the tool. The EarthStar service's electronics are designed to be low noise, making the receivers highly sensitive, with a high signal-to-noise ratio. With appropriate spacing between the transmitter and receivers, the tool is capable of detecting boundaries up to 60 m from the wellbore in optimal conditions.

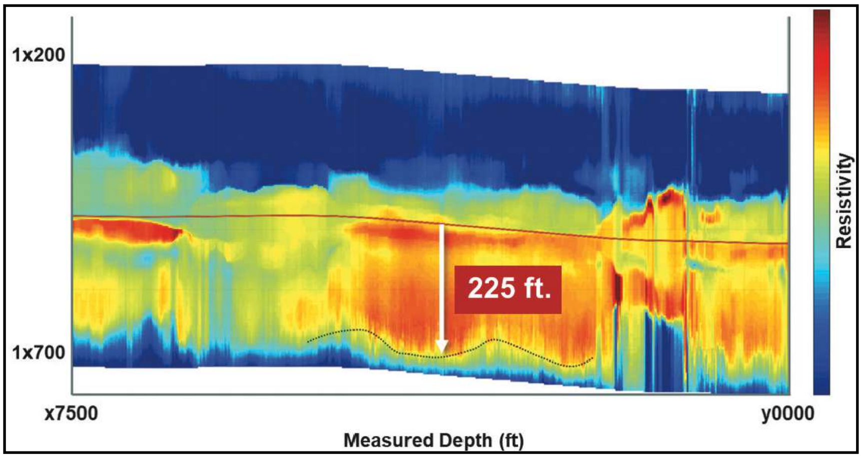


FIGURE 2. EarthStar's ultradeep geomapping capability helps operators maximize asset value. (Source: Wu, Hsu-Hsiang, et al., SPWLA-2018-X paper)

Case studies

In a mature carbonate field in the North Sea, an operator deployed the EarthStar service to help identify remaining hydrocarbons bypassed by waterflood production. The operator drilled two wells that passed close to each other, with a vertical separation of about 40 m (130 ft). One well passed through the center of a distinctive, oil-bearing fault-block, about 43 m (140 ft) in height, with clearly defined boundaries that were easily identified from the inversion results provided by the RoxC geosteering software.

The second well passed approximately 18 m to 21 m (60 ft to 70 ft) above the top of the fault-block. The EarthStar service was able to geomap the top of the fault-block as well as the bottom some 60 m to 69 m (225 feet) away (Figure 2). In doing so, the service demonstrated its ability to map resistivity boundaries far from the wellbore, significantly helping the operator maximize asset value through enhanced reservoir understanding and setting a new industry benchmark for performance.

In another application, an operator in the North Sea was developing a new oil field but was having difficulty placing wells close to the top of the reservoir using conventional geosteering techniques. The problem was that the top of the reservoir was not flat, and the overlying shales were highly unstable. Drilling out of the reservoir into the shale resulted in poor borehole conditions and several instances of stuck pipe. As a result, the operator had to place wells deeper in the reservoir to reduce the risk of unintended exits. This placed the well too far from the reservoir top for the conventional geosteering tools to detect it reliably, making navigation more difficult. Moving wells away from the top also increased the volume of nonproducible attic oil.

The EarthStar service easily geomapped the top surface of the reservoir, allowing the operator to anticipate changes in dip and position the well with greater confidence. The net result was a series of five production laterals placed within 6 m (20 ft) of the top of the reservoir, with a total drilled interval of more than 11,000 m (36,000 ft), with no exits into the overlying shale. The EarthStar service helped the operator reduce time to develop the field while simultaneously increasing sweep efficiency and producible reserves. E&P

Maximizing the potential of MWD and LWD

New service offers flexibility to switch between electromagnetic and mud pulse telemetry modes.

Melisa Ramirez Tovar, Schlumberger

Capabilities such as MWD and LWD have long proven their worth in measuring and transmitting critical formation data to the surface in real time, keeping pace as the industry seeks to expand the operational envelope in new and challenging frontiers while also pushing harder to improve ROPs. By transmitting measurements at regular intervals while drilling, MWD and LWD provide valuable information on well positioning, tool orientation, lithology indicators, reservoir content, geomechanics and drilling optimization to increase ROP, enhance wellbore stability and optimize well placement.

In recent years, advances in MWD and LWD technology have been a game changer in helping operators overcome the complexities of drilling directional wells, enabling quick and informed decision-making. As producers seek to optimize field economics by reducing the overall well construction cost while improving the quality of the borehole and wellbore positioning, services that reduce flat time, boost data transmission speeds and ensure accuracy in wellbore placement are more essential than ever.

Producers with land operations will typically choose between two methods of data transmission—mud pulse (MP) or electromagnetic (EM) telemetry—depending on the area, target formation and well conditions. EM telemetry can transmit data at very high rates of speed using EM waves, meaning that data acquisition and transmission can be completed while the pumps are off. This helps eliminate surveying wait time. MP telemetry, which transmits downhole data to the surface using pressure pulses in the mud system, is suited for deeper, more complex geologies where EM predicted signals could be weaker.

Data transmission options

As both EM and MP telemetry modes offer unique benefits, selecting a transmission option can be challenging, especially when by selecting one telemetry mode, the advantages of the alternative mode are lost. This can result in costly trips out of hole and minutes added to the operations. To overcome these challenges and provide greater flexibility to operators, Schlumberger developed a service that streamlines surveying procedures, improves data transmission and positions the wellbore within the reservoir with greater accuracy. The xBolt accelerated drilling service was designed to maximize on-bottom drilling times so operators can deliver wells faster and stay in the sweet spot.

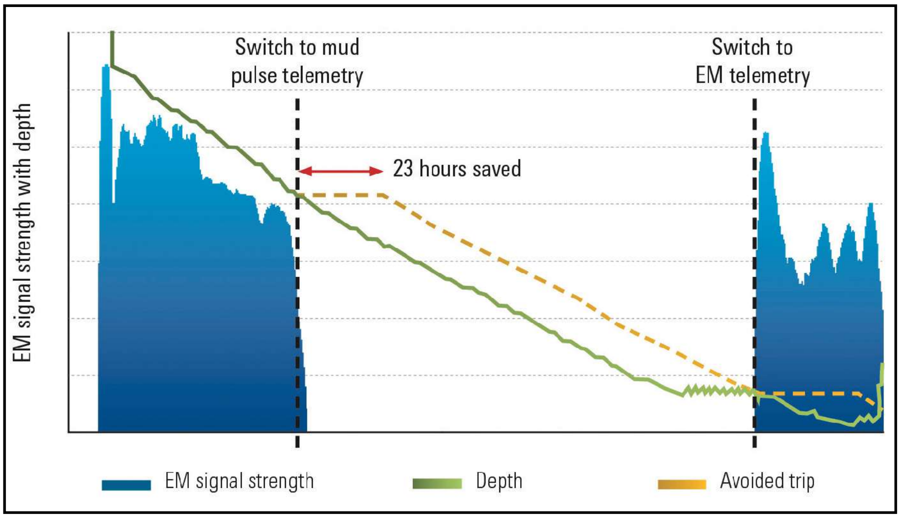
The service is available in three configurations to provide multiple data transmission options in a single tool: 1) ultrafast EM telemetry in signal-friendly zones, 2) reliable, high-speed MP telemetry for deeper, more complex intervals and 3) a flexible and redundant dual-telemetry configuration that supports either mode. Drillers can switch between modes in less than 1 minute.

Every minute counts

With the capability to use total and azimuthal-image gamma ray functionality to reveal bed crossings and boundaries at a temperature rating of 165 C (329 F), the service supports confident geosteering decisions. Improved imaging enables more accurate steering and minimizes sliding for increased ROP and reduced well porpoising, resulting in a smoother, less tortuous well profile. The service reveals formation dips while drilling to deliver a cost-effective solution for increasing total footage drilling per day and more precise well placement.

A key objective in drilling longer, more deviated laterals is the need to maximize efficiency by reducing flat time, a result of survey wait times when making frequent and necessary connections roughly every 27 m (90 ft). Although wait times might only be 5 to 8 minutes per connection, those minutes count. A 3,048-m (10,000-ft) lateral usually requires 100 or more connections, resulting in several hours of flat time.

Engineered with the latest in both EM and MP technology, the accelerated drilling service's dual-telemetry configuration offers a single, flexible system. Superior demodulation rates eliminate survey times when using the EM configuration, achieving data transmission rates up to 16 bits per second. The EM mode takes and trans-



An operator was able to avoid a 23-hour trip to switch between EM and MP telemetry tools by using the xBolt service. (Source: Schlumberger)

mits surveys offline while making connections. It also can withstand high concentrations of lost-circulation material without jamming, because the tool has no moving parts, and therefore the risk of component failure is significantly reduced.

For deeper and more complex intervals, the MP telemetry mode uses powerful Quadrature Phase Shift Keying (QPSK) technology, which transmits more data in the same unit of time to increase signal strength and neutralize drilling noise.

Algorithms move the MP signal into a wider-frequency spectrum to avoid low-frequency noise and overcome insufficient data transmission due to low-frequency demodulation. By delivering LWD/MWD data at transmission rates as high as 4 bits per second, compared to the industry standard of 0.5 bits per second, the MP telemetry configuration results in surveying times up to four times faster than conventional methods to achieve a significant increase in on-bottom drilling times.

Operators in the long-producing and geologically diverse Midcontinent Basin have successfully implemented the accelerated drilling service to significantly reduce survey time and costs and increase on-bottom drilling time.

Multiple options in one tool

In one application the service improved drilling efficiency across an eight-well pad where laterals reached 3,048 m. A key objective was to reduce survey time using EM telemetry, which would enable sending survey data while making connections instead of relying on the standard protocol of waiting for the mud pumps to turn on after a connection is made.

However, the formation layers above the wellbore and extended laterals prevented receipt of the EM telemetry signal. The operator deployed the accelerated drilling service, activating the dual-telemetry configuration. This enabled the driller to efficiently and quickly switch to high-speed MP telemetry when needed so as to produce and receive signals faster than traditional MP technology. The dual-telemetry tool responded to a downlink and effectively switched to the MP telemetry mode, minimizing the time to troubleshoot for signal quality. Toward the end of the run, the tool was switched back to EM telemetry mode to maximize on-bottom time.

By implementing the accelerated drilling service, the operator saved 53 hours of survey time across the eight-well pad, reducing connection time by 7.5 hours per 3,048 m of lateral and avoiding an estimated 23-hour trip.

Increasing on-bottom drilling time

In another Midcontinent application, the accelerated drilling service, using QPSK MP telemetry technology to boost bit rates and eliminate drilling noise, was implemented to improve drilling productivity by minimizing lost time due to poor survey data and slow transmission speeds. A key challenge involved overcoming low-frequency drilling noise, especially in unfavorable conditions, which prevented data captured by conventional tools from being demodulated at the surface. This forced the operator to relog every stand of drillpipe, and even retake entire surveys, to obtain accurate formation evaluation and drilling optimization data while drilling, resulting in hours of nonproductive time per well.

By deploying the accelerated drilling service, the operator was able to increase data transmission speed and deliver a continuous MWD signal, significantly increasing transmission reliability and eliminating the need for relogging and repeat surveys. System algorithms guided the MP signal to change frequencies onto a cleaner area within the spectrum to negate the drilling noise. The result was a 25% increase in on-bottom drilling time, from 62% to 78%. The service delivered a 2-bits-per-second transmission rate while drilling compared with 0.5 bits per second from standard high-volume, probe-based MP telemetry, ultimately reducing survey time by 2 minutes per connection. E&P

Proppant flowback control additive has success in the field

An operator controls proppant flowback by utilizing a new liquid additive.

Adam Harper, Hexion

When well production carries unbonded proppant out of the fracture, the resulting proppant flowback negatively impacts well economics. If proppant flows out of the fracture near the wellbore where the fluid velocity is the highest, fractures can pinch off near the perforations, leading to underperformance of the entire zone. Proppant flowback that makes it to the surface might result in equipment damage, resulting in costly repair or replacement. Separation and disposal of the proppant at the surface also creates added costs. Proppant deposition in the wellbore often leads to cleanouts, damage to downhole equipment or other remediation. The downtime spent dealing with these issues and the costs of remediation have a negative impact on the overall economics of the well and increase cost per barrel of oil equivalent.

With the evolution of completion designs leveraging longer lateral lengths and increased proppant intensity, proppant flowback control has become a critical challenge. Some operators and service companies have come to accept proppant flowback, remediation and downtime as a cost of doing business.

Economic flowback control

Hexion has developed the PropShield proppant flowback control additive. This liquid flowback control agent is applied directly to the blender tub on location and can be applied to any type of proppant regardless of mesh size (Figure 1). The PropShield additive also provides a logistical benefit because it arrives on location and is added to the fracturing fluid like any liquid additive.

The PropShield additive is compatible with most commonly used fracturing fluid additives. Prejob laboratory tests were conducted to confirm compatibility with friction reducers, biocides, scale inhibitors, gelling agents and corrosion inhibitors. It has been successfully field trialed with slickwater, linear gel and crosslink gel fluid systems.

Control additive properties

The PropShield additive has an affinity for the substrate, meaning that it will coat the substrate in the blender tub and not the equipment. The proppant develops tackiness while being pumped downhole, and it can be recirculated in the event of a screenout. Once placed in the fracture, the coating results in a higher critical flow rate compared to uncoated fracturing sand. The critical flow rate for a proppant can be defined as the rate at which proppant breaks loose from the proppant pack and begins to flow back out of the fracture. Third-party critical flow-rate testing demonstrates that the PropShield additive-treated sand withstands flow rates that are eight times higher than uncoated fracturing sand (Figure 2).

FIGURE 1. The PropShield additive is applied directly to the blender tub on location. (Source: Hexion)

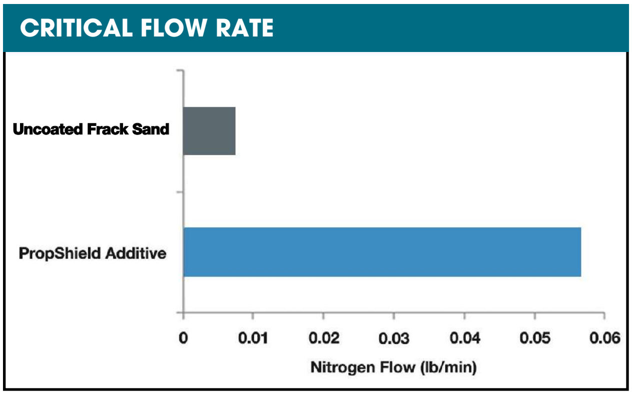


FIGURE 2. Third-party critical flow-rate testing demonstrates the PropShield additive's ability to control proppant flowback. (Source: Hexion)

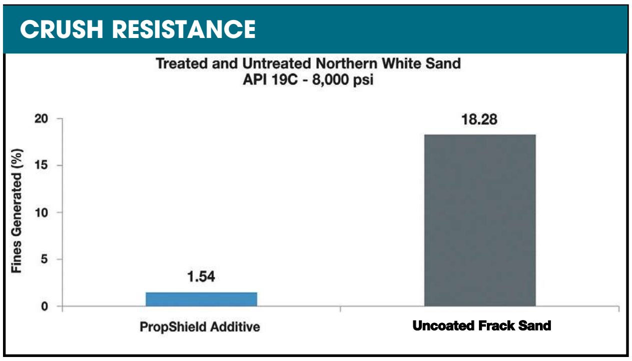


FIGURE 3. Crush resistance testing shows the PropShield additive's ability to control proppant fines' migration. (Source: Hexion)

The PropShield additive also is designed to be effective over a wide range of temperatures. Substrate treated with the additive can help control proppant flowback at bottomhole static temperatures ranging from 90 F to 275 F (32 C to 135 C).

In addition to proppant flowback control, the PropShield additive can help control the migration of proppant fines. The migration of proppant fines through a proppant pack can have a negative impact on well production. Crushed proppant particles can migrate and accumulate in the proppant pack and block pathways for oil and gas to flow. A study conducted by Coulter and Wells concluded that 5% of proppant fines can result in a 60% reduction in flow capacity of the proppant pack. The PropShield additive can trap these broken proppant particles and prevent migration, leading to better overall well production. Crush resistance testing demonstrates the PropShield additive's ability to trap these proppant fines (Figure 3).

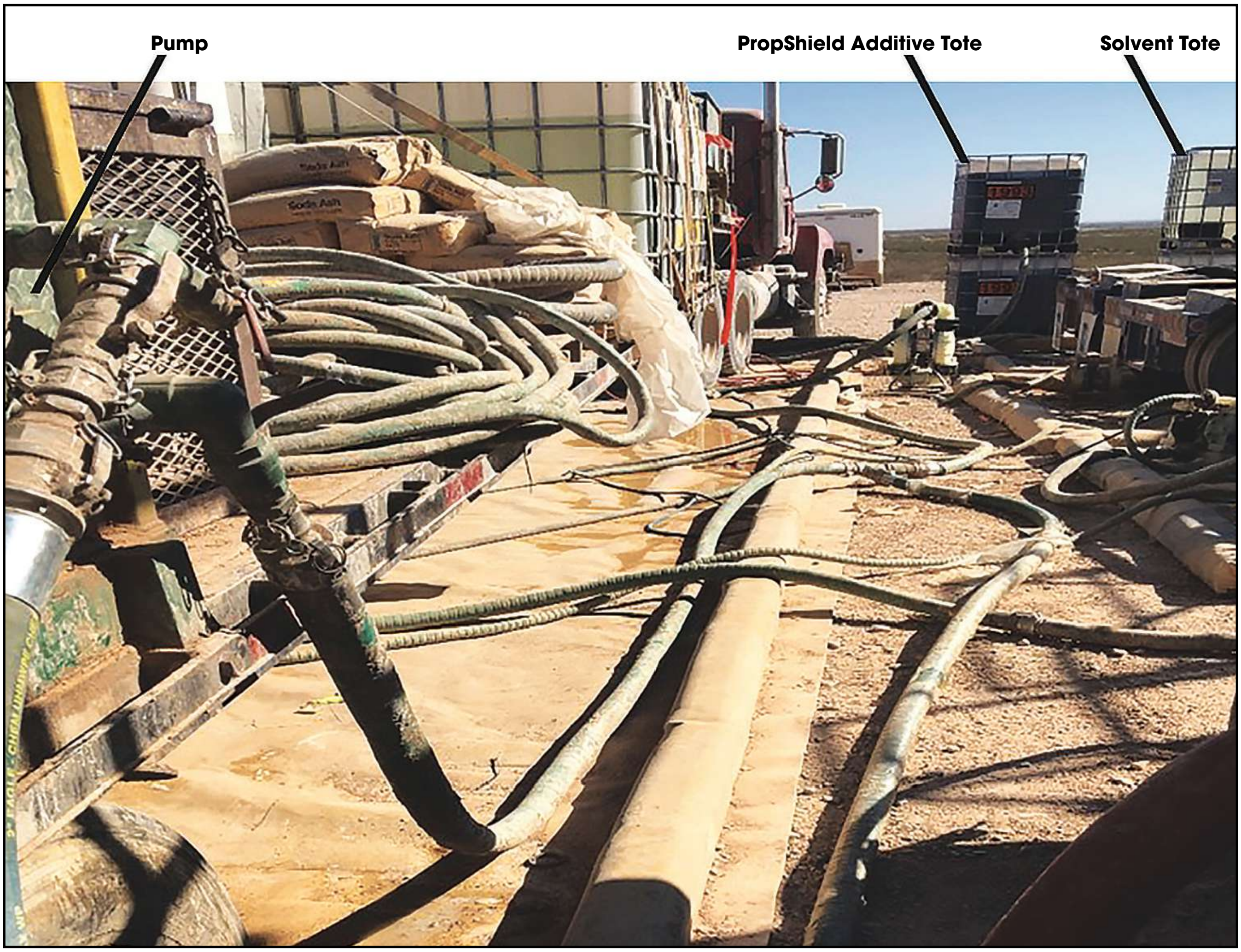


FIGURE 4. Backside setup of the PropShield additive is on location. (Source: Hexion)

Field data

The PropShield additive continues to be used successfully in the Permian Basin to control proppant flowback. It also has been utilized in the Midcontinent region and Canada.

An operator in the Permian Basin recently trialed the PropShield additive and compared the trial well to a direct offset well on the same pad. The trial took place in the Wolfcamp Formation in Reeves County, Texas. Both the PropShield additive well and the offset were slickwater job designs with a 1,295-m (4,250-ft) lateral and true vertical depth of about 4,693 m (15,200 ft).

Figure 4 shows the backside setup for delivery of the PropShield additive to the blender tub. Compared to the offset well, the PropShield additive user experienced 50% less proppant returned during drillout and 80% less proppant flowback once the well was put on production.

"We set up a two-well trial pad in the Permian Basin," said a representative from Centennial Resource Development Inc.

"During the stimulation there were no signs of increased friction while pumping the PropShield additive down the pipe and into the formation. The well in which the PropShield additive was utilized produced half the sand the offset well produced. The flowback phase yielded positive results as well. The PropShield additive well averaged 0.5 to 3 gallons per hour of sand recovered, while the offset well averaged 6 to 8 gallons per hour of sand recovered. We were very pleased with the results and will continue to evaluate the PropShield additive in various areas at varying concentrations across our acreage." E&P

References available.

Impacting proppant coating performance

Different sand factors affect coating selection and application to achieve effective silica dust control.

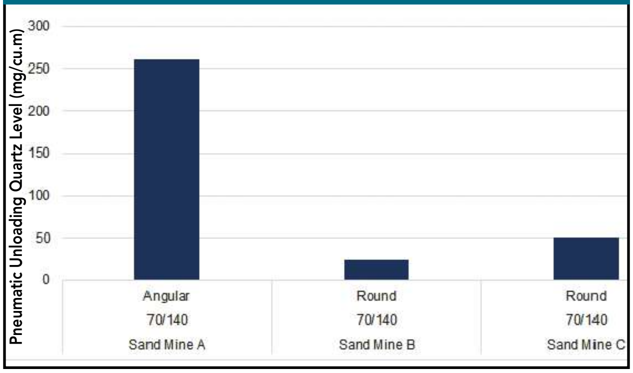
Michael Diaz, ArrMaz

Silica sand is used extensively as a proppant in hydraulic fracturing operations because of its durability and readily available supply. On its way from the sand mine to the fracturing site, the sand proppant is handled by multiple workers who might be exposed to silica dust generated by the sand at each point of transfer across the hydraulic fracturing supply chain. Respirable crystalline silica is known to cause serious health issues. As a result, the U.S. Occupational Safety and Health Administration (OSHA) recently revised its silica rule, cutting the permissible exposure limit (PEL) for silica dust in half while implementing an action level (AL) that triggers additional monitoring requirements and mandates the use of engineering controls to minimize worker exposure. These requirements have spurred new R&D efforts aimed at innovating silica dust control technologies to more effectively protect workers.

One system that provides continuous silica dust protection without the requirement for capital-intensive investment by individual sand companies, transloads and hydraulic fracturing operators is chemical silica dust control proppant coatings such as ArrMaz's SandTec. Once an effective proppant coating is properly and evenly applied to silica sand, the risk of worker exposure to silica dust is significantly and consistently reduced from the point of application to the point of end use.

However, not all silica dust control proppant coatings are alike. When evaluating proppant coatings, there are several criteria that must be considered. Initially, the coating must be compatible with the fracturing fluids being used and must not negatively impact the downhole performance of the well. Secondly, the individual characteristics of the silica sand being used as proppant must be studied to select the right coating and optimize the coating application rate to achieve effective silica dust control. The sand should be characteristically evaluated to understand its dusting tendencies by examining its shape, fines generation characteristics, surface area and composition. This second step, which often is overlooked, can significantly impact proppant coating performance, because not all sand is created equal and there is no universal coating that works with every sand type.

SAND SHAPE EFFECT ON PNEUMATIC UNLOADING QUARTZ LEVELS (mg/cu. m)



A pneumatic simulation was performed on 100 mesh sand with varying shapes from three different sand mines. The respirable quartz results were reported for each mine. Rounder proppant displayed lower levels of respirable quartz. (Source: ArrMaz)

Sand shape

One consideration when evaluating the dusting tendencies of silica sand is its shape, which impacts the coating process and application rate. The shape of sand used as proppant can vary widely. While some sands are very spherical in shape, other sands may have a high degree of angularity. Historically, rounder sand has been preferred because of its better packing ability in a fracture. Above ground, it has been observed that rounder sand also has a higher attrition threshold as opposed to angular sand. As the sphericity of sand improves, the tendency of the sand to attrite and generate dust during transfer decreases. When attempting to decrease the attrition tendency of highly angular sand, coating formulation and application must be adjusted to optimize dust control performance.

Sand fines

In general, sand fines can potentially hinder well conductivity and also create dusting issues during handling,

Providing high quality proppants with reliable near well logistics to the energy industry.

Premium Sand.

Marcellus & Utica
Haynesville, TMS & Eagle Ford
MidConn

CAPITAL SAND
PROPPANTS LLC

Dust suppressant keeping our employees and yours safe.

PUREPROP

Superior West Texas sand in the Permian Basin.

CAPITAL SAND
PERMIAN

presenting significant dust control challenges. A simple sieve analysis can be used to help quantify the fines percentage of sands of varying shapes. Depending on the origin and the processing of the sand, sand fines can fluctuate anywhere from less than 0.1% to greater than 10%. Generally, a lower percentage of fines will require a lower coating application rate, and a higher percentage of fines will require a higher coating application rate to effectively reduce silica dust levels.

Sand surface area

Sand surface area is another factor that must be considered, as it might be impacted by either the number of fines or the composition of the sand. To understand how surface area impacts the dust control effectiveness of a proppant coating, tests must be conducted to analyze the sand, the results of which will deliver valuable insight into the best proppant coating solution for the sand.

For example, recent tests conducted by ArrMaz on two sand mines producing sand about the same size from the same region yielded varied results for the same proppant coating solution. Sand from the first sand mine had a surface area of 0.22 sq m/g of sand. Sand from the second sand mine had a surface area of 0.81 sq m/g of sand. The second sand mine generated five times more respirable quartz than the first sand mine. Despite coming from the same region and being similar in size, these two sands yielded very different dust control results for the same proppant coating due to their different surface areas. The results indicated the higher the surface area, the higher the coating application rate required.

Although surface area can be reduced by mitigating fines, it is important to remember that surface area also is affected by sand composition.

Sand composition

Understanding sand composition is imperative when considering a proppant coating to calculate the correct coating application rate for effective silica dust control. Sand proppant composed of high-purity quartz silica is highly desired because of the durability it provides for the rigorous hydraulic fracturing process. However, sand mines use different mining and cleaning processes to achieve the highest quality of silica sand. Inevitably, different mines provide different qualities of sand, thus compositionally the sand that each mine provides may be different.

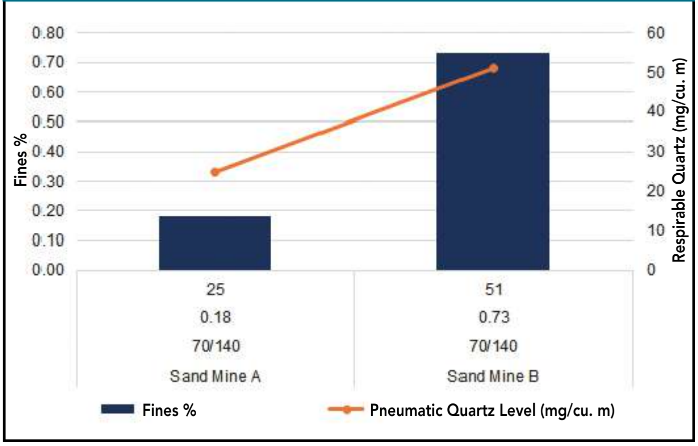
Because composition can affect surface area and contaminants may have a much higher surface area than sand, the surface area of the sand may be raised due to its porosity. In addition to determining impact on surface area, further compositional analysis might reveal the presence of impurities, which also can increase the sand's dusting tendencies. An appropriate dust control proppant coating should be able to handle such variations in the field. ArrMaz typically runs multiple tests to optimize the proppant coating and application rate to account for variations in sand composition.

Latest technology

ArrMaz developed SandTec silica dust control proppant coating technology with all of these sand characteristics in mind. SandTec coatings are customized to work with silica sands of varying characteristics such as Northern white sand versus Texas brown sand to ensure optimal silica dust control performance. Multiple trials with well service companies and oil and gas production companies indicate that the coating technology is effective in achieving dust reduction targets below OSHA's PEL and AL.

ArrMaz uses a defined testing platform to evaluate and set a specific coating application for each individual mine's specific sand, which provides targeted dust reduction across the entire hydraulic fracturing supply chain with no negative impact on sand handling characteristics or downhole well performance. By understanding sand characteristics, ArrMaz is able to provide both an effective silica dust control proppant coating technology and application system tailored to each customer's sand. E&P

EFFECT OF FINES (BELOW 200 MESH) ON PNEUMATIC UNLOADING QUARTZ SILICA LEVELS



A pneumatic simulation was performed on 100 mesh sand from two different sand mines with varying amounts of fines. The fines and the corresponding respirable quartz are shown in the figure. A higher amount of fines was shown to increase respirable quartz upon pneumatic unloading. (Source: ArrMaz)

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Paraffin remediation for mature fields

Biochemical-based treatments are transforming paraffin maintenance into a documented revenue generator.

Kirk Raney, Locus Bio-Energy Solutions LLC

Paraffin deposition is a major industrywide problem costing the petroleum industry billions of dollars per year. The extra cost is a result of many economic factors including increased chemical usage, reduced production, well shut-ins, abandonment of reserves and increased power and maintenance requirements. Paraffin is also a major contributor of underdeposit corrosion, which can lead to losses of hundreds of thousands of dollars in lost production and equipment repair or replacement costs. An array of remediation options are available, but until recently none of them offered a solution that was both cost-effective and did not cause skin damage.

Traditional paraffin removal methods

Conventional paraffin deposition control programs include chemical, thermal and mechanical methods. In many cases, excellent results can be achieved with these methods. However, these programs add significantly to the cost of oil production. The chemicals used to treat paraffin problems generally fall into two groups: inhibitors and dispersants.

The more expensive inhibitors are polymeric molecules added to the crude oil in the well at a constant, low dose above the wax appearance temperature. When dissolved in the crude, these inhibitors decrease the wax appearance temperature so that wax formation is reduced or eliminated during the production process.

In contrast, cheaper wax dispersants break up existing paraffin deposits into small fragments that can be mobilized in the produced fluids stream. Two of the most common dispersants are surfactants and solvents. Surfactants are typically used to disperse and potentially solubilize the paraffin wax into crude oil but can pose environmental and health concerns.

Solvents are used to solubilize and disperse existing wax deposits. In many cases, however, solvent treatments can damage the formation near the wellbore by making it more oil-wet. These solvents are also highly toxic.

Thermal well treatments are another common practice for removing paraffin deposits. These treatments involve adding hot oil or hot water through the well tubulars and flowlines on a regular basis. However, these types of treatments often result in long-term formation damage by forcing the heavier fractions of the paraffin back into the reservoir rock.

Attempts to develop alternative solutions

Biologically and microbial-derived products have been investigated for oilfield use for several decades as an alternative to traditional treatments. In theory, these formulations offer superior environmental performance and higher energy efficiency compared to the conventional paraffin treatment methods. However, many have exhibited reduced effectiveness in the field as a result of a one-size-fits-all approach, as well as lower comparative potency, or are cost-prohibitive (such as D-Limonene and other terpenes). One science-backed company created a cost-effective product with proven efficacy and safety as well as protection against skin damage, which could accelerate production declines.

Multidimensional dispersal treatment

A newly developed approach using a nonbacterial, microbial-derived, biochemical-based paraffin wax treatment has been successfully commercialized in the Appalachian and Permian basins. It is quickly exhibiting results that are considerably better than traditional equivalents as well as being cost-effective and consistent—driving quick adoption and high demand throughout the country's top oil basins.

In the field these treatments are performed in the same manner as solvent treatments. The product is pumped through the backside through the annulus with no shut-in required. The new treatments have several advantages compared to existing options. There are no toxicity or HSE issues such as those resulting from the use of toxic benzene, toluene, ethylbenzene and xylene solvents. Also, being aqueous-based, the product maintains a water-wet state in the near-wellbore region—preventing formation skin damage.

Testing results

Figure 1 shows laboratory screening results indicating rapid liquefaction and dispersion of 2 g of solid paraffin samples obtained from the Permian Basin in 30 ml of the formulation. Quick separation of the paraffin into a liquid oil layer with a sharp interface was observed, with dispersing performance comparing favorably to that of toluene.

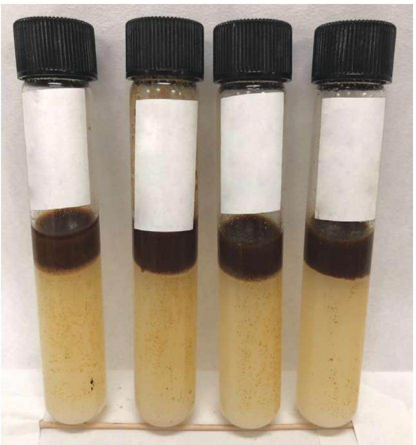


FIGURE 1. Liquefied paraffin dispersed within 25 minutes at 35 C (95 F) is compared to 20 minutes for toluene. (Source: Locus Bio-Energy Solutions)

The treatments are customized specifically to each client and formation. As a first step, the carbon chain lengths of a representative sample of the well's paraffin deposits are studied as well as the amount of inorganic matter such as solid iron sulfide scale embedded within the paraffin.

This analysis provides clues to formulation design to maximize penetration into the paraffin, while accounting for the scale. The dispersal effect is achieved as a result of a combination of mechanisms—one using enzymes and biosurfactants for increased penetration into the paraffin, and another using proprietary nongenetically modified organism cell proteins and biosolvents for rapid dispersal of the paraffin into the oil. Adjusting the ratios of the different contributing ingredients to match the hydrocarbon profile maximizes effectiveness; this is a rapid laboratory process typically completed within a day.

The treatment has been found to be effective, and treated rods and pumps exhibited almost no paraffin

FIGURE 2. Sucker rods exhibit paraffin deposits when they are pulled before treatment, and no paraffin is present after treatment. (Source: Locus Bio-Energy Solutions)

fied into the crude and stays emulsified. Pour point temperatures of the treated paraffin are very low (less than -20 C [-86 F]), limiting the chances of reprecipitation of wax downstream of the treatment. Also, enzymatic action contributes to viscosity reduction which helps reduce energy inputs as the crude passes from the well into downstream equipment. This ensures maximum recovery of the dispersed paraffin with the sales oil—a useful bonus for operators (higher income) and refineries alike (increased utilization).

Additionally, produced water, inorganic scale and other solids separate out and stratify naturally (Figure 3). Hardened tank bottoms also release hydrocarbons and naturally soften. This helps reduce costs associated with crude dehydration and tank cleaning operations.

when pulled from a well (Figure 2). Upon visual inspection, clients uniformly agreed that pulled rods and tubing had never looked better. Clean metal surfaces are essential to prevent underdeposit corrosion.

Unlike thermal treatments, this new approach does not push paraffin farther into the formation, with well failures almost nonexistent in the treatment of hundreds of wells. Tests also have shown the product is not a nutrient source for sulfite-reducing bacteria and has an inhibitory effect on corrosive biofilms.

Natural de-emulsification

Operators using this well treatment have reported the flowlines and storage tanks also are getting de-sludged. This happens because the dispersed paraffin is emulsi-

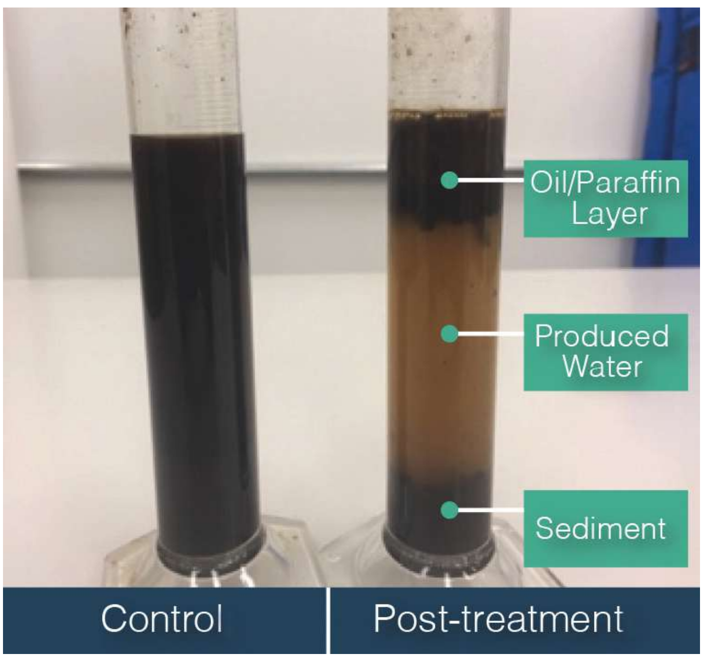


FIGURE 3. Tank bottom sludge is shown before and after the paraffin dispersal treatment. (Source: Locus Bio-Energy Solutions)

Production advantages

A feature of the new paraffin remediation process is its ability to provide sustained enhancement of oil production rates, an effect seen in both the Permian and Appalachian basins. A 70-well study in the Appalachian Basin yielded no well failures for more than 18 months, and 95% of the wells exhibited an enhanced recovery effect during the entire period. This resulted in an approximate 50% average increase in sustained production rate over baseline. Independent decline curve analyses of the field results forecast a substantial increase in future oil production as well, thereby significantly increasing the operating asset value. The increased recovery rates have transformed the paraffin maintenance program into a documented revenue generator for the operator.

Paraffin dispersal

Although traditional treatments have success in paraffin dispersal, demand is shifting to new, more effective and low-toxicity approaches as E&P companies witness extensive additional benefits from treatments—including increases in daily production and potential qualification for EOR tax credits. This HSE-friendly, multifunctional system mitigates paraffin wax problems and is creating a new industry standard for highly potent, customized products specifically addressing lease-level pain points. E&P

Meeting the challenges of deepwater pipeline inspection

Expanding the toolbox provides the best technologies for the job.

Judy Murray, Contributing Editor, Offshore

Moving tools into deepwater environments is a challenge. Even individual components rated for 3,000 m (10,000 ft) do not always perform as anticipated when they are connected in a system. Regardless, the tools are expected to work. So as companies develop inspection tools for deployment in deeper water, considerable effort is invested in eliminating impediments that could compromise performance.

Understanding restrictions

According to Mike Killeen, technical solutions lead for global subsea inspection at Oceaneering, "Everything in an inspection is some kind of compromise because no one technique can do everything."

In cases where an intelligent pig can be used to inspect a pipeline, things are fairly straightforward and cost-effective with regard to coverage per dollar spent. As long as the pig can transit the line, 100% of the line can be inspected.

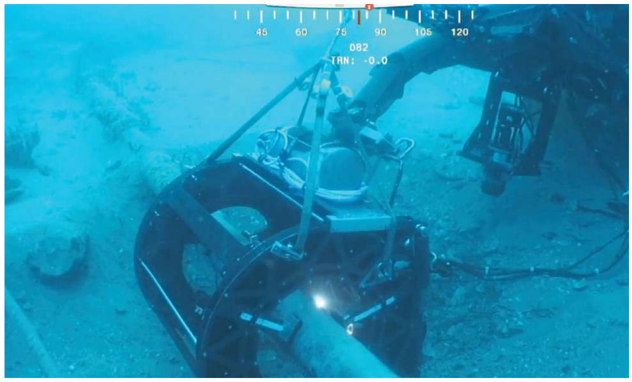
The problem is that about 30% of the pipelines in operation today are not "piggable." Sometimes there is no way to launch and/or receive the pig, or the flow is too low. Where sections of pipe have been replaced, introducing a line with a different schedule, the change in diameter can prevent a pig from passing. When a line has never been pigged, and the internal condition is unknown, owners often are leery of deploying a pig that could encounter extensive wax buildup, sand deposits or asphaltines.

Successfully launching tethered inspection tools depends on knowing the number of bends in the line and their radii, Killeen explained, because friction from the tether as it pulls tight around a bend could make it impossible to retrieve the tool in an emergency.

"If you can't get a pig inside a pipe, the other option is to inspect it externally," he said.

Inspection tool, limitations

When a pig is not the answer, sometimes external automated ultrasonic testing (AUT) is.



The Neptune ROV completed its deepest inspection to date in 2017 at 2,250 m water depth with equipment rated for 3,000-m buoyancy. (Source: Oceaneering)

"Used by divers in shallow water since the early '90s, AUT delivers precise encoded measurements to plus or minus fractions of a millimeter of accuracy," Killeen said, "but it isn't always feasible."

Full corrosion mapping with an external UT tool requires 360-degree external access to the pipe, which requires dredging. The coating can be an issue depending on sound penetration, which in some situations means coatings must be removed.

"Even where UT can be used, it is not fast, and there are associated costs of the vessel and the ROV to be taken into account while you're gathering data," he said. Digital radiography is another option, but it does not provide sub-millimeter accuracy measurements. "Unlike inspections that use a pig, external UT and radiography inspections do not cover 100% of the line due to the associated costs of doing so, but they yield sufficient data to assess a pipe's general condition."

Despite their inherent limitations, these technologies are providing deepwater inspection capabilities that were not available less than a decade ago.

Evolving capabilities

The first ROV scanners were not intended to work at 3,000 m but to replace divers in much more shallow inspections, Killeen explained. When Oceaneering introduced its first Neptune UT tool, an ROV-deployed

AUT scanner, the buoyancy rating was considerably less than 1,000 m (3,300 ft).

"We didn't need tremendous depth capability, because the water depth where we were doing mostly flexible riser inspections in the North Sea was at maximum 500 m [1,600 ft]," he said.

The depth of the ROV-deployed tooling changed when demand for flexible riser inspections began coming in from West Africa. "To work in West Africa, the equipment had to have greater depth capability," he said.

Most of the work continued to be in the North Sea, but global demand brought with it expectations for increased depth capability. In 2013 Oceaneering made the big step to 1,400 m (4,600 ft). Continuing to push the boundaries, the company completed its deepest inspection to date in 2017 at 2,250 m (6,400 ft) water depth with equipment rated for 3,000-m buoyancy.

Improving technology

Inspection efficiency evolved along with depth capabilities, Killeen said. "Moving from doing straight-up corrosion mapping with pulse-echo phased array has proved to be three to six times faster than conventional methods," he noted.

Escalating the ability to work at greater depths is one of Oceaneering's primary goals, he said, pointing to the company's subsea electromagnetic acoustic transducer tool as an example. "Over a span of six years, it went from being used in less than 100 m [330 ft] water depth to 1,300 m [4,250 ft]," he said.

Oceaneering takes time to consider the long-term prognosis for each tool, Killeen said. "Ideally, we want it to go to 3,000 m with every individual component rated for that depth. We want 100% spares. We have an ideal in mind for tool performance and then look at what has to be done from an engineering standpoint to get it there," he said.

For subsea AUT, this approach led to using hyperbaric testing to evaluate functionality at greater pressure levels that would be encountered at the deployed depth, beginning with ambient conditions and increasing depth incrementally to 3,000 m.

Set up in a hyperbaric chamber, the AUT tool moves a probe axially along a pipe for 20 in., then circumferentially around the pipe and then back 20 in. axially while engineers check to see if the depth has affected the mechanics.

"We look for things like whether it slowed down because the tolerances were tight because of the greater pressure," Killeen explained. "It's those little things that don't seem like they would introduce serious problems that can trip you up in the field."

The company also is taking specialist inspection techniques that are used topside and figuring out how to use them subsea. "There is way more technology used onshore and topsides than subsea," Killeen said. "The challenge is figuring out what fits and where because you're going to spend so much to develop and test it and get it accepted that the capability has to be worthwhile and deliver something different."

The next frontier

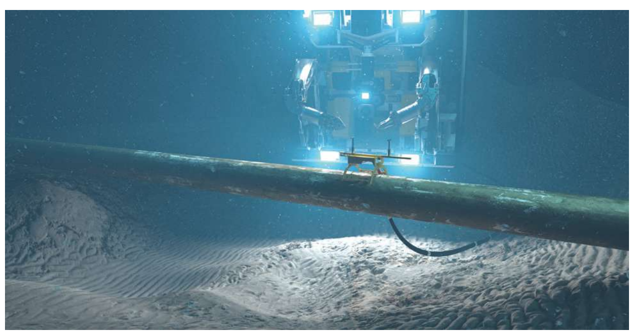
The next advancement, according to Killeen, is likely to be in a different area altogether. "I think one of the big things that will come to the fore over the next few years will be permanently installed monitoring systems with resident ROVs," he said.

Because so much mobilization is required for an inspection, leaving the ROV *in situ* subsea for periodic redeployment could be advantageous—allowing the ROV to ping the area of interest occasionally and having experts evaluate the data. "I don't think this is a million miles away," he said.

Another advancement will be derived from a bigger toolbox. Having access to more offerings from a single source would make it easier to find the right solution more quickly, simplifying evaluation of the pros and cons. This is one of the reasons Oceaneering is partnering on techniques to deliver deepwater inspection solutions.

Guided wave inspections are an example, Killeen said, pointing to work Oceaneering is doing with an equipment manufacturer to deliver this service topside. Now the companies are working to deliver the same service subsea, providing a complete solution by bringing subsea AUT capability and proven guided wave equipment together.

"Using new technologies and combinations of technologies in creative ways is what will move the industry forward," Killeen said. E&P



The Sea Turtle uses electromagnetic acoustic transducers to assess the plate or pipe condition of structures, pipelines, jumpers, flowlines and risers. (Source: Oceaneering)

Pipeline inspection takes the plunge

A subsea CT scanning system enables operators to overcome inspection challenges.

Jennifer Briddon, Tracerco

Since the construction of the first deepwater field—Cognac at 311 m (1,022 ft) depth—there has been an inevitable and increasing shift toward oil and gas production in deepwater fields. Indeed, the Bureau of Ocean Energy Management reported that more than 80% of developments in the Gulf of Mexico are in deep water; this is partly driven by the fact that many of the most easily accessible hydrocarbon reserves have been recovered.

Deepwater fields present many challenges for design, construction and operation, and many of these challenges translate into difficulties for ongoing inspection and monitoring of pipelines. Also, for deepwater discoveries that are too small to be economically developed as standalone projects, operators often might prefer to instead tie back the wells to existing production facilities. This, in turn, increases the number of flowlines, which are typically difficult to inspect, while usually being exposed to the most challenging pipeline operating conditions at the same time.

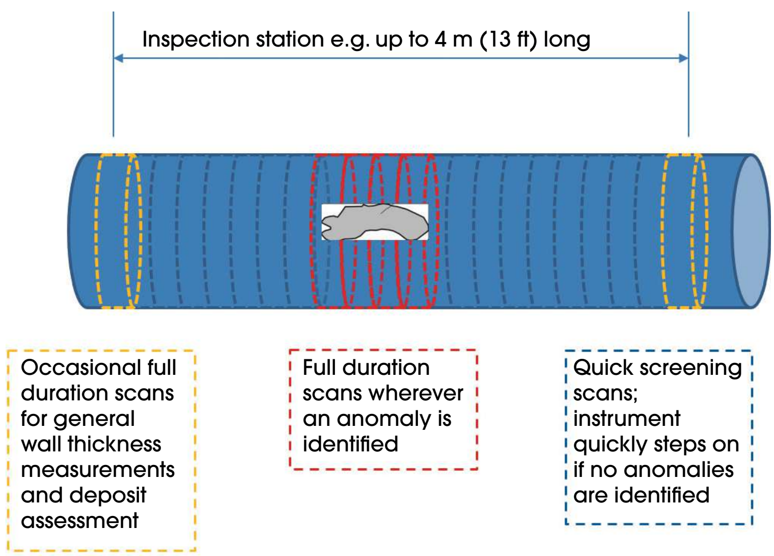


FIGURE 1. The Discovery fast scan process splits the areas to be scanned into sections with suitable intervals for full duration scans performed irrespective of presence (or lack of presence) of any anomalies or defects. (Source: Tracerco)

Design, inspection challenges

Historically, many deepwater developments have pushed the boundaries of the technology capabilities in the oil and gas industry at the time of their design. For example, deepwater pipelines are subject to a much higher external pressure than their shallow-water siblings. Pipelines are constructed from thicker and heavier material to withstand this increased external pressure. This places additional stresses on the line during the construction and installation stage, and can potentially lead to the development of unexpected or even entirely new failure mechanisms.

Due (in part) to the temperatures and pressures the transported product experiences at several thousand feet of sea depth, deepwater pipelines often will require chemical controls, heating and insulation to ensure the pipeline product continues to flow. In situations where these measures fail, deposits can form on the pipe bore. Initially, this leads to increased operational costs (as more power is required to push the fluid along the pipe) but ultimately this can lead to a partial or complete blockage of the line, which has both cost and safety implications.

It is not possible to internally inspect a pipeline with a partial or complete blockage, at least without significant cleaning of the pipe. Unfortunately, the insulation or heating systems can limit the effectiveness of many conventional external inspection techniques. For operators with these systems, Tracerco's Discovery system is available. Discovery is a subsea computed tomography (CT) scanner designed for external scanning of pipelines. The CT scanner is unaffected by the material it is scanning through and is easily capable of scanning through several inches of pipeline steel. Discovery enables an operator to see the condition of both the pipe wall and the bore, meaning that in a single scan, the system can provide relevant information for both ongoing integrity and flow assurance.

Reducing the inspection information gap

A continuous problem that operators face, particularly those with deepwater assets, is the amount of useful inspection data available to them. In many systems conventional inspection techniques might not be practical or even possible. In such cases, operators may be forced to limit themselves to performing localized inspections at potential hot spots; further inspections may be required depending on the information found at these hot spots. For all operators this can be a costly process, but this is particularly true for inspections in deepwater systems.

Techniques such as the fast scanning approach, which has been developed by Tracerco, provide rapid defect identification during CT scanning, allowing operators of deepwater systems to obtain the maximum amount of valuable data from a single inspection campaign.

By deploying the fast scanning approach, Tracerco has determined that certain key characteristics indicating the presence of a defect can be identified in pipe scans before completion of a full CT scan. Although these characteristics do not include sufficient information to enable the dimensions of the anomaly to be determined to within Discovery's stated tolerances, the fact that the anomaly can be identified at this early stage means a full sizing scan can be performed only when it is of most benefit (Figure 1).

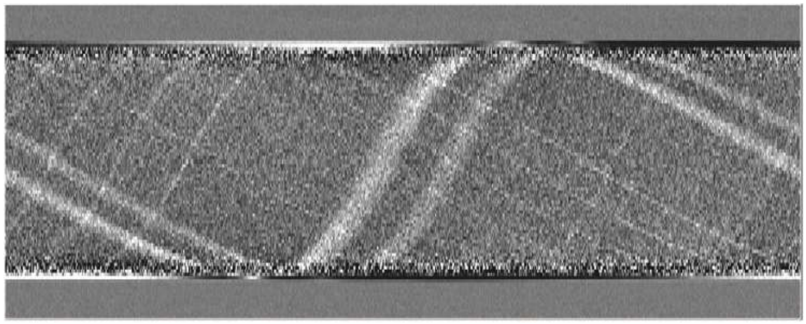


FIGURE 2. Characteristic defect traces are visible in this image created during a fast scan performed by Discovery. (Source: Tracerco)

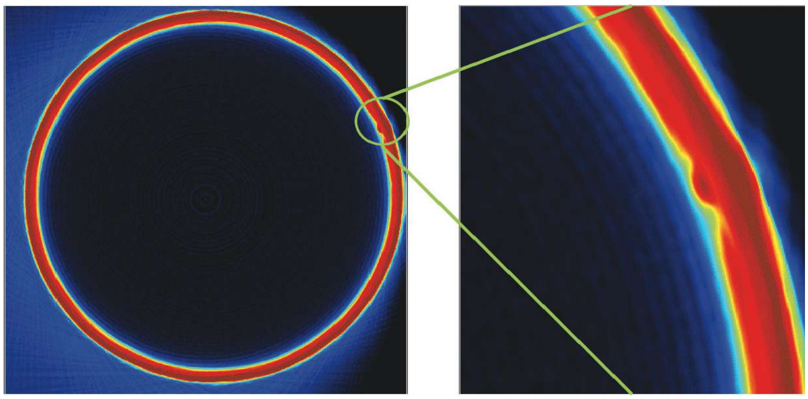


FIGURE 3. Fast scanning confirmed metal loss in the pipeline for the operator. (Source: Tracerco)

The area to be scanned by Discovery is split into separate sections and a suitable interval for full duration scans is determined. These full duration scans will be performed irrespective of presence (or lack of presence) of any anomalies or defects and enable general wall thickness measurements and deposit assessments to be performed (Figure 2).

For the remainder of the section, fast scanning is performed. Provided that no anomaly characteristics are identified, the Discovery scan can then finish at the end of the fast scan time. However, if an anomaly is identified, the Discovery scan is extended to a full duration scan to enable accurate sizing of the anomaly.

Case study

A pipeline life extension was required on a pipeline that was considered to be difficult to inspect by conventional pipeline methods. The operator was aware of several potential failure mechanisms (such as preferential weld corrosion) and had, by the use of corrosion and risk assessments performed before the inspection campaign, identified areas that were considered to be at the highest risk of failure.

A large amount of pipeline required inspection, but the operator was working within a restricted timescale due to various operational issues.

Discovery was identified as the most suitable method for inspecting the pipeline, but the predicted overall inspection campaign time (including full Discovery scans) was unsuitable. It was determined that the fast scanning method could be used and would enable time savings of up to 79% on the overall Discovery inspection time; this had the added benefit of saving the operator approximately 35% on the total project cost. Consequently, the operator deployed Discovery and, using the fast scanning technique, confirmed that corrosion had occurred (Figure 3).

Following the conclusion of the Discovery scanning campaign, the operator was able to perform remediation measures that enabled the pipeline system to continue operation.

With the increasing move toward oil and gas extraction in deepwater fields and the additional engineering complexities associated with installation and inspection at these depths, inspection techniques need to be developed and improved to enable their safe ongoing operation. Newer inspection techniques, such as Discovery, are available to operators with challenging deepwater assets.

SPE ATCE to highlight emerging technologies

Companies at SPE's annual technical conference and exhibition will be showcasing new products and services.

The Society of Petroleum Engineers (SPE) is hosting its Annual Technical Conference and Exhibition (ATCE) Sept. 24-26 in Dallas, Texas.

"For more than 90 years, ATCE has been the meeting of choice for SPE's members and other professionals seeking education on current and future technologies that help find and produce hydrocarbons faster, more efficiently, safer and more cost-effectively," the conference website stated.

The following is a sampling of some of the latest technologies that will be showcased at SPE ATCE 2018.

Editor's note: *The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.*

Complete end-to-end control automation and data management platform

Fracture spread control technology and cloud-based pump maintenance are among the technologies to be showcased by AFGlobal's AMI Controls & Analytics group. Complete end-to-end control automation and data management of hydraulic pressure pumping is provided by the FracCommand Suite control and data management platform. The suite collects fracture spread data and delivers those to the DVCommand control package. The platform is highly configurable to support upgrades and new installations. Its software library includes a family of control modules as well as support for existing controls. Plug-and-play hardware controls and a proprietary transmission control protocol/internet cache protocol network enable seamless installation and setup. A novel cloud-based system to collect and analyze fracture pump data provides robust support for managing maintenance to reduce field failures. By collecting and analyzing large amounts of data, the AFGlobal system provides the means to improve job performance through consistent, dependable operations and greater efficiency. *afglobalcorp.com*

The AMI Controls & Analytics group offers complete end-to-end hydraulic pressure pumping control automation and data management through its FracCommand Suite. (Source: AFGlobal)

Real-time process viscometer for drilling fluids

AMETEK Brookfield, a provider of oilfield in-line process viscometers, has released its latest in-line rotational viscometer, the TT-100 IECEx. The viscometer was designed from the ground up to measure viscosity in drilling fluids. It preserves the time-tested Couette geometry measurement method of previous models but adds an increased operating temperature range, more granular speed control, and IECEx, ATEX and North American explosion-proof certifications. Drilling engineers can use the TT-100 IECEx to collect critical viscosity data in real time no matter where in the world opportunity might lead them. *brookfieldengineering.com*

The TT-100 IECEx is certified to IECEx, ATEX, UL and CSA explosion-proof standards. (Source: AMETEK Brookfield)

Complete monitoring solution for ESP system

Apergy Artificial Lift (formerly Dover Artificial Lift) is releasing several new technologies to optimize wells.

The Apergy Gas Lift group has developed an algorithm to hunt for the optimal gas injection rate with continuous tuning to ensure the well is operating optimally, realizing a bottomhole pressure drawdown, and yielding increased production and decreased downtime. Theta Software's XSPOC is the engine powering the expansion of LOOKOUT Monitoring's extended capabilities. No longer only for electric submersible pump (ESP) systems, LOOKOUT is available on gas and rod lift. Continued focus on production optimization is increasing with the use of smart hardware and software in conjunction with smart analytics. Also powered by Theta Software, edge computing is possible on a multitenant platform with web-based, hosted solutions all while being mobile enabled. This allows pattern recognition along with a deeper level of smart analytics to make the best real-time decisions. These technologies allow more actionable data visualization, help predict and prevent catastrophic equipment breakdowns, and enhance safety. *apergy.com*

SMARTEN Controls provide increased safety, performance and value for effective operations of an UNBRIDLED ESP system. (Source: Apergy)

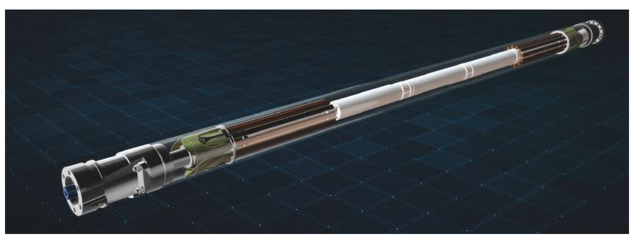
Silica dust control proppant coating technology

ArrMaz's SandTec proppant coating technology is an engineering control that provides effective silica dust protection across the hydraulic fracturing supply chain. It is proven to reduce silica dust by up to 99%, to below The U.S. Occupational Safety and Health Administration's permissible exposure limit and action level. While mechanical dust abatement systems do provide dust control, the impracticality of using them at all supply chain transfer points limits their effectiveness while slowing fracturing operations. SandTec provides continuous silica dust protection from sand plant to wellhead without capital-intensive investment by sand companies, transloads and fracturing operators. SandTec is customized to work with silica sands of varying characteristics such as Northern white sand versus Texas brown sand, to ensure optimal silica dust control. The SandTec product line is fracture-fluid compatible and includes an environmentally friendly, U.S. Department of Agriculture-certified 100% biobased product under the BioPreferred program. *arrmaz.com*

This side-by-side comparison shows airborne dust from untreated fracture sand versus the absence of dust from sand treated with SandTec. (Source: ArrMaz)

PMM improves operational efficiency

Operators are looking for new ways to increase electric submersible pump (ESP) system efficiency and lower lifting costs. Baker Hughes, a GE company's (BHGE) new Magnefficient permanent magnet motor (PMM) improves efficiency by lowering ESP system energy consumption. The Magnefficient PMM eliminates induction losses, lowering system power consumption by 20% and reducing motor power loss by as much as 67%. The Magnefficient motor has demonstrated positive results in the field and extended the applicability of ESPs into situations that weren't previously practical. Eight BHGE PMMs have been installed at present, in applications



The BHGE Magnefficient PMM improves operational efficiency and reliability by lowering ESP system energy consumption and minimizing the risk of downtime. (Source: BHGE)

ranging from waterfloods and unconventional oil and gas wells in North America to high-temperature and mature fields in Latin America. Some of the units have been running continuously for more than 800 days, and each installation has achieved a motor efficiency rating of more than 90% with no reported failures. *bhge.com*

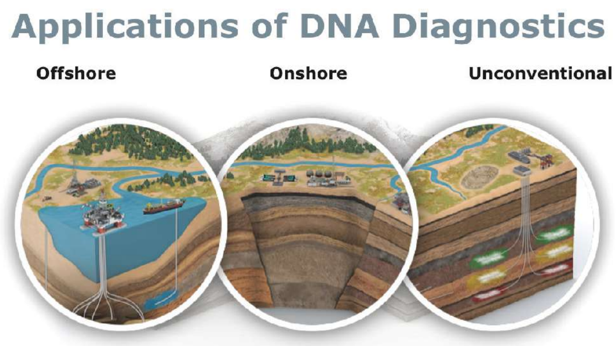
Power sections contain approximately 30% less rubber

SpiroStar Supreme power sections are the next generation in thru-tubing technology that has been developed by BICO Drilling Tools Inc. New power sections contain approximately 30% less rubber than previous generations of Evenwall power sections. This can result in a 35% to 60% increase in power and torque output. The thinner layer of rubber further reduces the probability of chunking due to hysteresis, which makes power sections more suitable for harsh application such as high bottomhole temperature and nitrogen. New hard rubber compounds have improved the sealing surfaces, while providing amplified power. This can reduce stalls up to 40%. High flow rate capacity has been incorporated into the overall design feature to enhance hole cleaning in horizontal or high-angle wells. Moreover, larger chamber capacity permits higher flow rates without creating critical internal velocities that can be detrimental to the motor power section life. *bicodrillingtools.com*

BICO's SpiroStar Supreme incorporates an Evenwall performance power section with uniform rubber thickness that provides strength and the ability to withstand harsh environments. (Source: BICO Drilling Tools)

New data science service delivers comprehensive reservoir models

Biota has globally deployed Subsurface DNA Diagnostics on more than 500 wells with a mission to maximize oil and gas reservoir economics. At ATCE Biota will introduce a new data science service that integrates DNA Diagnostics with existing reservoir measurements to deliver a comprehensive reservoir model. Biota will present new case studies in the conventional market with field trials in the Gulf of Mexico and Southeast Asia. The DNA Diagnostics service provides a novel, 4-D and noninvasive measurement of subsurface hydrocarbon fluid movement. These measurements address key questions in production allocation, reservoir connectivity, horizontal well drainage height, fracture hit monitoring and well-to-well connectivity. By delivering new subsurface insight with DNA Diagnostics, users can optimize field development, resulting in $5 million to $10 million net present value uplift per section of resource. *biota.com*



The new subsurface data source, DNA Diagnostics, can be applied across several oilfield assets. (Source: Biota)

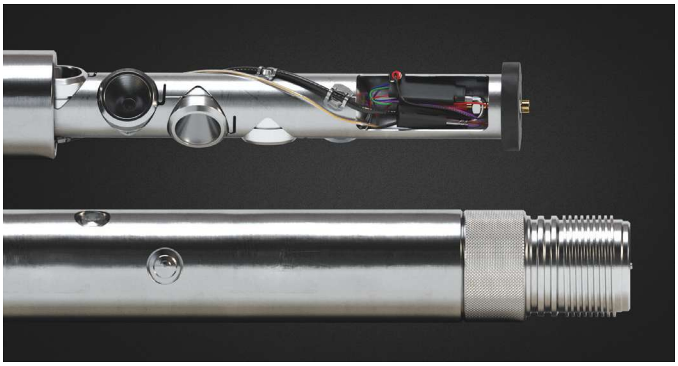
Well seals developed with bismuth-based alloys

BiSN's Wel-lok M2M technology seals wells with bismuth-based alloys. By harnessing the energy available from a thermite-powered chemical reaction heater and delivering an expandable, malleable metal alloy, BiSN has created an improved solution to the traditional methods of conventional bridge plugs, cement and resins. These seals can be applied throughout the life of a well. Wel-lok M2M technology addresses several downhole sealant challenges, producing significant time, cost and environmental benefits. The modified thermite chemical heater is nonexplosive, so no special licenses or handling permits are required. Each tool can be deployed on any standard wireline without special connection or power requirements. Bismuth expands on solidification, creating a V0 gas-tight seal in accordance with ISO 14310, and bismuth is noncorrosive, environmentally friendly and is not affected by H_2S, CO_2 or acid washes. In addition, the seal is created within minutes and ready to test within 1 hour. *bisn.com*

Perforating system eliminates misruns

The GameChanger perforating system from C&J Energy Services features a semi-disposable gun assembly designed to increase efficiency and reliability by eliminating the misruns and resulting nonproductive time associated with traditional gun systems. Compatible with all manufacturers' standard shaped charges, the port-free design eliminates pinch points that can

damage electrical connections, has no port plugs that can get lodged in the well and significantly decreases the chance of flooded guns. Addressable switches provide real-time confirmation throughout the downhole descent, and with no wires running between guns, the GameChanger system provides a high level of confidence in the wellbore. Using the compact C&J top sub and plug shoot sleeve, the system reduces the length and weight of the gun string, which requires less rigup equipment and provides safer onsite handling. *cjenergy.com*



To avoid crimped or scraped electrical connections, the GameChanger perforating system features a port-free design, no wires running between guns and a strategically placed detonator/switch assembly. (Source: C&J Energy Services)

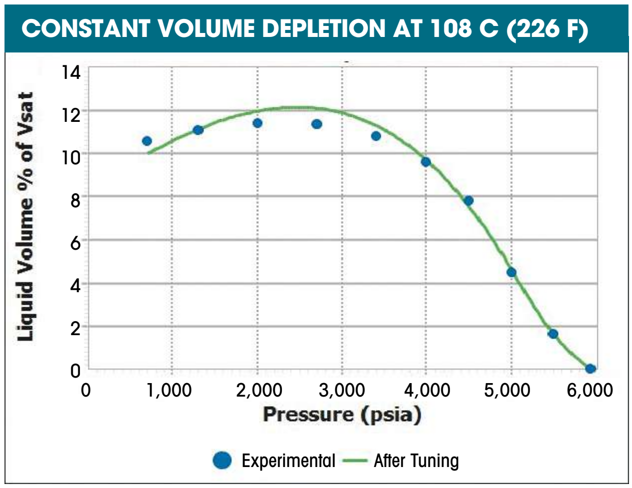
Identify diversion in real time with zero false positives

Traditional methods of identifying successful diversion assume that when the diverter material reaches the perforation, an increase in treating pressure is observed. While this might be an indication of diversion, it can be misleading. Calfrac's charting overlay approach identifies diversion in real time with zero false positives. No time-consuming or resource intensive analyses are required. Through the application of this technique, diversion can be identified with greater confidence and in a timely manner such that adjustments can be made to improve stimulation effectiveness in subsequent applications. *calfrac.com*

From left to right, CalVert PS (small particulate), CalVert P10 (large spherical particulate 8 mesh) and CalVert PF (flake particulate) are shown. (Source: Calfrac)

Automated tools for quality checking experimental PVT data, EoS modeling

Calsep has released PVTsim Nova 4.0, which features new pressure-volume-temperature (PVT) technology. Modeling reservoir fluids (EoS modeling) is considered to be a difficult task requiring the experience of experts in the field. Experts often will need days or weeks to construct a robust model. With Calsep's new Auto QC and Auto EoS technology, even engineers with limited experience in EoS modeling will be able to develop an EoS model in a much shorter time. Auto QC evaluates an input fluid composition. If the data turn out to be inconsistent, the software will automatically make the necessary adjustments. The user selects the number of components for the final EoS model, and PVT data importance is automatically ranked. Calsep's new Auto EoS tool will deliver an EoS model that provides a good match of all PVT data within minutes. *calsep.com*



PVTsim's Auto EoS menu generates a good match of PVT data in one click. (Source: Calsep)

Proppant prevents salt precipitation, eliminates freshwater injection costs

SALTGUARD is an encapsulated, porous ceramic proppant infused with halite-inhibiting chemicals that is placed throughout the entire fracture as part of the standard fracturing process. CARBO engineered SALTGUARD technology to be uniformly distributed with interconnected porosity in the proppant. The proppant is infused with a halite inhibitor and is then encapsulated to ensure a controlled release of the halite inhibitor on contact with produced water. This technology prevents salt precipitation from the fracture through the surface equipment and eliminates freshwater injection costs. SALTGUARD technology is cost-effective due to

Optimizing Diverter Performance in Real-time

Challenge: One of the ten largest US operators asked Seismos to evaluate and help improve diverter use. The project consisted of 4 wells in the Barnett play. The operator varied the volumes of diverter on each stage of the first well to evaluate how diverter impacts the development of the fracture system. The focus was on fracture propagation and the stimulation of new fractures.

Delivery: Seismos' **KVIEW**™ fracture evaluation technology was used to monitor the effects of varying diverter volumes pumped on every stage, in particular with respect to near- and far- field conductivities, reservoir connectivity, and near-wellbore complexity. Additionally, **KVIEW**™ measured the effective propped fracture length, and monitored the wellbore condition throughout the treatment.

The **KVIEW**™ measurements and processing were done in real time, enabling the operator to make changes on the remaining wells in the pad.

Results & description of findings: In stages with little or no diverters pumped, the stimulated fracture network was primarily characterized by a far-field system (Fig.1), meaning fractures with an extended connection to the reservoir. As the client increased the volume of diverters, the extension of that far field fracture system was restricted. Conversely the near field fracture region became more stimulated, increasing near wellbore conductivity and complexity. A threshold was observed past which further increasing the diverter volume affected negatively the development of the fracture system. **KVIEW**™ identified with accuracy the "sweet spot" for the optimal volume of pumped diverter leading to the desired combination of fracture propagation and near wellbore complexity.

KVIEW™ is the 1st technology to quantitatively measure the effect of diverters on the development of the fracture system.

Impact: Based on the Seismos measurements the operator revised their completion program for the subsequent 3 wells. The revision allowed further control and management of fracture propagation and fracture network complexity, saving more than 50lbs of diverter material on a stage by stage basis. Pumping less diverter resulted in significant economic improvements and savings.

Near/Far Field Conductivity vs Mass of Diverter

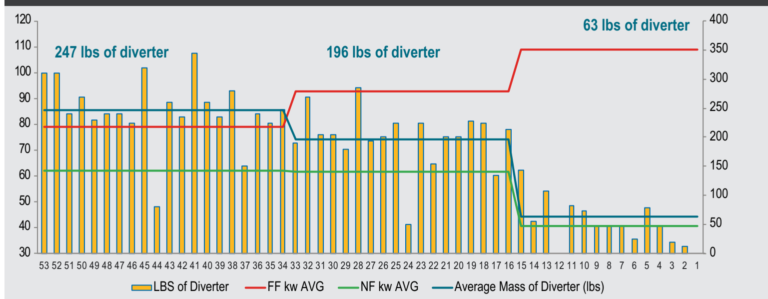


Fig. 1 Effects of diverter mass on the propagation of the fracture system and the near field conductivity

Conclusions: Seismos **KVIEW**™ Real-Time fracture evaluation technology allowed the operator to identify the appropriate volume of diverter to create optimum fracture characteristics.

Operators looking to optimize their use of diverters for the delivery of a target performance can use **KVIEW**™ actual measurements to make real-time decisions, rather than relying on an ambiguous predictive software model.

Seismos was not just able to provide a binary ('works' vs. 'doesn't work') assessment but was **the 1st technology to quantitatively measure the effect of diverters on the development of the fracture system**, to identify the specific element of the fracture system that got affected, and to correlate varying volumes of diverter to specific fracture system responses.

Company Brief: Seismos is a technology company offering completion diagnostics for the Oil and Gas industry. Seismos' **KVIEW**™ offers the industry's first non-invasive, direct measurement of fracture properties for real-time fracturing treatment evaluation. Seismos has applied its technology with most of the top 10 US producers to thousands of stages across various U.S. plays, including Permian Basin, Eagle Ford trend, Austin Chalk formation, Haynesville/ Bossier shale and DJ Basin. E&P

reducing the amount of chemical washout; preventing production impairment; eliminating costly remediation treatments, equipment failures and production loss from halite scaling in the fracture; and removing freshwater consumption and associated disposal cost. SALTGUARD has low minimum inhibitor concentration and is effective in brines with a presence of calcium and iron. *carboceramics.com*

Facility provides testing for downhole drilling technologies

Catoosa Test Facility (CTF) provides confidential oilfield tool and technology testing for companies that are developing new drilling, completion and production technologies. All types of advanced prototype downhole drilling technologies are tested and validated at this private and independent testing campus. CTF has discretely tested hundreds of downhole tools and has allowed the largest service companies and the smallest startups the ability to test and find solutions in a safe and cost-effective environment. CTF will be highlighting the new addition of test rig M37 at ATCE. This rig is an all-electric, triple cyber-walking rig custom designed by Nabors Industries to meet the information and data requirements needed to record and capture testing information. CTF has the privilege to be an integral part in the testing of many of the innovative tools and technologies being used today. *ctfok.com*

CTF's automated, all-electric triple cyber rig is capable of performing any type of downhole tool and technology drilling test. (Source: Catoosa Test Facility)

Tools enable well control, maximize downhole space

Ideally suited for long reach horizontal, multistage stimulated oil wells, D&L Oil Tools' ProTension safe tension tool allows complete well control at all times while setting a tubing string in tension using standard field procedure. ProTension is installed between the tubing hanger and the production tubing. Once the tubing hanger is landed, isolating the annulus, tension can then be pulled into the tubing string and safely locked into place without losing well control—no need to remove the BOPs or overstretch the tubing. The tool allows complete rotation of the tubing when setting downhole tools. The Trilobite Tubing Anchor/Catchers, designed for hydraulically or mechanically set retrievable tubing, have a unique design that uses three double-acting slips to maximize holding power in both tension and compression, while allowing increased annular flow and capillary tube installation outside the anchor. This allows operators to maximize space for gas bypass while running capillary lines, all without compromising the inside diameter of the tubing. *dloiltools.com*

Systems aerate water storage ponds, calculate inventory, monitor flowmeters

Direct Drivehead Inc. will be showcasing its Smart Pumper produced and fracturing water storage pond systems at ATCE. The Smart Pumper produced and fracturing water pond systems aerate the water, calculate inventory, monitor meters flow in and out and water quality, add chemistry as needed, control transfer pumps, and provide other options that reduce HSE risk and improve the operation. Built-in communications let customers know all these data and more while having remote on/off control capabilities in real time. *directdrivehead.com*

Smart Pumper is a universal platform (hybrid technology) that provides high-speed global connectivity with a processor that is used to support a multitude of applications to control and monitor anything through a customizable web-based interface from anywhere in the world. (Source: Direct Drivehead Inc.)

Water treatment microbiocide protects assets

Dow Microbial Control's new AQUCAR 736 water treatment microbiocide provides enhanced topside microbial control and near-wellbore efficacy in the North Sea. This

stable, one-drum formulation is Cefas gold rated and has shown superior biofilm efficacy over glutaraldehyde and tetrakis-hydroxymethyl-phosphonium alone in field validated trials, effectively protecting valuable assets and keeping them profitable for extended periods. This biocidal product also can be co-dosed with nitrate, making it the strongest drop-in solution available in the North Sea region. Expanded efficacy in the topside and near-wellbore areas combine multiple chemistries into one solution, reducing the platform footprint required for different products. Samples and laboratory data are available for AQUCAR 736. *dowmicrobialcontrol.com*

Technologies identify and assess early-onset damage

Productivity of wells completed in shale reservoirs can be substantially improved by Flex-Chem's OptaSTIM technology. Insoluble material capable of severely blocking flow commonly forms due to undesirable interactions between shale reservoir formations and additives in many completion fluid systems. This damage, which forms early in the production life of the wells, is associated with highly variable completion outcomes and production restrictions. At ATCE Flex-Chem Corp. will be highlighting its capabilities for identifying and assessing this early-onset damage as well as technologies and methods that address a range of formations and completion designs. Remedial treatments have shown marked success restoring flow conductivity in damaged zones and a proven record increasing well productivity. *flex-chem.com*

This truck is used to pump Flex-Chem's fluids for well stimulation. (Source: Flex-Chem Corp.)

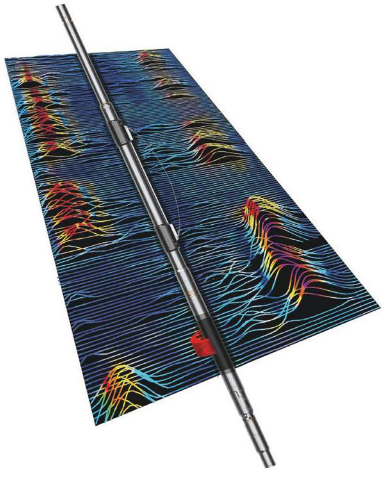
Enhance wells producing by ESP with compression

Flogistix LP uses advanced programming logic controllers to optimize compressors, whether it is handling surging flash gas volumes on the vapor recovery side or enhancing an existing well's production by lowering wellhead pressure. One such application in the wellhead application spectrum is casing drawdown. Casing drawdown is an application where an operator will set a rotary screw compressor on the annulus of a well on mechanical artificial lift. This lift type could be electric submersible pumps (ESP) or sucker rod pumps. Lowering the surface head pressure with a compressor will encourage more inflow of production and create an additional pathway for gas to break out of the pump. Flogistix has helped several operators improve the efficiency and production of wells on ESPs in the Midcontinent. Case studies will be presented at ATCE (referencing SPE-paper 191486). *flogistix.com*

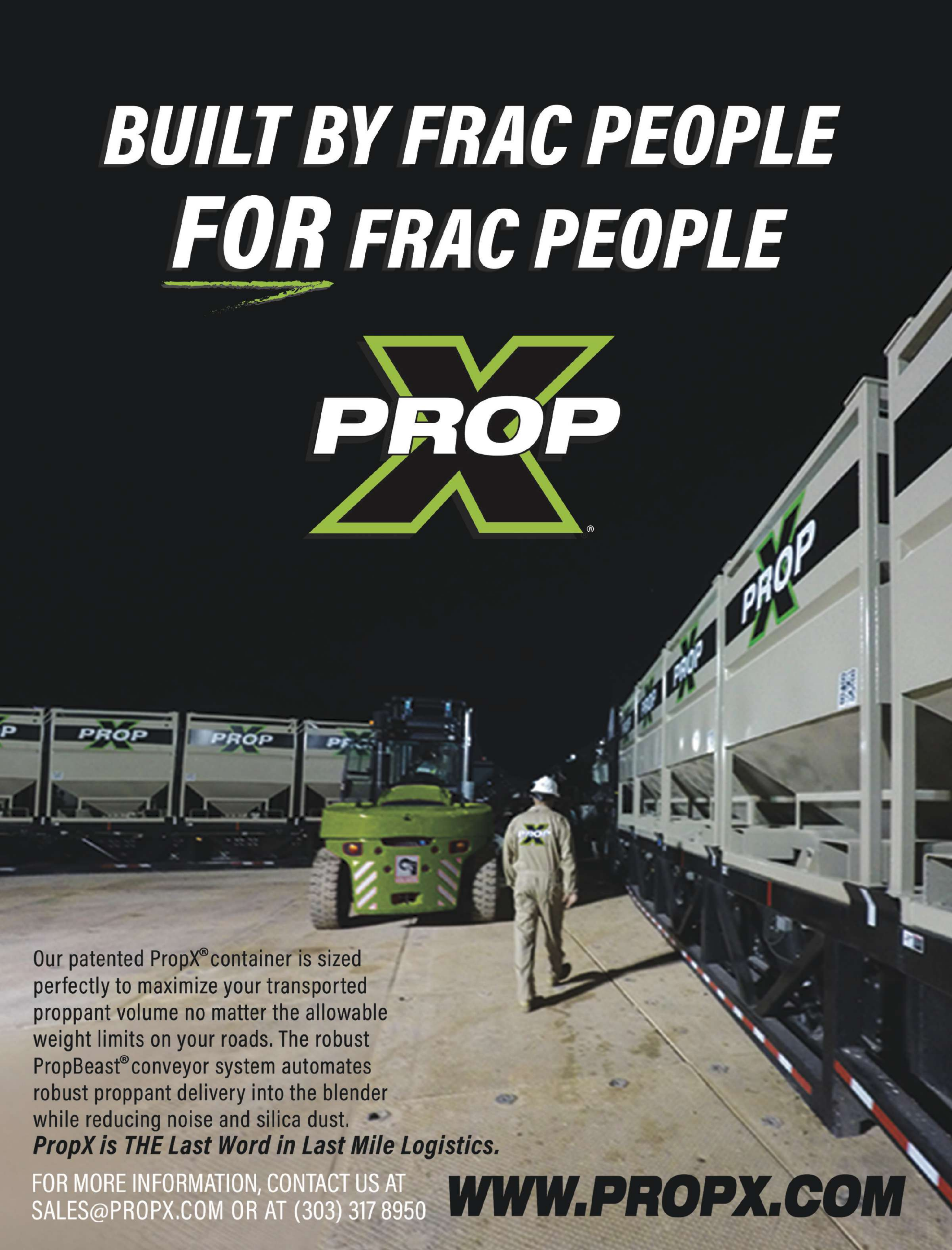
A Flogistix rotary screw compressor is on location performing wellhead drawdown. (Source: Flogistix)

Formation evaluation and LWD technologies to be showcased

The new Halliburton Xaminer Magnetic Resonance (XMR) service is the latest-generation magnetic resonance technology, engineered to provide excellent bed resolution and evaluate a reservoir's full range of pore sizes from micro to macro. The combinable XMR sensor provides full magnetic resonance solutions for basic to advanced formation evaluation requirements with a 35-kpsi rating. The EarthStar ultradeep resistivity service, an LWD technology, helps operators map reservoir and fluid boundaries more than 61 m (200 ft) from the wellbore, more than doubling the depth of investigation



The XMR service is the industry's only high-pressure rated (35,000-psi) downhole nuclear magnetic resonance sensor. (Source: Halliburton)


BUILT BY FRAC PEOPLE
FOR FRAC PEOPLE
PROP X®
Our patented PropX® container is sized perfectly to maximize your transported proppant volume no matter the allowable weight limits on your roads. The robust PropBeast® conveyor system automates robust proppant delivery into the blender while reducing noise and silica dust.
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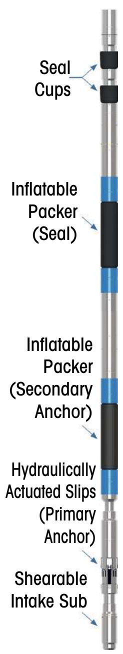
of current industry offerings. The service delivers a comprehensive reservoir view so operators can eliminate costly pilot holes and sidetracks, make informed geosteering decisions in real time and better plan future field development. Halliburton also will highlight DecisionSpace Production Insights & Engineering, new software capabilities that add analytical dashboards and production engineering capabilities to reduce costs and unlock production potential. *halliburton.com*

Inflatable packer system optimizes rigless installation of I-PCPs without PSNs

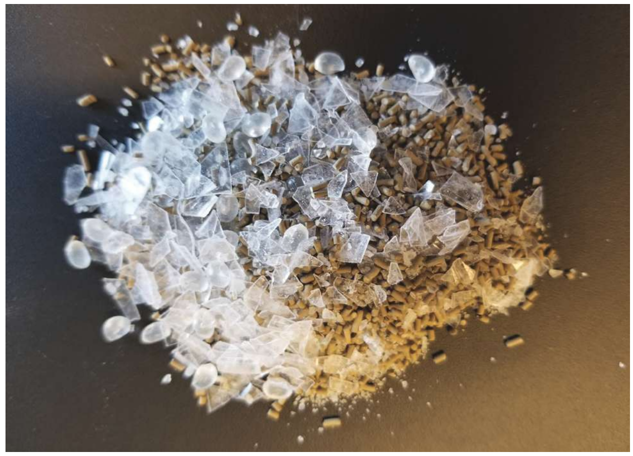
Inflatable Packers International's InflataLOK is the only inflatable packer system in the industry designed to optimize rigless installation of an insert progressive cavity pump (I-PCP) without the need of a pump-seating nipple (PSN). Conveyed on rodstring, it relies only on hydraulic pressure while eliminating the need for axial loads for its setting sequence. It incorporates inflatable packer technology and a hydraulically actuated anchoring-slip mechanism. It is equipped with seal cups and a shearable intake sub to obtain the required pressure competence to confirm tubing integrity and enable its setting sequence while maximizing flow-through capability after it is set. InflataLOK provides cost-effective rigless optimization in wells completed with I-PCPs. It confirms tubing integrity, allows installation within the production string in extended-reach applications beyond previously installed PSNs and eliminates axial-load limitations commonly encountered with J-Slot anchoring devices. *inflatable-packers.com*



Left, the InflataLOK I-PCP anchor does not require a PSN or rig for installation. (Source: Inflatable Packers International)

Enhancements to near-wellbore conductivity, sand flowback control

Recent trends in hydraulic fracturing are moving to proppants in the range of 40/70, 100 mesh or smaller. Pumping into formations with high closure stress, potential fines and embedment issues, or sand flowback issues can be a recipe for disaster. Development of hybrid diverting agents has remedied these issues. A hybrid diverter incorporates both multimode chemical diverting agents that hydrolyze with time, temperature and water, along with a rod-shaped ceramic proppant (RSP). The RSP has superior conductivity to sand or spherical ceramic, so near-wellbore conductivity is enhanced. The RSP also has impressive proppant pack stability and tremendous sand flowback control, keeping the sand in the fracture rather than in the wellbore. This hybrid diverter was highlighted in recent SPE literature (URTeC-2881395 and HFTC-189868 papers). Field deployment and independent laboratory testing show tremendous promise for operators to maximize their well performance and minimize workover frequency. *keanegrp.com*



Keane's ReDirect-3500 is a quad-modal hybrid diverting agent containing RSP. (Source: Keane Group)

Multiphase gathering systems handle production from multiple wells

The Leistritz Multiphase Gathering Systems (MGSs) are expandable versions of the Multiphase Wellhead System designed to handle production from multiple wells. Individual MGSs handle total flow rates up to 550,000 bbl/d equivalent and differential pressures up to 1,400

The fully automated MGS is designed to handle production of multiple wells. (Source: Leistritz)


BLACK MOUNTAIN

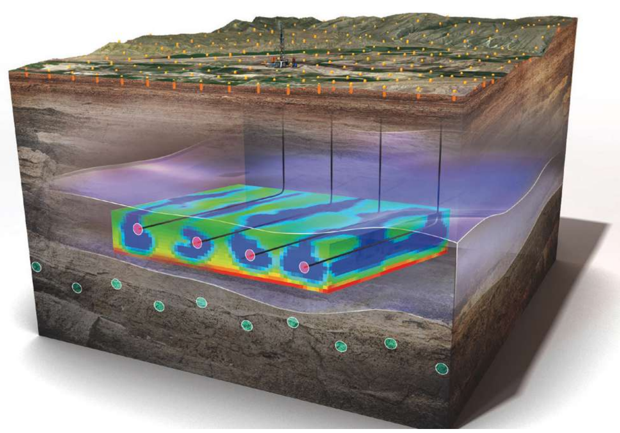
psi. These systems are fully automated and can be expanded to operate multiple MGSs in parallel for facilities requiring additional flow capacity. The utilization of multiphase pumps at the gathering facilities allows operators to centralize process facilities, reduce the local environmental impact and footprint at the well site, and operate safely and reliably. *leistritzcorp.com*

Multivariate analysis tool helps drive completion optimization

Fraconomics is powered by multivariate analysis (MVA) from an extensive petrophysical, completion and production database to verify what parameters independently drive production in different areas. It is a scoping tool for horizontal well completion optimization in unconventional reservoirs. Big Data statistical models use readily available information from thousands of wells, whereas detailed physical modeling is laborious and generally done on a few wells. The strengths of both methods were combined in this novel approach by using calibrated physics-based relationships between completion parameters and production as transformed nonlinear variables. This provides a more constrained and physically realistic prediction of production response to suggested completion changes. The hybrid MVA model is then coupled with completion cost models to determine which fracture design and completion methods are the most effective at lowering costs per barrel of oil. *libertyfrac.com*

Real-time production visualizer

Microseismic monitoring in real time provides a unique tool to adjust hydraulic stimulation on the fly by measuring the dynamic response of the reservoir. Rapid determination of microseismic location and failure plane allows real-time visualization of the effects of treatment and assessment of the induced fracture volume. Fracture models allow rapid estimation of drainage volume while the well is being fractured. This provides operators with a decision-making tool to address challenges currently seen when transitioning to full-field development. Applications include quantifying the impact of parent wells on child wells in terms of fracture geometry and EUR and ways to mitigate fracture hits or testing different cluster and diverter designs and quantifying differences in fracture geometry and recovery from those parts of the wellbore. In addition, history-matched microseismic-based reservoir models can quantify the impact of changes in various development and treatment parameters to account for the degree of variability seen in unconventional reservoirs. *microseismic.com*



Real-time microseismic-based reservoir analysis helps operators with decision-making. (Source: MicroSeismic Inc.)

Prevent system failures, reduce downtime and boost performance

MindMesh will be showcasing its RiMo digital well engineering platform at ATCE. The RiMo platform consumes critical data and leverages artificial intelligence and machine-learning-driven data visualization to develop unique solutions for service companies and operators alike. The company's global talent pool has successfully unlocked and combined physics and mathematical modeling to deep machine learning principles to create digital twins that quickly can enable companies to run more efficiently, safely and economically than ever before. The company's drillstring dynamics functionality allows drilling engineers to leverage analysis for static, directional tendencies, critical speed and time domain analysis. The RiMo well engineering platform can be used for the design of soft and stiff string as well as hydraulics. The company's workflow process has benefited companies that are in any stage of building their team. *mindmeshtech.com*

Overcome critical failure modes in highly interbedded formations

National Oilwell Varco (NOV) will be featuring its Tektonic drillbit platform with ION application-specific 3-D cutter technology at ATCE. ION cutter technology consists of a high-performance range of polycrystalline diamond cutters that have been specifically designed to overcome critical failure modes in highly interbedded formations. Formations with such characteristics present a challenge for many modern cutter technologies due to recurring dynamic bit dysfunctions, including thermal abrasive wear, excessive bit vibration and high levels of impact damage. The refined diamond feeds and increased sintering pressures of the ION cutters make them more durable and abrasion resistant, while deep-leach technology ensures


NEW TRILOBITE
GETS IT RIGHT.
Our new family of retrievable tubing anchor/catchers provides bi-directional holding power with full bore opening allowing for increased annular flow and capillary tube bypass area. Increase production with revolutionary Trilobite Hydro and Quarter Turn Anchors. D&L Oil Tools has been providing customer-driven solutions for over 27 years.
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thermal stability is maintained. ION 3-D cutters feature a durable pointed cutting edge that greatly increases drilling efficiency, making ROP increases of more than 20% possible at the same weight on bit. A polished mirror finish reduces friction on the cutting face, while optimized cutter geometry—obtained using modeled finite element analysis—leads to reductions in drilling torque and mechanical-specific energy. *nov.com*

ION 3-D cutters help overcome the challenges of drilling in complex, highly interbedded formations. (Source: NOV)

Maximizing reservoir contact in high stage count wells

Two recent technologies from Packers Plus Energy Services aim to solve completion challenges in extended-reach laterals by maximizing reservoir contact, increasing stimulation efficiency and reducing operational risk. With a wireline-deployed Latch-and-Perf System for limited-entry treatment and a pumpdown Ultra-High Stage Count System for single-point entry treatment, these new completion technologies can be deployed in a variety of applications to increase stage counts and reservoir access. The Latch-and-Perf System uses isolation latches that are pumped from surface on wireline and latch into a locating sub in the wellbore. After the casing is perforated, stimulation can begin. A ball inside the isolation latch provides isolation and fluid diversion for the stage. The Ultra-High Stage Count System uses sleeve actuation tools (SATs) that are pumped from surface and designed to latch into a specific sliding sleeve in the wellbore. Upon the SAT activating and opening the sleeve, a ball inside the SAT provides isolation and fluid diversion for the stage. Both systems provide a full inside diameter during stimulation that enables an effective treatment by maximizing pump rates, and the degradable ball eliminates the need for millout post-stimulation, which reduces operational risk. *packersplus.com*

The Ultra-High Stage Count System for single-point entry treatment (front) and the Latch-and-Perf System for limited-entry treatment (back) aim to solve completion challenges in extended-reach laterals. (Source: Packers Plus Energy Services)

Sand logistic technology increases efficiency

At ATCE PropX will be showcasing its Last Mile Frac Sand Logistics Technology including the hardware and software that drive efficiency and safety in this ever-changing sector. Unconventional well stimulations require about 13 MMlb of fracturing sand to be delivered to each well, often in less than one week. This volume of sand requires up to 300 truck deliveries—as many as 40 to 150 truckloads per day, which was nearly impossible using the industry's legacy sand hauling technology. Today's systems include smartphone software apps that provide better control and visibility of the proppant ordering, inventory and trucking component. This allows faster and safer unloading of the sand loads at the well site, which allows more round trips per driver per day and cleaner transfer of fracturing sand into the fracture blender, thus resulting in hydraulic fracturing operations meeting or beating the new U.S. Occupational Safety and Health Administration silica dust regulations, which began a three-year phase in June. *propx.com*

Completion diagnostic application for evaluating reservoir quality

ProTechnics has been observing the oil and gas industry embrace the importance of avoiding significant differences in lithology in the same fracturing stage to more evenly stimulate all perforation clusters. In an effort to place perforations across desirable reservoir targets and maximize stimulated reservoir volume, engineered perforating has become popular. To assist operators in this capacity, ProTechnics has developed a completion diagnostic application for evaluating reservoir quality and identifying high leak-off areas (e.g., natural fractures) along the lateral. Utilizing this technique, operators are able to identify natural fractures and design perforating schemes so as to increase completion efficiency,


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431
29
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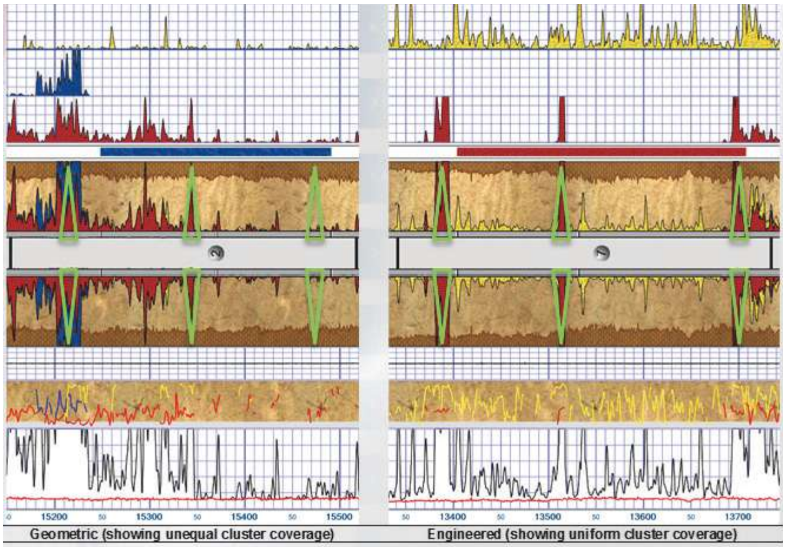
99.22
September 2015

increase production and yield a higher return on investment. *corelab.com*



A SpectraScan log shows treatment differences between equidistant perforation clusters versus selected perforation clusters. (Source: ProTechnics)

Drilling fluid system reduces environmental and disposal concerns

QMAXDRILL, a high-performance, highly inhibitive, water-based drilling fluid system, can be used in the most challenging and environmentally sensitive drilling applications onshore and offshore. The technology is applicable where highly reactive formations are present and water-based fluids are required, including in troublesome shales. The formulation reduces environmental and disposal concerns that may arise with oils or elevated chlorides, nitrates or sulfates. The dual chemical and mechanical inhibition mechanisms created by the amine and the polymeric combination maximize its performance. For specific applications, further enhancement can be achieved by the use of a proprietary glycol. The QMAXDRILL system offers low filtration rates, a wide range of rheological properties and enhanced lubrication. It is a cost-effective alternative to synthetic-based mud because disposal costs are cut in half when compared to a nonaqueous system. Furthermore, the cost per barrel of the QMAXDRILL system is effective compared to other water-based mud systems and oil-based fluids. *qmax.com*

A comparison of the cutting disposal area preremediation versus post-remediation through use of QMAXDRILL is shown. (Source: QMax)

Service establishes benchmarks, identifies trends

Whether in the field or the office, data are a crucial part of ensuring healthy oil and gas operations. Engineers and accountants alike need easy-to-use and easy-to-understand data with straightforward access. Clean, simplified data make the difference between trusting insights and never knowing if the best information for decision-making has been acquired. myQuorum Data Hub is a cloud-based service that makes well life-cycle data available for whoever needs it and ready for whatever business intelligence tools they want. Well life-cycle reporting tools and myQuorum Data Hub are a powerful combination, enabling drilling and completion operations to establish benchmarks, identify trends and reduce nonproductive time. With complete visibility into active jobs, field costs, budgets and rig performance, managers and executives can quickly and confidently understand what is happening in the field. This is all done through both native data visualization and support for third-party solutions. *quorumsoftware.com*

Changing the approach to building reliable reservoir models

Resoptima's ResX reservoir modeling and management software changes the way subsurface teams work. With a focus on next-generation digitalization, ResX breaks with traditional reservoir modeling approaches that persist in treating static and dynamic modeling as separate tasks, with asset teams continuing to work in domain siloes. Grounded in ensemble-based methods, ResX software enables a robust quantification of uncertainty across static and dynamic data conditioning and modeling. The software uses fit-for-purpose machine learning algorithms to augment the know-how of subsurface teams so that geoscientists and reservoir engineers can assess different concepts within a full range of geologically consistent—and equally likely—reservoir models. With the implementation of repeatable workflows, ResX generates models that honor all available data, abide by reservoir physics and incorporate uncertainty throughout the modeling chain. This enables subsurface teams

to better understand the subsurface and focus on driving high-value decisions. *resoptima.com*

Managing high-volume sand applications

The Sand X Beast features a double auger and is designed to manage high-volume sand applications including fracture screenouts. The Beast is used as the primary recovery tank in drillout and flowback. Flowback enters the gas buster, and the sand, water and hydrocarbons continue into the hopper. Sand then falls to the bottom of the hopper while being cleaned, is picked up by a lift system and then discharged into a roll off box or suitable container. Water and hydrocarbons flow over the weir plate and into the Beast tank. This process allows reuse of water for drilling, which saves money and the environment. The Beast also eliminates hazardous waste exposure and the need for confined space entry. The clean sand makes transport and disposal of the sand easier resulting in significant savings. *sandx.us*

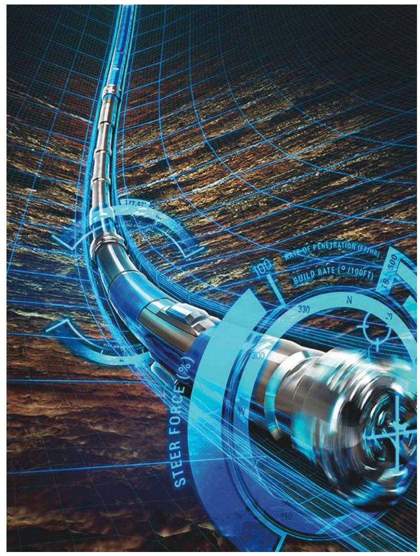
The Beast is designed to manage high-volume sand applications including fracture screenouts. (Source: Sand X)

Optimize hydrocarbon recovery to deliver reservoir performance

At ATCE Schlumberger will be highlighting how it is enhancing performance with domain leadership and digital enablement technologies that optimize hydrocarbon recovery to deliver reservoir performance. The company will be showcasing its WellWatcher Stim stimulation monitoring service and its Tempo instrumented docking perforating gun system. The WellWatcher Stim service improves fracturing, acidizing and other well operations by confirming downhole events in near real time. For one operator in the North Sea, the system identified stimulation fluid entry into previously treated stage, indicating incomplete isolation and prompted immediate action to drop a second actuation ball and restimulate the untreated stage. The Tempo system combines a plug-in gun design with real-time downhole measurements for enabling and monitoring the well's dynamic underbalance to create clean perforations that boost reservoir productivity. This is achieved while improving wellsite safety and operational efficiency. In Egypt the system's onboard diagnostics and radio frequency (RF) filtering technology provided operational assurance and RF protection during 11 perforation runs with no impact on simultaneous operations. *slb.com*

Rotary steerable system helps avoid costly trips, improves ROP

Scientific Drilling's HALO high-performance rotary steerable system solves U.S. land operators' reliability and economic challenges while yielding more efficient, smoother wellbores. Designed to complete vertical, curve and lateral sections in one run, it helps avoid costly trips and improves ROP. The system maximizes wellbore exposure in the target zone by drilling curve sections with build rates up to 15 degrees/30 m (100 ft), while its full 3-D Autopilot functionality delivers unparalleled lateral placement. It can be paired with conventional mud motors and operates at a maximum bit speed up to 350 rpm, maximizing performance and reducing rig time. Consisting of an integrated steering unit and MWD survey package with azimuthal gamma ray geosteering and pressure-while-drilling capabilities, the HALO system is fully assembled and qualified prior to delivery to the rig site. This minimizes bottomhole assembly time and mitigates associated HSE risks. Data are transmitted to the surface from the system's high-speed mud pulse telemetry. *scientificdrilling.com*



The HALO high-performance rotary steerable system is designed to complete vertical, curve and lateral sections in one run. (Source: Scientific Drilling)

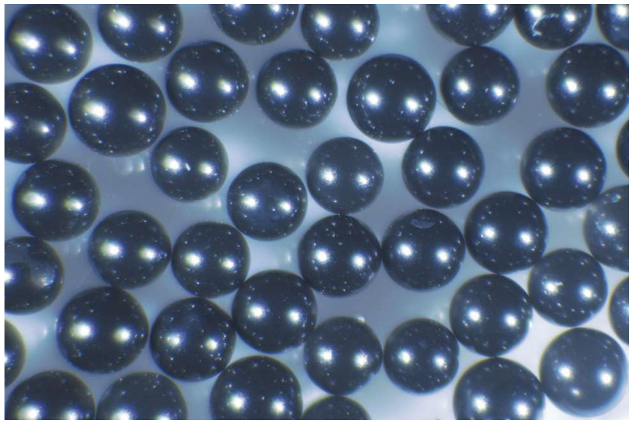
Tool quickly simulates extremely large reservoir models

Stone Ridge Technology's ECHELON reservoir simulator helps E&P companies save money and make better decisions by allowing engineers to quickly simulate extremely large reservoir models that were previously too large to simulate. Due to this new capability, companies can keep the geologic detail that is typically removed for previous simulators to achieve manageable run times. This allows engineers and managers to better understand the subsurface and make more informed decisions. ECHELON is able to simulate these detailed reservoirs in a fraction of the time that previous generation simulators used to simulate models with much less detail, which makes engineers more efficient and allows them to complete more projects. ECHELON is able to achieve this breakthrough performance by being the first reservoir simulator to completely run on modern graphics processing units. *stoneridgetechnology.com*

ECHELON runs on NVIDIA modern hardware (pictured above), which is a key part of the technology. (Source: Stone Ridge Technology)

Increase conductive fracture area

SUN Specialty Products has released its Proppant Transport Solution, the ultralightweight proppants FracBlack and OmniProp, developed to enhance well value by placing proppant in far field fracture areas increasing reservoir contact and ultimately production. With a specific gravity of 1.055 g/cu. m, FracBlack and OmniProp have superior transportability in water-based fluid fractures providing increased reservoir contact for greater hydrocarbon recovery. FracBlack and OmniProp are advanced thermoset nanocomposite beads, featuring near-neutral buoyancy, high strength and thermal stability for applications in most reservoirs with or without conventional proppants. These products can be used to substantially increase the conductive fracture area of unconventional wells, optimizing production performance and stimulated reservoir recovery. *sunspecialtyproducts.com*



FracBlack is an ultralightweight proppant with significant transport capabilities. (Source: SUN Specialty Products)

Liner hanger/packer system provides greater well control

The TIW XPak expandable liner hanger/packer system has been used to successfully hang an $18\frac{5}{8}$-in. outer diameter (OD) liner in 24-in. OD, electric resistance weld (ERW) seamed casing. The system design eliminated a two-stage cement job in unstable formations and provided greater well control. The liner penetrated 670 m (2,200 ft) of difficult and unstable geology, including water zones, sloughing shale and lost-circulation zones. The slip design provides a hanging load capacity equal to or greater than conventional liner hangers. Stacked metal-to-metal seals and elastomer backup seals, with no extrusion gaps, provide a HP/HT, gas-tight, liner-top seal. A honed inner diameter receptacle in the upper portion of the expander allows tieback to surface or patching a cased-hole section. Successful qualification testing prior

A drilling team on location installed the $18\frac{5}{8}$-in.-by-24-in. TIW XPak liner hanger/packer. (Source: TIW Oil Tools)

to running the XPak system confirmed the system can effectively seal in ERW seamed casing. *tiwoiltools.com*

Redesigning bit hydraulics with a split inner blade geometry

Ulterra Drilling Technologies will be showcasing the latest advancement in PDC bit technology—SplitBlade. The industry has long faced the problem of poor cuttings evacuation resulting in reduced ROP, wasted drilling energy and less toolface control. Ulterra has addressed this problem by redesigning bit hydraulics with a split inner blade geometry. By separating the primary blades and placing nozzles at the separation, SplitBlade creates a double-barrel hydraulic flow to help evacuate cuttings quicker. This improved cleaning allows the bit face to engage and fracture rock unimpeded, increasing ROP. SplitBlade's cone and shoulder layout provide increased control, durability and speed resulting in extended bit life. SplitBlade has changed the economics of drilling by regularly saving operators up to $55,000. *ulterra.com*

System treats produced water for reuse or surface discharge

Veolia Water Technologies will feature OPUS technology at ATCE. This reverse osmosis (RO)-based system achieves high water recovery using pretreatment processes to protect the RO membranes. OPUS technology is a proven solution in operation for more than 10 years. OPUS II incorporates ceramic membranes to provide an absolute barrier to contaminants in the RO feed water, which significantly reduces system footprint and installation costs. In either design, the RO process operates at an elevated pH, which effectively controls biological, organic and particulate fouling, eliminates scaling due to silica, and increases the rejection of silica, organics and boron. Treated effluent can be reused or discharged, eliminating the need for produced water reinjection. In some locations, treatment and discharge reduce formation pressure and facilitate oil recovery while providing a freshwater resource. System performance is guaranteed when combined with a Veolia operations and maintenance contract. *veoliawatertech.com*

This OPUS II facility generates clean water for discharge to a stream in an arid region, enabling it to support aquatic life year-round. (Source: Veolia Water Technologies)

Technologies that minimize production decline rates

Throughout ATCE Weatherford will feature technologies that execute reliable, safe well construction and minimize production decline rates. The technologies include additions to Weatherford's portfolio and enhancements to proven solutions. The new Magnus rotary steerable system combines reliable, high-performance drilling with precise directional control. Unique features—including independent pad control and a true inclination hold—help operators sustain drilling, stay on plan and reduce well construction costs. Weatherford also will highlight enhancements to proven technologies. Redesigned for 2018, the Rotaflex long-stroke pumping unit accelerates the transition to rod lift by 15% to 20%. The unit adds new features that reduce opex and simplify maintenance, including an optimized gear reducer, integrated hydraulic rollback system and larger access doors. The ForeSite production optimization platform introduces support for gas-lift systems, electric submersible pumps and additional surface facilities to extend enterprisewide production optimization. Lastly, the R2R advanced perf-and-wash system elevates the perf-and-wash technique; the permanent abandonment solution creates a rock-to-rock hydraulic seal with single-trip efficiency. *weatherford.com* E&P

The Magnus rotary steerable system combines features like independent pad control to help operators reduce well construction costs. (Source: Weatherford)

SPONSORED CONTENT

Rising Activity Spurs Interest in DUG *Eagle Ford* Conference

Over 2,000 oil & gas professionals expected to attend

Rising demand and increased supply uncertainty have fully awakened the "sleeping giant" – Texas' Eagle Ford shale. Growing exports revived drilling and producers are making deals to consolidate acreage and reduce operating costs.

As activity gains altitude, key region players will congregate **September 19-21** in San Antonio for Hart Energy's annual **DUG *Eagle Ford* conference and exhibition**. Over 2,000 attendees, exhibitors and sponsors will hear firsthand what's working and what's next in this transformative oil and gas province.

DUG *Eagle Ford* brings top decision-makers and analysts to the stage to provide in-depth insights into the future of South Texas' oil and gas industry.

In its ninth year, **DUG *Eagle Ford*** remains the largest event focused on the Eagle Ford and related unconventional plays. Industry executives and technology experts will present insights from the main stage starting at 8:30 a.m. on Thursday, September 20. They'll address a diverse audience of investors, active producers, midstream operators and future service company leaders.

Stephen Chazen, chairman, president and CEO of newly formed **Magnolia Oil & Gas Corporation**, will deliver the opening keynote address. Chazen retired as Occidental Petroleum's CEO in 2016. He formed publically traded TPG Pace Energy Holdings a year later, then partnered with Houston-based EnerVest to create Magnolia Oil & Gas this spring. The start-up quickly announced it was purchasing 360,000 net acres in South Texas from EnerVest for $2.7 billion in cash and stock. The position includes 14,000 acres in Karnes County and 345,000 acres in the Giddings field – where Magnolia intends to target Austin Chalk zones.

Straightforward insights from key leaders

DUG programs are known for a candid blend of financial acumen and applied technology, with a unique peer-to-peer environment that enables leaders to address all aspects of the business. In a "fireside chat" last year, Jay Graham, CEO of WildHorse Resource Development, shared why he was shifting to a pure-play Eagle Ford strategy. WildHorse is now the second largest Eagle Ford leaseholder.

A producer spotlight *this* year features **Eric McCrady**, CEO of **Sundance Energy** Australia Ltd. In March, Sundance announced it was acquiring assets in the play's volatile oil window for $221.5 million. The deal came after Sundance divested its Anadarko Basin position to focus solely in the Eagle Ford shale.

Producers are paying attention to the region's attractive economics. Last August, Michael Rozenfeld, a founder of Houston-based Boomtown Oil LLC, told Hart Energy the Eagle Ford "provides superior value. We're getting Permian EURs without having the pay Permian price." One of Boomtown's partners spoke in a private operator spotlight at **DUG *Eagle Ford*** 2017.

This year, **John Thaeler**, CEO of newly-formed **Vitruvian Exploration IV LLC**, will join an operator panel assessing play opportunities across the region. The Woodlands-based company has acquired 120,000 net acres of undeveloped and highly contiguous leasehold in one of its target areas, including Sanchez Energy's Javelina asset divestment.

UP NEXT

DUG EAGLE FORD
Sept. 21
San Antonio

DUG MIDCONTINENT
Nov. 15
Oklahoma City

Don't miss the **DUG *Technology*** program at **DUG *Eagle Ford***.

This year's conference will focus on South Texas' export potential, midstream infrastructure and technological development.

Emphasis on technology and engineering

Active Eagle Ford **rig count has roughly tripled since 2016**; only the Permian Basin hosts more drilling. Well costs have dropped as operators high-graded prospects, tested EOR techniques, increased well intensity and lateral lengths, and added Austin Chalk targets.

The second-day program at **DUG *Eagle Ford*** emphasizes technology-driven sessions. The focused Friday agenda will host expert panels, technical spotlights and roundtables on regionally relevant topics like:

- Sand and seismic – new sand mines, monitoring proppant behavior
- Stimulation practices and economic value
- Engineered approaches to automation and chemicals
- Well construction advances

Exports shift attention to natural gas

With LNG and piped gas going into Mexico, more LNG transits through the Panama Canal, and export terminals underway in Corpus Christi, it's easy to understand why interest in the **DUG *Eagle Ford* conference and exhibition** is running high.

The U.S. Geological Survey's most recent assessment found the shale still holds **8.5 billion barrels of recoverable crude, 66 Tcf of natural gas** and **1.9 billion barrels of natural gas liquids**. The USGS' lead author said, "Usually, formations produce primarily oil or gas, but the Eagle Ford is rich in both."

Conference and expo foster connections

Staying connected to intelligence from the field and making new business connection are principal reasons to attend. Full-conference registrants can:

- Hear directly from the **most active producers** about capex plans and technology applications
- See where **top analysts forecast oil prices** to finish in 2018
- Interact with top service and supply companies on the exhibit floor
- **Network with hundreds of peers** with 9+ hours dedicated to breaks and receptions

Speakers at the **DUG *Eagle Ford* conference** will address these exciting market dynamics. Be there when it returns **September 19-21** to the Henry B. Gonzalez Convention Center in San Antonio. E&P

In-depth Look at Exports

An optional half-day forum – **"The Ins and Outs of Exports"** – will take place on **Wednesday, September 19**, the day before the main conference. Industry leaders – in expert panels, roundtable discussions and spotlight presentations – will address crude oil and natural gas infrastructure, the Mexican market, LNG capabilities across the country, takeaway systems in the shale plays, and petrochemical demands. Ample opportunities for Q&A promise an insightful afternoon.

CONFERENCE & EXHIBITION
DUG EAGLE FORD

DUGEagleFord.com

CNX Resources has 392 producing wells in the Marcellus-Utica Basin. (Source: CNX Resources)

No signs of slowing the Marcellus-Utica

Appalachia gas production continues its record-breaking climb.

Brian Walzel, Associate Editor, Production Technologies

The beast in the East continues to grow. Despite takeaway capacity challenges in the Northeast, especially in Pennsylvania, where a lack of available pipeline is pushing up inventories and keeping natural gas prices low, production continues to escalate to record levels. In a recent report charting the growth of natural gas production in the Appalachia region, Deloitte noted that in 2007 Appalachia was the world's 32nd largest natural gas producing region. By 2017 it was the third largest, trailing only all of the U.S. and Russia.

"The speed and magnitude of Appalachia's emergence onto the global natural gas scene is unprecedented and due mainly to the Marcellus and Utica shale plays," Deloitte reported.

According to the U.S. Energy Information Administration's (EIA) Drilling Productivity Report, gas production in Appalachia has grown to 28.8 Bcf/d through August, significantly more than the next-closest basin, the Permian, which produced 10.8 Bcf/d that month. According to the Pennsylvania Department of Environmental Protection, first-quarter 2018 natural gas production in the state was 1.4 Tcf, an increase of 10% over the same period last year. Meanwhile, the Ohio Department of Natural Resources reported that the state produced 531 Bcf of natural gas in the first quarter of the year, an increase of 42.85% over the first of quarter 2017.

The EIA attributes the remarkable production gain—the average production per rig in the Marcellus-Utica has increased by 13 Bcf/d since 2012—to efficiency improvements in horizontal drilling and hydraulic fracturing capabilities in the region, which include faster drilling, longer laterals, advancements in technology and better well targeting.

The EIA reported in December that the average lateral length per well in West Virginia had increased from about 762 m (2,500 ft) in 2007 to more than 2,134 m (7,000 ft) in 2016. The leader in lateral length in the Marcellus-Utica—and everywhere else—is Eclipse Resources, which, according to the company, has through June drilled 15 super laterals averaging 5,600 m (18,375 ft) in length.

Continued growth

Despite Henry Hub prices hovering in the $3/MMBtu range for about the past three years, both supply and demand for natural gas have steadily increased, driven by the growing demand of the power sector, which has seen a compounded annual growth rate of 3.7% since 2009, according to McKinsey Energy Insights.

The Appalachia region will supply about 40% of the North American gas market by 2030 and, combined with output from the Permian Basin, will supply about 55% of the market by that time, according to McKinsey Energy Insights' "North American Gas Perspectives" report issued in June. Deloitte looked even further in its study into Appalachia natural gas production and predicted that by 2040, the Marcellus and Utica shales are projected to produce about 40 Bcf/d, half of domestic shale gas production.

Meanwhile, the McKinsey report stated that increased Appalachia natural gas supply has created a bottleneck in takeaway capacity, helping boost prices. But between 2019 and 2021, midstream growth capacities could negatively impact gas prices, McKinsey reported.

"As more pipeline infrastructure comes online post-2019, inexpensive Appalachia supplies will continue to grow and limit price fly-up potential," the report stated.

However, Deloitte predicted that even in a price-depressed environment, natural gas production in Appalachia is likely to remain economically viable. Deloitte's recent report stated that the Appalachia region is estimated to have 50 years' worth of natural gas that is recoverable for less than $3/Mcfe.

Operator updates

Range Resources owns and operates more than 4,550 wells primarily in the Marcellus Shale. Production in the first quarter of this year averaged about 1.8 Bcf/d, an increase of 20% over last year, the company reported in its first-quarter 2018 investor presentation. Throughout the remainder of the year, Range plans to bring on 100 wells and is expecting to average five rigs for the year, according to Range's first-quarter 2018 report.

In the first quarter of the year, Range set a new company quarterly record when its net natural gas production exceeded 1.2 Bcf/d. The company also drilled its two longest laterals to date—a 5,525-m (18,129-ft) horizontal well and a 5,448-m (17,875-ft) well. Overall, Range is drilling its Appalachia wells 21% longer through the first quarter of the year compared to the fourth quarter of 2017.

Chesapeake Energy's average production for the first quarter of the year in its Appalachia operations were about 1.3 Bcf/d, most of which was derived from its Marcellus assets. In its Utica operations, Chesapeake has seen a 10% increase in production this year, a result of improved well spacing to 305 m (1,000 ft).

During the company's first-quarter 2018 investor presentation, Frank Patterson, executive vice president of E&P, said the company has "reinvented" its Utica operations, adopting best practices from its other North American shale operations.

"Everything we've learned in the Eagle Ford, Haynesville and the other plays, we're moving all that

CNX produced 3.6 Bcm (129.5 Bcfe) in the first quarter of 2018. (Source: CNX Resources)

CNX's average lateral length in the Marcellus was 2,527 m (8,291 ft). (Source: CNX Resources)

knowledge to our plays as fast as we can," Patterson said. Those lessons learned include well landing locations and drilling longer laterals in the Utica.

Jason Pigott, executive vice president of operations and technical service, said during the presentation that Chesapeake has completely redesigned its Utica completion designs.

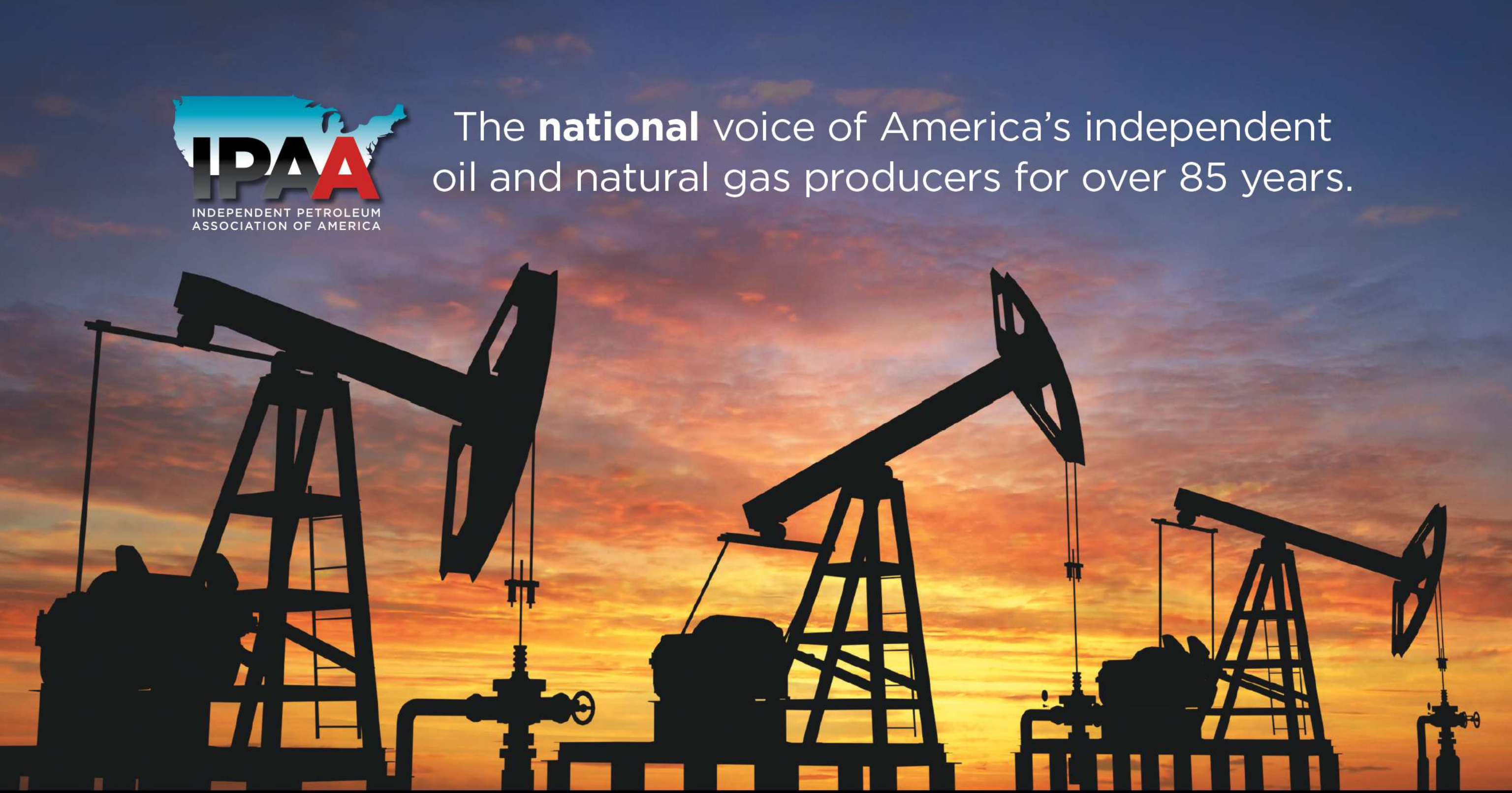
"We had to completely redesign the wells from the casing string onward," he said. "We've started changing the fluids that we pump, and we've also increased the sand concentrations like it was successful in other places like the Haynesville."

Cabot Oil & Gas plans to drill about 85 wells in the Marcellus Shale this year, primarily in Susquehanna County, Pa. Cabot is operating three rigs in the Marcellus and has seen its net production through 2017 increase about 19% from 1.4 Bcf/d in 2015 to 1.7 Bcf/d in 2017, according to the company's website. The company is estimating production growth this year of between 10% and 12% over last year. According to its second-quarter 2018 investor presentation, Cabot has about 3,000 undrilled locations remaining in the Marcellus Shale, and by year-end 2017 had 561 net producing wells. Cabot plans to put 80 more wells online this year. Twenty wells were placed on production in the second quarter, and 60 are planned in the second half. The company reported that no wells were placed on production during the first quarter of the year due to larger pad sizes in the first quarter and Cabot's second completion crew not coming online until February.

At CNX Resources, Tim Dugan, executive vice president and COO, said during the company's first-quarter investor presentation that the company's total Utica production is up 200% year-over-year. Part of the increase, he said, is attributable to revised completion designs and field optimizations in Monroe County, Ohio. CNX's Green Hill area in southwest Pennsylvania also has been a focus of the company's enhanced completion design efforts.

There, average lateral lengths have grown from 548 m (1,800 ft) in 2011 for CNX's GH Legacy well completions to 2,895 m (9,500 ft) this year for its GH-55 well completions, while its completion cost per foot has dropped from $3,384 in 2011 for GH Legacy to $903 this year for GH-55, according to CNX's first-quarter 2018 investor report.

"GH-55 wells turned in-line in the first quarter are seeing capital efficiency gains of nearly 40% compared to the wells from 2015 and 2016," Dugan said. "This is driven primarily by improved cycle times and longer laterals. Most importantly, these completion designs and operational techniques are transferring, as we speak, to the Richhill Marcellus area where we plan to execute stacked pay development in the near future." E&P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89th Annual Meeting
NOVEMBER 11-13, 2018
THE RITZ-CARLTON | NEW ORLEANS, LA


89th Midyear Meeting
JUNE 24-26, 2019
THE BROADMOOR | COLORADO SPRINGS, CO

Integrated packages for the marine construction market

Synchronization of systems offers automation capabilities.

Richard Urquhart and **Claire Kennedy Platt**, NOV

National Oilwell Varco (NOV) has expanded its offshore offerings. Coupled with NOV cranes, winches and handling equipment from legacy brands such as Hydralift, Norson and AmClyde, the new systems enable NOV to outfit an entire construction lay vessel. The complete, integrated packages are tailored to meet specific operational needs, offering higher flexibility and improved vessel utilization. Leveraging existing project execution experience from integrating drilling projects, NOV will manage the entire process from equipment package design to installation and initial operation support.

A key contributor to this strategy is the recent addition of technical solutions from Italy-based Remacut, which bridges previous gaps in the NOV product portfolio. These additions enable delivery of complete pipe and cable lay systems for any application and configuration. Integrated control system technology from decades of drilling projects gives NOV the ability to monitor and manage the entire lay process. This advantage allows synchronization of each step in the production line, including integration with the vessel systems such as dynamic positioning, propulsion and power management. Through a high level of integration capabilities, NOV can deliver systems with high levels of automation, reducing the number of required workers on deck while improving operation speed and consistency.

Reel drive systems deploy and recover umbilicals or flexible pipes that are stored on standard flexible product reels. (Source: NOV)

Lay system modularity

In constantly changing environments, maximizing vessel utilization is more important now than ever. NOV works closely with vessel operators, creating an open dialogue to learn more about unique project needs. Modular equipment and scalable system designs enable layout selection based on business objectives. Lay systems might be optimized for specific operations, and vessels can be efficiently repurposed between contracts. Changing between types of lay operations is possible with minimal modifications to equipment or layout. This offers a choice of an equipment package profile for vessels, enabling optimization for specific contracts that vessel operators are pursuing.

Rigid and flexible lay systems range from small, modular bolt-on tools that can be quickly mobilized on any vessel of opportunity up to large, specialized vessels with integrated pipe carousel systems. NOV uses extensive experience to create cost-efficient vessel adaptations that provide essential lay system characteristics.

NOV professionals work with customers to identify the most well-suited packages based on business objectives, optimizing lay systems for shallow or deep lay operations or providing the flexibility to do both. Scalable system layouts enable vessel reconfiguration through simple component upgrades or replacements. Following the optimization process, experts consider the type or level of product support in the lay system, whether it is rigid, flex or cable and select from equipment designed to handle a wide range of products. The contact points of tensioner pads, rollers, chutes and other products can be easily replaced to achieve the configuration required for the job. NOV's hybrid lay system philosophy offers the ability to cost-effectively repurpose vessels to pursue a broader range of lay contracts.

Cranes, A-frames and winches

Vessel packages, cranes, A-frames and winches are designed into the layout to support the lay operations and offer the ability to repurpose the vessel. S-Lay, the range of heavy-lift cranes, fulfills the lifting requirements for the largest vessels. Knuckle-boom active heave compensation cranes meet the needs of smaller flex lay vessels. The operational design dictates the level of simultaneous operations required, which affects power system requirements. To save cost and complexity, NOV designs the overall system to share drives, hydraulic power units and other components where there is an opportunity to do so.

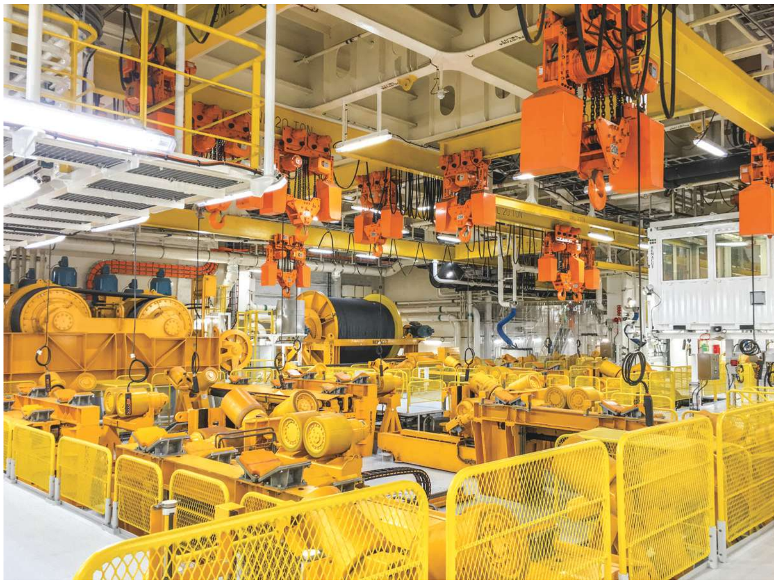
Cost savings

Purchasing a turnkey vessel reduces unforeseen integration issues during the commissioning process and improves communication between ship builder, vessel owner and equipment supplier. This reduces project risk during the building process and ensures the vessel owner takes delivery of a purpose-built vessel that is ready to go on contract from the first day of a project.

Improved safety

The use of an integrated control system enables the implementation of additional solutions on construction vessels. On drilling vessels, anti-collision system technology prevents collisions between cranes and vessel structures. In the construction environment, the technology provides an increased level of safety for personnel and reduces the risk of equipment damage for vessel operators.

Sealift compensation technology improves safety and reliability of ship-to-ship lifts between two dynamic vessels through the use of radio-transmitted heave, pitch and roll data. A basket containing a motion reference unit and a radio transmitter is placed on the vessel opposite of the crane, streaming live data back to the crane. The crane uses this information to automatically compensate for differences in vessel motion during the lift, allowing the crane operator to safely collect the payload and place it onboard the construction vessel. This results in a safer work environment for crane operators and deckhands. E&P



Pipehandling systems transport pipe during the pipelay process. (Source: NOV)

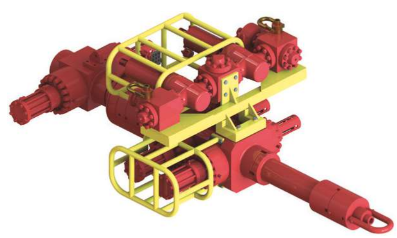
The *Lewek Connector* vessel is outfitted with a horizontal lay system. (Source: NOV)

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*.

Long-stroke pumping unit improves lift efficiency

Weatherford International Plc has released a new Rotaflex long-stroke pumping unit that is designed to improve artificial lift efficiency in challenging applications including deep, high-volume and high gas-to-liquids wells. The new Rotaflex design extends the functionality of a field-proven technology with more than 10,000 installations worldwide, according to a Weatherford press release. The units apply long pump strokes—up to 11 m (36 ft)—that allow more time for fluids to enter the pump intake before being lifted to surface. By delivering fewer strokes per barrel at a constant velocity, the Rotaflex design increases equipment runlife, mitigates downhole failures and decreases deferred production. The latest version of the Rotaflex unit adds numerous features that improve lift efficiency, including a purpose-built 350-series gear reducer and enhanced top drum. The unit also includes numerous enhancements that improve reliability and maintainability, including a built-in rollback system, greater accessibility, an enhanced lubrication system and a revised ladder system. *weatherford.com*

New test tree incorporates lighter, more compact design



The new Anson surface test tree uses improved valve and swivel technology to achieve high performance while reducing size and weight. (Source: NOV)

National Oilwell Varco (NOV) has released the Anson 6⅜-in., 15,000-psi compact surface test tree to its portfolio of intervention and stimulation equipment. The smaller, lighter and more compact design was accomplished by using existing valve and swivel technology while incorporating innovative design features to achieve a 20% reduction in length and 14% reduction in weight without any loss of performance, the company said. The unit has a tensile load capacity of 750,000 lb at 15,000 psi and 177 C (350 F) and torque capacity of 40,000 ft-lb in forward and reverse. The flowhead block is equipped with an integrated high-capacity, low-torque swivel, which allows full rotation of the string independent of the surface flow tree. The swab and master valves are oriented through 90 degrees to allow a balance stem to be included, providing true "fail-as-is" functionality and allowing a smaller double-acting hydraulic actuator. The flow and kill wings share a single port on the flowhead block, allowing the weight and space envelope to be reduced further. *nov.com*

PCM helps detect and predict corrosion issues

SGS and Baker Hughes, a GE company (BHGE), have announced a strategic alliance agreement for the joint deployment and commercialization of BHGE's real-time software and sensor-based Predictive Corrosion Management (PCM) solution, according to a BHGE press release. Leveraging the capability of the Industrial Internet of Things, PCM will enable asset owners to increase their ability to monitor facilities as well as detect and predict corrosion issues using real-time data powered by BHGE's ultrasonic sensing technology and advanced analytics. PCM generates wall thickness and temperature measurements from Rightrax PM ultrasonic sensors placed on critical equipment such as pipes, tanks and vessels; the solution applies advanced analytics, resulting in real-time assessment of data, which traditionally has been gathered through risky and time-consuming manual inspections. In addition, PCM can help with challenges involving corrosion-related risk and can help asset owners benefit from enhanced plant reliability and integrity programs, while maximizing operational safety and extending asset life. *bhge.com*

Three shaped cutters feature variety of benefits

Varel has introduced three new shaped cutters to its PDC drillbit features: SCOOP, TRIFORCE and FANG, a company announcement stated. The SCOOP is a concave-shaped cutter that provides lower energy requirements to fail the rock due to the cutter's efficient shape. Equivalent ROP can be obtained with lower-than-normal forces, which reduces torque and improves toolface control. The TRIFORCE cutter with leading-edge geometry creates a stress point in the formation to prefracture the rock. The FANG is a sharp-edged cutter designed to be active and prefracture the rock as a backup or secondary cutter. *vareloilandgas.com*

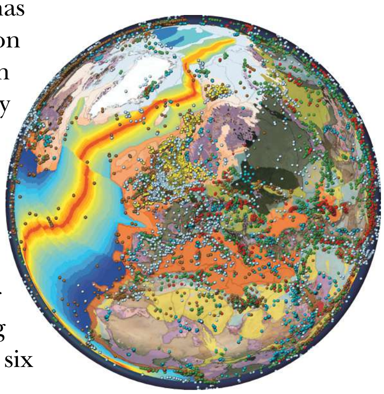
Software accelerates reservoir/subsurface model development

Emerson has released the Paradigm 18 integrated software solution suite, which runs on a unifying platform for generating high-resolution images and models of the subsurface. This software includes advanced technologies that use reservoir intelligence to help users improve performance, enhance operational certainty and support effective asset management, according

to an Emerson press release. Designed to optimize result accuracy while allowing users to work faster and more productively, Paradigm 18 offers artificial intelligence capabilities that enable quick and reliable identification of geologic facies from seismic data and wellbore data. In addition, it features seamless unification of the user interface and data management, from seismic processing to interpretation and modeling, enabling faster results with less effort. It also has support for cloud hosting, allowing remote teams to work together. The software includes high-resolution processing, imaging, interpretation and modeling geoscience software, delivering more accurate subsurface models. *emerson.com/paradigm*

Geoscience technology accelerates exploration efforts

CGG GeoConsulting has launched the Robertson New Ventures Suite, an integrated and digitally transformed family of exploration-focused geoscience tools and databases for global new ventures screening and frontier exploration, according to a press release. The six core products of the suite are Basins & Plays, Geochemistry, Plate Kinematics, Predictions, Provenance and Analogues. Built on the brands of Tellus, Frogi, Plate Wizard, Merlin+, ProvBase and ERGO, the updated products have been integrated and renamed as part of GeoConsulting's ongoing GeoVerse digitalization program that is providing a common architecture and taxonomy across the New Ventures Suite, allowing optimum interoperability and a broad range of exploration workflows. New Ventures teams can make quicker and more effective decisions by using this suite to interrogate one of the industry's richest sources of geoscience data and knowledge. Whether licensing the whole suite or individual components, exploration teams can access these integrated databases to better identify, understand, evaluate and de-risk emerging opportunities and plays so they can acquire the right acreage and increase their success rates. *cgg.com*



A cloud of locations for data and analyses were taken from component products of the Robertson New Ventures Suite, a collection of global geoscience tools to support a wide range of new ventures and exploration activity. (Source: CGG GeoConsulting)

Improved crane system reduces the risk of dropped loads

Keppel LeTourneau has released an Anti-Two Block system (A2B) that can be modified to fit most cranes in the market, according to a company press release. Weighing under 50 lb and with a compact body, the newly designed A2B can be installed on all LeTourneau cranes and is customizable to other brands upon request. It has an expected lifespan of more than 10 years and is made of forged stainless steel and high-impact polymer to resist corrosion. The A2B utilizes a dual chain suspension system that ensures it is highly resistant to spinning, thereby preventing it from being dragged up by the wire rope. In addition, the wide stabilizing arms cater for high winds, and pitch and roll motions. The A2B is equipped with versatile and reliable sensors. The redundant NAMUR proximity sensors are integrated in an easily replaceable cap, and the activation of limit sensors is not dependent on chain length or weight unlike other A2B designs. *keppelletourneau.com*

The newly designed A2B with field adjustable chains allows flexible stopping distances for a variety of applications. (Source: Keppel LeTourneau)

Optimized marine compressor range equipped with thermal mixing valve

TMC Compressors of the Seas has developed and released a new marine compressor range for use onboard vessels, according to a company press release. The crux of the new range is higher capacity output of control and service air but with lower energy consumption and service requirements, resulting in lower opex and harmful emissions to air. TMC has smaller units of 35 kW up to large compressors of 360 kW, which are typically used onboard drilling rigs, FPSOs or other vessels. The new compressors also are equipped with a new thermal mixing valve that provides accurate and effective cooling of the compressor, adapting to the environmental conditions. A new inlet valve with integrated control air components reduces the number of hoses to a minimum, which increases maneuverability when conducting maintenance work on the compressor. The entire range also has new and improved filters that ensure less oil carryover and significantly cleaner air. *tmc.no*

Fluid rotary union minimizes torque

Moog Focal has released its latest pneumatic and hydraulic fluid rotary union (FRU), according to a press release. The Model 810 FRU is designed for industrial, defense and marine applications where multiple fluid passes need to be transferred across a rotational interface. There are a number of design options, depending on the application. The standard Model 810 FRU is available with two or four threaded ports of size ½ in. or ¾ in. A ½-in. on-axis bore enables easy integration with an electrical slip ring, fiber-optic rotary joint or both. The Model 810 utilizes sealed-for-life rolling element bearings, ideal for long endurance applications, and are low maintenance. Filled polytetrafluoroethylene-based seals run on a hardened surface to provide long service life, minimizing frictional heat generation and operational torque. For marine applications, the Model 810 is available in hybrid and fully stainless steel versions for added corrosion protection. This FRU can be easily combined with Moog electrical and optical slip rings, contains pass isolation and cross-channel flow prevention, and has been tested up to 5 million revolutions. *moog.com/focal*

The Model 810 FRU has a pressure rating up to 6,000 psi. (Source: Moog Focal)

New alloy improves strength, ductility properties

Dura-Bar has released a new ductile iron grade, Solution Strengthened Ductile Iron (SSDI), according to a company press release. With improved strength and ductility, SSDI is an excellent alternative to 1045 steel used in a wide variety of oil and gas and fluid power applications. One of the key features of SSDI is the enhanced machinability due to the addition of silicon. Machining trials have yielded minimum productivity increases of approximately 30% with no negative impact in tool wear. SSDI has a minimum tensile strength of 75,000 psi, a minimum yield strength of 55,000 psi and a minimum elongation of 15%. SSDI also has a tightened Brinell hardness for consistency throughout the material compared to other similar ductile iron alloys. SSDI is an ideal choice for rotors used in air and natural gas compressors as well as hydraulic manifolds and cylinders used in fluid power applications. SSDI is initially available in 1-in. to 9-in. rounds, 3.25-in. and 3.75-in. squares as well as 6.25-in.-by-7.25-in. rectangles. *dura-bar.com*

Pipeline tools protect tubular objects from corrosion

Designed to prevent corrosion of pipelines and extend a pipeline's structural life, Cortec Corp.'s Corrologic CorrCaps powered by Nano VpCI (vapor phase corrosion inhibitors) are heavy wall black polyethylene pipe caps containing proprietary VpCI. By providing multimetal corrosion protection, CorrCaps protect pipe threads, pipe ends and other tubular objects from corrosion, mechanical damage and contamination during transit, handling and storage. Tough and durable, CorrCaps are specially designed for easy installation and removal. They offer protection all the way to the last pipe thread and are available in a variety of sizes to fit any standard pipe diameter. In addition, Corrologic Tube Strips powered by Nano VpCI also are designed for protection of tubes, pipes or conduits in storage or during shipping. Using VpCI technology, Corrologic Tube Strips make it possible to protect the interior of a tube or pipe against corrosion without expensive internal coatings. The flexible strip has an 8.5-mm (⅓-in.) diameter. It is extruded from low-density polyethylene containing a proprietary VpCI compound designed for protection of ferrous and nonferrous metals and alloys. Tube Strips are especially effective on more expensive stainless steel and aluminum pipes. *cortecvci.com* E&P

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

1 US

A high-volume, extended-reach Three Forks discovery by Marathon Oil Corp. was tested flowing 6.637 Mbbl of 40-degree-gravity oil, 248,310 cu. m (8.769 MMcf) of gas and 2.88 Mbbl of water per day. According to IHS Markit, the Antelope Field's 21-1TFH Mamie-USA well is in Section 2-151n-94w of McKenzie County, N.D. Production is from a horizontal lateral in Upper Three Forks extending from 3,773 m (12,379 ft) southeastward to 6,839 m (22,439 ft) and bottomed in Section 12-151n-94w with a true vertical depth of 3,322 m (10,898 ft). It was tested on a 54/64-in. choke after 45-stage fracturing between 3,804 m to 6,798 m (12,481 ft and 22,303 ft) with a flowing casing pressure of 1,750 psi.

2 Argentina

Echo Energy Plc completed exploration well 1-ELA at the company's Laguna Los Capones asset in Argentina. The well was drilled to 1,820 m (5,971 ft) in Upper Jurassic Tobifera. Wireline log evaluation has been completed and a final production casing has been run. The well will be suspended for possible testing and a sidetrack well may be drilled. The gross, unrisked gas initially in place for the structure on a P-mean basis is estimated at about 1.1 Bcm (40 Bcf). The block is operated by Echo Energy's partner, Compañía General de Combustibles.

3 Guyana

Exxon Mobil announced an eighth oil discovery in the offshore Guyana Stabroek Block at exploration well 1-Longtail. The well was drilled to 5,504 m (18,058 ft) and encountered approximately 78 m (256 ft) of high-quality, oil-bearing sandstone in a reservoir. Area water depth is 1,940 m (6,365 ft). The 1-Longtail discovery well is near the 1-Turbot well, southeast of the Liza Field. Additional testing is planned. According to the company, the combined estimated recoverable resources of Turbot and Longtail will exceed 500 MMboe.

4 Norway

Equinor announced an oil discovery in production license 167 on the Utsira High in the North Sea. The discovery is estimated to contain recoverable reserves of 15 MMboe to 35 MMboe. According to the company, the 16/1-29 S well hit an oil column of about 95 m (312 ft) with moderate-to-good reservoir quality. An oil and gas column of about 30 m (98 ft) also was encountered in Grid (Eocene). The effective reservoir consists of thin sandstone layers (10 m [33 ft]) with very good reservoir quality (about 5 m [16 ft] of gas and 5 m of oil). The completion also delineated the gas discovery at the 16/1-6 S (Verdandi) well with a gas column of about 15 m (49 ft) in Paleocene Heimdal with good reservoir properties. The size of the 16/1-6 S (Verdandi) well is between about 594 MMcm and 793 MMcm (21 Bcf and 28 Bcf) of recoverable gas. The well was drilled to 1,987 m (6,519 ft) and was terminated in basement rock. Area water depth is 114 m (374 ft). The well will be permanently plugged and abandoned.

5 Norway

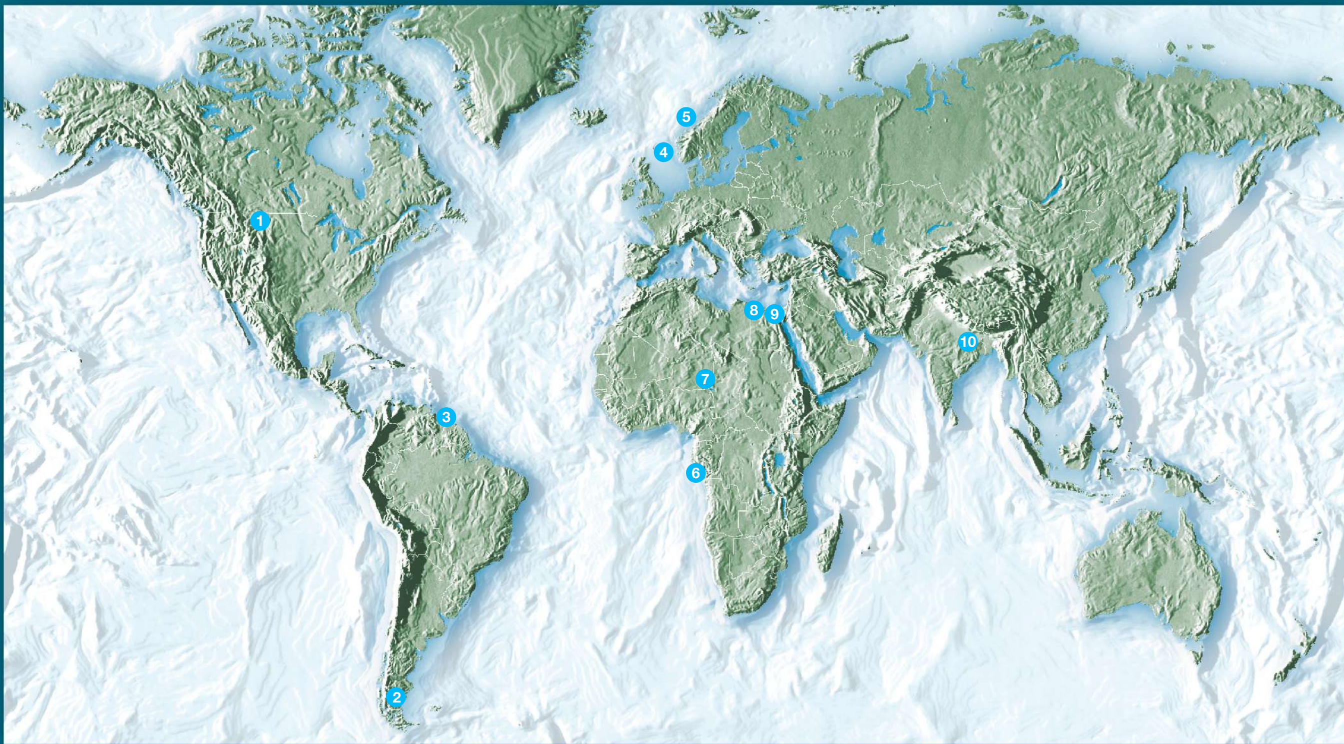
Faroe Petroleum completed sidetrack well 6506/9-4A and a successful drillstem test on the downdip appraisal well 6506/9-4S on the Fogelberg discovery in the Norwegian Sea. The sidetrack well penetrated a 58-m (190-ft) gross hydrocarbon-bearing and sand-rich reservoir in Garn and an 87-m (285-ft) gross hydrocarbon-bearing zone in the Ile reservoir. The well flowed 594,654 cu. m/d (21 MMcf/d) of gas and 547 bbl/d of condensate during a drillstem test. Fluid sampling during the drillstem test confirmed both high-quality gas and condensate. The preliminary analysis suggests a resource range of 40 MMboe to 90 MMboe (gross). The sidetrack well was drilled to 4,497 m (14,754 ft) and was targeting the gas- and condensate-bearing Middle Jurassic Garn and Ile to assess the productivity of Garn and to firm up the resource range for a commercial development. The appraisal well will be plugged and abandoned as planned.

6 Angola

Eni has announced a new oil discovery in Block 15/06 at the Kalimba exploration prospect in offshore Angola. The new discovery is estimated to contain between 230 MMbbl and 300 MMbbl of light oil in place. The 1-Kalimba NFW well hit 23 m (75 ft) of net oil pay in Upper Miocene sandstones with excellent petrophysical properties. The discovery is estimated to have a production capacity of about 5 Mbbl/d of 33-degree-gravity oil. The well was drilled to 1,901 m (6,237 ft) and is in 458 m (1,502 ft) of water. According to the company, the discovery opens new opportunities for oil exploration in the southern part of Block 15/06.

7 Niger

Savannah Petroleum announced results from exploration well 1-Kunama. The venture is in the R3 portion of the R3/R4 production-sharing contract (PSC) area in the Agadem Rift Basin in Niger. Wireline logs, fluid



sampling and pressure data indicate the well encountered an estimated 9 m (29 ft) of net oil-bearing reservoir sandstones in the E1 and E5 reservoir units within the primary Eocene Sokor Alternances objective. Wireline logs indicate the reservoir oil is equivalent to the 1-Amdigh well, the second discovery on the block. The well was drilled to 2,460 m (8,071 ft) and is being suspended for future re-entry. A production test is planned later in 2018, and another well is planned at the 10 Eridal well in the R3 portion of the R3/R4 PSC.

8 Egypt

Eni announced a second light oil discovery on the B1-X prospect in Egypt. The 1BX-SWM well is in the Southwest Meleiha Block in the Faghur Basin. The well was drilled to 4,523 m (14,839 ft) and encountered 35 m (115 ft) net of light oil in Paleozoic sandstones of Dessouky (Carboniferous) and in the Alam El Bueib sandstones (Cretaceous). It was tested flowing 5.13 Mbbl/d of 37-degree-gravity oil with some associated gas. Additional exploratory drilling is planned at wells 2A-X and 1X-B.

9 Egypt

SDX Energy has announced that a gas discovery at well 4X-SD in the South Disouq Concession in Egypt flowed 860,832 cu. m/d (30 MMcf/d) of gas. The completion was drilled to 2,379 m (7,806 ft) and encountered 27 m (89 ft) of net conventional gas pay in Abu Madi with an average porosity in the pay section of 24%.

10 India

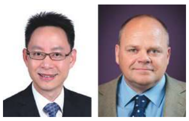
Oil India Ltd. completed a second hydrocarbon discovery in the onshore section of the Krishna Godavari (KG) Basin in India. The well is in Block KG-ONN-2004/1 in Andhra Pradesh state at the 1-Thanelanka well. According to the company, it is the first HP/HT well the company has drilled. It encountered multiple sands in Gollapalli (late Jurassic-early Cretaceous) and one zone in Raghavapuram (intra-Cretaceous). It was tested on a 16/64-in. choke producing from 4,912 m to 5,159 m (16,926 ft) in Gollapalli flowing 300,016.9 cu. m/d (10.6 MMcf/d). It is the second gas discovery in Block KG-ONN-2004/1, following the 1-Dangeru well. E&P

PEOPLE

Jones Energy Inc.'s board of directors has hired **Carl F. Giesler Jr.** as CEO. In addition, **Stephen Jones** has been appointed a company director, succeeding **Mike McConnell**.

Yuri Baidoukov has been elected group CFO of CGG.

Northwoods Energy LLC has named **Nate Wells** CFO.



Kreuz Subsea has appointed **Thomas Liew** (left) CFO and **Jerry Starling** (right) director of diving and ROV operations.

Tom Leeson has been elected chief commercial officer of HydraWell.

Evy Glørstad-Clark has been appointed senior vice president of exploration for Aker BP and will be part of the company's executive management team.

Danos has named **Reed Peré** (left) vice president of business development, sales and marketing and **James Callahan** (right) vice president of operations. In addition, **Mike Guidry** has been appointed general manager of production, and **Kevin Biringer** has been appointed general manager of Permian projects.

Emerson's Appleton Group has promoted **Andy Schwegel** (top left) to vice president of international and industrial/commercial sales, **Joe Ugarte** (top right) to vice president of hazardous and **Harish Shinde** (bottom) to vice president/general manager of Sola and Heating Cable Systems. In addition, **John Peterson** has retired as executive vice president of global sales.

Shale Support has hired **Keith Tubandt** as vice president of production management and **Leslie Gillespie** as director of supply chain.

Bob Swann has been named director of project management and controls of BCCK Holding Co.

DEA Deutsche Erdoel AG has named **Sameh Sabry** (left) general manager of DEA Egypt, succeeding **Thomas Radwitz**, who has been assigned board adviser.

Randy Little has been elected division manager of American Block's new repair and service center.

OriginClear Inc. has elected **Daniel "Dan" Early** head of its Modular Water Systems division.

Dr. Tao Zhao has been appointed Xodus Group's advanced engineering lead. In addition, the company has welcomed **David Livermore** as a technical safety and human factors consultant and **Gareth Jones** as a principal consultant in decommissioning.

Concho Resources Inc. has appointed **Steve Gray** to its board of directors.

PJ Valves has hired **Neil Kirkbride** as a nonexecutive director.

Sarah J. Mugel has been promoted to secretary of National Fuel Gas Co., and **Steven C. Finch** has been elected an independent director on the company's board.

Petroteq Energy Inc. has elected **David Kahn** to its advisory board.

Kate Richard has joined Flotek Industries Inc.'s board of directors.

The Petroleum Equipment & Services Association (PESA) has named **Tom Shepherd** (top left), **Quay McKnight** (top right) and **Marco Caccavale** (bottom) advisory board members. In addition, PESA has welcomed **Tim Tarpley** as vice president of government affairs.

Seadrill Ltd. has elected a new board of directors consisting of **John Fredriksen** (chairman), **Harald Thorstein**, **Kjell-Erik Østdahl**, **Scott D. Vogel**, **Peter J. Sharpe**, **Eugene I. Davis** and **Birgitte Ringstad Vartdal**.

Gazprom has appointed a new board of directors: **Andrey Igorevich Akimov**, **Timur Askarovich Kulibaev**, **Denis Valentinovich Manturov**, **Vitaly Anatolyevich Markelov**, **Viktor Georgievich Martynov**, **Vladimir Alexandrovich Mau**, **Alexey Borisovich Miller**, **Alexander Valentinovich Novak**, **Dmitry Nikolaevich Patrushev**, **Mikhail Leonidovich Sereda** and **Viktor Alexeevich Zubkov**.

COMPANIES

CORTEC and **Louisiana Economic Development** have announced a $2.5-million expansion of CORTEC's industrial coatings facility in Port Allen, La. It is expected to be completed by the second quarter of 2019.

American Block, a designer and manufacturer of oilfield drilling and marine lifting equipment, has opened a 1,858-sq-m (20,000-sq-ft) repair and service center in Oklahoma City.

E&P

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on the MOVE

HENDERSON has opened a new service center in Odessa, Texas. The 5,574-sq-m (60,000-sq-ft) service center on the 4.8-acre site includes a 465-sq-m (5,000-sq-ft) office space, sandblasting area, paint booth, weld shop, 15 overhead cranes and hydrostatic testing.

Milestone Environmental Services, a provider of oil and gas waste management services, has opened a disposal facility in Reeves County, Texas.

OriginClear Inc. has launched its new Modular Water Systems division that offers prefabricated water treatment systems.

Baker Hughes, a GE company, has agreed to sell its natural gas solutions business to private-equity firm **First Reserve** and the product line's Talamona branch in Italy to **Pietro Fiorentini SpA** for a combined value of $375 million. Both transactions are expected to close in the second half of 2018.

Concho Resources Inc. has completed its acquisition of **RSP Permian Inc.**

Equinor has agreed to acquire **Danske Commodities** for EUR 400 million (US$467 million).

Sixty Six Oilfield Services Inc. has acquired **Five Star Rig and Supply Inc.**, a drilling rig and supply parts company.

Sembcorp Marine Ltd.'s subsidiary **Sembcorp Marine Integrated Yard Pte. Ltd.** has entered into a sale and purchase agreement with **Sevan Marine ASA** to acquire its intellectual property rights for $39 million. E&P

ADVERTISER INDEX

Maintaining margins, limiting risk and leveraging technology during growth

The use of a third-party consulting company can help ensure an E&P company's continued success.

James Bradley, NES Global Talent

Recent booms within the upstream sector, triggered by higher oil prices, have historically led E&P companies to focus on increasing production. This has led to reactive procurement for services that have directly impacted margins on the production rates. These services can be wide ranging; however, new developments in technology make operations more efficient and lead to efficiencies in the supply of services.

Attracting the right talent is a key factor on company performance, but sometimes in the rush for hitting production goals companies can lose focus on their total workforce management processes. Oftentimes, companies employ overqualified, high-salary individuals who will perform duties that a less-experienced individual is capable of. It is normal practice for companies to recruit people well-known to them, but do they often fall into the trap of overpaying for the roles and responsibilities being performed?

It is becoming more important for companies to invest time to properly audit their suppliers through a thorough procurement process.

In a busy market, there is also increased exposure for companies when handling risk associated with managing third-party consultants. For example, companies must manage changes required by the U.S. Department of Labor regarding the correct classification of W2 consultants and independent consultants and closely monitor job classifications to determine which job functions should be entitled to overtime pay.

All of these complexities are often managed by third-party consulting companies, but the hiring companies can still be exposed to financial risk should there be a failing of due diligence from their suppliers. It is becoming more important for companies to invest time to properly audit their suppliers through a thorough procurement process. It may seem more practical to assume the third-party suppliers hold all the risk in supporting temporary labor, but is this really the case? Recent class action cases for unpaid overtime for miscategorized workers would suggest not.

An increase in labor demands creates a high-priority need of increasing the speed at which consultants are mobilized to a job site. However, before a consultant can commence work safety protocols, compliance steps and internal approvals are required. Compliance processes can include background checks, drug and alcohol tests, industry-specific tests, safety course certifications, information management system certifications, offshore evacuation training and many more. It can be challenging for consultants to stay on top of this documentation because each course certification can have various expiration dates.

The use of technology can help flag expiring certifications that reduce the exposure of having consultants on a job site with expired documents.

With the increased attention on domestic oil production, more operations are taking place in remote locations. An onshore company can run multiple job sites over a large geographical region, which presents challenges in staying on top of third-party workers. It is not uncommon for an E&P company to be unaware how many contingent workers they have working for them. This presents a real challenge not only in ensuring standardized compliance practices, but it also presents issues in standardizing pricing with suppliers and not falling victim to higher pricing negotiations that solve short-term needs in the haze of busy production.

Suggestions of how to manage consultants in various geographical regions include the introduction of electronic time sheet records, which allows hiring managers to approve multiple time cards for consultants through one streamlined software platform. Additional advantages of introducing technology include a uniform invoicing process, real-time reporting capabilities that monitor spending on consulting services per location and the identification of all consultant workers supporting E&P activity. E&P