HARTENERGY JANUARY 2021

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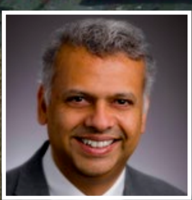
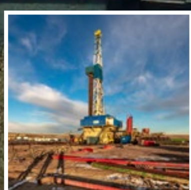
Charting a New Course

Frac innovations accelerate financial and environmental sustainability efforts



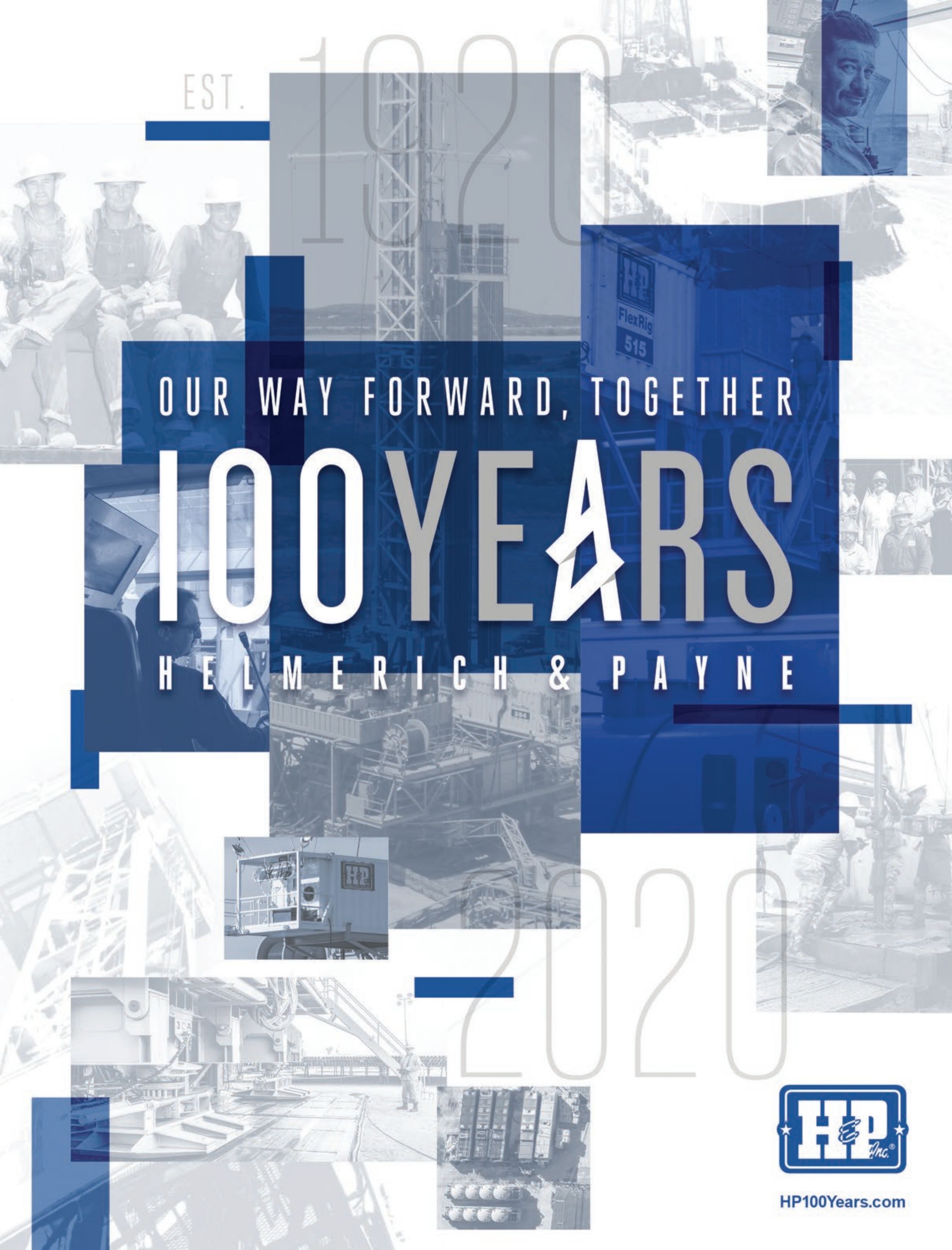
Q&A with Weatherford CEO Girish Saligram



Drilling Automation

Hydraulic Fracturing Tech Showcase

Special Report: US Shales Scorecard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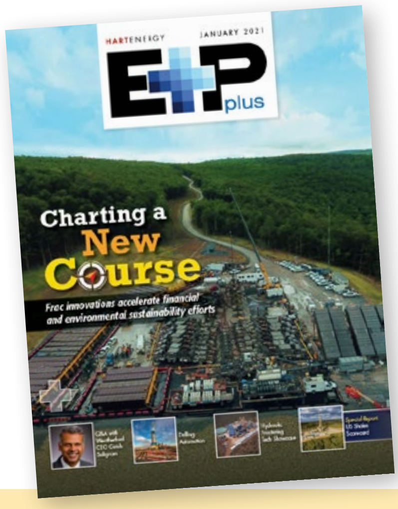

About The Cover: As the North American shale industry slowly recovers from the devastation of 2020, new technologies and frac designs are helping companies achieve greater operational and financial efficiencies. (Cover photo courtesy of Universal Pressure Pumping; Cover design by Melissa Ritchie and Alexa Sanders; Bottom images from left to right courtesy of Weatherford, Marc Morrisson/marcmorrison.com; Sobrevolando Patagonia/Shutterstock.com; and Marc Morrison/marcmorrison.com)

Coming Next Month: The February cover story will focus on remote operations and will include interviews with Weatherford, Emerson, Baker Hughes, BCG, Shell and InEight. The Executive Q&A will feature an exclusive video interview with Scott Dale, executive director with Halliburton Labs. This issue also will highlight an artificial intelligence roundtable video. The Company Spotlight will feature a video Q&A with Varel, and the Regional Report will cover the Arctic. As always, E&P Plus will include its exploration, drilling, completions, production and offshore features in every issue. While you're waiting for your next copy of E&P Plus, be sure to visit HartEnergy.com for the latest news, industry updates and unique industry analysis.

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Colorado School of Mines hosts online fall 2020 reservoir characterization project

By Larry Prado, Activity Editor

The Colorado School of Mines Reservoir Characterization Project featured field projects from across the globe including the study of legacy wells and wells currently being drilled by HighPoint Resources in the Denver-Julesburg Basin.

Pioneer's Sheffield: Few independents will survive oil downturn

By Joseph Markman, Senior Editor

The consolidation trend among oil and gas producers will continue before vaccines pave the way for recovery, Pioneer CEO Scott Sheffield said Dec. 1 at the Reuters Future of Oil & Gas 2020 virtual conference.

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HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

A&D roundtable: A pinprick of light at tunnel's end

2020 was a dark year for A&D, but a variety of factors point toward bright spots in the foreseeable future. Leaders from Detring Energy Advisors, EnergyNet and UBS Investment Bank share their thoughts on why in this roundtable with Hart Energy's Emily Patsy.

Executive Q&A: How ABB's new digital platform offers relief to struggling oil producers

Brandon Spencer, president of ABB Energy Industries, sits down with Hart Energy's Faiza Rizvi to explain how the company's Adaptive Execution portal offers relief to oil producers struggling with capital restrictions and project delays.

Hart Energy names 2020 Forty Under 40 honorees

Out of hundreds of nominations across E&P, service, A&D, midstream and finance, the Oil and Gas Investor team hand-picked 40 influential individuals who are furthering the goals of their organizations and the industry through their initiative, intelligence and persistence. View the 2020 Forty Under 40 honorees, their bios and video interviews at HartEnergy.com/fortyunder40/2020.

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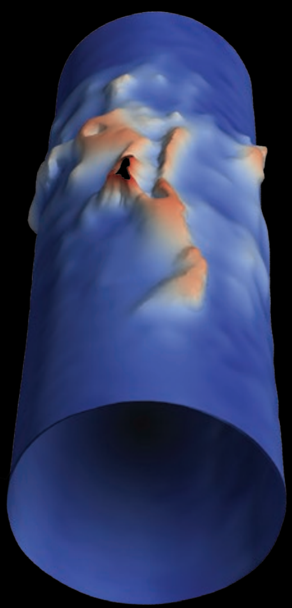
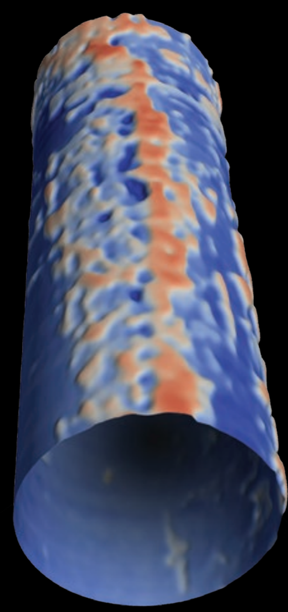


Casing Damage

Perforation Erosion



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As I
See It

Is this a watershed moment?

Watershed moment: A critical turning point in time where everything changes so that it will never be the same as before.

In this video interview, Daniel Yergin, vice chairman of IHS Markit and Pulitzer Prize-winning author, spoke with Hart Energy about his latest book and the industry.

By definition, it's impossible to definitively answer this question. Watershed moments, of course, are usually deciphered in hindsight. But what the heck, let's throw caution to the wind and try to look ahead anyway.

I had been pondering this question in my mind for the better part of autumn, and then I got the chance to ask it directly to someone who understands much more about the oil and gas industry and its history than me. So I asked Daniel Yergin, the vice chairman of IHS Markit and Pulitzer Prize-winning author, during a one-on-one video interview about his latest book, "The New Map: Energy, Climate and Clash of Nations," as well as the industry as a whole. Not surprisingly, I got a very insightful and even more thought-provoking answer.

"Yes, in the sense that the energy markets are going to be competitive in a way that they were not before. They'll be competitive with wind and solar, competitive with electric cars," he said, reiterating, however, all of this will take quite a bit of time. "I think that's a very interesting way to see it. It is a much more competitive landscape, and public policy is going to be much more active in it. Companies will adapt to that, but I think if wind and solar took a long time, carbon capture will have to be part of it because oil and gas are going to be a big part of the energy mix in 2040 and 2050."

So maybe we are in a watershed moment but just the beginning of it? I've started to see it that way of late. The industry's watershed moment is sure to last two to three decades, at least.

There is no doubt things are changing. The energy transition is in full swing.

As Yergin pointed out, solar and wind technologies actually began to take shape in the early 1970s but took 40 years or so to come to market. Now they are a very competitive part of the energy market.

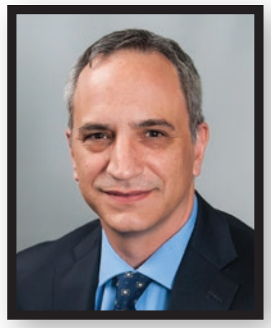
While I think we are in a watershed moment—and, of course, only time will tell for certain—there's still plenty of business to be had, particularly when demand for oil and gas in China, India and the developing world is still growing.

As Yergin discussed with me in the video, some 3 billion people still live in energy poverty. There's an interesting quote in his book from the Nigerian petroleum minister in which he said his country has a lot of people whose income needs to be improved, whose health needs to be improved, and they have to get natural gas to them.

We live in a modern society that wants quick answers and resolutions before it's time. Some impatient people like me even want to get answers to questions that only hindsight can illuminate. But energy is an industry that requires patience. We all know that from the cyclical nature of the beast throughout its history.

So expect this moment to last quite a long time. +

Len Vermillion



Len Vermillion
Editorial Director
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"I think that's a very interesting way to see it. It is a much more competitive landscape, and public policy is going to be much more active in it."

—Daniel Yergin, IHS Markit

Read more commentary at
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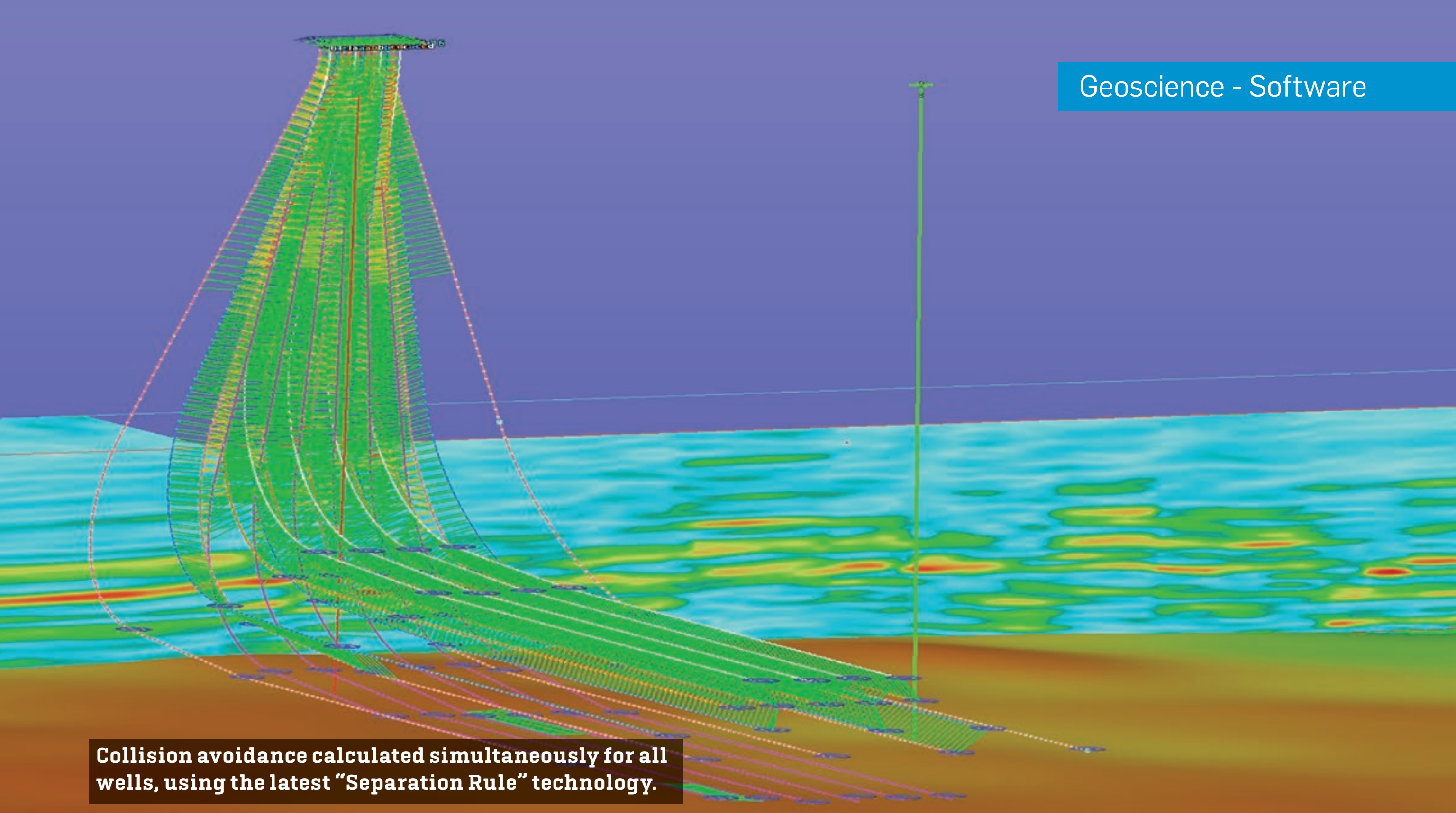
Geoscience - Software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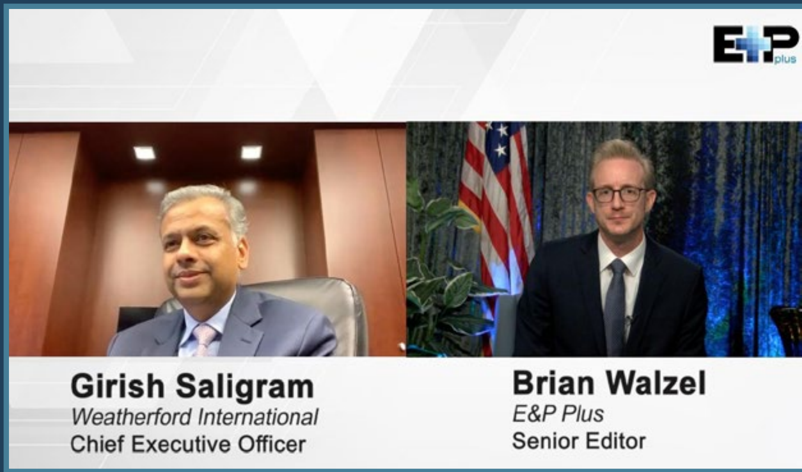

In this exclusive video interview, Weatherford CEO Girish Saligram shares how he plans to lead the company as the industry recovers.

New Weatherford CEO shares his plans for leading the company in 2021

Girish Saligram talks energy transition and developing mature fields.

Brian Walzel, Senior Editor

Girish Saligram

In September 2020, Weatherford International named Girish Saligram the new CEO. Officially taking over a month later, Saligram heads one of the world's largest oilfield service companies. Weatherford's offerings include tools and systems for drilling, completions, production, formation evaluation, tubulars, interventions and abandonment.

Before joining Weatherford, Saligram served Exterran Corp. as COO and previously as president of Global Services after joining the company in 2016. Prior to Exterran, Saligram spent 20 years with GE as a business leader in industry sectors across the globe, including his last position as general manager of Downstream Products & Services with GE Oil & Gas. Prior to that, Saligram led the GE Oil & Gas Contractual Services business based in Florence, Italy. Before his eight years in the oil and gas sector, Saligram spent 12 years with GE Healthcare in engineering, services, operations and other commercial roles.

Saligram recently sat down with E&P Plus to talk about how he plans to lead Weatherford as the industry recovers from one of the most challenging periods in its history. He also discussed the energy transition, Weatherford's role in the transition as well as the importance of continuing to develop mature fields—both onshore and offshore—around the world. +

SPONSORED CONTENT

Cut Frac Sand Cost, Improve Your ESG Score

The cost of hydraulic fracturing on a tight gas or oil well in North America is the single largest item in a well's AFE and proppant delivered is the largest single component of the fracturing invoice. PropX has developed a method to cut total delivered cost of proppant while reducing an operator's or service company's environmental impact.

This new method (patent pending) involves a system to store and deliver wet sand to the frac blender. Skipping the drying process after mined sand is washed saves significant energy and the CO_2, VOCs, Nox and silica dust emissions are reduced or eliminated.

Existing Technology – PropX worked with clients and manufacturing partners to develop this wet sand system. It's based on the successful PropX containerized delivery system, used on nearly 25% of U.S. hydraulic fracturing sites, which has enabled our clients to set new sand throughput records in multiple basins, often exceeding 10 - 13 Million #/crew/day.

Wet Sand Technology – The basic PropX platform was augmented to agitate wet sand inside the containers. This creates flow onto the conveyor which delivers wet sand to a metering conveyor belt. The metering belt bypasses traditional blender hopper augers and instead, delivers wet sand directly into the blender tub. This high-throughput system has pumped over 1 billion pounds of wet sand during the past year of field operations.

The direct delivery system digitally connects the metering conveyor to the blender control system and continuously calibrates required sand volume into the blender per unit of time, correcting for moisture content. Inputs from the frac van and blender adjust the PropX "Baby Beast" metering conveyor for seamless, automated use.

Impact on Cost of Sand Delivered – A typical frac sand mine has four operations: 1) excavating, 2) washing/sizing, 3) drying and 4) storage. Drying and vertical storage facilities are the plant's most operationally complex, expensive and labor-intensive operations. Total savings of $5- $10/ton comes primarily from variable cost savings for personnel, maintenance and energy cost.

Roughly 1/3 of plant personnel work in drying operations. Depending on burner efficiency and fuel source, $1.50 to more than $5.00 per ton can be saved just on energy to power the drying facility. In addition, 40-60% of the capital expense to build & permit a new mine lies in the drying and vertical storage facilities. This huge number can be eliminated by implementing wet sand processes. Finally, wet sand technology is ideal for novel "mobile-mini mine" concepts, offsetting prohibitively expensive utilities and air quality permits for a drying facility. Wet sand simplifies the supply chain by eliminating the drying facility, shrinks the plant and moves it closer to end users' acreage.

This innovative wet sand handling system is built upon the proven PropX containerized sand delivery process.

ESG Impact – Significant environmental benefits are realized with the use of wet sand because CO_2, NOX and VOC emissions from drying are reduced or eliminated. (Currently, around 200 tons of CO_2 is emitted per 10,000 tons of sand dried.) To put this into perspective, if all 43 million tons of sand used in the Permian Basin in 2018 had been wet sand, around 850,000 tons of CO_2 would have been eliminated, equal to removing about 300,000 cars from the road. Plus, safety is improved for all wellsite personnel. Silica dust measurements near the PropX wet sand system have registered below measurement equipment's threshold sensitivity.

Conclusion – PropX, a Denver-based last mile proppant logistics equipment provider, has developed a revolutionary system that fits today's market, meeting demand for cheaper, more efficient and more environmentally friendly frac sand delivery. PropX customers are using the containerized system in every major US tight oil or gas basin including the Permian, MidCon, Eagle Ford, Haynesville, DJ, Bakken and Utica/Marcellus. +

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ChampionX chemical solutions and services provide chemistry, technology, engineering support and onsite expertise to improve outcomes for upstream and midstream oil and gas operations. (Source: ChampionX)

ChampionX president and CEO talks R&D, digitalization and the energy transition

Soma Somasundaram shares details about how the company battled through 2020, its ESG efforts, digital technologies and current R&D projects.

Ariana Hurtado, Senior Managing Editor, Publications

In June 2020, ChampionX Corp. completed the merger of the businesses of Apergy Corp. and ChampionX Holding Inc., the former upstream energy business of Nalco Champion. Apergy then changed its name to ChampionX Corp. Now ChampionX has a team of nearly 7,000 people globally, and the company offers chemical, artificial lift, drilling and digital technologies for the reservoir, production, midstream and water treatment markets.

"The creation of ChampionX through the merger of Apergy and the Nalco Champion upstream chemicals business has been transformative and a complementary combination in strategic, operational and financial dimensions," President and CEO Soma Somasundaram told E&P Plus. "Our combination created a global leader in production optimization and an essential player in the oil and gas market with a strong portfolio, global customer base and footprint, and strong financial profile."

Somasundaram said the company's strategy moving forward involves five strategic elements: "realizing the synergies we have laid out, accelerating our digital and digitally enabled revenue streams, leveraging our enhanced global footprint to increase our international sales, building our continuous improvement culture, and evolving our portfolio for sustained growth as the world undergoes an energy transition."

In this exclusive interview with E&P Plus, Somasundaram shares details about how the company battled through 2020, its ESG efforts, digital technologies and current R&D projects.

E&P Plus: How did ChampionX successfully navigate through the chaos of 2020?

Somasundaram: It was a challenging year, but we transformed our company and capability in a hugely positive way.

Our teams adapted quickly to the virtual working environment amidst the global pandemic and worked diligently to complete the planned merger.

With COVID-19, we recognized risks early and quickly implemented protections for our site-essential and field personnel as well as remote-working protocols for others. Our Crisis Management Team managed our safety and health protocols and stepped up communication to employees.

We executed our downturn playbook, taking early action as the market changed. We know that responding quickly to industry cycles is important to protect short-term capability and be ready for the recovery. Like many companies, we focused on managing cash flow and expenses to weather the downturn, while preserving our core capabilities.

Coming together as ChampionX gave us a tremendous advantage, because it helped us take our 130 years of experience in the market and reposition what we do to meet the needs of the industry as it changed dramatically.

E&P Plus: Can you share details about any R&D projects you are working on for the upstream sector?

Somasundaram: One of our operating principles is developing and deploying technology that delivers positive impact. R&D is central to our purpose, and we prove it through the more than 2,500 patents we have as a company.

Our R&D priorities are focused on solving customer problems, improving their productivity and helping them safely produce oil and gas more sustainably. This means developing innovative chemistries, advanced materials and coatings, smart equipment, advanced digital solutions and thoughtful integration of digital and physical assets.

One recent example is the collaboration agreement we announced in November [2020] with Modumetal to introduce our Norris Rod couplings coated with nanolaminate technology to improve equipment reliability and lower customer operating expenses.

We've had other recent game-changing advancements, like our Excelceor chemical technology that adds water-soluble polymers to increase viscosity in injection water during the waterflooding process to improve sweep efficiency. We're now deploying that in onshore and offshore production.

Our innovation philosophy isn't limited to new molecules or equipment; it's also about continuously improving our operations to deliver superior outcomes to all our stakeholders. This involves digitizing our critical work processes to eliminate waste and improve customer and employee experiences.

E&P Plus: Big Data, artificial intelligence and digitalization are all current buzzwords. How is your company keeping up with these trends?

Somasundaram: Digitization of the oil field isn't new, and we've demonstrated our digital capability for years. Our digital portfolio brings together modular solutions for production optimization, asset integrity management, process control, downhole monitoring and more in a single secure platform that's easy to deploy. We combine proprietary physics-based models with artificial intelligence and advanced machine learning models to monitor, analyze, predict and optimize producing wells and assets. The modular nature of our digital solutions helps our customers choose the right solution for them depending on the economic value of their asset and their organization's digital maturity. Our goal is to deliver at least a fivefold return on our customers' investments in digital by delivering improved outcomes in safety, productivity and sustainability.

"We have unique opportunities ahead of us, and we're very excited about our future."

– Soma Somasundaram, ChampionX

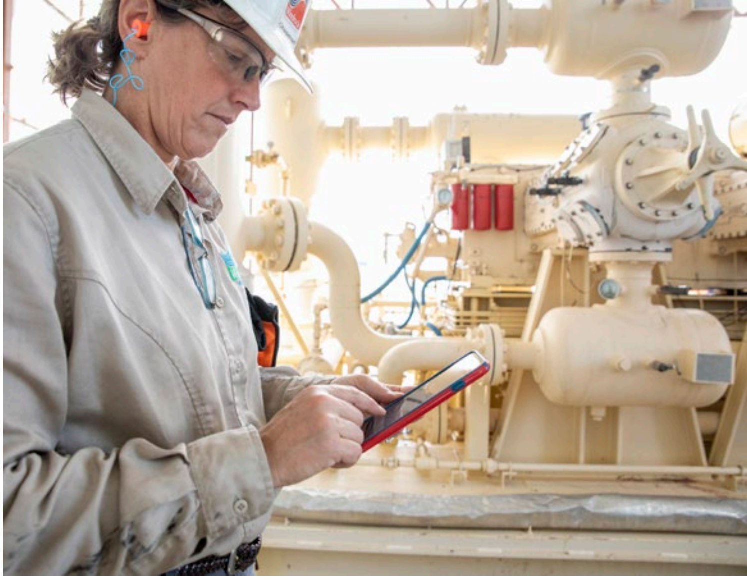
E&P Plus: Another buzzword is sustainability. How are you supporting operators aiming for a net-zero future?

Somasundaram: Our organization's purpose of improving lives is aligned with ESG and sustainability. We have further elevated our sustainability focus by creating a senior-level role reporting directly to the CEO that leads our ESG efforts. We already have many technologies–including our innovative chemistries, artificial lift and digital technologies–used by customers today that reduce carbon footprint and help them deliver on their sustainability goals. Our Chemical Technologies business is leading in these efforts and has developed example case histories of this around the world. We look forward to sharing more on sustainability as we advance our ESG efforts. We know the energy transition is upon us, and we believe we are well positioned to support the industry with our capability.

E&P Plus: What do you see as the path forward for the oil and gas industry?

Somasundaram: As I think about the future, it's clear that the energy transition is real and driven by the need to balance prosperity with sustainability. I see the oil and gas industry as part of the solution in the lower-carbon future, requiring us to drive innovations that produce oil and gas safely and sustainably. We need to integrate sustainability as part of our business strategy. In this transition, our industry has an important role to play in developing realistic solutions that use all available resources to produce reliable, affordable and cleaner energy that the world needs. In addition, we must exercise strong financial discipline and pursue goals that benefit all our stakeholders.

E&P Plus: You have held numerous CEO and senior leadership positions at notable service companies in the industry–Apergy, Dover and Baker Hughes to name a few–so what do you think makes a good leader?

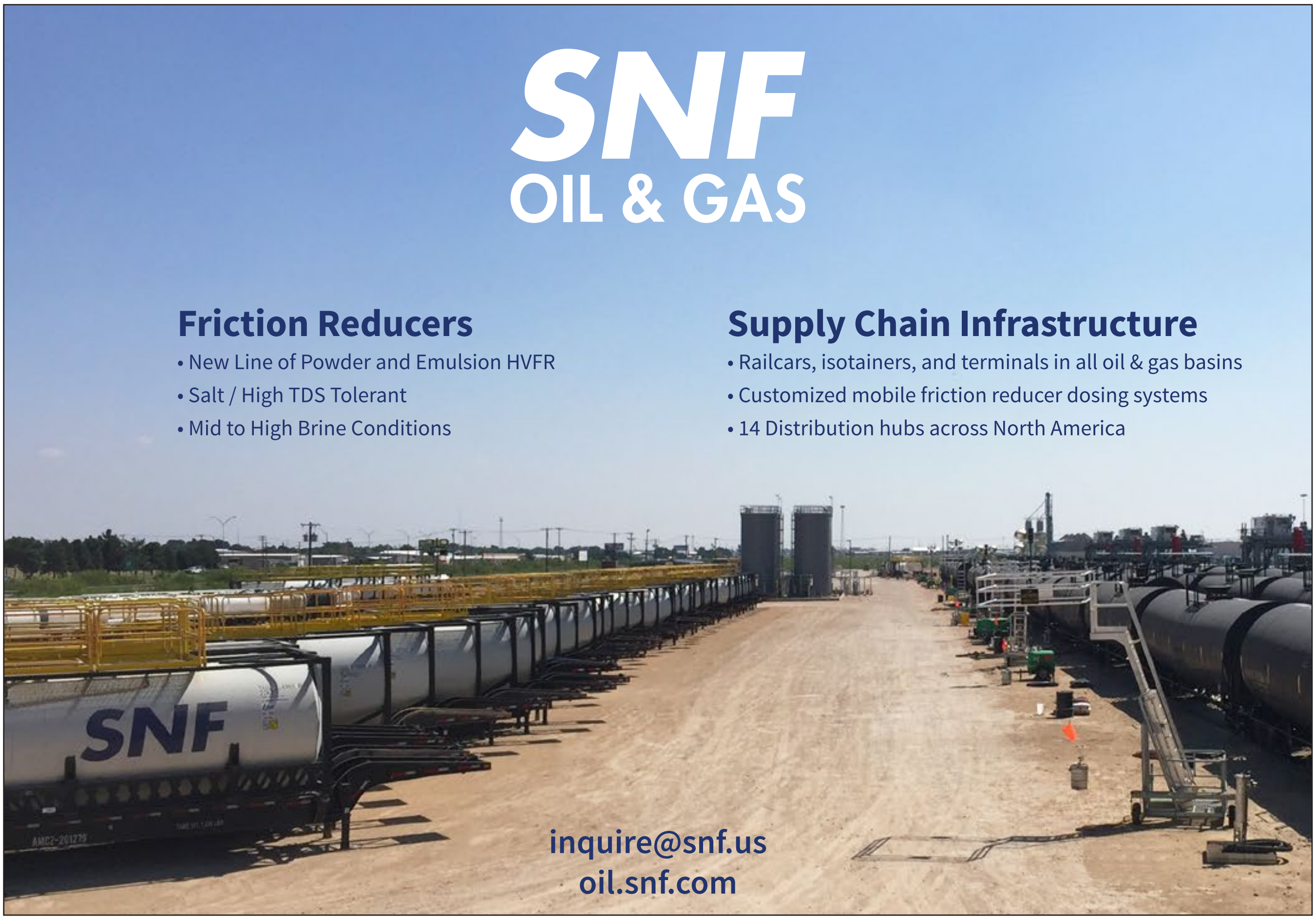


Windrock products and services digitally transform the way companies monitor, manage and optimize their reciprocating machinery and industrial equipment. (Source: ChampionX)

Somasundaram: I believe the process of being a good leader starts with being authentic and sincere. People tend to trust people who they feel are genuine in their intentions and efforts. Good leaders always put interests of their organization and teams ahead of their own. From there, I believe the path to being an effective leader involves three elements: commitment, alignment and engagement. It starts with making a personal commitment to the journey of being a better leader, followed by aligning the organization and teams around the purpose and key objectives. Once you align the organization, it is important to actively engage in supporting the teams to make progress and achieve these objectives. Good leaders are always self-aware, consistent in their leadership behaviors and credit their teams for success.

E&P Plus: What would you tell those that are newly appointed in top positions at their companies?

Somasundaram: I would encourage them to define a purpose for their organization beyond just financial goals and that includes all stakeholders. This helps employees feel part of something bigger and contributing to a higher cause. It energizes the organization. I'd also encourage them to focus on developing a positive, inclusive work environment and culture. I believe culture is the only sustainable competitive advantage a company can have, and CEOs play a leadership role in shaping that culture. I believe being a CEO is a privilege, and I must earn that privilege every day. +



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You should know the steps we're taking to safeguard health in our venues as we prep relevant programs to help get our industry moving. From increased sanitation and social distancing to touchless registration and catering, safety for speakers, attendees and exhibitors remains foremost in our minds.

In surveys, our attendees always cite two principle benefits from business conferences. They value *programming* – the topics addressed, by whom, and "lessons learned" – and they value *networking* – collaborative interactions with fellow professionals. Our goal is to inspire new business ideas and opportunities for every participant in any of our events.

Months of physical isolation taught all of us to work remotely, yet we value the unique benefits of face-to-face communication, whether virtual or "live" at appropriate distance. Connections between human beings propel the beating heart of business.

Please keep the opportunities shown here top-of-mind in planning your own 2021 calendars.

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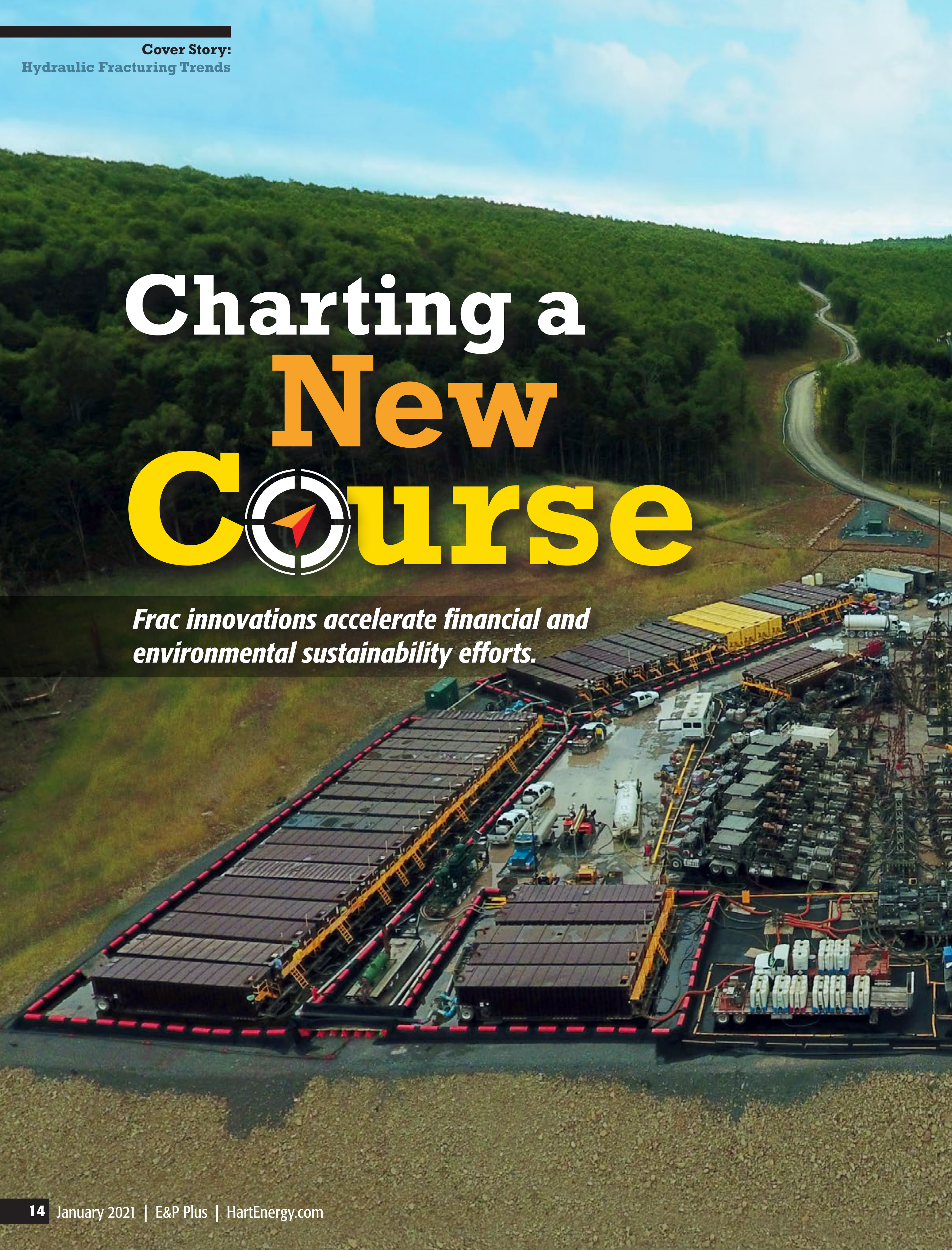

Charting a New Course

Frac innovations accelerate financial and environmental sustainability efforts.

***Brian Walzel**, Senior Editor*

As the saying goes, hindsight is 20/20. But as the industry looks back on the past year, it might be hard-pressed to come away with a clear vision of 2020. The oilfield services (OFS) sector, and in particular the hydraulic fracturing market, took the brunt of the blow, with many pressure pumpers seeing almost no work by late spring and early summer.

According to Westwood Energent, the number of frac crews operating in the Permian numbered 18 to 20. Even as pandemic restrictions began being lifted, and demand for oil started to marginally improve by the early fall, the OFS sector remained mostly stagnant as operators worked through their inventory of DUCs.

But as the calendar has flipped to a new year, the fracking industry is both taking stock of lessons learned from 2020 and pushing forward with innovations and technologies designed to optimize efficiencies for both operators and service providers. Meanwhile, as shale producers increasingly put more effort on achieving ESG goals, service providers are bringing to market systems and tools that cut down on emissions and generally reduce the carbon footprint of fracturing operations.

Although many industry insiders believe the shale industry will likely never again achieve its previous highs in drilling and completions activity, the heartbeat of the fracking industry gained strength toward year-end 2020, and while it might not be at full strength this year, it will continue to pump the lifeblood of the U.S. energy industry.

2021 trends

By most accounts, the fracturing market hit its floor mid-2020. By late fall and winter, operators began to initiate some activity while still maintaining low capex. Stabilized prices for oil and gas have allowed operators to set out their 2021 plans with some amount of certainty.

"It feels like we're seeing the new normal," said Michael Segura, vice

As the North American shale industry slowly recovers from the devastation of 2020, new technologies and frac designs are helping companies achieve greater operational and financial efficiencies. (Source: Universal Pressure Pumping)

president of the production enhancement business line with Halliburton. "There's some stabilization, [and] operators are able to make their forward year plans, so it feels cautiously stable at the moment. Obviously, [the market] will only be a portion of the size it was previously. It's still generally oversupplied and cost-challenged, and capital discipline is still very strong in operators' minds."

The general sentiment, if not formally announced in investor calls, is that producers in 2021 will be focusing on maintaining capital discipline rather than production growth. Even new activity is likely to look much different than it has in the past.

As Akshay Sagar, president of Universal Pressure Pumping explained, producers are looking to avoid long-term commitments with service providers, focusing instead on work packages.

"Customers are trying to get different packages of wells completed," Sagar said. "Fundamentally, I think a number of things are different. Number one, customers are not willing to make any long-term commitments. What's called a long-term commitment is really just an extended work package. The package-work format has taken over the committed-work format that used to be the normal format in pressure pumping."

He said that in an effort to maintain spending flexibility, work packages are smaller, whereas now a one-year deal with a service provider is made up of different packages that producers can get out of any time.

"And they do," he said.

Additionally, Sagar said operators are often not maintaining a steady pattern of work but instead opting for more concentrated field services.

"Operators want to get production in early, establish cash flow and then take a break," he said. "That's not ideal for the industry because any industry, even things like the airline industry, need to be running and not start and stop. So that's going to be challenging. The industry gets excited as we come off the very, very low point from where we were. So yes, compared to that, it is better. But it's nowhere near any peak, and we personally don't think the peak is happening any time soon."

Although the shale industry may be in for a long uphill climb, service companies continue to bring innovative technologies and systems to the market that enable operational efficiency, improve ESG goals and boost financial returns.

E-frac and dual-fuel

The name of the game in unconventional shale development has quickly shifted from production at all costs to maximizing cash flow and reducing emissions to improve ESG performance. Operators have placed a priority on their ESG efforts as financial institutions have prioritized responsible investing.

As producers' priorities similarly shift, service companies have responded, offering technologies and tools that help reduce emissions in various ways. At the forefront of emission-reducing technologies is frac pump power generation. E-frac and dual-fuel power-generated frac pumps have proven to reduce emissions either by cutting down on the amount of diesel fuel burned at the site or reducing flaring by utilizing excess natural gas to power engine turbines.

However, the two systems have varying degrees of total market penetration and present challenges in terms of cost and short-term value. But trends for the two systems are pointing upward.

One of the latest entries into the e-frac market has been National Oilwell Varco's (NOV) Ideal fleet. The fleet offers 5,000 hp of electricity-generated

NOV's Ideal electric frac fleet features 5,000 hp, electricity-drive pumps that can help eliminate costs related to engines and transmissions. (Source: NOV)

UPP's dual-fuel pressure pumping systems can reduce diesel fuel usage by up to 54%. (Source: Universal Pressure Pumping)

power, and it claims a nearly 90% reduction in fuel costs and up to a 40% reduction in total cost of ownership, according to the company.

"When we sat down and looked at this space, we realized it's an evolving market," said Travis Bolt, product development manager of pressure pumping equipment with NOV. "We wanted to make our system power agnostic. It can run off of line power, either fully or some percentage of line power. But then it can also support lots of generation technologies whether its multi-reciprocating or whether it's large single turbines. We really didn't want to necessarily tie pressure pumping to a particular architecture on the power side."

Bolt explained that the goal in the creation of the Ideal fleet was how the system can influence the cost of producing a well. That ultimately led to a design that Bolt said provides capabilities for those who might be familiar with e-frac.

"We really wanted to think about simplification, engineering out HSE concerns, engineering out failure modes, understanding that fracturing is still a mechanically intensive process and how we can influence what it means to live with an e-frac fleet long term," he said. "We understand that you're still going to have to service the pumps. How do you get to those pumps? How do you pull them out? How do you service them without disrupting the rest of the site? That's the way that we approached it."

Meanwhile, Universal Pressure Pumping (UPP) has been a leader in dual-fuel technologies, having first introduced its systems in 2013. UPP's fleet features 2,250-hp and 2,500-hp quintuplex pumps and can reduce diesel consumption by up to 54% when operated within optimal range.

Sagar said about 60% of the fracking industry is utilizing dual-fuel systems, as e-frac still emerges from its early days.

"I think the majority of the industry is settling on some sort of dual-fuel," he said. "There will be a sliver of the industry that will focus on electric frac, because that piece of technology in my mind is still very much in evolution and development. No one's really solved that; it's the early days, and that's purely economic. Ourselves, we were one of the first companies to get into dual-fuel a decade ago. That was early days, and now it's become quite prevalent and the norm."

Sagar said UPP is currently designing systems the reduce engine idle time as well as different methods of fluid delivery that can reduce costs as well.

"All of these are going to reduce

"It feels like we're seeing the new normal. There's some stabilization, [and] operators are able to make their forward year plans, so it feels cautiously stable at the moment."

–Michael Segura, Halliburton

the amount of fluid we'll need to pump to achieve efficiency, less repair maintenance and carbon footprint," he said.

The fully automated frac job

The evolution of e-frac and dual-fuel power generation systems are examples of how hydraulic fracturing in North American shale has transformed since it began in earnest. Ever-growing completion designs and larger sand usage have led to greater efficiencies and production growth. However, the next phase, and the one that could be truly transformational, is the fully automated frac job.

Opinions vary wildly on where the industry is at in terms of the elusive carrot on the stick of the automated frac–some believe it's here, while others think it's either still a ways off or perhaps even not possible. What nearly all agree on, however, is that in at least some capacity, frac automation is here.

Among those that believe the fully automated frac job is upon us is Halliburton. Its SmartFleet system was unveiled in October 2020. According to the company, SmartFleet offers operators real-time fracture control while pumping by integrating subsurface fracture measurements, live 3D visualization and real-time fracture commands.

A Halliburton release on the system stated that SmartFleet connects to the reservoir through subsurface sensing to continuously measure cluster uniformity and fracture geometry. The system applies the measurements to make intelligent adjustments that improve fracture placement. SmartFleet also provides users a direct line of sight to live, 3D fracture geometry, projected fracture growth and cross-well interactions.

"When we have historically monitored frac jobs, we recognize that frac performance is inconsistent," said Eric Holley, senior product line manager with Halliburton. "Fracture outcomes are oftentimes highly variable. That's from a surface perspective and also subsurface. So one of the key things that we really wanted to do with SmartFleet was tie those together more purposefully, bringing the surface and the subsurface together in one platform. The purpose of SmartFleet is to give an operator more control of fracture outcomes while pumping, both in terms of efficiency and how you pump your job on surface, and control of fracture placement in the subsurface. So it's really encompassing those key things and delivering consistent frac success."

UPP's Sagar is among those who see the fully automated frac job as a work in progress, and he explained that what some might consider automation might simply be optimization. These include tweaks to such processes as pumping parameters and efficiencies and optimizing fluid chemistries and water usage.

UPP's PTEN+ system offers 24/7 monitoring and identifies flat time opportunities with live data streaming. Metrics are tracked to the crew level to measure performances.

"We can see what's going on remotely and have the [subject matter expert] optimize the job," Sagar said. "The next phase is monitoring equipment health, which we also do remotely."

As Sagar explained, limited automation consists of sub-components of job automation, which includes individual components like an automated blender where no crew is needed at the site to operate the blending machine.

"And then you come to more complete automation, where you don't need 15 guys on a job," Sagar said. "Instead, we'd need three guys on a job. You press a few buttons and everything happens. I think that last phase is probably a while away. For one, it is complex and a large financial investment. And second, we have a DNA problem in the industry where people are uncomfortable taking everyone off the job. People are just uncomfortable that there is no one there to fall back on if you had a problem. So, my opinion is that it's somewhere between Phase 1 and 2."

Simul-frac

While the chase for even greater operational efficiencies and cost savings have pushed new innovations in pressure pumping and frac automation, shale companies are also evaluating ways to get the most out of how wells are fractured.

For multiwell pads, zipper fracs are the industry norm: alternating stage sequences on adjacent wells. Now some operators are experimenting and seeing results from pumping two adjacent wells at the same time, an emerging trend known as simul-fracking.

"What you're doing is simultaneously fracking two wells at the same time while you're prepping two other wells," Halliburton's Segura said. "It's a significant step forward in efficiency. Essentially, you're working on four wells simultaneously whereas you would have been on two wells simultaneously in traditional zipper fracking."

He said that although the idea is to improve efficiencies, with simul-frac "everything gets bigger and more intense."

"In terms of logistics planning—the ability to feed sand and water to operations, contingency planning, the ability to manage multiple wells simultaneously, the control systems that can track and manage what's happening in multiple wells—all of the planning and contingencies grow in scale when you go to simul-fracking," Segura said.

He added that Halliburton started doing this three years ago and has been regularly performing quite a bit of simul-fracking for clients in the Permian Basin and in the Rockies. However, he acknowledged that not every well pad is ripe for the strategy.

"It takes some unique conditions for it to work," he said. "Operators need to have adequate inventory, or a runway of wells, and it is typically most applicable to four-well pads or greater. The real benefit is completion speed for the operator and less shut-in time for neighboring wells. We see growing interest in it. It will be very applicable in certain places in the market, but I don't think it will be at all places at all times."

Additionally, splitting the fracturing operations between two wells requires some initial design alternations, as Halliburton's Holley explained.

"You can augment the spread with horsepower as needed for different wells," he said. "And operators can change their completion schemes in terms of number of perfs that they're shooting and the number of clusters; you can change accordingly to match the rates that you're putting down the wells. There are some modifications to design, and we have the ability to customize treatments for each well individually, so it's not a one-for-one split."

Like Segura, UPP's Sagar noted that simul-fracs are likely not applicable everywhere, and the decision to initiate the operation is often an economics-driven one. He added that oftentimes the rock is likely to behave differently in a simul-frac than traditional zipper fracs.

"If you use less flow and pressure and you're going to split it into two wells, then you don't get exactly the same as if you do it in one well," he said. "So, will the rock behave the same way? Not always. There are some wells where it will work, and some wells where it would not. We see some companies try; some do not. Some are seeing that their acreage is well set up for simul-frac, but for others it is not. So at the moment, I would call this a new entry into this space in terms of the concept. Some people are testing it out, some have tried and walked away, [and] some have stayed." +

Halliburton's SmartFleet connects to the reservoir through subsurface sensing to measure cluster uniformity and fracture geometry. The system applies the measurements to make intelligent adjustments that improve fracture placement. (Source: Halliburton)

Opinion: Digitizing well completions reduces the cost to complete a well

The stage is set to introduce autonomous frac sooner than most realize.

***Matt Steen**, Cold Bore Technology*

When we talk about the digitization of well completions, forget the buzzwords you are used to reading; while they sound nice, they mean nothing. Instead, let's focus on the concrete, monetizable solutions that operators are realizing right now.

Today, oil and gas companies face one main problem: the cost to complete a well is too high given current commodity prices. Operators need to improve their financial metrics by reducing the cost to complete a well.

That's where digitization (also called Industrial Internet of Things [IIoT] or Industry 4.0) comes in. First, add sensors to the wellhead. These sensors track operations at the wellhead, creating a common timestamp and format that all parties can use. This replaces the old method where every service has its own timestamp and format. Second, use one centralized operations platform to connect all services on site—every service company on one platform.

Matt Steen

Once the wellhead is digitized and all service companies are on one platform using a common timestamp, consider how cost is reduced.

Increase pump time

Every operator wants to increase their pump time each day. The traditional method of verbal communication over a crackling radio is being phased out thanks to Industry 4.0. As a result, an average of 3 minutes per stage, which was formerly lost during a game of telephone between humans on site, is now being used to pump.

Imagine a traffic light turns from red to green and no cars move for 3 minutes. That would be frustrating. Well, that is what happens on a completions site that lacks digitized wellheads. The only (huge) difference is the assets idling on a completions site cost significantly more than a Toyota Camry. Industrywide, it is a $500 million problem each year.

With digital, real-time data from wellhead sensors, supervisors instantly read from the data van the second the well is set to frac. This way, pumps are brought online immediately.

By flushing out the invisible lost time that digitized wellheads expose, operators can save an average of 3 minutes per stage.

For example, in October 2020, EQT Corp., the largest producer of natural gas in the U.S., announced that in one year (between the third quarter of 2019 and the third quarter of 2020) they experienced a 40% improvement in pumping hours per month per crew and a 35% improvement in stages per month per crew through its utilization of next-generation frac technology and a centralized operating system, which maximizes productive time and operational performance.

With time and greater automation, the potential savings only increase.

Automated flow of data

Automated sensor data are received in real time and actionable. In the past, operators performed their cost reduction analysis after the fact. Industry 4.0 gives humans the information and control at their fingertips, allowing them to make changes in real time.

As pumping time per day has improved year over year, the volume of administrative tasks for supervisors has increased at the same rate. These administrative tasks are time consuming, prone to inaccuracies and inefficient. With automated data capture and flow of data, experienced onsite leaders are freed from taking notes, able to focus instead on higher level operations improvement using IIoT to reduce costs, improve safety and pump longer each day.

Today, humans optimize operations using unbiased digital data, their minds and experience. Soon, algorithms will perform optimization, freeing up humans to support the platform, rather than drive it.

Like the foundation of a house, digitization is the base upon which future layers of automation are being built.

The future: autonomous frac

Digitization has led to a place where each service company's data talk to the others in a seamless autonomous fracturing operation. Soon, the need for a supervisor to give the verbal go-ahead for fracturing will be eliminated, replaced with a fast, efficient and safe automated process. The human worker will then be free to perform higher-level tasks.

In the past, high-commodity prices disincentivized innovation, but today's tight market means operators must find new ways to reduce costs and augment the performance of their operations. Just like in the retail, entertainment and manufacturing industries, digitization is undoubtedly the way of the future for frac. Those companies achieving quantifiable results today will be the winners of tomorrow. ✚

***About the author:** Matt Steen is the director of customer optimization with Cold Bore Technology.*

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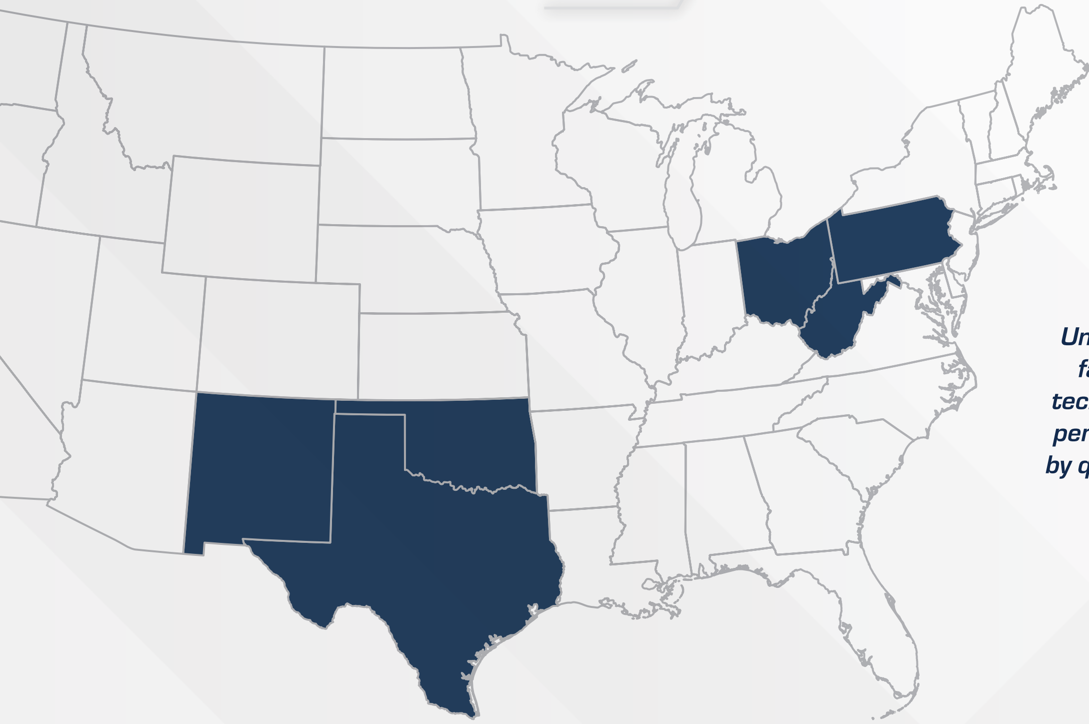
LOGISTICS AND LOCATIONS



Universal's centralized logistics facility utilizes state-of-the-art technology to ensure consistent performance and timely delivery by quickly identifying bottlenecks and resolving issues.

In addition to being an industry leader in fracturing services, Universal is also a leader in cementing capabilities.

Utilizing state-of-the-art equipment, we can pump specific blends designed in-house by our technical team that is committed to meeting each customer's individual requirements.

We also have a full-service laboratory to design, test, and quality check all blends in-house to ensure they meet the most stringent standards.

Specific Blend Designs

Full Service Laboratory

Top Tier Cementing

INTEGRITY. INSIGHT. INNOVATION.

40 YEARS Since 1980

(Source: Sobrevolando Patagonia/Shutterstock.com)

2021 Hydraulic Fracturing Technology Showcase

This special section highlights the latest hydraulic fracturing technologies and services from nearly 40 companies and how these tools aim to address operator challenges.

*Compiled by **Ariana Hurtado**, Senior Managing Editor, Publications*

Discover innovations for the next fracturing revolution

Profound scientific knowledge has catalyzed advancements in intelligent systems and applications for hydraulic fracturing. Industry professionals leading these innovations will present their findings Feb. 2-4 at the 2021 SPE Virtual Hydraulic Fracturing Technology Conference and Exhibition. The conference features a diverse portfolio of next-generation technologies, sustainable developments and best practices.

Fracture diagnostics sessions at this event will include a novel method and its application to define a maximum horizontal stress and stress path. Among other demonstrations are field applications of sealed wellbore pressure monitoring to evaluate completion effectiveness.

Through a focus on completion optimization, attendees will learn first-hand of a multidisciplinary approach for well spacing and treatment design using lateral pore pressure estimation and depletion modeling. Furthermore, multiple DFIT-FBA tests performed on a well pad at multiple points in a well for advanced treatment stage design and reservoir characterization will be explained.

With Argentina's Vaca Muerta Formation seeing significant developmental breakthroughs, presentations will highlight early applications of miscodifying friction reducers for fracturing operations in addition to well spacing and simulation design optimization in the region.

—Society of Petroleum Engineers

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

Meeting e-drilling and e-fracking demand

The shift to electrification demands efficient, flexible and reliable power. E-drilling and e-fracking create demand peaks that are not always easily supported through existing infrastructure. Burns & McDonnell's scalable, short-lead modular substation is capable of supporting early field development with the flexibility to adapt to ever-changing market conditions. Oilfield electrification equipment offers the opportunity to reduce operation and maintenance expenses, reduce lease operating expenses and lower greenhouse-gas emissions.

Burns & McDonnell's modular substation is designed to offer a scalable, flexible approach to meet short- and long-term production requirements. Quickly mobilized on skid-mounted equipment, the modular substation offers flexibility to scale up or down as needed as well as the mobility to move with production—all while reducing field construction time and improving construction safety.

With a reliable, cost-effective and environmentally friendly electrical solution in place, producers improve their ability to reduce costs of production and attract the investors and capital dollars needed to grow core business activities.

The Burns & McDonnell modular substation provides project teams and stakeholders the ultimate flexibility to react to changing market conditions by improving safety, speed to market, scalability and reliability. (Source: Burns & McDonnell)

Engines and processing system combine to achieve high displacement levels

Caterpillar Oil & Gas worked with GTUIT to successfully power a customer's fleet of Cat Tier 4 Final Dynamic Gas Blending (DGB) engines using field gas. Cat DGB dual-fuel engines automatically maximize the amount of gas used to displace diesel with CNG, LNG, pipeline gas or associated gas. With GTUIT's mobile gas processing systems and the Cat DGB engines, the companies demonstrated significant fuel cost savings and high displacement rates, exceeding the customer's expectations.

The Cat 3512E DGB U.S. EPA Tier 4 Final engine automatically maximizes the amount of gas used to displace diesel with CNG, LNG, pipeline gas or associated gas. (Source: Caterpillar Oil & Gas)

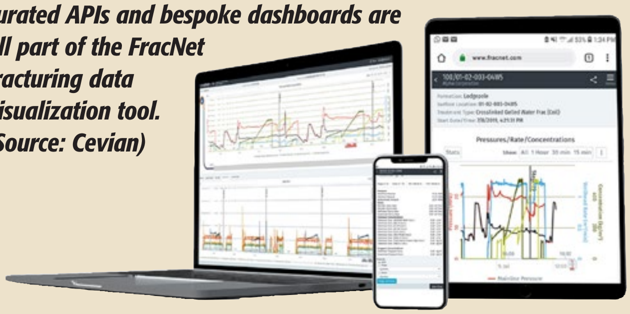
The demonstration consisted of collecting raw gas from a pipeline at the customer's frac site, where it was then processed and cleansed using GTUIT's mobile gas processing system. The gas was then transferred directly into Cat 3512 DGB U.S. EPA Tier 4 Final and Tier 2 engines. After the eight-day demonstration, the engines averaged consistent diesel displacement levels of 77%, with a peak displacement of 85%, which translated into lower emission levels and fuel cost savings compared to only operating the engines using diesel or transporting CNG or LNG to the site.

By utilizing GTUIT's mobile processing systems and the Cat DGB engines, operators can achieve consistently high displacement levels, reduce fuel costs and operate efficiently. Additionally, using associated gas directly from a flare or gathering line is ideal because it generates fewer emissions and costs less than diesel fuel.

Real-time fracturing data visualization tool

Cevian's FracNet provides a universal service company agnostic, real-time completions portal for fracturing operations that is coupled with curated application program interfaces (APIs) and a standardized, historic data warehouse. FracNet ensures completions data are homogenous and accessible for use in a company's data strategy. The APIs can be used for everything from KPI reporting to real-time data analytics. FracNet has been used as the sole system for remote, real-time completions decisions on more than 9,000 wells. Since commercially launching in December 2019, Cevian has loaded and QC'd more than 3,800 additional wells of historic frac data for its clients for use in data initiatives. Examples of initiatives

Real-time data solutions, data warehouse, 20-plus curated APIs and bespoke dashboards are all part of the FracNet fracturing data visualization tool. (Source: Cevian)



include studies on fracture-driven interactions resulting in decision metrics for management, ESG performance with real-time produced water and gas substitution during operations, auto-population of well data management software, and lookbacks to adjust chemistry for cost savings.

Many operators have formerly stored network drives full of "dark data" (e.g., PDFs or segmented CSV files) from fracturing operations, which doesn't allow for easy lookbacks or analytics. Additional data streams, such as offset or wireline, can be comingled for a single operational snapshot and time series dataset. FracNet's universal compatibility and customized acquisition tools ensure completions data are standardized, mapped and tagged right at the source. Stop spreadsheeting and start streaming.

Friction reducer technology helps reach pumping rates more effectively

In unprecedented times, with the COVID-19 pandemic and the resulting downturn in the hydraulic fracturing activity, Chemstream's new Nano-Dispersion Technology (NDT) is providing tremendous benefits and savings to the E&P entities that are still conducting operations. This friction reducer technology contains additives, allowing the operator to reach designed pumping rates more effectively and at minimal pumping pressures in any frac water reuse scenario. Rapid hydration and optimum friction reduction over an extended period allow for lower loadings, especially in longer laterals with higher pipe friction pressure, versus conventional technology. These results are further enhanced through a series of methodical pre-pad, on-pad and post-pad analysis, both in a traditional and onsite mobile laboratory.

NDT offers the dual perspective for savings, not only for the frac fluid design but 100% water reuse and those related benefits. Overall, the EUR for the well is optimized, allowing for revenue generation sooner, which provides increased capital for future exploration.

Connecting all service providers to allow autonomous operations

Cold Bore Technology's SmartPAD is a completions master control system (CMCS) for services on a completions site. The CMCS connects all service providers to allow autonomous operations while collecting all operational data from all service providers in one database and on a single timestamp.

Completion sites have four to six different service providers collaborating to hydraulically fracture oil and gas wells. Each offers its own control system and data capture capabilities, but none of them are integrated to create the efficiencies that come from autonomous fracturing. SmartPAD

A Chemstream engineer evaluates contact angle to optimize surfactant efficacy. (Source: Chemstream)

Using sensors, SmartPAD tracks operations directly at the wellhead and connects all onsite service companies to a trusted source of formatted and time-stamped operational data. (Source: Cold Bore Technology) connects these service providers (fracturing, wireline, wellhead, water storage, water transfer and sand storage) on one platform. This allows supervisors to optimize in real time by seeing Internet of Things sensor data in one place, and instance-based logic will have been used to detect the end of stage, signal to the wellhead provider to close the current wellhead, and then open the next wellhead. This removes the need for human intervention in the well-swap process.

Optimizing recovery in refractured wells with expandable technology

Mechanical isolation using expandable liner technology is a more reliable and effective method for refracturing wells than cementing casing to reline the previous producing interval. Notably, expandable liner technology demonstrates the potential for consistent repeatability in terms of mechanical isolation and operational costs.

Coretrax has developed ReLine MNS, which provides a single-trip solution with no shoe milling to clad and seal various wellbore integrity concerns with minimal loss of inner diameter (ID), while providing high burst and collapse ratings.

The cased-hole system is designed for deployment on jointed pipe and can cover long or short intervals from 30 ft to 7,000 ft. It can be configured to expand and seal across various ID restrictions in the wellbore, such as nipples or frac sleeves, even in high-pressure well scenarios. It creates a like-new wellbore in the cased-hole environment, whereby mechanical isolation then restores pressure integrity with minimal wellbore ID loss for the purpose of refracturing.

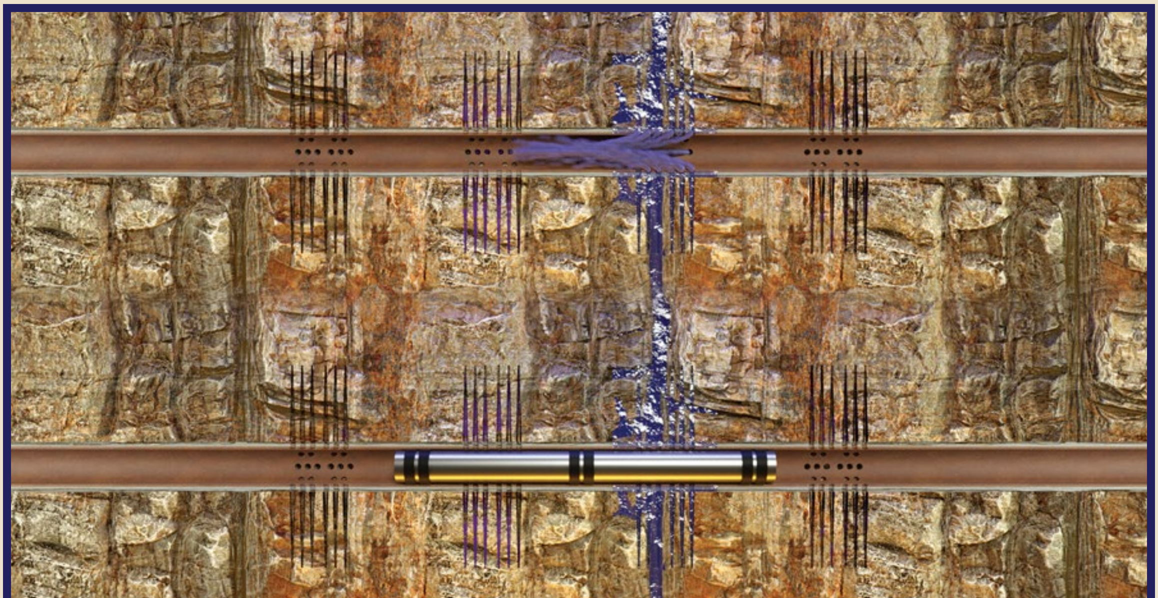
MV drive increases uptime and requires less maintenance

Electric high-pressure pumping for hydraulic fracturing has brought along many benefits including lower energy consumption and less emissions, less audible noise and smaller size combined with excellent controllability. Electric fracturing technology includes a variable frequency drive (VFD) that is used to control the speed and torque of the motor running the high-pressure pump.

The fracturing equipment is used in harsh operating conditions and is moved regularly from site to site. However, standard medium-voltage (MV) drives enclosures are designed for fixed installation in an electrical room. The VACON 3000 kit from Danfoss allows system integrators and original equipment manufacturers to create a definite-purpose MV drive in a fit-for-purpose enclosure that is optimized for mobile equipment operating in harsh conditions.

The VACON 3000 kit includes liquid-cooled medium-voltage power conversion units, which make it easy to create an enclosed, even-sealed VFD. The heatsinks of the VACON 3000 kit are grounded, and this allows new “normal water” closed-

For a 3,675-kVA inverter unit with a 4,160-v motor, the single-phase conversion module measures 25 by 9 by 30 inches. (Source: Danfoss)



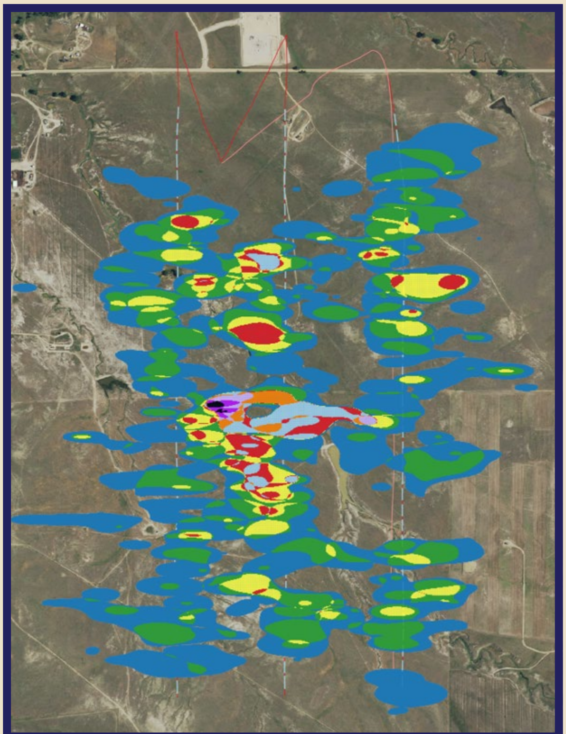
ReLine MNS technology provides a single-trip solution. (Source: Coretrax) loop cooling solutions, which increases uptime and requires less maintenance. The power conversion module has a rugged design, has no moving parts and is easy to handle.

Near-real-time frac fluid imaging technology

Deep Imaging has made great strides over the last year to commercialize a near-real-time frac fluid imaging technology that allows operators to make game-changing decisions during their fracturing operations.

With an array of highly sensitive nano-voltmeter receivers and a grounded dipole system laid out completely off the pad and directly over wellbore trajectories on surface, a direct measurement of frac slurry magnitude and direction is measured and displayed as a polygon taking shape over the stimulated rock area within 3 hours of the end of a stage. The technology is shown in a map birds-eye view to allow operators to make business-impacting adjustments on the well they are actually fracturing.

This technology addresses completions challenges and waste, including plug failures, extreme inter- and intra-well overlap into previously fractured stages, understimulated rock area and runaway fracture propagation toward parent wells, which lead to frac hits. Operators are able to be proactive with their completions and can improve on insufficient designs as they are realized.



Frac fluid imaging stage polygons with extreme stage-to-stage overlap are shown in different colors. (Source: Deep Imaging)

DS MicroSet arrives at the well site fully assembled and directly attaches to the string of DynaStage perforating systems. (Source: DynaEnergetics)

Disposable setting tool sets frac plugs in PNP applications

DynaEnergetics recently released DS MicroSet, a fully disposable setting tool used to set frac plugs in plug-and-perf (PNP) applications. The tool is maintenance free, eliminating many shortcomings of reusable setting tools, including metal fatigue and altered metallurgy, issues that can result in pressure leakage, reduce performance and cause downtime. DS MicroSet arrives at the well site fully assembled, including the power charge, eliminating the need for field assembly or rebuild as well as reducing risk of human error. The tool uses DynaEnergetics IS2 ignitor, which is fully compatible with the IS2 Intrinsically Safe initiating system used in DS perforating systems. The perforating systems and the setting tool can be surface tested prior to running in hole.

During field trials, a multitude of plugs have been successfully set by DS MicroSet in several different wells by numerous service companies for multiple operating companies. Capable of up to 60,000 lb of shear force, the average force of the plugs that were set was about 30,000 lb. Plugs were set at measured depths ranging from 9,000 ft up to 20,000 ft, with true vertical depth surpassing 12,600 ft. Tested for up to 20k psi on the tool, the calculated hydrostatic pressure experienced during the trials exceeded 13.5K psi.

New paraffin inhibitor is dispersible in water

A typical challenge encountered during hydraulic fracturing is severe wax deposition on the rock surface inside fractures as relatively cold fracturing fluids come in contact with hot crude oils. This results in multiple challenges for the operator such as decreased throughput because either crude oil viscosity increases or wax deposits narrow and clog the effective flow paths inside formation rocks and proppant packs. This can be of particular concern when the temperature and pressure start to drop rapidly right inside the fractures.

In the past, water-soluble surfactant-based wax dispersants have been frequently used to combat excessive wax deposition during fracturing. Polymer-based paraffin inhibitors, despite being more effective, however, have not been extensively deployed because they are insoluble in water and incompatible with commonly used frac additives.

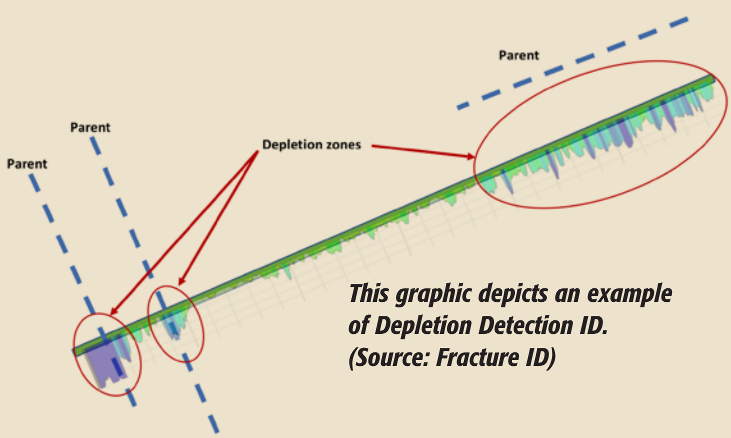
Evonik Oil Additives has developed a novel type of paraffin inhibitor that is dispersible in water. This solution allows the product to be fully compatible with most frac fluids. By incorporating a paraffin inhibitor, wax deposition during the frac process can be mitigated, potentially enhancing oil recovery from liquids-rich shale reservoirs.

Detection methodology identifies depleted zones along a wellbore

Fracture ID's mission was originally to provide rock mechanical properties and natural fracture locations efficiently and with zero wellbore risk using bottomhole assemby located vibration sensors. The company has successfully logged hundreds of wells in all active North American basins, providing high-resolution rock properties and supporting drilling and completions services.

Fracture ID has developed a methodology for identifying depleted zones along a wellbore caused by production from offset wells, using a calculated in-situ pore pressure. Comparing these measured results with expected readings, the company can identify where induced or natural fractures have been drained of hydrocarbon. Using these results, operators are able to adjust their completions programs to minimize frac hits on offset wells.

Additionally, issues such as casing damage during completions can be directly related to areas of depletions along the wellbore. This knowledge proves invaluable to operators that modify completions practices to avoid costly remedial work and so increasing free cash flow. Every dollar spent on bringing back a well from being knocked offline due to frac hits or on mitigation of casing damage comes straight from the bottom line.



This graphic depicts an example of Depletion Detection ID. (Source: Fracture ID)

On-the-fly resin coating controls proppant flowback and enhances conductivity

Hexion's PropCure on-the-fly curable resin coating allows users to coat proppant for hydraulic fracturing on location in the blender tub. The coating is a two-part system that is combined with a simple static mixer on the frac site. It is then added directly to the blender tub using standard liquid additive pumps. The chemistry has an affinity for proppants, so it coats the proppant and not the equipment. PropCure resin coating complements Hexion's PropShield proppant flowback control additive by extending the application range to bottomhole temperatures up to 350 F.

Once downhole, the PropCure coated proppant acts like a traditional curable resin-coated proppant. It provides all the same benefits of grain-to-grain bonding and keeps proppant in the fractures where it is intended to stay. Additionally, the PropCure coating has a tailored surface chemistry that alters the relative permeability of the proppant pack. Running this technology, even at a low concentration, can improve conductivity and reduce or eliminate the need for additional surfactants.

A Bakken operator stated that the PropCure coating resolved its sand flowback issues while increasing production by 200 bbl/d over its nearest offset.

Remote communications tool allows users to customize onsite experience

The new iNET RCS (remote communications solution) is a high-performance, enterprise-class mesh,Wi-Fi-6 capable, turn-key, end-to-end managed communications technology deployed to the remote edges of the oil and gas sector. INET RCS is backed with cloud management and machine learning that enables iNET customers to customize their onsite experience.

With this new release, users will be able to fully manage who uses their communications at the rig site and what experience that consumer will have—whether they want to give a contractor priority on the network or limit how long they will be allowed to use their communications, or even block them from accessing it completely. Users will be able to leverage analytics to gain insight into their remote network operations, previously unheard of in the oil industry. This will empower remote communications management of users and assets fleet-wide from anywhere in the world.

The iNET RCS high-availability architecture uses multiple bandwidth paths and connectivity technologies to give customers uninterrupted service under harsh conditions and in challenging locations. With Wi-Fi reaching across the pad and

iNET's RSC mobile communications technology is shown deployed on a horizontal drilling site in the Permian Basin. (Source: iNet)

extended range, it allows users to deploy Industrial Internet of Things, sensors or edge servers anywhere on the pad, which drives down costs and improves the safety of personnel on site.

Fracture face preservation and enhanced conductivity

EC Max is part of the next generation of completion fluid additives based on Integrity BioChem's biopolymer chemistry. Whereas typical completion stimulation fluids fall into the traditional buckets of water/brine, friction reducer (FR), biocide, scale inhibitor, surfactant and possibly breaker, EC Max paves the way for a new category that encompasses fracture face preservation along with enhanced conductivity due to embedment mitigation.

The current problem in unconventional reservoirs is that the fluids being pumped create a rapid loss of fracture conductivity due to the softening of the fracture face. This softening increases the rate of proppant embedment. The net results are steep decline curves and less production on these wells.

EC Max bonds with the fracture face at the exact points where proppant embedment is most prone to occur but without altering mineral structures it encounters. It is designed to slow proppant embedment allowing fluid to migrate through the fracture network more efficiently.

Regain permeability results in the Wolfcamp Shale showed a 32% increase in permeability without breaker and 42% with breaker. In the Barrea sandstone, EC Max showed a 23% increase in permeability over FR without EC Max.

New inline chlorine dioxide generation technology improves safety

International Dioxcide, a division of ERCO Worldwide, has released inline chlorine dioxide (ClO_2) generation technology for both existing well stimulation production enhancement and new well frac on-the-fly biocide application. The new generation technology minimizes the footprint, eliminating inventory of the ClO_2 solution and eliminating separate rig-ups by water transfer and biocide applicator.

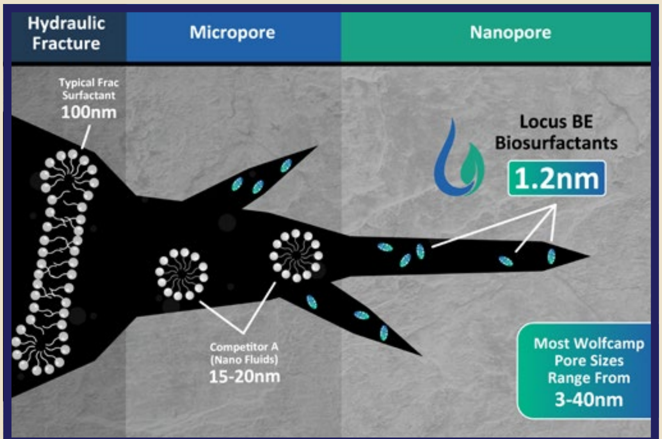
The new technology allows ClO_2 generation at the required rate and concentration inside the main water transfer line. The new technology was trialed by Texide Solutions and delivered.

Texide stated, "We had no rig-up other than water transfer, no air locks, no special hoses and the equipment allowed fine-tuned control of ClO_2 addition. We saved over $1,000 per job, while achieving zero bacterial counts for our customer with less potential for chemical exposure. [It was] another great innovation in delivering ClO_2 to the frac tank or downhole safely."

The 12-inch inline ClO_2 generation technology is shown being deployed for frac on the fly. (Source: International Dioxcide)

Biosurfactant technology maximizes IP and sustains higher rates

Most unconventional wells recover less than 10% of the original oil in place. These wells have high oil IP rates but decline very rapidly—up to an 80% decline in the first two years of production. With less capital available for drilling, operators need new hydraulic fracturing technologies that can maximize IP and reduce decline rates to extend the life of the well and improve economics.

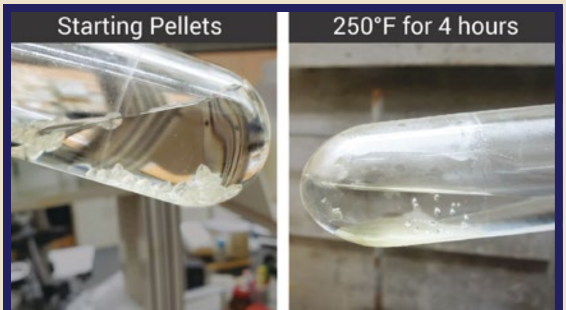


The ESG-friendly biosurfactant technology can penetrate into the smallest nanopores and mobilize oil that other hydraulic fracturing chemistries can't reach. (Source: Locus Bio-Energy Solutions)

SUSTAIN is a biosurfactant-based green chemistry for hydraulic fracturing that outperforms many synthetic surfactants. It has the ability to penetrate into the smallest reservoir pores and mobilize more oil—improving initial flowback performance, increasing total EUR and also enhancing ESG profiles. Developed by Locus Bio-Energy Solutions, the recently launched technology is formulated using biosurfactants with multifunctional properties that require as little as 1/50th of the dosage rate of traditional completions surfactants, significantly lowering costs. SUSTAIN helps operators boost IP, reduce decline rates and increase EUR, which all work to improve the economics of unconventional wells—a must in today's capital-challenged operating environment.

PLA-based degradable polymer for downhole applications

To reduce fluid loss encountered during the hydraulic fracturing process, NatureWorks has released a new polylactic acid (PLA)-based degradable polymer called Ingeo DH1900 for downhole applications. Ingeo DH1900 can be pumped downhole as fine, discrete particles that quickly change into a thick, degradable material at the targeted site.



(Source: NatureWorks)

Once located and upon the onset of the hydrolysis process, the polymer particles transform into a high-viscosity gel within 2 to 3 hours at 250 F or within 24 hours at 200 F. As the polymer continues to hydrolyze, it finds the path of least resistance where it agglomerates and can effectively minimize fluid loss before fully hydrolyzing to aqueous lactic acid, a substance classified as Generally Recognized as Safe, in 8 to 10 hours at 250 F or 48 hours at 200 F and allows flowback.

Rapidly determine problematic microbial populations

LifeCheck DNA qPCR is genetic testing for rapidly determining problematic microbial populations. It enables the detection and accurate quantification of specific microbes attributed to common problems in the oil and gas industry. The primary challenge associated with hydraulic fracturing where there is the introduction of foreign microbial communities to the reservoir is biogenic well souring (H_2S production).

OSP has created two qPCR packages that quantify the microbes responsible for H_2S production. These data validate if sour production is the result of uncontrolled microbes coming from the frac source waters, and it can confirm the efficacy of biocides used the fracturing package. OSP supplies a sample bottle with preservative fluid in it, and clients simply top it up and send it back to them, with a request for the LifeCheck qPCR souring package. Results are emailed back.

This new souring package ensures consistency for multiple testing locations, covers the broadest reach of souring-related microbes and ensures economic options are available for acquiring this important information on source waters, frac biocide efficacy and the health of the well.

Dissolvable frac plug designed to maximize isolation performance

Packers Plus Energy Services' LightningBOLT 2 Dissolvable Plug is designed specifically to maximize isolation performance during stimulation operations. The LightningBOLT 2 plug builds on the success of the LightningBOLT Dissolvable Plug. Both plugs incorporate dissolvable material that provides optimal degrade times to minimize debris left in the wellbore. The LightningBOLT plug is designed with a

The LightningBOLT 2 includes a second set of slips that secures the plug in the wellbore to maintain isolation during high-intensity completion programs. (Source: Packers Plus Energy Services) single set of slips, while the LightningBOLT 2 includes a second set of slips that secures the plug in the wellbore to maintain isolation during high-intensity completion programs.

The LightningBOLT 2 plug was developed in response to a customer's challenge of having another vendor's dissolvable plugs skidding in the liner during stimulation operations. During field trials, run-in times were maximized for the LightningBOLT 2 plugs. After successful pressure tests, the plugs held and maintained stage isolation during stimulation operations.

These unique plugs provide oil and gas operators with improved operations and reduced risk that will ultimately result in lower cost operations.

Alloys and elastomer compounds for downhole tooling applications

Parker Hannifin's Engineered Materials Group has developed a family of high-strength, lightweight, chemically active dissolvable aluminum alloys for downhole tooling applications. Parker's alloys exhibit high shear and compressive strength and excel in tight overlap, high-stage count, ball drop sleeve systems where predictable corrosion rates and reliable pressure holding performance is essential.

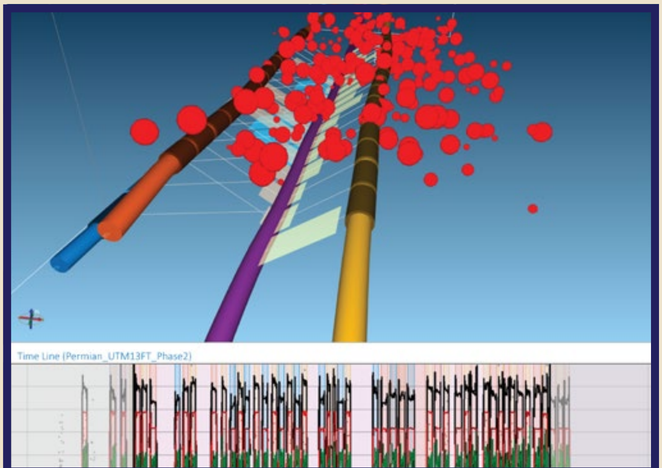
Parker has active development programs underway including delay coatings for high-acidity fluids, faster degradation rates for low-temp freshwater and higher modulus metal composites with improved erosion and wear resistance enabling thinner cross-section plug components and smaller form factor designs.

Parker dissolvable alloys are available as high-tolerance balls, machined-to-print components or as raw cast billets up to 6 inches in diameter in prototype and production volumes.

In addition, Parker has developed degradable elastomer compounds for downhole applications. These compounds allow fully degradable tool designs and are specifically designed to degrade into flowable non-clogging particulates to leave the wellbore free for unimpeded production. Parker's degradable elastomers are resilient rubber compounds available in either 80 or 90 Shore A hardness. These compounds have been proven to seal 10ksi pressure and degrade across an optimal temperature range of 130 F to 180 F, independent of fluid salinity. These compounds can be provided in common components such as packer elements, wiper fins, O-rings or custom made to print parts.

Operator increases completion efficiency with open interpretation platform

An operator has two technical experts to integrate and analyze fracture diagnostic data among three asset teams. Because a technical expert needs more than a month to analyze one pad's data, there is a significant backlog. The operator must implement a streamlined workflow to ensure rapid data interpretation that can be applied to new completions.



By integrating pressure analysis, microseismic and treatment data in the ORCHID platform, an operator can quickly understand the rock's response to hydraulic fracturing and use the information to make decisions about completion designs going forward. (Source: Reveal Energy Services)

By using Reveal Energy Services' ORCHID open interpretation platform that seamlessly integrates multiple datasets, an asset engineer updated a project daily and transferred it to a technical expert for analysis within two days of completing the pad. This step alone reduced the expert's time by three weeks, and the diagnostic work was finished in less than one week.

With the ORCHID platform's data value capture and discovery through interactive control of the spatial and temporal events, the operator is saving time and money by insourcing this work. The technical experts can now focus on data to implement the completion learnings immediately on subsequent pads. The asset engineers, with new data understanding, are offering insight into the two experts' analyses.

New tech reduces emissions, lowers costs

Modern hydraulic fracturing fleets are expected to pump harder, faster and more efficiently than ever before. Industry efforts are focused on meeting ESG targets aimed at lowering emissions, improving safety and being good neighbors. An abundance of natural gas is driving lower cost targets on diesel fuel consumption, while also facilitating lower emissions. E&P companies are challenged with reducing production costs and emissions, and service companies are faced with driving down operating costs while offering future equipment the industry is demanding.

Rolls-Royce's MTU Hybrid E-Frac Power System is a combination of proven mission critical natural gas powered gensets and intelligent battery energy storage systems. Several challenges are addressed by delivering a scalable solution aimed at reducing emissions by up to 80% and power generation total cost of ownership by 58%, while facilitating a more effi-

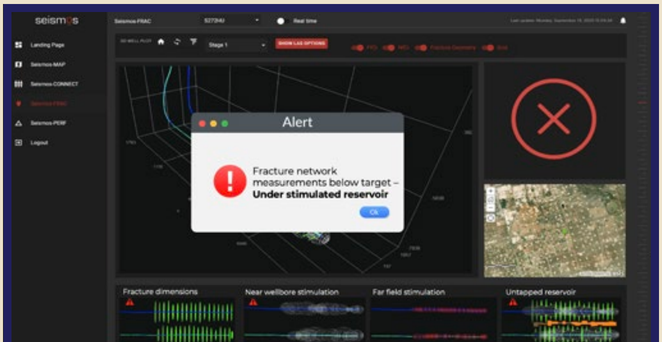
MTU Hybrid E-Frac combines proven power generation technologies focused on consuming natural gas, reducing emissions and lowering operating costs. (Source: Rolls-Royce)

cient autonomous system. Electrification and hybrid systems enable the oil and gas industry to achieve ESG commitments and shift to a more sustainable business, less impacted by fluctuations in commodity prices.

Real-time quality control agent for fracturing

Seismos-MWF (Measurements While Fracturing) is a quality control tool that detects and corrects understimulation in real time as it appears. The system tracks stimulation performance and fracture system properties while pumping operations are in progress. When understimulation or suboptimal reservoir coverage is detected (typically the result of subtle geological changes, stress buildup or offset well interaction), the system prompts for a subtle completions tweak, offsetting any such effect and eliminating the occurrence of "bad" stages that would contribute little/nothing to production.

Measurements of fracture complexity, conductivity, dimensions and more stream in real time to a user-friendly interface



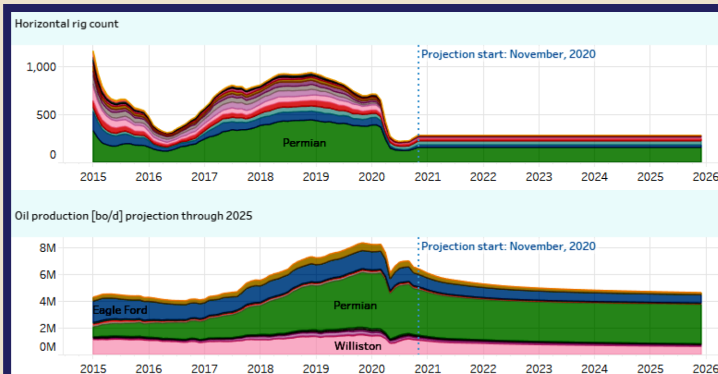
When the system detects under- or overstimulation, a virtual agent alerts the crew to adjust completion parameters and improve frac consistency. (Source: Seismos)

that is accessible by any device. Embedded AI-powered agents track the fracture system measurements and pinpoint to the type of stimulation inefficiency while highlighting the variables that need an adjustment (i.e., volume, rate or other).

The MWF quality control tool is designed to tackle understimulation in real time and provide critical downside protection. The tool holds a current track record of 8 boe/ft in additional production (six-month cumulative production data).

Analytics service reveals how much wells will produce and economic value

The Ultimate version of ShaleProfile Analytics was created to help industry professionals understand quickly how much oil and gas horizontal wells are likely to produce and the economic value attached to this. An advanced production forecasting engine was developed and optimized based on forecasting accuracy using all available historical data. Production forecasts are automatically generated on well level whenever new production data come in. These forecasts can be used in a well economics module to quickly calculate important financial metrics like (remaining) net present value. They are also an input to a supply projection model that allows users to simulate future tight oil and gas output based on their assumptions on how the rig count and well/rig productivity may change over time. Additionally, a well spacing analytics dashboard is available in which the relationship between spacing and well productivity can be unraveled. All production and completion data are publicly sourced, so no additional data licenses are required.



The Supply Projection dashboard contains an interactive model that relates the rig count with future oil and gas supply. (Source: ShaleProfile)

Electrifying fleets and switching to natural gas reduces fuel costs up to 80%

Siemens Energy, Electric and Mechanical Solutions are powered by Via mobile power units using gas turbine generators that can develop scalable power and distribution solutions for any electrically driven hydraulic pump fleet. Electrifying fleets

The Via portfolio of 5.8-MW and 7.9-MW class mobile power units provide scalable and rapid mobility solutions for power generation in a variety of oil and gas applications. (Source: Siemens)

and switching to natural gas fuels can reduce fuel costs up to 80% and reduce fleet maintenance costs 60%. Supported by a global service team as well as remote and edge analytics technology, the electric solution enables safer and more reliable operations, lowers emissions and increases profitability.

Biocides designed specifically for fracturing applications

Solvay's Tolcide4Frac is a broad-spectrum, fast-kill, THPS-based biocide formulation specifically designed for stimulation applications. With multiple modes of action and both biostatic and biocidal properties, it has been formulated to have enhanced efficacy against troublesome APBs, SRBs, GHBs and archaea in on-the-fly and downhole conditions, while also providing biofilm control. It has been proven to be effective in higher TDS water conditions where other biocides fail.

Unlike glutaraldehyde and glutaraldehyde-based formulations, Tolcide4Frac does not increase corrosion rates. It also works to dissolve FeS and Schmoo and is not inhibited by H_2S. This gives it the ability to facilitate demulsification while still performing as a biocide. Tolcide4Frac protects the integrity of assets, while its HSE profile makes it the safer choice for protecting the environment and onsite personnel.

Tolcide4Frac is more thermostable than other in-class biocides and retains its efficacy in the reservoir while it follows the water front, providing post-frac souring control and in-situ control of blackwater.

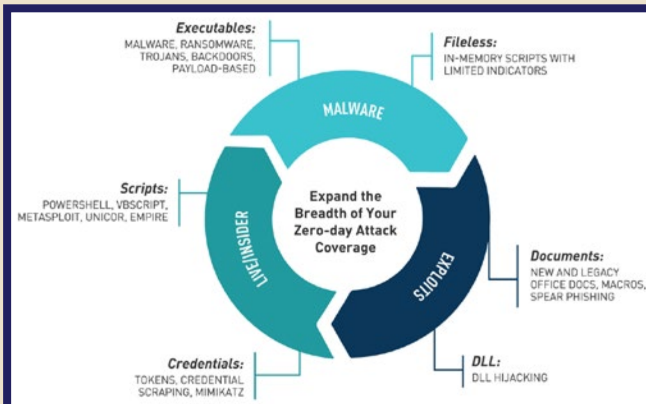
Tolcide4Frac has proven to be compatible with all stimulation fluids, including friction reducers and oxidizing breakers, while delivering cost savings through asset protection and operational benefits.

Machine learning tool protects against cyber threats

In an increasingly digital world, operational technology (OT) systems and industrial equipment face a growing risk of cyberattacks that threaten operations. Oil and gas companies, power generation plants and manufacturing facilities must contend with:

- Pervasive connectivity due to merging IT and OT systems, introducing more avenues for devastating cyberattacks;
- Aging legacy computer systems that are not equipped to prevent malware, ransomware and other forms of modern cyberattacks, threatening day-to-day operations as well as causing large-scale disruptions; and
- Traditional signature-based defenses that rely on constant, manual updates to the list of known threat signatures and rapidly become outdated on isolated systems.

Customers demand reliability and will divest from businesses that cannot defend their infrastructure. Yet companies face physical, financial and legacy constraints in securing infrastructure. By adopting an AI-based solution, companies can address OT systems' vulnerabilities.

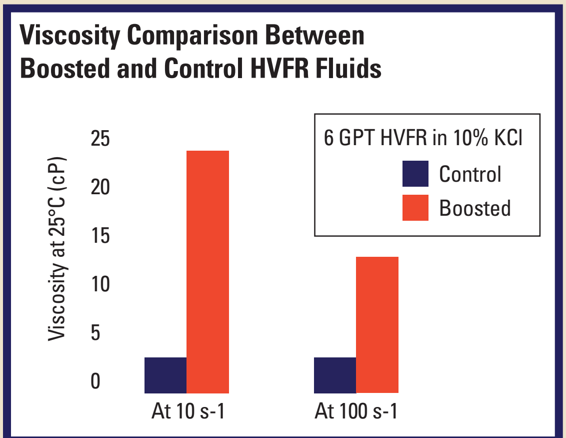


(Source: SparkCognition)

SparkCognition's DeepArmor Industrial is a scalable machine learning tool that protects OT systems, legacy assets and critical infrastructure from advanced zero-day cyber threats. As the first endpoint SCADA protection that specifically focuses on protecting legacy systems against various attack vectors, it meets the highest standards of North American Electric Reliability Corp.'s Critical Infrastructure Protection reporting and compliance standards.

HVFR booster additives enhance viscosity of fluids

Stepan Oilfield Solutions has recently commercialized additives for improving the performance of high-viscosity friction reducer (HVFR) fluids in recycled and produced water. HVFR fluids have very low tolerance to salinity and lose their viscosity and proppant carrying capacity in the presence of even small amounts of salt. This prevents the use of HVFR fluids in recycled and produced water. Stepan's HVFR booster additives significantly enhance the viscosity of these fluids in brines containing monovalent and divalent cations. The viscosity boost has been observed with anionic and cationic HVFRs. Furthermore, the increase in viscosity was corroborated by proppant transport



Viscosity of 6 GPT HVFR fluids in 10% potassium chloride brine with Stepan booster formulation shows improved performance versus control at two different shear rates. (Source: Stepan Oilfield Solutions)

measurements. HVFR fluids containing the booster formulation resulted in significantly improved proppant transport through a rectangular slot compared to analogous HVFR fluids without booster. By enabling HVFR fluids to be formulated in recycled and produced waters, Stepan's additive provides cost and sustainability advantages. Additionally, this also allows less HVFR to be used to achieve a target viscosity in brine, thereby reducing the risk of formation damage by the fracturing fluid.

Soy R&D leads to three new earth-friendly products

Synalloy Chemicals focused on soy chemistry in 2020 because it is an earth-friendly and annually renewable material source. The addition of soy fatty acid supply will help stabilize pricing, reduce shortages and offer some new performance advantages. Three new oilfield products resulted from Synalloy's 2020 soy research.

Manazoline HS1 is a soy imidazoline designed for corrosion formulation that is superior to most other fatty acid imidazolines in terms of performance and stability. Salting out is reportedly improved versus conventional imidazoline.

Manazoline HSQ is a highly charged soy imidazoline quat that is water soluble. It replaces conventional imidazoline quats with several advantages.

ManaSurf SF is an 80% sulfated soybean oil that can be used in drilling lubricant formulation and as a replacement for sulfated castor oil in other oilfield applications.

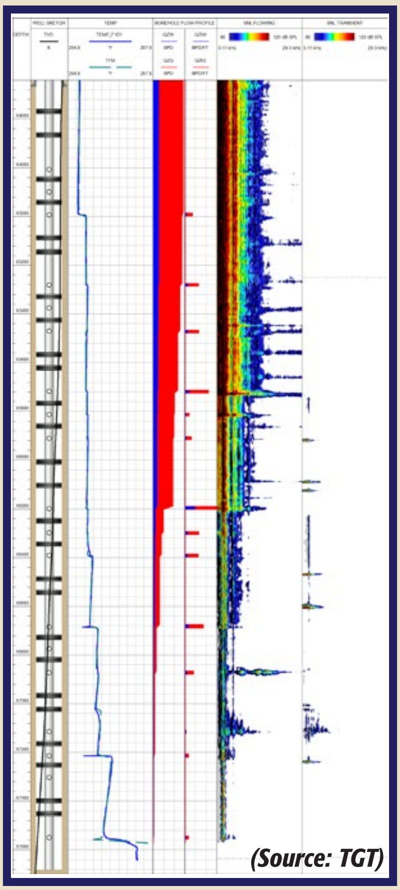
Soybean oil has a compelling environmental story (available from United Soybean Council) that was a key factor in launching these research projects. Taking advantage of an enormous supply stream that can quickly adjust production to demand on any scale moved soy research to the top of Synalloy's research priorities.

Isolation technology for refracturing

Conventional methodology typically involves running a liner and cementing to isolate existing perforations, which can result in complex procedures and a significantly reduced internal diameter. Tendeka's SwellFrac solution uses swelling elastomer technology to simply and economically isolate existing fractures in oil and gas wells while maintaining a full internal diameter, allowing the well to be refractured.

Since its introduction in 2019, Tendeka has conducted further work to define the performance envelope and improve pumpability of the sized swellable elastomer.

As sized swelling elastomer in aqueous slurry has a tendency to agglomerate, numerous surfactants were evaluated and the concentration optimized resulting in a uniformly dispersed, non-foaming aqueous suspension. Bench top testing demonstrated that the exceptionally high surface area results in relatively fast swell times and is being validated in an HP/HT test fixture.



(Source: TGT)

Additional tests have confirmed that filling of perforations with non-swollen elastomer will generate an immediate pressure differential demonstrating diversion capability during the pumping process. Most recent testing has confirmed that the sized elastomer will be retained in high side perforations once swollen.

Diagnostics locate flow before or after fracturing

TGT's Fracture Flow evaluates the effectiveness of a fracturing program. It uses the Chorus acoustic platform to record and analyze the acoustic wave propagation in the wellbore and rocks, plus well design information, to determine the location of the acoustic source energy produced by fluid flow in the fractures. When used during pre- and post-fracturing, it can analyze the reservoir flow profiles, qualify flow to or from the fracture network, reveal fracture density and identify unwanted fracture components that impact product. The technique can identify the location and determine the distance of the acoustic signal from the receiver. Combined, these insights offer operators the diagnostics they need to improve their fracturing program, so it can be targeted and optimized to deliver maximum time and cost efficiencies.

The logplot shows a horizontal tight sand gas condensate producer, completed with a non-cemented multistage ball-activated application. Stage separation was achieved by a dual hydraulic-activated packer. The results identified the presence of 22 active fractures, 17 were offset from flow ports and five could be aligned with the flow ports producing a unique signature covering a wide frequency range. The fracture distribution varied between stages with an average of three active fractures per stage.

A drill-out technology for frac operations

Over the past decade, the industry has experienced a dramatic shift in the requirements of downhole technology performance—lateral lengths are longer, stage counts are higher, temperatures are hotter and pressures are higher. For unconventional completions operations, myriad advancements in completion technology have enabled operators to achieve higher productivity and stronger economical return. A major contributor to this outcome is the innovation in drill bits used in the milling of frac plugs.

Varel Energy Solutions' (VES) Slipstream features a hybrid cutting structure. The roller cone drill bit utilizes tungsten carbide inserts on the outer rows for the tougher portions of the plugs and steel teeth on the inner rows to enable fast mill times.

VES is scheduled to release the newest generation of milling technology with SlipXtreme in early 2021—a design optimized for greater durability and performance while preserving the strength of the hybrid cutting structure. The bearing surface area has been increased to handle higher energy loads, and the seal location and compound has been modified to better resist wear and higher hole temperatures. In addition, the SlipXtreme is armed with VES' maximum carburization process to treat the cone steel to mitigate erosion and improve steel life.

The hybrid roller cone is designed for milling applications across various downhole environments. (Source: Varel Energy Solutions)

AI-enabled multivariate diagnostics, event recognition and real-time alerting condenses days of work into seconds. (Source: Well Data Labs)

Powering drilling and completions decisions with customizable AI

Now more than ever, operators need to go beyond basic analytics and visualization tools. The Well Data Labs AI-powered platform enables operators to automate workflows and make repeatable data-driven decisions. The flexible AI platform shifts time-consuming and costly workloads away from engineers, data scientists and boutique consultants, freeing them to focus on higher-value tasks. Leveraging Well Data Labs' cloud-based drilling and completions data, the platform can output anything from channel calculations to bleeding-edge multivariate diagnostics and real-time alerts initiated by machine learning.

Once a task is automated, it can be continuously performed on every well and for every team, bringing agility to every operator. The platform has been used to create sealed wellbore pressure monitoring reports and real-time fracture-driven interaction alerts. It also can identify key events such as pressure changes that can serve as early warnings for potential screen-outs and other issues. Because the Well Data Labs automation platform is flexible, operators can scale their data analytics programs throughout the organization, accelerating data-driven innovation and decision-making.

Automate chemical injection to protect frac water storage, transportation

WellAware On Demand Chemical for water management automates chemical injection to protect frac water storage

WellAware On Demand Chemical is installed on a tank in a field to automate chemical injection. (Source: WellAware)

and transportation infrastructure, enabling the treatment and reuse of clean brines and more efficient transportation of water for hydraulic fracturing operations.

With WellAware On Demand Chemical, a major pure-play operator in the Permian Basin was able to reduce freshwater consumption by 30% by introducing clean brine into their water gathering network. The chemical uses advances in edge compute, wireless networking and web dashboards to automate chemical injection pumps, provide real-time chemical visibility and improve chemical vendor accountability. WellAware On Demand Chemical continuously monitors water flow rates, adjusting chemical injection rates in real time to maintain precise chemical concentrations that protect critical frac water infrastructure. This solution works on most chemical pumps that inject scale inhibitors, corrosion inhibitors, methanol, iron sulfide inhibitors or other specialty chemicals used to treat water management pipelines and vessels.

Separation equipment designed for frac operations

With high pressure, high volume and sandy production, modern hydraulic fracturing operations place demands on surface separation equipment that simply didn't exist when much of this equipment was commissioned decades ago. Worthington Industries designs separators and heater treaters for today's frac-intensive operating environment. The company's ultra-efficient separators feature internals that withstand the rigors of the oil field and typically mean buying fewer pieces of equipment for lower overall cost. And with standard built-in sand management filtering sand down to 120 microns, Worthington units even help reduce maintenance and downtime in the field.

The company designed and implemented a new inlet device that almost eliminates oil carryover in the gas stream. CFD resulted in .02% oil carryover versus the typical 1% to 5% seen across the industry.

In a case study, Worthington's advanced separation technology enabled an operator in the Delaware Basin to eliminate the need for excess equipment. In addition to the associated cost savings, this enabled consolidation of equipment onto a single skid—not only minimizing footprint but also simplifying field setup. No additional hookups were necessary for that well, just a single tie-in on the inlet and outlet. In all, the modular solution reduced footprint by 62%. The resulting design simplified the well site, lowered overall capex spend and still delivered the same processing throughput with less oil carryover.

Stimulation mechanisms used to support dilated secondary fractures

Zeeospheres Ceramics LLC's Deeprop 1000 is a small, very strong, perfectly spherical proppant made in the U.S. that is used to support dilated secondary fractures created in shale during the hydraulic fracturing process. The material is designed to provide long-term conductivity in fractures that are 10 times smaller than 100 mesh can penetrate. It has no closure pressure or temperature limits. The economic benefits of utilizing this small proppant in both oil and gas wells have been demonstrated using production data from several different rock systems including the Barnett, Woodford, Utica, Delaware and Permian Basin shales.

In addition to the lift in production the microproppant has provided, it has found substantial immediate benefits by reducing the treating pressure as it is introduced (Figure 1). Because the material is very hard, it has been shown to abrade any near wellbore restrictions, which allows an increase in pump rate. This increase in pump rate shortens the time it takes to place a stage, which shortens the time it takes to complete a well, thus reducing the day rate charges. By increasing the pump rate, the fluid efficiency is also improved, which allows a larger SRV to be created with the same amount of fluid. An additional benefit of removing this near wellbore restriction is a reduction in the convergent flow excess pressure effects that occur as the flow in the fracture merges with the wellbore. +

HARTENERGY

CALL FOR ENTRIES

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Annually Hart Energy bestows the **Special Meritorious Awards for Engineering Innovation (MEAs)** to honor the best new products, methods and services for finding, developing and producing hydrocarbons.

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US Shales

An in-depth analysis shows what went right and what didn't in 2020 and the game changer that could push each major North American shale basin into prosperity in 2021.

ANALYSIS BY ENVERUS

As the industry often does, it will one day look back on 2020 in a variety of contexts—how demand destruction and a global price war sunk oil prices to previously unseen levels, how mounting debt problems coupled with a lack of investment opportunities drove widespread consolidation, and how production shut-ins crippled operators.

The 2020 details vary depending on which of the seven major shale basins are being reviewed:

- Activity dropped to merely a crawl in places like the Rockies and the Midcontinent;
- The Permian behemoth took a punch but quickly got up off the mat; and
- Gas plays like the Haynesville and Marcellus/Utica rode on the coattails of Henry Hub prices that reached \$3/MMBtu by early fall 2020.

The summer of 2020 was marked by unprecedented headwinds for the shale industry—for producers and service providers alike. WTI fell into negative valuation in May as a result of a lack of storage capacity coupled with overproduction. By mid-August, the number of rigs operating in North America had fallen to 244, the fewest since Baker Hughes began tracking rig counts in 2011. By the end of August, U.S. production was down from more than 13 MMbbl/d to 9.7 MMbbl/d. And according to Westwood Energent, the number of frac crews in the Permian had fallen to the 18-20 range.

Although the industry has never faced an environment quite like 2020, every downturn is inevitably followed by a recovery. By late October, the rig count slowly climbed to 287, with weekly gains every week since Sept. 11.

in 2020

The Haynesville, with ample takeaway capacity and being a gas-focused basin, will be called upon to help offset the natural gas deficit. (Source: Marc Morrison/ marcmorrison.com)

Most analysts believe that the rig count as well as the number of frac crews will pick back up in 2021 as companies put their DUCs on production.

Todd Bush at Westwood Energent estimated that for operators to maintain previous production levels, the industry would need to put about 150 frac crews back to work. Trends appear to be moving in that direction.

According to Tudor, Pickering and Holt (TPH), the number of pressure pumping crews increased by as much as 18% from August to September 2020, and another 6% from September to October. In fact, TPH analysts said late last year that if completion activity held through the end of 2020, the active spread count could be up by as much as 24% quarter over quarter.

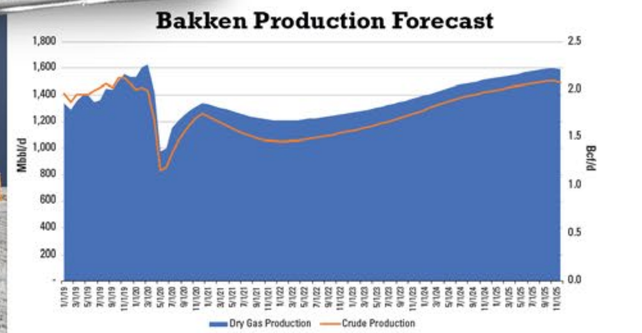
Certainly the U.S. shale industry took its hits in 2020, with some regions faring better than others. In the following special report, E&P Plus has partnered with Enverus to provide an in-depth analysis of the seven major shale basins—the Permian, Bakken, Rockies, Marcellus/Utica, Haynesville, Eagle Ford and Midcontinent. These “score cards” provide what went well for each shale, what didn’t, the game changer that will push that basin to prosperity, exclusive analyst insight into each basin and a production forecast for what Enverus sees moving forward. +

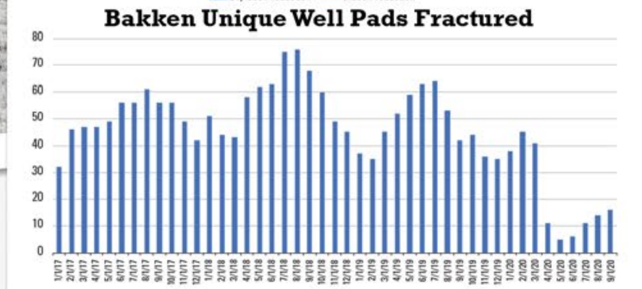
—**Brian Walzel,** Senior Editor

Editor’s note: *The analysis,insight and data included in this special report were provided in partnership with Enverus in late October 2020. All charts are courtesy of Enverus.*

BAKKEN

(Source: Marc Morrison/marcmorrison.com)





THE GOOD

After the 2015/2016 downturn, operators adopted modern completion designs. Proppant intensity increased from 2010-2015 levels at about 300-500 lb/ft to about 900-1,000 lb/ft, while fluid intensity increased from 6-12 bbl/ft to 20-23 bbl/ft during that same timeframe. The new completion design has proven optimal in the basin as operators have not deviated from the design since 2017, and productivity has responded positively.

THE BAD

Although operators in the Bakken have modernized completions, it is still one of the most mature unconventional basins in the country. Accordingly, the number of drillable locations in the core is dwindling. The lack of available inventory in the core will force operators to look into noncore areas for additional locations. Given the current price environment, operators are likely to focus on core acreage, which will diminish the limited core inventory even faster.

THE FUTURE

The Dakota Access Pipeline (DAPL), a 570,000-bbl/d pipeline originating in the Bakken, is a key pipeline that exports Bakken crude to downstream markets. DAPL has faced scrutiny since it has been built, and a judge ordered the pipeline to shut down earlier In 2020. While the order was ultimately overturned and DAPL continues transporting crude oil, the unknown of what may happen in the future is a major concern. Should DAPL be ordered to halt shipping, operators would be forced to move crude by rail, which would have significant impacts on netbacks.

WHAT THEY'RE SAYING

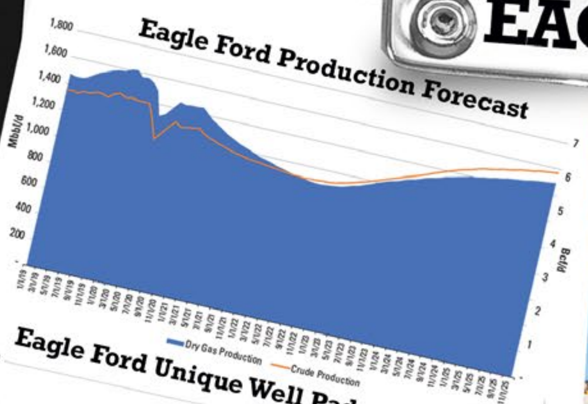
"The Williston has a clearly defined core, which is easily identifiable by looking at the lower water-to-oil areas. Completion designs have been optimized to modern parameters. While this helps returns, it also limits the upside for the basin as there is little room for efficiency gains. Drillable locations in the core of the basin are limited, especially as operators target their best acreage during the downturn."

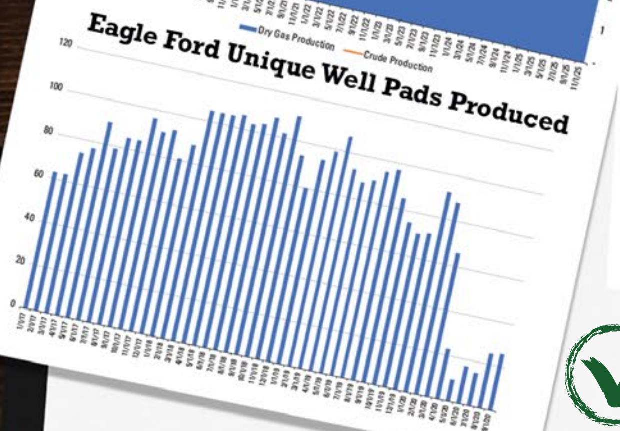
–Hakan Corapcioglu
Senior Energy Market Analyst, Enverus

THE GAME CHANGER

As one of the oldest unconventional basins in the country, older wells did not employ the optimal completion designs that we use today. Given that these wells may have had lower recovery rates, future refrac opportunities exist.

EAGLE FORD





(Source: Marc Morrison/marcmorrison.com)

THE GOOD

The Karnes Trough is still one of the most productive and economic areas in the country. In comparison to the northern oil window of the Delaware, the Karnes Trough normalized IP rates outperform by 29% from 2015 through 2018. In 2019 and 2020, the two areas were very similar in terms of normalized oil IP rates. The Eagle Ford hosts one of the most economic parts of the Lower 48, and other parts of the basin continue to screen well in terms of economics in the shale supply stack.

THE BAD

The Eastern Eagle Ford, largely controlled by Chesapeake via the WildHorse acquisition, has been underwhelming when compared to the Western Eagle Ford. Type curves in the Eastern Eagle Ford improved with high proppant intensity completion design, but it still trails its western counterpart. Given that the Eastern Eagle Ford is largely controlled by Chesapeake, which filed for bankruptcy earlier in 2020, development of the area will likely slow.

WHAT THEY'RE SAYING

"In the Eagle Ford, we see increasing interest in technologies like EOR and refracs, which provide operators optionality after primary development opportunities become exhausted. Furthermore, the combined effects of higher 2021 strip pricing and relative ease of market access support economic gas development in the western part of the play."

—**Heather Leahey**
Senior Associate, Enverus

THE FUTURE

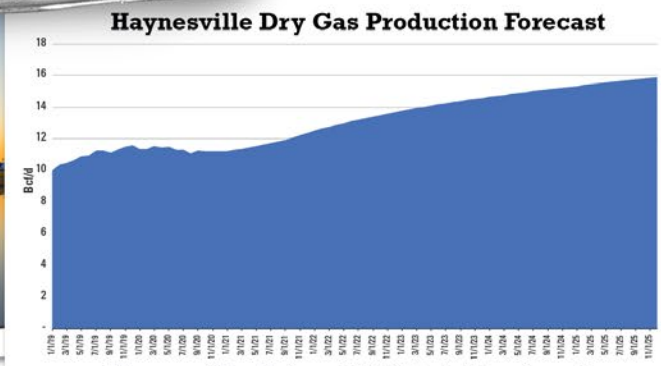
The Eagle Ford can be considered a mature unconventional oil play. Therefore, the number of drillable locations in the core is starting to dwindle. With the expectation that higher gas prices will be required to balance the market in 2021, the southwestern part of the play, where the Eagle Ford gets gassier, will likely see increased activity.

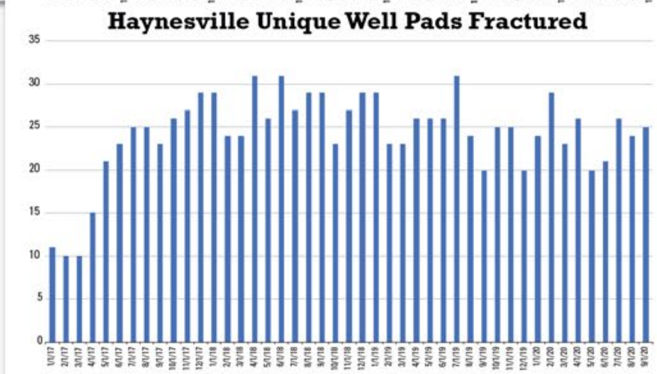
THE GAME CHANGER

As one of the older unconventional basins in the Lower 48, the Eagle Ford is running low on top-tier inventory. This has brought an increased interest in refracking wells as well as EOR methods. As older unconventional wells were not completed with the modern completions we have today, refracs or EOR could help increase recovery factors.

HAYNESVILLE

(Source: Marc Morrison/marcmorrison.com)





THE GOOD

In 2015 nearly 65% of the rigs and about 84% of the natural gas production in the Haynesville came from the Louisiana core. In 2020 (as of late October), only 39% of the rigs and 51% of the production in the basin came from the Louisiana core. Yet, average type curves remain intact, which bodes well for future production. Being near the demand centers and export markets helps the Haynesville in comparison with the Northeast.

THE BAD

The Haynesville is one of the main natural gas basins in the Lower 48, along with the Marcellus and Utica. However, unlike the Northeast basins, the Haynesville is nearly all dry gas production. Only producing dry gas leaves producers susceptible to natural gas prices without the ability to switch to a wet gas or condensate play. As we've seen over the last few years, associated gas production has exploded in the Permian, ultimately oversupplying the market and pushing natural gas prices down. Operators in the Haynesville, if not hedged, were vulnerable to those low prices.

THE FUTURE

The COVID-19 pandemic has taken its toll on many different industries, and the oil and gas sector is no different. With crude oil prices down and showing slow recovery, associated gas production will be down in the winter heating season and 2021. This decline in production is expected to cause an upward move in natural gas prices. The Haynesville, with ample takeaway capacity and being a gas-focused basin, will be called upon to help offset the natural gas deficit.

WHAT THEY'RE SAYING

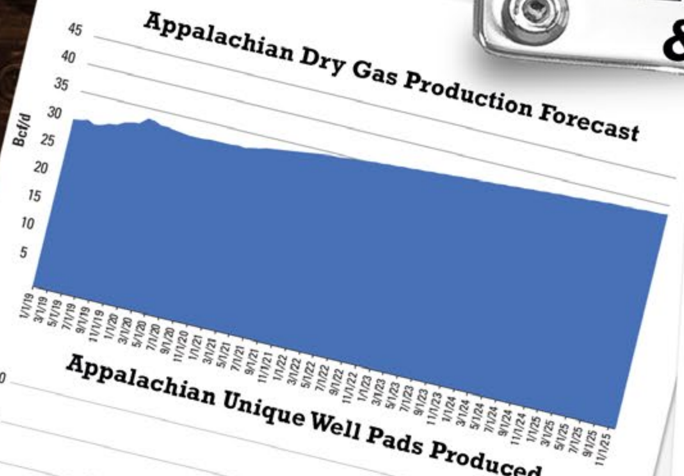
"In 2016 the Haynesville was sitting below 4 Bcf/d of gas production. Starting in 2017, operators adopted a higher intense completion design, which improved its competitiveness with Appalachia and allowed the play to reach 11-plus Bcf/d in late 2019, with most of the production increase coming from outside the traditional core. With ample takeaway capacity in the Haynesville and the possibility of higher sustained gas prices beyond 2021, some proven private operators, which drove production expansion in the past, will be motivated to initiate public-equity offerings to fund further growth."

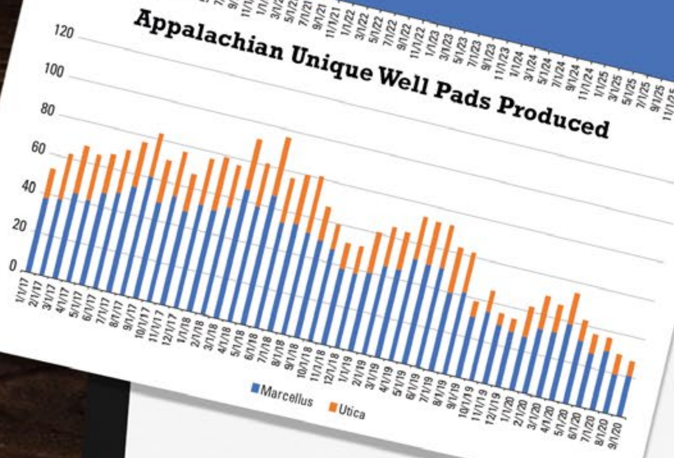
–Jimmy McNamara
Senior Intelligence Associate, Enverus

THE GAME CHANGER

Prior to 2017, the Haynesville was considered a second-tier gas play. However, the adoption of new completion designs in the basin brought it into the first-tier gas play bracket along with the Northeast. Proppant and fluid intensity increased following 2016, and this completion design change has helped the Haynesville look prospective for continued activity in a favorable gas price environment.

MARCELLUS & UTICA





(Source: Marc Morrison/marcmorrison.com)

THE GOOD

Longer laterals were drilled in 2020 when compared to 2019, and these longer laterals resulted in better overall 2020 normalized type curves. The core northeast Pennsylvania area saw laterals increase by more than 1,700 ft on average in 2020, and normalized type curves showed IP rates increasing 300 Mcf/d per 1,000 ft compared to 2019.

THE BAD

Infrastructure development has been difficult to get across the finish line. Most projects going north or toward the East Coast face legal battles or permit troubles. Many pipeline projects heading north have trouble acquiring permits, while projects heading toward the Mid-Atlantic have faced legal battles opposing the permits they have received, ultimately resulting in severe delays and cancellations.

WHAT THEY'RE SAYING

"After years of Appalachia operators outspending cashflow to chase double-digit growth, a combination of swelling leverage, investor sentiment and egress limitations has driven a point of inflection in one of the lowest-cost gas basins in the Lower 48. With operators pledging to invest within cash flow, near-term growth is limited even at the higher prices expected for 2021, with ultimate growth being capped by restricted spare capacity out of the basin."

–Matt Clenchy
Research Analyst, Enverus

THE FUTURE

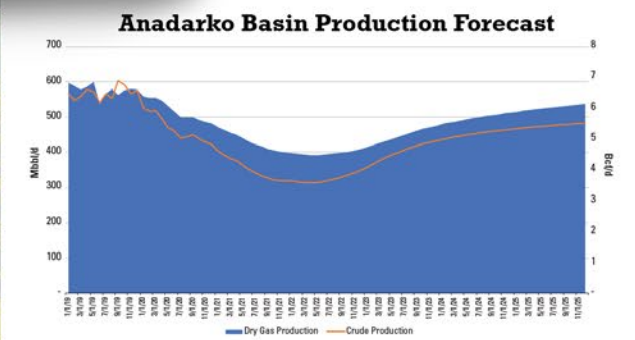
Core Marcellus and Utica have sub-$2.25/MMBtu gas breakeven prices. With associated gas production down due to crude prices from lagging demand, natural gas prices are expected to climb due to a supply shortfall. Accordingly, the Northeast will be called on to increase supply. MVP, a 2 Bcf/d pipeline taking gas to Virginia, will help in the near term. However, with Mountain Valley Pipeline being the only large pipeline development on the project slate, future production growth will rely on the ability to debottleneck pipeline capacity.

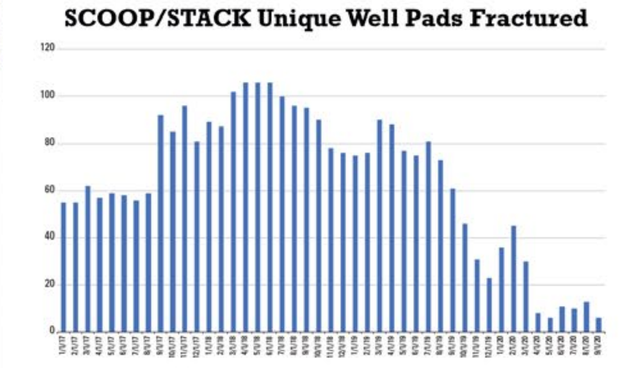
THE GAME CHANGER

As it becomes increasingly difficult to get new pipelines built to ship gas out of the region, production growth will be capped at takeaway capacity. The game changer in the Northeast could be positive or negative. Should pipeline bottlenecks arise, in-basin pricing will h ave downward pressure and production will be capped. Should additional capacity hit the market, production growth will be possible and regional pricing will be positively impacted.

MIDCONTINENT

(Source: Marc Morrison/marcmorrison.com)





THE GOOD

The SCOOP and STACK normalized oil type curves in 2019 for half or fully bounded wells saw production increases when compared to 2018. Wells in 2019 saw average laterals increase by about 1,100 ft with a slight increase in proppant intensity. This is promising for the SCOOP and STACK that had seen normalized oil type curve degradation since 2016.

THE BAD

After an improvement in normalized type curves in 2019, the SCOOP and STACK saw type curve degradation in 2020. A majority of wells, roughly 38%, in 2020 (as of late October) fall in the STACK Volatile Oil sub-play, most of which started producing in the first quarter. For half or fully bounded wells in the STACK Volatile Oil sub-play, spacing decreased more than 100 ft in 2020 on average, causing a drop in the normalized type curve.

WHAT THEY'RE SAYING

"The Midcon continues to be a challenging region to operate economically as seen by the exodus of drilling capital from most of the multibasin operators and cratering rig activity over the last few quarters [in 2020]. Those with the luxury to pivot to other plays have largely sidelined the STACK, while the SCOOP remains the only bright spot with some of the best Lower 48 well results coming out of this play, though scale and repeatability of the resource remains in question. Activity will be slow to rebound in the Midcon for the medium term as the oil price recovery continues to putter."

–Jason Levesque
Senior Associate, Enverus

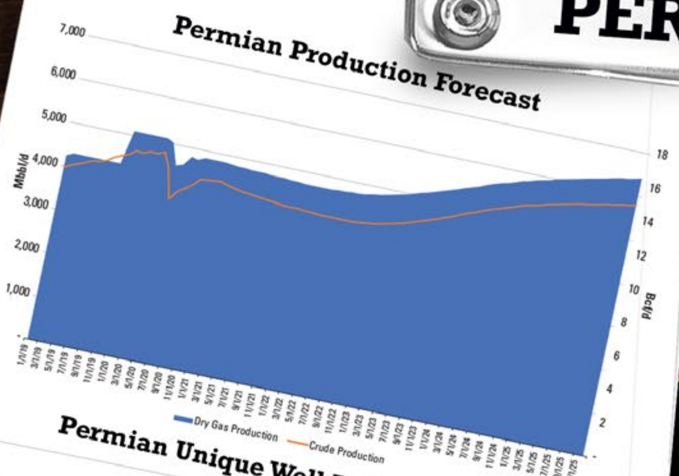
THE FUTURE

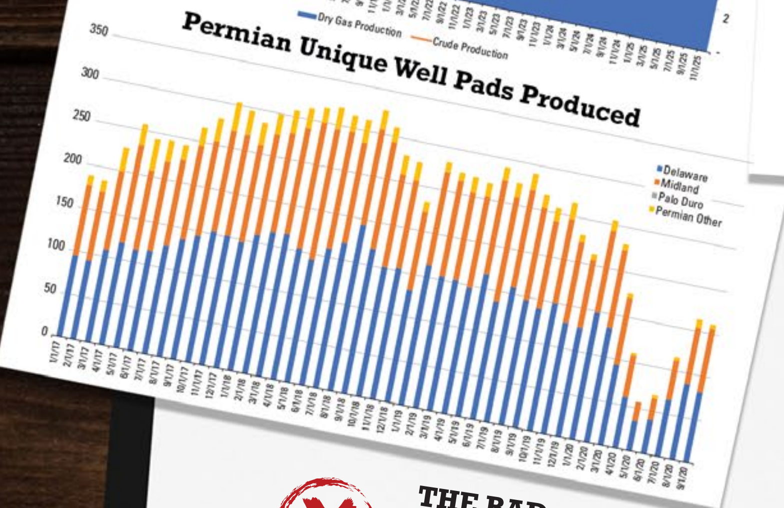
The Midcontinent craze that started in 2016 was not able to hold on for long. Operators had an expectation that the basin would continue to provide efficiency gains, but well spacing issues limited that expectation within a couple of years. While well spacing will be an ongoing battle, the core of the SCOOP and STACK remain economic plays for operators in the basin that employ sound spacing and completion optimization.

THE GAME CHANGER

Spacing has been, and will continue to be, the game changer in the Midcontinent. In 2019 operators had success for the first time since 2016 in achieving year-over-year normalized type curve growth. However, 2020 brought type curve degradation as well spacing decreased.

PERMIAN





(Source: Tom Fox/Oil and Gas Investor)

THE GOOD

While rigs in the Permian have not recovered from the drop following the pandemic, frac crews have picked up in the basin. The Delaware and Midland have been the primary drivers of the uptick in activity. Both plays hit their 2020 low point in frac crew activity in May. From May to September 2020, the Delaware frac activity increased 134%, while the Midland increased 236%.

THE BAD

After years of normalized type curve improvements because of drilling and completion efficiencies, 2020 brought slight type curve degradation to the basin. While fluid and proppant intensity per perforated foot has remained relatively the same, partially or fully bounded wells drilled in 2020 showed less impressive type curve results than those drilled in 2019.

WHAT THEY'RE SAYING

"While activity is still depressed compared to where it was to start the year, the Permian has picked up quicker relative to other basins from the plunge due to COVID-19. Operators that have large, multibasin portfolios are focusing their spending on the Permian over other basins due to the more favorable economics. Operators will continue to focus on developing their Permian acreage while crude prices recover."

–Bernadette Johnson
Vice President Macro Fundamentals, Enverus

THE FUTURE

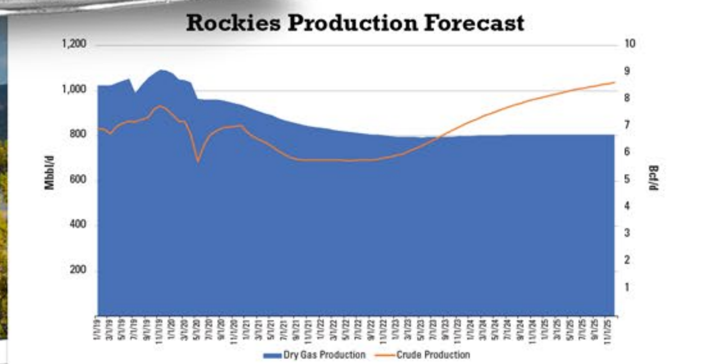
While 2020 brought type curve degradation to the Permian, economics in the basin remain some of the best in the country. The buildout of pipeline capacity over the last couple of years will allow commodities to exit the basin and make their way to downstream markets, the majority of which are on the Gulf Coast. The Permian has been the most active and productive basin in the country over the last few years and will continue to play a major role in production growth.

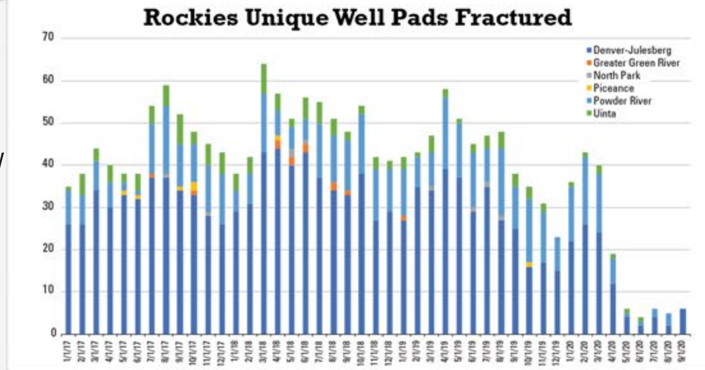
THE GAME CHANGER

The Permian exploded with production over the last half-decade, and the midstream sector was not able to keep up with providing takeaway capacity at the rate the basin was growing. However, over the last couple of years, midstream players have built crude, natural gas and NGL pipelines, mainly flowing to the Gulf Coast. With the buildout of these pipelines, bottlenecks were relieved in the basin and strengthened in-basin pricing.

ROCKIES

(Source: Marc Morrison/marcmorrison.com)





THE GOOD

The Denver-Julesburg (D-J) Basin is the heart of Rockies production. Well costs are low in the play and the core economics are top tier in the Lower 48, with breakevens in the core at sub-$40/bbl. If political risk factors do not hinder operators' abilities to develop their assets, economics are favorable for activity.

THE BAD

The core of the D-J has been largely consolidated. Two of its biggest operators, Anadarko and Noble, have been acquired by Occidental Petroleum and Chevron, which have larger portfolios where the D-J will have to battle for capex allocation. Adding in the tough regulatory environment, it is difficult to imagine the new owners focusing in the D-J, like Anadarko and Noble used to.

THE FUTURE

The future of the Rockies is largely dependent upon political risk and how stringent regulations become, particularly in Colorado. More regulation in Colorado for the oil and gas industry has been a factor over the last few years, and it is likely not going anywhere in the future. Operators with large, multibasin portfolios may avoid spending capital in the region in favor of other basins due to the regulatory climate. Outside of Colorado and the D-J, the Powder River Basin has seen normalized type curve degradation over the last few years, while the Uinta struggles to find markets for its crude quality. As long as the crude markets are in recovery from the pandemic, operators will focus on their core acreage in the Rockies.

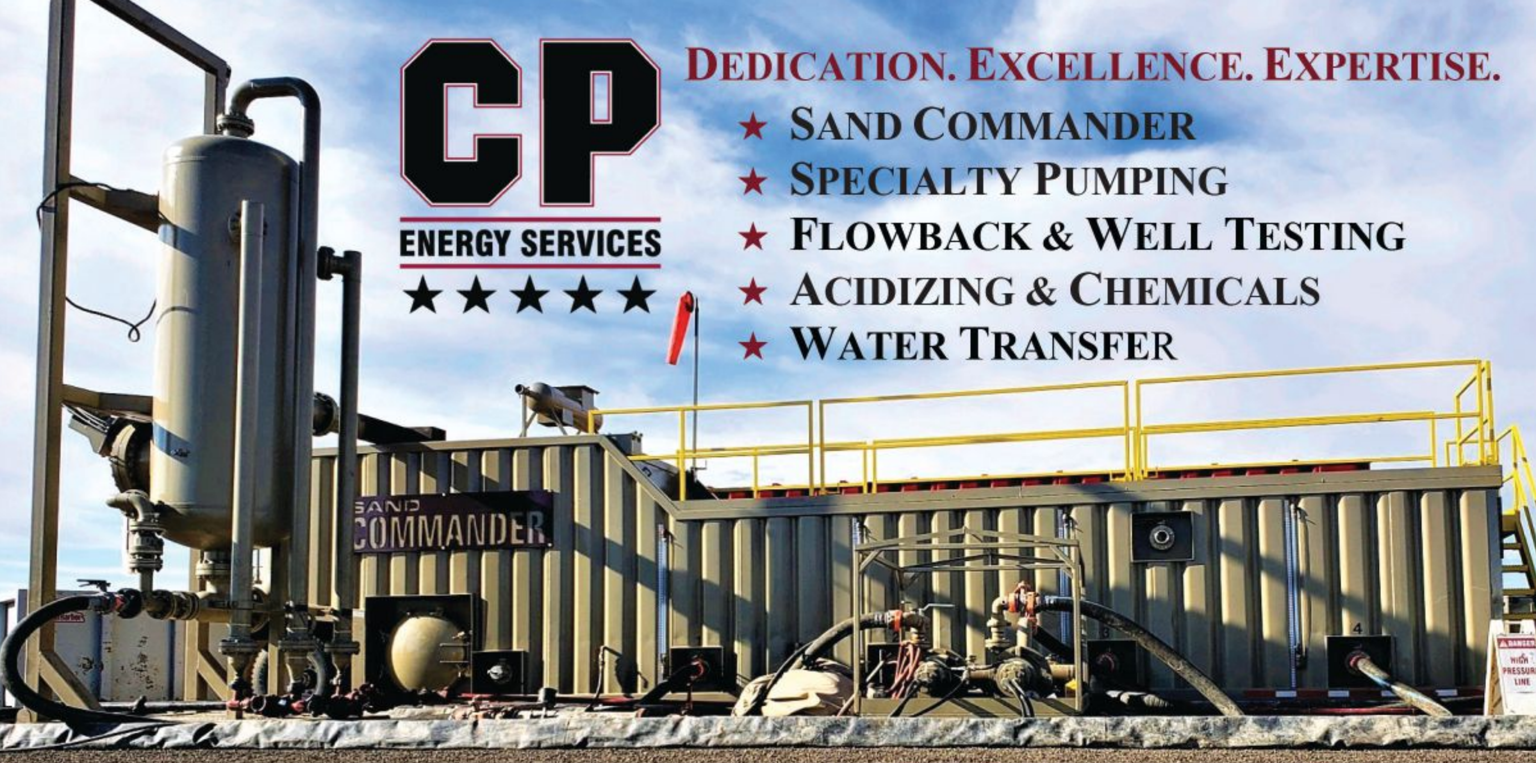
WHAT THEY'RE SAYING

"D-J is the Rockies basin with the most top-tier inventory, but political circumstances are souring the outlook for its development potential. The Powder River Basin has struggled to breakout, and mixed results in a low-price environment isn't desirable for operators with other options in their portfolio. Despite promising results in the Uinta, doubts remain around the areal extent, which can be exploited horizontally, not to mention the limited buyer for its production due to quality issues with its oil production."

—Sarp Ozkan
Senior Director of Energy Analytics, Enverus

THE GAME CHANGER

The state of Colorado, home to one of the Rockies best plays in the D-J, has proposed new regulations that would require new well pads to be 2,000 ft away from building units and school properties. This is an increase from the current setback of 500 ft. The Colorado Oil and Gas Conservation Commission (COGCC) has provided outlets for operators to drill within that 2,000-ft setback. However, the burden of proof will fall on the operators to convince the COGCC to approve the permits.



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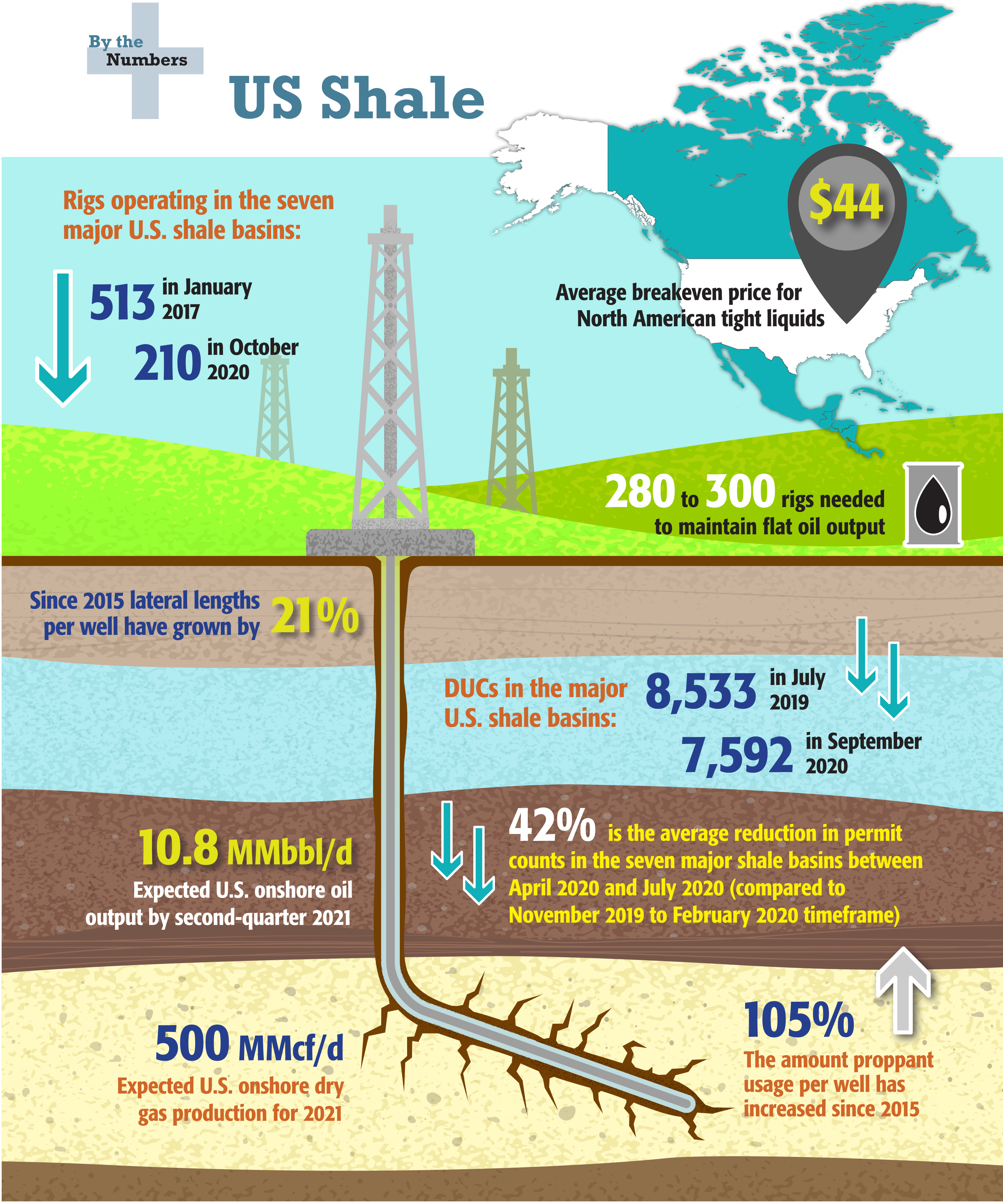
By the Numbers

US Shale



(Sources: A&D Market Monitor, Baker Hughes Rig Count, Rystad Energy, U.S. Energy Information Administration, and McKinsey & Co.; Data compiled by Brian Walzel; Design by Melissa Ritchie)

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Video

Vaccines, digitalization and energy transition to drive oil markets in 2021

Analysts from the U.S., Europe and the Middle East joined Hart Energy to discuss the 2021 oil and gas market outlook.

***Faiza Rizvi**, Associate Editor*

In this video, analysts from around the world answer questions regarding COVID-19's impact on the oil market, the energy transition, digitalization and more.

Jump to a topic:

- **0:46**–Shale outlook
- **2:00**–Resurgence of virus and impact on Europe's oil market
- **4:15**–Extension of OPEC+ cuts into 2021
- **7:43**–Joe Biden and the energy transition
- **12:26**–European oil majors realigning goals with net zero 2050
- **17:13**–'Hydrogen will be a game changer'
- **21:10**–Digitalization will shape recovery
- **28:46**–Final thoughts on the industry's path forward

In an exclusive roundtable discussion, analysts offered a bullish outlook for 2021, expressing cautious optimism that a vaccine breakthrough will significantly improve oil demand and prices as the economy goes back to normal in the second half of 2021. Speakers in this in-depth discussion include:

- Dr. Keith Myers, president of research with Westwood Global Energy;
- Dr. Yousef Alshammari, CEO and head of oil research with CMarkits; and
- James West, senior managing director with Evercore ISI.

"The [North American] shale outlook is a little bit better, but there are still a lot of rigs and equipment lying around; so pricing is going to be under a lot of pressure," West said.

Discussing the roadmap to recovery for European companies, Myers said, "It's a very exciting time to be in the energy business, but it's also very uncertain."

"Everything in our business hinges on oil prices," he added, stating that the resurgence of the pandemic in Europe had a "knock-on effect" on the expected oil recovery.

The analysts also discussed how the Biden administration will push investments in renewables and green energy moving forward.

"There has been some belief and speculation that Joe Biden's victory can be bearish for the oil markets, but I have certainly been cautious in agreeing to the statement," Alshammari said. "We must remember that during the era of Obama's administration when Joe Biden was vice president, oil prices were way above $100 per barrel, and that period between 2011 and 2014 played a key role in revolutionizing the U.S. shale industry."

The analysts agreed that hydrogen will play an important role in the energy mix of the future and that technology will be key in shaping the market recovery.

"We're bullish on hydrogen for a variety of reasons," West explained. "We have policymakers that are putting hydrogen into the rebuilding programs and will subsidize hydrogen for probably the next decade, which will bring us to scale. Secondly, the ESG and societal pressures are putting typical oil and gas companies into the hydrogen business…hydrogen will be a game changer." +

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(Source: DNV GL)

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Liv A. Hovem, DNV GL – Oil & Gas

New research from DNV GL reinforces the message that pressure on the global oil and gas industry to decarbonize its value chain to maintain its social license to operate will continue to increase in a rapidly changing world.

The 2020 Energy Transition Outlook estimates that fossil fuels will account for 74% of world energy-related CO_2 emissions in the mid-century and more than 80% of combined emissions of CO_2 and methane (measured as CO_2 equivalents). While global energy-related emissions will be roughly halved between 2018 and 2050, emissions from the entire oil and gas value chain will fall by a third.

The Outlook sets out DNV GL's modeling of a single likely future of the world's energy system through to mid-century. It forecasts that industry trends will play out against the backdrop of the energy transition being too slow to achieve Paris Agreement targets to limit global warming. The implication is that governments, regulators, investors and society will make increasing demands on the industry to decarbonize its value chain.

Focus on upstream emissions

Outlook modeling suggests 75% of the industry's emissions come from the combustion of oil and gas, three times as much as from production and distribution (Figure 1).

Scope 3 emissions across the value chain, including from end use, are far more than Scope 1 direct emissions from company-owned or controlled operations and greater than Scope 2 indirect emissions such as those from purchased electricity, steam, heating and cooling.

With 4% of carbon emissions coming from upstream and more focus on decarbonizing production, several large oil and gas companies are targeting carbon-neutral E&P by 2050 or sooner. Several emissions reduction efforts are already underway through varying applications.

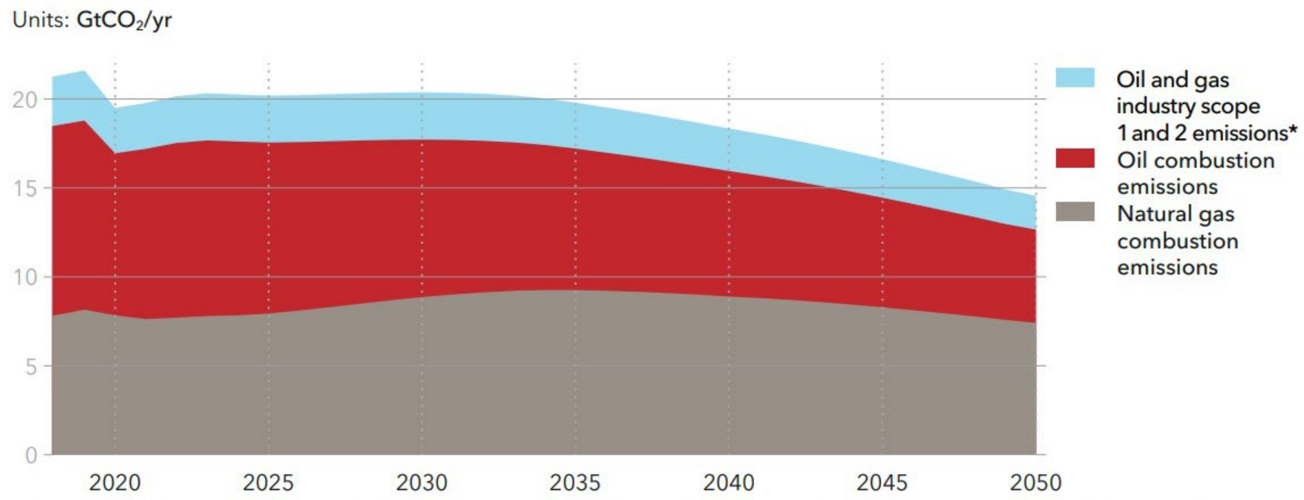
Electrification of oil and gas platforms

Instead of using wellhead gas and diesel to fuel onboard generators, gas compressors and pumps, there is a growing trend to cut emissions by electrifying offshore operations.

China's CNOOC is planning to bring power from an onshore grid to two fixed, high-voltage AC power platforms in the country's first platform electrification. In the United Arab Emirates, ADNOC's offshore production facilities will connect to Abu Dhabi Power Corp.'s onshore electricity grid via the region's first high-voltage direct current subsea transmission system.

By 2023, 16 Norwegian Continental Shelf (NCS) installations will receive power from shore, according to the Norwegian Petroleum Directorate. The directorate estimates this will avoid emissions equivalent to

Oil and gas industry CO_2 emissions



*Scope 1 and 2 emissions do not include the oil and gas industry's scope 1 and 2 emissions from own combustion of oil and gas. It is also assumed that the Scope 1 and 2 emissions shown in blue are 15% of the combustion emissions throughout the firecast period, which reflects the current level.

FIGURE 1. Outlook modeling suggests 75% of the industry's emissions come from the combustion of oil and gas. (Source: DNV GL 2020 Energy Transition Outlook)

a quarter of those from Norway's oil and gas sector in 2019. The U.K. Continental Shelf (UKCS) operators, including bp, are also considering using renewable power via subsea cables.

Integration with renewables assets

Operators have started to integrate renewable power sources—solar photovoltaic (PV), wave energy and wind power—alongside onshore and offshore oil and gas production. For instance, Italian operator Eni and the Algerian NOC Sonatrach supply power for gas treatment in Block 403 fields in the Sahara Desert from their joint venture 10-MW solar PV plant at Bir Rebaa North. They may expand solar to other Algerian sites.

Likewise, Eni and Politecnico di Torino are progressing toward making a 100-kW peak power version of their Inertial Sea Wave Energy Converter available for industrial uses including medium-to-large offshore platforms.

The Outlook forecasts rapidly increasing offshore wind capacity (Figure 2) and that cheaper associated costs will open up greater use of wind power by oil and gas installations.

Equinor is to develop Tampen Hywind on the NCS as the first floating wind farm to power offshore oil and gas platforms. U.K. regulator the Oil and Gas Authority has called on the UKCS oil and gas industry to source electricity directly from offshore renewables for business benefits as well as to reduce emissions.

Reducing methane emissions

Other common targets for lowering emissions from production offshore and onshore include:

- Reducing incomplete flaring of waste gas from oil and gas processing;
- Stemming fugitive (unintended) leaks of methane along the value chain;
- Alleviating the need for intentional venting (for safety or technical reasons) of methane at points such as compressors, pumps and valves; and
- Making greater efforts to detect and stop methane.

Some operators already see flare/vent volumes as a key performance measure in day-to-day operations.

The International Energy Agency (IEA) 2020 Methane Tracker estimates the oil and gas industry methane emissions were equivalent to more than 81 MMtonnes of CO_2 in 2019: 4% from incomplete flaring, 28% from fugitive releases and 68% from venting.

The U.S. shale gas boom has seen emissions from flaring quadruple in a decade, as lack of gathering infrastructure and pipeline capacity in some shale areas make it cheaper to vent or flare cheap natural gas than to transport it to buyers.

The IEA estimates that some 75% of emissions from flaring could be avoided and 40% overall could be prevented at no net cost if captured gas was commercialized.

By more accurately predicting problems, and enabling more timely interventions, the receiving and automated analysis of data from digital sensors and other sources in oil and gas field operations can reduce the chance of unintended releases of emissions.

Greater collaboration and urgency required

Partnerships will therefore be crucial in scaling up innovation and new technologies for decarbonization. Recent activity includes:

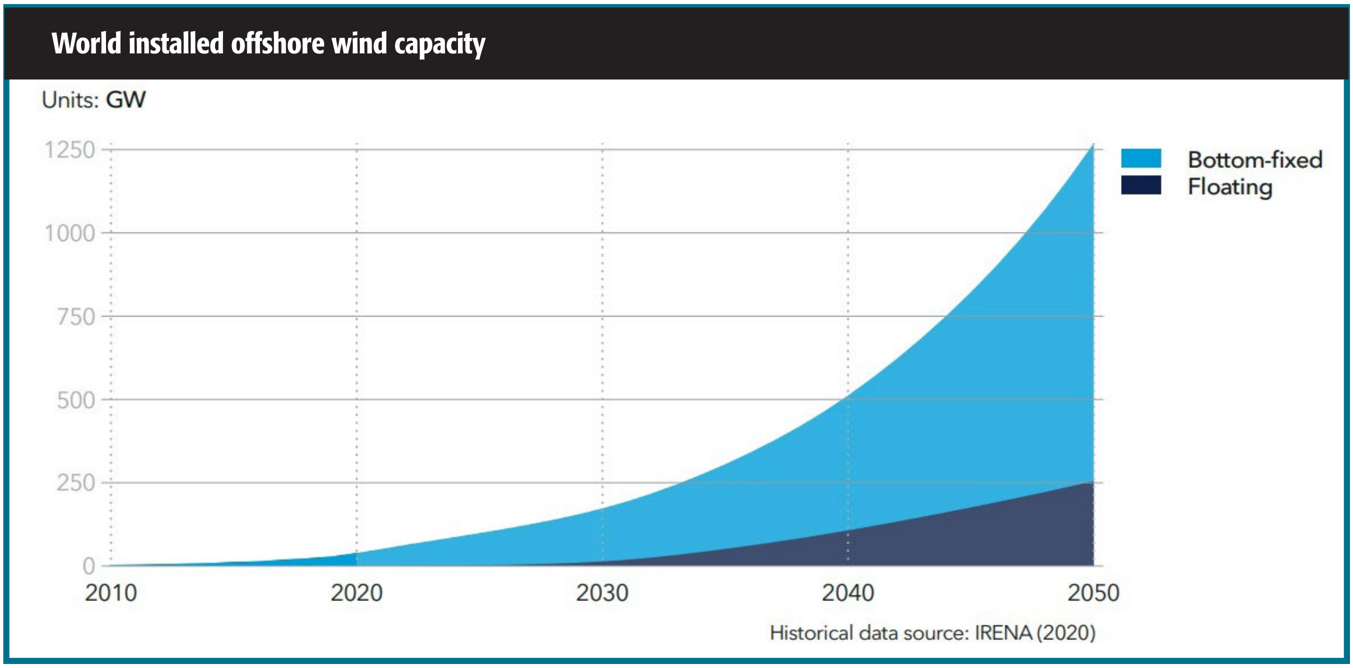


FIGURE 2. DNV GL forecasts significant scaling of global installed offshore wind capacity. (Source: DNV GL)

- bp, EDF, Eni, Equinor, Shell, Total and Wintershall Dea have collectively made policy recommendations to the EU to standardize methane emissions data collection;
- More than 20 leading oil and gas companies are committed to the Methane Guiding Principles partnership pledged to reduce methane emissions; and
- The Oil and Gas Climate Initiative, the International Association of Oil & Gas Producers, and IPIECA are collaborating toward developing a best practice guideline on detecting, monitoring and reporting such emissions.

"To develop technology to reduce upstream emissions, companies should seriously consider supporting collaborative joint industry projects and projects in research centers as well as their own R&D efforts."

–Liv A. Hovem, DNV GL – Oil & Gas

Industry leaders are also discussing best practices for electrification and energy efficiency management and identifying supply chain emissions reductions. Some operators are also considering whether to adopt a common set of key performance indicators for reporting progress on emissions.

To develop technology to reduce upstream emissions, companies should seriously consider supporting collaborative joint industry projects (JIPs) and projects in research centers as well as their own R&D efforts. Recommended Practice DNVGL-RP-F302 Offshore leak detection is one example of a DNV GL-led JIP collaboration with 19 companies involved.

Currently, carbon emissions per barrel produced is commonly used to gauge the carbon intensity of production. By 2050, DNV GL expects the industry will be broadly measured by life-cycle emissions per barrel of oil or gas consumed. Drivers for this shift in reporting emissions will include national net-zero targets and other relevant policies as well as external pressure from investors, other industries and society.

The quicker that governments incentivize the industry to adopt technology, such as through a competitive carbon price, the earlier the industry will take the technology (e.g., carbon capture and storage [CCS] and hydrogen) down the cost-learning curve.

Ultimately, it is anticipated that from the mid-2030s, these policies could transform the oil and gas industry into the decarbonizer of hydrocarbons and supplier of CCS. However, this transition will be too slow to meet Paris Agreement targets. ✚

References available upon request.

About the author: *Liv A. Hovem is CEO of DNV GL – Oil & Gas.*

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The future of work in oil, gas and chemicals

With heightening employment cyclicality and layoffs challenging the industry's reputation as a reliable employer, workforce and business transformation have become a strategic imperative.

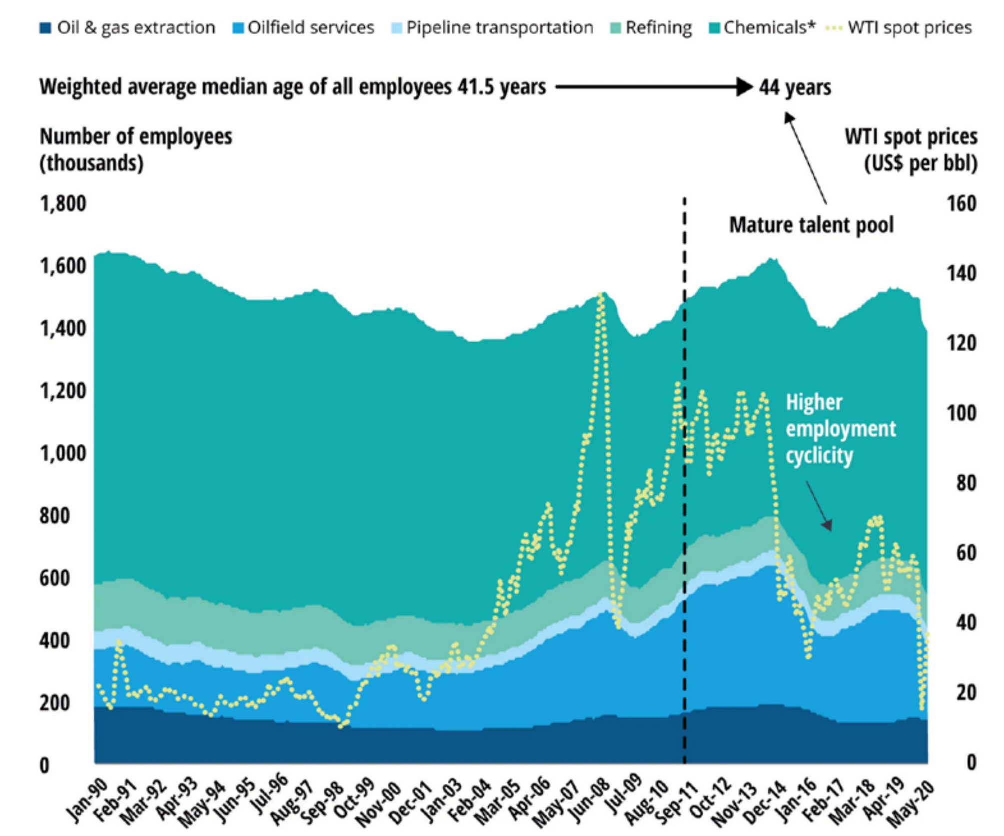
Duane Dickson and Noemie Tilghman, Deloitte

The U.S. oil, gas and chemicals (OG&C) industry brought the country to an era of energy security on the back of its nearly 1.5 million-strong workforce. This talent enabled the upstream shale boom and downstream energy renaissance in the country, and the industry in turn rewarded its workforce generously with large paychecks. In fact, the U.S. energy and utility sector had the highest median salary of any industry in the S&P 500 in 2018.

However, supply from this boom started running ahead of oil demand. The result? Oil started its longest and deepest downturn in 2014, and the growth narrative changed into mass layoffs of about 200,000 employees between 2014 and 2016. The COVID-19-led lockdowns and the resulting oil price crash to negative levels exacerbated the situation, leading to the fastest layoffs in the industry: about 107,000 workers were laid off between March and August 2020.

Put simply, the industry's reputation as a reliable long-term employer could be damaged by rising cyclicality in its employment due to the short-cycled nature of shales and higher sensitivity of employment to oil prices. During 2014 to 2019, every dollar change in oil prices affected 3,000 upstream and oilfield service jobs, as against 1,500 in the 1990s. Although the industry is not in a hiring mode currently, retaining its existing top employees and tackling the challenge of an aging workforce (median age of above 44 years) will likely be among its prime concerns in 2021 (Figure 1).

FIGURE 1. Employment trends: At the cusp of employment cyclicality and fading



(Sources: U.S. Energy Information Administration; Bureau of Labor Statistics; Deloitte analysis)

FIGURE 2. Proportion of lost jobs recovering by 2021 in three business-as-usual scenarios

	Pre-pandemic (December 2019)	Pandemic (August 2020)	Forecasted (end of 2021)	Lost jobs recovered (2021)
Pessimistic ($35/bbl; $2/MMBtu)			1,386,000	3%
Consensus ($45/bbl; $2.5/MMBtu)	1,490,000	1,383,000	1,414,000	**30%**
Optimistic ($55/bbl; $3/MMBtu)			1,464,000	76%

Methodology:

- Normalized monthly data (starting 2010) of employment, oil price, natural gas price, production, and valuations for each subsector.
- Calculated statistical coefficients between employment and oil price, natural gas price, production, and valuations for each subsector.
- Developed three business-as-usual scenarios for end-2021 using four variables:
  1. Pessimistic: Oil at $35/bbl, Gas: $2/MMbtu, Production: -10% to -5% (over 2019), Valuations: -50% to -15% (over 2019)
  2. Consensus: Oil at $45/bbl, Gas: $2.5/MMbtu, Production: -5% to -2.5% (over 2019), Valuations: -47% to -10% (over 2019)
  3. Optimistic: Oil at $55/bbl, Gas: $3/MMbtu, Production: -3% to -1% (over 2019), Valuations: -15% to -7% (over 2019)
- Multiplied coefficients with predicted values to find end-2021 employment levels for each subsector.

Note: All dollar amounts are in US$.

Sources: CapitalIQ; analysts' estimates; Deloitte analysis.

(Sources: CapitalIQ; analysts' estimates; Deloitte analysis)

Disruption beyond workforce

The OG&C industry is in a great compression where companies' room to maneuver is restricted by multi-decade low prices, unforeseen demand destruction and changes in end-use consumption due to mass telecommuting, mounting debt loads and a renewed focus on health from COVID-19. The compression is not challenging the talent landscape alone, but it is impacting three deeply interconnected dimensions of organizations—the nature of the core hydrocarbon work (the work), who is best suited to do the work (workforce) and where the work can be done in a highly efficient way even in a remote working arrangement (the workplace).

Work: In addition to shifting roles from human-operated to digitally powered remote operations centers, COVID-19 has accelerated the prospect of peak oil demand, degraded investor appetite for fossil fuels, renewed focus on the energy transition and permanently altered mobility trends. Although nations are easing COVID-19-led lockdowns, oil transportation demand associated with local office commute and international travel is expected to remain below pandemic levels in 2021.

Workforce: With 53% of oil and gas workers highlighting job security as a concern and COVID-19 shifting toward the health and well-being of people, the flow of incoming young talent desiring flexible working conditions and a green footprint could drop significantly. Moreover, strict on-field presence of some roles and limited career mobility for highly specialized roles could put the OG&C workforce at a disadvantage. This raises a deep-seated question: How can the industry stop organizational challenges from snowballing into acute business problems?

Workplace: Despite the focus on workplace safety, the industry's fatality rate is substantially higher than in other industries. With a majority of the workforce off-field due to the pandemic, mitigating risks (including regulatory compliance and cyber) and ensuring continuity of key tasks become challenging. One of the critical areas, for example, is regular inspection and maintenance of wells and plants, which typically require personnel and technicians on site. Similarly, processing petabytes of data from home screens without a secure remote environment isn't easy. In fact, less than 1% of U.S. OG&C employers offered flexible workplace arrangements before the pandemic. The new trend of home-based workers shouldn't be seen as transitory—as it impacts behavior and may become an expectation in the post-COVID-19 world. The cost of waiting out this downturn could be very high for the industry. If the industry continues to chase price cycles and follow the traditional work-workforce-workplace strategy, about 70% of jobs lost in the pandemic may not come back by the end of 2021 in a $45/bbl business-as-usual scenario (Figure 2). Are there any bright spots then?

The four levers of transformation

COVID-19 has given organizations the much-needed push to transform themselves and find new ways to reclaim their earlier appeal. How? The four levers of transformation: energy transition, integrated human-machine collaboration, recoded careers and organizational agility. These could push OG&C organizations into the future.

Sustainability as a way of business: With the return on invested capital of oil and gas companies (6% to 8%) now at par with top renewable energy companies, organizations can craft a new carbon-free energy agenda. But that requires a structured pathway—from adhering to the bare

Organizations need to promote sustainability, offer new digital and remote ways of working, add a distributed workforce to the mix, pair millennials and perennials, and build a sense of pride among its workforce.

minimums (foundational HSE requirements) to laying building blocks (advanced electrification, emissions and efficiency measures) to developing new blueprints (portfolio of low-carbon fuel mix, energy sources, green and service-oriented businesses like carbon capture) to finally winning the future (a license to operate and lead in a clean-energy economy, and influence net-zero paths of consumers). A net-zero pathway, with tangible medium-term targets, is essential for the industry's current and future workforce to gain the social and economic license to work in this industry.

Digital to transform the way of working: While advanced technologies brought higher efficiencies in the industry, many companies still struggle to choose from myriad technologies or quantify their return on investment. COVID-19 presented a new mandate-cum-challenge to put people along with operations at the core of digitalization efforts. Though projects virtualizing on-field assets and data were underway before COVID-19, the pandemic accelerated the need to mitigate HSE risk by leveraging more cloud-based platforms without disrupting operations. Nevertheless, the final stage of digitalization entails educating partners and the workforce through immersive platforms and ultimately virtualizing the business through technology-enabled, human-driven decision-making using the technology-as-a-service model.

Recoded careers to build the workforce of the future: There is a dichotomy for the OG&C industry: big layoffs amid the great crew change. Negative image, HSE concerns, rigid demographics, excessive specialization and possible knowledge drain are some of the challenges along the career life cycle that are fueling this gap. Organizations need to promote sustainability, offer new digital and remote ways of working, add a distributed workforce to the mix, pair millennials and perennials, and build a sense of pride among its workforce. Also, traditional hierarchical structures need to be broken to hire and engage the workforce of the future. Like organizations, employees have to do their bit. Employees need to reequip themselves with the right mix of technical, professional and digital skills to do the work of tomorrow and co-lead the change for the industry.

Organizational agility for new business models: Usual operational performance levers are either plateauing or giving dwindling gains due to limited room to reduce costs further. Thus organizational—and not operational—agility is the way forward. This may be achieved in four ways:

1. Redraft organization-wide operational vision by driving down costs and programs that are not aligned with new ways of working;
2. Variabilize fixed cost structures by outsourcing and offshoring intelligent process automation on cloud and by structurally reducing SG&A costs;
3. Explore flexible and scalable resource models by shifting task-based, on-demand, transactional roles to off-balance sheet resource models that lower fixed costs; and
4. Embrace open energy systems by forging a multisided platform of operators, suppliers and potential talent to streamline the ecosystem through timely estimation and management of material and services.

Building an organization of the future

Expecting blanket transformation across the industry or even an organization is unwise. But piecemeal transformation and solutions (i.e., tweaking existing processes and throwing in a few cyclical solutions) could yield suboptimal results in the post-COVID-19 environment.

The coming years are likely to be pivotal in determining the path of the OG&C industry at large. Naysayers may call the new normal part of the industry's cyclicality. However, organizations that see the coming decade as an opportunity for transformation will likely outlive this compression and may even lead the industry into the future of work. But for that, fundamental changes and a new mandate must come from the top. Leaders will have to constantly probe their plans, take hard business decisions and course correct to deliver added value. Such continual self-assessment will likely go a long way in generating a resilient company.

After all, the end goal in building successful OG&C organizations of tomorrow and tackling these questions is simple: making bold choices today to make sustainable energy the core work of tomorrow, expanding job canvases of the workforce by creating redesigned, cyber-physical teams and fungible roles, and embracing a digital workplace culture that remains open to future innovations. Can this happen? Why not? The industry has transformed itself in the past and may do it again in the next decade. +

Editor's note: *References available. Article was written in late October 2020.*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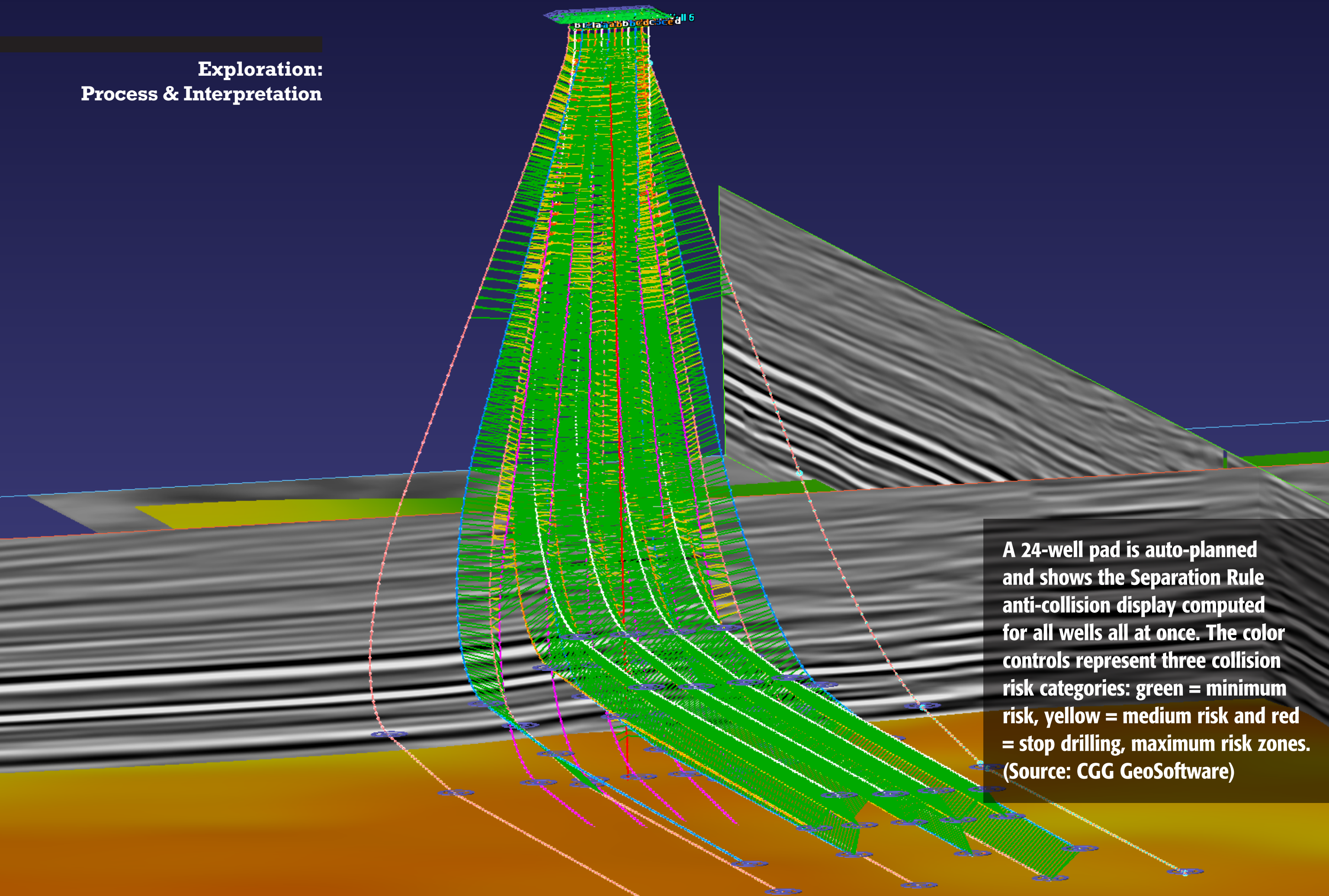


A 24-well pad is auto-planned and shows the Separation Rule anti-collision display computed for all wells all at once. The color controls represent three collision risk categories: green = minimum risk, yellow = medium risk and red = stop drilling, maximum risk zones. (Source: CGG GeoSoftware)

Providing crucial data visibility

New software integrates engineering planning with geoscience data for optimal well path designs.

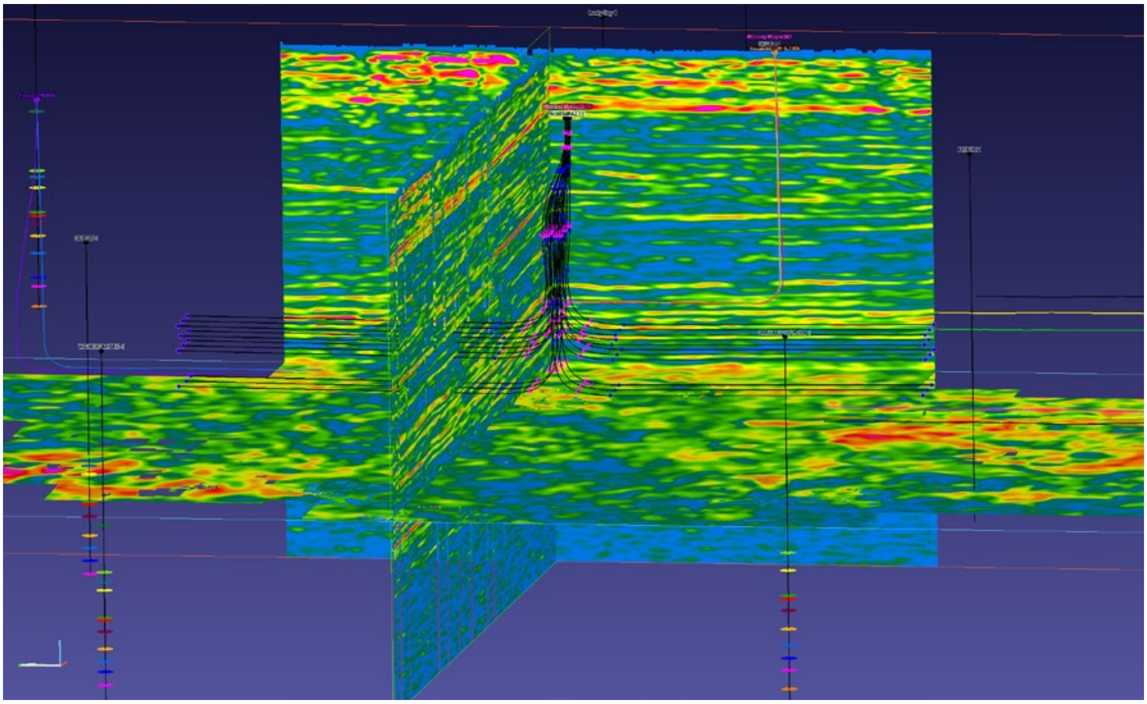
***Joe Dominguez**, CGG GeoSoftware*

Expert knowledge resides in individuals, but data belong to everyone. The petroleum industry is adopting a more integrated team approach to well planning and drilling, with software technology bringing engineering and geoscience closer together for better well trajectory designs. The ability to integrate all available geological and geophysical (G&G) data and related interpretations, and also identify the locations and paths of planned and existing wells, optimizes well planning in unconventional and fractured reservoirs.

A collaborative team of technical experts with access to all relevant data can provide benefits in terms of safety, efficiency and delivery cycle times, and help maximize the project's return on investment. Software advances that support the integration of engineering planning and geoscience data will assist these new collaborative teams to function effectively.

Well path planning technology

Part of the CGG GeoSoftware portfolio, InsightEarth's new interactive 3D



A 24-well pad with automated planned trajectories uses a reservoir characterization volume to plan the landing zones at multiple levels. Automated tools reduce planning cycle time to manage demanding rig schedules. (Source: CGG GeoSoftware)

well path planning solution, WellPath, combines G&G data and interpretation results with engineering planning tools. These tools include well trajectory planning and editing, semi-automated path planning, the latest collision avoidance technology, and reporting and plotting features for company archives. This software environment enables planning and optimization of individual well paths, multi-slot platforms, multi-well pads and development projects. At the same time, it helps minimize wellbore collision risks and maximize potential performance of the overall development plan.

Many current operators use a workflow siloed into various technology domains. Experts within each silo solve specific challenges only within their area of expertise and then pass along their solution to the next team. Integrating these technical experts into collaborative teams in which they can share and access information and discuss corporate data implications will produce the best well plan design. The desired outcome is that the planned trajectory is safe, drillable and traverses the subsurface targets to maximize contact with the reservoir.

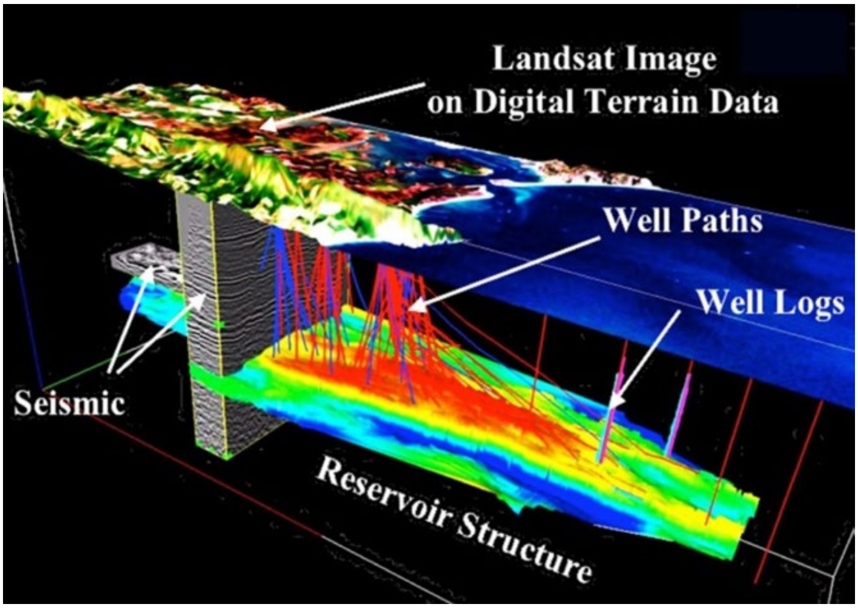
In shale plays, use of reservoir characterization data to change well spacing and alter fracture stimulation stage designs helps mitigate wellbore interference and hits to nearby producing wells. Furthermore, collaboration and access to all salient data enable planners to consistently deliver plans that are drillable. They traverse subsurface targets while managing tortuosity in the plan and thus reduce stuck-pipe zones in the planned trajectory.

The complexity of large multiwell onshore pads and offshore platforms makes it challenging to reserve space for future planned wells. An integrated software environment is conducive to successful drilling efforts that prove up additional reservoir space. Geoscience data, such as reservoir facies and geomechanical property volumes, reveal the subsurface drilling environment's complexity in 3D, including the probable reservoir extents, so drillers can plan for future wells on high-density, multilateral pads and multi-slot offshore platforms.

Interactive directional well path planning that simultaneously adheres to engineering design and geological constraints improves efficiency, optimizes well paths and minimizes wellbore collision risk.

Anti-collision

New software technology improves anti-collision calculation accuracy and implements the latest SPE-recommended Separation Rule for collision avoidance calculations, which is a safety-critical aspect of the integrated platform. Among collision analysis software features is access to graphical representations of positional uncertainty, such as ellipses of uncertainty, a minimum of three anti-collision risk categories, and various plots to analyze



The integration of all geoscience data and well planning tools optimizes well path designs. (Source: CGG GeoSoftware)

collision risks and how this danger may change along the planned trajectory. A 3D display and a ladder plot show the anti-collision calculations graphically as green, yellow and red lines between the reference well and any offset wells, and the separation factor report captures collision risks in numerical detail.

By having the planning and collision avoidance views linked to a 3D viewer with a clear color-coded system to highlight potential collision risks, the team can quickly focus on those safety risk areas and wells. The team and planner can then work to minimize any collision risk in crowded project areas and ensure that the planned well is safe and drillable while still meeting project objectives.

Planning methods

When well paths are modified to resolve collision risks, reservoir facies volumes and interpretation data provide important information that can help planners ensure the planned path stays in the intended reservoir while the plan is being adjusted. Working with geoscience data, it is also possible to represent the reservoir presence uncertainty by setting a target diameter or size. Providing subsurface uncertainty allows flexibility while planners make needed adjustments to a planned well trajectory.

This unified platform offers planners the ability to view and work with volumes of predicted pore pressure and fracture gradient, which helps to delineate no-drill zones and provides valuable information for the casing plan and mud program. When a 3D attribute volume is loaded into a well planning project, inline, cross-line and depth slice views of the volume can be used to place subsurface targets in 3D space. Other surfaces, such as structure maps, fault surfaces and geo-bodies, can be used for setting targets or delineating no-drill zones. This critical information-sharing within an integrated environment enables engineers to plan and adjust well paths to intersect reservoir subsurface targets while adhering to engineering design and safety constraints.

Automated planning methods allow collaborative teams to consider possible design changes to achieve greater cost savings without sacrificing reservoir or safety objectives. Engineers can quickly create a well path plan using at least one surface location and one or more targets. Once targets are connected to a chosen surface location, section curve types are automatically selected to build a well path. Well planners may find it useful to evaluate multiple surface locations and target combinations to determine which trajectory best satisfies the planned path objectives.

When target information and slot locations are available for multiple wells on a pad or platform, integrated software can save well planners considerable time. Rather than building each individual well path one at a time, the automated planner feature will create the well paths for a large number of wells all at once. Editing and adjusting the plans generally takes much less time than building them one at a time. Automation tools such as quick-planning all wells all at once for an entire large pad or platform yields efficiencies and reduced cycle time.

Conclusion

Well planning and drilling, under the best of circumstances, are technically demanding disciplines. Engineers need the best available tools that provide crucial visibility to all data. New technology brings together all the well planning tools with available geoscience data in an easy-to-use and highly effective software that enables useful reporting for quick decisions. Shorter planning cycle time helps planners and drillers meet demanding rig schedules.

A collaborative team of experts, supported with the latest software technology and access to all available engineering and geoscience data, can simultaneously work toward safety and efficiency in the well planning process. This integrated team workflow will reduce cycle time, produce the best trajectory designs, and drive the project to minimize costs and maximize the return on investments. ✚

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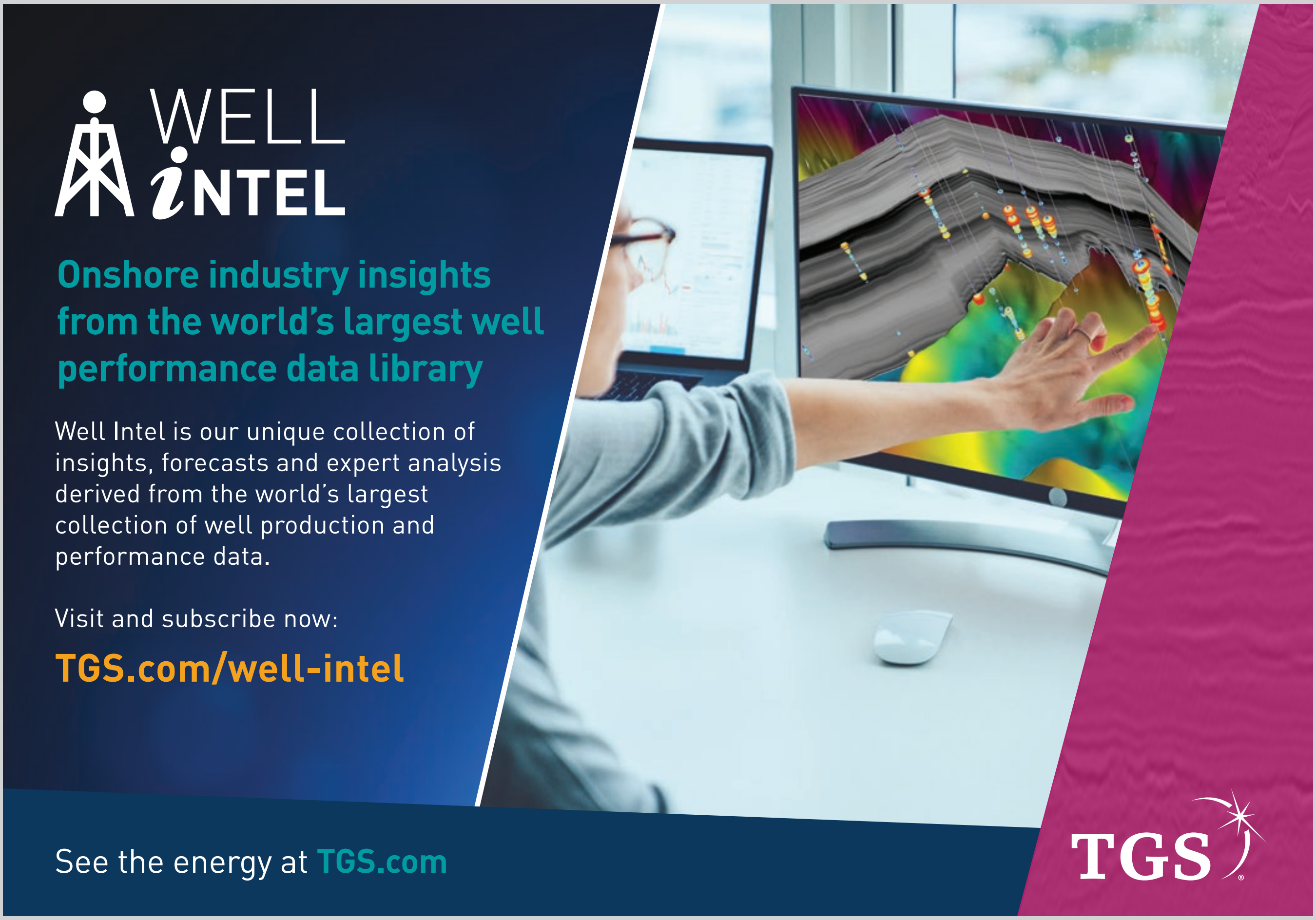

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Transforming well construction with autonomous direction drilling

***Ziad Akkaoui**, Schlumberger*

The well construction domain needs to transform and can do so by leveraging intelligent and autonomous systems.

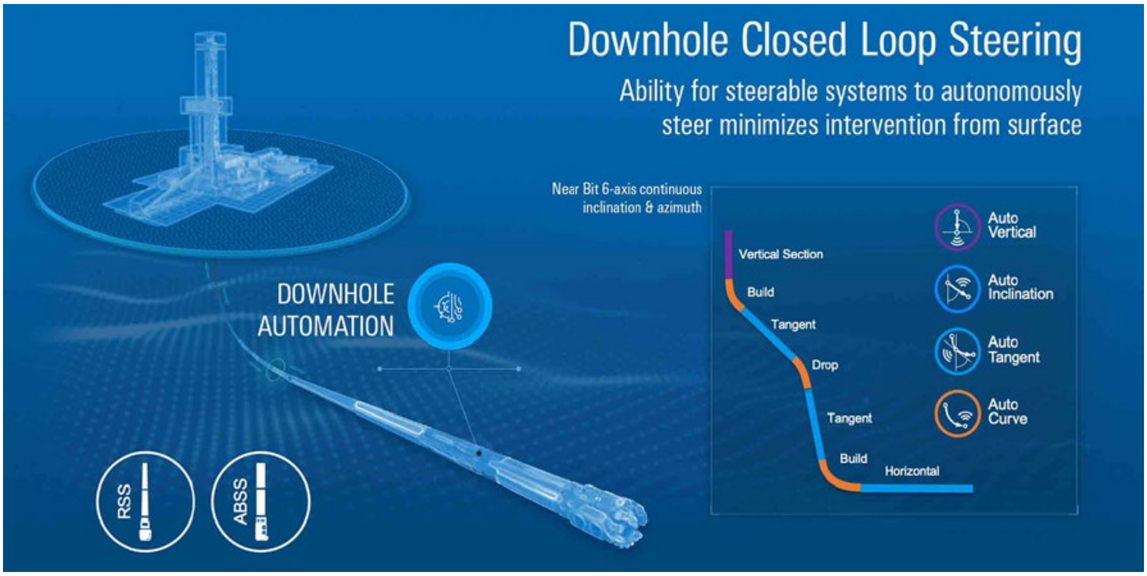
The oil and gas industry is facing an unprecedented challenge to operate more efficiently and sustainably than ever before. The industry will be unable to meet this challenge without using disruptive technological innovations. More specifically, the well construction domain needs to transform and can do so by leveraging intelligent and autonomous systems.

An autonomous and self-steering bottomhole assembly (BHA) that is supported via a fully integrated data architecture eliminates siloed and independent workflows and harmonizes all aspects of well construction operations. The end result is an autonomous system that can drill wells for any field, rig or trajectory in the most efficient and consistent manner possible. Through increased efficiency and consistency, operators can deliver better drilling outcomes and economics, which enables optimal equipment and power utilization, minimized HSE risks and a reduction of the carbon footprint.

Autonomous journey

Enabled through recent digital innovations, autonomous directional drilling (ADD) is now positioned to answer the call to transform well construction operations. Making ADD a reality, however, has taken more than 18 years of continuous development. A structured road map was used to guide the journey to autonomous capabilities.

The early phases of this journey were largely driven by monitoring, assisting and other singular automation capabilities that define the directional



The fully autonomous, self-steering BHA constantly analyzes its position, formation characteristics, conditions and trajectory to optimize steering, performance and well placement. (Source: Schlumberger)

drilling workflows used in operations every day. These capabilities included trajectory monitoring and projections, anti-collision monitoring and downhole singular automation algorithms, such as inclination hold.

In the next phase of the road map, the intelligent system is capable of supporting analytical decision-making by combining and unifying multiple support features. The system becomes aware of the directional drilling workflow and assists with managing all steering decisions. The DrillOps on-target well delivery technology unifies directional drilling workflows with other well construction workflows, which enable rig automation.

To reach the ADD vision, the final step in the journey provides autonomous well construction capabilities that utilize all relevant data, such as downhole logging while drilling, formation evaluation, mud logging and drilling fluids. This drives intelligent automation that surpasses existing operational capabilities and ultimately transforms how wells are constructed.

Pillars of autonomous directional drilling

When taking a holistic view of what would be required to deliver ADD, it was clear that the technology must be capable of supporting all aspects of the process, not just what happens at the well site or on the BHA. As such, the focus for ADD includes four key pillars: intelligent planning and intelligent execution, in addition to surface automation that complements downhole automation.

Intelligent planning. Well construction operations are initiated in the planning phase. For ADD applications, a predictive steering workflow is used that leverages the DrillPlan coherent well construction planning technology to take advantage of cloud computing and machine leaning models. Doing so enables the drilling engineers to utilize data and learnings from previous applications to ensure the best tendency response out of the BHA, while also mapping out the capabilities versus the demand of the planning trajectory. This workflow combines the IDEAS integrated dynamic design and analysis platform and data pipelines, resulting in automated analysis that is used to optimize the BHA and well trajectory, and contributing to the digital drilling program.

Intelligent execution. The digital drilling program that was completed in the intelligent planning phase is used to drive the directional drilling adviser, which is an automated system that facilitates the analytical tasks that traditional directional drillers would take while steering and executing the well trajectory. This system monitors the environment, captures real-time surface and downhole data, and determines the current and projected position of the wellbore.

Contextual data from the intelligent

Through increased efficiency and consistency, operators can deliver better drilling outcomes and economics, which enables optimal equipment and power utilization, minimized HSE risks and a reduction of the carbon footprint.

Autonomous directional drilling must be approached holistically with a focus on four key pillars: intelligent planning, intelligent execution, surface automation and downhole automation. (Source: Schlumberger)

planning phase and objects such as trajectory targets, expected BHA tendency and operating parameters are then used to determine what needs to change in steering to reach the next target while ensuring all future targets and total depth position are satisfied.

The directional drilling adviser supports motors, rotary steerable systems and at-bit steerable systems regardless of tool or hole size. This is deployed at the edge and has a parallel native cloud workflow that is used to support remote operations, thus providing consistent and repeatable directional drilling performance that is transparent to stakeholders across all domains.

Surface automation. Surface automation begins with a data acquisition system that utilizes the digital drilling program to drive edge-related workflows such as demodulation with smart telemetry, automated survey management, smart alarms and general well monitoring capabilities. This facilitates data, insights and connectivity to support remote engineers so the interaction between the well site and the office is seamless and contains all context related to critical decision-making.

The surface steering aspect addresses the mechanization of the physical steering activity, whether it is downlinking to the BHA or steering a positive displacement motor. This is further enhanced by a direct link to the directional drilling adviser system that passes on digital commands for execution regardless of location, while ensuring critical approval roles such as the driller remain front and center.

Automated energy management workflows provide insight into drilling disfunctions and drilling performance aspects like shock and vibration and ROP optimization. This capability also prioritizes and manages drilling parameters that are defined by the pre-job operator-approved road map.

Downhole automation. For nearly two decades, there have been downhole steering capabilities in development, with continuous improvements focused on new functionalities and optimizing algorithms to drive steerable systems. In the early days, this started with automating the specific inclination, then on to more advanced capabilities such as auto vertical that enables drillers to rely 100% on the tool to keep the well vertical without any surface intervention. The next challenges included addressing tangents, horizontal sections and providing the ability to hold and manage both inclination and azimuth.

However, despite these significant downhole automation achievements, addressing curves, whether 2D or 3D, build or turn sections were deemed too difficult to automate and remained a manual task. With ADD, however, this challenge has been overcome, as 3D curves can now be drilled autonomously without any intervention from the surface, enabling a complete focus on drilling performance and optimization.

Aspiration to reality

Recent successes indicate the journey to ADD has reached a significant milestone.

In the intelligent planning space, predictive steering has been utilized in North America land to help multiple operators plan and execute one-run curves and laterals. In one example, predictive steering enabled an operator to increase the intended dogleg severity (DLS) of curves based on the modeled expected tendency. This provided the operator with the confidence to safely drill a 10-degree/100-ft DLS curve, which was significantly higher than wells that were previously drilled using conventional methods.

The ADD digital acquisition system was used on more than 750 wells in 2020 and accumulated over 120,000 hours of below rotary table operations. Ten wells have been executed using the auto-curve downhole closed-loop automation algorithm, which has eliminated the need for downlinking from surface. Operators have realized up to a 20% increase in ROP while drilling the curve. These runs, both onshore and offshore, were achieved in basins ranging from the North Sea to the Middle East to North America, and addressed both 2D and 3D curves in various hole sizes.

Autonomous directional drilling directly addresses the oil and gas industry's challenge of delivering more efficient and sustainable operations. While still evolving, ADD drives procedural adherence to produce consistent and repeatable results, while also enabling greater efficiency and sustainability, thus transforming the way wells are constructed. +

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The future of remote operations with managed pressure drilling

Focusing on automation can remove operators from controlling the system.

Scott Miller, *Halliburton*

The world of managed pressure drilling (MPD) is a confusing one. For instance, a term like "lite MPD" means "lightweight"—not "light on capabilities." Terms like "flex" are used to describe multiple service levels. Operators often discuss electric and hydraulic choke control methods and argue about which system controls better—when actually they are manipulating surface backpressure to hold a constant bottomhole pressure, which is usually over a mile away down a hole filled with all different types of compressible fluids, temperature variations and complex geometries. And what does it really mean to have an MPD-ready rig?

The MPD Committee of the International Association of Drilling Contractors strives to standardize communication in this area and to provide terms and tables that will clarify the capabilities and levels of MPD. There are so many different owners of equipment and many different ways that MPD systems are being used, so it can be quite a challenge to properly standardize these industry terms.

However, it should be an easier task to standardize the levels of automation in MPD systems, as these levels can be classified following the same standards that the Society of Automotive Engineers (SAE) has released for automated vehicles. The SAE J3016 standard defines six levels of driving automation, from SAE Level Zero (no automation) to SAE Level 5 (full vehicle autonomy). Leveraging the same structure as the SAE J3016 standard, the adaptation for MPD is shown in Figure 1.

(Source: Marc Morrisson/marcmorrison.com)

Casing Size in.	Weight lb	Tool OD in.	Tool ID in.	Tool OAL in.	Temp. Max(F)	Pressure psi
5.5	17-23	4.30	1.00	20.75	350	10,000

FIGURE 1. The chart depicts levels of MPD automation, as adapted from the SAE J3016 standard. (Source: Halliburton)

Similarly, MPD automation can be defined as a six-level system. The MPD system also can be divided into two major categories: one where the human has to control the MPD system and the other where the human does not have to control the MPD system.

Six levels of driving automation

Before diving into the subject of remote operations, it must be understood where MPD systems are currently positioned on the automation journey. Most MPD systems that claim to be automated are largely or wholly Level 0. Included within Level 0 capabilities are providing kick detection based on static conditions, monitoring flow in versus flow out, and ensuring that proper data are being captured and utilized in hydraulic models. Level 0 systems can monitor all major parameters and advise MPD operators of changes that may be required based on the status of the equipment and the drilling program.

Level 1 MPD systems incorporate some understanding of changing rig conditions and automatically adjust backpressure to compensate for changes in surface and mud conditions as well as changes in running speeds and injection rates. Level 1 systems can automatically do pressure trapping, compensate for surge and swab effects, and detect and apply mud changes. Today, only some of the highest-capable MPD systems can handle the majority of these surface changes automatically.

Level 2 MPD systems can incorporate changing rig conditions and downhole conditions at the same time, and then, with multiple variables changing, determine the best course of action. Features associated with Level 2 MPD systems incorporate dynamic event detection based on changes in surface and downhole parameters and can automatically perform dynamic leak-off and pore pressure testing to properly define the boundaries of the wellbore as the well is being drilled.

Level 3 MPD systems start the truly automated MPD systems, acting on the boundary conditions and changing surface and downhole conditions by automatically controlling influxes and losses, as much as possible, wholly within the MPD system. This means that controlling kick and loss scenarios is not based on flow in and flow out, but that the system automatically determines the best control method for kicks and losses, adopts the proper process and then executes the process to bring the well back to stable conditions. While no MPD system is capable of this yet, Halliburton has laid the foundation for many Level 3 MPD capabilities within its system.

Level 4 and Level 5 MPD systems do not exist on the market. These advanced systems can be fully remote controlled (from a remote location that is not on the rig), and they do not require any MPD advisers, specialists or anyone with MPD understanding to be on the rig. The reliability and sophistication of these MPD systems well exceed real or advertised capabilities of MPD service providers or software developers. Furthermore, any MPD systems that attempt to incorporate Level 4 or Level 5 features that have not advanced through or incorporated features found in Level 0 through Level 3 are risking the future of the MPD industry. The parallel to the automotive self-driving car industry could not be stronger.

Building an automation foundation

The industry cannot be implementing Level 4 and Level 5 automation without building a strong and reliable foundation that can be trusted to always do the right thing. Therefore, much thought must be given on when and how to approach remote operations within MPD. And in remote operations, there are really two major areas to consider.

The first area of remote operations to consider is remote control. This part of remote operations can be equated to IT services taking control of a computer or device. When a strong internet connection exists, several companies can remotely control MPD systems. As of today, this type of control is used in MPD services for troubleshooting, configuring and validating that the system is set up correctly, just as IT uses remote control capabilities for computer support. This type of remote control will continue to be used in this fashion until both the reliability and certainty of the MPD systems reach certain automation levels (likely, when the MPD system, as a whole, is classed as Level 4 or above).

The second area to consider is remote monitoring, which has been implemented in some capacity for many years now. However, data protection, data security and laws around data transmission across country borders have greatly evolved. Information protocols and data exchange services must comply with company policies and with local and international laws. Remote monitoring requires companies that have experience in global data transfer and that have implemented security features to keep customer data protected. While automation does not play a key role in the ability to remotely monitor, auto-

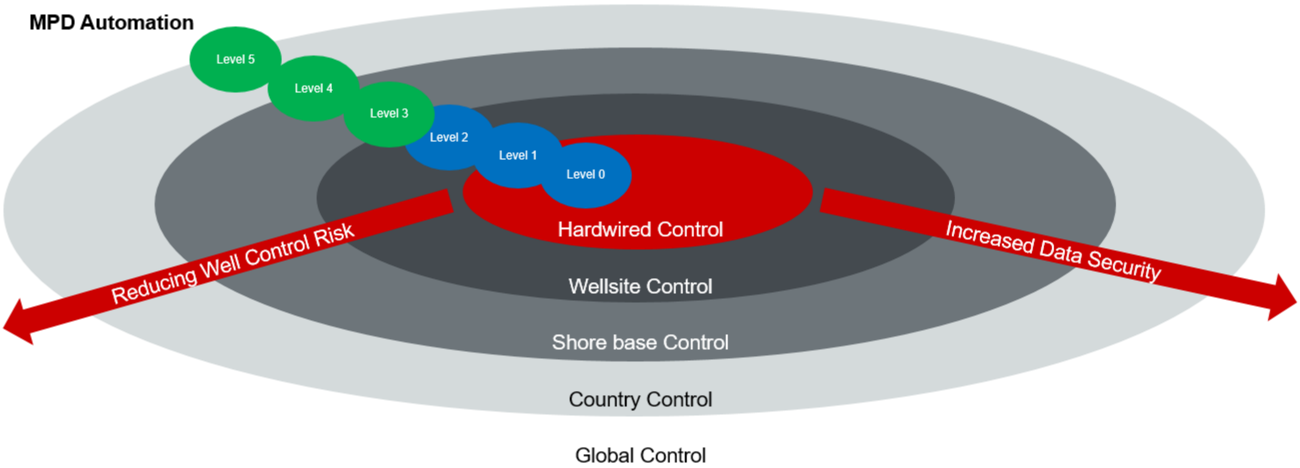

FIGURE 2. The relationship between MPD automation, well control risk, data security and remote operations are shown. (Source: Halliburton)

mation does determine how much the data can be acted upon during remote operations (going back to remote control or, at a minimum, remote advisory services).

A final important consideration on remote monitoring is data quality. While data quality is critical throughout an MPD operation, it is even more critical when moving away from the rig site because there can be fewer indicators to the operators that the data are inaccurate. Self-checking and, if necessary, self-correcting algorithms must be incorporated as part of the data system being remotely monitored. Sensor redundancy also is critical to ensure that data quality is not compromised.

To move to a higher level of remote operations, MPD providers must minimize risk. The higher the level of automation, the reliability of the MPD system, the stronger the data transmission, the better the security around data and, most importantly, the greater the ability to mitigate well control risks, the farther away operators can be from the well site for controlling the MPD systems. These levels of automation can be illustrated as simple concentric circles (Figure 2).

Implementing remote operations

The industry is on a continued journey of efficiency gains through automation and remote operations. It must be recognized that several factors tie together and a cohesive strategy must be implemented to ultimately achieve remote operations safely. This requires continued advancement in automation to further reduce well control risk and increase data security.

For a recent example of remote operation implementation, Halliburton was providing MPD services for a customer in the Asia-Pacific region. Due to travel restrictions around the COVID-19 pandemic, many members of the originally selected crew were not able to enter the country. This required Halliburton to subcontract several crew members to execute the work. Halliburton accelerated training to ensure the personnel delivering the MPD service were competent on the Halliburton system, and the company provided additional remote support.

Prior to the operation, the MPD system had to be properly configured—mapping all the data inputs and testing the system for proper communication and response. This configuring was completed remotely by the global team (based in North America) working with the local team to verify physical connections. Once the configuration was proven, the global team also remotely configured the hydraulics model with verification from onsite personnel.

After starting the operation, while the onsite crew was monitoring and controlling the automated MPD system, the global team was occasionally connected with the operation to verify the system was still performing as expected. Whenever an issue with the configuration occurred, the global team quickly intervened and corrected the problem, thus minimizing downtime.

All of this could be accomplished because the Halliburton system has strong data security, contains a continually evolving sophisticated barrier management tool that reduces well control risk and it incorporates several Level 2 and Level 3 features into the control software and real-time hydraulics model.

As the industry continues to advance, so will the ability to safely provide remote operations capabilities within MPD services. The industry must continue to drive automation forward, and must also be rigorous around testing the automation in myriad scenarios to ensure a safe and proper response of MPD equipment and to minimize well control risks. +

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(Source: FreezeFrames/Shutterstock.com)

New plug designs make improvements and lower costs

To create a more efficient cleanout operation—not eliminate cleanouts altogether—a dissolvable plug must be economical.

***Ariana Hurtado**, Senior Managing Editor, Publications*

The evolution of frac plugs has been a key enabler in the economic development of unconventional reservoirs in the U.S., according to John Ray, vice president of completions with Innovex Downhole Solutions.

"The industry has experimented with a variety of different completion technologies over the last 10 years, but we are firm believers that frac plugs are the simplest, most robust way to complete horizontal wells."

A fairly new company, Innovex Downhole Solutions was formed in 2016 from the union of Team Oil Tools, Antelope Oil Tool and Isolation Technologies. And the acquisition of Quick Connectors Inc. and Enerserv in 2019 created Innovex's well production segment centered on artificial lift technologies and related services.

Recently, Innovex entered into a definitive agreement to acquire Rubicon Oilfield International, which aims to create an independent well-centric products and technology company. The transaction is expected to close in early 2021.

In an exclusive interview with E&P Plus, Ray shared case study details on the company's latest plug technology as well as his insights on how frac plugs are evolving in the industry.

E&P Plus: Your company offers plugs for several different func-

tions. How are these plugs different from other options available?

Ray: Innovex has developed proprietary alloys for the dissolvable plug market for over five years. We have an outside-the-box design to differentiate ourselves from conventional plugs on the market. Our goal has to been to take the pros of conventional composite plugs and eliminate the cons of dissolvable plugs to create a truly unique solution for plug-and-perf operations. Our design allows us to provide one of the shortest and lightest plugs on the market. Along with plug design, our dissolvable material knowledge allows us to provide a reliable and predictable dissolution rate. Most importantly, our goal has always been to create a more efficient cleanout operation—not eliminate cleanouts altogether—so our dissolvable plug must be economical.

E&P Plus: Can you share any recent case study details?

Ray: A Delaware Basin operator tasked Innovex with providing a reliable, dissolvable frac plug for a 49-stage, 2-mile-long horizontal completion project. Job preparation considerations included the lateral length and limited annular velocity in the 4.5 inches by 7 inches completion design during the post-frac coil tubing cleanout. The 4.5-inch Bubba Plug was chosen and installed without issue. The cleanout was completed in 29 hours (run-in-hole to bumped up at surface) and set a new record for this customer.

General Info:
Loving County, Texas - Delaware Basin
49 Stages: Qty. (48) 4.5″ Bubba Plugs
7″, 32ppf x 4.5″, 13.5ppf Casing
TOL: 11,029′
KOP: 11,319′
PBTD: 21,891′
Freshwater Details:
TDS: 1961.9 mg/L
BHT: 150°F
Cleanout Results:
Conducted on CT
Surface-to-surface in ~29 hours
~2 pints of plug parts captured for entire clean-out
10 plugs tagged, but only 1-2 minute mill times reported

E&P Plus: Are you currently working on developing any new plugs, completions technologies or enhancements?

Ray: Innovex is constantly working on new plug designs to make improvements and lower the cost. We have dedicated a lot of resources and time to providing the best material on the market. As the dissolvable material technology improves, we will be looking for ways to incorporate dissolvable technology into different applications. We feel that there are possibilities for dissolvable material in drilling, intervention and production phases of oil and gas.

Innovex recently launched the Bubba Plug, which is our shortest and lightest dissolvable plug to date. In addition, it utilizes the fastest dissolving material that Innovex has in its suite of material options. We ran over 5,000 Bubba Plugs in 2020 and hope to rapidly increase our market share.

E&P Plus: How do you think frac plugs have evolved over the last year or two? Why?

Ray: Plugs have gone through a rapid evolution in the last two years. Most providers have developed a shorter plug design to eliminate material and debris that is left downhole. In addition, plugs have moved to a fully composite design, eliminating any cast iron or metallic materials.

The smaller plugs have reduced the plug cost making plug-and-perf operations economical and the preferred method of completing unconventional reservoirs.

E&P Plus: What's your future outlook for this space?

Ray: We feel that dissolvable plugs will soon replace composite frac plugs. As the incremental cost of a dissolvable versus a composite plug has decreased, this has allowed for dissolvable plugs to be used more broadly. Lateral lengths continue to increase making dissolvable plugs more appealing to simplify drill-out operations.

E&P Plus: What's next for Innovex?

Ray: Innovex recently announced an agreement to acquire Rubicon Oilfield International, which we expect to close in first-quarter 2021. This acquisition will create a leading independent supplier of high-value, well-centric products, with Innovex's U.S. strength complementing Rubicon's strength outside the U.S. As a combined business, we will be positioned to offer our customers even greater value and our employees the potential to develop their careers within a larger organization. The added scale and financial strength, which comes from a fundamentally larger company, will also provide greater stability as we move forward.

Our goal is to take what Innovex has done well in the U.S. over the past four years and bring the same innovation and solutions to the international market. Over the last several years, Innovex has efficiently served our customers enabling us to thrive in spite of recent market conditions. This has put us in a position to complete this transaction and not only grow Innovex's product lines but also extend our reach into broader international markets. +

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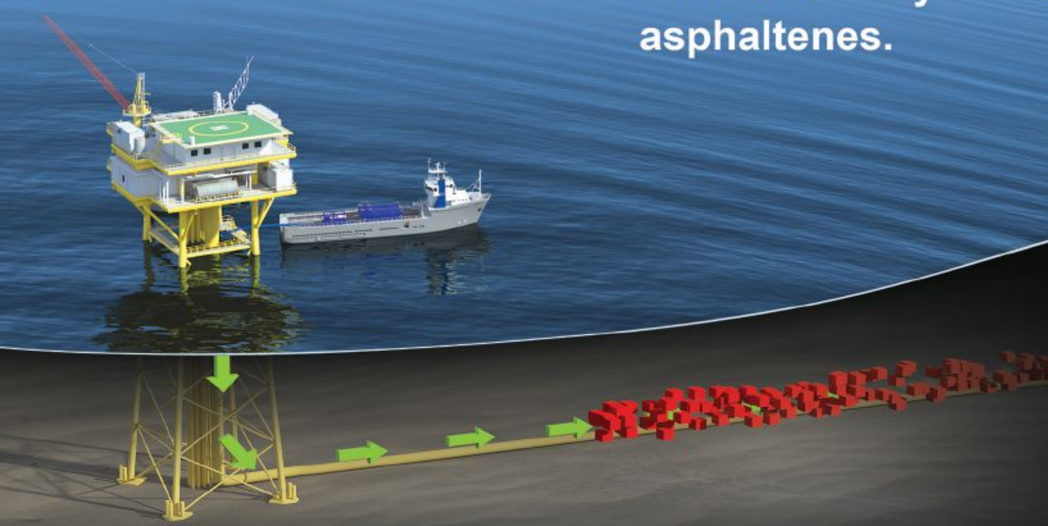

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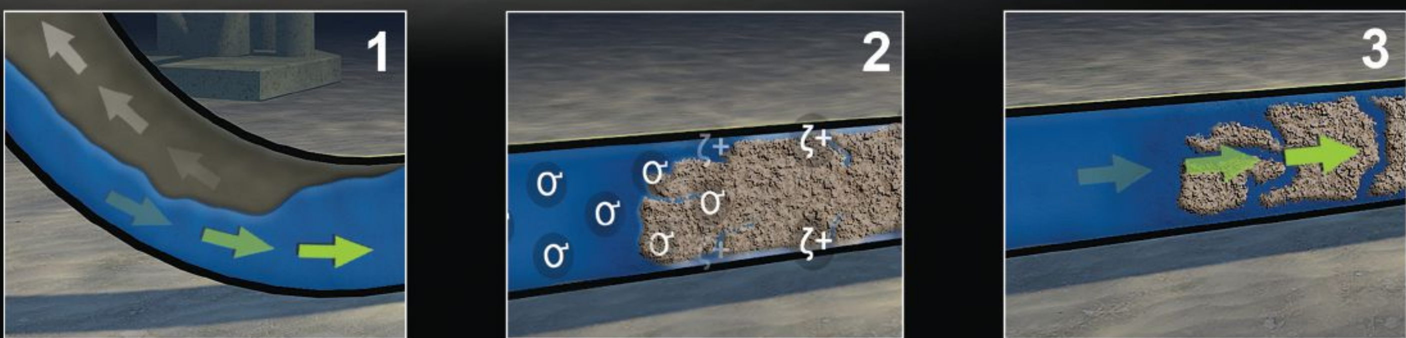

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Warm Solvent	No	No	
Hot-Oil Treatments	No	No	
Coil Tubing		No	No

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When poor integrity leads to blowout

A case study reviews well integrity in ageing assets and the remediation efforts required in the aftermath of a land-based well blowout in the Middle East.

***Aaron Scheet**, Wild Well Control, USA*

A well is broaching with fire from an adjacent well with a snubbing unit and relief well drilling rig shown in the background. (Source: Wild Well Control)

There are a variety of triggers that can lead to surface and underground blowouts on oil and gas wells. Drilling and workover operations that exhibit a compromised hydrostatic barrier can permit formation fluids to come to surface. Additionally, a surface barrier may fail on a production well. In both cases, these events could lead to a surface blowout.

On the other hand, underground blowouts can happen if there is formation flow from a high-pressure reservoir to a formation with lower integrity. This is typically the result of some type of downhole failure.

A particularly severe event can occur if loss of well control barriers follows. The crucial factor in the ability to cap a surface blowout, or reenter and concentrically kill an underground blowout, is the well control specialist's ability to gain access to the wellhead.

The challenge of access

Access within the wellbore via the wellhead is usually preserved in the event of underground blowouts. These type of blowouts benefit from wellhead access, but they feature added layers of risk via a surface blowout through the wellhead system or through the outside of the casing barrier envelope. They call for supplementary assets to be installed for diagnosis and remediation, adding to the risk to personnel and property.

Conversely, the majority of surface blowouts can be capped with a new wellhead. If analysis shows the current well construction can handle shut-in pressures applied after capping operations, the well will be shut in at the surface with blind rams (or equivalent). If the well construction does not allow for the well (flow) to be shut in at the surface, the well will still be capped, but instead of being shut in, it will be diverted to a safe location. This allows for snubbing or coiled tubing (CT) to be installed and remediation or well killing operations to occur concentrically within the original wellbore.

On the occasions when it is not possible to access downhole components, reenter the well or to reliably enter the flowstream and perform a dynamic kill, a relief well is the only alternative option to stop the flow. Surface broaches adjacent to wellbores are frequently very challenging operations as a balance must be found between installing assets onto the well to kill/ mitigate the well and the time available before the broach migrates toward the wellhead, making surface interventions no longer possible.

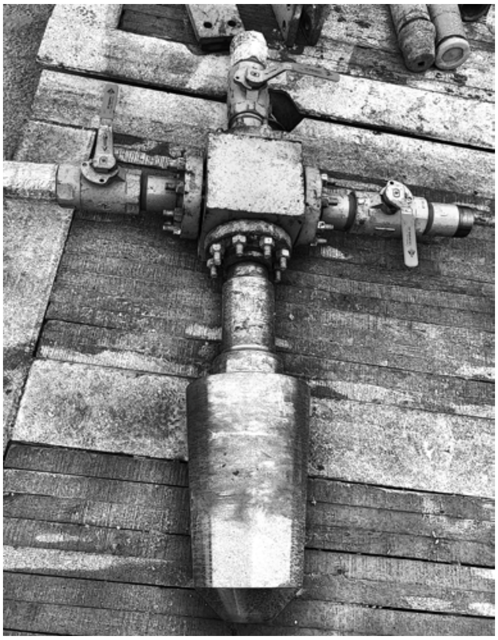
Case study

In April 2018, a production well in a mature field in the Middle East blew out gas from a known formation to a tortuous flow path of unknown sections of the compromised casing and packer via compromised tubing. Surface broaches from the production tubing and casing were observed as far as 300 m from the blowout well. Wild Well Control understood there was an uncontrolled flow of formation fluids due to the irregular and ever-changing surface tubing and production casing pressures. Furthermore, cathodic protection wells in the area were showing signs of gas and fluid production that were not in production intervals.

Diagnosing the problem

Since the wellhead location was showing no signs of broaching or instability, wireline logs could be run and evaluated. A production spinner survey, temperature and tubing integrity log were performed. The production spinner survey demonstrated changing velocities as the log progressed to the bottom of the well. Usually, this is an indication of holes in the production tubing. The temperature log highlighted a significant cooling interval at ~2000 ft, indicating a large volume of gas expansion to the annulus and most likely outside of the production casing.

The tubing integrity log was performed, but results would take several days before they were available for evaluation. At the client's direction, an inflatable plug on CT was installed as deep as possible and set in an effort to block the flow, but this was unsuccessful. It is often difficult to place large bore components/plugs into flowing wells or to a depth where they are successful at stopping a flow.



A stinger assembly is shown with a diverter manifold for installation on an adjacent well. (Source: Wild Well Control)

As pressure built up in the thief reservoir, nearby cathodic protection wells began to flow oil, gas and water from a shallow, water-bearing formation. As they did, they were filled with cement. This process was initially successful at stopping the flow oil, gas and water from a shallow, water-bearing formation. As they did, the wells were filled with heavy cement. This process was initially successful at stopping the flow, but as pressures in the shallow reservoir were unable to relieve themselves, pressure continued to increase, and additional water and cathodic protection wells (up to 800 m away from the blowout well) continued to flow to relieve the pressure that was building.

Remediation efforts

Initial remediation efforts included pumping mud and brine from the surface to attempt a well kill, which was unsuccessful. It was determined that a hydraulic workover unit would have to be installed to pull the tubing as the well continued to flow and a new, uncompromised string of tubing could be installed and a dynamic kill performed.

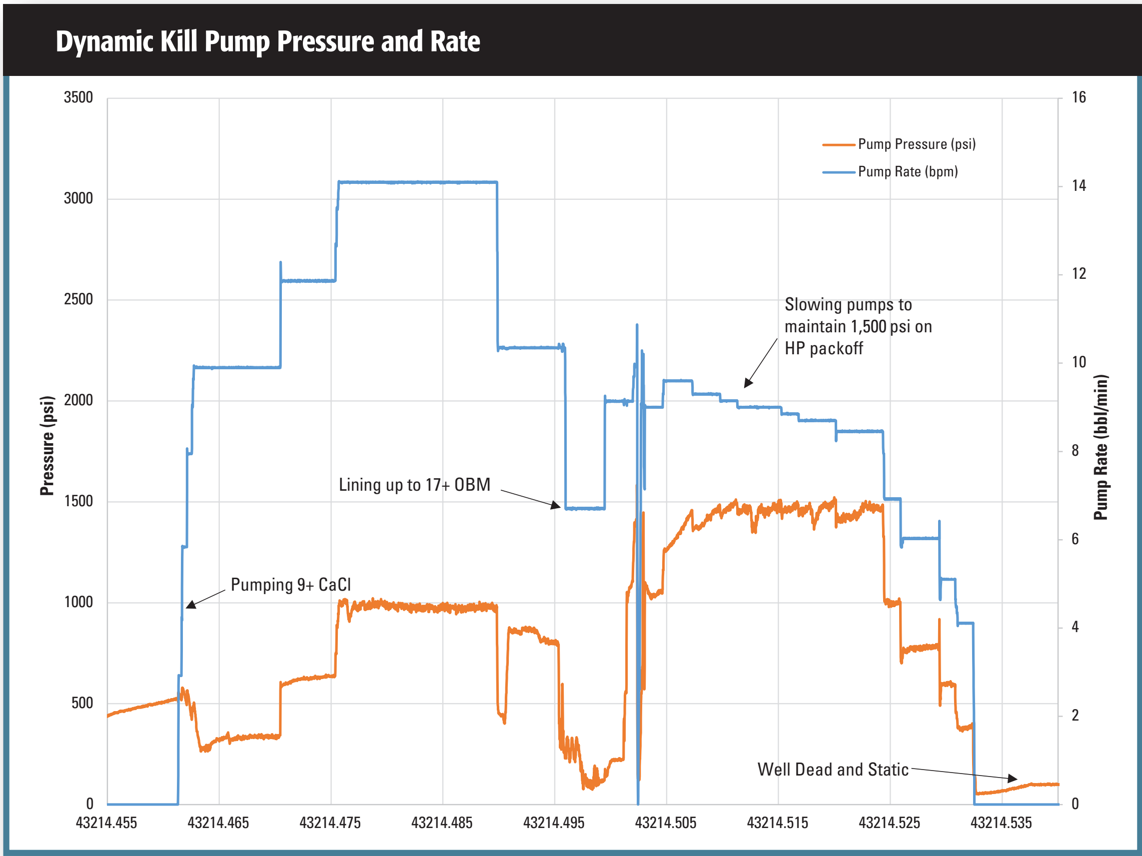
Since the tubing was compromised, it was determined that BOPs would have to be installed that would allow the cutting and removal of the tubing from the well one or two joints at a time while maintaining pressure integrity on the well. A snubbing unit was mobilized from The Netherlands and additional BOPs were mobilized from the U.S. After the production tree was removed and the hanger was latched, a radial torch cutter on wireline was used to cut the production tubing above the inflatable plug (above the production packer). The hanger was pulled into the BOP stack, the tubing was cut with BOP shear rams and the hanger laid down. The tubing fish required milling within the BOP stack to allow latching the lower fish with an overshot. This development drastically increased the time line to cut and pull the tubing string from well.

Contingency planning

Contingency planning included utilizing a relief well to intersect and perform a dynamic kill operation. The initial planning considered using an existing nearby wellbore for reentry and sidetracking operations. Satellite imaging showed that the area near the wellbore was increasing in height, making drilling a new well risky. Partners and teams were mobilized to engineer and plan sidetracking operations on an existing well to make an intercept and dynamic kill.

Resolution

Additional broaches occurred and caught fire, increasing the incident visibility,



A dual gradient dynamic kill through compromised tubing string is depicted. (Source: Wild Well Control)

requiring a rapid resolution. By the time the hanger was removed and laid down, the tubing integrity log was available for field personnel to review. The integrity log showed the location and size of the holes through the tubing string.

Wild Well Control suggested to the client that a dynamic kill was a feasible option through the open-ended tubing even though there were holes throughout the tubing string. A surface broach ignited that evening, and due to wind conditions, the location was shut down and required evacuation. After the location was secured, a dynamic kill through the damaged tubing string became the primary option to regain control of the well. Wild Well Control calculated fluid densities, pump rates and volumes required for a successful dynamic kill attempt. After the fluid was mobilized, a high-pressure pack-off was installed to the tubing fish in the BOP stack, and a dynamic kill through the tubing was simulated and successfully completed with 500 bbl of 9+ ppg NaCl brine followed by ~500 bbl of 17+ ppg OBM at a maximum rate 10 bpm. The well was topped up with 5 bbl of 9+NaCl brine before the pressure was observed indicating the well was full. The pressure was monitored for 30 minutes without any changes, confirming the well was dead.

Subsequent plug and abandonment

After the well was confirmed dead, the tubing was pulled from the well and laid down conventionally, without the need to shear and lay down each joint. After laying down the final joints of tubing, the visual assessment indicated that the radial torch cut failed to cut the tubing, and the production packer was still attached to the tubing. This eliminated a separate trip to recover the packer.

With the tubing and packer removed, a cement retainer was installed above the production perforations and in the well was secured with a cement plug.

Conclusion

Operators in mature fields experiencing well integrity problems in aging assets monitor tubing and casing pressures on a regular basis to determine when casing barrier envelope may have integrity issues. Having a clear insight into their well's integrity or lack thereof makes planning significantly easier. Wells that are not left unattended, or not monitored regularly, require significant diagnostic efforts to remediate. Wells flowing underground pose additional risk of broaching prior to ultimate resolution. This factor should always be planned for in the instance that a surface broach migrates to the well pad or around the wellhead itself. +

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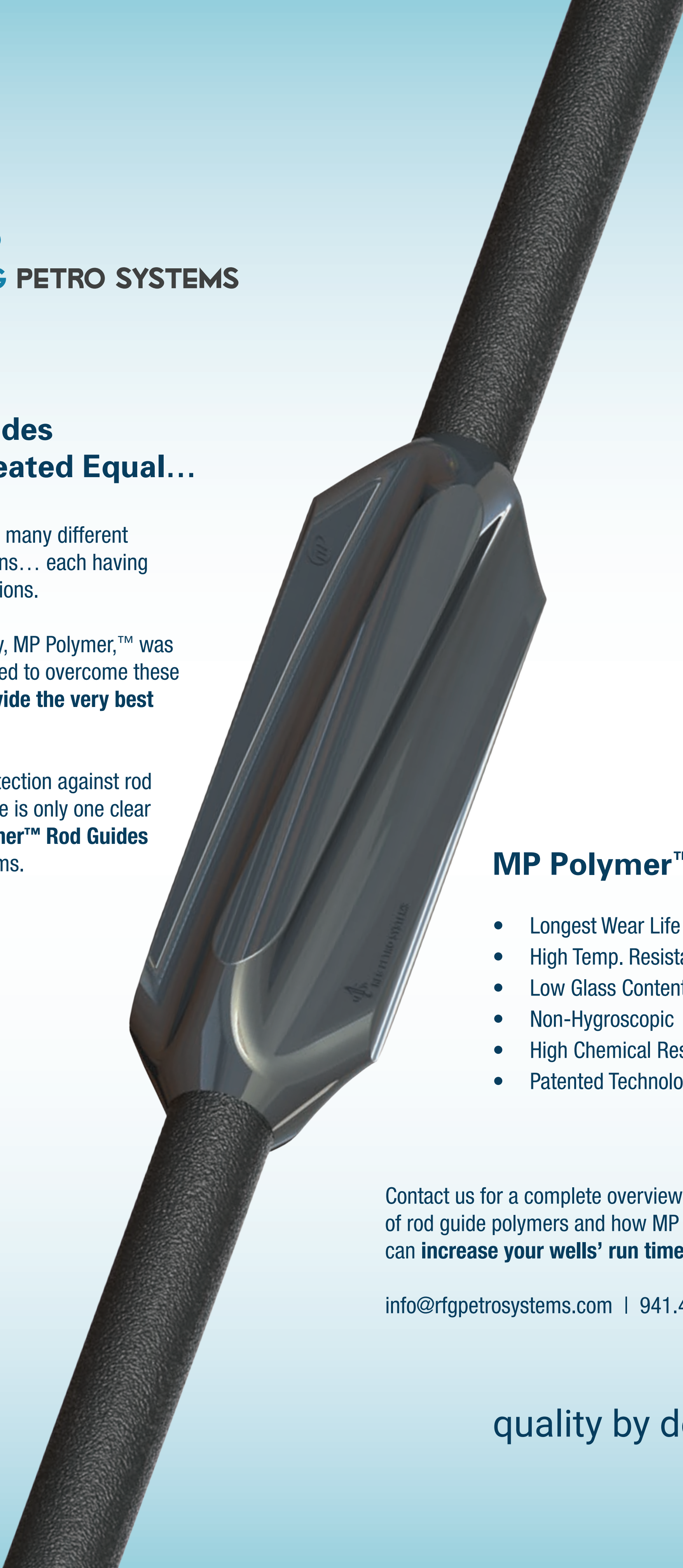

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Subsea Cooling Modules, owned by MWCC, support deepwater drilling advancement by enabling extended flowback of HP/HT wells. (Source: MWCC)

MWCC CEO discusses emergency response readiness

The company recently added a 20,000-psi capping stack and subsea coolers to its portfolio.

***Faiza Rizvi**, Associate Editor*

The Marine Well Containment Co. (MWCC), which was established in the aftermath of the *Deepwater Horizon* disaster, has designed a comprehensive emergency response program to contain compromised deepwater wells in the Gulf of Mexico (GoM). In an exclusive interview with E&P Plus, MWCC CEO David Nickerson discussed how the company remained continuously ready to respond to a deepwater well control incident in the GoM amid a global pandemic and higher than average tropical storm activity.

E&P Plus: In what way have the pandemic-induced challenges affected MWCC, and how have you managed them?

Nickerson: It has been a pretty rough 2020 for sure. And like many others, we found ourselves having to deal with the pandemic and the tropical storm activity in parallel.

As an emergency response organization, we have been considered an essential business. If we were not continuously ready to respond to our members—who contribute to about 70% of all the wells that are being drilled in the GoM—they might not have been able to drill, which would have major potential implications on U.S. energy independence.

What we did beginning in March [2020], when the pandemic really started to hit us, is stand up MWCC's business continuity team to handle events that we had never envisioned. The team has been working for nine months now, managing events all through the pandemic. This is the same team that we used to deal with some of the concerns we had with

"As an emergency response organization, we have been considered an essential business. If we were not continuously ready to respond to our members–who contribute to about 70% of all the wells that are being drilled in the GoM–they might not have been able to drill, which would have major potential implications on U.S. energy independence."

–David Nickerson, MWCC

tropical storms that threatened some of our locations.

During the pandemic, we tried to stay focused on three key objectives. The first is the health and safety of our staff and contractors, the second focus has been maintaining response readiness and the third is keeping our key stakeholders informed. We've had to maintain close contact with our members and regulators throughout the pandemic.

So far, it's been a great success story, but it has required a tremendous amount of work to make sure we maintain response readiness.

E&P Plus: This year has been full of tropical storm activity. How have you maintained response readiness during this time?

Nickerson: We've had to take preemptive action on three separate occasions when major storms struck our shorebase locations where we keep equipment. On top of that, we have contingent staff that resides in Louisiana, which has been hit by five major storms this season. So we didn't just have to worry about managing continuity of our business operations but also the safety and security of our personnel, including those who live in Louisiana.

E&P Plus: Can you discuss MWCC's addition of its 20,000-psi capping stack?

Nickerson: Despite the challenges this year, we haven't slowed down one single bit. We've really had a historic year completing our entire suite of HP/HT capabilities for the portfolio. So the 20,000-psi capping stack is one element of that, but there is a bit more development on the technology side that provides the full suite of capabilities.

A part of our challenge is that we have to stay several years ahead of what our members' drilling needs are. So the first HP/HT well permits for our members were expected to begin submission in 2021. We've been working on building these capabilities for the past five years. We actually built the 20,000-psi capping stack [in 2019], but [in 2020] we went through the process of getting the capping stack rerated for higher temperatures of up to 400 F. So that's a major development on the capping side of things.

The other big development we had [in 2020] is accepting two rather large subsea coolers that will sit on the seafloor and are collectively capable of cooling down production in an extended flowback situation when relief wells would have to be drilled.

E&P Plus: What role will new technologies play in the area of well control?

Nickerson: One of our critical success factors is to keep connected with our members and stay ahead of their drilling needs. Really, the HP/HT stuff that we've been working on for the last five years is the next big trend.

Our focus for the perceivable future is going to be about bringing more into the drilling exercise space. We've talked about the three pillars that differentiate us as an organization: response equipment, which is the most extensive in the industry; our dedicated organization that wakes up every day, ready for the phone call; and third is our very comprehensive drilling exercise program. +

The 275,000-lb capping stack is lifted by a crane during a full-scale mobilization exercise conducted at MWCC's Texas Deployment Facility in October 2020. (Source: MWCC)

(Source: Tom Buysse/Shutterstock.com)

What can the US learn from Europe in the global energy transition?

Europe and the U.S. are often referred to as the Old World and the New World, respectively. In the case of the energy transition, the New World stands to learn from the Old, which took the plunge a bit earlier in the game.

***Francois Laborie**, Cognite North America*

Evolution is underfoot in the 160-year-old oil and gas industry. It's a slow change spurred on by digitalization, and the efficiencies and opportunities it creates, as well as a call to action for our climate. The energy sector is responding by turning its attention toward a sustainable future.

Responsible investment adds to energy transition pressure

In addition to the European political pressure, the financial community is also taking a stand. More investors are focused on the ESG side of the business world, issuing mandates stating that responsible investments are the way forward. The world is watching the decisions of the oil and gas players, prompting the European companies to take action as they work to reduce their emissions and make the transition to renewables to be more palatable for the responsible investors. The U.S., however, is not feeling the same level of pressure.

One year ago, I relocated to the U.S. to run the North American division of Norway-based Cognite, and I've experienced firsthand the energy, enthusiasm and burn for innovation that runs strong here. I don't feel the same sense of urgency in the U.S. to transform the oil and gas business. There isn't an immediate regulatory demand, there are little to no incentives from the government and the case for renewables still doesn't seem to fully sway our friends in fossil fuels.

O&G companies need to play the long game

Most companies acknowledge that a transition to renewables isn't an instantaneous, money-in-the-pocket

"The world is watching the decisions of the oil and gas players, prompting the European companies to take action as they work to reduce their emissions and make the transition to renewables to be more palatable for the responsible investors. The U.S., however, is not feeling the same level of pressure."

– Francois Laborie, Cognite North America

kind of thing. It's a bet, a long-term one at that, on the future. It is one that requires foresight and some willingness to invest, based on a belief that it will pay off eventually.

If I look back on some of the greatest advances in American history, the boldest ones have resulted from a greater need, for the greater good. They haven't resulted because the government said so. To me, this is what defines America. Innovation that moves people forward. And this is what I believe will happen in the oil and gas industry.

Offshore wind is more tenable for O&G investment

For European oil and gas companies, offshore wind has been a natural next step. Companies are discovering that their current offshore infrastructure has value for generating this particular type of renewable energy, making it an easier investment to justify. There are several areas of crossover, particularly in engineering and in the product and project management areas. These areas can be easily applied to budding offshore wind divisions, even within traditional oil and gas companies.

In addition to exploring wind, we are also seeing that European oil and gas companies are having success in reducing their own emissions through the increased digitalization of their operations.

Insights show where energy losses occur

By connecting the billions of datapoints from across an oil and gas operation, companies are able to extract insights that tell them where they are suffering energy losses, for example. Cognite estimates that through the use of data alone, companies are able to cut energy loss by approximately 10%, which is equivalent to more than 13 Bkg of CO_2 per year, a number which most companies will happily report.

Transparency through reporting in demand

There is a growing expectation in Europe, as well as in some parts of the U.S., for increased transparency across the oil and gas industry. This increased scrutiny stems from greater climate awareness, forcing companies across the board to be open about their emissions and how they are working to reduce them. As Peter Druckner says, "If you can't measure it, you can't improve it."

From health and safety to carbon emissions to measures taken to reduce climate impact, the industry trend is to be more open. This is a positive trend in my opinion, because reporting forces us to confront where we are lacking and to do something about it.

Reflecting on U.S. history, the country isn't one to stay behind for very long. In the energy transition, there's much to be learned from European counterparts that have been pushed a bit harder in these early days. But to truly take the next step and possibly even surpass Europe, the American oil and gas industry needs to forge its own path ahead. This means taking the best from Europe and coupling that with good, old-fashioned American innovation and rapid advancement.

The energy transition is happening whether we like it or not.

It is slowly but surely accelerating as governments gain awareness and use regulation to ensure that we are collectively able to slow climate change.

I may be a bit biased, given my role working in the U.S., but I have no doubt that the biggest transformations in the oil and gas industry will take place right here in America, the place where some of the most life-changing innovations have been born.

Let's learn from Europe and take it even further. +

***About the author:** Francois Laborie is president of Cognite North America, overseeing the company's expansion and operations in the U.S. and Canada.*

(Source: Tom Buysse/Shutterstock.com)

AI-powered gas leak detection technology improves workplace safety

The new AI module provides pattern-finding automation for gas leak detection.

Mary Holcomb, Associate Editor

U.S. oil and gas companies are seeking new technologies to address an old problem: gas leaks. Many organizations have long relied on fixed hardware or manual assessments to monitor leaks. Naturally, the occurrence of a major leak requires immediate response, but detecting the source of a leak from the beginning can ensure a quick and safe correction or evacuation.

Blackline Vision, the data science team of Blackline Safety, is developing its AI Gas Leak Detection module, which resolves this issue by leveraging artificial intelligence (AI) to automate the process while providing situational awareness and connectivity. The module provides advance alerts of gas leaks by identifying patterns in low-level gas readings streamed to the Blackline Safety Cloud from G7 wearable gas monitors.

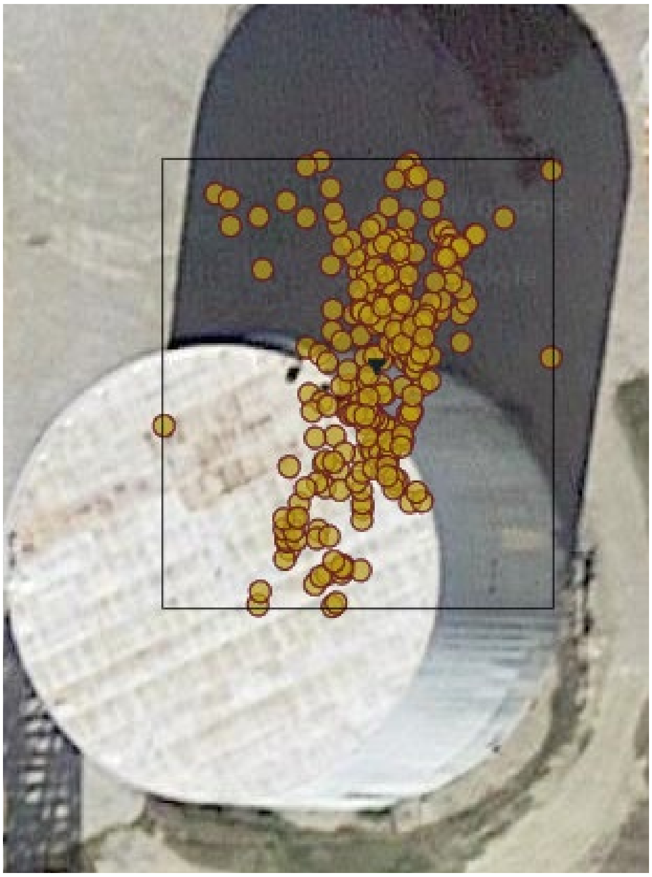
"The module's algorithm automatically gathers a lot of data from all of the different devices and indicates where a leak or process fault is happening," said Lohrasp Seify, lead of Blackline Vision. "This advance notice of a gas leak helps minimize unexpected future downtime while keeping workers safe."

Traditionally, health and safety professionals would conduct assessments to identify the riskiest places of gas exposure or process faults and then determine where to put fixed systems. A small leak, he noted, would take weeks or months to hit a point where a significant amount of gas has escaped and thereafter cause instrumentation to go off.

"With our system, you no longer have to do guesswork," Seify said. "You don't have to think about where the possible leaks are going to be and then make an investment. All you have to do is equip your people with the devices, and before leaks become real problems, we automatically detect and report them in their initial stages."

Blackline's module provides alerts in the early stages of a leak and does not require any additional infrastructure costs or equipment, eliminating the risk of human error and maximizing an organization's uptime while keeping workers safe.

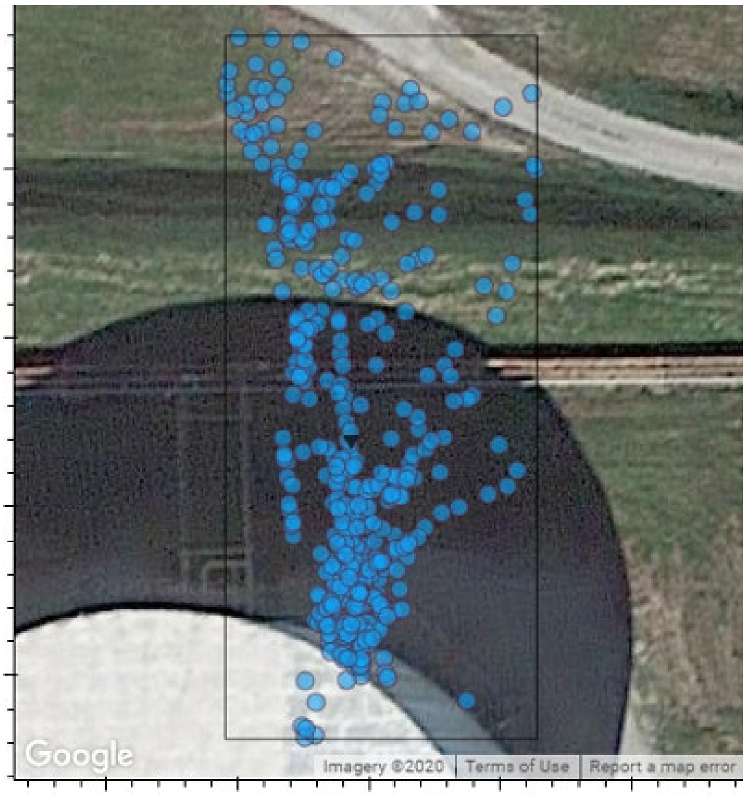
"We took what was already equipped on workers and increased the value by an order of magnitude," he said. "There is no change management required, so our clients quickly go from wanting to use our technology to seeing the value. And in our industry that's kind of unheard of because usually you have to keep setting up infrastructure."



Blackline Vision's AI Gas Leak Detection module will provide customers with clusters of gas readings that have been measured across different personal gas detectors throughout time at a specific location on a work site. These groups are automatically detected and classified by the module using location-enabled data. (Source: Blackline Safety)

Each worker is equipped with a personal connected gas detector, which enables Blackline to monitor an entire site and collect residual, low or high gas readings in real time. The georeference data are accumulated and sent to a central server, Seify said.

"To date, we've collected 130 billion datapoints, so it's not easy to just look at it and determine if there is a leak," he said. "You have to



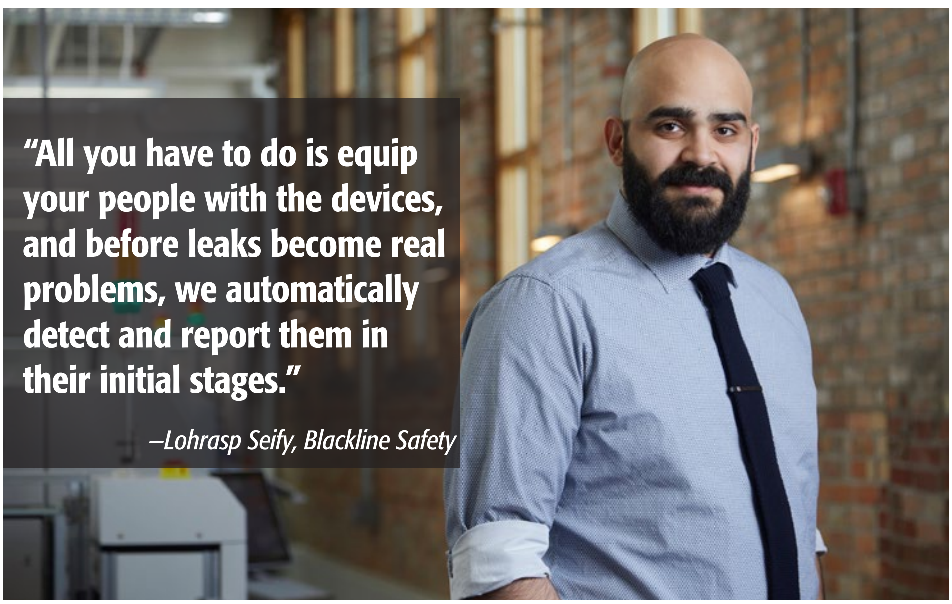
Currently in the testing phase, the beta site of Blackline Vision's AI Gas Leak Detection module displays all locations on a work site and the relevant parameters where its algorithm automatically detected consistent clusters of gas readings. (Source: Blackline Safety)

automatically study a bunch of different dimensions and our AI can do that."

In addition, the G7 device indicates if the worker is using the technology efficiently like administering regular calibrations. It also features SMS messaging and voice-calling capabilities, so in the event of a safety alert, the user can communicate directly with the Blackline Vision team.

The module is still in the testing phase and will remain there until early 2021. But the company intends to use this period to gather feedback on how to improve the model and how to increase the learning capacity of the AI.

"We would like to understand what the uptick is going to be like in terms of what value our technology is going to add, and I think that's going to crystallize over the next six months and reveal where it will be most useful," he said. "After this loop of self-learning is established and the AI successfully learns from the feedback that our end users give it, we're going to make it available to all of the Blackline Safety customers, and they will be able to leverage this module to be safer and avoid leaks and process faults proactively." ✚



"All you have to do is equip your people with the devices, and before leaks become real problems, we automatically detect and report them in their initial stages."

–Lohrasp Seify, Blackline Safety

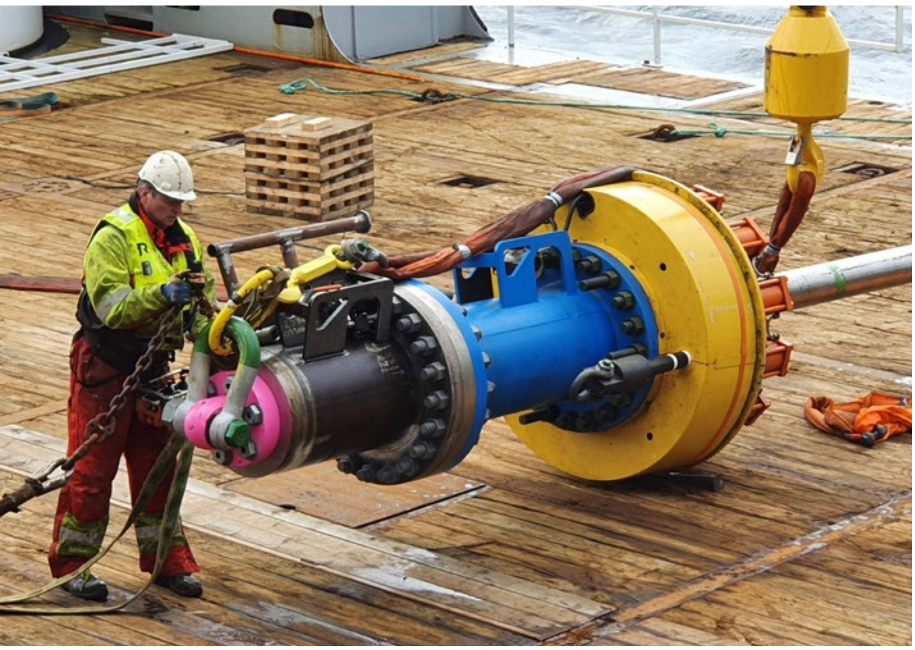
The G7 connected safety device delivers work-anywhere, wireless, two-way voice communication, text messaging, evacuation management and complete customization for every business. (Source: Blackline Safety)

New low-carbon technologies

Despite the challenges brought on by COVID-19, oil and gas companies are investing in low-carbon technologies, in line with the broader energy transition taking place across the industry.

Vessel-deployed subsea wellhead cutting system to reduce carbon emissions

Baker Hughes has released its Terminator vessel-deployed subsea wellhead cutting system. The system can reduce fuel consumption with its 100-hp motor and is also smaller and lighter compared to the original 1,000-hp abrasive water cutting system typically used on similar types of vessel-based operations. The Terminator technology affirms Baker Hughes' commitment to energy transition by helping customers decarbonize oil and gas operations. Using a mechanical wellhead removal method, the system has already proven its capabilities by successfully cutting a subsea wellhead from an abandoned exploration well owned by Wintershall DEA in Norway. Baker Hughes worked with Wintershall DEA to cut the subsea wellhead from an abandoned exploration well in 360-m water depth in only 35 minutes. By comparison, alternative abrasive cutting methods could take as long as 5 to 6 hours for the cut alone. The Terminator system can be deployed from a vessel and uses a mechanical cutter, rather than water jet cutting methods of conventional systems, to eliminate associated risks with high pressures.



Baker Hughes' Terminator system reduces fuel consumption and weight compared to older systems, significantly reducing CO_2 emissions.(Source: Baker Hughes)

Fiber-optic sensing-based monitoring tool for CCS

Silixa has released Carina CarbonSecure, its distributed acoustic sensing (DAS) based technology for continuous or on-demand monitoring of all stages of carbon capture and storage (CCS) operations. The new tool offers offshore and on-land operators the necessary monitoring measures with a reduced cost and environmental impact of their CCS facilities. The tool enables operators to provide the assurance to regulators and communities necessary to expand CCS adoption worldwide. Carina CarbonSecure delivers ultrahigh resolution, densely sampled acoustic data for real-time continuous and/or on-demand monitoring. Elements of the tool include microseismic monitoring and passive seismic throughout the lifetime of a CO_2 storage facility. The system also includes 3D vertical seismic profiling, time-lapse seismic, well-integrity and leak detection to ensure maximum safety over the various stages of CCS development.

Carina CarbonSecure is a reservoir management tool. It can be deployed to assess the viability of geological formations for carbon storage during site characterization; monitor microseismic activity during the injection phase; ensure well and storage integrity when CO_2 is being injected; and provide 4D monitoring of the CO_2 plume migration throughout the lifetime of the facility.

New carbon capture technique for power plants

Scientists from Exxon Mobil, University of California, Berkeley and Lawrence Berkeley National Laboratory have discovered a new material that could capture more than 90% of CO_2 emitted from industrial sources, such as natural gas-fired power plants, using low-temperature steam, requiring less energy for the overall carbon capture process. Laboratory tests indicate the patent-pending materials, known as tetraamine-functionalized metal organic frameworks, capture CO_2 emissions up to six times more effectively than conventional amine-based carbon capture technology. Using less energy to capture and remove carbon, the material has the potential to reduce the cost of the technology and eventually support commercial applications. By manipulating the structure of the metal organic framework material, the team of scientists and students demonstrated the ability to condense a surface area the size of a football field into just 1 gram of mass—about the same as a paperclip—that acts as a sponge for CO_2. Additional R&D will be needed to progress this technology to a larger scale pilot and ultimately to industrial scale. The research successfully demonstrated that these hybrid porous metal-organic materials are highly selective and could capture more than 90% of the CO_2 emitted from industrial sources. The materials have much greater capacity for capturing CO_2 and can be regenerated for repeated use by using low-temperature steam, requiring less energy for the overall carbon capture process.

Tracking tool to reduce emissions and improve operations

Geosite has released a new emissions tracking tool called EMIT for the energy industry. EMIT fuses data from multiple sources to provide energy companies with software for monitoring emissions from all their assets. The tool tracks locations of high methane emissions, the scale and scope of incidents, and provides comprehensive intel for complete situational awareness and advanced analytics for predictive maintenance and incident response. Combined with Geosite's communications and project management capabilities, which enable remote operations and mitigation efforts, operators can now lower unwarranted methane emissions events and manage their assets by exception.

Companies partner to accelerate low-carbon technologies

Gas Technology Institute (GTI) and the Electric Power Research Institute (EPRI) have announced a five-year joint initiative to accelerate the development and demonstration of low-carbon energy technologies. With increasingly ambitious decarbonization goals from private companies and governments alike, existing technology is not enough to achieve those targets. The Low-Carbon Resources Initiative (LCRI) is an international collaborative spanning the electric and gas sectors that will help advance global, economy-wide deep decarbonization. With 18 anchor sponsors, the LCRI leverages the collaborative research model employed by both EPRI and GTI, bringing industry stakeholders together to conduct clean energy R&D for society's benefit. Seeded with $10 million from the EPRI collaborative, funding for the initiative is expected to be leveraged many times over its $100 million target through public and private collaboration.

Multigas detector to monitor hazardous gases

Concentrations of hazardous substances in the ambient air at a work place should not exceed specified limit values, and monitoring these low values is a demanding task. Dräger has released Dräger X-act 7000 to measure carcinogenic and toxic substances in the lower ppb range. The range of gases to be measured is being constantly expanded. The measurement-sensitive system of the X-act 7000 is based on colorimetric chemical sensor technology and measures even the lowest ppb concentrations. It can replace conventional laboratory analysis and delivers exact reliable results directly on site. False-positive measurement results and false alarms can be largely reduced. This tool saves time and costs and is easy to use. After an automatic self-test, the X-act 7000 analysis system is immediately ready for use. The user controls the measurement task via the three-button operation unit and the 2.4-inch color display. The measurement result, location and time can be stored in the internal data logger and read out with the Dräger CC Vision software. The Dräger X-act 7000 can be used with the Dräger X-am pump by connecting to it with a small connecting adapter. This makes it possible to measure carcinogenic and toxic substances in the ppb range even in inaccessible locations.

Dräger's new X-act 7000 multigas detector provides precise gas measurement in the lower ppb range. (Source: Dräger)

Environmentally friendly products to clean up oil spills

Green Boom has released a number of biodegradable, water repellent oil-only absorbents. The line of ecofriendly absorbent products works for oil spill prevention, response and remediation. The company is dedicated to producing a variety of products that can be used in marine, land and industrial environments to clean up oil spills and ensure a greener future. Green Boom's products are made from biomass up-cycling technologies that use sustainably sourced agricultural wastes and textiles. Green Boom has created a technology that converts renewable, biodegradable and low-value agricultural materials into water-repellent, oil-only absorbents. Green Boom products are water repellent and are made up of fast-wicking materials that reduce clean up time and labor. ✚

Editor's note: *The copy herein is compiled from press releases and product announcements from service companies and does not reflect the opinions of Hart Energy. Submit your company's updates related to new technology products and services to* ***Faiza Rizvi*** *at* ***frizvi@hartenergy.com****.*

Midland Basin: Many opportunities across 75,000 sq miles

The region of the eastern Permian Basin has seen a steady amount of new E&P activity since 2011.

Larry Prado, Activity Editor

The Midland Basin region of the eastern Permian Basin has seen a steady amount of new E&P since 2011.

The Midland Basin underlies an area approximately 250 miles wide and 300 miles long, and it includes the West Texas counties of Borden, Dawson, Martin, Midland, Upton, Reagan, Glasscock and portions of Andrews, Crane, Gaines, Ector, Terry, Lynn Howard and Irion counties.

The Midland Basin is bounded to the east by the Eastern Shelf through a series of north-south trending fault segments, to the north by the Northwest Shelf and to the west by uplifted areas of the Central Basin Platform. Southward, Midland Basin formations thin out into the Ozona Arch, an extension of the Central Basin Platform, which separates the Delaware and Midland basins.

One of the main drivers for exploration is its stacked potential with multiple benches. The primary and most productive benches for the Wolfcamp play are Upper (A), Middle (B), and Lower (C, D) and other producing formations include San Andres, Spraberry, Dean, Atoka and Strawn. The four benches of the Wolfcamp Formation each display different geologic characteristics.

According to the U.S. Geological Survey estimates, the undiscovered continuous hydrocarbon resources of the Wolfcamp Formation in the Midland Basin exceed 19 Bbbl of oil, 15 Tcf of gas and 1.5 Bbbl of NGL, making it one of the largest hydrocarbon plays in the U.S.

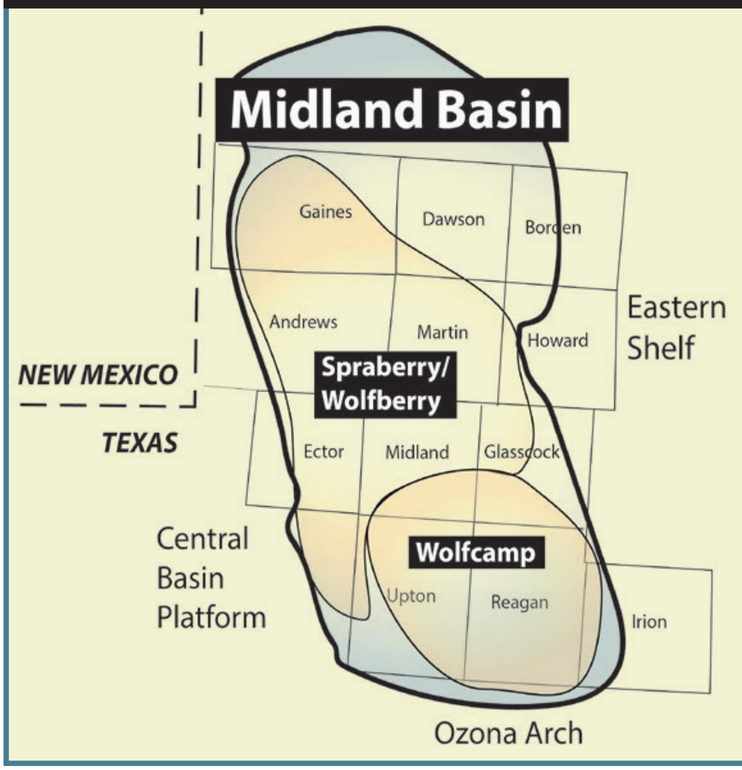
Spraberry and Dean sandstones have produced oil throughout the Midland Basin since the late 1940s. Known as the Spraberry Trend, productive areas extend across 18 counties and contain more than 10 Bbbl of oil.

Operators have been including deeper formations in their Spraberry trend completions—first the Wolfcamp (Permian) that underlies the Dean and then deeper zones in the Pennsylvanian (Wolfberry play).

Multiple fracture-stimulation stages open up low permeability formations to production over an interval between 6,000 ft and 10,000 ft. More than 5,800 Wolfberry oil wells have been completed since the late 1990s. IP averages 30 to 125 bbl/d, and ultimate per-well recovery is estimated at 100 MMboe to 140 MMboe. .

One of the most active operators in the basin is Pioneer Natural Resources. According to President and CEO Scott Sheffield, the company placed 85 horizontal wells on production during the first quarter of 2020. Sheffield also said it will continue to evaluate drilling and completion activity on an economic and coronavirus-safe basis, with activity levels assessed monthly.

Midland Basin Region, Producing Formations and Counties



(Source: Larry Prado/Hart Energy)

Selected Midland Basin completions

Dawson County – Reliance Energy Inc. completed a horizontal Spraberry Trend producer at #1H Caballo Azul 28-33 that was tested on-pump for 519 bbl of 36.9°API crude, 276,000 cf of gas and 3,935 bbl of water per day from acid- and fracture-stimulated Spraberry.

Smith Energy Operating Co. completed a CMI Field-Spraberry producer at #1 Wheelis 14 pumping 152 bbl of 36-degree-gravity oil and 35 Mcf of gas per day. In 2017 Smith completed its first well in the reservoir at #1 Alexander 13 that produced 313 bbl of oil and 194 Mcf of gas per day during its first five months online.

Borden County – A horizontal Spraberry Trend well was completed by Koch Exploration. The #1H Elise 39-46 pumped 223 bbl of 38-degree-gravity oil, 110 Mcf of gas and 2.284 Mbbl of water per day from Wolfcamp. The #1H Zagato 42-43 pumped 343 bbl of 37-degree-gravity oil, 153 Mcf of gas and 3.03 Mbbl of water daily from fracture-stimulated Pennsylvanian perforations.

Surge Operating completed two Spraberry Field-Wolfcamp wells: #6AH Jotunn Unit B 25-13 produced 960 bbl of oil with 447,000 cf/d of gas and the offsetting #7AH Jotunn Unit B 25-13 flowed 1,080 bbl of oil and 446,000 cf of gas per day.

Andrews County – Ring Energy Inc. completed a horizontal San Andres well, #1H Caesar, that flowed 506 boe/d.

Pacesetter Energy LLC has completed two San Andres producers. The #1H University Frodo was tested on-pump for 701 bbl of 31-degree-gravity crude, 210 Mcf of gas and 2.242 Mbbl of water per day. In Shafter Lake Field, #1H University Samwise flowed 234 bbl of 31-degree-gravity oil, 65 Mcf of gas and 2.677 Mbbl of water per day.

Howard County – Occidental Petroleum Co. announced results from two more completions in Spraberry Field. The #1H Santana 2432D produced 1,727 bbl of 37°API oil, 1.278 MMcf of gas with 1,329 bbl of water per day from commingled Spraberry/Dean. The #1H Santana 2442WA was tested flowing 1,222 bbl of 38°API oil, 1.162 MMcf of gas and 1,396 bbl of water per day from Wolfcamp.

Crownquest Operating completed a Wolfcamp producer, #2HB WR Vitex, in Spraberry Field that flowed 1.475 Mbbl of 39-degree-gravity oil, with 1.43 MMcf of gas and 2.076 Mbbl of water per day.

Ector County – Two more horizontal San Andres producers have been completed by Raptor Petroleum Development. The Jordan Field discoveries are #281H Connell, tested on-pump for 347 bbl of 33-degree-gravity crude, 109,000 cf of gas and 3.155 bbl of water per day and, #291H Connell, which pumped 121 bbl of 28-degree-gravity oil and 3,829 bbl of water daily.

Founders Oil & Gas has completed a vertical Ellenburger well at #1 Connell Section 10. The Jordan Field well pumped 59 bbl of 44°API crude and 3,925 bbl of water per day.

Midland County – A Spraberry Field-Spraberry producer by Pioneer Natural Resources Inc., #112H Baumann E16K, initially produced 1,244 bbl of 40.7°API oil, with 948,000 cf of gas and 369 bbl of water daily.

A Crownquest Operating discovery at #1 Teriyaki 20 flowed 120 bbl of oil, 355,000 cf of gas from commingles perforations in Dean, Strawn, Atoka and Mississippian and Devonian zones.

Summit Petroleum completed two Spraberry Field wells. The #12LS Carmanita produced 1.028 bbl of oil and 664,000 cf of gas from commingled Spraberry and Dean. Within 1 mile to the southwest, #08WB Carmanita initially flowed 1,475 bbl of oil and 1.27 MMcf of gas from Wolfcamp.

Glasscock County – Parsley Energy Operations LLC completed two Spraberry Field-Wolfcamp discoveries. The #4303H Julia 45-4-B was tested flowing 1,166 bbl of 42°API oil, 1.263 MMcf of gas and 3,716 bbl of water per day, and #4203H Julia 45-4-B flowed 1,749 bbl/d of 42°API oil.

Two Spraberry Field-Wolfcamp wells were reported by COG Operating LLC. The wells were drilled from a pad: #9AH Calverley 37-36 flowed 816 bbl of 44°API oil and 830,000 cf of gas per day, and #10BH Calverley 37-36 produced 882 bbl of oil and 1.042 MM cf of gas per day.

Upton County – Pioneer Natural Resources Inc. announced results from a Spraberry Field discovery at #103H Brook N-13F, which initially flowed 1,501 bbl of 42°API oil, 1.541 MMcf of gas and 4,482 bbl of water daily from Wolfcamp.

COG Operating LLC completed a Spraberry Field-Wolfcamp well at #6704BH Amacker 67B. The venture initially flowed 1,502 bbl of 42°API oil, with 1.393 MMcf of gas and 2,147 bbl of water per day.

Reagan County – A Spraberry Field-Wolfcamp discovery was reported by Laredo Petroleum Inc. The #7SM SUGG B 111-110 (Allocation-G) initially flowed 744 bbl of 42°API oil, 12.313 MMcf of gas and 1,086 bbl of water daily.

Sable Permian Resources completed three Wolfcamp C-Midland Basin wells from a drillpad in Lin Field. The #03HK Section 235-220 Allocation 01 produced 3.251 Mbbl of oil, 2.502 MMcf of gas and 3.167 Mbbl of water per day; #08HK Section 235-220 Allocation 04 flowed 2.76 Mbbl of oil, 1.795 MMcf of gas and 3.235 Mbbl of water per day; and #13H Section 235-220 Allocation 08 produced 2.753 Mbbl of oil with 2.166 MMcf of gas and 3.234 Mbbl of water per day. ✚

Midland Basin Stratigraphy

Era	System	Formation	Benches
Paleozoic	Permian	Guadeloupian	San Andres
			Yates
		Leonardian	Upper Leonard
			Upper Spraberry
			Lower Spraberry
			Dean
		Wolfcamp	Upper Wolfcamp (A)
			Middle Wolfcamp (B)
			Lower Wolfcamp (C, D)
	Pennsylvanian	Pennsylvanian	Cisco
			Canyon
			Strawn
			Atoka
			Morrow

(Source: EIA 2018; compiled by Larry Prado and Peggy Williams/Hart Energy)

1 Wyoming

Two Campbell County, Wyo., Parkman producers were completed by EOG Resources Inc. The wells were drilled in Crossbow Field on a pad in Section 5-42n-72w. The #0508-01H Congo was drilled to 16,820 ft (true vertical depth of 7,446 ft). It produced 1,017 of 58°API oil, 1.459 MMcf of gas and 1,095 bbl of water per day from perforations at 7,854 ft to 16,754 ft after 22-stage fracturing. The offsetting #0508-02H Congo was drilled to 17,356 ft (7,467 ft true vertical depth). It flowed 1,210 bbl of 57°API condensate, 1.079 MMcf of gas and 987 bbl of water daily after 24-stage fracturing. Production is from perforations at 7,619 ft to 17,292 ft after 24-stage fracturing.

2 North Dakota

A Hawkeye Field completion by Hess Corp. initially flowed 4,082 bbl of 40°API oil, with 7.107 MMcf of gas and 1,302 bbl of water per day from Middle Bakken. Located in Section 34-152m-95w in McKenzie County, N.D., #152-LE-95-3427H-1 HA-Nelson A was drilled to 21,294 ft (10,698 ft true vertical), and production is from a perforated zone at 11,155 ft to 21,113 ft. It was tested on a 42/64-inch coke, and the flowing casing pressure was 2,044 psi.

3 Texas

Barron Petroleum has scheduled a Val Verde Basin test in Ozona Field in Texas' Crockett County (RRC Dist. 7C). The #4 Sahota will be drilled to 7,700 ft on a 1,000-acre lease in Section 9, Block XX, GC&SF RR Co Survey, A-3139. According to the unapproved permit, the test will target either the Canyon Sand in Ozona Field or a wildcat zone. Ozona Field produces from more than 1,700 wells, and producing formations include the Spraberry, Clear Fork, Canyon and Ellenburger. According to Barron, the 13,000-acre project holds an estimated 74.2 MMboe in oil and gas reserves and has identified 67 high-graded Strawn locations on the acreage. Barron could potentially develop Canyon at 9,000 ft and Ellenburger at 16,000 ft.

4 Texas

A Newark East Field-Barnett Shale well was completed in Tarrant County (RRC Dist. 5) in Texas by TEP Barnett. In Stephen Richardson Survey, A-1266, #2H Little Bear A was drilled to 16,554 ft (7,684 ft true vertical) and flowed 5.418 MMcf/d of gas from a perforated zone at 8,216 ft to 16,444 ft. Gauged on a 49/64-inch choke, the flowing tubing pressure was 901 psi and the shut-in tubing pressure was 1,249 psi.

5 Louisiana

According to IHS Markit, GEP Haynesville has completed the two strongest Haynesville Shale wells drilled to date in North Louisiana's Holly Field. The De Soto Parish discoveries were drilled from a single pad in Section 18-14n-14w. The #1-Alt Land & Knowles 7-6HC flowed 45.062 MMcf of gas from a fracture-treated zone at 12,340 ft to 22,035 ft. Tested on a 35/64-inch choke, the flowing tubing pressure was 7,828 psi. It was drilled to 22,103 ft (11,906 ft true vertical), and it bottomed about 2 miles to the north in Section 5. The offsetting #1-Alt Land & Knowles 8-5HC produced 40.846 MMcf/d of gas from perforations at 12,348 ft to 22,040 ft. It was drilled to 22,104 ft (true vertical depth of 11,953 ft), and it bottomed about 2 miles to the north in Section 6.

6 Louisiana

Prime Rock Resources has completed an Austin Chalk oil well in Vernon Parish, La. IHS Markit reported that #1 Crosby 10 flowed 1,824 bbl of 46°API crude and 5.4 MMcf/d of gas from fracture-treated perforations at 16,186 ft to 22,249 ft. Tested on a 40/64-inch choke, the flowing tubing pressure was 5,075 psi, the flowing casing pressure was 775 psi and the shut-in casing pressure was 7,406 psi. The Sugartown Field well is in Section 10-2s-6w, and it bottomed within 2 miles to the south in Section 32-2s-6w in neighboring Allen Parish. It was drilled to 22,360 ft (15,650 ft true vertical). The well was sidetracked out of an initial horizontal hole that was junked and abandoned at 14,901 ft.

7 Ohio

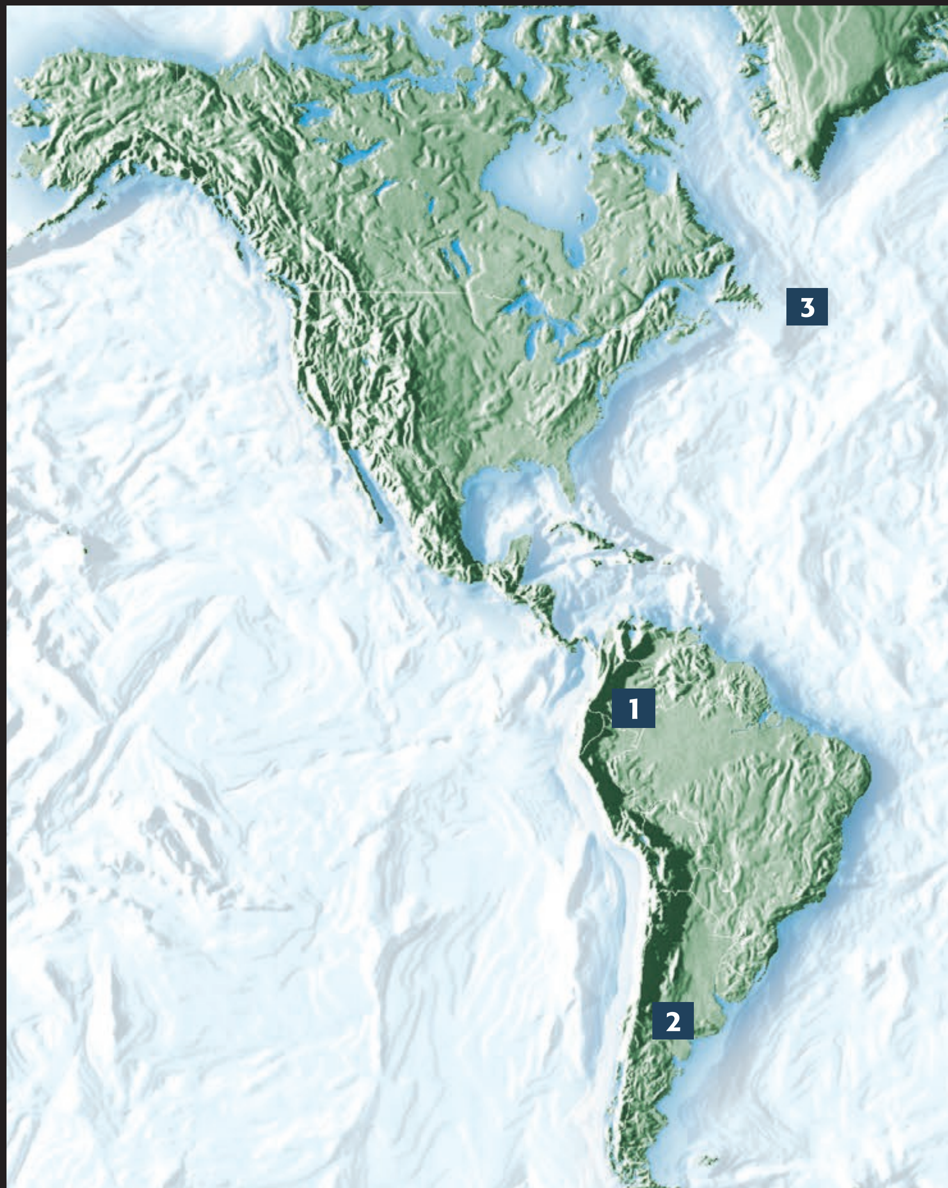
A Harrison County, Ohio, Utica Shale completion was announced by EAP Ohio LLC. The #6H Wallace K 4-11-6 is in Section 4-11n-6w. It was tested flowing at a 24-hour rate of 1,457 bbl of oil, 14.749 MMcf of gas and 343 bbl of water. The Forks South Field well was drilled to 26,744 ft (true vertical depth of 8,357 ft). Production is from perforations between 8,282 ft and 26,594 ft.

8 Ohio

A Herick Field-Marcellus discovery was announced by Chesapeake Operating Inc. in Pennsylvania's Bradford County. The #106HC Brown Homestead initially flowed 44.238 MMcf/d of gas with a shut-in casing pressure of 3,414 psi. It was drilled in Section 7, Laceyville 7.5 Quad, Wyalusing Township to 18,120 ft (7,251 ft true vertical depth), and it was tested after 31 stages of fracturing. Production is from perforations at 7,508 ft to 18,106 ft.

—By Larry Prado, Activity Editor

For additional information on these projects and other U.S. developments, visit the drilling activity database at hartenergy.com/activity-highlights.



1 Colombia

GeoPark announced results from an appraisal test in Colombia's Block CPO-5. The well, #2-Indico, was drilled to 10,925 ft and flowed 5,200 bbl of 35°API oil per day from Une (LS3). It was tested on a 40/64-inch choke, and the wellhead pressure was 330 psi. According to the company, the well bottomed within one-half mile to the north and 151 ft down-dip of a previous test, #1X-Indico, which hit a net pay zone of approximately 161 ft. Additional production testing is planned. The drilling rig is being moved to the nearby Aguila exploration prospect in the block to test several targets in Une (LS3). Up to six more wells are planned for the block by GeoPark.

2 Argentina

President Energy reported test results from exploration well #1-xEVN near Estancia Vieja Field in northern Rio Negro Province, Argentina. Two pay intervals in the previously untested Estancia Vieja North structure were confirmed by well logging, with an unreported amount of 36°API oil and gas flowing to the surface. The preliminary testing indicated that IP levels can be expected in line with P50 pre-drill expectations of more than 200 bbl/d of oil plus associated gas from this lower interval. The well is near the main Estancia Vieja pipelines and facilities. Additional exploratory drilling and testing are planned.

3 Canada

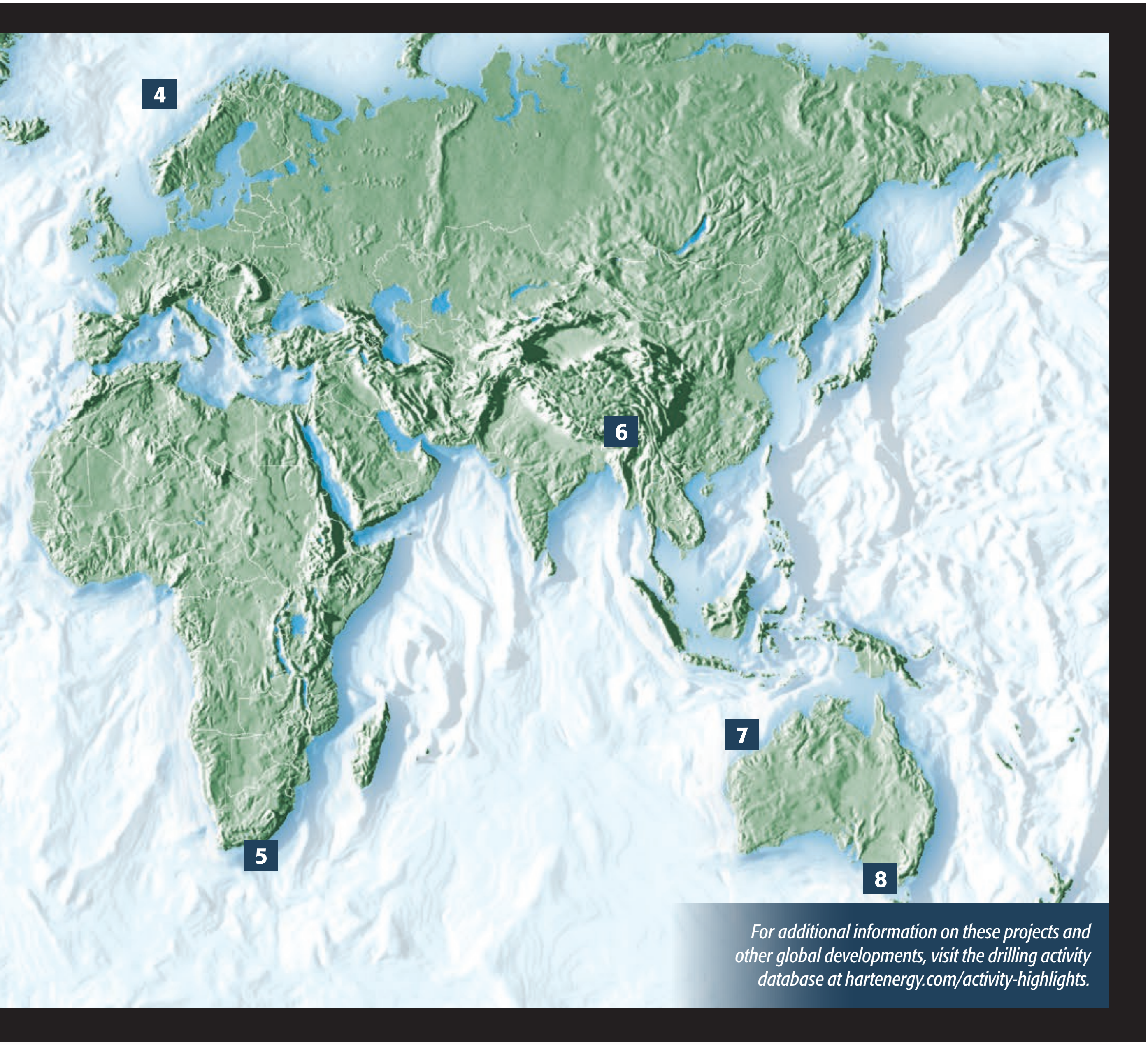
Equinor announced that it made two offshore Newfoundland oil discoveries. The two wells at the Cappahayden and Cambriol prospects in the Flemish Pass Basin have proven the presence of hydrocarbons; however, it is too early to provide specific information on volumes. The #1-Cappahayden well was drilled in about 1,000 m of water, and the #1-Cambriol well was drilled in a depth of 600 m.

4 Norway

ConocoPhillips announced a new gas condensate discovery in the Norwegian Sea in PL1009, Block 6507/4 near Victoria Field and northwest of Heidrun Field. The Warka discovery well, #6507/4-1, was drilled in 399 m of water to 4,985 m. Preliminary estimates indicate the discovery holds between 50 MMboe and 190 MMboe recoverable. The primary and secondary exploration targets for the well were to prove petroleum in reservoir rocks from the Albian and Aptian ages and in the early Intra Lange sandstones (Cretaceous). In the primary exploration target, the well hit a 27-m gas column in sandstone layers in Lange with moderate but uncertain reservoir quality. No gas/water contact or reservoir rocks were encountered in the secondary target. Additional appraisal work is planned. After completion, the rig will be moved to drill exploration well #6507/5-10S (Slagugle) in PL891, north-northeast of Heidrun Field.

5 South Africa

Total announced a gas condensate discovery on the Luiperd prospect offshore South Africa. The #1-Luiperd was drilled to about 3,400 m and encountered 73 m of net gas condensate pay in well-developed, good quality Lower Cretaceous reservoirs. Coring and wireline logging are planned to assess the dynamic reservoir characteristics and deliverability. The discovery is on Block 11B/12B in the Outeniqua Basin, and it follows the adjacent play



opening Brulpadda discovery, which proved a significant new petroleum province in the region. Water depth at the site is 1,795 m.

6 India

Oil India Ltd. reported an oil and gas discovery at the #1-Dinjan exploration well in the Tinsukia District of India's Assam state. The venture is in Tinsukia Petroleum Mining Lease in the Upper Assam Basin. It encountered multiple sands in Kopili, Narpuhand Lakadong, and Therria formations with a total net pay of about 10 m. It flowed approximately 4,061 cf/d of gas from perforations at 3,614 m with a flowing casing pressure of 3,750 psi.

7 Australia

bp is underway at the #1-Ironbarkl exploration well in exploration permit WA-359-P in the Carnarvon Basin. The offshore Western Australia venture will be drilled in about 300 m of water and will test the Ironbark gas prospect, which has a best estimate of 15 Tcf prospective recoverable gas resources. The primary target is the Deep Mungaroo at approximately 5,335 m. Several additional reservoir objectives within the same formation also will be tested. The operator is planning an extensive LWD program, and it will be plugged and abandoned following the completion of operations.

8 Australia

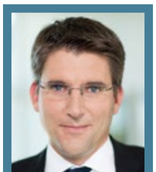
Beach Energy announced a gas discovery in the Otway Basin at the #1-Enterprise exploration well in license VIC/P42(V). The well was drilled from an onshore location about 3.5 km north of Port Campbell, Victoria, and was directionally drilled using extended-reach techniques with a 3.2-km step-out. It was drilled to 4,974 m and hit the primary reservoir target, Upper Waarre. The well encountered a 146-m gas column, including 115 m of net gas pay with no gas-water contact identified. The well will be cased and suspended as a future producer.

–By Larry Prado, Activity Editor

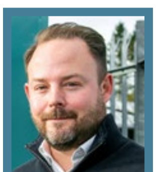
PEOPLE


Constable

Fluor Corp. has named **David E. Constable** CEO. Constable succeeds **Carlos Hernandez**, who has retired as CEO and a member of the company's board. Constable brings 30 years of insight to Fluor, having held various leadership roles within the company from 1982 to 2011 before returning as a board member in 2019.


Becker

Siemens Gamesa Renewable Energy announced that **Marc Becker** is to return to the company as CEO of its offshore business. Becker served as managing director for Germany and head of offshore sales and projects with Siemens Gamesa before leaving the company in early 2020. Becker, who is to be the permanent replacement for **Andreas Nauen** who was promoted to CEO of the company in June, will be based in Hamburg and start his new role on Feb. 1. **Pierre Bauer** will continue as interim CEO in the meantime.


Slattery

Motive Offshore Group has appointed **Declan Slattery** CFO. Slattery, who co-led Enpro Subsea through its recent acquisition by Hunting Plc, joins Motive as it continues to implement its domestic and international growth strategy.

Evolution Petroleum Corp. has named **Ryan Stash** CFO. He will succeed **David Joe**, who has elected to retire. Stash comes to Evolution from Harvest Oil & Gas Corp. where he served as vice president and CFO since October 2018.

Ovintiv Inc. has named **Brendan M. McCracken** president. He replaces **Michael McAllister**, Ovintiv's former president who retired in June 2020 after 20 years with the company and nearly 40 years in the industry. McCracken, who currently serves as executive vice president of corporate development and external affairs, will maintain his current responsibilities following the promotion.


McCracken

Data Gumbo has welcomed **Bruce Bain** as vice president of channels and alliances.

Chevron Corp. has named **Al Williams** vice president of corporate affairs, effective March 1. The company also appointed **Paul Antebi** vice president and general tax counsel, effective Feb. 1. **Marillyn A. Hewson** was elected to Chevron's board of directors, effective Jan. 1. She will serve on the audit committee of the board.

The Texas Railroad Commission has revealed that Railroad Commissioner **Wayne Christian** has been selected to be the vice chairman of the Interstate Oil and Gas Compact Commission.


Sinclair

Global Energy Group has appointed **Iain Sinclair** to the newly created role of executive director of renewables and energy transition with plans to launch a new operation in Edinburgh. Sinclair will be responsible for developing plans that utilize the company's oil and gas skills and experience as it further diversifies in line with clients' needs.

Cairn Energy plc has appointed **Nicoletta Giadrossi** chair of the company.

MRDS, an Aberdeen drilling services firm, has appointed **Colin Whyte** director for the Middle East and North Africa as part of its growth plans in the region. Having worked in the region for almost 15 years, Whyte brings a strong track record having held managerial positions with National Oilwell Varco, Weatherford and Seadrill.


Whyte

Petrobras has created an executive management team to lead actions related to carbon management, the reduction of atmospheric emissions, energy efficiency and climate change. The team will be led by **Viviana Coelho**, the company's current manager of emissions, energy efficiency and transition to low carbon.

MRDS Group, an Aberdeen drilling services firm, has appointed **Craig Yeoman** finance director.

The Society of Exploration Geophysicists (SEG) board of directors has selected **James (Jim) C. White** as the new SEG executive director.

The International Association of Oil & Gas Producers has welcomed **Iman Hill** as its new executive director, succeeding **Gordon Ballard**, who stepped down at the end of 2020.

Flotek Industries Inc. has welcomed **Michael Fucci** to its board of directors.

COMPANIES

Logan Industries has opened a new Pressure Vessel Heat Exchanger facility at its Hempstead, Texas, site. The facility enables Logan to manufacture, test, certify and stamp high-end alloy vessels.

Equinor has announced changes in its corporate structure, effective by June 1. E&P Norway and E&P International have been established as two new business areas. Renewables will continue as a business area, renamed from New Energy Solutions. Technology, Digital & Innovation will be established as a separate business area, while Projects, Drilling & Procurement will become a more focused business area.

Varel International Energy Services has rebranded as **Varel Energy Solutions** (VES). The VES strategy is to be a leading value creator in the well construction energy sector and to strengthen its current offerings through strategic acquisitions and organic investment in highly adaptive, low-cost manufacturing.

Eni and the Norwegian energy entrepreneur and investor **HitecVision** have established a new joint venture company, **Vårgrønn**, with the aim of developing new green energy projects in Norway and the Nordic market.

Southwestern Energy Co. has acquired **Montage Resources**.

S&P Global and **IHS Markit** have entered into a definitive merger agreement to combine in an all-stock transaction. The transaction is expected to close in the second half of 2021.

AqualisBraemar ASA has entered into an agreement to acquire 100% of the shares in **LOC Group.** Closing of the acquisition was expected on or around Dec. 21, 2020. +

AD INDEX

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E&P plus

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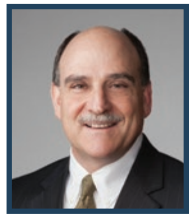
Why the outlook for the OFS sector is down but not out

OFS companies will need to preserve capital and ride out the storm before they can expect to see an uptick in activity.

Dean Price and **Kevin Cannon**, Opportune LLP

Kevin Cannon



Dean Price

Historically, there has been a correlation between rig counts and oil prices driving capital spending in the upstream sector of the energy industry. Likewise, this has typically been an indicator for the performance of the oilfield services (OFS) sector as well.

The onset of 2020 began with an active rig count of 796, down from the peak of 1,075 in January 2019. Post-COVID-19, the rig count declined to 247 and has since rebounded slightly to 269. Pre-COVID-19, the disconnect between rig counts and oil prices was evidenced by the change from 2019 to 2020. Post-COVID-19, the lowest WTI closing price was $16.94/bbl; however, the WTI crude price has since rebounded from historic lows to hover at approximately $40/bbl.

Is this a long-term trend or will the correlation return as we consider the current $40 to $45/bbl crude oil pricing environment? What impact will the above have on the OFS sector?

Navigating volatility

Assuming oil prices trend upward and the supply side of the oil equation moves toward equilibrium, there is an expectation that capital spending will eventually increase, and rig counts will rebound as a result. Nevertheless, there are three questions that will need to be addressed in the industry:

- Will shareholders continue to demand return of capital and deleveraging of balance sheets?
- Will borrowing base redeterminations and other credit-related issues decline, increase or remain static?
- Will OPEC+ control its supply to meet demand without negatively impacting oil prices?

Recent revenue forecasts for the OFS industry indicate 2022 being the year of upward trajectory.

In terms of shareholders, it is very likely that there will be a continued demand to increase shareholder value in the E&P sector. The significant decline in market value of publicly traded companies will lead to continued stress from shareholders and will require upstream oil companies in particular to effectively balance their production, restrain capital spending, lower debt loads, right-size their back office and create added value for shareholders.

On the credit front, as has been evidenced from the recent borrowing base redeterminations for reserve-based loans earlier this year and expectations for the current round, banks are expected to reduce their exposure to the upstream industry in the near term. As banks are under pressure to reduce their exposure, certain producers will have to find alternative sources of capital—most likely at higher rates.

For companies primarily focused on oil production, the expectation is their borrowing bases will at best remain unchanged and/or be decreased. The consequences of reduced borrowing bases will limit an oil producer's availability to capital, thereby reducing capital deployed in the sector in 2021. Many oil producers will focus on maintaining production rather than increasing production because of limited capital. Consequently, these factors will continue to place stress on the OFS sector.

Cloudy with a chance of survival

What does this mean for the OFS sector? The next 12 to 18 months will continue to be challenging due to the factors mentioned above. Recent revenue forecasts for the OFS industry indicate 2021 will be a year of nominal to no growth, with 2022 being the year of upward trajectory.

Additionally, private-equity-backed OFS portfolio companies may be more receptive to the idea of portfolio company/investment combinations, or smashcos. In this environment, both sponsors and portfolio companies are looking for cost savings wherever they can find them and, as such, they may be looking for ways to promote cross marketing and other synergies among portfolio companies.

As we head into 2021, it is imperative that OFS companies preserve capital and ride out the storm before they can reasonably expect to see an uptick in activity. +

Editor's note: *Dean Price is an Opportune LLP partner responsible for the Oilfield Services sector and the Valuation Advisory and Tax Advisory service lines. Kevin Cannon is a director in Opportune LLP's Valuation practice.*