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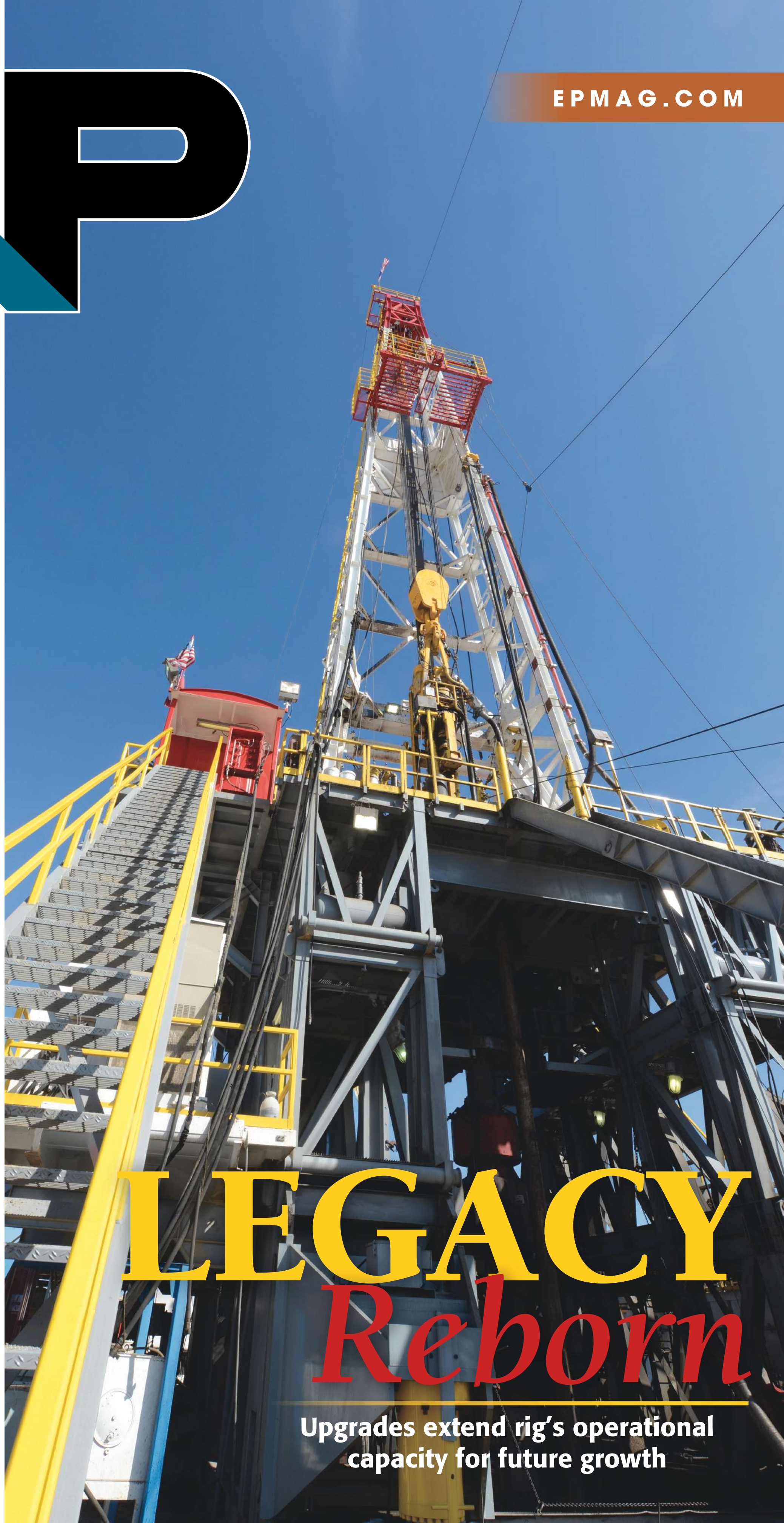

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FEBRUARY 2019
VOLUME 92 ■ ISSUE 02

A HART ENERGY PUBLICATION

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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The March edition of ***E&P*** will be our special 2019 water management techbook issue. Chapters will include an overview, key players, technology, midstream and case studies. As always, while you're waiting for your next copy of ***E&P***, be sure to visit ***HartEnergy.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER Energy Drilling Co.'s Rig 16 sees new life drilling oil wells in the Eagle Ford Shale. Left, production began in March 2018 at Moho Nord off the coast of the Republic of the Congo. *(Cover photo by Robert Allred, courtesy of Henderson; Left photo courtesy of Total; 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.

From the Digital News Group

HARTENERGY.COM: We're In This Together

Meet the team that is building the most comprehensive energy news and information site in the industry. And, you're on it.

By Len Vermillion, Group Managing Editor

From the Associated Press to the *Houston Chronicle* to FOX and NBC news affiliates, Hart Energy's Digital News Group editors bring decades of collective journalism experience to the new HartEnergy.com, which is set to launch Feb. 4. This core group of energy industry journalists will bring you the daily industry news and happenings, exclusive executive interviews and energy sector trends each and every day on a variety of platforms including articles, columns, videos, infographics and photography that you won't find anywhere else.

But they aren't alone. They are supported by a worldwide network of experienced energy correspondents in shale plays across the U.S. and in offshore regions such as the North Sea, Gulf of Mexico and South America. HartEnergy.com contributors also are stationed in the Middle East, Asia, North Africa and Australia. And this network is growing rapidly.

The Digital News Group editors and contributors bring a wealth of knowledge and connections to our coverage having extensively covered the oil and gas industry, both onshore and offshore, and they use that access to cover a vast array of topics including acquisitions and divestitures, exploration activity, midstream, production technology, policy and regulatory matters and renewable energy, to name a few.

Columnists come from a variety of sectors and many are well-known to industry insiders. We've recently welcomed veteran energy industry journalist Jeff Share, the former longtime editor of *Pipeline & Gas Journal*, into our collection of columnists.

We're upgrading our video capabilities to boot. So expect to hear directly from more top executives and analysts in the oil and gas and renewable energy sectors as we move forward.

Among the new offerings you'll find is a daily news and interview program in the mold of the popular television programs "Closing Bell" and "Squawk Box." The program airs Tuesday through Friday exclusively on HartEnergy.com and is hosted by veteran television news anchor Jessica Morales. It also regularly features exclusive interviews with newsmakers, energy executives, analysts and politicians discussing big picture topics within the industry. The program is available via podcast as well.

But that's just the tip of the iceberg. HartEnergy.com is your place to find everything you need to know, every day, about the energy industry. To make that happen we need your input. We're always on the look-out for new ideas for features and videos, and we want you to let us know what you want us to cover. My inbox is always open at lvermillion@hartenergy.com.

Our editors, too, welcome your comments, story pitches and questions. To make it easy, I've listed the contact information for the editors in charge of each of HartEnergy.com's vertical categories (see below).

Don't just tell us what you want to read and watch; let us know how you can contribute. Maybe you'd like to be part of our contributor network? Maybe you have something to say and would like to be part of our executive video interview series? Perhaps you can offer commentary on stories and trends?

HartEnergy.com is a site built to be our site—you, me and everyone else in the industry—and we want all of us to be part of making it the most comprehensive and useful site for energy professionals available. ■

Len Vermillion

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Brick by brick

The world is rebuilding its energy system, but cracks in key pillars have emerged.

During the winter holiday break, I spent time with friends over dinner discussing the many challenges they faced in the building of their first house. Listening to them describe myriad "before we could do Y, we had to solve for X" type of construction problems made me appreciate my landlords all the more. The description of the process of getting connected to the electrical grid made me appreciate the larger community of professionals responsible for providing electricity all the more, too.

As oil and gas professionals, it is a community that you and I contribute to daily. Even though the world's energy system is being restructured to include renewable forms of energy, ours is a community that will continue to be relied upon to provide the raw material to power future generations. However, while progress is being made in this reshaping, cracks in the key pillars of affordability, reliability and sustainability have emerged, according to the International Energy Agency's World Energy Outlook 2018.

In regard to affordability, the report cited the falling costs of solar photovoltaics and wind while oil prices climbed above $80/bbl in 2018 for the first time in four years. On reliability, risks to oil and gas supply remain (e.g., Venezuela), and one in eight of the world's population has no access to electricity. In examining sustainability, the report noted that after three flat years, global energy-related CO_2 emissions rose by 1.6% in 2017 and early data suggest continued increases in 2018, far from a trajectory consistent with climate goals.

"Affordability, reliability and sustainability are closely interlinked; each of them and the trade-offs between them require a comprehensive approach to energy policy. The links between them are constantly evolving," the report stated.

During December last year, shortly after the report was issued, the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) conducted an auction for about 390,000 acres offshore Massachusetts for potential wind energy development. The auction drew 11 companies to participate, with three winning bids from Equinor, Mayflower Wind (a Shell and EDP Renewables joint venture) and Vineyard Wind totaling about $405 million. If fully developed, the areas could support approximately 4.1 GW of commercial wind generation, enough electricity to power nearly 1.5 million homes, according to a BOEM press release.

In the same month, oil prices dropped below $50 for the first time in a year. In its own special way, the deconstruction and reconstruction of a global energy system is a cyclical collection of "solve X before Y" challenges. Cracks will form, but cautious and continual planning for the next phase will ensure the wheels keep turning and the lights keep brightly shining. E&P

Jennifer

Clearing hurdles, checking off boxes in the transfer of oil and gas assets

The devil is in the detail when it comes to ownership transfer of assets.

Iain Morrison, Lloyd's Register

The sale of oil and gas fields and their physical assets is a common necessity with the evolution of hydrocarbon basins. Deals in the U.K. sector alone surpassed $8 billion in 2017, according to the U.K. Oil & Gas Business Outlook 2018. It also is an increasing trend where the large, international operators divest their assets to small independents or mid-cap players that have a geographical focus or specialize in certain reservoir types.

However, purchasing an asset and taking on operatorship are part of a complex process, requiring robust due diligence and a well-considered transition plan to ensure achievement of production goals. Most deals are predicted to have a monetary upside, and so pursuing these incremental projects can be successful as long as there is a clear understanding of the condition and life expectancy of assets, realistic capex and opex estimates, identification and management of the risks involved, and the post-purchase strategy to maximize production and identify new revenue sources.

	1 PRODUCTION	2 TRANSITION	3 HSE & INTEGRITY
GOAL	- Day 1: No interruption - Maintain current production	- Day 1: All management, ops and support functions in place	- Manage HSE to required standards - Strategy and plan for managing integrity
KEY ISSUES	- Readiness for handover - Impacts on production of integrity failure	- Long lead items, eg contracts, personnel, spares, ware-house systems crossovers	- Implementation of new HSE procedures - Unknown integrity issues
RISK MITIGATION	- Handover preparedness review - Maintenance and well integrity plan	- Transition plan and risk register - Integration with existing team	- HSE implementation plan - Pre handover site visits
RISK MANAGEMENT	All risks cannot be eliminated but can be identified and managed		

FIGURE 1. The transition process and the asset transfer are governed by a number of objectives that cover three areas: production, transition, and HSE and integrity. (Source: Lloyd's Registry)

The actual transfer of operatorship is a specific time and date on which the outgoing operator relinquishes its responsibilities and the incoming operator takes over legal responsibility. Asset transfer represents a significant change process across a typical organization's technical and functional groups and has a hard deadline and often complex issues to address (Figure 1).

Issues and challenges that could arise during an asset transfer process are numerous, and it is important to understand the risks.

Duty of care and regulatory compliance

The primary task is to ensure that the new operator can meet the legislative requirements of an operator from day one—executing its duty of care to the legislative standards of the country in which it operates and to its organizational standards. In instances where the regulator's requirements are not met, third-party duty holders may need to be appointed.

Integrating the people factor

An asset transfer relies on the knowledge and skills of the personnel involved. People are integral to the transfer of knowledge. While there will be operating procedures, manuals and guidance, retaining the existing working knowledge of the asset is the cornerstone of achieving a safe and efficient transfer of operatorship.

Experience has shown that setting up a dedicated asset transfer management team to operate the asset and deliver the functional support required is essential. This team is also responsible for structuring a framework for the project governance which includes project tracking, reporting and assurance at appropriate review points.

Managing systems and process

Organizational operating systems need to be considered, and it could be as simple as transferring key management systems from the outgoing company into the new one. However, it is often the case that the operating systems are corporate and not standalone, and cannot be transferred directly but have to be substituted.

Enterprise risk planning (ERP) systems typically contain finance/human resources/inventory management and maintenance systems, and systems need to be migrated. On a large asset transfer, this will include a huge volume of data. Each operator will run its customized ERP system so any migration will need a process to map systems, data and extensive quality assurance/quality control and testing along with safety case and environmental plans.

Asset integrity and architecture complexities

It is a basic requirement to understand what is being bought, such as the asset inventory, as well as its boundaries and interfaces with other assets. An asset integrity review is needed to determine the status of wells, platforms, production facilities and pipelines. Taking over existing projects that the outgoing operator has already started also requires a high level of coordination to agree how and when the projects will be taken over and where the financial responsibility lies between each company.

Additionally, larger assets are a complex network of wells, platforms and pipelines. There may be interrelated third-party arrangements for platforms processing hydrocarbons and product transported by pipelines. In extreme cases, there may be different license holders for different reservoirs in the same field. This adds to the complexity of any transfer and the ongoing responsibilities and liabilities between the new operator and other stakeholders.

Reservoir and data management

Often the subsurface team will not transfer from the previous operator, and this presents challenges given the accumulated knowledge is lost, even though subsurface data and models are transferred. The asset transfer goal for reservoir management is usually on the basis

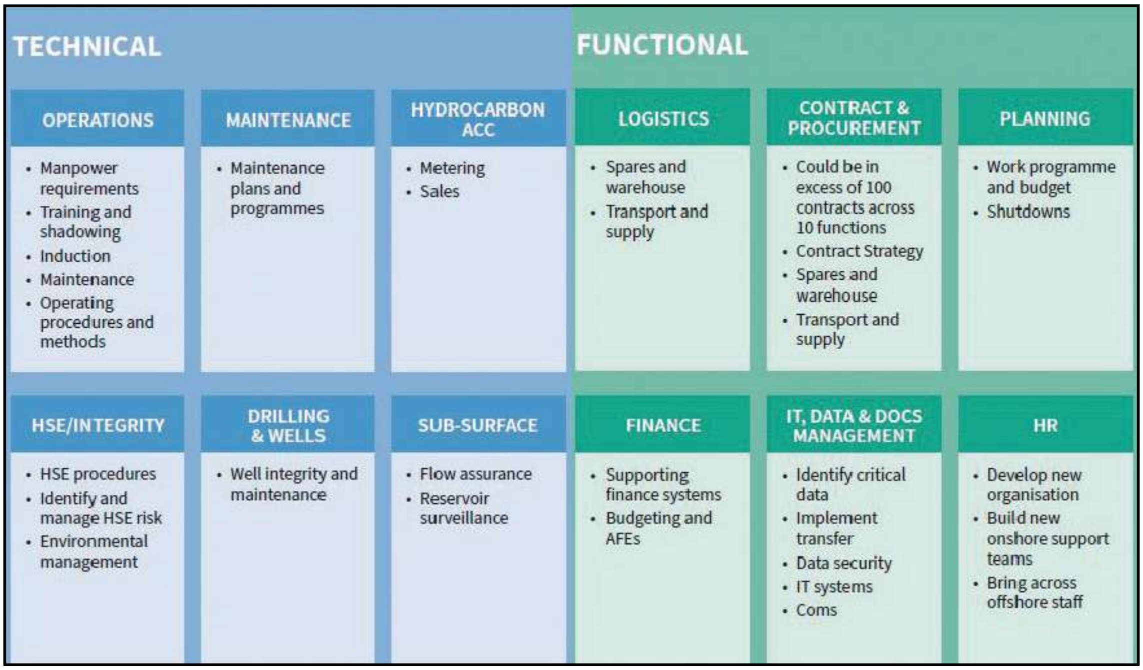


FIGURE 2. There are 12 key areas of focus during the transition of assets. (Source: Lloyd's Registry)

that reservoir performance is maintained, flow assurance strategies are in place and that well intervention plans are enhanced to maintain production.

Decommissioning liability

The liability for decommissioning an asset rests with the licensees, and this is transferred to new operators under the Petroleum Act 1998. Current guidance suggests that this liability persists in "perpetuity" and the government reserves the right to hold licenses responsible both jointly and severally. The current regulatory framework also permits previous licensees to be pursued for decommissioning costs even if they have transferred ownership to other parties. All operators are required to have a mechanism for ensuring financial security to cover their potential decommissioning liabilities. This has been a factor in some large merger and acquisition opportunities in oil and gas where an accurate view of any company's asset retirement obligations (AROs) are an important part of the valuation of an asset.

A recent financial review suggests that eight international oil companies (IOCs) have AROs on their balance sheets of more than $10 billion each, and, since 2010, the AROs of the seven largest IOCs have increased year over year. Estimating future costs is inherently risky, as the industry does not know how technology or standards will develop. So while decommissioning is a critical issue, it is difficult to tell whether sufficient or excess capital is being set aside.

Recent high-profile transfer cases have demonstrated that previous owners, although not responsible for how the asset is decommissioned, have retained some liability regarding costs. For example, the decommissioning cost associated with the assets sold by Shell to Chrysaor in 2017 is estimated at $3.9 billion, and Shell has retained a fixed liability of $1 billion for decommissioning these assets.

Transfer plan

There may be up to 12 functional areas to consider across technical and nontechnical disciplines (Figure 2). The plan should focus only on key tasks required to deliver the objectives of the asset transfer, including a framing session such that everyone is at the same starting point in the project and that the company objectives of the asset transfer are clearly articulated and understood by everyone.

The asset transfer management team also can create a transition agreement between the outgoing and incoming operator. This agreement sets down the agreed methodology between the two parties on the implementation of specific noncontractual tasks of the asset transfer plan.

There are complexities in any asset transfer that increase the risk potential. An asset transfer risk register created alongside the main transfer plan can help to identify these risks and determine the mitigation measures needed depending on the criticality of each risk. E&P

Keeping the faith

One independent energy company sees capability and expertise as critical to fueling its onshore and offshore growth engines.

Jennifer Presley, Executive Editor

Location is king when it comes to investing in real estate, and it is no different with oil and gas properties. Lately, it has been the drier locales that have done better than wetter ones. However, there is only so much dry land to work with, and the oceans are deep with potential. Harnessing the potential of deep water requires more time and more funds to realize that success than it does onshore. Just as some prefer steak over lobster, there are those who prefer both options.

For Hess, it is not an "either/or" decision, as the company views both onshore and offshore as its engines of growth. A quick review of the company's website provides ample proof of focused intensity in the Bakken, the Gulf of Mexico (GoM) and Guyana. About 75% of its $2.9 billion capital and exploratory budget for 2019 is allocated to its high-return growth assets in the Bakken and Guyana, according to a press release.

"In 2019 in the Bakken, we plan to operate a six-rig program, up from a 4.8 rig average in 2018; drill 170 wells, up 42% from 2018; and complete the transition to higher intensity plug-and-perf completions, which is expected to generate a significant uplift in net present value and initial production rates while also increasing the estimated ultimate recovery of oil and natural gas," said Hess COO Greg Hill in the release.

"In Guyana, 2019 will be the peak spend year for the Liza Phase 1 development, which is on track for first oil by early 2020," he added. "We also will begin Liza Phase 2 development spending, complete the plan of development for Payara and advance front-end engineering and design work for future development phases."

Managing these dual growth engines is a challenging feat. Never before has capability and expertise been more important when it comes to investing in deep water and unconventionals, according to Richard Lynch, senior vice president of technology and services at Hess. He shared his views on this and more as part of his remarks at the International Association of Drilling Contractors Annual General Meeting held in November last year.

Richard Lynch

Need for upstream investment

The outlook for global energy demand is robust with population growth and increasing affluence driving energy demand, Lynch said, citing data from the International Energy Agency's (IEA) World Energy Outlook 2018. According to the IEA, the global energy demand is expected to grow by about 20% by 2040, adding that during that time the energy mix will change, with natural gas/renewables taking up a larger share. Also, global oil demand is forecasted to grow to about 105 MMbbl/d in 2040, up from about 92 MMbbl/d in 2014.

Meeting this future demand will require investment in onshore and offshore projects. Lynch said significant curtailment in upstream investment during the last five years has occurred as a result of oil prices, adding that investment is down by almost 40% since 2014. New deepwater projects were among the first to be delayed or canceled during this time. Now offshore projects are making a comeback, and the projects receiving the green light are much leaner and fitter than they were before. Only the best projects are moving forward, with breakeven oil prices in the $25/bbl to $40/bbl range, according to the IEA's 2018 Offshore Energy Outlook.

These lower breakevens—made possible through simplified designs, standardization, digitalization of offshore operations and more—are enabling an environment in which a significant near-term rise in offshore investment is essential to balance the market, according to the IEA.

The IEA estimates that $580 billion in investment is required every year to 2040, Lynch noted, adding that the total level of investment is more than $12 trillion. More than 50% of the future investment will be focused on the development of new oil and liquids supplies. As an example, Lynch said that keeping a constant liquids supply requires an additional 78 MMboe/d of liquids to be produced by 2040, while meeting future increases in demand requires an additional 97 MMboe/d.

Significant investment in natural gas also is needed, with the IEA projecting approximately 2% per annum rate of growth driven by Asian demand. Meeting these demands requires investment in more than just onshore resources, Lynch said, noting that almost $6 trillion of investment is required in offshore. The challenge is significant, as few companies are willing to venture into offshore, he said, adding that the world is going to have to invest in more than North American shale to meet future demand.

Meeting the need

According to Lynch, Hess is one company that has continued to "keep the faith" in offshore. Lessons learned early through its involvement in offshore opportunities in the North Sea at South Arne, in the GoM's Conger and Shenzi, and West Africa's Okume and Ovang helped make the company's recent successes at Tubular Bells, Stampede, North Malay Basin and Liza possible. The technical expertise developed through these projects transferred across all operating areas for the company, he said.

At Stampede, for example, the company delivered the largest undeveloped field in the GoM in about three years from sanctioning, about six months ahead of schedule and $800 million under budget. At North Malay Basin, the company delivered a three-phase gas development with up to 11 wellhead platforms, pipeline and an FPSO on time and on budget, about three years from sanctioning. Hess is now the region's largest gas producer, providing 25% of Peninsular Malay needs.

The company continues its work with Exxon Mobil in Guyana on the more than 5-Bbbl development, with first oil at Liza scheduled for 2020 producing 220,000 bbl/d, he noted, adding that the area will see up to five FPSOs producing 750,000 bbl/d by 2025.

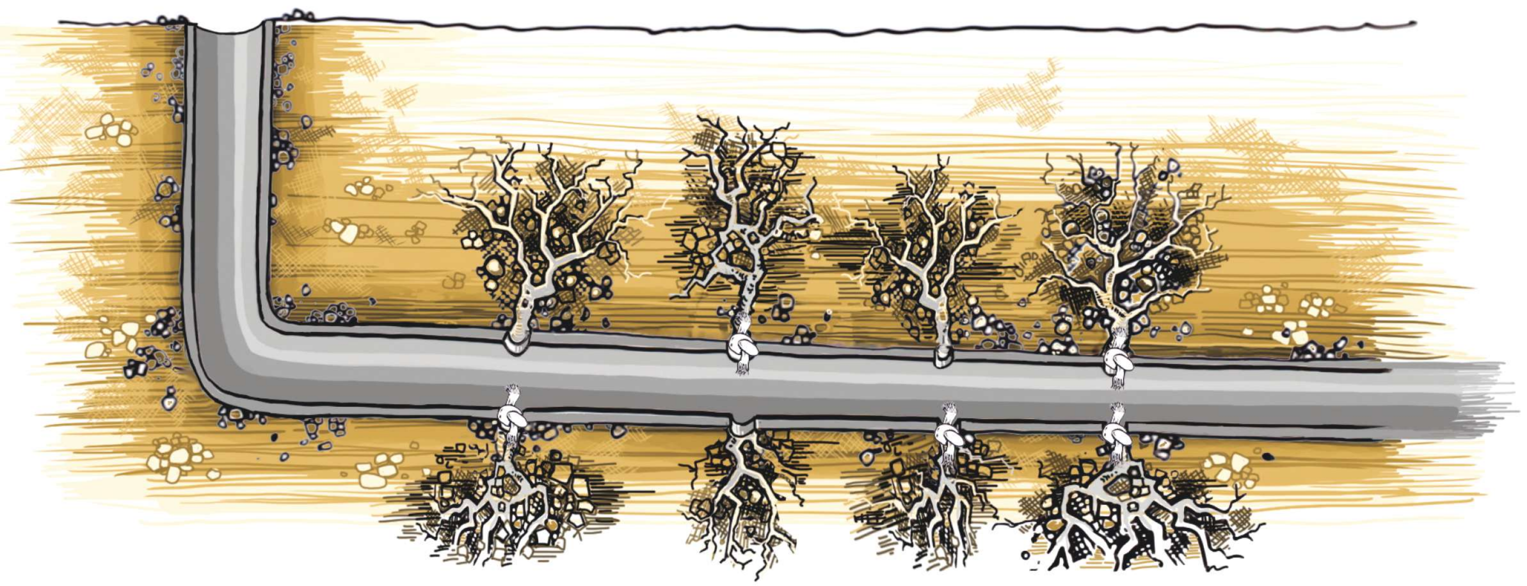
The company's success in its operations is made possible through its application of and adherence to lean management techniques, citing significant reductions in drilling cycle times as an indicator. Through the application and reapplication of lessons learned at Stampede, the company realized a 37% reduction in well cycle times, and at North Malay Basin, it realized a 52% reduction, Lynch said.

On the onshore side, the company is applying and reapplying lessons learned to reduce drilling cycle times in its Bakken operations significantly. From 2010 to the first half of 2017, the company realized a 70% improvement in spud-to-spud times, from 50 days to just 15 days.

Innovations in technology, along with lean, helped to make these successes possible. Technology is changing exponentially and will continue to transform the industry and the world. By 2023 the computing power of one computer will equal one brain, he said, and by 2045 computing power will surpass brainpower equivalent to that of all human brains combined.

Meeting future energy demands will certainly require the capabilities, expertise and brainpower honed by decades of experience in all sectors. E&P

PERF PODS SEAL AT A 1:1 RATIO



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SlicFrac is replacing the need for frac plugs while providing an economical solution for better fracture stimulation. Unlike other diverting agents, TTS' Perf PODs are designed to effectively seal directly inside the perforations and eliminate any formation damage or residual fracture obstructions.

TTS' SlicFrac diverting technology is setting the standard for optimizing well stimulation.

SlicFrac Benefits:

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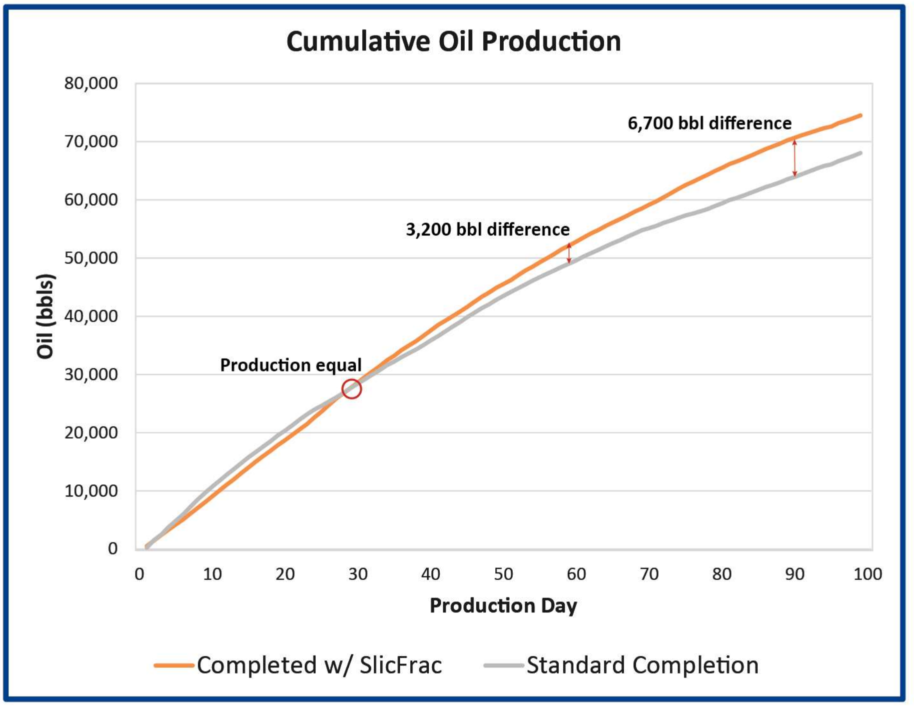
- *Mid-stage diversion for maximum cluster efficiency*
- *Eliminate bashing on offset wellbores*
- *Block flow at the perforation in the casing*
- *Perf PODs form to geometry of irregular shaped holes*

Increase Production with SlicFrac

Incorporating Perf PODs as a mid-stage diverter allows the Operator to achieve maximum cluster efficiency while stimulating the entire stage without leaving orphan clusters behind.

A customer in South Texas was interested in determining the most effective solution to optimize their production.



Under similar wellbore conditions, they utilized a two well pad to evaluate the use of **Thru Tubing Solutions' SlicFrac** Diverter System to stimulate one well and completed their standard plug-n-perf design on the second well.

SlicFrac Perf PODs were deployed mid-stage to effectively plug the dominant perforations and divert the proppant to understimulated clusters, thus generating increased reservoir contact. Utilizing **SlicFrac** allowed the Operator to maintain a more consistent stimulation volume into each perforation cluster, ultimately providing a more balanced treatment and allowing the target reservoir every opportunity to perform to its full capacity.

Initially, oil production started lower on the **SlicFrac** well but caught up to the offset well by day 29 and steadily surpassed it by day 60 with a cumulative 3,200 bbl difference. The trend continued into day 90 where the **SlicFrac** stimulated well produced approximately 6,700 barrels more than the non **SlicFrac** stimulated well.

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The quest for the ultimate wellbore

A completions services provider emerges from the downturn better equipped to deliver on its mission.

Jennifer Presley, Executive Editor

Ann Fox

The idea for the company that would become Houston-based Nine Energy Service was initially rooted in the belief that the completions process for unconventional wells would become more complex. The increased complexity would drive the need for new technologies and teams capable of delivering results. This was in 2010, years before single-well pads had expanded into multiwell pads, and before laterals lengthened in increments measured not in hundreds of feet but in multiple miles, proving out the investment thesis proposed by the company's founders.

"We met our first entrepreneurs with the right tools in the right location, which at the time was the Bakken Shale," said Ann Fox, CEO and president of Nine Energy Service. "We finished that transaction in March of 2011 with a company called Northern States Completions. It formed the foundation of Nine in a couple different ways."

The first was by being leaders in their capacity and by being entrepreneurs.

"It set the DNA for Nine, which is to be very nimble, entrepreneurial and hyperfocused on increasing EURs for our customers and reducing their cost to complete," Fox said. "A very close second to that mission is the right to prosper and socioeconomic movement. And that underpinning of the American dream and that philosophy is something that the management holds very dear and that really gives rise to our servant leader culture here at Nine. And that started with those entrepreneurs there in the Bakken."

From the Bakken, the company has grown its operations into all of the major shale plays and enhanced its tech toolbox through strategic acquisitions. In the fourth quarter of 2018, the company acquired Magnum Oil Tools and Frac Technology, adding dissolvable tools and the BreakThru casing flotation device to its products portfolio.

E&P recently spoke to Fox at the company's headquarters in Houston.

***E&P*: How has the landscape changed for service companies like Nine Energy Service these past few years?**

Fox: The inflection point has been significant with the rise of the multiwell pad and the lateral lengths increasing. Operators are concentrating risk now in the multiwell pad. In a single-well pad, if they had a service company that was not performing or was not living up to their standard, a blunder on a single-well pad is something that the operator could blend into their overall numbers.

Now as we start to see six-well pads, 13-well pads—Pioneer's talking about going to 21-well pads—not only is that a $40 million-plus construction project, but if you don't select the right service company then the efficiencies on that well pad are fundamentally impeded, and their return on investment is impeded. The concentration of risk goes up similar to offshore, and the service selection process is more discriminate. Operators are looking for the best technologies and the best service companies.

For us, the fact that service selection is about competency and proficiency gave rise to 167% market share growth in stages completed in the U.S. from the end of 2014 through the third quarter of 2018. That has given us a real seat at the table to be an expert in what we do. Moreover, I think the culture that we are building allows us to sustain that service execution because we have a highly motivated team from the people that are building your perf guns all the way to the people that are running them, as well as our people that are designing tools. That linkage between the field and the C-suite is important.

***E&P*: What are your thoughts on the ability of shale technologies to scale up in countries beyond the U.S. and Canada?**

Fox: We are certainly starting to see it. If you look at Saudi Aramco going through what I'll call the development phase of some of their horizontal shale plays, they are now getting more into the cost optimization and efficiency phase, more of what we call in America the manufacturing mode. I think the U.S. is leading on that front, and a lot

of the international market is not a horizontal fracturing market. However, I do think that where we do see horizontal fracturing, we're starting to see the concept of the manufacturing mode and the time efficiencies proliferating overseas.

In the U.S., we've made considerable progress in reducing the cost to complete a well per lateral foot. I think great service companies are developing these technologies and working much more hand in hand with the operators on completions efficiencies; we'll be able to help keep the operators competitive globally for the incremental barrel of oil because we are going to continue to reduce the cost to complete the well.

E&P: What technologies do you foresee as having the greatest impact in the upcoming years?

Fox: We are very focused on the ultimate wellbore, which for us is an intervention-less wellbore. It is the wellbore of the future. There are steps to get there. One of the steps we've recently taken is investing in dissolvable technologies. These technologies create efficiencies from a time perspective for the operator. It also helps them deal with parent-child well interference. For example, there is no need to intervene in the wellbore once the casing is damaged when using a dissolvable because they eliminate the drillout. We see dissolvables as one of those steps on the ladder to getting to an intervention-less wellbore.

E&P: Speaking of opportunities, what's next for Nine Energy Service?

Fox: We certainly are still a very small part of North American completions. In the U.S. we only complete about 16% of the stages completed today, and we have a lot of room for organic growth. However, we also are hyperfocused on leveraging the technology that we just acquired and developing new technology. We'll be developing tools inside the wellbore that compress the completion schedule and decrease the cycle time for the operator to bring their product to surface. We will continue to focus on that.

E&P: What are some ways that you see the compression of the completion schedule being possible?

Fox: It's certainly happening with dissolvable plugs. For example, it takes on average four days to mill out plugs in a 10,000-foot [3,048-m] lateral. If you fill that wellbore with dissolvable plugs, operators save four days per well. If you're on a six-well pad, that's saving 24 days. Most operators are going to do a cleanout run, so taking that into account, operators are saving 12 days. Either way, operators are still saving a signficant amount of time. If you multiply the revenue from that pad by 12 days or 24 days, that's very significant, which helps drive their return on investment.

E&P: Is there a digital component to the intervention-less wellbore?

Fox: It would be interesting to me if people did not see there being some portion of the wellbore being digital over time. I think we're still further away from that, but that has to come. The ability to get real-time data easily needs to happen, and we need to get smarter about what's happening downhole. We're still relatively dark on what's happening on a real-time basis. I'm talking about the industry as a whole. I think there are a lot of opportunities there. E&P

Nine Energy Service sees dissolvable technologies as one step on the ladder to an intervention-less wellbore. (Source: Nine Energy Service)

Tough times for sand miners

Disruption comes to the proppant market as low commodity prices cap demand and mining capacity expands rapidly.

Richard Mason, Chief Technical Director

Remember the record year for energy industry IPOs in 2013? Sand miners accounted for three of the top 10 energy firms in equity value appreciation following public market debuts. This included all new energy IPOs engaged in oilfield services, midstream and the E&P sector.

But times change. A basket of publicly held sand mining companies saw equity valuations decline 51% in 2018, the largest drop among all oilfield service groups—including the decimated offshore drillers.

Wall Street carnage illustrates how sand miners are facing a structurally oversupplied market in 2019. The major tight formation basins, plus Canada, consumed between 85 MMtons and 95 MMtons of sand last year. Completions—and sand consumption—peaked mid-2018 before fading after Labor Day.

- **A rapid increase in sand mining capacity collides with softening demand.**
- **A surge in regional sands displaces traditional Northern white sand.**

Then it got worse. Mining utilization fell from 80% of capacity in 2017 to 50% by year-end 2018. Pricing per ton of sand dissipated like dust in the wind, reaching the low $20 per ton range with some spot market regional sand being sold in the high teens as 2019 got underway. Pricing for some grades of sand declined 40% over a four-month period.

Sand miners responded by shutting in mining capacity (mostly Northern white sand) with estimates suggesting 30 MMtons idled in a market featuring 175 MMtons of capacity. Aggregate industry sand consumption rose 16% in 2018. It was only expected to rise 5% this year as demand forecasting became a precarious undertaking with West Texas Intermediate parked below $50.

As of Jan. 4, a loose consensus projects 2019 sand consumption to increase to 127 MMtons. Getting there requires an asterisk. The number reflects an average of five major financial firms or industry analysts with the highest at 154 MMtons. This 127-MMton consensus stands in stark contrast to projections from the nation's largest and most diversified sand supplier, which argues industry headwinds will keep this year's oilfield consumption flat at 100 MMtons.

Whatever the number, sand supply is accelerating faster than demand as the market witnesses a production landslide from new regional mines. The Permian is at the fore with 65 MMtons of new capacity coming online by mid-2019 versus 30 MMtons of demand. Elsewhere, the Eagle Ford is balanced at 22 MMtons, while new regional mines in the Midcontinent will add 16 MMtons of supply to a market with 7 MMtons of demand.

The good news is sand consumption per well is still rising as slick water and finer proppant grow to dominate well completion techniques. However, the rate of increase per well is slowing as E&P companies bump into diminishing returns. The economic sweet spot for slick water varies between 1,800 lb/ft and 2,500 lb/ft of lateral. Several basins display two distinct profiles with leading-edge sand use above 2,000 lb/ft of lateral and a lower cluster at 1,200 lb to 1,500 lb per lateral foot. The lower cluster is edging toward the upper cluster as more E&P companies adopt similar completion techniques, a process favored by the reduction in sand pricing, which represents up to 15% of well cost.

Simultaneously, inexpensive regional sands are crowding out premium Northern white sand as E&P companies opt for lower well costs that generate similar IP rates, even if data show rapid production declines consuming any initial cost advantage for regional sand through proppant degradation and lower ultimate recovery.

Meanwhile, drilled but uncompleted wells imply a six-month completion backlog and 50 MMtons of potential consumption. It could be a bright spot for sand miners who await stability in outlook from reconfigured 2019 E&P budgets. E&P

Strong year ahead for the Gulf of Mexico

A supermajor inks a contract for the first drillship rated for 20,000-psi operations.

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For several months it has appeared that a recovery is underway in the Gulf of Mexico (GoM) and that 2018 was an inflection point for the basin that has endured more resurrections than a cat living out its ninth life. Optimism dared to peek out from behind its curtain of caution as energy forecasters proclaimed 2019 to be a historic one for the GoM.

However, the market winds shifted in December and oil prices fell to below $50/bbl, driving budget makers back to their spreadsheets. Did the price collapse take some wind out of the sails for 2019? Possibly, but that does not mean the year ahead will be any less historic.

"We expect 2019 to be a strong year for the Gulf of Mexico," said William Turner, senior research analyst at Wood Mackenzie, in a press release. "In addition to exciting new project sanctions, which could usher in more than $10 billion of investment into the region, a couple of historic firsts set to occur next year could set the stage for years to come."

The first-ever production from a Jurassic-aged reservoir in the GoM will occur when Shell's Appomattox development in Block 392 of the Mississippi Canyon Protraction Area goes online as planned. The project—featuring the company's largest floating platform—is considered a cornerstone for Shell's deepwater global strategy. Average peak production from the Appomattox and Vicksburg fields is estimated to reach about 175,000 boe/d, according to the company.

"If the Jurassic roars to life in 2019, it could give operators greater confidence in the play's potential," Turner said. "However, if Appomattox disappoints, the Jurassic could continue to lie dormant. The wider region would also be missing an expected strong production growth contributor."

Considerable interest surrounds the possible sanctioning by Chevron of its Anchor project in Block 807 of the Green Canyon Protraction Area. With an operating pressure of 20,000 psi, it would be the first ultrahigh-pressure project in the world to reach a final investment decision, according to Wood Mackenzie. Joint industry R&D projects surrounding the design of equipment and systems that can safely produce at 20,000 psi have been underway for more than a decade.

"Anchor will be an important one to watch," Turner said. "The sanction of Anchor will be a significant milestone for Chevron, Total and Venari, but [it will] also mark a crucial point for the offshore industry as it enters the final frontier in deepwater development."

Success at Anchor could lead to plans for other Paleogene projects (Tiber and Kaskida come to mind). Wood Mackenzie believes that if Anchor moves forward, more than $10 billion of investment could flow into the region, according to the press release.

With no decision yet on Anchor's fate, Transocean announced in late December a five-year $830 million drilling contract for one of its newbuild ultradeepwater drillships with Chevron. The drillship is under construction in Singapore and when complete will be the first floater rated for 20,000-psi operations, according to the press release. The ship will feature dual 20,000-psi BOPs, the net hookload capacity of 3 MMlb, a 165-ton active heave compensating crane and an enhanced dynamic positioning system. It is expected to commence operations in the GoM in the second half of 2021. While it is too early to begin playing "Anchors Aweigh," there's no harm in getting the band tuned up and ready to perform. E&P

Jennifer

No signs of stopping in 2019

Operators push forward with ambitious plans despite price volatility.

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OPEC and Russia's decision in early December 2018 to cut production in 2019 by 1.2 MMbbl/d sent a wave a relief through an industry that had seen the price of oil fall 30% from its peak in October last year.

As a result of seasonal operational trends and low commodity prices in the fall, operational activity slowed significantly toward the end of the year, as Patrick Schorn, vice president of wells at Schlumberger, noted at the Cowen 8th Annual Energy & Natural Resources Conference in December.

"There was a surge in hydraulic fracturing activity in the second quarter, especially in the Permian," Schorn said. "This activity surge leveled off in the third quarter and [dropped] in the fourth quarter, which will show up in the first half production numbers in 2019."

Indeed, oil prices teetering in the $50/bbl range, as is the case in early 2019, did not seem to dampen the enthusiasm for continued record production by operators as they made their plans for this year. This is primarily a result of breakeven prices that remain attractive even as West Texas Intermediate staggers. According to Pioneer Natural Resources' December 2018 investor presentation, none of North America's major shale plays feature breakeven costs of even $40/bbl, and many are under $30/bbl. In the Permian Basin, for example, Pioneer's breakeven costs are just over $20/bbl.

Even after the price of oil sunk to $42/bbl in early December, and before OPEC announced its cuts driving prices back up, operators revealed plans to power forward this year. At the Capital One Securities 13th Annual Energy Conference in December, WPX Energy CEO Clay Gaspar announced his company would increase 2019 capex by as much as 32% over 2018 while planning a 28% growth in oil and gas production to as much as 105,000 boe/d.

Meanwhile, Devon Energy reported in its December 2018 investor presentation that it was planning 15% to 19% growth in oil production this year, particularly in the Stack play. According to the report, Devon is planning between four and eight wells per unit at its Morning Thunder, Northwoods, ML Block, Scott and Brachiosaurus developments this year. Devon also plans to accelerate development in the Rockies where it will shift its Super Mario area into development by spudding 35 Turner wells, according to the report.

In its December 2018 investor presentation, Chesapeake Energy reported its plans to more than double its oil production in the Powder River Basin. Also, Chesapeake reported it is planning a 65-well IOR project for June in the Eagle Ford, which it hopes will achieve 1.3 to 1.7 times potential improvement in oil recovery.

Low prices bruised the industry to close out 2018, and early production numbers this year will likely reflect that. However, as Schorn said, the new year will likely see a gradual recovery as the market, hopefully, stabilizes. Even if prices do continue to teeter, the market decline of 2014-2016 taught operators a discipline that has paid off in low breakevens, and subsequently, operational breathing room. E&P

Brian

The market decline of 2014-2016 taught operators a discipline that has paid off in low breakevens, and subsequently, operational breathing room.

Prioritizing innovation

Overhauling processes and updating technologies can modernize oil and gas companies.

Q Manning, Rocksauce Studios

Oil and gas companies have not always generated a culture of innovation. When it comes to internal operations, plenty still depend on software written at the turn of the century, back when cellphones just made calls and Twitter wasn't even an idea. Many are now adapting software as a service to meet certain needs, but the end result is a hodgepodge of disparate systems.

As is the case with many enterprise endeavors, the oil and gas industry needs custom solutions in a big way. With solutions tailored to specific operational models, companies can take advantage of applications that are simultaneously feature-rich and user-friendly on a commercial scale. However, innovation in this space is not without hurdles.

Removing the rust

About a decade ago, during the era of serious mobile and cloud solution proliferation, the global oil and gas market was facing a downturn as a result of the shifts in the economy. This resulted in a static acceptance of existing processes and systems. Making new hires and adapting to trends were less necessary. Now a new workforce is encountering an oil and gas industry that does not operate in the way it has been trained, and companies are forced to try to shoehorn paper or monochromatic interface systems into an iPhone and Facebook world. It's a bad look.

Businesses that recognize the importance of modernization and innovation will be far more attractive to top performers in the industry, allowing them to recruit and retain a talent pool that is pushing the boundaries of what is possible in the 21st century.

Of course, there is innovation in the act of digital transformation. For decades, companies have been collecting terabytes of data, tracking everything from safety trends to what is happening in the field. Much of this information sits in antiquated databases or binders in storage units: too dense to parse and too costly to learn from. By tapping into artificial intelligence to analyze these data—coupled with new, custom systems created for delivering just-in-time reporting and predictive results—oil and gas companies can scale in previously unimaginable ways, with a return on investment that

Technology platforms that empower communication and collaboration are essential to driving an innovative culture. (Source: Rocksauce Studios)

can translate into hundreds of millions of dollars in operational efficiencies.

As technology continues to advance, however, the cost of innovation expands. Like a drillbit left uncleaned in a pool of stagnant water, every moment that processes are left unattended increases the difficulty of removing the rust. The time to innovate is nigh.

Overcoming obstinacy

In many ways, the success of the industry rests on strategies dictated by conventional wisdom. When a process works well enough, executives abandon other options because they represent an additional cost, whether it is in the form of money, training time or some other investment. The phenomenon is understandably commonplace.

Today, though, technological advances have far outpaced the rate at which large businesses can adopt them. From innovations, such as virtual reality and robotics to the data collection capabilities provided by drones and wearables, modern technologies are extracting as much as possible from a day's work—but only if companies figure out how to incorporate them into their existing processes.

As the oil and gas industry continues to experience a massive shift in its workforce, the keepers of the old processes are retiring. Innovation will only grow costlier as technology keeps advancing, and for the most competitive companies in the space, now is the time to embrace a new wave of innovation that will attract top talent, improve efficiency and further contribute to sustained success.

By gaining the insights of internal teams and outside experts, a company can more clearly define a process that will propel innovation. (Source: Rocksauce Studios)

Importance of internal innovation

When it comes to production, the same companies that are using manual entry processes are embracing innovations such as directional drilling and various fracturing methods. Not surprisingly, innovation is being used to achieve great successes in the field.

With any large company, the speed of adoption depends on working through internal bureaucracy and procurement processes—not to mention the politics of an old guard not yet willing to let go of the wheel.

One thing that oil and gas companies can learn from the entrepreneurial sector is how to enable the spirit of new ideas and allow innovation to happen in a safe environment. Companies need to be willing to take risks via pilots or tests, rather than requiring any new endeavor to have an accountant-certified five-year rollout plan before a single concept can be drawn out on a whiteboard.

Indeed, smart companies have become purposeful in focusing their culture on innovation. To capitalize on the shift, there are a few ways in which executives can embrace the three pillars of innovation and achieve more effective internal processes as a result.

1. *Define a process.* An innovative culture rarely takes root on its own. Instead, it requires a process like the one outlined in the Harvard Business Review's "Innovation Stack." It sounds counterintuitive, but a defined process actually frees innovators to create without the looming fear of damaging their career paths. The entrepreneurial market operates on incremental failure. When companies can effectively manage this failure, it's more likely to lead to a "Eureka!" moment.

2. *Create a platform.* A process is useless without a platform for distributing it throughout an organization. Whether the platform is a website, a mobile app or a suite of tools based in the cloud, it must send proposed innovations through the process in which they are vetted, joined and shared within a company. The chosen platform must also maintain a level of transparency that encourages trust and collaboration, as these are both key ingredients to inspiring innovation that, if left out, will cause an effective transformation to stagnate.

3. *Promote the above.* In the same way customers cannot buy a product they are not aware of, people in an organization will not use a process or a platform they have not heard about. After investing in a process and platform, companies must promote them to spark the desired cultural shift. Adopting the latest software or gadgets and sending out an email will not move the needle on culture. Instead, elements like campaigns, messaging, companywide announcements and rewards are necessary to encourage employees to make waves in their careers.

Whether or not a company is innovating, it can be sure that its competitors are doing so. The best way to keep up is to inspire a culture that welcomes innovation instead of stifling it. The initial cost might be an incremental failure, but the payouts are processes that revolutionize the way companies of all sizes do business.

The three pillars of innovation are a great way to jump-start the shift toward innovation in a company, but they are only a start. Innovation takes time, but executives know that the best time to start a lengthy process with vast potential returns is today. Put it off, but in one short year, companies will likely wish that today had been the day they dove right in. E&P

LEGACY *Reborn*

Upgrades extend rig's operational capacity for future growth

Jennifer Presley, Executive Editor

The rapid pace of technology development in the oil and gas industry ensures that all players in it are in constant pursuit of the next innovation that will deliver the next barrel and the next dollar safely and efficiently. For land drilling contractors, this chase is evident in the evolution of rig technologies.

As operators optimized their development programs, the demand for higher horsepower Tier 1 rigs with alternating current (AC) electric drives and self-mobilization systems increased. Many drilling contractors met this demand by building new rigs or upgrading their

Energy Drilling Co.'s Rig 16 drills a well for Ram Energy Resources in Fayette County, Texas. (Photo by Robert Allred, courtesy of Henderson)

existing AC fleet to Tier 1 and stacking Tier 2 rigs with silicon-controlled rectifiers (SCR) and mechanical rigs.

Strong customer demand for the highest spec rigs continues to drive the upgrade cycle and a sustained shift away from legacy rigs, noted Anthony G. Petrello, CEO of Nabors Industries Ltd., in his third-quarter 2018 remarks at the end of October. At that time the company had 110 rigs working in the Lower 48, including 14 legacy AC rigs and two SCR rigs, and about 45 idle AC rigs that were viewed as potential candidates for an upgrade at the cost of up to $9 million each, he noted.

Helmerich and Payne (H&P) upgraded and converted 54 FlexRigs to super-spec during its fiscal year 2018, bringing the number of super-spec FlexRigs in its

Rig 16 was recently refurbished by Henderson at its new service center and rig yard in Houston. (Photo by Robert Allred, courtesy of Henderson)

U.S. land fleet to 207, according to H&P CEO John Lindsay. The remark came during the company's fourth-quarter 2018 review held in November. The company expects to "maintain an average or conversion cadence of 12 rigs per quarter for the next few quarters," he said, adding that the company at that time had first and second fiscal year 2019 quarters fully committed, with the average length of term for these contracts being two years in duration.

The decision to upgrade for some drilling contractors can mean the difference between their company surviving market fluctuations or not.

"The larger drilling contractors have all upgraded their older equipment and then put them back out onto the market as higher spec rigs than what they were when they were stacked," said Wayne Workman, rig services director for Henderson, a full-service rig and equipment dealer.

"For smaller drilling contractors that do not have the capital assets to do that, they have to find a way to compete. They need to innovate and grow their business without busting their budgets to survive."

Energy Drilling Co. (EDC), with the help of Henderson, found that the answer to remaining competitive was through the upgrade of a legacy SCR rig that once drilled geothermal wells in California and now, post-upgrade, is drilling shale wells in Texas.

Going horizontal

Based in Natchez, Miss., EDC was formed in 1979. It operates nine drilling rigs in the southern U.S. and specializes in drilling for independent operators doing turnkey, footage and daywork applications. In the company's 40 years of operations, it has grown from trailer-mounted double rigs to include higher horsepower triple rigs.

"In the beginning, we had just a couple of the little rigs and did work mainly in Mississippi, South Louisiana and Alabama," said Jody Helbling, general manager for EDC. "We were 90-100% turnkey in the early days."

The company cut its teeth drilling shallow Wilcox Trend wells in Mississippi, moving on to drill gas wells in the Cotton Valley Trend in northern Louisiana. According to Helbling, EDC drilled 318 wells on turnkey for KCS

Energy, an operator that would eventually become part of BHP Billiton through its merger with Petrohawk, as well as hundreds of other wells in northern Louisiana for other operators.

"At that time, we had six trailer-mounted doubles and three mechanical triples," he said. "Then all of a sudden, the Haynesville came on and that left the Cotton Valley behind. The number of U.S. land wells being drilled went from, in that quick period, about 60% horizontal to about 80% horizontal. We [EDC] saw that the world was going horizontal and that we needed to start moving in that direction."

In the years since, EDC has upgraded its fleet as needed in a cost-conscious manner. These upgrades included the conversion of its 1,200-hp Rig 14 from mechanical to SCR and the new construction of Rig 15, a 1,000-hp SCR walking rig.

In 2014, before the market downturn, the company had purchased the components to build in its yard its first 1,500-hp SCR rig with a walking system and 7,500-psi mud pumps.

"We didn't put that rig together for about a year, and when the market began to pick back up, we assembled it," Helbling said. "That is our Rig 11, and it went to work in October 2016. It drilled one well in South Louisiana before moving to Texas to drill wells for WildHorse Resources around the College Station area," he said. "It was our introduction to the world of high-speed, horizontal, multiwell pad drilling operations, and Rig 11 is still working in the area today."

In 2018 EDC decided it was time to add a second high-horsepower rig to its fleet.

"Our idea was to find another 1,500-hp rig," Helbling said. "We couldn't build a new $25 million AC rig, so we went looking for one that we could upgrade while staying under cash flow."

California dreaming

EDC, having worked with Henderson previously on the sourcing and purchasing of rig equipment, contacted the supplier to locate, purchase and upgrade a suitable rig. The quest would take the companies to an abandoned weed-covered yard outside Sacramento, Calif., where a bank-owned rig had been sitting since being stacked in 2014.

"Due to its location in a drier climate, the rig and its equipment were in great shape," Workman said. "Everything from the drawworks to the engines to the mud pumps all looked brand new. When I stepped into

Three 1,600-hp, 7,500-psi mud pumps were added to Rig 16 as part of the upgrade. (Photo by Jennifer Presley)

The Rig 16 floor crew at work in Fayette County, Texas. (Photo by Robert Allred, courtesy of Henderson)

the SCR house, it felt like I was in a brand new one. We were expecting a nice rig but not one that was in such amazing condition."

In May 2018, Henderson entered into a contract with EDC to purchase and refurbish the rig.

Texas bound

Extensive communication between the companies ensured that the rig would be ready for shale drilling upon completion.

"We had many meetings to discuss their goals for the rig," Workman said. "We worked together to identify what the rig needed to be competitive in today's market, and EDC listened to our suggestions on what improvements were needed to make it ready for future upgrades."

With the arrival of the rig in Henderson's yard in Houston in June last year, the transformation began.

"We started with an inventory of the rig, and from there, it became an exercise in determining what would be needed to be competitive. It was a team effort," Workman said. "For example, we all agreed that a third mud pump was needed and that to compete in Texas, it would need to be a 7,500-psi pump."

The decision was made to add a National Oilwell Varco TDS-11 top drive due to easy access to spare parts and experienced technicians, he added.

"The walking system, third mud pump and top drive were the main things right off the bat," Workman said. "EDC mentioned they wanted three mud shakers as they felt it was something that gave them a competitive advantage, so it is set up that way. Also, the decision was made to go with PSL 3, 10M choke manifold after reviewing API [American Petroleum Institute] specs."

In another example, the contractor asked that the design and placement of the rig equipment be identical to Rig 11. Workman, in looking at the design saw a way to potentially reduce the number of truckloads it would take to move the rig.

"I noticed that their trip tank, choke, mud gas separator, flowlines and more would take about five truckloads to move and knew that we could reduce that number," he said. "I worked with our engineers on a couple of different designs and found a way to go from five loads down to three loads."

EDC liked the design and gave the green light to make the changes that included the installation of the mud gas separator and choke on a long tank skid, according to Workman.

"It is a design similar to what one would see on a high-spec rig. By reducing the number of loads, trucking costs are reduced, and that makes the operator happy. It's easier and faster to rig up and rig down," he said.

Rig 16, as it is now known, is an upgraded 2,000-hp drilling rig with AC top drive, three 1,600-hp, 7,500-psi mud pumps, a walking system, 9.1-m (30-ft) box-on-box substructure and 1-MMlb derrick with a 600,000-lb setback.

In October last year, Rig 16 moved out of the yard and began drilling wells on a contract basis for Ram Energy Resources in Fayette County, Texas.

Next steps

The step from Tier 2 to Tier 1 status for Rig 16 would be the installation of an AC drawworks. It is a step that by design will be easier to make in the future, according to Workman.

"We partnered with Hydraulic Systems Inc. in the development of the rig's walking system," he said. "In that process, we ensured that the hydraulic power unit was robust enough to not only support rig walking functions, but also to support switching to a drill mode to run the iron roughneck when it is installed at some future point. We have a spot, for example, on the MCC [motor control center] panel for the catwalk."

By preparing for these future enhancements in the yard, there are cost and time savings, according to Workman.

"Also, while developing the walking system, we installed an AC cable management system," he added. "We looked at the current SCR setup and worked with our vendors on the best way to prepare the rig for a future AC upgrade.

"Energy Drilling was very progressive in its thinking, in knowing that maybe its first AC rig isn't a newbuild but is Rig 16," he said. "They were willing to take the small step now in that direction to set themselves up for success in the future."

According to Helbling, Rig 16 can now do everything it needs to do while also taking the contractor one step closer to being an AC rig.

"If we'd have gone out and built this rig right away as AC, it would have cost us $25 million," Helbling said. "We did it for about $11 million, and with a further upgrade down the road, whenever that is, we'll be somewhere around $15 million. We decided that for us it was the best way to go." E&P

Smaller drilling contractors need to innovate and grow their business without busting their budgets to survive.

In-bit logging tool helps operators optimize drilling programs

A post-run analysis of data collected in the drillbit during drilling leads to improved drilling in challenging applications.

Ben Pontier, **Alamzeb Khan** and **Stephen Forrester**, NOV

The case has been made repeatedly over the past decade to better integrate data collection into drilling operations. While significant technology improvements throughout this time frame have yielded an abundance of tools designed to collect downhole data for post-run analysis, most of these tools do not capture data directly from the bit; rather, they are placed in a carrier sub or various positions in the bottomhole assembly (BHA).

For more than a decade, National Oilwell Varco (NOV) has been measuring high-frequency at-bit and in-the-bit dynamics to further optimize bit and BHA designs as well as to provide information on optimal running parameters. Continuous advances in downhole technology at NOV have resulted in the development and iterative improvement of a tool that can be placed in the drillbit to measure tangential acceleration and angular position, which results in axial, lateral and torsional vibration and RPM values. Knowing such parameters acquired directly at the bit allows operators to optimize their drilling programs for challenging applications where significant drilling dysfunctions require superior bit performance.

NOV's BlackBox HD tool is a memory-mode logging tool designed to help operators address common downhole drilling dysfunctions, such as stick/slip and whirl, by enabling better decision-making in future wells to improve overall drilling performance and reduce well delivery costs. The tool has no nonmagnetic requirements and a self-contained power supply, meaning it does not interfere with other electronics in the drillstring (Figure 1).

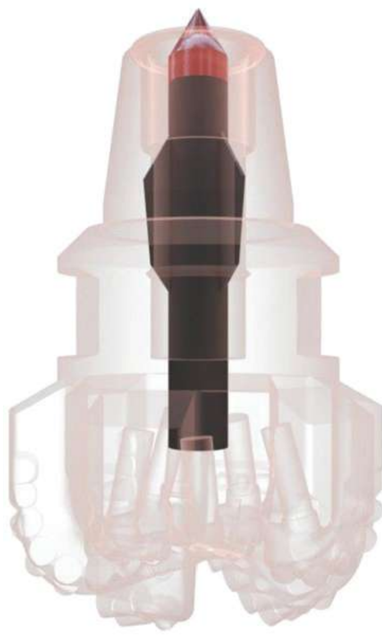


FIGURE 1. This image shows the placement of the BlackBox HD tool within the drillbit. (Source: NOV)

The tool records for up to 150 hours of battery life and captures high-frequency burst data at 800 Hz. These data are the core component of a drilling optimization service provided by NOV, with subject matter experts both on the rig and in NOV engineering technology centers analyzing the data and highlighting areas where parameters or designs can be changed to improve drilling performance and overcome dysfunctions.

Case histories

An operator in Kenya was drilling a challenging section through hard volcanic basalts. NOV's FluidHammer performance drilling tool offered a new method to fail the rock while maintaining high ROP through the volcanic basalts. The operator needed to achieve higher ROP without creating excessive damaging vibration, which would prematurely damage the PDC drillbit. The primary objective was to consistently drill the section through the volcanic basalts in one run, including drilling through the cement using the FluidHammer toolset with a bend to allow effective sliding and building to the tangent. The operator needed to validate that the section could be drilled with a PDC bit, as it had previously only used roller-cone bits, and that the FluidHammer tool would not cause excessive harmful vibration.

Data from the BlackBox HD tool at the bit revealed that the FluidHammer tool maintained axial oscillation within safe levels to maintain the PDC bit's cutter integrity, and lateral vibration decreased with the FluidHammer tool engaged and BHA oscillating axially. On this run the operator achieved on-bottom ROP of 18 m/hr (59 ft/hr) and a high ROP of 16.6 m/hr (54.4 ft/hr) through the volcanic basalts with the tool effectively engaging the volcanic section with no

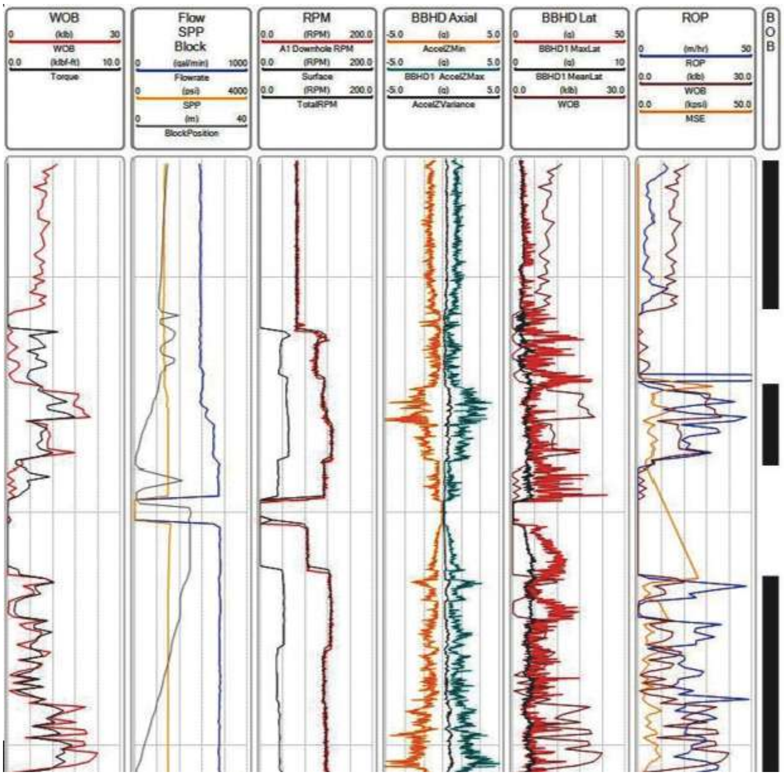


FIGURE 2. The drilling dynamics analysis of the section revealed that the FluidHammer tool was effectively engaging the volcanic basalts. (Source: NOV)

stick/slip. The bit dull came in with a positive result, and the higher ROP eliminated almost two days of drilling time (Figure 2).

In a different application, an offshore Congo operator was drilling long horizontals in its 8½-in. section and suffering from extreme vibration and poor directional control to the point of risking reductions in production potential. After running the BlackBox HD tool and conducting the associated optimization analysis service, NOV determined the root cause of the dysfunction and identified the service company's tools were experiencing full stick/slip.

During the slip phase, the dysfunction translated to apparent lateral vibration as measured by the slower speed data recorded on the service company's accelerometers. This occurred because the offset-from-center accelerometers were confusing radial acceleration (due to high and violent angular acceleration during the slip phase) with lateral vibration, causing the operator to reduce RPM and increase weight on bit (WOB). Though this was intended to eliminate the lateral vibration, the misconception exacerbated stick/slip farther, as the operator would have done the opposite—increase RPM and decrease WOB—if it had had the correct data. Once the operator ran the BlackBox HD, the data quantified the severity of the stick/slip and lack of lateral vibration. The data proved it was impossible for the rotary steerable system (RSS) to maintain toolface control during events with such high torsional vibration.

After running NOV's enhanced measurement system tool, which adds high-speed downhole WOB and torque-on-bit measurements, the operator discovered that the torque generated downhole from the bit/BHA was negligible; rather, most of the torque and drag came from the heavyweight drillpipe, which was causing the stick/slip. Raising RPM only increased the severity of the stick/slip, and decreasing WOB had little to no effect due to the lack of drilling torque, as most of the torque was coming from drag along the string. Realistically, small pipe in this extended horizontal application will almost always encounter such a problem, but due to equivalent circulating density limitations, running larger pipe was not an option.

Several options were explored to resolve the issue. However, after understanding the tool, parameter and equipment constraints, NOV determined that stick/slip could not be eliminated and it must simply be reduced to acceptable levels. The final solution was to maintain RPM below a certain range so that RPM would not exceed the RSS toolface control limit during the slip phase. This was accomplished even though RPM in the slip phase was exceeding top drive RPM speed by almost 200%. By remaining within the tools operating limitations even during the slip phase, the operator and service company were able to achieve their directional targets successfully. Understanding the root cause of the problem using high-frequency measurements inside the drillbit and along-string measurements allowed the best solution to be implemented.

Conclusion

The need for better forms of data collection and analysis has grown due to the challenges of unconventional wells. As continued oil pricing pressures necessitate greater efficiencies, drilling optimization will remain an important method of cost-effectively achieving business goals and operational success. Being able to collect high-quality downhole data and drilling dynamics information at the bit is one step toward proper drilling optimization, and the BlackBox HD tool has been making this a reality for a decade. E&P

Rig reactivation prompts tackling the rising risk of dropped objects

Dropped objects are one of the most frequent HSE safety incidents reported, and the changing oil and gas landscape threatens to increase the risk.

Mike Rice, Dropsafe

Years of low oil prices meant that a large number of drilling rigs were stacked for storage, especially in areas such as Asia, where major Singapore shipyards took in semisubmersible rigs and drillships from drilling sites around the world, including from Brazil and Mexico, in 2016.

Now the market has seen a significant upturn, with the price of oil back to about $60/bbl and natural gas predicted to provide up to 45% of power generation during the next 20 years. Drilling rigs are being reactivated to meet increasing market demand. However, this return to work also brings with it substantial commercial pressures for drilling contractors, given significant costs associated with bringing rigs out of retirement and back into operations. In a period of narrow margins, financial risk mitigation is essential.

A smooth transition for rigs back into operations may be jeopardized by damage sustained during the time spent out of action. Although rigs are meant to undergo regular maintenance while stacked, this is often not the case in reality due to the economic strain experienced by contractors. Reactivated rigs often have suffered damage from harsh weather, rust and corrosion, compromising their structural integrity.

The Dropsafe steel pouch encloses and tethers an engineer's communication device. (Source: Dropsafe)

Corrosion sustained by vessels and offshore infrastructure during periods of inactivity without maintenance is likely to elevate the risk of dropped objects. Additionally, cost pressures resulting from "boom and bust" cycles, combined with the drive toward life extension and increasing personnel turnover, may ultimately impact the sector's ongoing response to health and safety challenges.

These factors may contribute to a substantially increased risk of dropped object incidents, posing a real threat to the safety of engineers and the integrity of the equipment. As the industry returns to work, the crucial issue of dropped objects must be placed high on the list.

Scale and nature of the challenge

Dropped objects are one of the most frequent incidents reported both onshore and offshore. The Dropped Objects Prevention Scheme industry initiative cites dropped objects as a top 10 cause of injuries and fatalities in oil and gas operations. This is reflected in a report from a major oil and gas company that stated dropped objects caused 68% of its high potential incidents.

Dropped objects come in many shapes and sizes, and objects may fall for a variety of different reasons. Incidents are considered either static or dynamic. As the name suggests, static incidents include fixed objects, such as lights and closed-circuit television cameras, that fall from height possibly due to the failure of the mounting bracket caused by corrosion, vibration or poor maintenance. Should they fall, the size of these objects threatens not only personnel safety, but also critical equipment in the potential impact zone.

Dynamic dropped objects include hand-held items carried around by personnel, such as tools, hand-held radios and gas detectors. Personnel working at height, in a derrick or on a raised walkway, are at risk of dropping these objects, which can cause injury or a possible fatality.

The number of reported incidents of dropped hand-held tools is significant, and the true scale of this threat remains unclear, as many incidents and near-misses are unlikely to be recorded. This issue poses a significant threat to both the safety of personnel and the legal, financial and reputational standing of energy companies.

Fleetwide self-regulation

Oil and gas majors and drilling contractors are not only becoming increasingly aware of the dangers of dropped objects but are starting to take fleetwide actions to protect personnel and equipment. Some firms are already showing this proactivity in self-regulation. One major company recently shut down fleetwide operations to provide dropped object risk mitigation best practice training to all staff and engineers.

An adoption of secondary securing nets, retrofit barriers on guard railing and pouches or tethering for hand-held objects is becoming standard practice on many rigs and drillships. A stainless steel mesh net, for example, tested to greater than the product safe working load, will hold fixture mounting brackets in place and prevent fixtures from scattering shrapnel upon impact, reducing the risk of further harm to personnel.

A proven solution to preventing hand-held object drops is the use of a stainless steel mesh pouch that can secure items and be attached to an engineer working at height. A custom-designed pouch for use in extreme weather conditions fully encloses and tethers the item to the user, effectively preventing an incident from occurring.

Additionally, rig managers have the technology available, such as lightweight mesh barrier systems, to act as a preventative measure against drops. These are less prone to corrosion, easier to inspect and also save time and money throughout both installation and maintenance when compared to barriers made of cladding or fabric, which have previously been used along walkways on rigs.

The adoption of high standards and technical safety solutions across the board could ultimately enable drilling contractors and other players to cultivate a reputation as a premium service offering and benefit from more sustainable day rates. Additionally, project managers can take control of tailoring safety solutions to individual rigs, rather than allowing external regulations to limit the cost-efficiency of implementation and effectiveness of robust technological risk mitigation solutions.

Tackling the issue of dropped object risks head on will allow operators to set themselves apart from a reputational standpoint while mitigating the risk of injury to personnel and costly damage to equipment. It also will help to ensure the success of the industry as it returns to work. Investing in robust dropped objects mitigation during this high-risk period, while it may constitute an immediate cost, may make a huge difference in the long term.

While the oil and gas industry is currently seen to be leading the way in proactive mitigation of this prevalent issue, it is imperative that this rate of progress is maintained as rigs are reactivated and the market continues on an upward trajectory. E&P

Controlling solids on multiwell pads

Technologies are supporting shale well pad advances.

Even Gjesdal, Cubility

Few would dispute the significant advances shale operators have made over the last few years when it comes to technology developments and the impact on profit margins.

Chief among these advances are the technologies at the well pad and the rise of multiwell pad drilling. The market for multiwell pad drilling technology is expected to surpass $180 billion by 2024, according to a report by Global Market Insights, with the accompanying technologies related to drilling, completions and production enabling multiple wells to be effectively activated from a single drillsite.

The impact on the bottom line is also significant. Today rigs can be mobilized in just a matter of days rather than weeks with unconventional operators understandably frustrated if there are any delays. At a time when there is a greater focus than ever on profits, margins and reduced costs, multiwell pad drilling could not have come at a better time.

However, for well pad drilling to operate at its full potential, there is a need for accompanying technologies to meet the same requirements well pads demand. These criteria include a light environmental footprint, quick and flexible installation as well as the ability to deliver returns in a matter of days, which can be particularly challenging.

Some technologies, however, have struggled to achieve this. One of those operations is solids control.

Importance of solids control

There is little doubt as to the importance of solids control in shale operations. The cost-effective and efficient handling of waste in unconventionals (i.e., everything from drilling cuttings to spent mud to flowback water at the fracturing stage) is vital and central to a company's license to operate.

However, solids control technologies are equally important at the drilling efficiencies level. The effectiveness of drilling fluids or muds—and their many roles in cooling and lubricating drillbits, carrying drill cuttings to the surface, and controlling pressures and formations—are highly dependent on the ability to separate the mud from rock particles. That way, clean mud can be recycled and circulated back into the drilling system to support drilling efficiencies.

Given the importance of their role, traditional solids control technologies are struggling to provide the lean, immediate return on investment focus that today's shale pad operators demand.

For example, traditional shale shakers tend to be unwieldy and expensive, with the need for the screen panels to be continually replaced at significant cost and man-hours spent.

There are also size implications on already crowded well pads. One screen panel weighs about 22 lb and a three-deck has up to 16 panels giving a total of 353 lb per shaker. This does not take into account the costs

The MudCube has been deployed in a number of shale operations including with EQT Corp. in the Marcellus Shale. (Source: Cubility) and space and weight of secondary equipment, such as drying shakers, cuttings dryers and centrifuges, which all result in more onsite equipment, personnel and potential HSE risk at the well pad.

This, together with the inefficiencies of the shale-shaker-based process itself that uses more solids in the drilling fluid than necessary and higher volumes of mud being lost, seem an unsuitable companion for today's lean and flexible well pad technologies.

Cubility has developed the MudCube, a compact, lightweight solids control system that uses a vacuum-based/rotating screen filtration system. Compared to the 22-lb shaker screen panel, the MudCube rotating filter belt weighs only 6 lb.

Drilling fluids are cleanly separated from drill cuttings by the combination of high airflow, vacuuming the cuttings clean, and micro vibrations that direct all g-forces to the particles instead of surrounding structures. The results are clean drilling fluids that are returned to the active mud system and the drilled solids carried forward on the filter belt for disposal. As much as 80% more mud is recovered than competing technologies—a significant benefit when taking into consideration the large number of rigs and wells shale operators deploy.

Operator deployments

The MudCube has been deployed in a number of shale operations, including with EQT Corp. in the Marcellus Shale in western Pennsylvania and for Murphy Oil in Canada.

In the Marcellus, the size and weight of each MudCube offered an array of options to meet EQT's demands for a particular pad. As an additional benefit, the setup was also very clean compared to normal shaker operations, helping to keep rig cleanliness at an all-time peak.

However, it is with the continued demands for rapid deployment on well pads, limited space and manpower, and fast mobilization/demobilization requirements that Cubility has launched the MudCube X. The MudCube X comes with an enhanced modular design allowing integration into all rig designs and fast installation and maintenance so that the MudCube X is up and running and delivering immediate value to shale operators.

Also, as opposed to shakers, the MudCube X processes 100% of the mud, thereby immediately increasing performance. The MudCube X also is engineered for local manufacturing and assembly worldwide.

Cubility also has teamed up with Stage 3 Separation (S3S) to incorporate the MudCube into Stage 3's modular S3S Performance Platform for onshore shale operations. Through the platform, the MudCube is again easily and inexpensively installed in rigs and well pads with minimal impact on ongoing operations. E&P

The MudCube is a compact, lightweight solids control system that can be added to existing operations. (Source: Cubility)

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*.

Hybrid wellbore cleanup tool achieves a century of runs in Saudi Arabia

Tool performs isolated negative inflow tests on liner tops and casing shoes.

Ian Spence, Coretrax Technology Ltd.

Once a well is drilled and the casing is run and cemented, an efficient and immaculate wellbore cleanup operation is paramount as it can make a huge economic difference to the success of the production and completion phases. Within this cleanup process, liner tops and casing shoes are tested to confirm well integrity.

Coretrax, an independent wellbore cleanup and abandonment specialist, has created a robust wellbore cleanup product line that includes applications for HP/HT, extended-reach drilling and multilateral projects. Along with nonrotating scrapers, brushes, magnets and circulating tools, the company deploys its Liner Top Test Tool (CX-LTTT) to provide assurance of well construction before a completion is run.

With pressure in the formation and the removal of what is essentially a barrier of heavy fluid, this intentionally creates a weak point, often at the liner top. Therefore, it is necessary to test integrity through simulation with a packer.

The CX-LTTT is designed to perform isolated negative inflow tests on liner tops and casing shoes. When teamed with various other wellbore cleanup tools, it can be used as part of a single trip wellbore cleanup and displacement run. It works by setting down weight to compress and extrude the elements. The large bypass facilitates quick running speeds when running to depth. Capable of combining the cleanup, displacement and inflow test operations in the same run, the device is a proven and reliable inflow test packer.

The LTTT-HD in the Coretrax wellbore cleanup string creates an efficient and effective one-trip system. (Source: Coretrax)

Enhanced wellbore cleanup

Drilling through multiple types of materials like cement, shoe tracks and plug sets have traditionally been carried out over multiple trips in the hole. Due to the high volumes of debris created over each run, this can potentially have a detrimental effect to the liner top packer.

On the request of a major operator in the Middle East to design a heavy-duty tool that can deliver further rig time savings, Coretrax developed the CX-LTTT (HD), a cement drill-out device. This enhanced version of the LTTT was designed for all inflow test applications to include situations where there is a need for drilling through cement, plug sets, float collars and partial shoe tracks. This determines the integrity of the liner top before the next section is drilled.

Wellbore cleanup has traditionally been an operation where the environment needs to be devoid of large pieces of debris that can damage the string. With additional debris generated through the drillout of cement and various types of metal, there was an increased need for a heavy-duty packer to use in these applications. Following extensive research, analysis and testing over three months, the Coretrax in-house engineering and design team added a robust, purpose-built packer to the wellbore cleanup assembly to allow inflow testing to be performed concurrently in this harsh environment.

Several technical and safety challenges were apparent, including long drilling hours of about 30 hours, circulating large pieces of debris past the packer element in a high flow-rate environment and working across different metallurgies in the shoe track.

The tool is designed with a large concentric bypass that allows quick running speeds and a generous flow area passed the tool to achieve high flow rates, essential for recovering the debris out of the hole and minimizing the risk of damage to the packer.

Case study

Over two years, the CX-LTTT (HD) has achieved a substantial run history for operations in the Middle East and has delivered excellent results for the operator. In early 2017, the CX-LTTT (HD) device was used for cement drill-out operations and inflow testing of a 7-in. 32# liner. The cement was tagged at 3,629 m (11,905 ft) measured depth and drilled out along with the landing collar and float collar to a depth of 3,746 m (12,291 ft) measured depth. Over a period of 12 hours, 118 m (386 ft) were drilled.

The hole was circulated clean before landing the tool on top of the 7-in. liner at 3,502 m (11,490 ft) and setting down 35,200 lb to shear and function the tool. Over 10 minutes, a backside pressure test of 1,000 psi was completed confirming the integrity of the device.

The packer was then unset and freshwater was pumped to achieve a final drawdown pressure of 4,400 psi. When set down with 30,000 lb, the pressure was then bled off in stages of 500 psi to perform the inflow test, which was plotted on a Horner graph per the client's procedures. Once the test was confirmed as successful, the drillstring was pressured to 4,400 psi and the device unset and pulled out of the hole.

This one-trip hybrid tool string now saves the operator about 30 hours of rig time per job and has been utilized in challenging conditions, including being successfully set at 5,334 m (17,500 ft) with a well inclination of about 74 degrees.

In the initial three-month period of bringing the LTTT-HD to the market, Coretrax has successfully performed eight inflow tests. Of these, seven were cement drillouts and one was a conventional wellbore cleanup and inflow test. By combining the inflow test with a cement drill-out run, the CX-LTTT (HD) saved about 480 hours (20 days), which equates to a further financial saving of $1.2 million. To date, the company has successfully reached more than 100 well runs, saving the operator more than 3,500 hours of rig time and about $9.2 million in costs. E&P

New treatment options for well restimulation

Huff-and-puff technology revives existing wells.

Robin Watts, Linde

As the race continues to complete new pipelines linking the Permian Basin to the Gulf Coast, operators are reviewing strategies that can maximize returns once the spigots open. Staking claim for new wells is the primary strategy. However, there are tens of thousands of existing wells, including marginally producing ones, that are worth a fresh look, and they may deliver more expedient returns.

During the past decades, second-generation huff-and-puff (HNP) treatments using CO_2 or nitrogen (N_2) have delivered a step change in performance versus traditional steam methods (Figure 1). An energized HNP treatment that uses nanoparticle technology, nanoActiv HRT by Nissan Chemical America, offers the potential for use in a wide range of the more than 1 million active wells in the U.S.

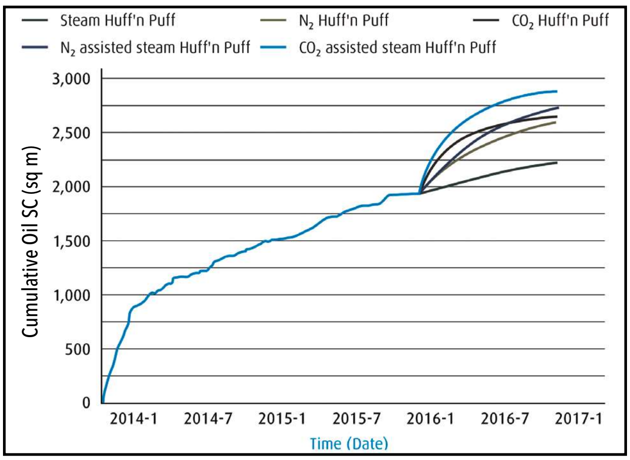


FIGURE 1. The chart depicts the impact on production of several new types of HNP treatments since 2014. (Source: Linde)

Known as RECHARGE HNP, an enhanced hydrocarbon recovery treatment, the technology was jointly developed with Linde LLC and Nissan, and formally announced at the Unconventional Resources Technology Conference in July 2018. The new treatment has generated double- and triple-digit increases in daily production rates for oil and gas wells since 2016. Like traditional HNP, the treatment consists of three phases: injection, soaking and production. However, experience indicates soak times can be reduced to speed payback to 60 to 90 days or less on select wells.

How it works

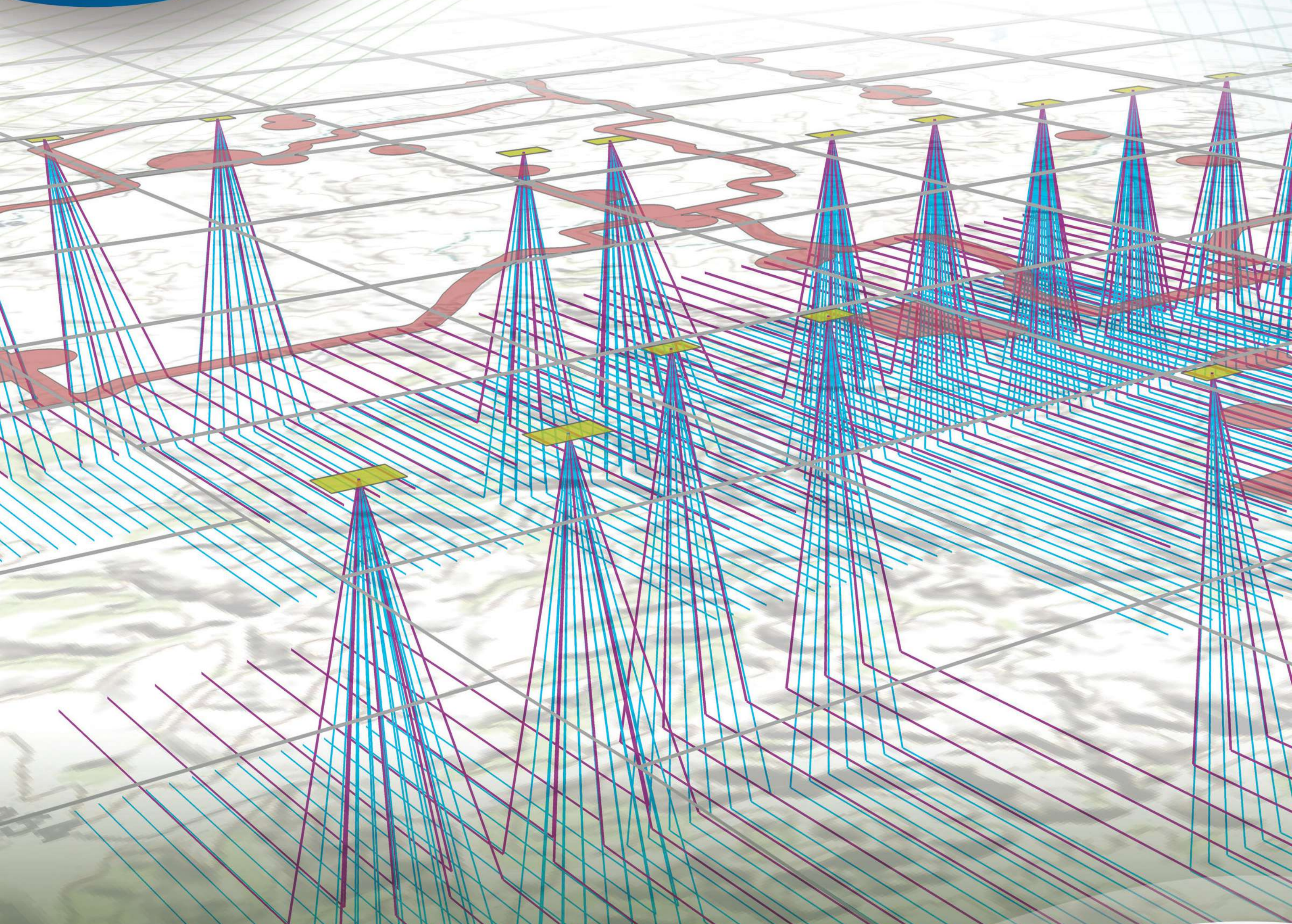
CO_2 or N_2 is used to drive proprietary nanoActiv HRT nanoparticles farther into the formation and enables them to penetrate deeper into the capillary fractures and micropores of the rock. The gas works synergistically with the Brownian motion of the dispersed particles, which wedge between rock and oil, releasing additional hydrocarbons.

The new technology can address multiple downhole problems simultaneously in almost any type of existing well or formation. It can be effective in virtually any U.S. oil- or gas-producing region from the Permian Basin to the Bakken reserves in North Dakota. Because the multispectrum treatment is also low cost, it can create new opportunities wherever existing wells are starting up again.

If an operator manages 300 wells, for example, and can treat each one for a fraction of the cost of refracturing, that represents a low-risk proposition, especially when the investment could be recouped on many of those wells in less than 90 days. While there is no production guarantee, every well treated to date has responded. Once a well responds, it can be treated repeatedly as long as residual returns meet the operator's goals.

Figures 2 and 3 show cumulative results for both high- and low-dose treatments on two horizontal openhole completions in the Austin Chalk and Buda formations in central Texas, monitored for 180 days. Production improvements in barrel of oil equivalents ranged from 12% to 174% in the Austin Chalk (Figure 2) and from 30% to 564% at the Buda wells (Figure 3). (A fifth well, a shut-in treated at a fractional dose and with a high water cut, did not generate appreciable levels of oil for 160 days, and then produced a 20% uptick.)

As the chart indicates, the high-dose wells produced substantially higher returns. There was also direct correlation between dosage rate and duration of response. Since



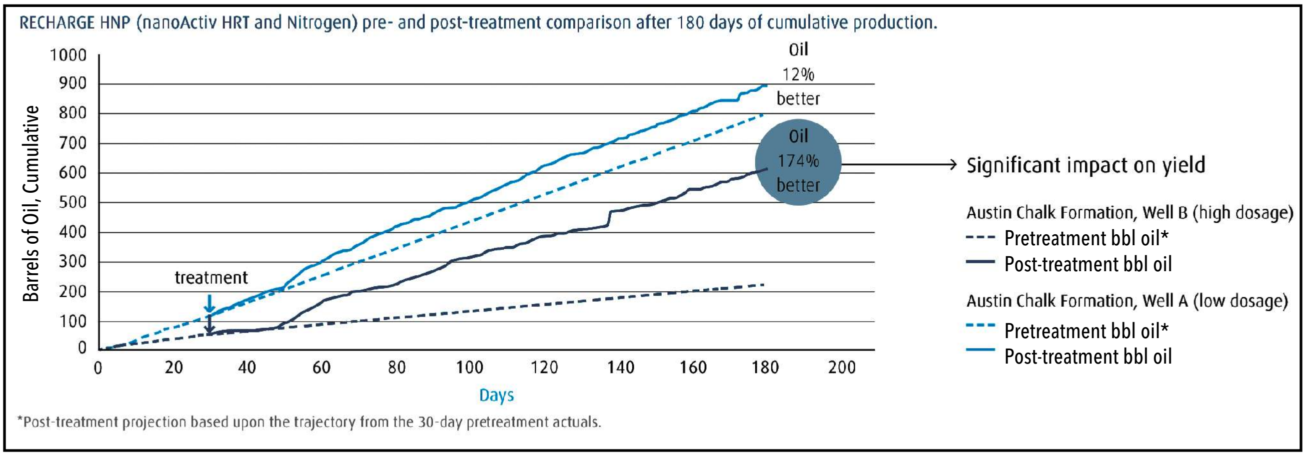


FIGURE 2. The chart reflects cumulative oil production for the Austin Chalk wells before and after a RECHARGE HNP treatment (with N_2 and nanoActiv HRT nanoparticles). (Source: Linde)

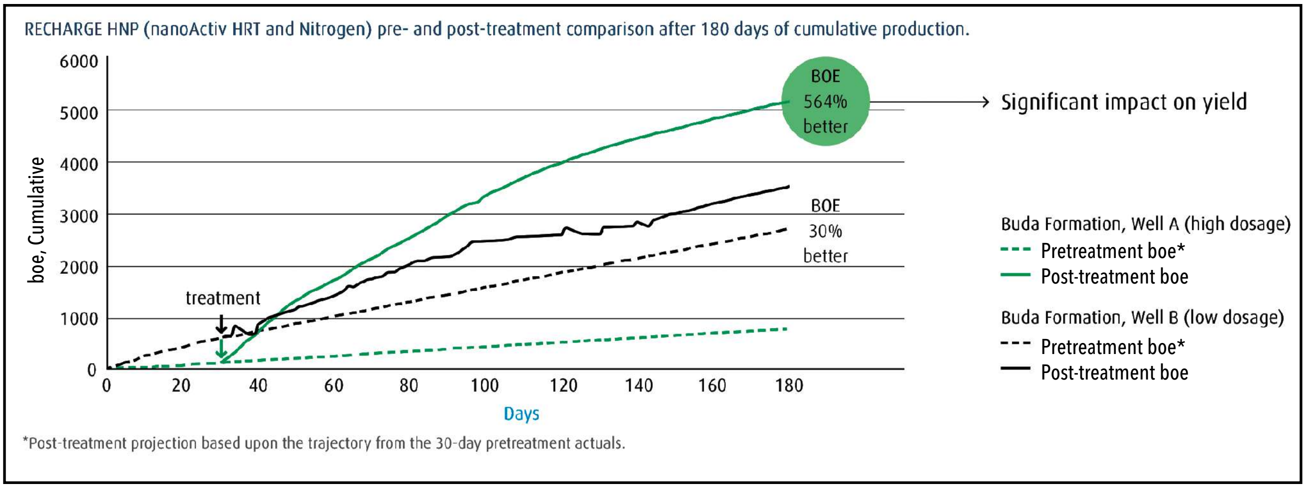


FIGURE 3. The chart depicts cumulative barrel of oil equivalent production at selected Buda wells before and after RECHARGE HNP treatment (with N_2 and nanoActiv HRT nanoparticles). (Source: Linde)

the initial treatment, all the high-dosage wells have produced above their starting levels for more than two years.

Linde's oil and gas services team considers any well that produces a net gain within 180 days after treatment successful. The new technology also can help operators even if their goal is not immediate payback. Those managing marginal wells, or even those with slightly or moderately negative returns, are often more interested in postponing completion costs or at least narrowing losses. The new HNP treatment can be applied this way—and may generate bonus returns that exceed breakeven for months or potentially years.

For most existing wells, though, rapid payback is the primary goal. The main challenge is how to evaluate wells for treatment and payback potential. Toward that end, the accompanying sidebar lists screening criteria for wells most likely to deliver payback within the first 60 to 90 days.

The RECHARGE HNP treatment can be effective on wells that do not meet all the rapid-payback criteria. Each well is individually assessed and prescribed the recommended treatment by Linde and Nissan. Part of the reason the treatment has been so successful to date is that both the gas and the nanoparticle are relatively benign to the rock and well conditions. The treatment can work, for example, whether the well is water-wet or oil-wet or the rock formation is limestone, sandstone, shale or a mixture.

However, it is important to be aware of conditions that can negatively affect the nanoparticles—in particular, acids and very high total dissolved solids. These conditions should be avoided but can be overcome. If a well recently underwent an acid job, for example, then a flush with a freshwater pill before injecting the nanoparticles downhole is essential before treatment. A water pill before the nanoparticle dose also can help clear any concentration of dissolved solids near the wellbore.

The new energized HNP treatment offers plays for both conventional and unconventional wells.

Conventional wells

Operators dealing primarily in older fields might be managing many vertical wells that are marginally economic. At the tail end of production, operators can delay the cost of plugging, which could be $15,000 to $20,000 per well, and deploy capital elsewhere. The new HNP treatment can treat multiple wells in a day for less than the cost of completing a single well.

At the other end, operators might have vertical wells producing moderately well but that could use a workover. The energized treatment can eliminate blockages due to fines migration and clay swelling. It offers a relatively low-cost method to clean near wellbore to get the well flowing again.

Unconventional wells

One method to restimulate or enhance recovery of unconventional wells is refracturing. Production of these wells typically declines by 75% to 95% after 12 to 18 months. During the past five years, operators have reviewed their options for unconventional wells. Acid jobs, which are common and relatively inexpensive, carry their own risks and limitations. Operators could refracture, which is expensive and imprecise, or they could treat with RECHARGE HNP at about 10% of the cost of refracturing. If the rock has more oil in place that can qualify for recovery, then this treatment offers potential with low risk.

In conclusion, the effectiveness of the treatment depends on both the gas and the nanoparticle as well as the prescribed dosing and pumping sequence for each well. The choice between CO_2 and N_2 generally depends more on delivery costs than on any real difference in performance, and the gas might come from any supplier. However, the prescription for the new treatment must be defined by the technical team. This is based on treatment goals, available site data and a growing bank of oil and gas well experience. As RECHARGE HNP treatment is deployed across more wells, that field feedback will be used to enhance predictability and performance further. E&P

References available.

Well screening criteria for rapid payback

These criteria help identify existing wells most likely to generate a payback within 60 to 90 days after RECHARGE HNP treatment. Wells do not have to meet all criteria to benefit. Treated wells have typically produced results over extended periods.

Production

A good IP with a gradual decline curve indicates continuous well depletion and wettability issues. Current production should be less than 10% to 20% of IP, preferably more than 5 to 10 bbl/d (greater than 20,000 scf/d).

Field data

Well performance should be on par with other wells in the field. "Thief zones" and extensive fractures need to be understood.

Treatments

Acid and other past chemical treatments may negatively impact properties of nanoActiv nanoparticles (pre-wash required).

Well equipment

Pumps, linings and gaskets must be in good mechanical condition to ensure proper pressure levels and treatment.

Water

Excessive salt content (e.g., potassium chloride) and total dissolved solids may negatively impact the nanoparticles.

Water cut

Less than 80% with N_2 or less than 90% with CO_2 is ideal, and the dilution rate may increase with greater treatment dosages.

Net pay zone

The net pay zone should be greater than 30 m (100 ft) vertical to optimize 60- to 90-day payback.

Porosity

Porosity should be greater than 8% on conventional wells or greater than 4% on unconventional wells.

Oil

Oil gravity should be less than 30°API, CO_2 preferred. Avoid asphaltene precipitation conditions. ■

Machine learning for better wells

System enables data conditioning and direct access to curve data.

Fred Jenson, CGG GeoSoftware

Machine learning is rapidly becoming a standard technology within the oil and gas industry. This is especially true in petrophysics, where Big Data tend to need more efficient and faster data analysis.

The term "machine learning" was coined in 1959 by Arthur Samuel and can be defined as data-driven predictions of behavior rather than rule-based algorithms. Essentially, it is a computer science that uses statistical techniques to give computer systems the ability to learn with data and without being explicitly programmed.

A simple example is to record many measurements of the time required for objects of differing attributes to fall various distances and then build a predictive model using linear regression. This predictive model would not be based upon the theory of gravity or the gravitational constant. Instead, through many observations, the model would learn the underlying order in the data. Supplying more data to the model would increase the model's accuracy. Thus, machine learning models should improve and become better over time as more data become available.

Two common types of machine learning for petrophysics are multilinear regression and clustering. This article focuses on the clustering of data to determine facies, a description of distinguishing rock characteristics.

Data clustering

The two types of clustering analysis are unsupervised and supervised. Unsupervised clustering organizes data into classes that have high intra-class similarity and low inter-class similarity and no defined target attributes. Supervised learning discovers patterns in the data that relate input data to a target attribute. An expedient way

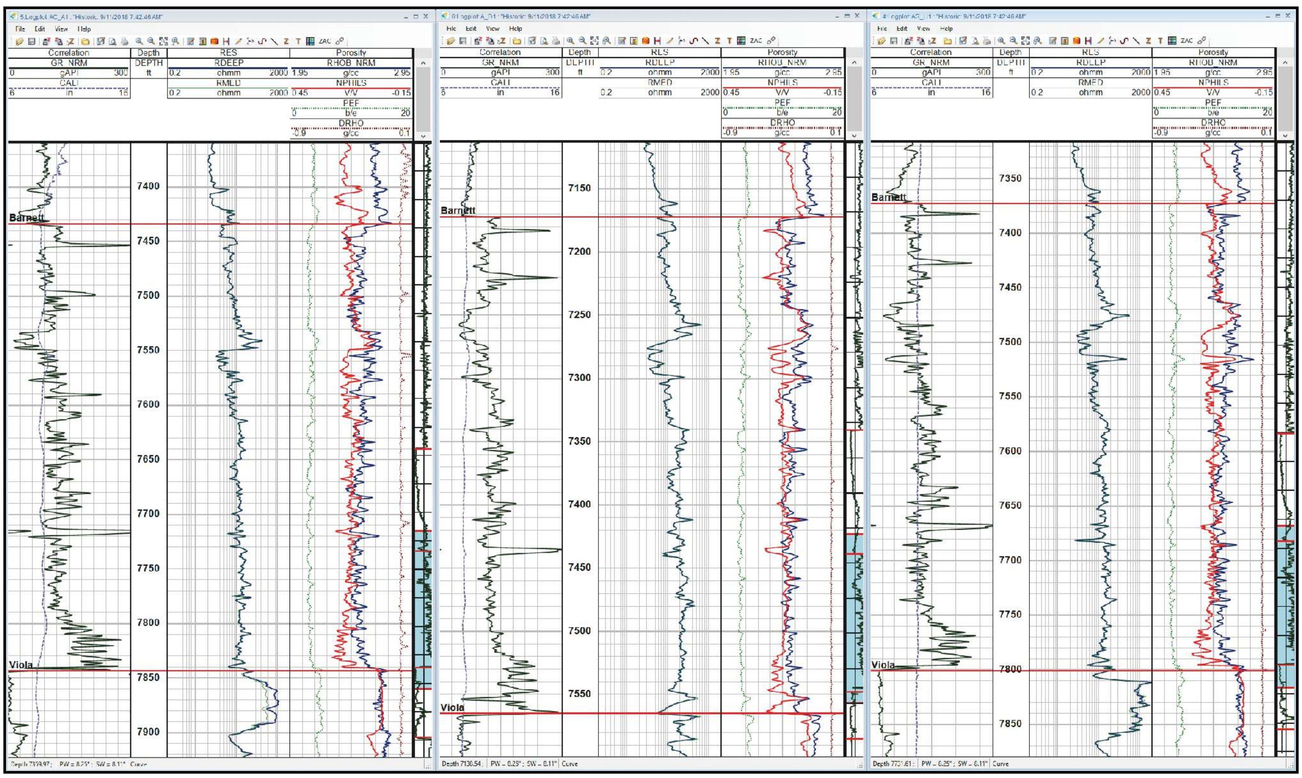


FIGURE 1. The normalized raw curve data: gamma ray, deep resistivity, density, neutron and PE curves were used in clustering analysis for the Barnett Formation. (Source: CGG)

of conducting facies classification over a large number of wells would be to perform unsupervised analysis on selected wells and then use the results as a facies target log to run supervised classification.

Unsupervised classification is far more compute- and memory-intensive than supervised classification, so it is impractical today to generate unsupervised facies on hundreds or thousands of wells.

Cluster analysis

Machine learning for data preparation requires petrophysical software, and CGG's PowerLog Ecosystem was the petrophysical platform used in this analysis. Environmentally corrected, normalized and depth-shifted input data are needed to ensure valid interpretation results. The system enables data conditioning and direct access to corrected curves and other curve data along with tops, zones, zone parameters, and other project and well data. This facilitates the machine learning process by eliminating difficult data export, editing and formatting required for machine learning when using other petrophysical software.

Python is an open-source interpreted language used for writing code to perform machine learning. Python has utilities and programs that include hundreds of scientific calculations, data analysis and visualization libraries. The interpretation example in this article uses Jupyter as the Python Interpreter for developing the clustering workflows. Jupyter is a web-based interactive application that is easy to use and has numerous features that make it ideal for modeling missing log curves and using data clustering for facies classification.

In this example it was used to perform an unsupervised classification for generating facies for a set of well logs. A "Gaussian Mixture" method was selected to generate facies in the Barnett wells used in this example. This method supports irregularly shaped clusters that are commonly observed in log curve data in unconventional reservoirs.

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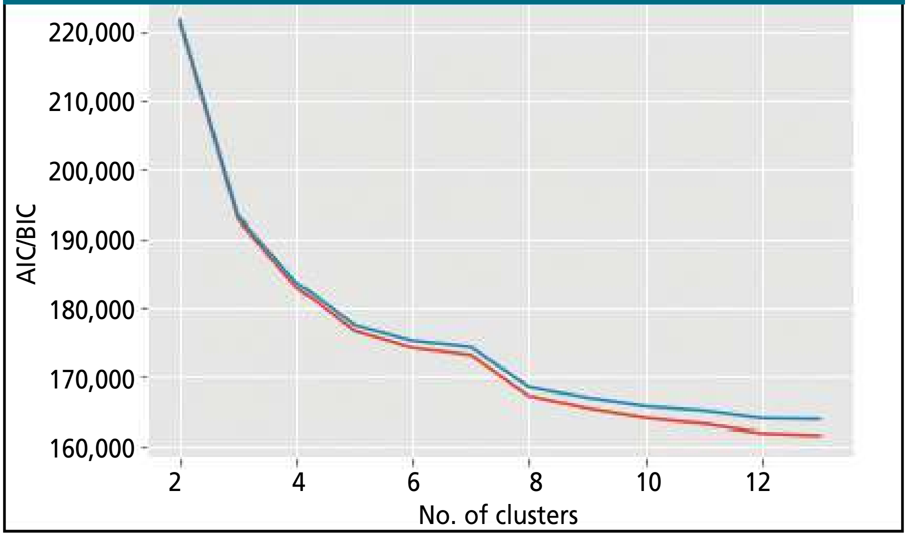


FIGURE 2. This visual representation shows the number of clusters (horizontal axis) versus the size of clusters (AIC/BIC vertical axis). (Source: CGG)

The analysis uses wells from the Barnett Formation of North Central Texas, and all the boreholes have a reliable and complete suite of well logs. A sample of the well data used in this interpretation is presented in Figure 1. A key decision to be made when clustering data is which input curves to use in the analysis. The requirement for input curves is that they exist on all wells and provide coverage over the zones of interest. The curves used in this analysis are the bulk density log, neutron curve, gamma ray, photoelectric factor and logarithm of the resistivity. The logarithm of the resistivity is a superior input for classification as it does a better job at the lower resistivities, where variations in the measurement are more significant.

> The potential for machine learning to improve understanding of wells, reservoirs and producing fields is virtually unlimited.

To neither overfit nor underfit and bias the model, it is important to choose the number of clusters that will properly represent the facies in the Barnett wells being evaluated. This method includes two information criteria that help optimize the number of clusters to best fit the data, as shown in Figure 2.

The inflection points on the plot indicate where the benefits of additional clusters do not add to the characterization of the data. The leveling off of AIC/BIC curves at nine clusters, as shown in this plot, corresponds to a model that adequately characterizes the

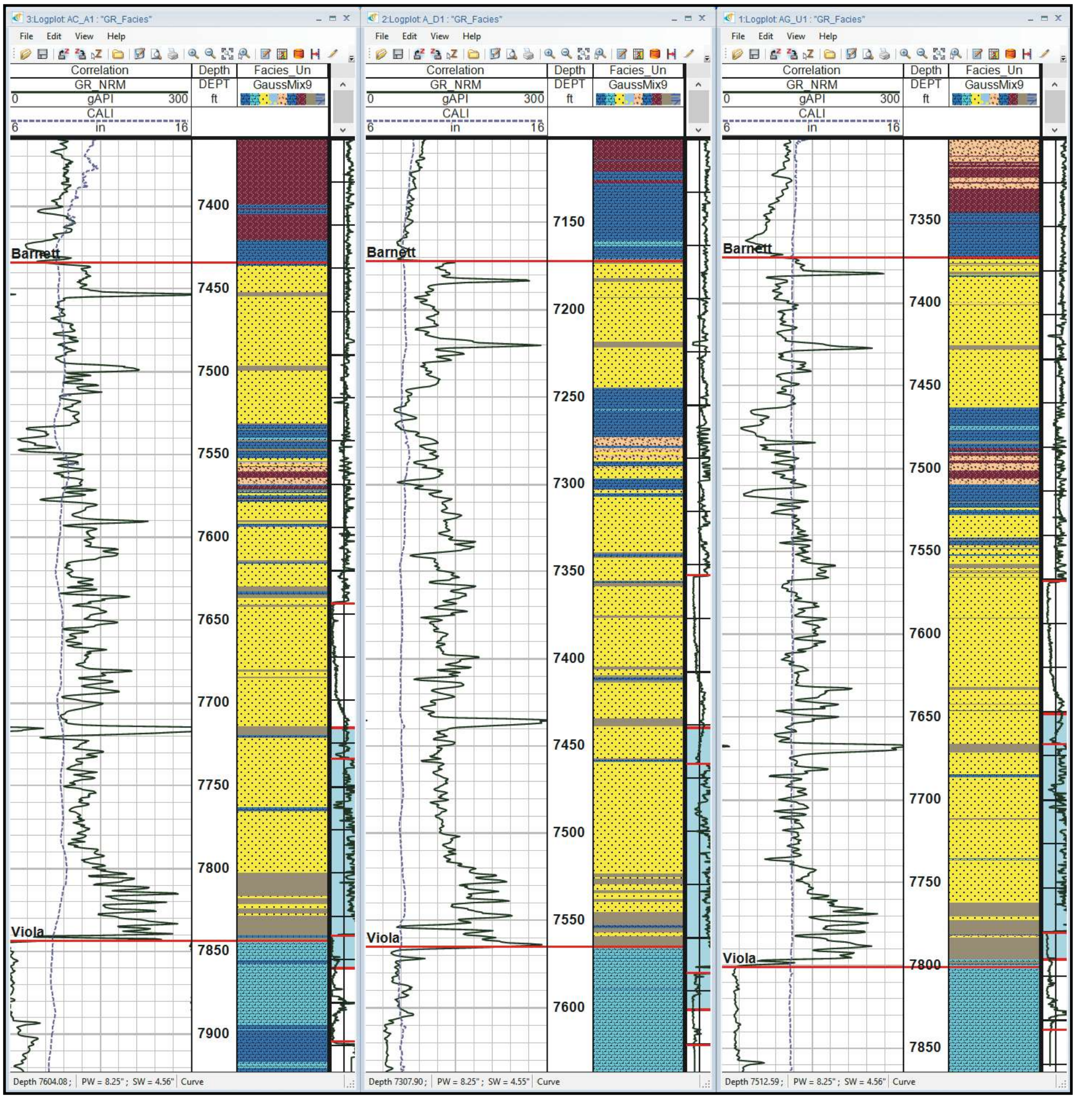


FIGURE 3. Facies determination by the Gaussian Mixture clustering analysis was used for selected wells across the Barnett Formation. (Source: CGG)

facies described by the Barnett well logs. The Jupyter workflow using Gaussian Mixture and generating nine clusters was run on selected wells in the project, and results are displayed in Figure 3.

Consistent results generated from well to well provide confidence in the validity of the analysis. The carbonate interval (dark blue and light blue sections) in the Barnett is easily identifiable as the Forestburg limestone, the dividing marker between upper and lower Barnett sections. The higher kerogen sections of the lower interval are correlated with grey facies and the high-quartz sections with the yellow sand facies. These facies results are consistent with prior knowledge regarding the Barnett Formation geology.

This machine learning unsupervised cluster analysis of selected wells in the Barnett and surrounding formations has been generated and evaluated, and various clustering packages were tested before selecting the Gaussian Mixture. The large number of methods available, along with the ease of use, makes this system the preferred platform for clustering analysis and other machine and deep learning workflows. Geologists can use clusters associated with specific facies to aid in correlating wells and picking tops, and geophysicists can use the facies logs to determine the accuracy of seismic inversions and to calibrate inversion results to specific facies. Quantitative seismic interpreters frequently aim to use 3-D seismic data to determine facies and calibrate the process to well log-determined facies, and engineers can use facies to aid in selecting stage intervals in multistage frac designs where limiting a stage to a single facies will maximize frac efficiency.

Machine learning and deep learning are technologies with multiple applications in oil and gas. Using this system for clustering petrophysical data is just one example of applying machine learning to gain better reservoir understanding. This can significantly improve completion design and help E&P companies drill more productive wells. The potential for machine learning to improve understanding of wells, reservoirs and producing fields is virtually unlimited, and to some extent, it all begins with well log data. E&P

Using the drillbit as a sensor

A new technology provides real-time information about a formation boundary at the point of transition.

Richard Stevens, AnTech Ltd.

The need for optimal wellbore placement to maximize recoverable reserves is a given, and engineers have always harnessed the available technologies to do this. However, the technologies have fallen short of the optimum, impacting productivity and profitability. RockSense provides at-bit bed boundary identification, giving engineers real-time information about a formation boundary at the point of transition. The technology turns the theory of mechanical specific energy (MSE) into practice. This article reviews what this new technology can achieve in practice using two historical datasets, both based on the availability of conventional logs from adjacent wellbores for corroboration.

The first dataset is from a coiled tubing (CT) drilled sidetrack of a well in a densely drilled site in North America. No horizontal wells had been drilled in the area previously, and the objective was to increase production through increased reservoir contact.

The operator used 3-D seismic to evaluate the formations and identified a subsurface ridge that could be acting as a trap. The well path was planned to pass about 4.5 m (15 ft) below the formation top and track the formation by holding inclination. The oil-water contact was believed to be 12 m (40 ft) below the formation top and, if entered, would significantly impact the well economics. Gamma ray sensors were used for depth correlation because relying on seismic depth alone would not provide the accuracy required. The hole section was drilled using a single phase fluid in the build section.

Running RockSense on the data gathered during this job revealed compelling similarity in the shape of the density logs and the RockSense trace when plotting porosity against true vertical depth (TVD) (Figure 1).

The second dataset involves underbalanced CT drilling in a shale gas well in the U.S. (Figure 2). In this instance, a 4¾-in. lateral was drilled using a mixture of up to 40% nitrogen to minimize formation damage. The aim was for the wellbore to stay within an identified formation layer. Processing the historical data using RockSense identified substantial footage drilled below the target formation. If the technology had been used

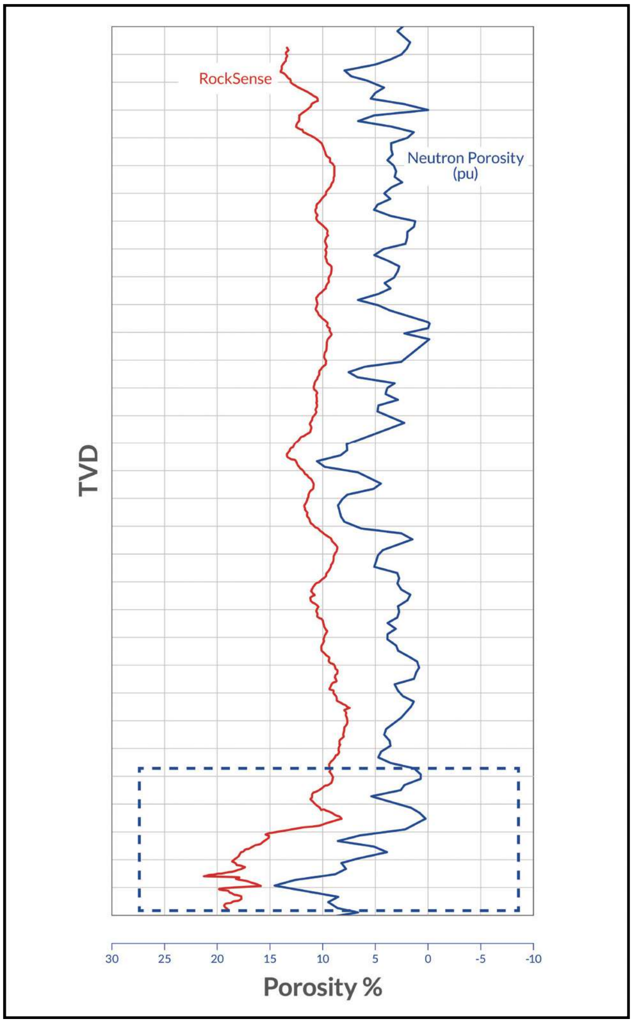


FIGURE 1. A compelling similarity between the shape of the density log for nearby wells and the RockSense log when plotting both quantities against TVD is shown. (Note the RockSense scale is offset in this view.) (Source: AnTech Ltd.)

in real time, a more reactive steering strategy could have been followed to avoid exiting the formation.

Operation

MSE is the energy required to drill a length of the hole in a formation, which reveals the composition of the formation. As the drillability of the formation changes, so

does the energy required to drill it. Although the theory had the potential to revolutionize drilling accuracy, the technology available until now has meant the practical application has been limited. This is because calculating MSE accurately requires real-time measurement of downhole weight on bit (WOB) and torque.

Historically, these were derived from surface measurements, with empirical corrections applied to the effects of buoyancy and friction. However, the noise of the corrections was almost always louder than the MSE signal changes caused by differing formation characteristics. More recently, technology advances have made downhole measurement of WOB and torque possible, but mud pulse bandwidth limitations have imposed severe constraints on the definition that can be achieved.

The latest generation of CT drilling bottomhole assemblies (BHAs) features integrated downhole sensors and high-speed wired telemetry to provide a technology platform that finally makes high-definition MSE measurements possible.

It works by measuring the power input to the motor as the hole is being drilled to gain an understanding of the type of rock being drilled. The technology measures differential pressure and flow rate. With knowledge of principal operating constants for the motor, an expression for power regarding pressure and flow rate can be written. This power is integrated as the hole progresses, giving a value of energy expended per foot of hole drilled and therefore giving a relative indicator of the changes in formation.

By continually monitoring torque, WOB, pressure and ROP, RockSense provides information about the formation being drilled in real time. Further, because wired telemetry has a high data rate, multiple measurements can be made for every foot drilled, and operators can gain inch level resolution. It opens a new window on the downhole environment as drilling progresses.

Considering the advantages

In the absence of the ability to accurately measure MSE, two geosteering methods have traditionally been used. The first method uses sensors measuring factors such as gamma, resistivity and porosity. Although these sensors are mature, reliable and consistent, the position of the sensor along the BHA is a significant drawback. The drillbit sits at the bottom of the BHA, but the directional sensor package sits perhaps 6 m to 7 m (20 ft to 25 ft) farther back, behind the mud motor. A change in formation characteristics is not evident until the bit is 6 m to 7 m farther into the formation. Even if there is no productivity impact, the time spent drilling unproductive formation impacts the project's bottom line.

The second method for geosteering is by cuttings analysis. However, the time taken to circulate cuttings to surface, capture them and prepare them for analysis inevitably means a delay. Once again, the formation of interest is penetrated before confirmation is received at the surface, reducing the TVD available to complete a steering action. Dispersion of cuttings in the annulus (different sizes and densities travel at different speeds) also can adversely affect depth resolution.

Both methods undoubtedly represented the best available solution for their time, but both are superseded by the technology now available.

With RockSense, at-bit bed boundary identification is possible for the first time. The information is delivered in real time and because the data are representative of conditions at the bit—not behind it—the driller can deliver an optimally placed wellbore with more meters drilled in the target zone. The result is improved lifetime productivity, higher IP and substantially improved project economics. E&P

UNDERBALANCED CT DRILLING DATA

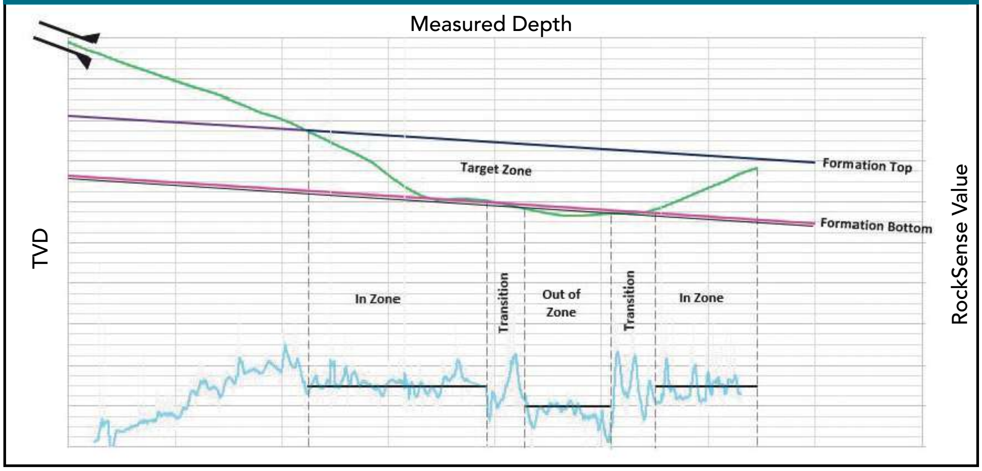


FIGURE 2. Applying RockSense historically reveals its sensitivity to boundary crossings. (Source: AnTech Ltd.)

SPONSORED CONTENT

High-Pressure Coiled Tubing Fishing Technique in Haynesville Saves 55+ Days and Approximately $4 Million

How Challenging Well Conditions Hindered Frac Plug Drillouts

An operator deployed 2-in. coiled tubing (CT) to drill out composite frac plugs following a well stimulation from 13,000 to 17,580 ft. Outdated cleanout techniques utilizing gel sweeps and high concentrations of friction reducer had saturated the fluid system in polymer, increasing viscosity and decreasing cleanout efficiency.

Upon reaching the 26th plug at 16,528 ft., the motor locked in a stalled condition, resulting in loss of circulation and a stuck CT string. Since pumping down a cutting tool was not possible, wireline cut the stuck CT at the kick off point, leaving 4,528 ft. in the well. With a shut-in wellhead pressure of 6,000 psi, various fishing alternatives (e.g. a workover rig, a snubbing unit, and other alternative methods) were ruled out.

How a Hybrid Approach Resulted in Dramatic Savings in Time and Cost

As a solution, Nine Energy Service proposed a unique hybrid strategy using a combination of a rig-assist snubbing unit, slickline, and CT. The well was loaded with $CaCl_2$ fluid to reduce wellhead pressure and minimize risk. A rig-assist snubbing unit rigged atop the CT BOPs in order to run a 2 7/8-in. workstring with fishing BHA to latch the 2-in. CT fish. The workstring and fish were pulled into tension, providing a conduit to the CT fish.

An initial wash run using 1 1⁄4-in. CT was made, running through the 2 7/8-in. workstring and into the 2-in. fish. A pressure-actuated radial jet cutter was then run to friction lock-up depth of 14,925 ft., cutting the 2-in. CT string. The 1 1⁄4-in. string was pulled out and rigged down. The rig-assist snubbing unit pulled the 2 7/8-in. workstring out of the well and hung the 2-in. CT fish in the surface BOP's. Slickline set two bridge plugs at the bottom of the fish for wellbore isolation. Finally, a 2-in. CT unit made the connection to the fish and spooled 3,000 ft. from the well without incident. The remaining 1,528 ft. could have been removed by repeating the procedure, but was left due to operator time constraints.

The entire operation was completed in 18 days with no HSE incidents and saved the operator more than 55 days and approximately $4 million when compared to conventional techniques. More than half the wellbore was returned to production clear of obstructed flow. E&P

Ensuring wellbore connectivity through improved perforations

In onshore and offshore applications, the latest systems advance safety, wellbore communication and restimulation efforts.

Brian Walzel, Associate Editor, Production Technologies

The goal of modern completion tools is to maximize reservoir productivity efficiently and effectively. A key component to the well completion chain is perforating the wellbore, where clean perforations can ensure quality connectivity between the reservoir and wellbore and help deliver fluid and proppant to their intended targets.

Ineffective perforation systems can lead to damaged equipment, ineffective stimulations and can even pose a risk to wellsite workers. Service companies challenged with solving these issues, along with a host of others, have developed an array of systems that have been deployed worldwide, both onshore and offshore.

Docking gun system

In March 2018, Schlumberger released its Tempo instrumented docking perforating gun system. According to the company, the Tempo system combines a plug-in gun design with real-time advanced downhole measurements, which enables and monitors the well's dynamic underbalance to create clean perforations that boost reservoir productivity.

According to Schlumberger, the docking components of the gun system streamline the deployment of up to 40 guns for selective initiation to perforate multiple reservoir zones with a maximized explosives payload in a single trip into the well.

"By optimizing the dynamic underbalance in the well to minimize or eliminate perforation damage, customers will benefit from increased hydrocarbon production through better quality perforations providing improved connectivity between the reservoir and the wellbore," said Djamel Idri, president of wireline for Schlumberger, in a press release.

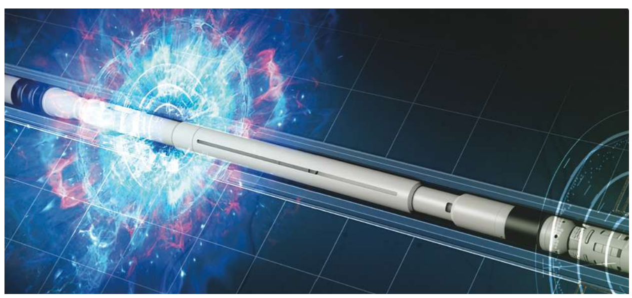
Badr El Din Petroleum Co. (Bapetco), a joint venture between Shell Egypt and the Egyptian General Petroleum Corp., wanted to improve the efficiency of multizone perforating operations in deep wells in the Western Desert. According to a Schlumberger case study on the operation, Bapetco was challenged with improving the efficiency of the its multizone perforating operations in deep wells. Schlumberger deployed the Tempo system, which features a safety- and efficiency-enhancing plug-in design with integrated measurement capabilities.

According to Schlumberger, the deployment of the Tempo system saved significant operational time by arming perforating guns in less than half the previously required time and conducting early downhole verification of system integrity.

Enabling targeted restimulations

Baker Hughes, a GE company (BHGE), developed its OptiStriker straddle packer hydraulic fracturing system, which enables targeted restimulation of individual perforation clusters in existing wells to boost production. According to BHGE, the system features a large inside diameter and two resettable coiled tubing-enabled packers offering a pump rate of 20 bbl/min and a differential pressure rating of 10,000 psi. BHGE reports that these features enable high-rate, high-volume treatments that optimize well restimulations and maximize production.

The OptiStriker system isolates individual clusters to better deliver fluid and proppant, especially to areas that might have been untreated or undertreated during the initial fracturing job. According to BHGE, this target-specific fracturing equipment uses only the amount of fluid and horsepower needed to treat



BHGE's OptiStriker is a straddle packer hydraulic fracturing system that enables targeted restimulation of individual perforation clusters in existing wells to boost production. (Source: BHGE)

each cluster, which minimizes operational requirements and costs by more than 30% compared to other restimulation techniques.

The OptiStriker can be deployed for restimulation operations, formation diagnostics and minifracs, fluid and gel injection, cased-hole wellbores, and in vertical and horizontal wells.

In a recent deployment of the OptiStriker system, an operator needed to restimulate a series of individual fracture clusters as efficiently as possible across a 1,489-m (4,886-ft) lateral section, BHGE reported in a recent case study. Using an OptiStriker straddle packer system, BHGE delivered controlled treatments to 26 individual clusters in a single trip.

TCP tools

Halliburton's tubing-conveyed perforating (TCP) technologies enable long intervals to be perforated using large pressure differentials while allowing vertical and horizontal intervention using a variety of perforating technologies, including an electronic firing system (EFS). The TCP system can be deployed in deepwater or onshore applications as well as for harsh environment applications.

A field in Angola featured wells that needed to be completed in a single trip, according to a Halliburton case study. The study reported that traditional firing head initiation pressures exceeded the wellhead tree rating. To overcome firing head pressure initiation challenges and enable offline activities, Halliburton deployed a TCP shoot-and-drop string that incorporated an EFS. The result was that the smart EFS single-trip completion provided the means to move some of the work offline, saving an estimated $800,000 in rig operations.

Halliburton reported that the EFS features an 18-day battery life, auto-release mechanism to drop guns after detonation and also enables offline activities like setting a completion packer, performing slickline runs and providing displacement to lighter fluid.

The case study stated that the displacement with lighter fluid before perforating allows the well to flow without killing it and/or exposing the formation to completion fluids that could damage the formation.

Built-in casing perforations

National Oilwell Varco's (NOV) i-Frac system offers an alternative to conventional perforating tools that utilize guns and explosive charges and are therefore risky. In an NOV case study, the company stated that conventional perforation methods have a negative effect on near-wellbore permeability and also can lead to mechanical damage.

"The impact stress associated with shaped charges and the outward traveling shockwave weakens the rock matrix, which increases the risk of sand production," the study reported.

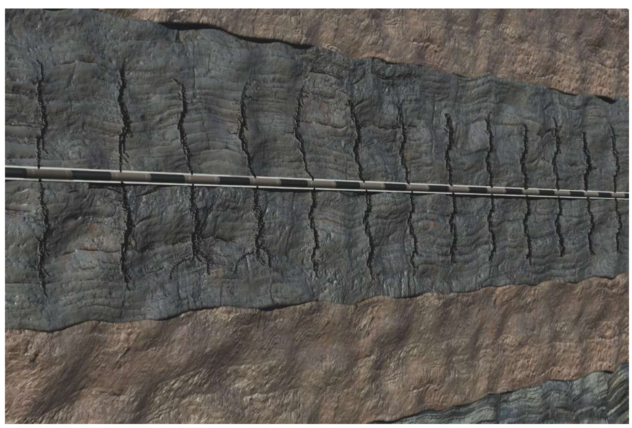
The i-Frac system features built-in casing nozzles that cause no damage to the formation because no charge or shock is imposed to the formation. Additionally, the system's application helps avoid impacts from underbalanced or overbalanced pressure differential between the wellbore and formation, according to NOV.

The built-in casing system features nozzles that are activated from the surface through deployment of specific activation tools. Once the tool engages with the targeted profile, the nozzles are opened and projected into the wellbore fluid.

"With pressure applied from surface and circulation of cement-dissolving fluid, cement detaches from the casing, breaks and then formation connection is initiated," the study reported. "Quantity and size of nozzles are engineered as per downhole injection and production design criteria."

NOV cites that an advantage to utilizing perforations with built-in casing technology is consistency in perforation diameter because nozzles are premanufactured and therefore identical.

"Unlike perforations with shaped charges, there is no development of high-stress compact shell around the tunnel with BIC [built-in casing]," NOV reported in the study. "Fractures can find their natural path through the formation and near-wellbore tortuosity is reduced. More efficient proppant placement and efficient fracture conductivity are ensured." E&P



NOV's i-Frac system offers built-in casing nozzles that avoid using charges or shocks, therefore avoiding damage to the formation. (Source: NOV)

Alleviating firing system safety risks and costs

A fully assembled perforating gun system increases efficiency and safety.

Thilo Scharf, DynaEnergetics

The need to streamline perforating operations while alleviating the risk of misfires, assembly and downhole time, labor and maintenance costs is a key component to hydraulic fracturing operations, particularly when completing long horizontal wellbores in unconventional shale plays. DynaEnergetics' DynaStage perforating system incorporates technology in the addressable firing system and an improved mechanical design to help improve overall plug-and-perf (PNP) operations. It optimizes perforating operations with fully assembled and ready-to-shoot gun modules delivered to the base or well site.

The fully disposable, maintenance-free system is made more robust by eliminating traditional approaches to selective perforating, detonators, gun hardware and accessory equipment and, with its additional safety features, allows other wellsite operations to run in conjunction with the perforation process.

System features

The system includes intrinsically safe, integrated switch-detonators, preassembled guns with shaped charges and a composite plug, a firing panel, and a surface tester. Commercialized in 2016, the DynaStage system has targeted two areas to improve efficiency and reduce costs.

The first is safety, for which the system has a simple design that eliminates the risk of inadvertent detonation from stray current or voltage. Surface explosive handling and arming can be conducted in less time and in conjunction with other operations. The design eliminates the need to hold the gun system at shallow subsurface depth during simultaneous operations. Both factors reduce wait times at the well site.

The second targeted area is reliability. The design of the electronic system and simplification of the mechanical field assembly process help to reduce the number of misruns, which increases efficiency and lowers the cost of completions.

Improved assembly at surface

During the assembly of conventional perforating systems, including mechanical component assembly, arming the system and connecting the gun string to the wireline, there is a risk that resistorized detonators can be initiated with radio frequency energy, stray current or stray voltage on the surface. These traditional detonators can contribute to an increased risk of injury and destruction when connecting the detonator to the gun string and wireline truck.

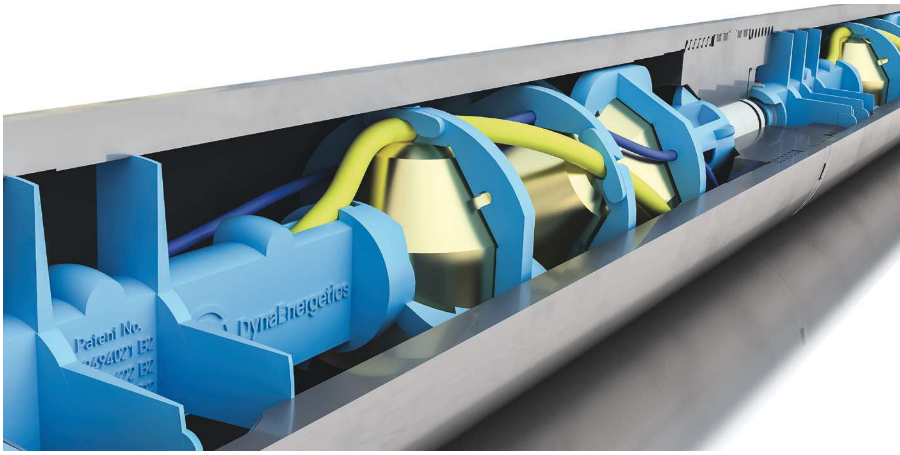
Safety procedures have been developed to address these risks, and the American Petroleum Institute provides guidelines for safe handling of explosives through Recommended Practice 67. When a traditional gun string with a resistorized detonator is used, all surface operations, including hydraulic fracturing, radio communications, cellphone communications and other wellsite activities, are suspended at the start of a perforating run until the gun string is at least 61 m (200 ft) into the well. Operations must be halted again after perforation when the gun is raised to within 61 m of the surface.

The DynaStage system's integrated switch-detonator design replaces all wiring and crimping to eliminate human error and significantly reduces the risk of inadvertent ignition or detonation. Arming a gun is as efficient, safe and reliable as placing a battery in a flashlight. True intrinsically safe microprocessor switch-detonators require no wiring, so they achieve measurably higher reliability than standard separate switch-detonator combinations and are immune to potential hazards that can impact standard selective perforating equipment in use today.

The integrated switch-detonators will either stay safe and operational or fail-safe should any external differential potential occur. They may be damaged by excessive stray current or voltage, but they cannot be initiated except through digitally coded signals sent by the surface firing panel.

Surface test equipment detects any malfunctions before running in hole, and the software allows continuous monitoring of all downhole components until initiation and in between shots. All wellsite operations can continue without interruption, and full selectivity, communication to all detonators, stage-skipping and gun redundancy are enabled for the most complex completions. Gun length, shot phasing, shot density and charge type are fully customizable with injection-molded gun parts that do not create unwanted debris after perforation.

System features, including the plug-and-go-style detonator and single-use connector subs, minimize assembly time. The time required for changeover from a used assembly to the connection of a new gun system is less than 10 minutes from rigdown to rigup. The DynaEnergetics detonator technology has successfully communicated and initiated on command during more than 500,000 perforating operations without a safety incident.



The DynaStage system helps wireline companies and operators streamline perforating operations while reducing assembly time maintenance and risk of misfire. (Source: DynaEnergetics)

Improved downhole reliability

The system is intended to virtually eliminate misruns by aiming to achieve a 99.9% operating efficiency (one misrun per 1,000 runs). To achieve this goal, the mechanical and electrical assembly of the gun system was redesigned, including changing the way the detonator is assembled within the system. A traditional detonator is assembled into the perforating gun connector sub requiring wiring connections and a port plug with O-ring seals. Wiring connection issues and leaking O-rings are among the most common causes of perforating gun misruns.

With the DynaStage detonator, the wires have been removed and replaced with an injection-molded connector, eliminating crimped wire connections and the associated risks of wiring damage and poor electrical connections. The detonator also was relocated to the gun body, from the tandem arming sub, which allows the use of a much shorter, disposable perforating gun connector sub and eliminates the port plug.

The gun is shipped to the wireline customer fully assembled, except for the detonator. All preshipping assembly operations are performed in the DynaEnergetics gun assembly line, which has been optimized for high-volume assembly, automated inspection and electrical verification of the assembled product. The production line process mitigates the risk of human error typical in the manual redress, cleaning, wiring and assembly of conventional perforating guns. Field assembly only requires inserting the plug-and-go detonator and threading the guns together.

Success in the field

Since the commercial launch, 500,000 guns have been fired. The production success rate has been one misrun per 420 runs for a perforating efficiency of 99.41%. DynaEnergetics continues to refine the system components, assembly process and operating procedures with the objective of attaining the 99.9% efficiency rate.

Each perforating stage run with the system reduced completion time by an average of 32 minutes, compared with a conventional system, as a result of the efficiency of surface-level transitions from gun to gun and well to well. Improved downhole reliability also was achieved, with an average decrease in nonproductive time of 2 hours per 100 runs. A significant part of the improved reliability was a reduced need for onsite user interactions that often lead to electrical issues and misruns in conventional wired perforating systems.

The use of the perforating system resulted in fewer days on location and operator cost savings as high as six figures. A Permian Basin operator who used the commercialized DynaStage system has incorporated it into the company's normal completion program.

Conclusion

The DynaStage system leverages component-level features and a system design approach to produce a perforating system that eliminates many of the causes for misruns, increases simplicity and safety of operations, and delivers higher well productivity. Operators and wireline service companies can optimize their operations with this PNP system because risk and costs are significantly reduced. Multiple perforating and hydraulic fracturing wellsite operations can occur without interruption, and full selectivity, stage-skipping and gun redundancy are enabled to ensure every stage and perforating cluster can be stimulated. E&P

Innovation in conveyance

A rigless intervention system works to optimize perforation operations.

Duncan Troup, Archer

Archer is continuing to develop rigless intervention techniques with the ComTrac carbon composite rod system. The properties of the semi-stiff rod bring considerable benefits to the process of perforating both new and existing wells. Deployed in combination with downhole tractor devices, ComTrac has completed hundreds of meters of pay-zone perforations in horizontal wells.

When planning for effective perforating jobs, there is always a trade-off between the length of the perforating gun that can be run and the total number of runs to be made. Longer strings might be run on pipe by means of a rig, which is very expensive, while using electric wireline removes the need for a rig to be on location, but the length of gun is severely reduced due to the physical limitations of the wire.

The way that conventional braided wireline cable heads are built puts a limit on the shock loads that can be applied without risking failure, and this necessarily leads to a maximum weight of explosive that can be used. If the intervals to be perforated lie in the horizontal section of a well necessitating recourse to a downhole tractor, the effective payload on wireline can be reduced even further. The ComTrac rod is twice as strong as a conventional wireline cable for one-third of the weight in air which—when combined with the rod's extremely low friction coefficient and its rigidity—means that even very large perforating strings can be successfully run.

The complete ComTrac system, including crew, is prepared for rigup. (Source: Archer)

Case studies

Recent cases have highlighted the capability of the ComTrac system to significantly reduce expenditure in both time and money. A horizontal well required re-perforating to maximize productivity, taking into account the well history and the possible movement of hydrocarbon contacts dues to depletion.

To determine the exact zones to be perforated, a saturation log was run over an extended interval of about 300 m (984 ft). With a logging speed of less than 0.6 m/min (2 ft/min), each pass takes hours to complete, and multiple passes had to be made because the saturation measurement relies on statistical significance.

The consistent movement conferred by the rigidity of the rod, allied to the precisely controlled logging speed possible with the fully electric ComTrac unit, meant the number of passes required for quality data was reduced, thereby saving more than 24 hours in operating time.

To shoot these zones using a tractor and conventional wireline cable would have only been possible by making four separate interventions. In the event the job was completed using the ComTrac system in only two runs, it would effectively cut the time taken in half. More than 30 m (98 ft) of guns were fired in a single run and there was no detectable damage of any kind to the rod. Having proved the system to be capable of conveying large perforating guns, and surviving the ballistic shock on detonation, the potential for even larger interventions becomes not just possible but highly probable.

The limiting factor for this job was not the ComTrac rod or the tractor, but the rigup height available to safely enter the well under pressure. Proprietary modeling software designed specifically to describe the ComTrac rod behavior was used to establish the envelope for future perforating operations.

All aspects of the bottomhole assemblies were taken into account to predict the largest possible gun strings that could be conveyed into a planned new well. Without limiting the string by rigup length available, the modeling exercise showed that extremely long and heavy strings could be successfully deployed to the target depth.

Having proved this was possible, thoughts turned to not just saving time by reducing runs but to the absolute performance of the perforation. If a perforation is made underbalanced (essentially where the reservoir pressure exceeds the wellbore pressure immediately prior to detonation), then near-wellbore damage to the formation is minimized, making cleanup far easier and ultimately increasing productivity.

A drawback to shooting perforations underbalanced is that there will be a pressure surge from formation to wellbore when the charges fire. With wireline cable in general, and especially for horizontal perforation operations, there is a very serious risk of the guns being blown up in the hole. This can lead to serious issues, especially if the flexible wireline cable becomes knotted or parted. An occurrence such as this will almost certainly result in the string becoming stuck in hole and ending up in an expensive fishing job, which might be even further complicated by having a nest of cable at the top of the fish. Because the ComTrac rod is rigid, the risk of getting blown up in the hole is vastly reduced. This means that shooting underbalanced, with all the obvious advantages associated with it, becomes far less of a risk.

The ComTrac system features a flexible, rigless intervention system. (Source: Archer)

Orienting perforation charges

Another aspect of reservoir performance related to perforation is the orientation of the perforating charges with respect to the formation. Controlling the placement of charges can be achieved by the use of charge carriers designed for the installation of the shaped charge explosives in specific arrangements. If the gun is then oriented in a specific direction in the well, then the direction of each shot may be controlled. In a horizontal hole, this may be done by the use of off-center weights that hang down toward the low side of the hole. These weights are very heavy and have traditionally been used only for tubing-conveyed perforating carried out with a rig because conventional wireline is not strong enough. The properties of the ComTrac system mean that oriented perforation becomes possible, even without an expensive rig in attendance.

Following the extensive modeling exercise, it was predicted that a full string of 140 m (460 ft) length weighing in at 7,275 lb could be conveyed to the target depth. To take full advantage of this, the completion was designed with a deep-set lubricator valve installed to allow rigging in and out of the well under pressure without recourse to a deployment bar solution. In all, more than 400 m (1,312 ft) of pay zone was perforated (with the first zone fired significantly underbalanced) in only five runs in hole along an 830-m (2,723-ft) horizontal section with a maximum angle of 92 degrees. The longest string included the tractor, correlation tools for positive depth control, release devices, shock absorbers, swivels, three sets of orienting weights and 15 6-m (20-ft) guns with a total perforated interval of 105 m (344 ft) from top to bottom shot.

As a comparison, had this job been planned and executed using conventional techniques, the number of runs would have been at least 18. The ComTrac system has a growing track record of maximizing reservoir productivity while reducing expenditure of time and money and minimizing risk exposure. E&P

Utilizing downhole camera and video inspection for well intervention

Technology ensures the rapid and efficient deployment of remediation systems.

Prakasen Vatakkayil, Expro

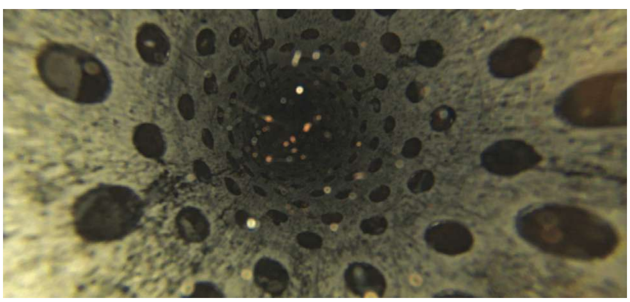
With drilling and completion activity forecast to grow by a 4% compound annual growth rate until 2020 and some 72,000 wells estimated to be completed by the end of 2019, well intervention activity is set to rise.

Indeed, the latest global well completion and intervention expenditure is expected to reach $79 billion for onshore and $13 billion for offshore this year, according to a November 2018 Rystad Technology Oilfield Service report.

For most operators, well integrity and production optimization remain the key drivers in the planning of well intervention activity. To help make these vital decisions, they look to the service industry to develop tools that bring sensory capabilities and assist in understanding the well conditions. This includes visual, acoustic and, in certain cases, the thickness of wellbore casings and tubing. A key enabler for visualizing this is camera technology, captured in real time or memory, using HP/HT tools deployed on wireline.

These techniques have reached a point where the industry can use 3-D headsets to visualize the well and identify the problem, including the capability to measure and gauge the size of fishing necks on stuck tools, hole sizes for perforations and the nature of debris and scales.

This technology is critically important for well intervention activity as it provides a clear understanding of the (previously unknown) wellbore. The camera and video technology can be deployed in a wide range of operations, including casing and well integrity monitoring, downhole inspection, operational verification and production monitoring for both on and offshore wells globally.



Imagery captured from the Vision WellCAM provides a wellbore view of a sand screen. (Source: Expro)

The data gathered then allow decisions to be made on location, helping reduce downtime and cost, while ensuring remediation solutions are delivered quickly and efficiently.

Fracturing applications

One of Expro's North America clients leveraged this technology to support a recent hydraulic fracturing campaign to avoid leaving hydrocarbons stranded, particularly in zones with smaller perforations. The camera was used to identify and measure the entrance hole size while understanding the position of perforations in its 5.5-in. casing. The operator needed to deliver this in a cost- and time-efficient manner, avoiding traditional methods such as electric line with tractor or e-coil conveyance.

On this basis, a Vision WellCAM system and WellViewer software with an image measurement feature were deployed to understand which zones had received the initial fracturing treatment, while identifying areas of focus for a second fracturing operation. A single camera string visually logged the well in one seamless, high-resolution color image, harnessing the 360-degree horizontally and 180-degree vertically pan-and-tilt capability. This allowed complete side and downhole viewing in memory and e-line mode, supported by a large internal 128-GB storage capacity that provided 24 hours of continuous recording.

Using measurements as little as 1 mm, the operator successfully discovered oversized perforations in the areas that had received the frac sand, which resulted in erosion from flow through the perforations. The full campaign inspected more than 700 perforations, with the largest variations in perforation size being .5 in. by .9 in., .58 in by .79 in. and .26 in. by .41 in.

This allowed the client to understand the results of its perforating program better, allowing it to plan a more productive second campaign, saving more than $100,000 and about two days of rig time compared to standard coiled tubing.

Geothermal applications

Downhole video cameras also are being used for high-temperature geothermal applications, where caliper and camera services are routinely performed as part of the well surveillance program worldwide.

On one particular project in which a client required to run routine pressure and temperature logging in its geothermal well, the existing service company was unable to retrieve the logging tools. Also, the temperature of the well was more than 148 C (300 F), posing additional technical challenges.

Assuming there was a casing integrity issue in the well, the client sought an alternative solution to running gauge rings or a caliper log.

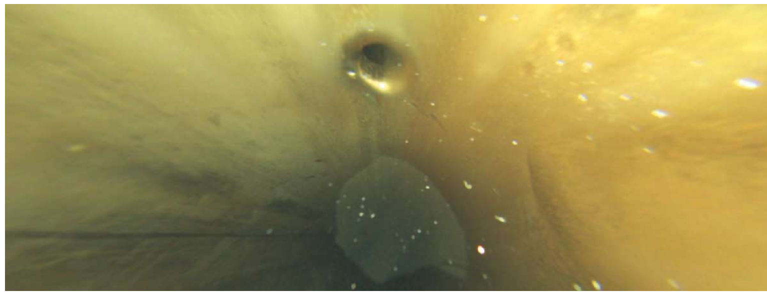
Expro was approached to deploy its high-temperature (up to 176 C [350 F]) downhole video camera, which confirmed the parted 13⅜-in. casing was causing rock and cement to enter the wellbore and trapping the logging tools downhole. Running additional tools could have been potentially caught in the split casing and either damaged the casing or become deemed irretrievable.

By helping to inform decision-making, this saved 12 hours of rig time and two separate runs in the hole. Visualization of the parted casing provided detailed images of the rock and cement that entered the casing, allowing the most cost-effective remedial solution to be implemented.

The client now routinely deploys downhole video cameras within its maintenance program up to twice a year to monitor the effects of corrosive fluids in these geothermal wells. This proactive approach avoids well integrity issues and associated costly repairs, saving up to $1.5 million to repair the well or $5 million to cement the well.

New technology developments

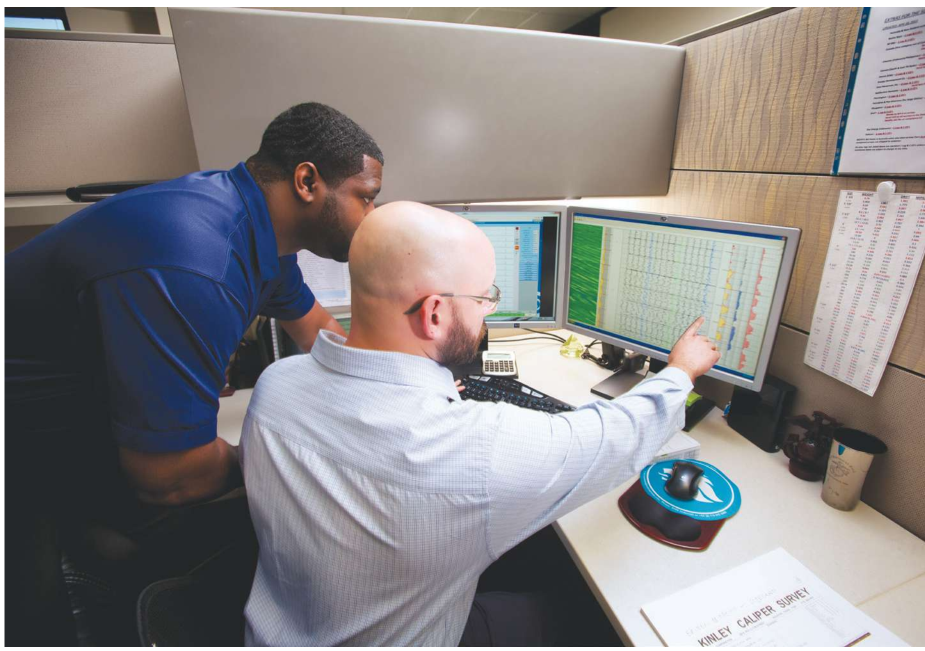
In addition to using video and camera technology to monitor wellbore conditions, operators can use a combined camera and caliper system, providing a more accurate representation of wellbore conditions. The combined caliper and video string, CalVid, allows wellbores to be measured and visualized at the same time, giving operators a complete understanding of the wellbore. Critical decisions regarding well and production integrity can be made based on a complete and accurate assessment of the entire wellbore, minimizing separate runs and rig time.



The Vision WellCAM produces high-resolution color images making perforation identification and measurement a quick and easy operation. (Source: Expro)

Working in partnership with Expro's camera services partner, Vision iO, both companies are enhancing the technical capability. One such development includes cameras that can visualize the downhole environment in a 3-D view that will enhance the information provided from down the well back to the surface.

As the well intervention market continues to grow this year and onward, and as the need to receive information in real time increases, operators are looking for innovative and advanced technology options to ensure they can make decisions quickly. Utilizing video and camera technology can help drive the decision-making process, allowing operators to save both time and costs, ensuring remediation solutions are delivered quickly and efficiently. E&P



The WellViewer software helps users with decision-making during perforation operations. (Source: Expro)

Unconventional well control

Shale wells offer unique challenges when it comes to maintaining well control.

Mohamed Amer, Wild Well Control

The risk inherent with a typical fracturing operation is tied to the fact that an abrasive mixture of sand, water and/or propane gel is pumped downhole at a very high rate for an extended period. The fluids and high pumping speed combine to create a mixture that causes a range of erosion issues that can ultimately compromise the mechanical integrity of well control barriers, usually at the surface. Leaks, compromised frac valves and erosion in the pumping line can follow, which can lead to the uncontrolled release of hydrocarbons at the surface during fracturing. However, these events do not happen without any prior indicators, and they typically involve a chain of contributing factors and warning signs before any blowout occurs.

The drilling-related incidents Wild Well Control typically experiences for unconventional plays tend to relate to high-pressure pockets or narrow margin wells when additional wells have been drilled on the flanks of a field to investigate pressure regimes. Repetition and familiarity establish complacency and mishandling of the situation by personnel unaccustomed to managing an unconventional well control event, which can compromise well integrity downhole. In these situations, crossflow events can occur, whereby reservoir influx from high-pressure zones can leak into lower pressure zones, inhibiting proper development of the field and resulting in loss of production.

Developing a risk management program

The appropriate, engineered redundancy of barriers, whether operational or mechanical, is the only way to mitigate operators' risks throughout fracturing operations. Wild Well encourages all clients to develop a robust risk management program that supports them with identifying, analyzing and mitigating the well control risk throughout the well life. This, of course, includes proper assessment of equipment risks, making sure all drilling and pumping are properly selected, fit for purpose, correctly rated and properly installed. However, the importance of considering the human factor cannot be overstated. For example, proper training in the form of crew awareness orientation plays an important role in helping the crew develop an understanding of how a simple well control event can quickly escalate and compromise well control barriers, resulting in a blowout. If key personnel members are not confident that they have ownership in the decision-making process, they will not be able to serve as an effective line of defense against well control events.

Wild Well responds to a blowout resulting from compromised wellhead equipment. (Source: Wild Well Control)

Concerns in unconventionals

Most unconventional plays in the U.S. are drilled underbalanced because the majority of these plays do not have

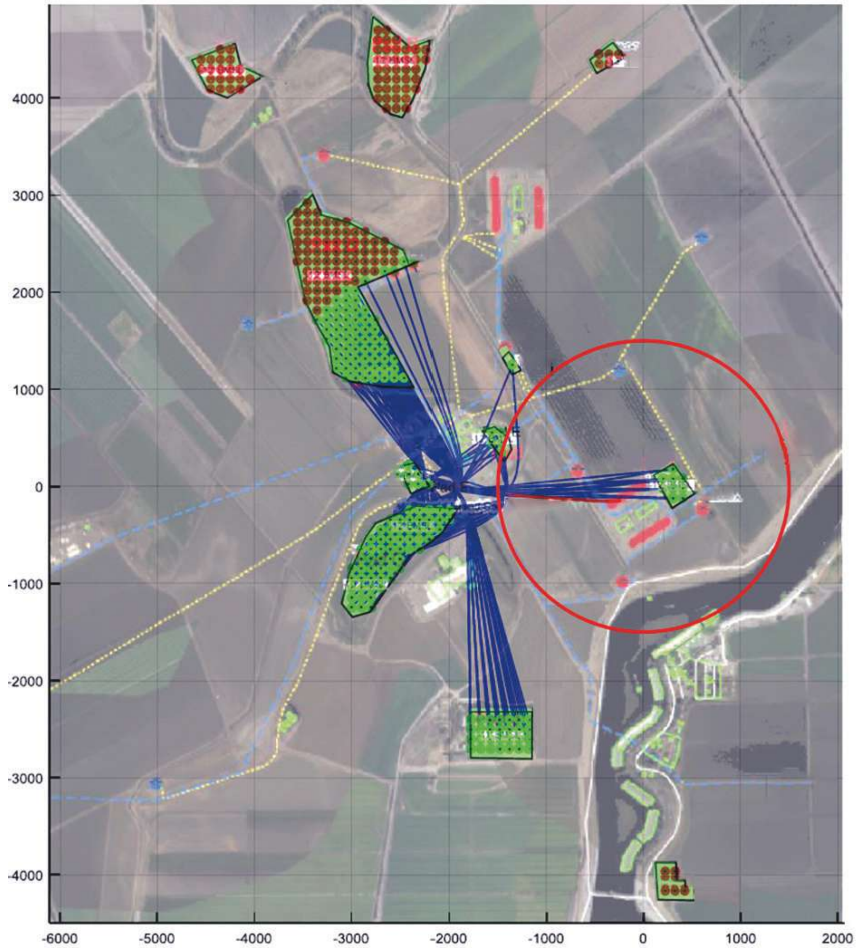


FIGURE 1. A feasibility study, including well-specific plans for frac and relief wells, focuses on anti-collision well placement issues. (Source: Wild Well Control)

natural fractures. It is a procedure where the wellbore is kept at a pressure lower than the formation being drilled. This approach improves operational efficiency as the wells are drilled faster, smoother and with the overall cost of the wells maintained at competitive levels. However, as the hydraulic fracturing activity increases, well control problems begin to increase due to these induced fractures. These increasing well control problems draw attention to the importance of implementing conventional well control practices of using hydrostatic columns higher than the formation's pore pressure.

As the number of unconventional wells has increased dramatically across the U.S., frac hits or "frac bashing" is now a common issue for some U.S. operations, in which fracture-initiated well-to-well communication events can create production losses and mechanical damage. Some operators are suspending their drilling operations to allow others to complete their fracturing operations, but there is room for further collaboration between operators to mitigate the hazards of impact. It is an area that could be further enhanced by operational guidelines, standardizing operations or regulation.

In particular, one of the main well control issues with unconventional plays is blowouts due to faults in casing design. Before the hydraulic fracturing of the well, the maximum allowable surface fracture pressures are typically calculated. The fluid gradient inside and outside the pipe is accounted for during this assessment. During fracturing, additional pressure is exerted from the surface and a ballooning effect is created on the production casing. If this effect adds more tension load that is not accounted for, it will cause an issue. During fracturing, the production casing typically cools down as the thermal load on it reduces. Frac fluids are delivered at ambient temperatures, which are colder than downhole temperatures. This design issue can lead to frac stacks and wellheads being ejected in extreme scenarios.

Typical response plan

Wild Well's typical response to a blowout event resulting from hydraulic fracturing is an attempt to regain hydrostatic control of the well and reinstate a mechanical barrier to the surface by "capping" the well. The typical capping process involves four stages:

1. Wild Well personnel respond to the event and conduct a site assessment;
2. Any compromised equipment is removed from the surface;
3. Capping of the well is performed; and
4. The final phase is recovering the wellbore and getting it back into production mode or to an abandoned state.

Most blowout events involve compromised wellhead equipment at the surface, whether it is a production or frac tree or a BOP. These components are checked for pressure sealing integrity. If they fail, they should be removed and replaced with properly rated equipment to reinstate the pressure seal.

Additionally, Wild Well advises on how to enhance well placement to maximize productivity from the wells and perform the correct survey quality checks. Well-specific plans for frac and relief wells are developed that focus on anti-collision well placement issues that can typically pose a hazard on high-density wells on small footprint pads (Figure 1). Survey management helps to eliminate uncertainty, which is a key criterion for relief well success if a blowout cannot be managed at the surface. Relief wells can be relied upon to regain hydrostatic control of a well's subsurface, and wellhead spacing is critical from a relief well and response standpoint.

Engineering capability example

The production casing failed in a recent fracturing operation. The casing provided a conduit for delivering fracturing fluids at a high rate and pressure at the surface. Wild Well responded, capped the well and worked with the operator to perform a hydraulic pressure transient analysis to investigate the sudden high-pressure release from the well because of the casing failure and attempted to analyze the structural ailures. A computational fluid dynamics (CFD) analysis was incorporated with mechanical model assessment, and a model was built to recreate what happened on the well (Figure 2). Once the pressure distribution was completed, a mechanical model was built and those forces applied upon it to understand the possible failure points.

The analysis revealed that during the millisecond of peak pressure while fracturing, there was recoil of the casing due to the production casing failure. At the time, the operator was embarking on a campaign to upsize its pressure release system after realizing that it was too small. Wild Well's analysis and modeling support the fact that the pressure release system did not affect the performance of the system as the recoil force in the string alone was enough to launch the wellhead and cause the blowout. E&P

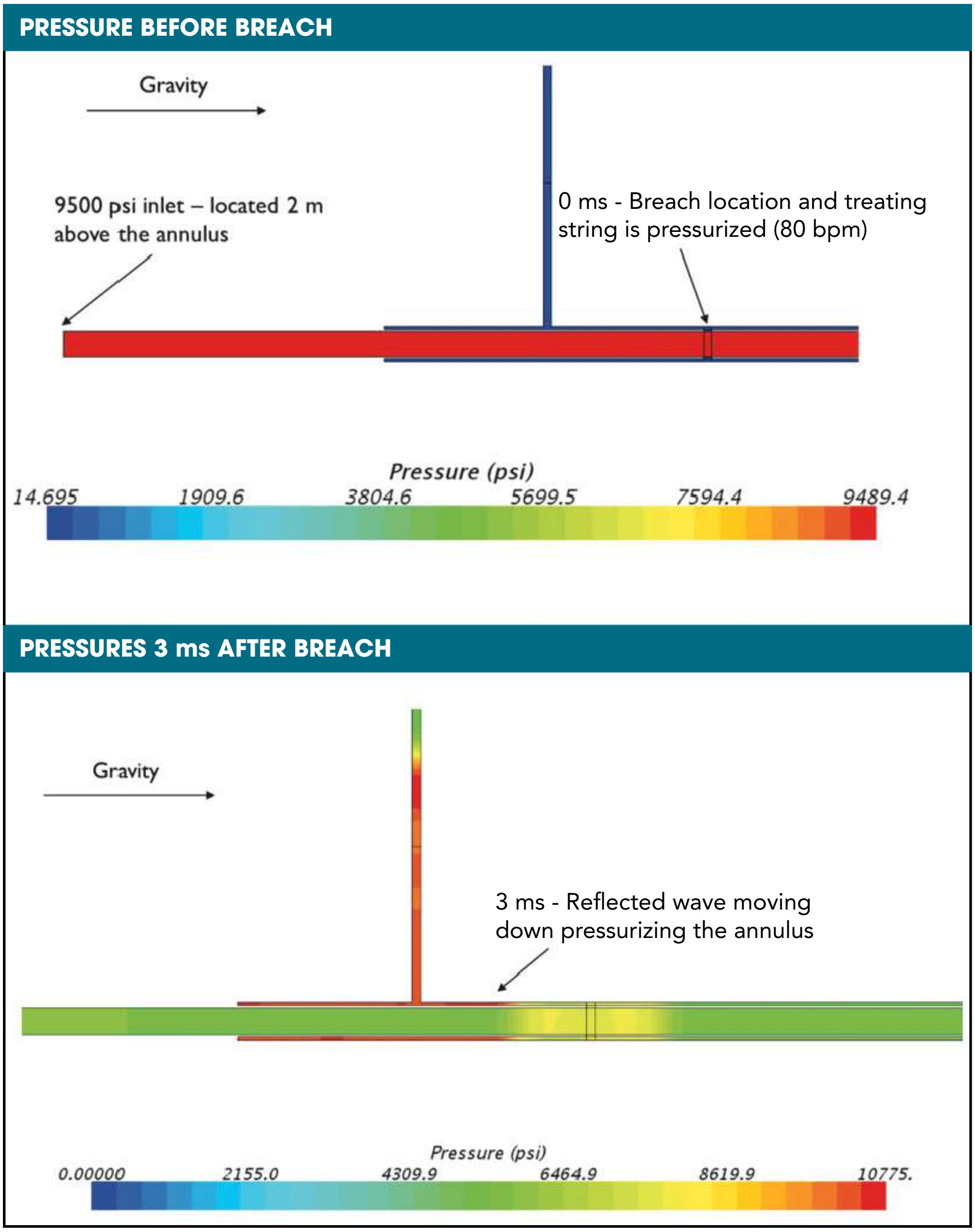


FIGURE 2. A CFD analysis of pressures is depicted before and 3 ms after the breach. (Source: Wild Well Control)

Changing the subsea boosting application landscape

Multiphase pumps in use in Moho North Field are qualified for high-viscosity applications.

Halfdan Rognes Knudsen, **Ina Ekeberg** and **Hans Fredrik Kjellnes**, Schlumberger OneSubsea; and **Pierre-Jean Bibet**, Total E&P

Subsea boosting has reached a significant milestone regarding high-viscosity capabilities. In March 2017, Total E&P installed and put into operation a newly qualified high-viscosity, high-boost pump in the Moho Field offshore the Republic of the Congo. The pump had been through an extensive qualification program comprising flowloop testing on multiphase conditions ranging from 0% to 75% gas volume fraction (GVF) and viscosities from 1 centipoise (cp) to 800 cp. The pump also demonstrated the capability to perform cold startups up to 30,000 cp—a viscosity equivalent to maple syrup. The qualification of this technology has opened an opportunity to offer high-boost pumps in applications that were regarded as impossible for dynamic multiphase pumps in the past.

FIGURE 1. A high-viscosity, high-boost pump in a subsea pump station was tested at the OneSubsea test facility in Horsøy, Norway. (Source: Schlumberger)

The first subsea boosting pumps were 400 kW and installed at modest water depths. Since then, the boosting capabilities have increased regarding power, design pressure, differential pressure and throughput. Their unique design is highly sand tolerant and handles a wide range of GVF. OneSubsea has delivered more than 100 subsea pumps worldwide and accumulated more than 3 million hours of successful operation.

Some of the world's largest reserves are heavy oil reservoirs, defined as liquid petroleum of more than 200 cp at reservoir conditions. Production of heavy oil in combination with increasing water cut brings a potential for very high emulsion viscosities. Combining this with multiphase flow and the trend of increasing tieback lengths, a traditional artificial lift method like gas lifting can be rendered inefficient. However, seabed boosting can represent an attractive production-enabling technology for such fields. It draws down wellhead pressure, and at the same time, it reduces flowline pressure drop by adding heat to the process fluid.

Project overview

In production since 2008, the *Alima* floating production unit (FPU) situated offshore the Republic of the Congo produces from the Moho and Bilondo tiebacks. Water depth in the area is approximately 800 m (2,625 ft), and the development concept is based upon a subsea production system connected with a riser system to the FPU.

In 2013 Total decided to develop a new tieback from the Bilondo reservoir and back to *Alima*. Having experienced the benefits of subsea boosting compared to alternative technologies, they decided to implement subsea pumps to boost the high-viscosity oil of the Bilondo reservoir.

OneSubsea was awarded an engineering, procurement and construction contract for Total's Moho 1bis development. The contract included a subsea pump station with two 3.5-MW high-boost multiphase pumps to meet the forecasted production profile (Figure 1). Also, OneSubsea committed to a qualification program verifying the boosting capabilities at viscosities that had never been tested with subsea multiphase pumps before.

The maximum differential pressure requirement was set to 110 bar. The pumping system was designed to operate one pump at a time according to wet spare philosophy as well as parallel operation of the pumps. The substantial head, capacity and viscosity requirements resulted in the highest power rating ever supplied for a subsea multiphase boosting system.

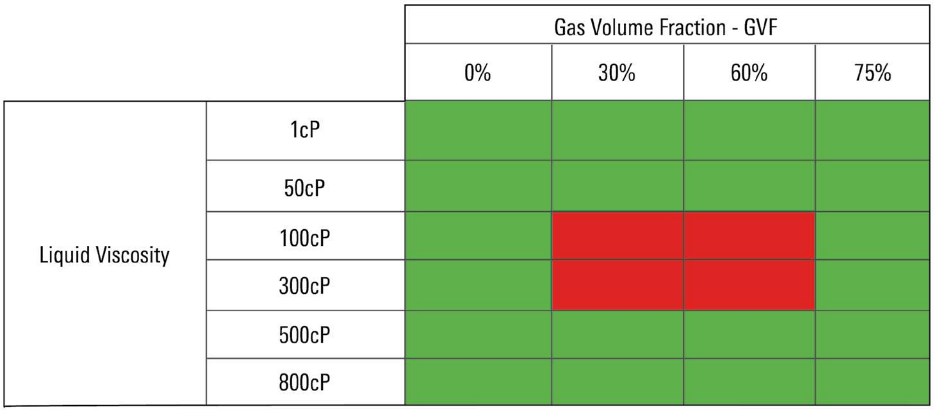


FIGURE 2. During initial testing, unwanted vibrations were observed at certain combinations of GVF, viscosity and pump differential pressure. The challenging conditions are indicated with a red background in the test matrix presented. (Source: Schlumberger)

Qualification program

In addition to the standard factory acceptance test and endurance test, OneSubsea committed to demonstrating the high-boost pump's ability to operate continuously on 800 cp at various GVF while monitoring rotor dynamic and hydraulic performance. An additional performance mapping on viscosities ranging from 50 cp to 800 cp also was executed.

A high-viscosity multiphase test loop was designed and built for full-scale testing of the pump. This setup comprises a 40-sq-m (430-sq-ft), two-phase separator, chokes, process coolers and advanced measurements to secure viscosity control and conditioning of the multiphase fluids for precise performance characterization. The test loop enabled operation through the full capacity range of the pump: a liquid flow rate of up to 600 cu. m/hr (21,189 cf/hr), or 90,000 bbl/d, and 0% to 75% GVF.

Throughout the test campaign, the engineers in the pump control room learned many valuable lessons. The combination of high-viscosity and multiphase conditions proved to have a surprising and severe impact on the rotor dynamics of the pump. A large number of research-related operating hours laid the foundation to update design principles, performance models and protection logic. Following this, the upgraded pump was run through the full test matrix of varying viscosities and GVF. Its performance was dynamically stable under all conditions. In this case, the investment in a comprehensive test program was instrumental for the reduction of project risk. The gained competence and test facilities developed during this project will undoubtedly be leveraged to provide guidance and ability to execute future high-viscosity pump projects (Figure 2).

The performance of the pump was validated through full-scale testing at liquid viscosities from 1 cp to 800 cp, GVFs from 0% to 75%, and the full range of power, speed and differential pressure. As part of the performance mapping, the pump also proved its ability to start at extreme viscosities of 30,000 cp. The tested viscous performance was greater than predicted, disproving the misconception that viscous pumping requires displacement pumps.

Field implementation

Nine months before the startup, OneSubsea was informed that analysis performed on the actual process fluid from the Moho reservoir showed an even higher viscosity than initially predicted. The assessment of the new production profile also showed that the multiphase pump system was going to operate with a significant recirculation rate. The high recirculation rate gives an increased pump inlet temperature, which again results in a lower viscosity compared to the fluid from the wells.

The world's first high-viscosity, high-boost pump system was successfully installed, commissioned and started at the Total Moho Field in March 2017. The subsea boosting system has proved its operational flexibility by handling the late updated production profile. The reduced viscosity in the downstream flowline has proven to be a secondary positive effect of boosting when operating on high viscosity. Because of the high recirculation rate, the multiphase pump is equally used as a booster and a heater, reducing the flowline viscosity. The high-boost pump has been running with 100% availability following the startup.

During the test program, the high-boost pump proved its ability to perform cold startups up to 30,000 cp, exceeding the requirements for the Moho project and most relevant future subsea fields. E&P

***Editor's note:** This article was adapted from the OTC-28953-MS paper, "Qualification of the HighBoost Multiphase Pump for Heavy Oil Applications."*

Comparing records can reveal aging subsea equipment condition

Advances in technology, data science and operating experience have made inspecting the 'uninspectable' possible.

John Upchurch, ABS

Operators of aging subsea assets have a unique opportunity during the next decade to extend the operating lives of what will prove to be some of the most robust equipment ever built to extract offshore hydrocarbons. In the late 1990s, when this generation of equipment was installed, uncertainty about its performance in a deepsea environment produced 20-year designs that were based on conservative assumptions about how conditions would affect corrosion, motion and fatigue. Generally, this is good news for life extension.

The benefit of subsea field experience has since refined those views; for example, less conservative assumptions have led to new equipment designs being more narrowly defined and cost-effective. It also has offered more visibility of the potential for fatigue and corrosion in equipment that operators have historically struggled to inspect, such as manifolds, subsea pipelines, steel catenary risers, umbilicals and flexibles.

While it remains impractical to pull those components to the surface for a thorough inspection—and often too costly or risky to pig subsea pipelines—advances in technology, data science and operating experience now offer better insight into the condition of "uninspectable" equipment.

Inspection life cycle

During the life of a field, assets undergo an inspection-review cycle: design, fabrication, installation and preliminary inspection. Later in the field's life, it is important to establish an initial starting point, which entails a reassessment of the design and whether it was installed as planned.

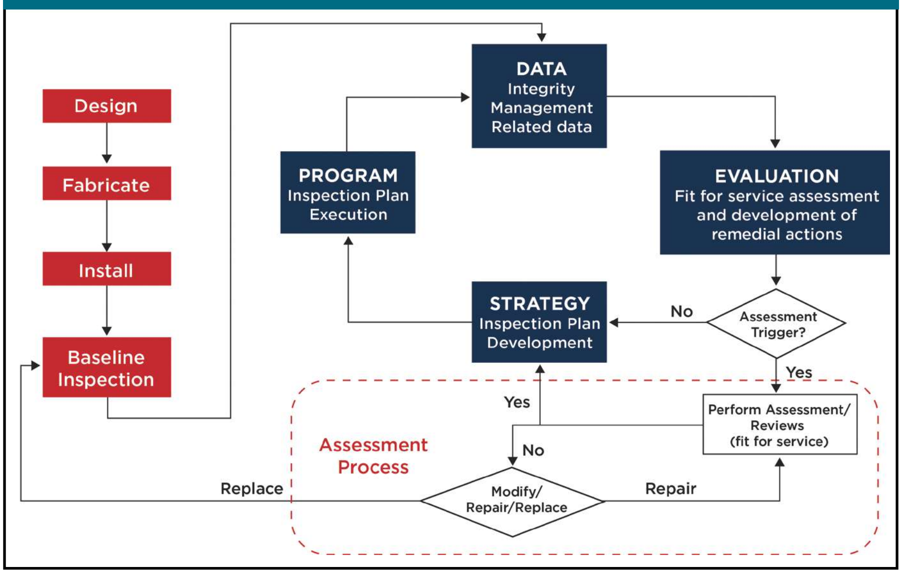
Comparing the post-installation inspection to the asset's current condition can reveal if it and its environment have behaved as expected.

For example, a good place to start a riser inspection is with the top hangoff region of the platform for unusual wear and tear. Cleaning the marine life of the flex joint, for example, will reveal its condition.

It is critical to look through the water column, especially for external damage. Are the strakes, orbs or bearings still there? Because strakes limit vortex-induced motion (and therefore the stresses that cause fatigue) caused by ocean currents, they are a key way to assess an asset's remaining life.

A similar close inspection of pipelines will reveal the rate of anode consumption, which are critical points for corrosion. The state of the anodes offers insights about whether overall cathodic performance is meeting

INSPECTION REVIEW CYCLE



Comparing the post-installation inspection records against the asset's current condition can reveal if it and its environment have behaved as expected. (Source: ABS)

design expectations. While internal pipe inspections are not always possible, external assessments can reveal a lot, beyond obvious external damage. The position of the pipe as compared to where it was originally installed can reveal operational behaviors. Most sections of pipe lie on the seabed, where movement leaves traces, which may have exceeded original expectations. Excessive movement raises the potential for fatigue.

Pipes move, so it is important to determine whether any obstructions have prevented movement. If, for example, the pipe is where it was originally installed, then something may be limiting its motion.

It also is critically important to monitor the location of pipe spans against their original placement. High currents shift the seabed, prompting pipes to settle on a terrain's high spots or bring the lower sections to the seabed ground. This can compromise support for the span, or lengthen it, with the obvious implications for fatigue life.

Data gathering

The offshore industry has entered the era of "smart" operations, but most data generated from normal onsite operations are not gathered specifically to measure the life of the equipment. However, data derived from production, metocean and external events still hold insights into the life cycle of the asset.

Production data, for example, reveal whether the volume, pressure and temperature—as well as crude characteristics such as sweet versus sour, water content, H_2S and CO_2—met the expectations of the original design. If the original assumptions on water, corrosive fluids or chemical inhibitors differ from expectations, then the potential for a corrosion problem escalates.

Production data also record how many startups and shutdowns a well has undergone. For the manifolds and pipes on the seabed, post-production assumptions are that a relatively constant temperature will be maintained. Stop and start cycles raise and lower temperatures, even with insulated pipe, causing materials to expand and contract.

Unlike on drawings, where pipelines often are represented as straight lines, on the seabed they often are

Revisting post-installation inspection records can offer insights into the present condition of pipelines being considered for life extension. (Source: ABS; photo by NickEyes/*Shutterstock.com*)

curved in three dimensions. When wells go into production, they heat up and the curves push out; when they are shut off, temperature falls and they pull back.

Evidence of this can be seen on the seabed, and the movement and frequency of these cycles may have impacted fatigue. Production data should be compared to the original design assumptions.

Records of environmental conditions offer insights into the risk of fatigue. If the asset is located next to metocean buoys or other recording devices, good data are available. But if not, then environmental performance is recorded on most platforms and should be reviewed.

Analytical advances

Assessments of a system's life have been greatly enhanced by the emergence of new analytical tools. Typically, operators have used "response amplitude models" to estimate the reactive behavior of a waterborne asset in the original design. With historical operating data available, it is possible to build a time-domain model using performance data. The result may or may not support life-extension goals, but it will provide a better picture of the asset's consumed/remaining life. The same can be extracted from metocean with regard to vessel direction, and therefore actual versus estimated stress forces.

If necessary, fatigue testing of similar equipment can offer useful performance analyses. The original design projections for fatigue should have been based on the best available curves; current curves may indicate a change. The curves themselves may not have changed, but industry performance may suggest a more appropriate curve for the specific location or asset design.

For the present class of offshore assets under lifecycle review, the original designs were probably based on working-stress analyses. For life-extension purposes, better insights would be derived from load-factor resistance analyses, which focus more on equipment performance (i.e., how much it can take) to determine how much it may have left.

The new analysis should include any full-scale testing results that may have been done. The operator should review the reports from the factory acceptance testing and site integration testing that were done before installing the equipment. Lastly, the asset's photographic history often is overlooked when assessing its present condition; pictures and videos taken during or post-installation may offer insights into how it was behaving.

With the benefit of 20 years of operational data at hand, a recalculation of the expectations for the design will help to determine what was likely to have been consumed and to more accurately forecast future conditions. This reevaluation may or may not support life-extension goals, but it will likely give owners a better understanding of the present condition of the equipment that is notoriously hard to inspect. E&P

Growth continues in the Haynesville

The rise of LNG and gas exports and proximity to the Gulf Coast keep the Haynesville Shale play attractive.

Jennifer Presley, Executive Editor

The Haynesville Shale's location is helping keep interest in the play high. Stretching across East Texas and North Louisiana, the primarily dry gas play offers players shorter access to Gulf Coast ports. The rise of U.S. LNG and gas exports has made the Haynesville attractive with its proximity to hubs in South Louisiana and Texas, according to Drillinginfo.

In the decade or so since the opening of the Haynesville Shale play by Chesapeake Energy, the region's fortunes have peaked, troughed and are now ascending again. Gas production for the fourth quarter of 2018 was forecast to hit about 221 MMcm/d (7.8 Bcf/d), according to Drillinginfo, up from about 164 MMcm/d (6 Bcf/d) in the fourth quarter of 2016. Production for year-end 2019 is forecast at about 229 MMcm/d (8 Bcf/d).

In an exclusive report provided to *E&P*, Drillinginfo noted that more than 7,000 horizontal wells had been spudded in the Haynesville over the past decade. Spudding activity declined from 2010 to 2016 but has rebounded in recent years. Wells coming online in 2017 and 2018 are reaching 24-month cumulative values that were higher than EURs for wells completed before 2016, according to the market analysis firm.

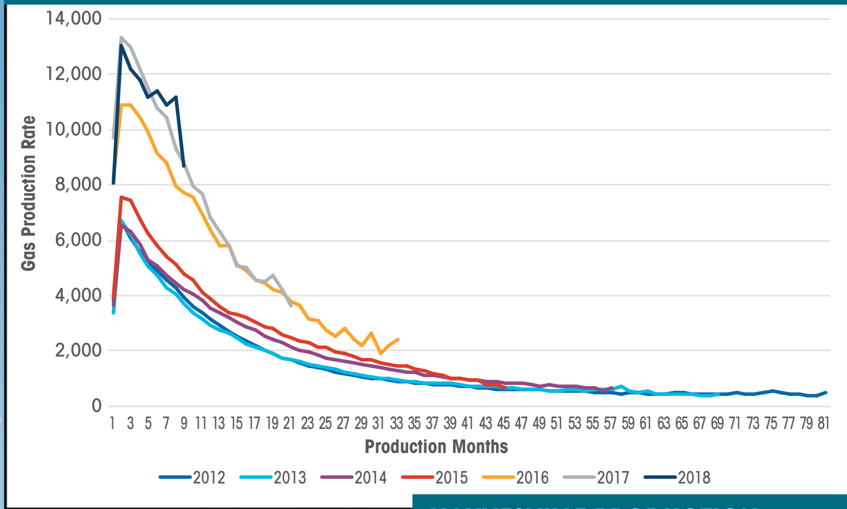
Drastic improvements in well performance have helped grow production since the start of 2017. Renewed interest and improved designs in completions in 2016 are cited in the report as having brought about the step change in well performance and consistent growth. Proppant intensity has greatly increased in the Cotton Valley Sands and Haynesville and Bossier shales, the report noted, with lateral lengths reaching about 2.4 km (1.5 miles) long.

Operators in the region have time to continue making improvements in well performance as the proposed Haynesville Global Access Pipeline (HGAP) is set for in-service beginning in 2023. "HGAP will connect the Haynesville Shale with growing markets in Southwest Louisiana, where natural gas demand is expected to triple, reaching approximately 12 Bcf/d [340 MMcm/d] by 2025," said Tellurian President and CEO Meg Gentle in a press release. "HGAP will improve the connection between North and Southwest Louisiana, debottlenecking existing pipeline routes and providing shippers access to expanding markets."

News of the construction, ownership and operatorship of the $1.4 billion 42-in. diameter pipeline was announced by HGAP LLC, a subsidiary of Tellurian Inc., in early 2018. The pipeline will stretch about 322 km (200 miles) from northern Louisiana south toward Gillis, La., and will have a delivery capacity of about 105 MMcm/d (3.7 Bcf/d) of natural gas from the Haynesville/Bossier shale area, according to HGAP. E&P

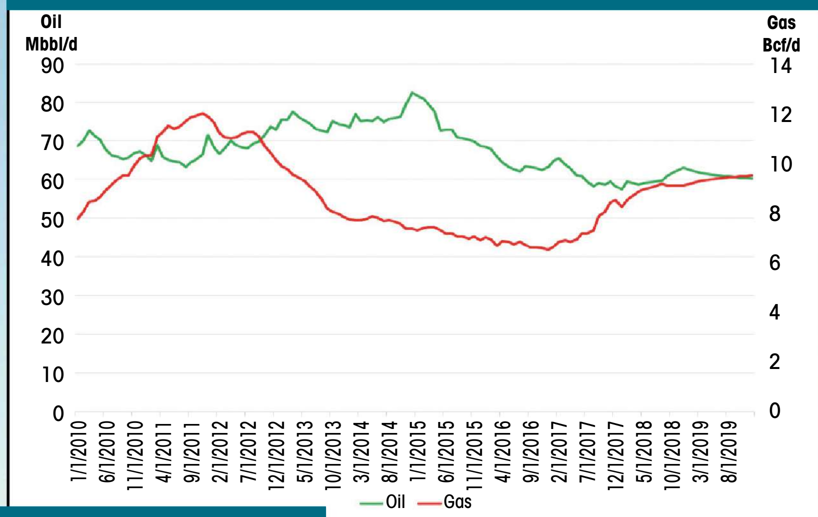
The sun sets on the piney woods near Greenwood, La., where a rig is drilling a well in the Haynesville Shale. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)

VINTAGE TYPE CURVE—GAS

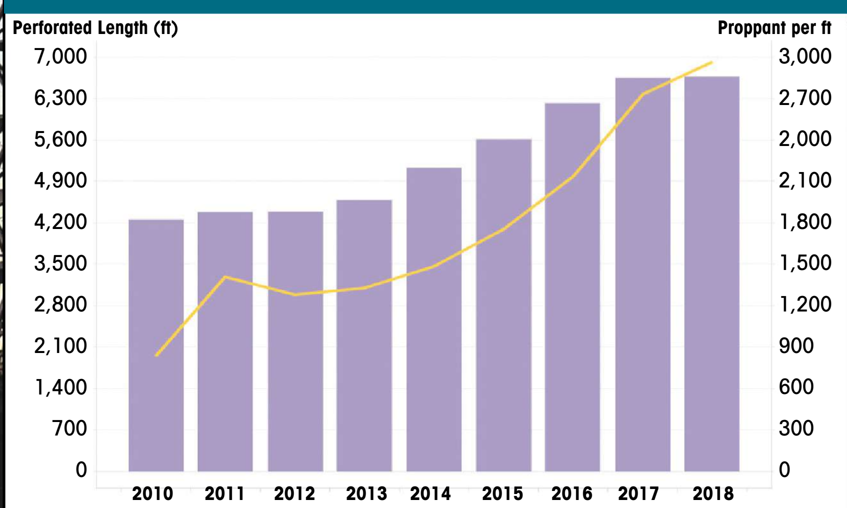


A consistent improvement in the region's gas type curves demonstrates the application of new well completion designs impact on production. (Source: Drillinginfo)

HAYNESVILLE PRODUCTION



COMPLETION PRACTICES OVER TIME



Top: Gas production in the Haynesville peaked in the fourth quarter of 2011 with an all-time high of about 292 MMcm/d (10 Bcf/d) and reached its low at about 164 MMcm/d in the fourth quarter of 2016. (Source: Drillinginfo)

Bottom: Increased proppant intensity and longer laterals are helping modern wells (2017 and 2018) outperform wells completed prior to 2016. (Source: Drillinginfo)

SPONSORED CONTENT

Bright Spot for Shale Resources

DUG *Haynesville* conference tracks business opportunities

The earliest U.S. shale-gas plays (the Barnett, Haynesville and Fayetteville) paid a hefty price for being first to prove that, yes, wells can be completed in shale.

Producers in shale basins rich in natural gas led the way in developing the effective one-two punch of horizontal drilling plus multi-stage fracturing. Yet their success ultimately brought too much gas to market too fast – and overwhelmed demand. Activity in the early plays nearly ground to a halt as drillers focused on the prolific "Beast in the East" – the Marcellus.

Fast forward a decade (and many miles of pipeline later) and the demand-challenged Haynesville has become prime leasehold again. The first-ever **DUG *Haynesville* conference and exhibition** demonstrated how much renewed interest – and investment – was accumulating in February 2018 when a near-capacity crowd jammed the Shreveport's convention center, the largest venue in the Ark-La-Tex region.

Now, against a background of stronger natural gas pricing, increased LNG export capacity and a world full of end-users growing accustomed to the U.S. as a natural gas exporter, the **DUG *Haynesville* conference** is poised for a repeat performance February 19-20, 2019 in Shreveport.

On stage at the inaugural DUG *Haynesville* conference in 2018, Nissa Darbonne (left), editor-at-large for Hart Energy's *Oil and Gas Investor* media platform, interviewed John Howie, senior VP - upstream for Tellurian Inc. Howie returns to the 2019 DUG *Haynesville* conference and exhibition February 19-20 in Shreveport.

2018 EVENT METRICS

779 Attendees

Exhibitors 40

47 Sponsors

Executive Presentations 12

Location, location, location – plus timing

Today Haynesville shale producers enjoy two economic advantages. First, their assets are closer than most to the massive petrochemical complex and growing LNG export terminals along the Gulf Coast. Second, resource development strategies and methods have become much more capital-efficient.

Drilling and completion technologies and logistics advanced as shale explorers moved rigs to oilier targets in the west, then worked to survive sub-$40 oil and sub-$2.50 gas. A lot of "science drilling" and "enhanced completions" along the way ushered in an era of smarter tools, greater engineering efficiencies and new sources for frac sand – all of which help contain F&D expenses.

These sorts of topics are addressed on-stage and across the exhibit floor by seasoned leaders, from producers, midstream operators and analysts to technology providers, at the **DUG *Haynesville* conference**. Full-conference attendees get unparalleled access to presenters in lively Q&A sessions

"One of the best and most relevant examples of how **DUG *Haynesville*** can make a difference with people across the play"
— Christian Walters, VP Land & Business Development, New Century Exploration Inc.

Hundreds of petroleum industry professionals focused on activity in the Haynesville shale will converge February 19-20 at the Shreveport Convention Center for the second annual DUG *Haynesville* conference and exhibition. Beyond topical presentations in the main session room, there will be plenty of active networking on the exhibition floor during breaks throughout the day as well as before and after scheduled sessions.

while individuals employed by E&P companies, pipeline operators, refineries and utilities always get complimentary access to technology displays on the exhibit floor.

Hear from the primary producers

Tim Beard, Chesapeake Energy's vice president for Haynesville and Rockies, told the 2018 audience, "The Haynesville was trying to find its way... and then it came roaring back when it found its thing and its thing is longer laterals, bigger completions and producing wells appropriately." His firsthand experience in the play offered the sorts of insights DUG conference attendees come to hear.

This year's attendees can look forward to comparable high-quality content. The roster of Haynesville producers is a compact list – and Hart Energy editors work for months to recruit executives and experts with the sort of in-depth regional expertise for which DUG conferences are known.

Charles Goodson, president and CEO of PetroQuest Energy, Inc. was just one of the producers speaking at the inaugural DUG *Haynesville* conference in 2018. A speaker slate featuring an array of public and private producers is one of the hallmarks of Hart Energy's DUG conferences.

For updated information about speakers and to view the full conference agenda, please visit HartEnergyConferences.com and click on **DUG *Haynesville*** in the "Events by Date" tab. E&P

Producers and midstream operators committed to speak (as of Nov. 30)

John Howie, Senior VP – Upstream, Tellurian Inc.

Craig Jarchow, President & CEO, Castleton Resources, LLC

Todd Nelson, Director, Marketing & Business Dev't, Enable Midstream Partners LP

Alan Smith, President & CEO, Rockcliff Energy LLC

Rob Turnham, President & COO, Goodrich Petroleum Corp.

Frank Tsuru, President & CEO, Indigo Resources Inc. and CEO, Momentum Midstream LLC

New year signals new potential in West Africa

Favorable economics could push forward planned projects as more come online.

Brian Walzel, Associate Editor, Production Technologies

Evolving development economics in West Africa have breathed new life into a region that has seen declining production rates in recent years, yet still holds vast amounts of recoverable resources. According to Wood Mackenzie, Sub-Saharan Africa holds at least 23 Bbbl of oil and 1.5 Tcm (54 Tcf) of gas still left to be developed. As the company pointed out in a June 2018 report on the region, about half of that amount of future reserves lie in Angola and Nigeria.

In its 2017 annual report, Total reported that its production costs in Sub-Saharan Africa have fallen from $2.1 billion in 2014 to $1.3 billion in 2017, indicating more favorable economics are to be had in the region.

As a result of improving economics, Equatorial New Guinea is expecting market and project development this year through expected foreign direct investment with 11 new wells to be drilled. Exxon Mobil, Kosmos Energy, Marathon Oil and Noble Energy all hold greenfield prospects in the region that will be sites of new wells this year.

Meanwhile, in developments offshore Angola, Eni announced startup production from the Ochigufu Field early last year. The project added 24,000 bbl/d to the field's current production levels, according to an Eni press release. The Ochigufu wells are connected subsea to the Sangos production system and are tied in to the *N'Goma* FPSO.

Angola

On July 27, 2018, Total announced it had begun production at Kaombo, the largest deepwater offshore development in Angola. The project is located in Block 32, 260 km (161 miles) off the coast of Luanda.

According to a Total press release, *Kaombo Norte*, the project's first FPSO, will produce about 115,000 bbl/d, while *Kaombo Sul*, the second FPSO, is expected to begin production this year. Total reported that the overall Kaombo development is expected to reach peak production of about 230,000 bbl/d, while the associated gas will be exported to the Angola LNG plant.

Total's *Norte* is Kaombo's first FPSO, which will produce about 115,000 bbl/d. (Source: ALP Marine Services for Total EP Angola Block 32)

According to Total, 59 wells will be connected to the two FPSOs developing from six fields: Gengibre, Gindungo, Caril, Canela, Mostarda and Louro over an area of 800 sq km (497 sq miles).

Total is the leading operator in Angola, having produced 229,000 boe/d in 2017. In addition to the Kaombo project, Total also operates Block 17 where a final investment decision (FID) was announced by the company in May 2018 for the Zinia 2 deepwater offshore development.

Zinia 2 is located 150 km (93 miles) offshore Angola and will have production capacity of 40,000 bbl/d from the Pazflor Field, which has been in production since 2011.

Total stated in a release that Zinia 2 is the first of several possible short-cycle developments in Block 17 that will unlock the field's full potential by connecting satellite reservoirs to the existing FPSO.

According to Total, Zinia 2 comprises nine wells in water depths ranging from 600 m to 1,200 m (1,968 ft to 3,937 ft).

In its report on West Africa, Wood Mackenzie stated that there could be at least a dozen "Zinia 2-like potential incremental developments" containing 1.4 Bbbl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that could qualify for Angola's marginal field terms. Those terms, according to Wood Mackenzie, require an internal rate of return of 15% for fields up to 300 MMbbl. According to Wood Mackenzie, Zinia 2 holds 80 MMbbl.

Total has at least two more Angolan projects in the works. According to the company, CLOV Phase 2 will require drilling seven additional wells with first oil expected in 2020 and peak production to reach 40,000 bbl/d. Meanwhile, Dalia Phase 3 will see six more wells drilled with first oil expected in 2021 and a production peak of 30,000 bbl/d.

Combined with Zinia 2, CLOV 2 and Dalia 3 will develop 150 MMbbl to maintain the Block 17 production plateau above 400,000 bbl/d until 2023, Total reported.

In March 2018, Total announced it had initiated production from the Moho Nord deep offshore project, 75 km (47 miles) offshore Pointe-Noire in the Republic of the Congo. According to Total, the project has a production capacity of 100,000 boe/d. Moho Nord produces from 34 wells and is tied back to a tension-leg platform and to *Likouf*, a new floating production unit.

Nigeria

Outside of Angola, Total has three additional projects in the works offshore Nigeria that it expects to move forward in the coming two years. According to the company, Owowo with 1 Bboe of resources might see an FID in 2020 with first oil planned for 2024. Total plans for 160,000 boe/d of production leveraging existing facilities in the field.

Bonga South West holds estimated resources of 600 MMboe and could see an FID by 2020. Total reports that first oil could be achieved there in 2024.

Total is also the operator for Preowi, with 100 MMboe of resources. The company reported that an FID is expected on the project by 2020, with first oil planned for 2022. The Preowi project will produce 70,000 boe/d leveraging the *Egina* FPSO. On Jan. 2, Total announced production had commenced on the Egina Field, which is located in about 1,600 m (5,250 ft) of water. According to the company, production from Egina is expected to reach 200,000 bbl/d.

Mauritania and Senegal

BP, in partnership with Kosmos Energy, awarded a FEED contract of the Tortue LNG development project offshore Mauritania and Senegal, which the company announced was nearly complete by year-end 2018. Meanwhile, on Dec. 21, BP and its partners announced the FID for Phase 1 of the development.

BP Upstream Chief Executive Bernard Looney stated in a press release that the FID represents the beginning of a multiphase project that is expected to deliver LNG revenues and gas to Africa and other regions for decades.

In February 2018, the governments of Mauritania and Senegal signed an inter-government cooperation agreement (ICA), which enabled the development of the project to move forward toward an FID. The ICA calls for a 50:50 initial split of resources and revenues between the two countries, as the Tortue Field straddles the border between Senegal and Mauritania.

The West Africa Tortue discovery was made by Kosmos in 2015, which later sold a 60% share and operating duties to BP. First gas on the Tortue project is expected in 2021. According to BP, the Tortue gas field holds an estimated 425 Bcm (15 Tcf) of gas.

Production began in March 2018 at Moho Nord off the coast of the Republic of the Congo. (Source: Total)

Ghana

In January 2018 Exxon Mobil announced it had signed a petroleum agreement with the government of Ghana to acquire E&P rights for the Deepwater Cape Three Points Block. According to Exxon Mobil, acquisition of seismic data and analysis commenced last year. The Deepwater Cape Three Points Block, located 92 km (57 miles) offshore Ghana, measures about 1,482 sq km (572 sq miles), or 366,000 acres, in water depths ranging from 1,550 m to 2,850 m (5,085 ft to 9,350 ft).

Exxon Mobil will be the operator on the project with 80% interest, according to the company, with Ghana National Petroleum Corp. holding 15% interest.

In its 2017 Annual Report, Nigeria's Department of Petroleum Resources listed deepwater and ultradeepwater greenfield projects in the definition stage by Exxon Mobil. The ultradeepwater Nsiko Field in Block 140 is expected to produce at 100,000 bbl/d. Bosi in Block 133 will produce at 140,000 bbl/d, Uge in Block 140 will produce at 110,000 bbl/d and other satellite fields in Block 70 will add 80,000 bbl/d of production to the region. E&P

Optimizing acid diversion in naturally fractured reservoirs

A successful wellbore stimulation program relies on proper fluid placement.

Julio Vasquez, **Christopher Lewis** and
Aaron Beuterbaugh, Halliburton

In addition to an optimized acid fluid formulation that properly removes the corresponding formation damage type, fluid placement is fundamental to successfully stimulating a hydrocarbon-producing wellbore. However, proper acid placement is important when addressing challenging conditions such as long intervals, highly heterogeneous zones, the presence of natural fractures and depleted formations.

This article discusses the successful field implementation of AccessAcid Stimulation service, a self-degradable diverter (SDD) that has been tailored to help provide optimal placement in naturally fractured reservoirs and overcome the limitations of conventional diversion systems.

Various diversion methods to optimize acidizing treatments have been developed and used within the oil and gas industry. The diversion method best suited for a particular situation depends on several factors, including the type of well completion, perforation density, the type of fluid that is produced or injected after the treatment, casing and cement sheath integrity, bottomhole temperature and bottomhole pressure.

These diversion methods generally fall into three categories: mechanical, chemical and dynamic diversion. Mechanical isolation devices, such as a straddle packer, are one of the most effective means to obtain complete acid coverage; however, this method is often impractical or not economically feasible. Various types of chemical diversion methods have been successfully implemented, including graded rock salt, benzoic acid flakes, viscous pills, *in situ* crosslinked acid, crosslinked gel systems, relative-permeability modifiers, degradable particulates, foam and viscoelastic surfactants.

AccessAcid Stimulation service uses self-degradable particulates that effectively divert acid stimulation treatments away from high-permeability and naturally fractured zones to low-permeability zones and/or damaged zones. The system provides leak-off control properties at the fracture level by bridging off against the fracture face or formation face (Figure 1a). The diversion agent is placed in alternating stages with the acid throughout the entire treatment. Customized particle blends can provide near-wellbore diversion for matrix acidizing treatments, and/or near-wellbore and far-field diversion for acid fracturing treatments. Figure 1b shows the SDD blend for near-wellbore diversion. They can be bullheaded or pumped through a coiled tubing (CT) unit. When the acid stimulation treatment is completed, the particulates in the diversion agent will self-degrade based on reservoir temperature at a predicted time, providing excellent regained permeability to hydrocarbon. No cleanup stage is necessary to remove the particles.

FIGURE 1a. Left, AccessAcid Stimulation service provides leak-off control properties at the fracture level by bridging off against the fracture face or formation face.
FIGURE 1b. Right, AccessAcid Stimulation service uses self-degradable particulate with proprietary multimodal, customized particle blends. (Source: Halliburton)

Onshore

The service has been effectively used in a wide variety of reservoir and wellbore conditions, including matrix acidizing and acid fracturing treatments for near-wellbore and far-field diversion.

In one case history, Well A is a land well completed in a mature, oil-producing, naturally fractured carbonate reservoir. This well had a cased-hole and perforated completion with eight perforated intervals (gross interval approximately 417 m [1,368 ft] and net perforations approximately 200 m [650 ft]). After five acidizing treatments, it was not possible to positively impact the decline curve in this well, mainly because of high heterogeneity and a thief zone identified at the bottom zone. It was decided to enhance the matrix acidizing treatment with real-time monitoring using distributed temperature sensing and CT to optimize fluid distribution. The real-time fiber-optic capability allowed adjusting the diverter design in real time to obtain optimum acid coverage. Four alternating stages of acid and diverter were used. After the acid stimulation treatment, a steady hydrocarbon production uplift of 82% was achieved, increasing oil production from 920 bbl/d to 1,680 bbl/d, under the same choke conditions. Figure 2 shows the final acid fluid distribution across the eight intervals.

In another case history, Well B is a land well completed in a mature, gas-producing, naturally fractured carbonate reservoir. This well had a vertical, cased-hole and perforated completion with five sets of clusters (gross interval approximately 45 m [150 ft] and net perforations approximately 27 m [90 ft]). Because of the heterogeneity of this formation, acid diversion was expected to be a challenge.

The operator decided to perform a high-rate matrix acidizing treatment using three acid cycles and two SDD near-wellbore diversion cycles (using emulsified acid and viscosified acid). Additionally, two SDD far-field intra-stages were included in between the acidizing stages. After the pressure response from the first SDD near-wellbore cycle, a decision was made on location to increase the volume and concentration for the second near-wellbore cycle. Both diversion stages were successful based on their pressure response (Figure 3). After the treatment, a temperature log confirmed effective diversion based on contribution

WELLBORE SCHEMATIC AND ACID FLUID DISTRIBUTION

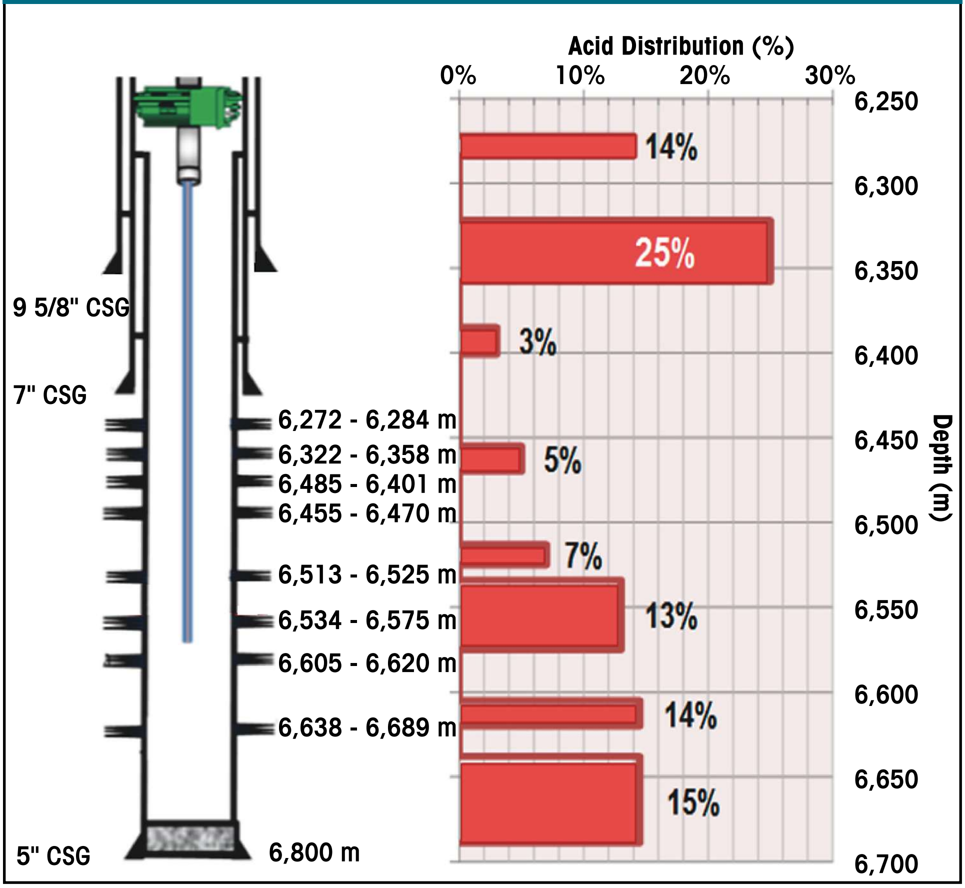


FIGURE 2. At left is the wellbore schematic for Well A, and on the right is the final acid fluid distribution after four diversion stages. (Source: Halliburton)

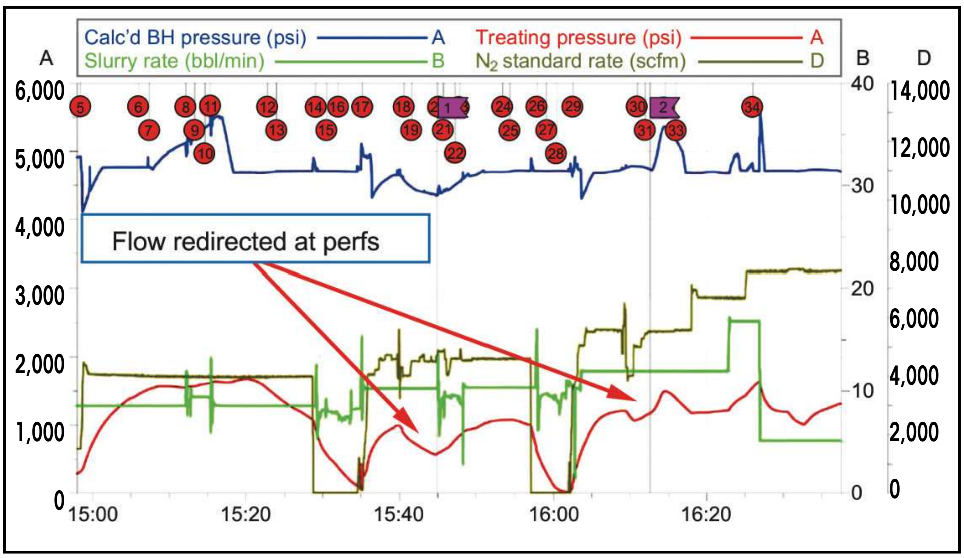


FIGURE 3. The graph depicts Well B's high-rate matrix acidizing pumping schedule, including the SDD near-wellbore and far-field diversion cycles. (Source: Halliburton)

to production from each interval. Post-job analysis showed a skin value of -3.4 and productivity index value outperformed offset wells.

Offshore

Well C is an offshore well completed in a mature, oil-producing, naturally fractured carbonate reservoir. This well had an openhole completion extending 118 m (387 ft) (39°API oil, bottomhole temperature approximately 175 C [347 F], average porosity of about 10% and average permeability 10 mD to 80 mD). The operator requested an acid stimulation treatment in the well. However, because of the long interval, openhole completion and natural fractures, acid diversion was a major challenge in this well. It was decided to incorporate two cycles of the SDD system to help divert the acid away from the natural fractures into the lower permeability zone. Additionally, to further optimize acid coverage, another diverter agent based on a relative permeability modifier was included into the pumping schedule to enhance diversion at the matrix level. After the stimulation treatment, the skin value effectively changed from 23 (measured) to -3 (calculated), with an increase in oil production of 5,300 bbl/d at the same choke conditions. E&P

New CT string design allows shorter taper sections

National Oilwell Varco (NOV) announced the commercial availability of TRUE-TAPER XR, a new coiled tubing (CT) string design optimization that allows shorter taper sections to achieve better results for CT operators working in extended-reach applications, the company said. The TRUE-TAPER XR achieves a linear taper by gradually varying the thickness of the flat steel strip, reducing stress concentrations and bias welds while optimizing safety factors and strength-to-weight ratio. The string design enhancement has more precise string-weight distribution in the lateral, which allows operators to maintain higher performance levels with longer strings while meeting stricter weight requirements. In an early project, a TRUE-TAPER XR string design allowed a customer to reduce the number of tapered sections in its string from four to two; additionally, the total average length of the tapers was reduced by almost 65%. *nov.com*

Subsea system lowers costs by 30%

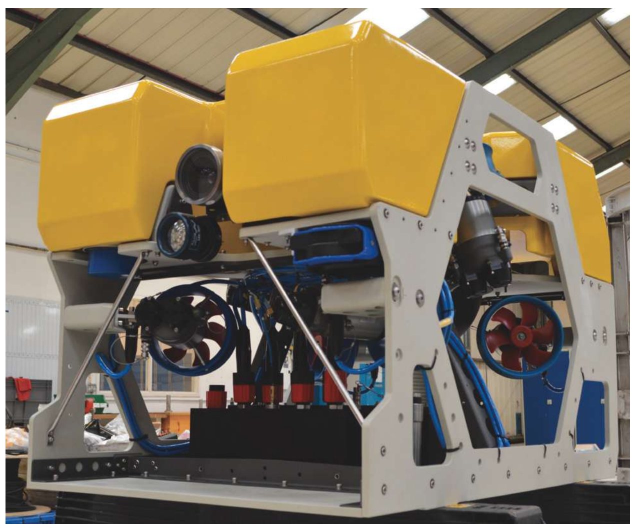
Baker Hughes, a GE company, has released its new approach to subsea development: Subsea Connect, including its Aptara TOTEX-lite subsea system, a suite of new lightweight, modular technologies designed for the full life of the field, a press release stated. By combining planning and risk management, new modular deepwater technology, innovative partnerships and digital tools into a single offering, Subsea Connect can reduce the economic development point of subsea projects by an average of 30% and has the potential to unlock an additional 16 Bbbl of reserves globally. *bhge.com*

New well testing technology delivers actionable information for safer operations

Schlumberger has released its Concert well testing live performance technology. Concert brings real-time surface and downhole measurements, data analysis and collaboration capabilities to well testing, according to a company press release. In the Concert performance ecosystem, all well test data are digitally integrated via wearable technology, wireless sensors and video cameras. Robust software drives web dashboards, accessible anywhere customers specify, with separate teams able to view the same data. Extensive testing of the Concert performance technology has been conducted in Kazakhstan, Saudi Arabia and Australia. The new technology was used in testing the first development wells of a major offshore gas condensate field in Australia. Concert performance introduced new efficiencies to managing the testing spread required for the ultrahigh flow-rate wells. The automated real-time data collection and communication enabled collaborative analysis that accelerated the understanding of the testing operation while significantly reducing the personnel required. *slb.com/concert*

New eROV offers savings for operators

Forum Subsea Technologies' latest electric ROV (eROV) addition is driving cost efficiencies for the subsea sector, a press release stated. The recently launched XLe Spirit is the first observation-class ROV to utilize Forum's Integrated Control Engine to bring greater functionality only commonly found in larger work class vehicles. The advanced control electronics pod fitted to all Forum XLe observation class vehicles enables superior connectivity and expansion capabilities when compared with other ROVs on the market, according to the company. Ethernet interfacing allows seamless integration with other industry sensors using common IP architecture and ease of remote data transfer. The XLe Spirit incorporates several features to maximize its stability for use as a sensor platform, including regulated propulsion power, optimized thruster orientation and location, accurate thruster speed control, and a wide range of auto-functions for positioning and flying. *f-e-t.com*



The XLe Spirit recently completed a 12-week test program at Forum's test tank in Kirkbymoorside, Yorkshire, and it will be sent for sea trials in the first quarter of 2019. (Source: Forum Subsea Technologies)

Frac plugs increase efficiency in cemented completions

Packers Plus Energy Services Inc.'s latest suite of frac plugs is providing operators with higher efficiency plug-and-perf systems worldwide. The TREX cemented prod-

uct line now offers composite and degradable plugs to improve deployment and reduce/eliminate mill-out operations, saving time and reducing risk, a press release stated. The suite of frac plugs includes Lightning Composite Plug, LightningPLUS Composite Plug and LightningBOLT Degradable Plug. The Lightning plug has a combination of composite and cast-iron slips, while the LightningPLUS has full composite slips. Both plugs have a short length that enables fast deployment and quick mill-out operations. The LightningBOLT degradable plug is designed with proprietary material and provides optimal degradation times to minimize debris left in the wellbore. The plugs are rated up to 10,000 psi differential and can be run in conditions up to 149 C (300 F). Each plug is paired with a ball to provide zonal isolation. With more than 2,300 installed in North America, operators are seeing faster mill-out operations from a shorter plug design and composite slips. *packersplus.com*

New technology boosts oil recovery

Tendeka has launched a new technology to optimize oil production and assist with the challenges of effective water injection in fractured reservoirs. FloFuse can increase oil recovery by improving injected water conformance in fractured reservoirs or by ensuring the effective placement of matrix stimulation acids, according to a press release. When installed across a segmented wellbore, FloFuse autonomously chokes back injection into thief zones or large fractures that dominate the outflow profile and ensures effective injection into the rock matrix or fracture structure. This prevents early water breakthrough into production wells, thereby increasing total oil recovery and reducing water production. By triggering at a predetermined flow rate, it reduces the outflow area in the completion compartment. Furthermore, the dynamic and reversible operation of the valve makes it suitable for applications where the permeability contrasts change over time, such as in thermally fractured water injection wells and where matrix stimulation is used to improve near-wellbore permeability. Unlike conventional waterflood management technologies, FloFuse devices are easy to run in horizontal wells and high-rate environments and have a longer life expectancy with less need for maintenance. *tendeka.com*

New fluid mechanics app provides calculation of results

Trelleborg Sealing Solutions has released its Fluid Mechanics Calculator App. The new app covers a wide variety of topics in the field of fluid mechanics and serves as a reference for the analysis, design, maintenance and operation of fluid-related systems, a product announcement stated. The app provides results for different fluid mechanics equations, including those used in civil, structural, pipe flow and general engineering. The Fluid Mechanics Calculator has more than 130 formulas and 360-plus different calculations. It provides fast and convenient calculation of results along with unit conversion support. The app can be downloaded for free in iTunes or Google Play. Claude Kornelis, director digital business development at Trelleborg Sealing Solutions, said, “The Fluid Mechanics Calculator is designed to support fluid thinkers, whether they are students, engineers, analysts or researchers, working in the automotive, aerospace, biotechnology, fluid power, mining, marine or oil and gas industries. It’s for anyone involved in fluid mechanics, not just those specifying seals, and is aimed at making the working lives of engineers easier, whether at their desks or on the go, 24/7.” *tss.trelleborg.com*

New oilfield water intelligence platform

Sourcewater is no longer just a water marketplace, according to a product announcement released in December 2018. Sourcewater acquired the Digital H2O Water Asset Intelligence service from Genscape in November and launched an all-new integrated oilfield water and disposal intelligence platform serving the upstream energy industry with advanced water data science. Sourcewater gathers intel from its exclusive marketplace, weekly satellite imagery, terabytes of state regulatory files and from daily outbound market research calls to thousands of water market players. Then the company runs quality assurance and data science on all of these data and puts the results in a fast, easy-to-use online digital map. With its acquisition of Digital H2O, Sourcewater now shows which operator leases send water to each Texas disposal each month, how much water they send, water production for every lease, and utilization and pressure trends for every saltwater disposal well. *sourcewater.com* E&P

1 US

According to IHS Markit, Oxy USA Inc. has completed two high-volume, extended-lateral Delaware Basin discoveries in the Mesa Verde Field area in Lea County, N.M. The Mesa Verde WC Unit 001H is in Section 17-24s-32e. It produced 4,775 bbl of oil, 254,852 cu. m (9 MMcf) of gas and 5,736 bbl of water per day from the Wolfcamp. It was drilled to 6,791 m (22,281 ft) out of a 4,313-m (14,150-ft) pilot hole. The lateral bottomed 3 km (2 miles) to the north in Section 8 with a true vertical depth of 3,674 m (12,054 ft). An offsetting horizontal Bone Spring producer, Mesa Verde BS Unit 001H, flowed 2,246 bbl of crude, 104,772 cu. m (3.7 MMcf) of gas and 5,082 bbl of water per day from perforations at 2,881 m to 5,868 m (9,451 ft to 19,251 ft). Gauged on a 41/64-in. choke, the shut-in casing pressure was 1,077 psi. It was drilled to the west to 5,903 m (19,366 ft) with a 2,832 m (9,291 ft) true vertical depth.

2 Colombia

Amerisur Resources completed the Indico-1 well in Colombia's CPO-5 Block. The well was drilled to 3,232 m (10,604 ft) and was targeting L3 Sandstone in Une. Initial wireline analysis indicated 64 m (209 net ft) of pay with no water in an oil column in L3 Sandstone. The L3 Sandstone unit is a high-quality sand with some shale intercalations and is in the Paleozoic basement. Additional wireline logging, including pressure and sampling across the reservoir, are planned. The L3 Sandstone package also produces at the nearby Mariposa-1 well, which tested flowing approximately 3,200 bbl/d of oil from a 3-m (10-ft) interval. When operations are finished at Indico-1, the rig will be moved to drill Sol-1 about 6.5 km (4 miles) south of Indico-1 and it will be targeting LS3.

3 Argentina

President Energy has completed and tested the PFE 1001 well at its Puesto Flores/Estancia Vieja prospect in the Rio Negro Province in Argentina. The eastern Neuquén Basin well was targeting secondary Pre Cuyo and primary Punta Rosada, and it was tested flowing approximately 400 bbl/d from Punta Rosada with little water and good downhole pressure. A third well in the field is underway at development venture PFO 1007.

4 Guyana

Tullow Oil Plc is planning to drill an exploration well in offshore Guyana's Orinduik Block this year. The operator will drill the venture from a conventional drillship in 1,350 m (4,429 ft) of water. The target is a stratigraphically trapped canyon turbidite Upper Cretaceous formation. Partners in the block are Eco Atlantic and Total. A second well is planned later in the year.

5 Guyana

Exxon Mobil Corp. reported another discovery in the offshore Guyana Stabroek Block at Pluma-1. The well hit approximately 37 m (121 ft) of high-quality pay in a hydrocarbon-bearing sandstone reservoir. It was drilled to 5,013 m (16,447 ft) and is in 1,018 m (3,340 ft) of water. This discovery increases the recoverable resource for the block to more than 5 Bboe. The drillship will be moved to drill at the Tilapia-1 prospect about 6 km (4 miles) to the west. Ongoing work will evaluate development options in the southeastern portion of the block, potentially combining Pluma with prior Turbot and Longtail discoveries into a major new development area.

6 UK

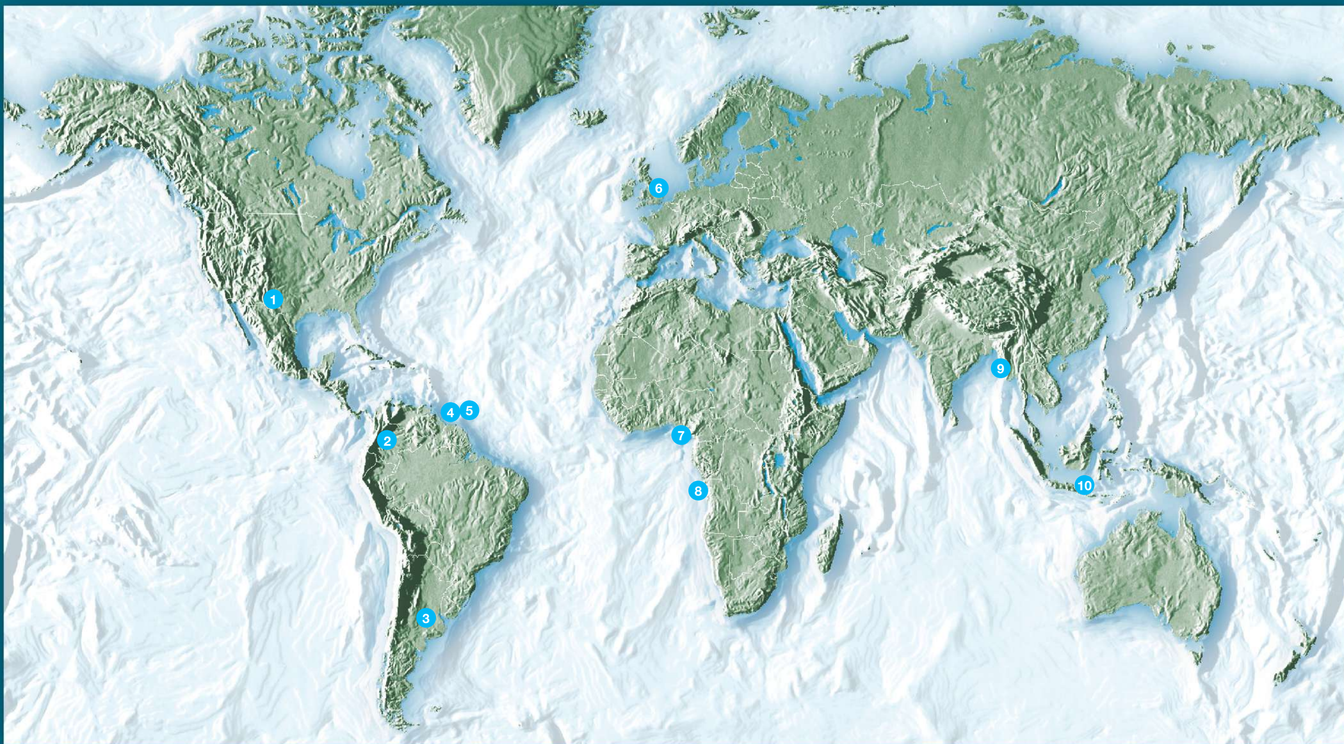
Egdon Resources Plc has received permission to drill exploration well Biscathorpe-2 in onshore Lincolnshire, U.K., in the petroleum exploration and development license (PEDL) 253 Block Biscathorpe Prospect. The venture is on the southern margin of the Humber Basin, on trend with and west of Keddington Field and Saltfleetby gas field. It is one of the largest remaining undrilled onshore U.K. oil prospects where there is stratigraphic trapping. A 2,100-m (6,890-ft) vertical well is targeting Carboniferous Westphalian A-aged basal sand. Biscathorpe has mean gross prospective resources of 14 MMbbl. Egdon Resources is the operator of PEDL 253 and the test (35.80% interest) in partnership with Montrose Industries (22.20%), Union Jack Oil (22%) and Humber Oil & Gas (20%).

7 Nigeria

Test results were announced by Eland Oil & Gas Plc from exploration well Ubima-1 in Nigeria's Block OML11. The venture is a dual completion in E1000/E2000 and the F7000 reservoirs. The F7000 reservoir was tested flowing about 2,500 bbl/d of oil, and the E1000/E2000 reservoir flowed 900 bbl/d to 1,000 bbl/d. It was tested on a 24/60-in. choke with a flowing tubing head pressure of 315 psi. The company is planning to perform an extended well test this year. Eland holds a 40% interest in partnership with Allgrace Energy, holding the balance of interest in the Ubima Field. The partners plan to initiate an early production system in the field.

8 Angola

A new oil discovery was reported by Eni in the Afoxé exploration prospect in offshore Angola Block



15/06. The discovery is estimated to contain between 170 MMbbl and 200 MMbbl of oil in place. The Afoxé-1 NFW well is in the southeastern portion of Block 15/06. The well was drilled to 1,723 m (5,653 ft) and area water depth is 780 m (2,559 ft). The well proved a 20-m (66-ft) net pay zone in Upper Miocene Sandstones. Current testing indicates a production capacity in excess of 5,000 bbl/d of oil. The new nearby discoveries of Kalimba and Afoxé have an estimated potential of 400 MMboe to 500 MMboe of high-quality oil in place, and development planning is underway. Eni is planning to drill up to four new offshore exploration wells in Block 15/06 this year.

9 Myanmar

A deepwater gas discovery was announced by Woodside Petroleum on Myanmar Block A-6. The Shwe Yee Htun-2 exploration well was the fifth consecutive discovery within the Southern Rakhine Basin concession. The 4,850-m (15,912-ft) well was drilled to appraise the Shwe Yee Htun-1 discovery and area water depth is 2,325 m (7,628 ft). The wireline formation evaluation, including pressure measurements, indicates that the reservoir is in pressure communication with Shwe Yee Htun-1, which is about 10 km (6 miles) east. The minimum total gross gas column based on wireline pressure data from both wells is estimated to be approximately 240 m (787 ft). The formation evaluation also indicates that Shwe Yee Htun-2 encountered 40 m (131 ft) of net gas pay and was tested flowing 1.4 MMcm/d (50 MMcf/d) of gas during testing on a 40/64-in. choke. Woodside is the operator (40% interest) along with Total (40%) and MPRL E&P (20%).

10 Indonesia

Cue Energy Resources Ltd. announced a gas discovery at the offshore Paus Biru-1 exploration well in East Java in Indonesia's Madura Strait. The well flowed 317,149 cu. m/d (11.2 MMcf/d) of gas during testing on a 64/64-in. choke with a wellhead pressure of 525 psi. Preliminary gas sample analysis indicates low inert content. The discovery is in the Sampang PSC and is east of the producing Oyong Gas Field. It was drilled to 710 m (2,329 ft) and intersected an estimated net gas pay of 29 m (95 ft) across the primary Mundu Limestone Globigerina reservoir. The well is being plugged and abandoned as a gas discovery. E&P

PEOPLE

THREE60 Energy has named **Walter Thain** group CEO.

Katy Gifford has been appointed CEO of Aubin, a chemical solutions provider, and former CEO **Paddy Collins** has been appointed CTO.

Keyera Corp. has appointed **Bradley W. Lock** COO and senior vice president, and **C. Dean Setoguchi** has been named senior vice president and chief commercial officer. The company also selected **Jamie Urquhart** as vice president of marketing; **Rick Koshman** as vice president of corporate development; **Jarrod Beztilny** as vice president of operations, gathering and processing; and **John Hunszinger** as vice president of operations, liquids infrastructure.

Hydraulic Systems Inc. has elected **James Bement** CEO.

Will Giraud has assumed the position of executive vice president and COO at Concho Resources, succeeding **Joe Wright**, who retired from the role at year-end 2018 and continues to serve on the company's board of directors. **Brenda Schroer** has been appointed senior vice president, CFO and treasurer, and **Price Moncrief** has been appointed senior vice president of corporate development and midstream. Additionally, Concho promoted **Clay Bateman** to senior vice president of assets; **Keith Corbett** to senior vice president of corporate engineering and planning; **Scott Kidwell** to senior vice president of administration; **Jeff Gasch** to vice president of the Delaware Basin; **Jacob Gobar** to vice president and chief accounting officer; **Aaron Hunter** to vice president of the Midland Basin; and **Jere Thompson** to vice president of planning.

Husky Energy has named **Jeff Hart** CFO.

Elizabeth T. Wilkinson has been appointed CFO of Flotek Industries. **Matt Marietta**, executive vice president of finance and corporate development, has left the company. Additionally, **H. Richard Walton** will no longer serve as chief accounting officer; however, he will continue with the company as a consultant to facilitate the leadership transition.

Chevron Corp. named **Navin Mahajan** vice president and treasurer, effective Feb. 1. The company also appointed **Dale Walsh** vice president of corporate affairs, effective March 1. **Debra Reed-Klages** has been elected to Chevron's board of directors.

EOG Resources Inc. has promoted **Kenneth W. "Ken" Boedeker** to executive vice president of E&P. **David W. Trice** will assume the role of executive vice president and general manager of EOG's Denver office. EOG also appointed **Julie J. Robertson** to its board of directors and announced that Ambassador **Frank G. Wisner** plans to retire from the board at the end of his current term and not stand for re-election in 2019.

Consumers Energy named **Tonya Berry** vice president of operations performance.

TAM International Inc. has promoted **Barton Sponchia** to vice president of the western hemisphere.

Caroline Muir has been promoted to partner at Deloitte's Aberdeen office.

TWMA, a provider of specialized drilling waste management services, appointed **Mohamed Galal** regional director for the Middle East and North Africa.

TEMS International has appointed **Nicola Lomax** as QHSE manager.

The Petroleum Industry Data Exchange Inc. standards body welcomed **Wissam Kahoul** of Baker Hughes, a GE company, as its newest international ambassador.

Nissan Chemical America Corp. added **Dr. Sam Maguire-Boyle** as its most recent hire to the nanoActiv team in Pasadena.

Devon Energy Corp.'s board of directors has elected **Duane C. Radtke** as its new vice chairman. Also, **John Richels** will retire from the board in June.

ROVOP has appointed **David Lamont** as a nonexecutive director.

Kreuz Subsea has selected **Knut Eriksen** as the board's first independent nonexecutive director.

MDU Resources Group Inc. has elected **Edward A. Ryan** to its board of directors.

Strike Energy Ltd. has appointed **Stephen Bizzell** nonexecutive director, and **Tim Goyder** has resigned from the board.

Cairn Energy Plc announced that **Jackie Sheppard** retired as a nonexecutive director of the company.

on the MOVE

COMPANIES

Saudi Aramco has broken ground at Lomonosov Moscow State University for an R&D center that will explore upstream technologies and artificial intelligence.

Siemens has started the construction of a new, modern energy service and training center in Warnes, Bolivia. The center is located on a 9,200-sq-m (99,028-sq-ft) site at the Parque Industrial Latinoamericano and also will function as a hub for servicing power equipment installed in the South America region. Siemens is investing more than $23 million in the facility.

DynaEnergetics, a business of **DMC Global Inc.**, has officially opened its manufacturing, assembly and administrative facilities on its industrial campus in Blum, Texas. The facility spans 6,875 sq m (74,000 sq ft).

Diamondback Energy Inc. has completed its acquisition of **Energen Corp.**

Santos has completed its acquisition of **Quadrant Energy** for $1.93 billion.

Sourcewater Inc. has acquired the data and technology of **Digital H2O Inc.**, a subsidiary of **Genscape Inc.**

Sharp Energy Group (Services) has completed its acquisition of **Alpha Oil Tools** from **Weatherford International.**

DEA Deutsche Erdoel AG has signed an agreement to acquire **Sierra Oil & Gas**, an independent Mexican oil and gas company. Once completed, it will be the largest upstream mergers and acquisitions transaction in the country since the liberalization of the petroleum sector in 2013. The transaction is expected to close in the first half of 2019. E&P

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Connecting subsurface intelligence with surface operations

The digital twin makes operational collaboration a reality across E&P operations.

Steve Santy, Emerson Automation Solutions

The oilfield designation "exploration & production" (E&P) dates back to Spindletop. Historically, however, the strongest connection between the two very different worlds often has been the ampersand. Exploration teams invest millions of dollars to collect mega-volumes of data that characterize the subsurface. Once drilling begins, however, these data frequently sit idle, untapped by production teams despite the data's incredible value in reservoir imaging, interpretation, modeling and characterization. Today, help is on the way.

The emerging concept of a digital twin is bridging the gap between E&P by connecting all surface and subsurface components of the exploration-to-market value chain. Integrating data from smart sensors with new types of reservoir intelligence enables full-scale operational control and collaboration between the subsurface reservoir and surface operations—a means of reduced risk, significant savings and increased recovery.

> With the massive growth in petrotechnical data, machine learning has become an essential tool for E&P applications.

Widespread adoption of cloud technology is breaking down barriers that have traditionally kept geoscientists and engineers trapped in workflow silos and prevented the day-to-day use of subsurface models in production operations. With the cloud, digitalized information can be shared easily across the enterprise, and intelligence can be made available to all stakeholders in the workflow.

The advent and maturation of Big Data analytics—both physics-based and machine learning—complete the digital twin. With terabytes of archived data, powerful, automated analytical tools are needed to create the actionable information that drives more holistic insight into improving business value.

With the massive growth in petrotechnical data, machine learning has become an essential tool for E&P applications. Emerson uses machine-learning-based technologies to characterize the hydrocarbon potential and behavior of the subsurface from large amounts of data. This enables users to describe and explain an existing outcome, predict what will happen and provide recommendations for risk management and decision-making.

Emerson uses five key elements to link subsurface intelligence to surface operations:

1. Pursue the best science, avoiding approximations by using all available data;
2. Provide a comprehensive software solution that covers the entire workflow;
3. Deliver a platform that integrates relevant third-party data to help unify the workflow and minimize the duplication of data;
4. Deploy software and domain expertise as a turnkey service to ensure the highest value actionable intelligence to solve problems; and
5. Leverage an extensive line of smart sensors and devices to provide secure, reliable, real-time data and communications that drive the digital twin.

By leveraging these elements, Emerson has been able to create unique value in a variety of real-world scenarios. For example, a major international oil company sought to establish an automated and repeatable workflow to capture and propagate uncertainties across project stages. The goal was to establish a durable, evergreen modeling workflow that could be easily updated as new data arrived. Combining the cloud and modern analytics, Emerson used real production data to update the original models and reduce uncertainties automatically. The result was that the operator reduced cycle times by more than 60% and achieved a better history match and understanding of reservoir uncertainty.

By connecting predictive analytics and smart sensors in a cloud-based environment, the digital twin improves E&P operations. Applied across the oil and gas value chain, it can eliminate billions of dollars in inefficiency, accelerate operations, increase recovery, minimize capex and reduce risk. Moreover, it is finally connecting E&P for benefits far more substantial than an ampersand. E&P