HARTENERGY OCTOBER 2020

E+P plus

environmental social governance

ESG takes root

Achieving real results, not satisfying buzzwords

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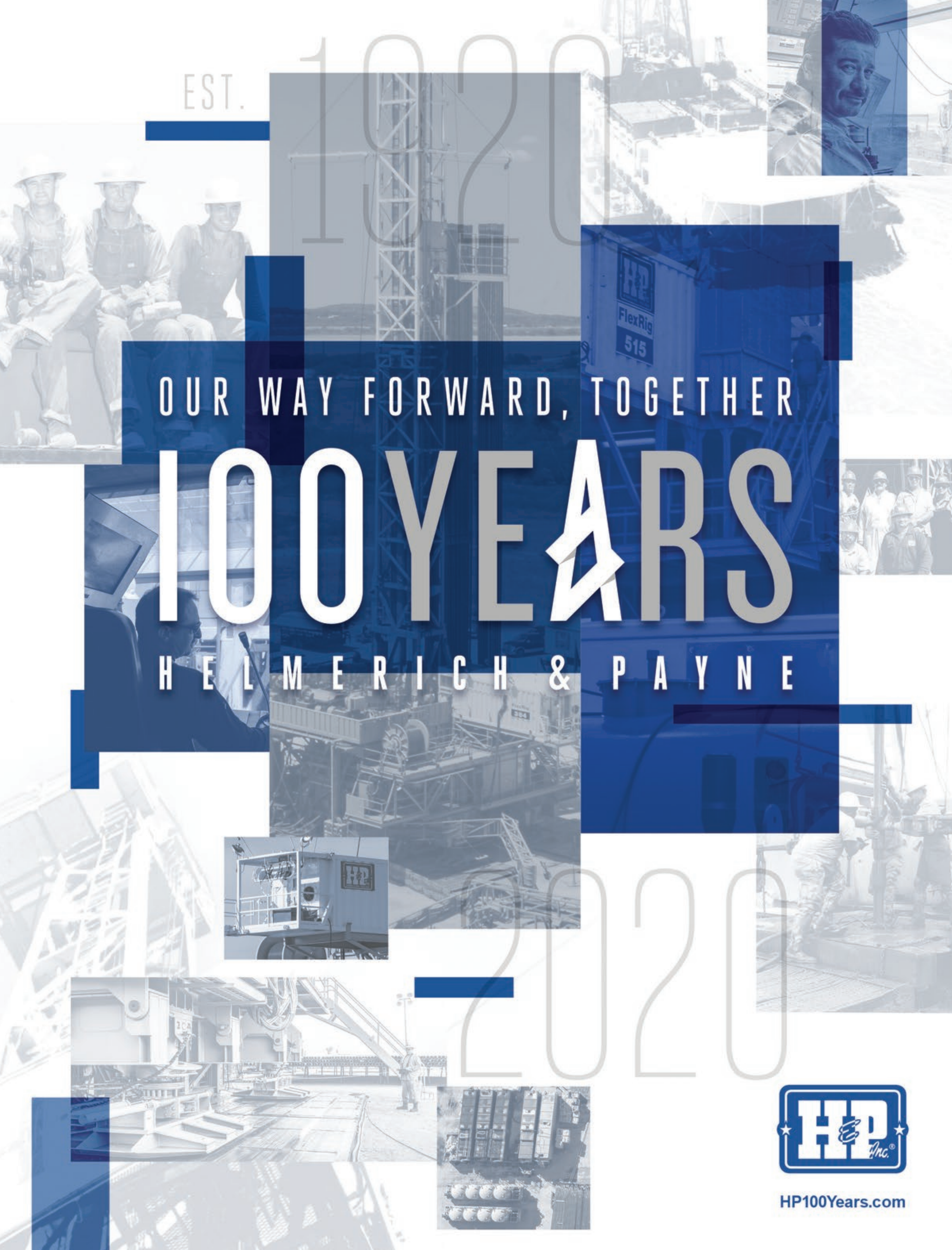

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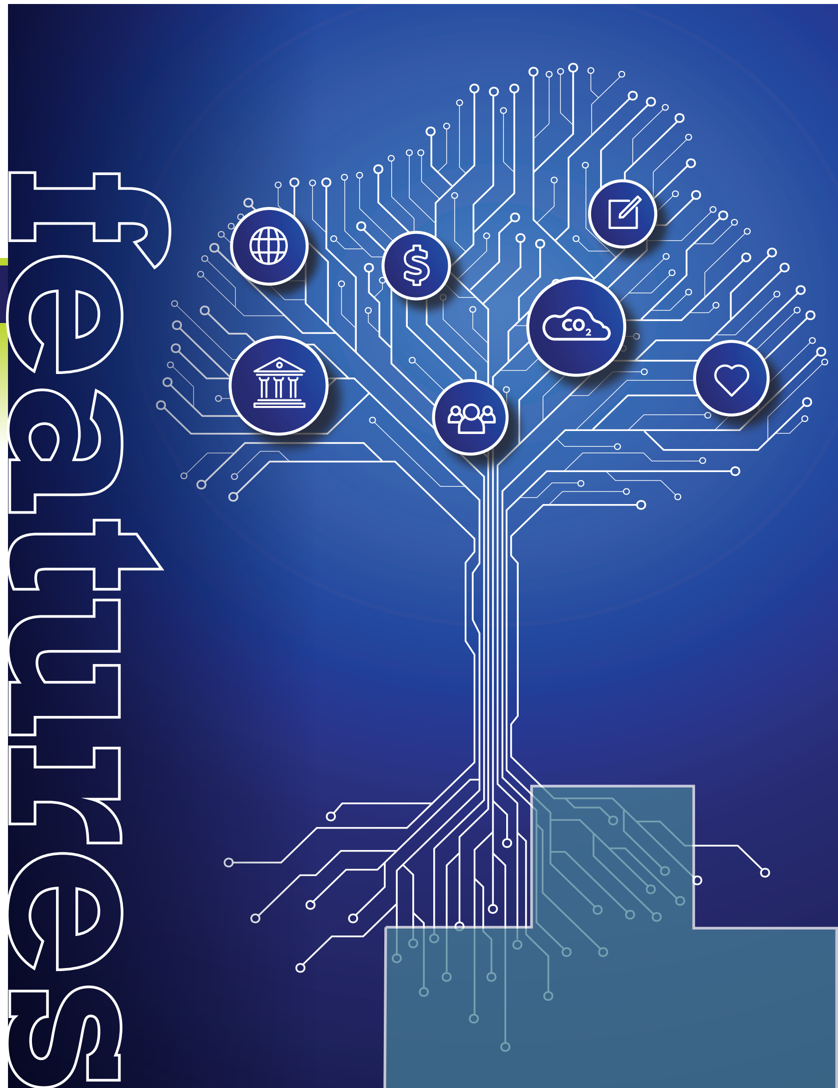
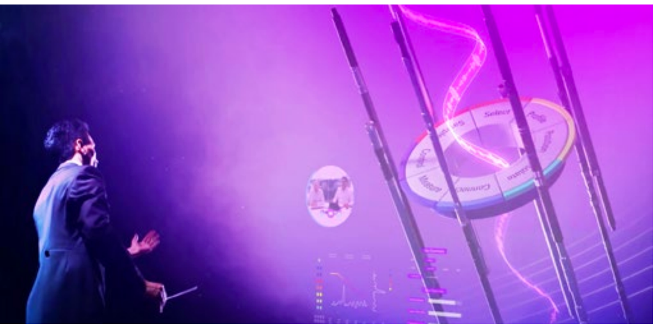


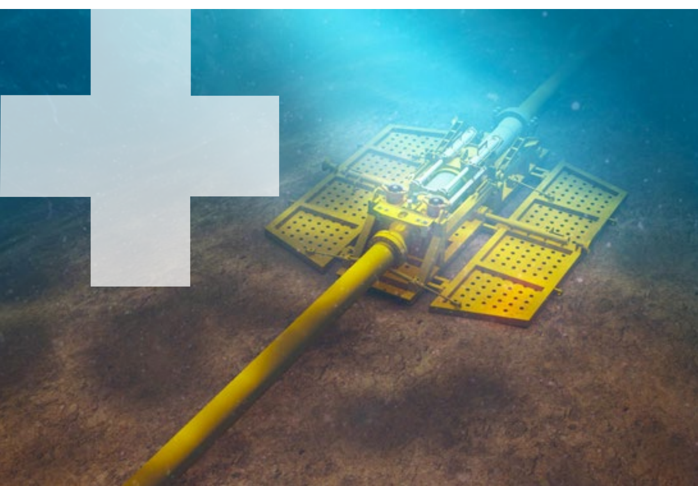
Cover Story: ESG

Reservoir Testing



Drilling Automation

Drawdown Optimization



Diverless Technology

Powering the Oil Field

E&P plus

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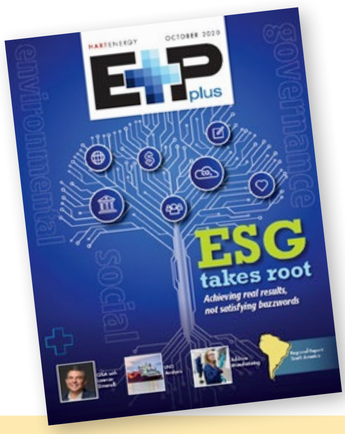

About The Cover:
This tumultuous year helped speed up the growth of ESG in the oil and gas industry. While the seeds of ESG reporting had been sown, there's little doubt they've taken root. But what is real action beyond satisfying buzzwords? The industry struggles to define its successes in reducing emissions and making progress in social responsibility and corporate governance. *(Cover images courtesy of bookzv/Shutterstock.com; Bottom images from left to right courtesy of Baker Hughes, Wojciech Wrzesien/Shutterstock.com, Siemens, and Mdesignstudio/Shutterstock.com; Cover design by Alexa Sanders)*

Coming Next Month:
The November cover story will focus on data analytics and will feature interviews with IFS, Schlumberger, IBM, Halliburton, Honeywell, ABB, Equinor and Deloitte, plus video! The Executive Q&A will showcase an exclusive video interview with Schlumberger's Hinda Gharbi, EVP of Services & Equipment. The Operator Spotlight will feature an exclusive interview with Goodrich Petroleum, and the Regional Report will highlight Southeast Asia. As always, **E&P Plus** will include its exploration, drilling, completions, production and offshore features in every issue.

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EOG commits to 'staying disciplined' amid market uncertainty

By Velda Addison, Group Senior Editor

The company also looks to focus on its premium inventory as it pursues exploration opportunities.

Concho Resources eyes efficiency gains in Permian Basin

By Velda Addison, Group Senior Editor

Simultaneous fracs are among the methods being discussed by some U.S. shale players to drill and complete wells faster and more efficiently.

Oil majors work to advance offshore wind energy

By Velda Addison, Group Senior Editor

Executives from Equinor, Shell, Total and WindEurope discuss how producers of oil and gas are transferring knowledge to offshore wind.

Exploration outlook: key oil, gas prospects to watch post-COVID-19

By Velda Addison, Group Senior Editor

Despite spending cuts made across the oil and gas industry, some companies are moving ahead with plans to drill exploration wells.

VIRTUAL CONFERENCES ON DEMAND

Hart Energy's DUG conferences are the fastest, easiest and safest way for you to stream relevant market intelligence on dynamic regions directly to your desk—no matter where your desk is today. Start streaming these free conference sessions on demand:

- ***DUG Midcontinent Virtual Conference at DUGMidcontinent.com; and***
- ***DUG Permian Basin and Eagle Ford Virtual Conference at DUGPermian.com.***

HART ENERGY VIDEOS

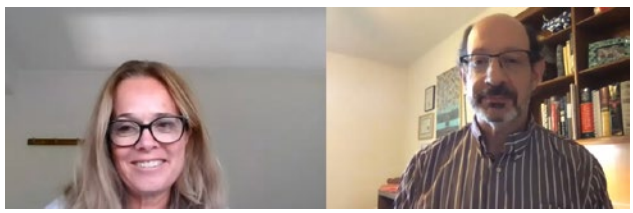
By Jessica Morales, Director of Video Content

Leaders from 'Big 4'—Deloitte, EY, KPMG, PwC—provide recovery outlook for energy

Leaders from the "Big Four" accounting firms–Deloitte, EY, KPMG and PwC–joined Hart Energy's Emily Patsy to discuss the biggest hurdles facing their clients this downturn and what the oil and gas industry will look like post-pandemic.

DNV GL's Liv Hovem on the energy transition and what it means for shale

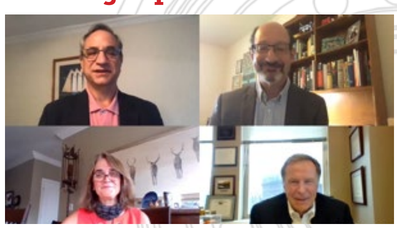
The company's 2020 Energy Transition Outlook forecasts that carbon emission reductions will fall far short of the Paris Agreement's 2050 goals. Liv Hovem, CEO of DNV GL – Oil & Gas, discussed the conclusions of the report with Hart Energy's Joseph Markman.



Honeywell CTO on remote oilfield tech, data analytics

Jason Urso, CTO of Honeywell Process Solutions, joined Hart Energy's Faiza Rizvi to explain the growing significance of remote technologies in the current environment in which oil and gas companies operate.

Babst Calland attorneys target oil and gas political issues to watch



As the November election draws closer, Hart Energy's Len Vermillion and Joseph Markman sat down with Babst Calland's Kevin Garber and Jean Mosites who analyze the stance of major party candidates on key environmental issues and what the oil and gas industry can anticipate, depending on the victors.

A new industry workforce

Oilfield jobs have taken a stunning hit, but the drive toward digitalization and a low-carbon future will create new opportunities for the industry's workers.

(Source: kentoh/Shutterstock.com)

By any measure, and by any lens through which it is viewed, the number of job losses in the oil and gas industry has been staggering. According to a recent report by the Petroleum Equipment and Services Association (PESA), layoffs in the oilfield services (OFS) sector linked to pandemic-related demand destruction hit more than 103,000 in August. Producers have laid off tens of thousands more. Texas, the country's leading oil producer, has been hit the hardest with some 50,000 job losses, more than the next six states with the most layoffs combined.

If there is good news to be found in all of this, it is that the industry layoffs are beginning to plateau. Between January and May, the OFS sector saw nearly 85,000 layoffs. But from May to August, the sector has seen just under 20,000 job losses, according to PESA.

There is, of course, optimism for 2021. The hope of a vaccine and an expected increase in global energy demand mean that many jobs could return next year. But what will those jobs look like? In many ways, the jobs that were lost might not be the same ones that return.

PESA President Leslie Beyer said as a result of an emerging reliance on remote operations, artificial intelligence and digitalization, there will be a "new-looking workforce in oilfield services."

"We'll be looking for a little bit different kind of person, one that has the skills to work in data and automation," she said.

Although it might not be a priority now, technologies that enable the energy transition are going to play an increasingly significant role in energy company operations while offering new job growth opportunities.

"As you see more people talking about the energy transition and reducing their environmental footprint, it's a bright spot for oilfield services because we develop the technologies that are going to achieve that," Beyer said.

The macro-evolution of the oil and gas industry is quite easy to recognize—from what are now considered crude tools in the early 20th century to today when entire drilling operations are conducted by computers and robots. And up until just a few years ago, the micro-evolutions were, if not hard to spot, practically nonexistent. For many years, the practices of drilling, completing and producing a well, with notable exceptions, largely remained unchanged. What worked before still worked, and there was just no good reason to change.

But thanks to COVID-19, the evolutionary accelerator has now been pushed to the floor. Of course, there will still be jobs in the field—rig platforms will still need rig hands. But years from now we may look back on this summer and see that the oil and gas industry shed its skin, emerging anew. +

Brian

Brian Walzel
Senior Editor
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Technologies that enable the energy transition are going to play an increasingly significant role in energy company operations while offering new job growth opportunities.

Read more commentary at
HARTENERGY.COM

Video

Q&A

In this video, Baker Hughes CEO Lorenzo Simonelli chats with Hart Energy's Editorial Director Len Vermillion in an exclusive interview about the path forward for the oil and gas industry.

Baker Hughes CEO talks OFS companies and the road ahead in a new energy world

Lorenzo Simonelli discusses the digital transformation, offshore technology, LNG, the energy transition and more.

Len Vermillion, Editorial Director

As an energy technology company, Baker Hughes' portfolio spans across oil and gas, alternative and renewable energy, as well as other industrial sectors, making it well positioned to respond to various market opportunities.

Lorenzo Simonelli, chairman and CEO of Baker Hughes, recently provided E&P Plus with an exclusive video interview in which he shared his views on the way forward for oilfield service companies in a post-pandemic future.

In addition, the Q&A below delves into even more details on Baker Hughes' plans and strategies presently and looking ahead.

"I believe COVID-19 has been a tipping point, hastening the energy transition and presenting an opportunity both within and outside our industry to take energy forward."

–Lorenzo Simonelli, Baker Hughes

E&P Plus: What will the oil and gas industry look like as it moves forward into a post-pandemic world? What does a field service company look like to you in the future? How is your company positioned to make that shift? How is digital helping make that shift possible?

Simonelli: Now more than ever, our customers will demand technology and solutions to support the productivity and efficiency of their operations, both to achieve their carbon reduction goals and to navigate the current macro environment. This gives us an opportunity to engage with customers on new commercial models based on outcomes and new technical and operational solutions focused on transforming efficiency, reducing emissions and maximizing shared value.

For example, the COVID-19 pandemic has accelerated deployment and utilization of remote and virtual operations. Remote drilling services, critical asset monitoring and virtual equipment testing limits HSE risks and nonproductive time, and it allows us and our customers to operate more effectively and efficiently.

Many of these capabilities also are beginning to be further enabled by the convergence of digital technologies and artificial intelligence [AI] that will lead to more transformative outcomes and even higher levels of efficiency and productivity.

E&P Plus: Where do you see offshore fitting in this new energy world?

Simonelli: Offshore will require continuous innovation to improve economics on both current and new projects, and digital capabilities will need to be expanded to enable further remote operations.

Already, our Subsea Connect business model helps customers accelerate time to production, maximize recovery over the life of the field and reduce their total expenditures. By connecting various work streams in a subsea development, we can fundamentally improve project economics—lowering the economic development point of individual subsea projects by up to 30%. That means adding tangible value to planned developments and potentially transforming uneconomic offshore assets into newly viable opportunities.

As we continue to lead in technology for the offshore space, access to reliable power will remain essential. We are currently developing new technology to provide high-voltage electric power distribution to subsea developments. Our high-voltage connectors for traditional subsea power distribution also have applications for the floating wind segment, which we can support with monitoring devices to detect costly and critical turbine failure modes.

E&P Plus: The oil and gas industry has a bit of a reputation for being slow adopters of new technology. How do you see the current downturn impacting technology adoption?

Simonelli: The rate at which our industry adopts new technology will likely accelerate. The industry has innovated before, but it tends to innovate from within, and we need to learn from other industries. The COVID-19 pandemic has required employees and customers to embrace new digital tools at an accelerated rate. For that reason, COVID-19 might be a digital tipping point. It's reduced the barrier to change, and we are seeing the benefits.

For instance, new digital solutions have proven vital to business continuity during the pandemic, ensuring customer projects move forward despite COVID-19 travel and social distancing restrictions.

As a result, an increasing number of customers are showing interest in our remote drilling services. We now deliver more than 70% of our drilling services remotely, up significantly from about 50% in 2019. Remote drilling is the new normal.

The benefits of remote operations extend well beyond business continuity and safety. We have been able to drive cost efficiencies, improve productivity, enhance well performance, reach new technical milestones and reduce emissions.

E&P Plus: How is your company helping to transform the LNG space?

Baker Hughes released its "Energy Forward: 2019 Report on Corporate Responsibility" in August 2020. Click the image to learn more.

Simonelli: Baker Hughes has a long heritage of LNG innovation, built on a 30-plus years' experience in the space, and we have continuously invested in turbine and compressor technology. We also have paired our LNG technology with leading execution, testing, sensing and monitoring capabilities to increase project efficiency and productivity while reducing risks, total costs and carbon footprint.

For instance, our turnkey liquefaction modules shorten lead times to engineer equipment and simplify manufacturing and installation processes. The modules, proven in the most extreme conditions, can integrate with auxiliary systems and controls, so we can connect everything before delivery to further reduce project disruption. This can reduce installation time and costs by up to 30%.

Going forward, we have an important role to play as a partner to LNG customers by helping them lower their carbon footprint through our gas turbine and compressor technologies.

One of the key differentiators is our LM9000 aeroderivative turbine. The LM9000 was recently validated as the world's most efficient simple cycle gas turbine in its class after its First Engine to Test for Novatek' Arctic LNG 2 project—a key milestone for the ongoing development of our technology.

With our installed base of over 400 mtpa of liquefaction equipment globally, our LNG service portfolio is uniquely positioned to offer upgrades and technology services that can extend equipment life, enhancing availability and performance, and contribute to further emissions reductions. This includes expanding our gas turbines' fuel flexibility, specifically around hydrogen blends, and applying technology to reduce potential methane leaks.

E&P Plus: Disruption became the new normal years ago. It seems like the cycles of change are speeding up. How do you lead a company or go about planning for the future when those plans could become obsolete within minutes of being made?

Simonelli: In times like these, it is best to focus on what we do know and what we can control. We know that the world needs more energy, and the world needs more from energy. And we don't see that changing short term or long term.

For that reason, our purpose is clear, and our commitment is firm. We make energy safer, cleaner and more efficient for people and the planet.

I am proud that our people push the boundaries of what's possible. We use technologies that explore the future of design and manufacturing, AI and computing at the edge to evolve our portfolio to lead through the energy transition as a company and for our customers.

In early 2019, Baker Hughes was among the first in the industry to make a commitment to achieve net-zero carbon emissions from our operations by 2050 as well as use our own portfolio to help the industry control and reduce its emissions.

Ultimately, this commitment plays an important part in driving our strategic decision-making and R&D approach. Maintaining focus allows us to manage across market cycles in pursuit of a low- to zero-carbon energy future.

E&P Plus: There are many E&Ps and service companies struggling and looking for a new strategy in today's environment. What would you say differentiates your company from others?

Simonelli: As an energy technology company, Baker Hughes stands apart from other service companies for its ability to offer truly differentiated technology at scale across a variety of energy sources—from oil and gas to alternative and renewable energy.

The scope and scale of our portfolio gives us a unique advantage to bring the most complete suite of low-carbon solutions to energy and other industrial markets. This is a capability our customers require and look for to reduce the carbon intensity of their operations, particularly on major projects.

We also continue to innovate on new low-carbon products and services to help our customers reduce their emissions within oil and gas operations as well as to support the future energy mix. Capabilities such as carbon capture, use and storage; hydrogen; and energy storage are becoming more relevant. These are all areas in which core technology can be applied today as our customers lean into the energy transition.

Internally, we have also taken several concrete steps to advance our own energy transition strategy. This includes actively reducing our emissions by conducting hundreds of facility energy audits as well as increasing our share of energy purchased from renewable sources.

E&P Plus: With more people working remotely and in more dangerous locations, it appears the opportunities are limitless for digital systems. Where does digital—quite possibly the greatest disruptor of all—go from here?

Simonelli: Digital technologies are now fundamental to navigating today's market realities and tomorrow's uncertainties. The industry must find ways to reduce operating costs, maintain critical asset reliability and enable remote operations in order to survive.

Remote drilling services existed in various forms over the last two decades, but today restrictions due to COVID-19 limit travel and require social distancing at rig sites. In some instances, this means that if we can't drill or complete a well remotely, we can't drill or complete the well at all.

In order to overcome these challenges, the industry is accelerating adoption of differentiated technologies. As businesses gain more comfort with remote operations, we envision moving more personnel off the rig site and into a centralized location to further reduce costs and minimize HSE risks.

Digital technologies like AI are also helping to grow and enhance predictive maintenance, production optimization and energy management. The industry can benefit today from the deployment of AI because the underlying infrastructure is in place. AI is now an important mechanism to deliver productivity, efficiency and safety.

Our BakerHughesC3.ai joint venture alliance is critical to delivering enterprise-scale AI applications that energy companies can adopt across all sectors.

E&P Plus: Climate change remains a dominant topic of conversation and concern. ESG is a front-burner issue for many investors and E&P companies. In building a new energy system that is renewable or more sustainable, how do we ensure the hard lessons taught to and learned by those in the oil and gas space are not repeated in this new energy system? Put another way, how do renewables learn from and not make the mistakes of fossil fuel?

Simonelli: One lesson the renewable power industry can learn from the oil and gas industry is to consider the full life cycle of operations and to be transparent with the public about that process early on, encouraging ongoing two-way dialog to build trust.

This is critical to helping people understand, assess and support the trade-offs required—costs and benefits as well as risks and rewards—in the development and use of various sources of energy.

For instance, renewables companies use oil and gas power generation during their manufacturing and disposal processes. And increasingly, oil and gas companies use renewables to power their manufacturing processes. We do as well.

In 2019, we announced a new agreement to purchase renewable electricity for our facilities in Texas, our largest global region for energy consumption. The renewable power agreement will eliminate a substantial portion of Baker Hughes' global carbon equivalent emissions over the 10-year term of the agreement.

There is not one perfect energy solution without impacts to consider and mitigate. We need to continue driving informed discussions and cross-industry collaboration to overcome challenges and maintain a license to operate long term.

We will also need a variety of energy sources to meet the dual challenges of decreasing carbon intensity, while increasing access to energy. Only by working in partnership will we be able to tackle the dual challenge successfully.

E&P Plus: What advice do you have for those inventors of the next great technology that are struggling to get it accepted or adopted by the industry?

Simonelli: As I lead a company of inventors driven by continuous innovation, my advice is to focus on the outcome delivered by new technologies, not simply the applications. We also must accelerate the development of technologies as we enter the next few years and the energy mix changes, so speed is critical.

The energy transition to low- to zero-carbon solutions by 2050 is one of the greatest opportunities for innovation we've seen. We need inventors to think differently and at scale to help us take energy forward. +

An installation of fiber and pressure gauges at this well in western Oklahoma led to the discovery of the sealed wellbore technique. (Source: Devon Energy)

Another step closer to real-time hydraulic fracture design

With the commercialization of a sealed wellbore pressure monitoring system, more operators have access to improving the efficiency of their fracture clusters.

Hart Energy Staff

The holy grail of optimizing well completions is the ability to design in real time a hydraulic fracturing operation. Slowly fading are the days of "pump and pray," replaced in part by the technological leaps made in the collection and analysis of millions of datapoints. With these datapoints, it is now possible to recreate the subsurface to better visualize the movement of fluid, the length of fractures and more.

With the commercialization of sealed wellbore pressure monitoring (SWPM), completions engineers can monitor fracture growth and the fluid volumes between treated wells by tracking the pressure response in a nonperforated wellbore. As fractures approach the sealed wellbore, a pressure response is generated. Engineers are able to use the response to determine fluid volumes quickly using pressure gauges mounted at the surface.

One way to visualize it is to think of a balloon animal.

"When we began cross-plotting and overlaying different monitoring techniques, we overlaid the sealed wellbore pressures from the downhole gauges within the strain data. That was really the 'aha' moment."

–Kyle Haustveit, Devon Energy

"Take the balloon and curl it 90 degrees, so it looks like a horizontal wellbore," explained Kyle Haustveit, a senior completions engineer with Devon Energy. "When you squeeze the base of that balloon, you see the upper half expand. So if you had a pressure gauge at the end of that balloon, you'd see a pressure increase. The squeezing is the same force that a fracture from an offset wellbore applies to the sealed wellbore when it intersects the wellbore. That pressure response we see, when squeezing the balloon, is the same that our transducer sees on the wellhead when we have a fracture intersection from an offset or more than one offset wellbore."

The sealed wellbore, in a way, is working as an antenna to transmit the pressure response to the surface.

"The small squeeze of probably less than a few centimeters of the casing string creates the pressure signal," Haustveit said. "We amplify the pressure signal by having the sealed wellbore full of fluid, normally whatever drilling leaves in the hole, some type of freshwater or brine."

E&P Plus recently talked with Haustveit as well as Trey Lowe, vice president of technology with Devon Energy, and Ryan Guest, director of services with Well Data Labs about the development of the SWPM and its uses at the well site.

E&P Plus: Explain how the Well Data Labs system works.

Guest: Our role really spans the whole process for operators that are looking to use this technique. We'll meet with them and their associated service companies to review all the details that are required for an optimal SWPM set up, and how to do that in relation to their treatment wells, given what they're looking to learn, whether they're trying to understand how best to do their stage spacing and their well spacing, depending on what kind of hypothesis they're looking at.

After that, we'll ingest all the data and use our proprietary algorithms and machine learning to provide some detailed visualizations and analysis with regard to cluster efficiency and fracture geometry. And we'll have our in-house completions experts provide interpretation so that it will help to guide their operators with that information on what to do with the rest of that pad within a formation. And lastly, we'll provide all of that information back to the operators in the Well Data Labs app, as well as in Spotfire, so they can manipulate and analyze as they see fit.

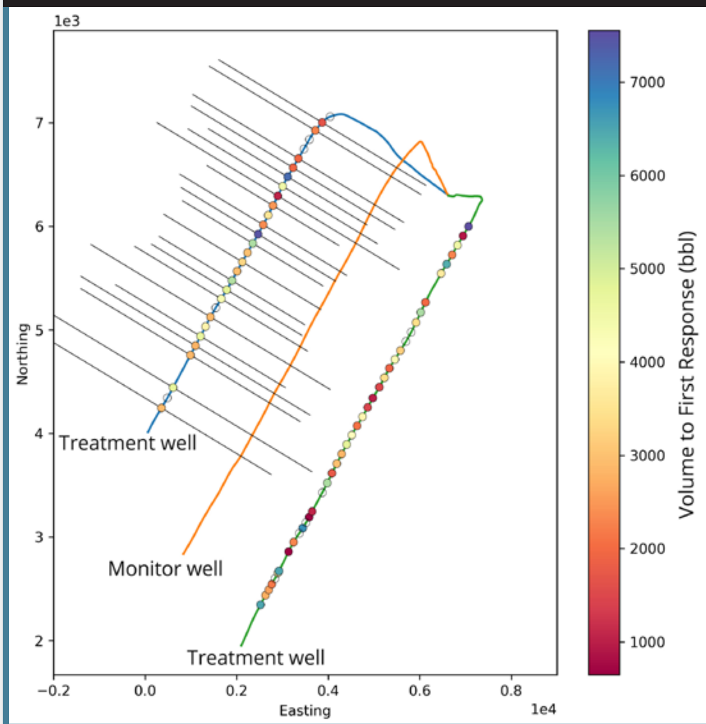
E&P Plus: Where did this idea come from?

Haustveit: The birth of the sealed wellbore took a while, and it occurred in 2008. We had a large integrated diagnostic in the STACK. The diagnostics included downhole pressure gauges and permanently installed fiber-optic cable. We had six down-pressure gauges at three locations along the lateral to toe at the midsection, not the heel. At each location, we had one gauge that was ported to the inside of the casing and one ported to the outside measuring the reservoir side. We completed our fiber-optic loads last in most cases so that we can use the fiber to monitor cross-well strain. Cross-well strain is much clearer when the wellbore is uncompleted and not perforated. We watched the external gauges and we watched the strain, and we didn't see a strong relationship between when pressure would respond on the external gauges and when strain would arrive.

It was probably a month after we completed the project that Wolfgang Deeg [completion engineering adviser] first recognized and documented these pressure responses from the gauge inside the pipe. And it's important to note that the toe sleeve wasn't open; there were no perforations. He was recording these pressures from the permanent downhole gauges while the wellbore was sealed. They were less than 10 psi, normally between 1 and 2 psi responses.

The team chalked it up as an interesting observation that we really didn't know what it meant at the time. And it took another month or two before we came back to the strain. It was the first time that we had collected cross-well strain on one of our wells. When we began cross-plotting and overlaying different monitoring techniques, we overlaid the sealed wellbore pressures from the downhole gauges within the strain data. That was really the 'aha' moment.

SWPM Overhead Fracture Plot



The image shows a project involving one sealed wellbore and two treatment wells. Each of the colored dots on the treatment wells represents a stage and the corresponding volume to first response. The treatment well on the left has fracture lengths plotted, which were calculated based on data received from the gauges on the sealed wellbore and plugged into proprietary algorithms. (Source: Well Data Labs)

"Now we're talking about measuring fractured geometry, not with million-dollar numbers, but now we're in the tens of thousands of dollars–so, orders of magnitude cheaper."

–Trey Lowe, Devon Energy

"There is a thorough review and quality control process for the data we ingest. If any issues are identified, we'll work with the operator up front to make sure that we fix those."

–Ryan Guest, Well Data Labs

E&P Plus: How is this option different from other options that are available?

Lowe: The first time that we started rolling, we really got serious about trying to understand the geometry of the fractures. I was actually an engineer at the time, and it was almost eight years ago. We spent almost a year and over $2 million installing fiber optics to listen acoustically to fractures. And since that time, we've continued to try to improve upon that, and we've used strain measurements. We've driven the cost down from $2 million now approaching $1 million, and what the team has discovered and basically invented through all of those processes is sealed wellbores. Now we're talking about measuring fractured geometry, not with million-dollar numbers, but now we're in the tens of thousands of dollars–so, orders of magnitude cheaper.

E&P Plus: How are the data and pressure readings used?

Guest: The data and pressure readings are run through our machine learning platform and algorithms, and that provides an understanding of fracture geometry and response volumes. It's then used to gain information and test hypotheses on a pad in a formation, and it can help to inform optimal well spacing, whether wells with fewer stages will perform as efficiently as those with more. And it can predict how long fractures will remain open and help to mitigate depletion issues.

E&P Plus: Do you need the datapoints to be cleaned or quality control-checked before your analysis?

Guest: There is a thorough review and quality control process for the data we ingest. If any issues are identified, we'll work with the operator up front to make sure that we fix those. Among the most critical steps is ensuring that we have accurate time synchronization of the various gauges, because you'll have some that are on the monitor well, as well as gauges that are monitoring the treatment wells themselves. We want to make sure that that's synched up, and we want to make sure that the frac parameters are clear and set and that we're selecting the appropriate smoothing method.

E&P Plus: What made this technology possible now versus before?

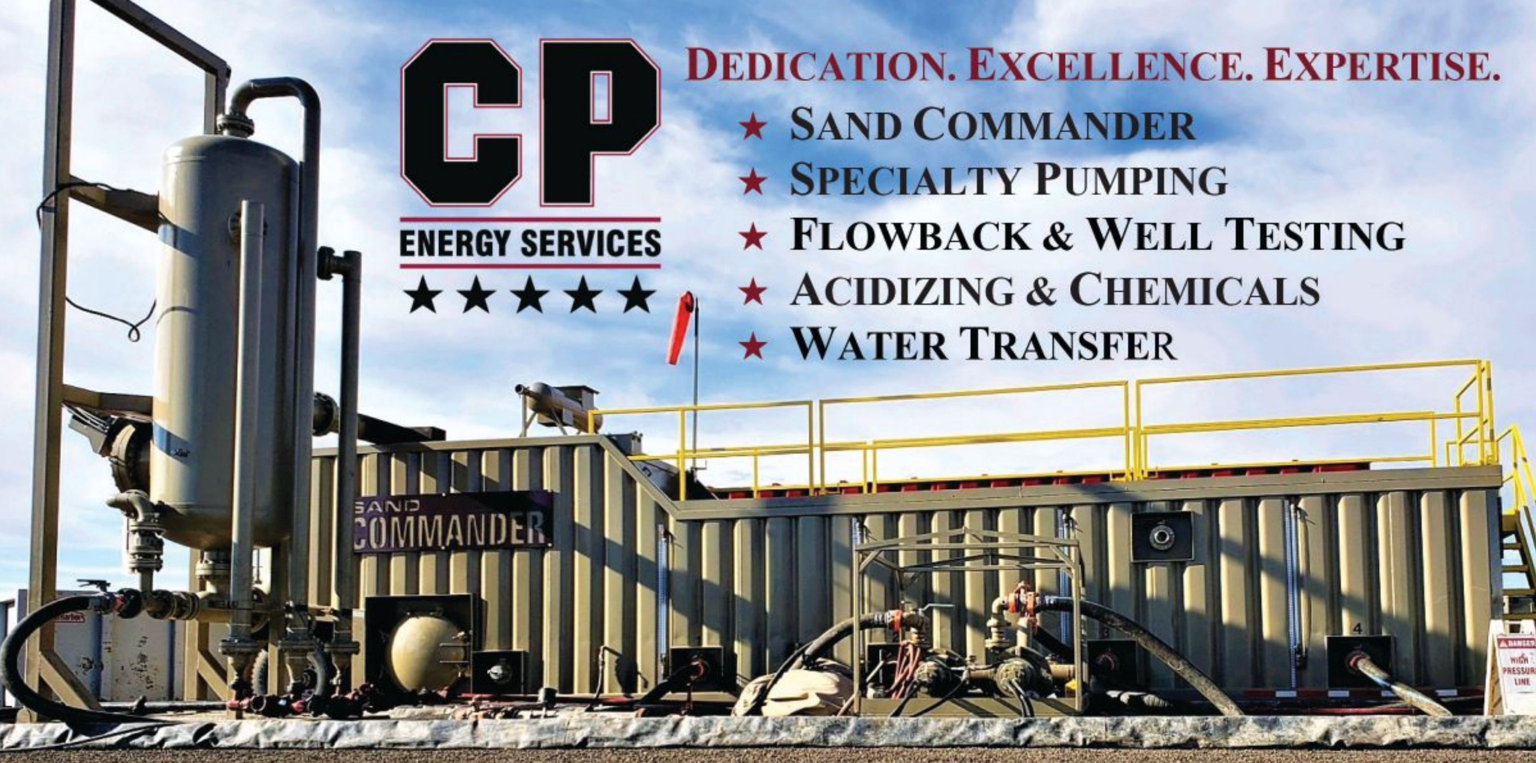
Lowe: Devon has invested heavily in the tools and the processes that speed up the analysis described. When you marry that investment with tools, the engineering talent and the discoveries, they seem to be coming much faster than we've seen before. Specifically, several years ago we decided as a company that we were going to collect and stream all of our frac data from our well sites into our own proprietary systems. That forced us to build out the tools and the processes to have good quality data that we could do analysis around.

E&P Plus: Is there a recommended ratio between monitor wells and producing wells?

Haustveit: One monitor can monitor multiple offset wells, but to the number, the more we can get, the better. But it's really based on the goal of the project. If it's to be focused on a depleted area, and you're trying to understand the asymmetry, you may only need one monitor well. If you're trying to understand the impacts of vertical staggering and multi-vendor developments, it's best to have a monitor in one or more benches to understand height from a treatment well up or down into a different bench. So it's tough to put a single ratio on it.

E&P Plus: What further improvements or refinements are planned or in process?

Haustveit: The next big advancement operationally is using a zipper operation, using two wells and creating a sealed wellbore in each well as we zipper by, either setting a different type of plug or ball in place, which we normally do to set a plug, [and] we have our frac ball on top of the plug. We can pressure up on it and then create a sealed wellbore above that plug. That's going to be a big step forward because it's going to open the door for a lot more monitoring. +



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ESG takes root

(Source: bookzv/Shutterstock.com; design by Alexa Sanders/Hart Energy)

There's little doubt sustainability will be part of doing business in oil and gas fields going forward. Now, how do companies go about quantifying their efforts?

***Len Vermillion**, Editorial Director*

Riddle us this: what comes first, the E, the S or the G?

The answer of course is the E. Wait, maybe it's the S. It might just be the G when you really think about it.

Precisely.

No one agrees as to how one leads to the others, but everyone agrees the three common factors of measuring sustainability—environmental impact, social responsibility and corporate governance—are sure to be part of doing business this year, next year and beyond.

But that's only if you want investors to like you, customers to choose you, other companies to work with you, and politicians to, well, leave you alone.

Just kidding, we know that last one will never happen.

But ESG *is* happening. Have you listened to an oil and gas company's earnings call lately? ESG reporting has moved from an afterthought at the end to a highlight at the beginning. Companies large and small—operators and service providers—are releasing separate sustainability reports in more frequency.

All kidding aside, it is important to focus on all three of the aspects because there is no one answer or method to getting there. At this point, there is not any consensus on ratings or defined measurements. It all depends on whom you are talking to in the moment.

"First of all, there tends to be a very strong focus on 'E,' which is obviously critical for all of us. But we shouldn't forget the 'S' and 'G' as well," said Kristian Johansen, CEO of TGS, in a recent interview for Hart Energy's Path Forward video series. "I think while cohesive ways to measure and achieve net zero targets remain a work in progress, it's easy to focus on the environmental questions and forget the industry has made strong contributions to the social and governance areas."

Johansen pointed out that corporate social responsibility and corporate governance initiatives are key drivers to enabling the industry to eventually reach net zero targets.

"Expanding access to affordable energy is one of the key drivers to increasing the standard of living across the globe," he continued. "The oil and gas industry continues to help people move out of poverty and expand the health and life expectancy in the developing world."

The point being that getting there (sustainability) means traveling a long and winding road that contributes to meaningful progress. While it is a road the oil and gas industry has already been on, there are still many more miles to travel.

In this exclusive video interview with Hart Energy's Len Vermillion, TGS CEO Kristian Johansen discusses ESG, service contracts, R&D and more. The industry veteran says we shouldn't forget the oil and gas sector's contribution to striving toward net zero emissions.

Technology companies will be relied upon more and more to aid E&Ps with getting the message out about the industry's ESG efforts. (Source: Liberty Oilfield Services)

"One of my biggest issues with ESG right now, and this will get better with time, is that it's just so compartmentalized," said Chris Wright, CEO of Liberty Oilfield Services. "To me, every human activity has impacts, pluses and minuses. We're in this industry because we love the holistic impact of our industry on people's lives around the world.

"Do we have negative impacts on the environment? Of course. Do we have positive impacts on human lives and the environment? Absolutely. In fact, they're much larger," he continued. "It doesn't mean we shouldn't try to shrink the negatives, but I want to shrink the negatives and grow the positives."

In short, CEOs in the industry expressed a bit of frustration with the way the industry gets portrayed to the public and investors when it comes to the environment, especially when efforts focus around satisfying talking points versus a holistic approach to progress.

"We don't want to feel good and have buzzwords; we want to quantify what's important, what we are actually doing and what the real numbers are."

–Chris Wright,
Liberty Oilfield Services

Wright has told legislators as much directly.

"I testified at the U.S. House Climate Committee and one of my points was if your goal is to lower greenhouse-gas emissions–and in my mind particulate matter is the giant pollutant that really impacts people's lives today–you [can't] make this guideline so stringent. In the United States or in Colorado or anywhere you're actually more likely to increase global emissions than to shrink them," he said.

Why?

"You're not changing demand; you're just moving production clean, tight environmental standards areas to lower environmental standards areas," Wright added.

If you read between those lines, oil and gas production would not only increase in places like Russia, Brazil and Mexico, but also Iran and North Africa.

They won't know what you can't show them

Whether you're talking about the public, politicians or–gasp–investors, ESG is ultimately about being able to show your value in the future. That future is most certainly to include growing voices on climate change from inside and outside of the investment community.

For operators, especially large public ones, there is no choice but to tell their ESG story. For private independents, the timing may have been a little slower but private-equity funds are increasingly bound by ESG requirements.

Are those messages getting out from the oil and gas industry?

"No, and that's frustrating to me," Wright lamented. "What is ESG is mostly brought from outside of our industry. They say, 'You have to show us how you are reducing your greenhouse-gas emissions.' If we let it be defined by people who don't appreciate the broader impact of our industry, you end up going down a path that isn't necessarily the best path."

Companies such as Liberty, TGS and others, even in the service sector, will need to begin to define that holistic approach to ESG as far as the oil patch in concerned.

Wright said Liberty will produce its first full ESG report later this year.

"It's going to be to try to lay out the positives that we want to grow, the negatives we want to shrink and quantifications of both of them," he said.

Quantifying results, in the absence of a pure ratings systems, is among the strongest paths forward. Perhaps that means putting some technical evidence in front of people versus satisfying buzzwords.

"We don't want to feel good and have buzzwords; we want to quantify what's important, what we are actually doing and what the real numbers are," Wright said. "That has actually gotten a huge amount of interest from investors, from customers. It's sort of opened people's eyes."

As an example, Wright said Liberty's report will show emissions from its average horsepower-hour of frac pumping. It will show the trend in Liberty's history of nitrogen oxide emissions, carbon monoxide emissions and greenhouse-gas emissions.

"Too often when people say emissions or pollutants, they only talk about greenhouse gases. They're real, but in the short term, they're actually not the most concerning emissions," Wright said.

How the service sector is a big part of the ESG story

The oil and gas service sector may be down right now, but it's not out. In fact, there may be opportunity for the sector's survivors when the COVID-19 pandemic passes and oil and gas demand increase again.

That's because operations and production technology of all types will play a vital role in not only reducing emissions from oil fields but also in monitoring and recording the data.

"We're working on developing new technologies for being more efficient in our processes and imaging, for example," said TGS' Johansen of the seismic company's efforts to help operators be more efficient and improve emissions reductions.

TGS is also an asset-light company so it must ensure its own vendors are paying attention to ESG requirements in the future.

"We don't have our own vessels or trucks. We're a big investor in seismic data projects, meaning indirectly we obviously have a significant carbon footprint through our suppliers," he said.

Johansen said life as a service provider means straddling both sides of the fence.

"Typically, the operator would put a [ESG] requirement on TGS to acquire seismic on their behalf and then we'd put that same requirement on our suppliers. We're all in the same boat," he added.

In this exclusive roundtable video, hosted by Hart Energy's Len Vermillion and Jessica Morales, panelists discussed the oil and gas industry's position on ESG: what work has been done, how we advance the dialogue to get industry companies on the same page and if we are taking advantage of the opportunity to spread a better message to investors and the public. Hear insights from Wil VanLoh, founder and CEO of Quantum Energy Partners; Pam Lacey, chief regulatory counsel with the American Gas Association; and John Ale, retired senior vice president and general counsel with Southwestern Energy.

Sand Commander separates all hazardous material, captures 99% of harmful gases, recycles water for reuse on location and extracts 95% of the sand. (Source: CP Energy Services)

Johansen said the requirements have been included to a larger degree in service contracts over the past "probably year, year and a half." He said entering into a contract today with a supermajor means dealing with tougher requirements in terms of due diligence.

"You need to have a track record. You need to show you can trust your suppliers," he said. "This is getting more important."

ESG and R&D: it's a new way of innovating

While greenhouse-gas emissions have caught the eye of many today, ESG trends in the oil field also affect the ground, in particular water.

That has left technology providers to put their thoughts toward solving more traditional drilling issues along with potential ESG issues.

"As we set out to try to design a high-value solution for flowback operations, we were having discussions with field superintendents and engineers on what problems they were experiencing that were not being solved by the current mix," recalled Tracy Turner, CEO of CP Energy Services. "Two themes kept coming back, particularly in the high-volume, high-pressure areas of South Texas, North Dakota and the Delaware Basin. Those two problems were getting a lot of associated gas back and a lot of near-perforation proppant."

In the process of solving those problems, Turner said the company saw another obvious issue that would become more important.

"Within our solution for the sand and gas, we wanted to build something that also cleans and filtrated the water, allowing it for reuse," he said. "We strongly felt water was going to be a bigger and bigger issue in all of these basins."

The result was the Sand Commander, which Turner said has become part of the standard operating procedure for some international majors because "we truly capture 99.9% of the gas. It takes out 95% of the sand, and the sand that comes out is dry and hydrocarbon mitigated enough that you can take it to a regular landfill. As important, with our continuous circulation we have been able to make the

The Sand Commander was designed by CP Energy Services to address both flowback issues and water reuse in one unit. Watch this clip to learn more. (Source: CP Energy Services)

water pure enough that it can be either taken downhole or stored for other workover operations.

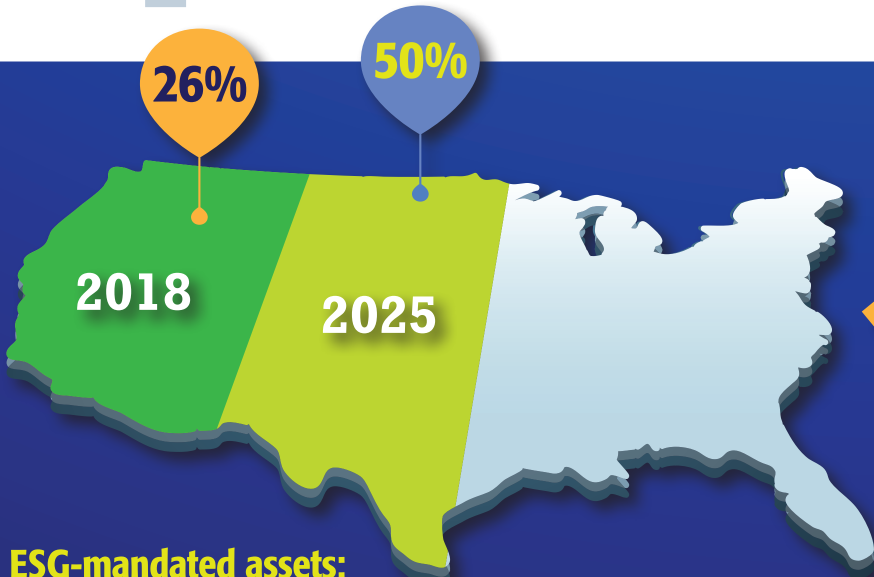
"We think we have hit most of the components of ESG by capturing all of the associated reservoir gas and clearing the water so it can be used again," Turner continued. "The important part of us capturing the gas is it allows us to provide the E&P companies alternatives to what to do with the gas and, so far, our options are we can reinject it back downhole for artificial lift, something done quite actively in the Middle East, and we can wheel it to a generator that can power an electric motor."

While R&D is sure to adjust with the growing focus on ESG, technology companies will be relied upon more and more to aid E&Ps with getting the message out about the industry's efforts. +

Editor's note: *More information and quotes on this subject can be found in the "Scribbles and Sources Notebook" on the Hart Energy LinkedIn page.*

By the Numbers

Carbon emissions and ESG



The amount of CO_2 emissions from all U.S. energy sources has declined by 14% since 2010.

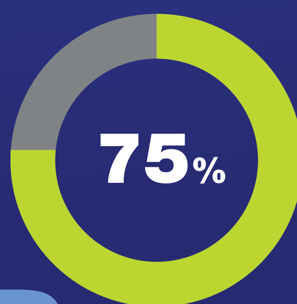
ESG-mandated assets:

In 2018 ESG-mandated assets made up 26% ($12 trillion) of all managed assets in the U.S. It is projected to be 50% ($34.5 trillion) in 2025.

The amount of CO_2 emissions per capita in the U.S. has declined from 17.3 tCO_2 to 15 tCO_2 since 2010.

Total U.S. renewable energy consumption has increased by 56.3% since 2010.

Fossil fuels were the source of 75% of total U.S. human-caused greenhouse-gas emissions in 2018.



46% of U.S. energy-related CO_2 emissions came from burning petroleum fuels in 2019.

59% of energy and industrial sector executives identified digital technologies that improve energy efficiency as a technology priority for a low-carbon future.

Carbon emissions from U.S. fossil fuel and cement production has declined by 9.7% since 2000.

(Source: U.S. Energy Information Administration, International Energy Agency and Deloitte Insights; data compiled by Brian Walzel; design by Melissa Ritchie)

Siemens Energy's AM workshop at its industrial plant in Finspång, Sweden, was the first facility in Sweden—and within Siemens—for global development, manufacture and repair of metal components using AM technology, which is commonly known as 3D printing. (Source: Siemens Energy)

The future of additive manufacturing

The Siemens Energy AM Monitor's machine learning algorithms impartially evaluate the recoating during the printing of a 3D-printed component.

Ariana Hurtado, Senior Managing Editor

Additive manufacturing (AM) involves the technologies that build 3D objects by adding layer upon layer of material (e.g., plastic, metal or concrete), and the process involves making objects from 3D model data.

In this exclusive Q&A with E&P Plus, Andreas Graichen, group manager for digitalization and industrialization of additive manufacturing with Siemens Energy, discusses the Siemens AM Monitor—a 2020 Offshore Technology Conference Spotlight on New Technology award winner.

E&P Plus: What is the Siemens Energy AM Monitor?

Graichen: Thanks to the development teams in Munich and Finspång, the Siemens Energy AM Monitor was created to answer the industry need to quickly identify defects in the powder beds used in the AM process, known more commonly as 3D printing. The quality of the powder beds, and indirectly, the components produced by AM, is critical but has been inconsistent. This is particularly true of components with complex geometries.

The AM Monitor is artificial intelligence [AI]-enabled technology that provides a fast, impartial and precise assessment of the quality of a powder bed in the selective laser melting process and gives an indication of the quality of the 3D printed part. In just seconds, the AM Monitor reviews the thousands of digital photos taken as the 3D-printed parts are made, layer by layer, to identify deposition flaws. We jokingly refer to this technology as 'poor man's computer tomography.'

We built the tool to compare a real powder layer against an ideal, perfect 'master layer'—a photo of a high-quality deposition job. Each layer is assigned a severity score between 0 and 1, which is an assessment of the probability of an issue. A value closer to one means a higher risk of a quality problem. If the severity score falls outside preset quality limits, then the part is either scrapped, repaired or deemed fit for use as is. This provides a fast and precise assessment of the part's quality—well before it is sent to the field.

E&P Plus: How is it different from other options available?

Graichen: The standard practice for evaluating part quality calls for a human inspector to carefully evaluate the pictures of each layer and look for defects. Not surprisingly, this is a time-consuming and tedious practice that produces questionable results due to human error and fatigue.

Compared to the human eye, AM Monitor's use of AI delivers far greater precision and speed while assessing print quality. A photo-by-photo evaluation that might take a human worker a day or more is completed in seconds [with AM Monitor].

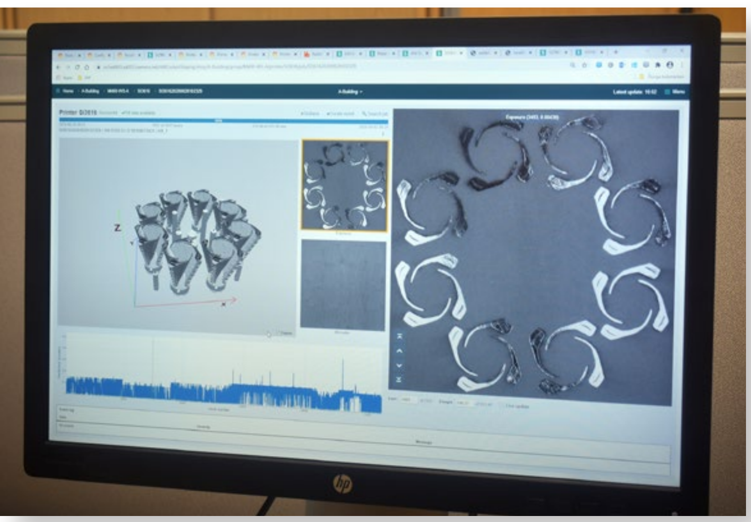
Also, the severity score, which can be considered a digital fingerprint of each print job, is an artificial but reliable overall quality indicator of the process quality. This feature is only available with the Siemens Energy AM Monitor.

Once the visual inspection using the Siemens Energy AM Monitor has become standard practice in the oil and gas industry, other nondestructive testing methods like surface crack detection, X-ray or ultrasonic testing might be phased out for cost reasons.

E&P Plus: With the current focus on doing more with less and making advances on operations with new technologies, what role does the AM Monitor perform?

Graichen: There is certainly a push for higher speed and certainty in oilfield processes, and manufacturing is no exception. With AM Monitor's automated quality assurance [QA] based on cloud-based analytics, we believe that this tool will give operators greater confidence to use 3D-printed parts in more applications. In fact, we're already using the AM Monitor in our AM workshop in Finspång, Sweden, where we've connected more than 10 AM machines. It's also being scheduled for our Berlin, Germany, facility.

We also expect that as confidence in AM quality grows, equipment manufacturers and operators will build more geometrically complex parts, including thin-walled tubing and lattice structures, with AM. Components like these have proven impossible or too expensive for conventional manufacturing techniques.



AM will likely become more popular as systems like the Siemens Energy AM Monitor confirm component quality, backed by a well-documented analysis that is free of human error. (Source: Siemens Energy)

"AM Monitor brings Siemens Energy closer to our goal of making 3D printing on metal as seamless and effortless as printing on paper. Today we are focusing AM Monitor on recoating quality."

– Andreas Graichen, Siemens Energy

E&P Plus: What do you see as the next area of progress in the digital monitoring space?

Graichen: We predict that as AM Monitor keeps bringing structured QA to AM, a demand for 'printing on location' services will open up. AM could be used to reliably and efficiently make a range of niche, bespoke devices when and where they are needed. This promises to streamline the supply chain–shortening delivery times and lowering transportation costs–by manufacturing and evaluating high-quality spare parts at the well site. In the industry, this concept is called digital warehousing.

E&P Plus: Is there anything else you'd like to share about this technology or future projects related to the AM Monitor?

Graichen: AM Monitor brings Siemens Energy closer to our goal of making 3D printing on metal as seamless and effortless as printing on paper. Today we are focusing AM Monitor on recoating quality. In the future, we will see further technical development where thermal reflection, meltpool behavior, acoustic responses and other metrics might be considered–allowing quality issues to be prevented with much higher confidence.

Ultimately, AM will likely become a more popular manufacturing method as systems like the Siemens Energy AM Monitor confirm the quality of the delivered components, backed by a well-documented analysis that is free of human error. +

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Looking ahead to a post-pandemic gas market

Although some demand may be permanently lost, the gas market is still expected to follow a growth path.

Kristy Kramer, Wood Mackenzie

As the world grapples with the dreadful human cost of COVID-19, the global economy is also coming to terms with the scale of the pandemic. While the impact on oil markets was swift and dramatic, the gas and LNG sectors have also been hit hard by coronavirus.

Even before the coronavirus pandemic, oil price crash and ensuing economic upheaval, 2020 was already shaping up to be one of oversupply for global gas markets. Last year was a record year for new capacity additions, with nearly 40 MMtonnes of supply added in 2019—supply that was poised to put downward pressure on prices in 2020.

The events of early 2020 are impacting the gas market this year. The impact on gas demand was immediate as countries around the world went into lockdown. However, as restrictions loosen, demand is already showing signs of recovery.

Demand growth continues in the face of the energy transition as companies and governments alike focus on reducing emissions.

The macroeconomic environment will continue to shape the trajectory of gas demand. If containment measures prove to be successful and the economy has a sharp recovery through the second half of 2020, demand will be resilient. While some demand is forever lost in 2020, global gas demand will follow a parallel growth path to the pre-coronavirus view. High growth markets recover more quickly than established markets where demand losses, particularly in the industrial sector, will be structural.

LNG

LNG demand is even more resilient through this period. Prolonged low prices allow LNG to outcompete more expensive pipeline contracts in growing markets like China, where the reduction to the LNG import forecast only reflects one-third of the reduction to the gas demand forecast through the early 2020s.

But the events of 2020 will have a longer-lasting impact to supply. LNG projects under construction are suffering up to 12-month coronavirus-related construction delays, which reduce the supply compared to the pre-coronavirus view by 10 MMtonnes per annum (mtpa) in 2025.

Furthermore, the current economic environment has halted supply-side investments. With long development times, decisions not to spend in the upstream over the coming months will impact supply for the coming years. Compared to the pre-coronavirus view, supply from existing LNG facilities is reduced by about 5 mtpa through 2024 due to reduced or deferred upstream investment.

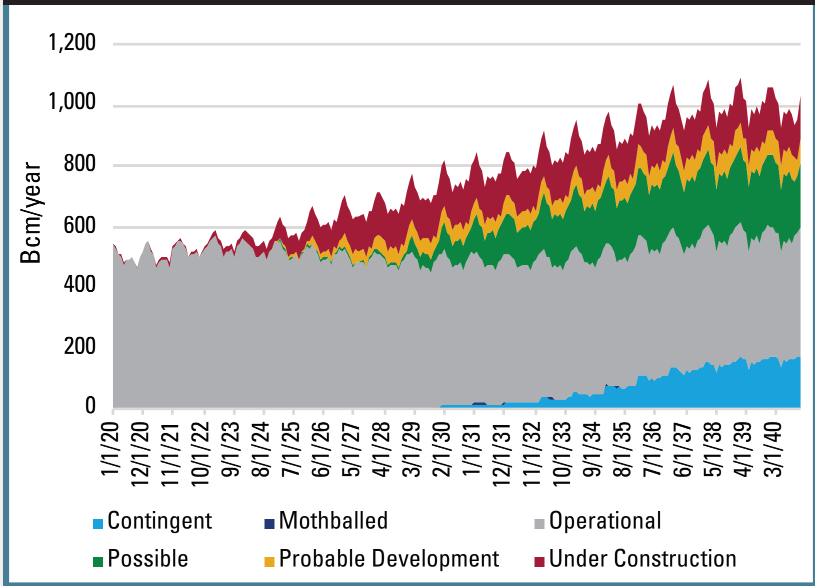
The investment discipline theme transcends the industry as corporate producers across the globe—including in short-cycle unconventionals—will approach a recovering market with caution by spending less, even when presented with the same economic incentives. On 15% rate of return opportunities, Wood Mackenzie estimates U.S. producers are generally drilling 6% fewer wells than they would have last year.

With the final investment decision (FID) momentum from 2019 now all but lost, Wood Mackenzie's view is that near-term LNG FIDs will be limited to strategic decisions made by the lowest-cost resource holders and smaller projects, which are already advanced in contract negotiations.

Wood Mackenzie expects Qatar to invest through the cycle, bringing on four megatrains (32 mtpa) starting in 2025. Based on contracting progress and commercial momentum, Wood Mackenzie expects FIDs over the next two years at Costa Azul, Corpus Christi Stage 3, Woodfibre and Obskiy LNG, adding 13 mtpa by 2027. Wood Mackenzie also expects continued investment upstream to backfill major facilities in Australia and Malaysia.

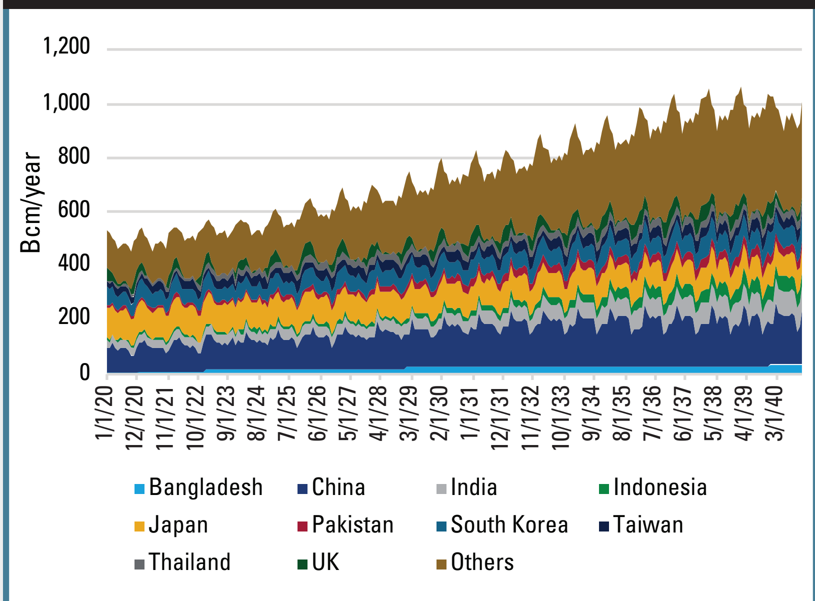
While strategic investments like Qatar's North Field expansion adds a large volume to the market, they only defer the need for new supply development and do not eliminate it completely. Wood Mackenzie forecasts a growing gap between LNG demand and supply by 2030.

LNG Supply by Development Status



(Source: Wood Mackenzie – Global Gas Model – Next Generation)

Top 10 LNG Importing Markets (+Others)



(Source: Wood Mackenzie – Global Gas Model – Next Generation)

Using Wood Mackenzie's Global Gas Model Next Generation, it forecasts further probable and possible pre-FID supply is needed to meet this growing demand. Combining Wood Mackenzie's commercial intelligence, cost of supply analysis and model optimization, it determined the new supplies are needed from low-cost West African projects in 2028; U.S. expansion trains, Mozambique and PNG are needed in 2029; and major new projects in Qatar and the U.S. are needed in 2030.

Energy transition

Demand growth continues in the face of the energy transition as companies and governments alike focus on reducing emissions. Through the 2020s, gas and LNG demand growth continues as gas substitutes for higher emitting fuels, namely coal, in the power and industrial sectors around the world.

However, this trend does not continue through the 2030s. Gas demand in these markets will reach its peak and begin to decline as zero emission technologies displace gas.

In developing markets, though, gas demand will continue to increase as total energy demand increases. And when this increase in gas demand is combined with declining domestic production and regional pipeline imports, demand for LNG imports in South and Southeast Asia will grow even faster—with emerging markets jumping to the top importers list.

A key risk to this view is related to the potential for a second coronavirus outbreak and therefore the pace of economic and gas demand recovery. Wood Mackenzie's view is predicated upon the effectiveness of current containment measures and ensuing economic and demand recovery from the second half of 2020.

But Wood Mackenzie acknowledges things could develop differently, providing downside risk to the gas demand view in the medium term.

In the longer term, the forecast becomes increasingly sensitive to the view of the energy transition. Europe's Green Deal policy is the most aggressive in terms of targeting emissions reductions, and other markets could follow with policies of their own as well.

At the same time, companies through the gas value chain, from producers to transporters to consumers, are becoming more conscious of greener alternatives to the traditional way of doing business, often referring to shareholder pressure.

Further policies or changes to corporate strategies could create the way for an accelerated energy transition. A more carbon-conscious world would impact demand as well as supply development and market prices. +

Symphony live downhole reservoir testing is a technology platform that enables operational control of the downhole testing toolstring to deliver real-time downhole measurements. (Source: Schlumberger)

Bringing new levels of flexibility to well testing operations

Live downhole reservoir testing enables dynamic data acquisition in Asia, the Middle East, North Sea and Africa.

***Carlos Merino** and **Bryan Zimdars**, Schlumberger*

Dynamic reservoir data are a key enabler for oil and gas operators to prove reserves and maximize hydrocarbon recovery. However, traditional well testing approaches, where a job is planned, executed and interpreted in a linear fashion, can limit operators from obtaining the optimal amount of data during the well test. Furthermore, this approach is inefficient and rigid, significantly increasing the time operators spend between acquiring data and making key field development decisions.

For many decades, the linear well testing approach remained unchanged until the introduction of wireless telemetry about 10 years ago. Wireless telemetry enables acoustic data to be transmitted across downhole repeaters from the downhole gauges to surface in real time. Prior to this innovation, the only way to gather real-time data was through a wireline deployment during the drillstem test (DST), which increases risk and cost.

While wireless telemetry, combined with a conventional DST tool string, enabled some data acquisition flexibility for real-time data interpretation, it stopped short of providing operators with the ability to acquire dynamic data for making actionable field development decisions in real time. To achieve this, operators needed a way to enhance the flexibility of well testing operations by increasing the control of the downhole tool string.

To improve performance during well testing operations, Schlumberger has released the Symphony live downhole reservoir testing platform. This platform (Figure 1) enables operators to position, isolate, connect, measure, control, sample, select and profile the reservoir with a digital tool string wirelessly and in real time.

The wireless tools are united via Muzic wireless telemetry, providing bi-directional feedback of tool position for operational control and enhanced capabilities. The digital tool string is customized for the operator's reservoir evaluation objectives.

Advancing reservoir testing flexibility

The live downhole reservoir testing platform delivers the capability to both communicate data and digitally control the tool string in real time, enabling the operator to rapidly adjust operations in response to dynamic conditions and acquire the optimal amount of critical data and the most representative downhole samples from the reservoir test. This enhances safety, reliability and efficiency when compared to traditional well testing methods.

During field tests of the live downhole reservoir testing platform in Asia, the Middle East, North Sea and Africa, the digital tool string was customized for each operator's reservoir objectives. A common thread across each test was a complex reservoir environment. The digital tool string provided the flexibility for the operators to make actionable decisions in their workflows. This enabled them to acquire the dynamic data they needed while overcoming challenges, including, but not limited to, shallow reservoir depths, fluid compressibility issues, low bubble point pressure, crew optimization and rig time reduction.

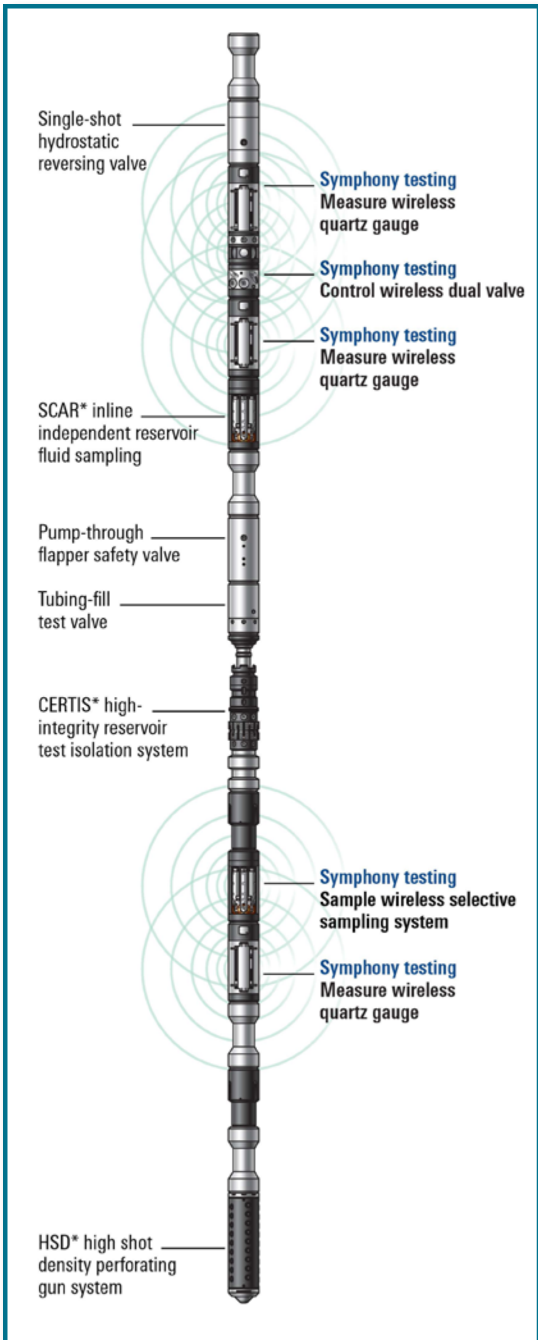


FIGURE 1. The illustration depicts the Symphony testing toolstring. (Source: Schlumberger)

Shallow reservoir test in Asia

In a shallow reservoir in Asia, using the wireless selective electronic firing head, wireless quartz gauges and wireless dual valve enabled a reservoir test in a previously untestable environment. The total reservoir depth was approximately 1,600 m with a water depth of 1,000 m and was prone to sanding, which made conventional DST tools, which rely on high annulus pressure cycling, unfeasible for this application.

The electronic firing head was acoustically initiated in the reservoir, which was already partially pre-perforated, and bi-directional communication provided confirmation of successful initiation of the tubing conveyed perforating guns. The pressure-free signal did not apply stress to the open perforations that prevented the potential of sanding during the reservoir test. By using this technique to fire the guns, the operator avoided an additional run with wireline to perform the perforation, thus saving time and risk of wire inside the DST tool string.

The wireless dual valve incorporated an independently operated test valve and circulation valve providing isolation within the tubing and from tubing to annulus, respectively. Since it did not require pressure pulse for activation, the operating envelope was ideal for a shallow reservoir environment. It provided full well integrity and control throughout the reservoir test.

The wireless quartz gauges provided continuous real-time data, which through digital workflows and connected operations allowed the operator to make informed decisions toward optimization of the reservoir test.

Crew reduction in the Middle East

A Middle East operator utilized a wireless correlation tool to combine workflows during the DST to eliminate the conventional wireless depth correlation for the reservoir test string in a 23-well campaign on a jackup rig.

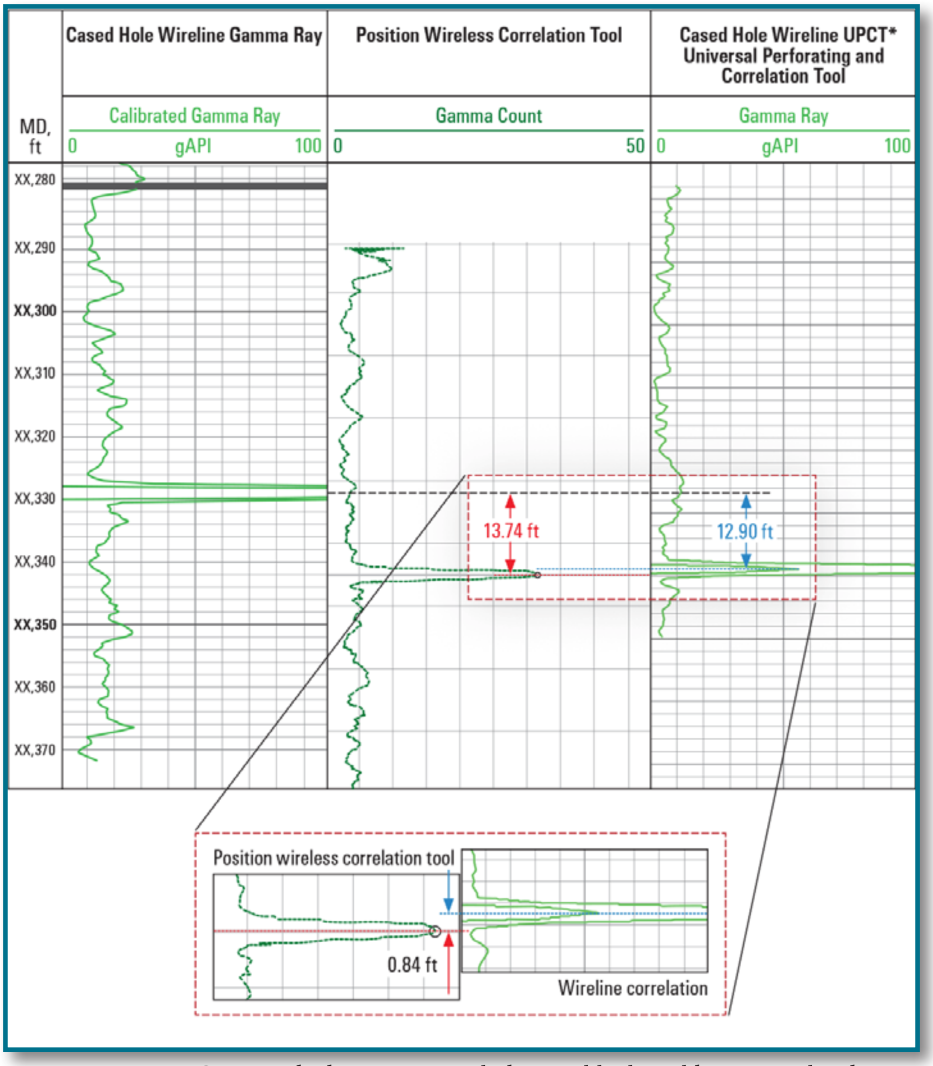


FIGURE 2. The log compares wireless positioning with a conventional wireline cased-hole method. (Source: Schlumberger)

The wireless correlation tool used gamma ray measurement incorporated into the digital tool string and transmitted to surface via the wireless telemetry. The addition of this tool reduced the overall correlation time, reduced the personnel on board by eliminating the three-person wireline crew and avoided running wireline into the tool string, hence decreasing HSE risk.

During the first DST, the operator opted to run both correlation methods to evaluate the use during the rest of the multiwell test campaign. The results shown in Figure 2 proved accurate to the cased-hole correlation within 1 ft, which satisfied the operator's requirements. The entire correlation was completed in 1 to 2 hours, saving approximately 10 hours of rig time per well test operation.

On-demand representative samples in the UK

The main challenge in a U.K. operation was a very low bubble point, which meant that conventional DST samples taken above the well testing packer would not be representative. Therefore, Schlumberger recommended the wireless selective sample system that can be placed below the well testing packer and as close to the formation as possible.

The operator initiated four of the single-phase sample bottles during the cleanup phase as its contingency samples. During the main flow period, the four samplers were initiated on demand from the operator to capture its most representative samples during the flow period. The activation of the wireless sampling system in both cases was confirmed at surface with the bi-directional communication, increasing the operator's confidence in its reservoir test.

Heavy mud wireless control in Gabon

During a barefoot reservoir test in Gabon, an operator was attempting to test in 1.80 g/cm^3 oil base mud. Historically, this can cause a pressure transmissibility issue for conventional and hydraulically operated DST tools. The only option for the operator to perform the test in these well conditions was to use an acoustic operated tool to control the well, transmit data and obtain representative samples. The digital control of the testing tool string, which included wireless dual valve, wireless quartz gauges and wireless selective sample system, allowed the operator to meet its well test objectives in this challenging environment.

Conclusion

By increasing control of the downhole tool string, operators can acquire the dynamic data they need during a well test to make important field development decisions. Live downhole reservoir testing overcomes the limitations of legacy linear well testing approaches and advances the capabilities of the tool string that wireless telemetry alone could not provide. Because of this, operators can achieve greater reservoir insights safer and more efficiently. +

Video

In this exclusive video interview, Paul Madero discusses the importance of technologies.

(Source: Michal Poracky/Shutterstock.com)

Baker Hughes VP of drilling: remote drilling is here to stay

Paul Madero explains why remote and autonomous drilling operations will enable better wells and better production.

***Brian Walzel**, Senior Editor*

Remote and automated drilling capabilities are nothing new for the oil and gas industry. Its roots can be traced back more than 20 years, but adoption has accelerated with the evolution of digital and machine learning technologies throughout the past decade.

Now, with the onset of the COVID-19 pandemic, remote operations are playing an increasingly important role in the industry. In this exclusive video interview with E&P Plus, Paul Madero, vice president of drilling services with Baker Hughes, discusses why these technologies are so important in the oil and gas industry today.

He explains that many wells that have been drilled and completed this year very likely would not have been drilled at all without automated capabilities.

This year, Baker Hughes reported a significant increase in its drilling operations, with more than 70% of them utilizing remote capabilities, up from 50% in 2019. Those operations include achieving new execution milestones such as remotely drilling two miles in a 24-hour period.

Recently, Baker Hughes partnered with Equinor to implement the service company's advanced integrated operations model on another six rigs, reducing field service personnel on the rigs by 50%.

"What our customers have seen is that through this process these capabilities really do drive better outcomes," Madero said. "So we're setting records on wells, whether it be from an ROP standpoint or from a wellbore placement standpoint."

While COVID-19 might have accelerated the adoption of remote and autonomous drilling operations, they are likely here to stay.

"You drill faster wells, and you place them better," Madero said. "So ultimately you're going to end up with the best production profile." +

Drawdown management in unconventional reservoirs

Darryl Tompkins, *Revo Testing Technologies*

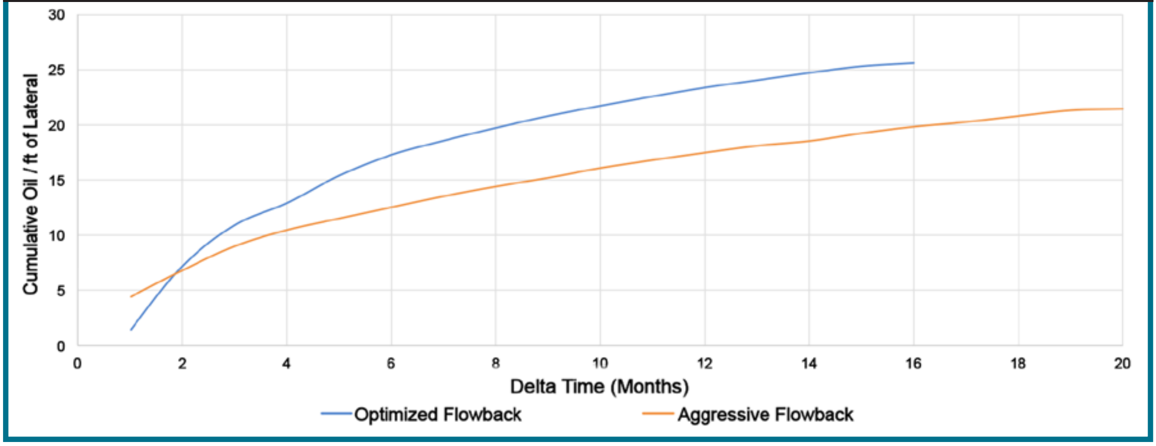
A real-time workflow evaluates flowback data and improves well performance.

Now more than ever, operators are focused on methods of improving well performance to reduce costs and increase production. Much of that improvement is centered on well spacing, completion designs and surface efficiency. Drawdown management during the IP period—or flowback—is an often overlooked means of improving well performance. The data collected during this early-time flowback period offers one of the first glimpses of valuable information that helps to evaluate well performance and reservoir responses.

Many operators tend to either flow wells too aggressively or too conservatively. This approach is often derived from rules of thumb or simplified diagnostics that fail to capture the true effects of drawdown on well performance. A real-time workflow must be used to evaluate flowback data to optimize the drawdown strategy so operators can maximize the production of each well, in the shortest amount of time, all without damaging the reservoir or completion.

(Source: Hart Energy/Shutterstock.com)

Permian Flowback Strategy Comparison



A comparison of cumulative oil production per foot of lateral for two Permian Basin wells landed in the same zone, less than a mile apart, with similar completion design and lateral orientations or no offsets. (Source: Enverus)

Revo Testing Technologies has developed an integrated workflow that has been successfully utilized on more than 500 unconventional wells to optimize drawdown strategies during IP. The workflow incorporates a proppant mobilization model, real-time well performance visualizations and specialized diagnostic techniques. Side-by-side comparisons have been completed in every major unconventional basin. These comparisons were done on optimized wells versus wells that employed aggressive flowbacks—and the wells had similar completion and reservoir parameters. The comparisons have consistently shown Revo's drawdown optimization workflow improves well performance compared to an aggressive flowback strategy.

Generalized workflow

Significant research has been conducted on flowback optimization and diagnostic techniques. Improvements in well performance have been observed in the field when managed pressure drawdown strategies are employed. Many operators utilize additional sand management equipment during flowback to handle high sand volumes believing that high flow rates create better wells. This adds additional costs to handle excessive sand rates at surface, and this approach has been shown to decrease well performance.

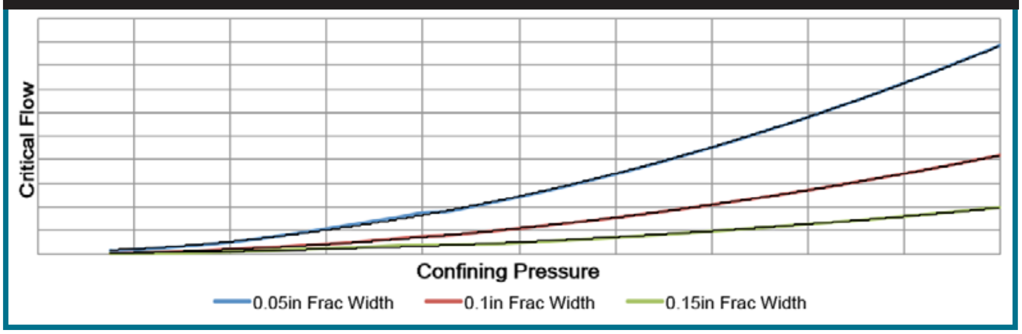
Revo uses an algorithm to calculate the minimum mobilization velocity of proppant in the fractures when confinement stresses are low at the beginning of flowback. This helps determine the initial target rate and choke size so proppant is not washed out of the fractures when the well is first brought online.

As confinement stress increases during IP, and more of the lateral begins to contribute to total flow, the well can then start to be flowed more aggressively. By simply flowing the well a bit more slowly in the beginning, sand volumes and the associated equipment costs to handle these solids can be significantly reduced and well performance can be improved.

Garbage in, garbage out

After the initial flow rate of a well is determined, an initial choke size can be selected to bring the well online without mobilizing proppant from the fractures. Some wells produce

Initial Flow Rate



Models for critical flow velocity needed to mobilize proppant from fractures. (Source: Revo Testing Technologies)

	Revo Transient Analysis			Linear Transient Analysis		
Day	xf	k	Revo iQ	xf	k	xf/√k
1	296	0.04	33.91454	707	0.015	86.59
2	324	0.02	17.22662	707	0.015	86.59
3	333	0.02	17.30826	707	0.015	86.59
5	335	0.02	17.32611	605	0.015	74.10
8	336	0.01	8.667496	525	0.015	64.30
12	343	0.01	8.698218	478	0.015	58.54
17	348	0.01	8.719782	399	0.015	48.87
25	353	0.01	8.741037	281	0.015	34.42

This comparison shows fracture half-length and permeability of linear transient analysis and specialized transient analysis utilized by Revo Testing Technologies. (Source: Revo Testing Technologies)

oil, some produce gas, but all wells produce data, and those data need to be of the highest quality possible to accurately assess well performance in real time and to optimize the drawdown strategy. Once the initial target rate and choke size is established and the well is brought online, the next step is to assess data quality and identify possible measurement errors. Measurement errors cause significant ambiguity in well performance analysis and can mask reservoir responses.

Surface rate measurement errors can be caused by a variety of sources. The most common sources tend to be from poor measurement methods and poorly trained onsite personnel that are not operating the testing equipment correctly. Simply taking manual readings at inconsistent times, from one hour to the next, has been shown to introduce significant noise into the data, making real-time performance evaluations nearly impossible. Revo utilizes the Revo iQ software from the FlowSmart solution set to identify and diagnose surface rate measurement errors. Deploying this software, Revo can assess real-time well performance and help optimize customers' drawdown strategies during flowback.

The Revo iQ software can be used to quickly diagnose surface rate measurement errors and asses real-time well performance using its built-in performance indicators and data visualizations.

Properly assessing well performance during flowback

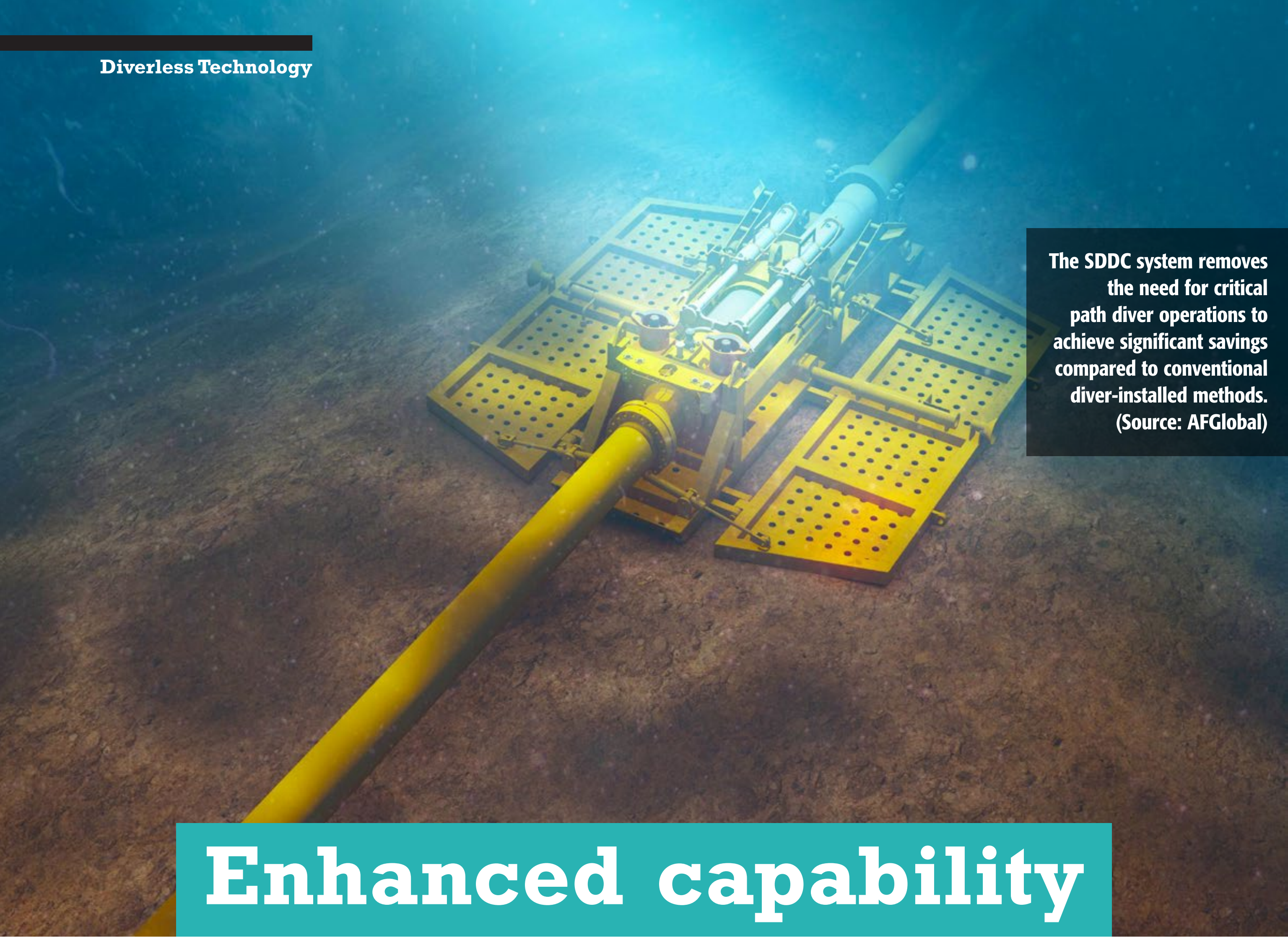
After the initial target rate is determined and data quality has been assessed in the Revo iQ dashboard, real-time diagnostics are used to evaluate well performance. This performance evaluation is based on the drawdown resulting from each choke change. A common misconception in the industry is that flow regimes seen during long-term production—and the associated superposition time functions used to analyze them—are applicable to flowback. After analyzing more than flowbacks, Revo experts do not see evidence to support this notion.

The Revo engineering team utilizes a transient diagnostic analysis method for drawdown optimization that addresses the dynamic multiphase flow conditions that are encountered during flowback. This analysis method allows the Revo team to see the effects that the drawdown strategy has near-wellbore and far field. This allows the drawdown strategy to be adjusted for areas that experience pressure-dependent well performance.

During flowback, the permeability should initially look high as the well is producing primarily from a high permeability proppant pack. Additionally, the fracture surface area available to flow hydrocabons is relatively small because the fractures are full of water, thus the apparent system fracture half-length appears small. As the flowback progresses and the well cleans up, more of the fracture surface area flows hydrocarbons resulting in an increase to the apparent system fracture half-length. At the same time, more of the production is coming from the matrix, so the system permeability decreases. The effect of increasing apparent system fracture half-length—caused by well cleanup and decreasing system permeability from initially producing from a high-permeability proppant pack, and then transitioning to lower permeability matrix—cannot be seen using traditional linear flow diagnostics that are typically applied to long-term production data.

Not only is linear flow not typically seen during flowbacks when chokes are changed frequently (once at least every 48 hours), but because the far-field transmissibility (k) and apparent system fracture half length (xf) are lumped into a single linear flow parameter term, one of them has to be assumed to determine the other. The traditional assumption of constant permeability is not appropriate for capturing the dynamic effect that occurs during flowback. The transient diagnostic method used by Revo determines system permeability and system fracture half-length independent of each other, so the effect of increasing fracture half-length and decreasing permeability during flowback can clearly be seen. Changes in either of these parameters, caused by the drawdown from choke changes, guides operational decisions to improve well performance.

To optimize the drawdown of a well, it is important to first determine the maximum rate the well can be flowed to avoid mobilizing proppant from the fractures. Second, high-quality data are essential, and the data constantly need to be assessed for surface rate measurement errors that can affect the interpretation of real-time well performance. Finally, a diagnostic analysis that can account for the dynamic nature of flow seen during flowback is required to properly evaluate well performance. ✚



The SDDC system removes the need for critical path diver operations to achieve significant savings compared to conventional diver-installed methods. (Source: AFGlobal)

Enhanced capability for single well step-outs and tiebacks

Subsea connection advances facilitate diverless shallow-water tieback.

***Robert McWilliams**, AFGlobal UK*

Novel use of diverless connections in construction of a shallow subsea tieback offshore Malaysia cut costs by approximately 20% while improving safety and reducing the project's carbon footprint. A key project component was a Stinger Deployed Diverless Connector (SDDC) developed in a partnership between AFGlobal and pipeline contractor Cortez Subsea.

Deployed as part of Vestigo Petroleum's Tembikai Non-Associated Gas (TNAG) field development program, the project integrated new and proven technology to connect the pipeline to two flexible risers and to connect pipeline sections without the need for divers and welding. AFGlobal and Cortez Subsea developed the SDDC system to connect the pipeline to the host facility.

The greater Tembikai development comprises a central processing platform connected to a floating storage and offloading vessel via a flexible subsea pipeline. The field development is operated by Petronas Carigali unit Vestigo Petroleum, which awarded the pipeline system contract to Alam Martime in partnership with Cortez Subsea. The recent tieback connected a new wellhead platform to the *Berantai* FPSO and involved laying 36 miles of 12-inch rigid pipeline in approximately 230 ft of water.

Success of the project introduces

The SDDC substantially alters pipelay considerations and economics. It removes the need for critical path diver operations to achieve significant savings compared to conventional diver-installed methods. (Source: AFGlobal)

a cost-effective capability for single well, shallow-water step-outs and tiebacks, and it suggests new capabilities and efficiencies for deepwater applications. The advance is central to industry efforts to develop small and stranded fields. In addition to monetizing and adding value to Malaysian assets, the technology has applications in many other offshore theaters including the larger Asia-Pacific area, West Africa and Egypt.

Tembikai industry firsts

Development of the SDDC system for the Tembikai project is one of two industry firsts that eliminated welded connections and the need for divers. In its initial use, the AFGlobal system joined the pipeline to the host facility by connecting the rigid pipe to flexible risers using an ROV and deployment frame. The pipelay also marked the first subsea use of NOV-Tuboscope's Zap-Lok mechanical connector, a non-welded pipe joining technology, offshore Malaysia.

Development of AFGlobal's SDDC technology was driven by the need for a shallow-water connection between the pipeline and riser that did not require welding or the need for divers as well as the desire to reduce project costs and time. Presented with an imminent project application, the SDDC went from an initial concept to deployment in one year. The fast-paced AFGlobal development process began in April 2019 and included design, fabrication, testing and deployment of two SDDC systems.

The SDDC system is based on AFGlobal's Retlock clamp technology, which has more than 25 years service history with over 1,750 connections made in shallow-water and deepwater applications. Tailoring the technology to the Timbikai tieback involved extensive design and modeling of a landing system made up of guidance equipment and ROV tooling.

The resulting package eliminated riser end terminations and jumper spools, which allowed direct, diverless, weld-free connection of the flexible riser to the pipeline. In reducing time and expense, the system enabled cost-effective use of an ROV in the shallow-water application. Eliminating the need for divers improved project safety, reduced manpower and support requirements, and cut installation time. In addition, the operations required fewer and smaller surface vessels, further reducing the project's cost as well as its carbon footprint.

Evolution of diverless connections

The SDDC technology is the latest advance in diverless connection innovations leading up to the Tembikai project. The Retlock ROV-operated twin-bolt clamp connector at the core of the SDDC system has a decades-long history. It is qualified for applications up to 15,000 psi in water depths up to 10,000 ft and is available in diameters up to 22 inches. Bespoke configurations enable contingency recovery of moving components, and mono- and multibore connection capabilities. The technology is also installable with a pipeline receiver and launcher for commissioning directly after installation.

Developed with inherent design flexibility, the Retlock connection allows a single system to be used across the entire field and installed with the same tooling and work class ROVs for a more cost-effective solution. The diverless clamp is engineered for both conventional and HP/HT developments in shallow-water or deepwater mono- and multibore installations.

In 1994 AFGlobal released the Diverless Maintained Cluster (DMaC) in BP's North Sea Foinhaven Field, and later in the Schiehallion Field. The drag-to-place connection system features flexible, interruptible installation with jumper, tree and manifold that are separately deployed. Designed to operate in extreme environmental conditions, the DMaC enables wet parking of jumpers for later installation. The technology maximizes installation flexibility and over the life of the field with a low field opex.

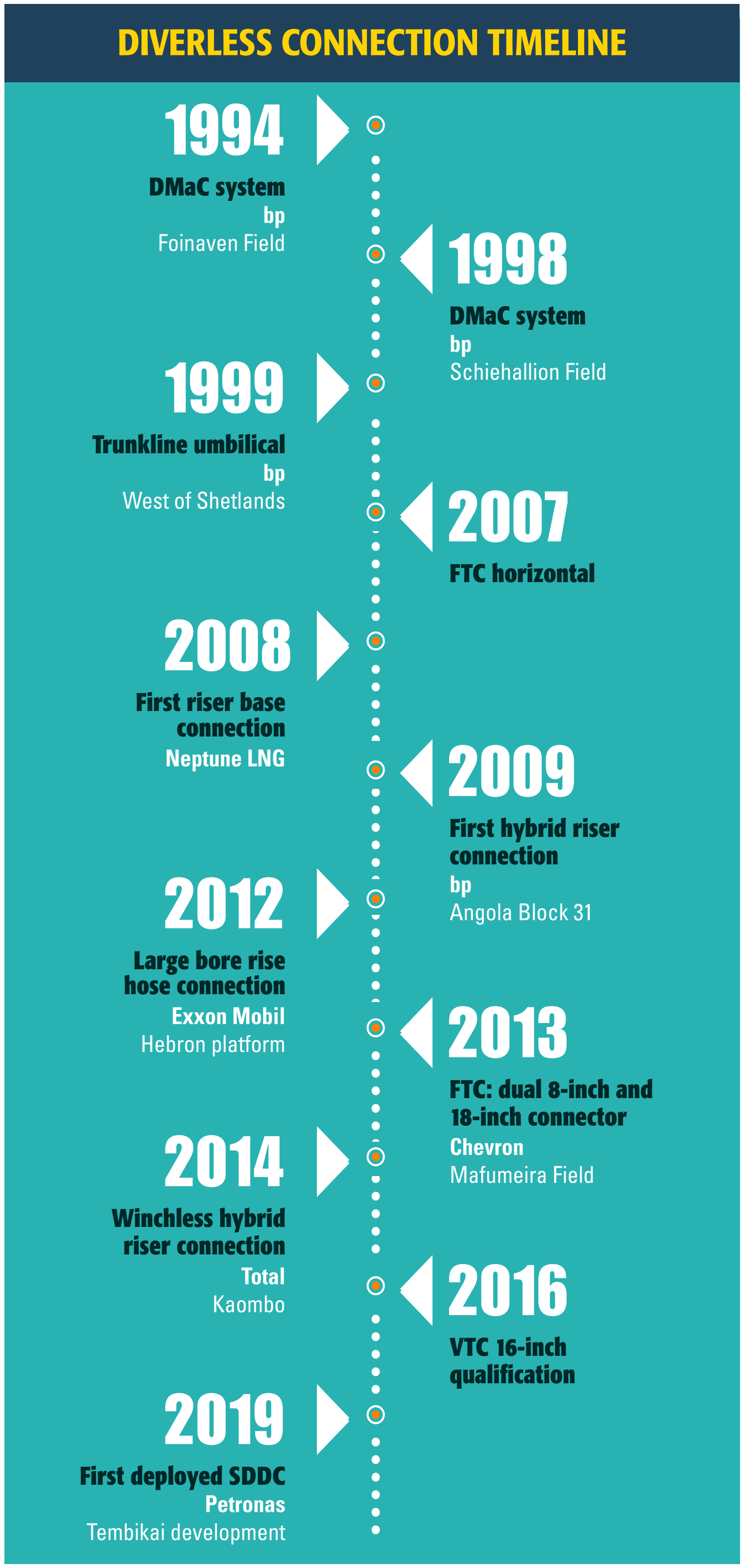
Released in 2013, the Flowline Type Connector (FTC) on Chevron's Mafumeira Field offshore Angola provided a new capability with a reliable, cost-effective and adaptable means of installing and connecting both rigid and flexible horizontal flowline jumpers. The horizontal connection system has guideless installation and provides stab and hinge-over landing ability using a common and retrievable pull-in tool.

Offshore Angola also saw the initial use in 2014 of AFGlobal's Riser Top Connector (RTC). Deployed for Total's Kaombo ultradeepwater development, the RTC was developed to facilitate connection of a single hybrid riser. Used for both riser base and riser top tie-in, the technology makes it possible to make connections in less than 2 hours once landed on the host structure.

A disruptive advance

The SDDC introduced for the Tembikai project is the latest system in a steady advance of diverless technology. Integration of guidance and ROV tools with Relock clamp technology marks a significant new industry capability.

The SDDC system removes the need for critical-path diver operations to achieve significant savings compared to conventional diver-installed methods. Eliminating the need for divers has many repercussions, including improvements in safety as well as lower manpower and time requirements. It also reduces the size and number of support vessels required by the operation and contributes to a reduced carbon footprint. ✚



A long history of AFGlobal subsea connection advances set the stage for the SDDC Tembikai deployment.

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As producers look for options to reduce costs, energy-related top LOE offers a hidden opportunity for significant cost savings through conversion to electrical power or improvements to existing electrical infrastructure. (Source: Burns & McDonnell)

The business case for oilfield electrification

Electrification opens a world of opportunity to improve operations, including lower LOE, de-risking, ESG benefits and more.

***Joshua W. Evans, P.E.**, Burns & McDonnell*

Oil and gas production and delivery to midstream refiners consumes significant amounts of energy in the form of onsite generation and utilization of equipment fueled primarily by diesel or natural gas. The costs associated with this energy routinely rank as a top LOE for operators. As producers look for options to reduce costs, energy-related LOE offers an opportunity for significant savings through conversion to electrical power or improvements to existing electrical infrastructure.

Reducing LOE can often be accomplished while achieving other benefits, such as reductions in greenhouse-gas (GHG) emissions, improved resiliency and all-around de-risking of operations.

This article explores the factors driving the shift to electrical energy sources, and key attributes of areas capturing the greatest value and benefits justifying electrical conversion can be identified.

Why now?

The status quo of deploying temporary power options is often considered a cost of doing business. However, significant downward pressure on oil and gas markets challenges producers to think outside the box to reduce costs and improve the market's perception of their environmental stewardship.

The oil field has changed significantly over the past decade. Horizontal well drilling and technology advances drive bigger well pads, requiring more water handling and central facilities, all resulting in increased energy consumption. Acreage positions are changing as companies work to consolidate their operations. Finally, public and investor demands have driven nearly every company to develop and publicly state a commitment to ESG principles.

Energy consumption and load density are huge drivers behind the economics of electrification. With concentrated and sustained loads, it becomes easier to justify long-term

"The benefit of investing in existing electrical infrastructure upgrades and/or converting to electrically driven equipment is a value-added proposition that should be considered."

– Joshua W. Evans, Burns & McDonnell

investment in the infrastructure required to distribute power. Nearly every piece of equipment used in oil and gas production is available in an electric option or is already electric powered by onsite generators fueled by diesel or natural gas.

With e-drilling and e-frac technology, electrification opportunities start early in the development process. Once a well is completed, electricity can be used to power well pads including EOR equipment such as electric submersible pumps (ESPs). As drilling techniques advance to include multiple wells per pad, and laterals increase in distance, power requirements steadily increase.

Data gathered from mid to large producers show a range of expected loads:

- Well pad: 0.25 MW to 2.5 MW;
- Central delivery point: 15 MW to 35 MW;
- Water handling: 0.5 MW to 10 MW;
- E-frac: 25 MW; and
- Gas processing plant: 5 MW to 15 MW.

Understanding specific power requirements is key in establishing the right approach to electrification. Electric grid power has long been one of the most cost-effective sources of energy. The benefit of investing in existing electrical infrastructure upgrades and/or converting to electrically driven equipment is a value-added proposition that should be considered.

Justification

Justifying major investments demands a customized approach. The long- and short-term value, especially when considering noncore infrastructure, requires buy-in from stakeholders.

Across the industry, producers are making significant investments in electrical infrastructure. Though the primary justifications vary, the reasoning can be summarized into three major categories: ESG benefits/GHG reduction, resiliency/de-risking and economics.

ESG/GHG: Driven by a new wave of socially driven investors, 2018 brought a new way of thinking to the market, catalyzed in part by Larry Fink, CEO of $7 trillion investment firm BlackRock. Major institutional investors began analyzing ESG data quantifying environmentally responsible policies on climate change, water management practices, global supply chain management and worker health and safety, among other metrics.

The ESG implications of electrification are straightforward. Conversion from inefficient, diesel or field gas motors and generators to electrically driven systems substantially reduces GHG emissions.

In addition to the tangible benefits of reduced environmental remediation costs and lower LOE, intangible benefits include the ability to attract investors and investment capital; GHG reduction supporting air permitting; operational efficiency; and added flexibility to develop and distribute power in the form of large-scale generation using field gas, renewables or other alternative power sources.

Resiliency/de-risking: Added operational resiliency and de-risking is an added benefit to converting to electrically driven systems. To achieve this result, the conditions required include

- A reliable power source is available or can be created;
- Producers have solutions for "behind-the-meter" infrastructure (versus a direct utility connection);
- Electrical infrastructure was built to a highly reliable standard; and
- Producers properly maintained electrical infrastructure and had a response plan for restoring power in the event of an outage.

Producers noted improved uptime resulting in the ability to consistently meet quarterly production goals. Furthermore, most reported decreased maintenance of field equipment.

The intangible benefits included an improved ability to deliver consistent quarterly results (many reported 98% or more reliability), an added ability to control the outcome when building electrical infrastructure behind the meter, and improved remote monitoring and control capability.

The tangible benefits included an improved reliability and life span of equipment, reduction in vibration-induced failures and reduction of production deferment.

Economics: In many—if not most—cases, the economics of electrification are very favorable.

To illustrate the potential for return on investment, consider the following analysis based on a case study completed in the Permian Basin for a greenfield development. The study evaluated the potential for cost savings by accelerating electrical infrastructure and eliminating the use of onsite rental natural gas generators. To determine these savings, a baseline power usage was established based on a forecast drilling and production schedule. To simplify the evaluation, an average power cost ($/MW) was established for both onsite generators and the equivalent grid power. Once the raw power costs savings were calculated, the cost of electrical infrastructure required to electrify well pads and facilities was subtracted to determine the total potential savings.

Savings = Onsite Generation Costs (Rental + Maintenance + Fuel) - Equivalent Grid Power Costs - Electrical Infrastructure Costs	
	3-Year Summary
Cumulative Operating Load (MW)	25 MW (Year 1) ramping to 500 MW (Year 3)
Onsite Generation Cost ($MM)	$163
Equivalent Grid Cost ($MM)	($42)
Electrical Infrastructure Cost ($MM)	($54)
Savings ($MM)	**$67 (41%)**

In this example, the producer developed an electrical infrastructure solution for everything behind the utility's primary meter entrance. Utilities bill customers based on both consumption of power and rate tariff schedules. In many cases, large power users that develop their own infrastructure to connect to the grid capture additional savings related to their electric rates.

Using conservative assumptions, the study showed the potential for 40% or more savings over a period of three years when connecting to electrical power.

The tangible benefits included decreased maintenance costs based on a reduced number of diesel/natural gas-consuming engines and the simplicity of electric motor maintenance; grid power cost discounts (based on usage and infrastructure); and reduced cost of power (onsite generation versus grid power).

Key considerations when evaluating potential for savings

To determine the opportunity, a detailed study is required to understand specific load requirements, identify potential power source(s) and develop an electrical infrastructure plan to connect the load with the source. To get started, consider basin, load, power source and acreage position.

Basin: An electrification strategy shouldn't be the same for all regions. Evaluate the basin. What electrical infrastructure exists? Is the existing infrastructure adequate? How much power is required to produce and deliver oil and gas? The business case for electrification exists in many scenarios, but solutions vary dramatically.

Load: Start by identifying the facilities to convert or build utilizing electrical power. Develop a load list with the peak demand and sustained energy requirements. Generally, the larger and more sustainable the load, the greater the potential for long-term savings using electrical infrastructure.

Power source: A good starting point is to identify nearby electrical infrastructure such as substations, high-voltage transmission lines and an adequate distribution system. The farther away, the higher the cost in developing electrical infrastructure. Although proximity is a material consideration, it does not necessarily dictate the outcome of project economics nor does it mean there are not other electrification options to consider (such as a microgrid). Keep in mind, even with electrical infrastructure nearby, there may not be adequate capacity available. A grid study is required to identify interconnection potential and may result in a list of utility upgrades required to support the new load(s).

Acreage position: A contiguous acreage position with high well/facility density is the most economical model for most oil and gas infrastructure. Intuitively, electrical infrastructure is no different. High electrical load requiring minimal infrastructure is an ideal candidate for electrification.

There is a lot more to electrification than pure economics. When considering an approach, identify the overall key drivers supporting the need for alternative power solutions, such as reliability, GHG reduction/ESG and long-term planning. The ideal candidate for electrification likely includes some combination of ESG, contiguous acreage positions, load consisting of wells and facilities with wells utilizing long-term power, and an identified need to improve resiliency of the system.

What are the traps?

Electrical power is not typically a core business focus for producers. As a result, electrical infrastructure often goes unnoticed until there is a significant event or disruption to the system.

To maximize the benefit, users must do it right, especially when choosing to own, operate or outsource a distribution system behind the primary meter entrance. Some common pitfalls include inexperience and the inability to properly plan and layout the system, failure to properly design electrical infrastructure and improper maintenance.

To avoid the traps and realize the full benefit(s) of electrification, engage the right team to properly plan, design, construct, operate and maintain the system. +

Failed electrical infrastructure, like this one in the Permian Basin, often goes unnoticed until there is a significant event or disruption to the system. (Source: Burns & McDonnell)

Realizing the value of data in oil and gas

With integrated analytics operationalized and simplified at scale, energy companies can adopt a true data-driven approach.

Niall O'Doherty, Teradata

Technology often drives industry disruption and is a foundational element to support and react to any changes in the business. But for industries experiencing the ripple effects of disruption brought on by the COVID-19 pandemic this year, adopting advanced technologies and a digital-first strategy have become critical for many companies to merely survive.

While energy organizations were among the first to adopt digitization, Deloitte emphasized in a recent report that many are now taking the necessary next steps to embrace the power of analytics, collect and integrate troves of HSE and security (HSSE), operations, supply chain and finance data, as they recognize the opportunity to make their "$3.4 trillion asset base smarter and more efficient."

To understand how data and analytics can best be delivered at scale for organizations as large as E&P operators, this article will note three key pillars that play crucial roles in helping oil and gas organizations realize the full value of data and turn insights into action—data integration, speed and simplification.

Integration

Implementing the right technology within an organization to provide a real-time, holistic view of their data helps companies make more fact-based decisions that ultimately impact the bottom line to reduce costs, increase workforce productivity and safety, and improve output.

However, barriers such as siloed and unstructured data and an evolving regulatory climate have slowed how companies move forward on leveraging data to guide business operations, meaning it can take months or even years to act on insights. But addressing these issues does not require a complete overhaul of the technology already in place.

Companies can integrate the collective data from sources including field assets, rigs, wells, plants, sensors and more, for increased visibility to ensure it is being used more effectively and helping to avoid silo-induced blind spots. Businesses can improve productivity, resiliency and agility through the whole supply chain as well by leveraging data analytics to combine operational data, inventory data and logistic information.

Sharing data analytics across the organization also goes beyond pure optimization to empower all employees, including those in the field, to make data-informed decisions. For example, someone stationed on an oil rig can determine if the equipment is working correctly, and employees downstream can ensure gasoline is blended correctly—all in a matter of hours rather than months.

Decentralized decision-making gives employees—from supply chain operators to the finance department—the necessary information to see changes or deviations in near-real time and address them immediately, compared to waiting for communications from the top down. By integrating data at a detailed level, it becomes available to whoever needs it, when they need it, to turn insights into action faster.

Speed

Energy companies don't have months to spare translating data insights, running the risk that information becomes stale and useless before it

Having a strong data foundation in place will ensure organizations have the data they need to make an informed transition.

can be acted upon. With the right data platform, however, companies can collect and integrate various types of data into one holistic view, for example, analyzing HSSE data faster and applying automated rules for proactive identification of possible issues. A scalable platform capable of bringing together, analyzing and sharing data in a reliable way builds credibility in the data and delivers high-value outcomes. It allows companies to better predict potential issues, make more informed decisions and move toward automation.

Safety and health have long been a priority within the energy industry. Companies that have progressed in their digital evolution are using safety analytics and machine learning to identify high-risk environments quickly and offer insights into both human and machine behaviors that may result in an accident. Capturing various data types—Internet of Things (IoT) sensor, voice, text and multichannel data—from end-to-end processes allows the creation of dynamic safety intelligence.

Speeding up data insights gives all employees the on-the-ground tools and insights they need to do their jobs in a more timely and effective manner. This allows them to be more successful in creating a safer and more productive work environment and removing themselves from potentially hazardous situations.

However, creating this type of environment requires the ability to access, share and analyze extensive and complex datasets achievable with a scalable, integrated and simplified analytics platform.

Simplification

Making data intelligence pervasive within an organization is necessary to equip it with the tools and insights to compete amid the unprecedented situation caused by COVID-19 and the accelerating need for digital innovation to drive business value. Enabling highly complex processes with a simplified data and analytics approach, to minimize complications, provides decision-makers with the right data at the right time with the right governance.

Cross-industry initiatives, like the Open Subsurface Data Universe, are helping to further simplify data implementation by creating a standardized data platform to reduce silos and centralize data within organizations. Companies that break down previously siloed datasets and pivot to integrate data pervasively throughout the organization can realize new synergies, visibility and business value. Two other examples of data simplification include optimizing the entire supply chain with rich, cross-functional cost forensics or moving from a spreadsheet-driven culture to a simplified, multi-source data-driven integrated dashboard for running a refinery.

With integrated analytics operationalized and simplified at scale, energy companies can adopt a true data-driven approach to their business to achieve new levels of efficiency, safety and asset optimization as well as remain competitive in a continuously changing landscape.

Rethinking data

By combining integration, speed and simplification, oil and gas companies can create a truly data-first approach to make more informed decisions faster and enable improvements across the end-to-end process—from drilling and production to finance and supply chain. Even as the energy industry turns its eyes toward future initiatives, such as the EU goal to become carbon-neutral by 2050 or American oil companies adapting to lower oil prices, having a strong data foundation in place will ensure organizations have the data they need to make an informed transition.

Many energy companies have already begun to embrace the power of analytics to realize the value of their data; therefore, they don't require revolutionary changes to how they're using it. Evolutionary changes, however, can simplify their analytics to prudently advance toward immediate and enhanced efficiency, sustainability, safety and productivity—delivering all of the above at speed to lay a strong foundation for recovery and growth. ✚

(Source: REDPIXEL.PL/Shutterstock.com)

Improving recovery in natural gas wells with artificial lift

Downhole compressor technology drives adoption of artificial lift for natural gas wells.

Herman Artinian, Upwing Energy

It would be no exaggeration to say that artificial lift has made a tremendous contribution to increased production in oil fields. More than 50% of oil wells use artificial lift techniques, such as pumps and injection methods, to boost production. It is estimated that the artificial lift equipment market amounts to almost $10 billion annually, enabling $800 billion of oil production per year.

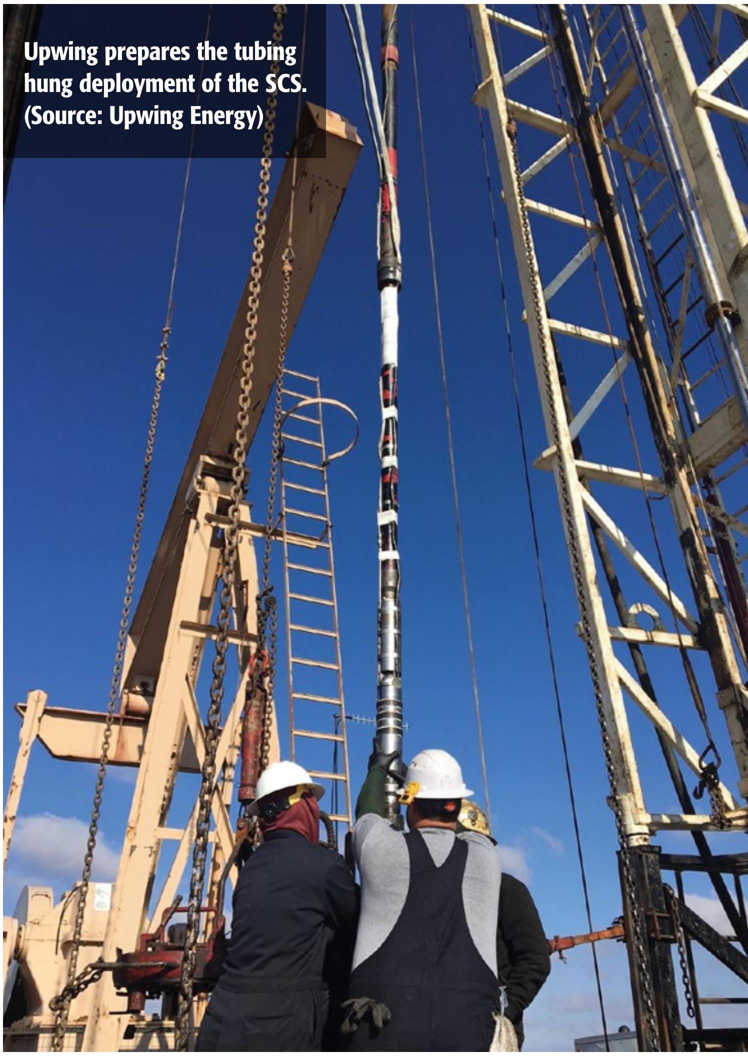
Despite these impressive results in the oil segment, artificial lift has gained relatively little traction in gas wells, both conventional and unconventional. This is largely because until now there have been no artificial lift tools that can directly induce energy into the gas to increase production and recoverability. While operators have been able to get positive results using wellhead compressors, experience has shown that these devices can accelerate liquid loading, especially in unconventional wells, due to higher critical lifting velocity and lower production fluid density within the wellbore. The result is decreasing productivity and premature abandonment.

Downhole system uses magnetic technology

Upwing Energy has developed and tested a new Subsurface Compressor System (SCS) that significantly increases gas production and recovery while also alleviating liquid loading. The SCS is a cost-effective downhole system that uses advanced magnetic technology to eliminate the primary failure points of electric submersible pump artificial lift systems. Key components are a high-speed downhole compressor driven by a hermetically sealed high-speed permanent magnet motor and a magnetic coupling that conveys torque from the motor to the compressor with no mechanical shaft or seals. This architecture eliminates the need for a protector shield to isolate the motor from the downhole fluids. The system also includes a sensorless wide-frequency variable speed drive at the surface that controls the downhole motor at speeds of up to 50,000 rpm.

The SCS creates a suction effect at the compressor inlet at the bottom of the wellbore, thus lowering the bottomhole flowing pressure and increasing gas velocities in the wellbore, enabling more liquids to be carried to the surface. Decreasing backpressure from liquid loading results in increased gas production, which in turn accelerates liquid unloading and prevents vapor condensation when exiting the compressor.

The SCS architecture maximizes gas and condensate production, recoverable reserves, gas-in-place recovery efficiency and liquid unloading—all at the same time—while lowering total cost of ownership and reducing surface footprint. These benefits can be realized in any type of formation and wellbore geometry for both onshore and offshore environments.



Upwing prepares the tubing hung deployment of the SCS. (Source: Upwing Energy)

Field trial

The first full-scale commercial SCS deployment took place over a two-month period in a liquid-loaded shale gas well operated by Riverside Petroleum in Indiana. The trial resulted in a 62% increase in gas production and a 50% increase in liquid production over its steady-state performance with a rod pump prior to the SCS installation.

For the Riverside demonstration, the SCS was deployed in an unconventional well with a 2,000-ft vertical wellbore and a 5,000-ft horizontal wellbore where liquid had accumulated. The compressor was installed at the bottom of the vertical section with a tail pipe extending approximately 1,000 ft into the horizontal section to provide enough velocity to carry liquids while minimizing friction losses.

Prior to installing the SCS, the well's gas production was about 185,000 scf/d, and its liquid production via rod pump was 5 to 7 bbl/d. Without the rod pump, the well choked in a few hours. With the SCS, the well stabilized at a gas production rate of 300,000 scf/d. When the SCS operated at 30,000 rpm, the gas velocity increased to 29 ft/sec and a high rate of liquid was carried to the surface. The hybrid axial compressor was able to atomize the liquid into a very fine mist, which, together with the increased velocity and heat generated from the exit of the compressor, helped carry the liquids to the surface.

At the conclusion of the trial, the SCS was removed and inspected. The compressor blades showed no signs of degradation despite moving a significant amount of liquids.

The next major commercial trial for the Upwing SCS will take place in a higher flowing conventional gas well in the U.S. early next year.

Predictive tools

Modeling tools make it possible to evaluate and predict the outcome of conventional wells with the SCS. This is due to better understanding of the conventional reservoir, existing verified models and available historical data. Operators can insert the SCS compressor maps into their reservoir models and verify the incremental improvement in production and recoverability.

As Upwing continues with its trials, the results are being verified with comprehensive in-house models that incorporate the SCS tool, reservoir, wellbore and top-side equipment. For conventional reservoirs, these modeling tools can predict results fairly closely. For the next trials coming up in a conventional gas well, Upwing predicts a more than 62% incremental increase in gas and NGL production and an over 60% incremental increase in condensate production.

Simulations have been conducted along with feasibility studies for wells that have significant production up to 53 MMscf/d. Wells evaluated to date include the Norwegian Continental Shelf, North Africa and onshore and offshore Australia, all showing significant positive results with the SCS with up to and more than 100% incremental increase of production of gas, NGL and condensate.

With conventional wells, Upwing's models can accurately predict the production increases and reservoir response achieved by the SCS. With unconventional wells, the company can currently predict liquid unloading and production increases but not ultimate hydrocarbon recovery with SCS.

Upwing's SCS offers potential for artificial lift to play a transformational role in boosting revenues from gas wells.

Upwing is looking to partner with universities in the U.S. to develop a way to model the effects of the reservoir behavior with the SCS in unconventional gas wells. It is simple to deploy the SCS and recognize the incremental production improvement, but it is necessary to understand the reservoir behavior to duplicate results and develop a reliable prediction tool that will enable operators to construct their economic models for unconventional shale gas wells.

In short, artificial lift is underused in gas wells. This means both conventional and unconventional gas wells are too often abandoned before reaching their full potential. Using advanced magnetic technologies downhole, Upwing's SCS offers potential for artificial lift to play a transformational role in boosting revenues from gas wells. +

UpwingEnergy	Current State		With SCS		Incremental Gain	
	Bottom Hole Pressure (psia)	Production (MSCFD)	Bottom Hole Pressure (psia)	Production (MSCFD)	Production (MSCFD)	Percentage
Conventional Well	1,050		750			
Natural Gas Rate (MSCFD)		3,498		8,012	4,514	129%
Condensate Rate (BPD)		86		216	130	151%
Unconventional Well	700		230			
Natural Gas Rate (MSCFD)		685		1,218	533	78%
Condensate Rate (BPD)		15		72	57	380%

Simulation results for a conventional onshore well in Africa with liquid loading issues are compared to an unconventional shale well in the U.S. Marcellus Shale play. (Source: Upwing Energy)

SPONSORED CONTENT

Higher natural gas prices lift producers' spirits

DUG Haynesville virtual program offers well-timed insights

Natural gas producers along the Texas-Louisiana border will play leading roles in the upstream sector's recovery from the depths of its 2020 market disruptions. That positive news ranks as a key takeaway from the FundamentalEdge report published Sept. 9 by data services leader Enverus.

Producers nationwide dramatically trimmed 2020 spending plans as commodity prices fell alongside dropping demand, one notable result of the COVID-19 pandemic. Rig activity was cut and production declined nationwide as oversupply overtook the market, particularly in oil-directed plays. In turn, associated gas production dropped – and the so-called "dry gas plays" made up the difference as natural gas prices rose to multi-year highs this summer.

"For all that happened to oil, to some degree the inverse is true for natural gas," said Rob McBride, senior director of strategic analytics at Enverus. "Natural gas is well poised for the near future. Since the historic crash a few months ago, gas has slowly crept up, but drilling rigs haven't yet followed suit."

While crude oil demand cratered with the "double black swan" of a Saudi-Russian crude oil "price war" and coronavirus shutdowns, gas-reliant industries like heating and power weathered much better.

"For all that happened to oil, to some degree, the inverse is true for natural gas. Natural gas is well poised for the near future."

Timely updates from leading players

Now Enverus projects dry natural gas production in the Haynesville to grow by 5 Bcf/d over the next five years – and the annual **DUG *Haynesville* conference** provides the perfect opportunity to get firsthand updates on what's happening and what's coming for this productive region.

A "frac-side chat" with **John D. Jacobi**, CEO & president of **Javelin Energy Partners** and co-founder of **Covey Park Energy**, promises to provide unique perspectives on the Haynesville play's past and future prospects. Registrants also will hear C-level executives from leading Haynesville producers like **Goodrich Petroleum**, **Aethon Energy** and **Rockcliff Energy**, as well as Ark-La-Tex players like **Castleton Resources**, **New Century Exploration**, **Sabine Oil & Gas**, and **Velandera Energy Partners**.

Originally set as an in-person conference and exhibition, the event became another pandemic casualty due to the state's social distancing restrictions. Now the show will go on(line) **October 28** in virtual format. Online registration takes only a minute or two at dughaynesville.com. Best of all, registration is available at ***no cost*** thanks to generous support from Hart Energy's sponsors. +

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The Liza Phase 2 project development involves a second FPSO vessel, *Liza Unity*, that is designed to produce up to 220,000 bbl/d of oil. (Source: Exxon Mobil Corp.)

South America's pending success to overshadow harsh 2020

Upstream activity will fuel the region as a leader on the road to recovery.

Mary Holcomb, Associate Editor

As the oil and gas industry continues to weather the storm of the downturn, South America's upstream sector is preparing for a wave of new growth and opportunity.

Across the globe, operators have slashed capex and reduced activity after the worst price crash in decades wreaked havoc on the sector. The current state of the market has put the U.S., Europe and Africa in a dire state, offsetting a potential 2021 recovery by two or more years.

Although the outlook for the sector remains uncertain, South America is expected to lead the recovery among regions given its attractive onshore and offshore prospects, the political resolve in Guyana and Argentina's hydrocarbon production, according to Wood Mackenzie analysts.

In all, South America's resilience during distressed times signals a positive recovery. The country's progress could prove to be a useful blueprint for the strategies across the globe as E&P companies begin to emerge from the downturn.

Guyana

Following a monthslong political dispute over the election results, Guyana swore in Mohamed Irfaan Ali as president in August. The resolve of the political crisis has allowed delayed projects and Guyana's oil and gas industry as a whole to begin to move forward.

"On the development side, we saw some delays from the government on project approval," said Luiz Hayum, Wood Mackenzie's upstream research senior analyst for Latin America. "But, finally the situation with the election has been resolved. This should allow the government entities to work on moving the oil industry and the decision process for project approval forward."

Although Exxon Mobil Corp. has acknowledged that the political conflict and coronavirus outbreak will cause a six- to 12-month delay on the development of certain projects, Hayum noted both the company and its partner Hess Corp. have resumed normal operations with four active drilling rigs.

Exxon Mobil also recently added to its oil discovery tally offshore Guyana with the Redtail-1 well in early September. The discovery marked the 18th find on the Stabroek Block made by the Exxon-led consortium that also includes Hess and China's CNOOC Ltd.

In a statement, John Hess, CEO of the U.S.-based independent, said the Redtail-1 discovery will add to the gross discovered recoverable resource estimate for the block of more than 8 Bboe.

"Redtail is the ninth discovery in the southeast area of the block, which we expect will underpin future development," Hess added.

While Guyana remains a priority region for companies like Exxon and Hess, Hayum said the company's success at the Stabroek Block and Tanager-1 exploration well in the Kaieteur Block are significantly raising the attractiveness of the small country.

"Guyana is an area of focus for development for both Exxon and Hess, despite the investment reductions elsewhere, including in the U.S.," he said. "In particular, Tanager-1 is one of the exploration wells that we are waiting for the results and is probably one of the most exciting prospects for the year. If this well is successful, it will help prove that the petroleum system expands even further from the coast and that could open up an exploration licensing round in a couple of years."

In addition, results from Tanager-1, which is located in the block adjacent to Stabroek, will prove that exploration success can be replicated outside of the current cluster of development by Exxon.

"It will help de-risk some of these blocks in deeper waters and open a new horizon of investments and possible developments for years to come," Hayum said.

The impact of discoveries on the Stabroek Block, the pending success of the Tanager-1 exploration and alluring offshore prospects will make Guyana a new entrant this decade, according to a Rystad Energy report released in February.

With more than 8 Bbbl of recoverable oil discovered in Stabroek and recent discoveries in the Guyana-Suriname Basin proving a wider petroleum system, companies will boost their capex in the area, the report said.

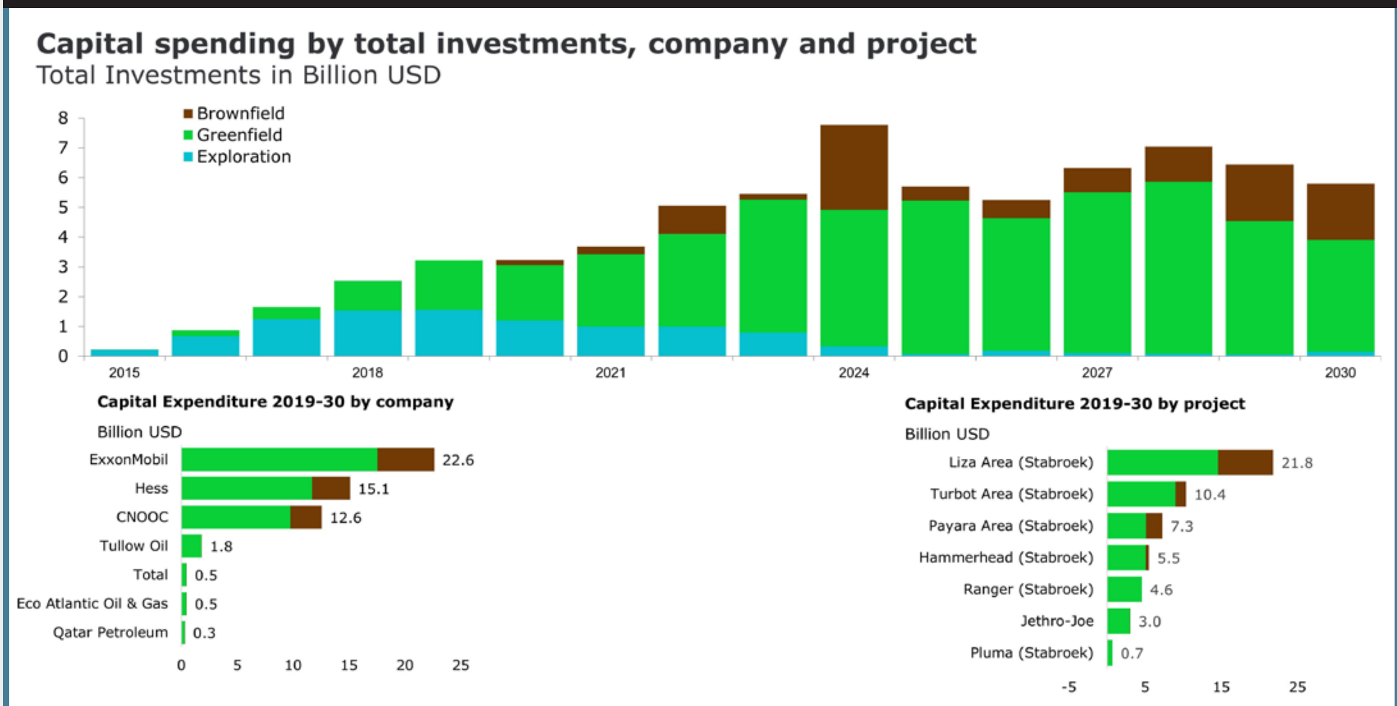
South America is expected to lead the recovery among regions given its attractive onshore and offshore prospects, the political resolve in Guyana and Argentina's hydrocarbon production.

Rystad expects the Guyana's coveted Stabroek Block to bring in billions in investment from oil firms. The firm anticipates global oil firms are preparing to spend more than $53 billion in the block with Exxon Mobil leading the way at $22.6 billion. Following Exxon, the analysts project roughly $15.1 billion in spending by Hess and CNOOC at $12.6 billion.

The Liza Field will attract most of the capital, with the Turbot Field and the Payara Field expected to round out the top three, according to the report.

Additionally, offshore prospects will increase the appetite of energy companies in Guyana. In particular, the appeal of lower breakevens and competitive payback times will make oil projects offshore South America more attractive versus similar projects in other parts of the world.

Guyana Capital Spending



Global oil firms plan to spend more than $53 billion in Guyana's coveted Stabroek Block during the coming decade. (Source: Rystad Energy)

"Offshore activity in Latin America is expected to recover from 2021 with more than 3 million barrels per day of peak production estimated to be sanctioned in Brazil and Guyana alone by 2025," the Rystad report stated. "Of this, more than 80% of the capacity has breakeven prices of less than $45 per barrel and is expected to get sanctioned despite the current market environment."

Together Brazil and Guyana will account for more than one-third of the offshore investments over the next five years, and roughly 30 offshore oil projects will be given the green light across the continent in the next three years, according to recent findings by Rystad.

Vaca Muerta: 'Argentina's Permian Basin'

Onshore South America, the Vaca Muerta Formation has become more relevant for hydrocarbon production in Argentina, adding to the promise and potential of the shale play.

Production from the play accounted for roughly 25% of the total hydrocarbon production in the country in 2020, according to Wood Mackenzie principal research analyst Ignacio Rooney.

Liquids production halted across the country in April and May, but Rooney said production began to recover by June and July. The same blocks that had decreased in production at the beginning of the pandemic in Argentina are now the ones that are driving liquids production recovery.

"[Argentina's] oil production is not at the same levels as it was before the pandemic," he said. "But we're seeing that the liquids output numbers from the Vaca Muerta are above what we saw during April and May. Right now, the liquids part of the play is what is most attractive for companies."

Furthermore, Rooney said the Vaca Muerta's liquids production growth will steadily increase and recover faster than gas, possibly returning to pre-pandemic levels by next year.

The light is a bit dimmer on the gas side given the price environment, he noted. However, the Argentinian government is discussing a potential low-price incentive scheme for offshore companies. The incentive is designed toward ensuring that gas production does not decline going forward and will incentivize upstream activity. If implemented, the incentive will apply to all basins within the country and signal opportunity for offshore producers, Rooney said. +

An onsite technician wearing smart glasses inspects an electrical panel. (Source: Sodexo Energy & Resources)

Smart glasses provide immersive experience

Onsite technicians can send, receive, or open and view documents on smart glasses as well as receive real-time expertise, which reduces downtime and HSEQ risks.

Stephanie Hertzog, Sodexo Energy & Resources – North America

Augmented reality (AR) is having a transformative impact on the oil industry, especially now during the COVID-19 pandemic. It is playing an evolving role in managing critical asset malfunctions and breakdowns on remote sites while assisting in maintaining social distancing through audio/visual-based virtual communication.

Asset management

The oil industry is asset-intensive, and downtime presents major challenges. Whether on land, offshore or in deep water, remote and oftentimes hostile locations make managing assets logistically complicated. Keeping qualified staff is harder, and downtime is costly and can develop into HSEQ issues.

Energy companies strive to mitigate issues with scheduled maintenance for critical assets and reactive attention for noncritical assets, but assets and sites are not created equal. Variances in operational processes, environmental conditions and locations create unique situations for each site. More importantly, maintenance is only one portion of management.

Stepping boldly toward a new era, the industry has taken advancements further by assigning repetitive labor to technology, which allocates more time for business analysis and improvement, leading the way to modern predictive maintenance approaches made possible by the Internet of Things. Smart connected assets, condition monitoring sensors and software, and advanced data analytics platforms and solutions provide significant business value for industry operators.

AR

In continuing to find innovative ways to capitalize on new technologies, the oil industry is adopting AR for asset management.

Sodexo Energy & Resources has released Remote Technical Assistance Powered By Smart Glasses, an AR technology that incorporates assisted reality, dynamic workflow management and online scheduling. It creates a situation where it can seamlessly connect onsite technicians via head-mounted technologies to its team of experts from a knowledge hub. The technician is guided remotely and in real time by the relevant expert to resolve the issue, thereby eliminating the need for travel and ensuring faster turnaround times for service requests.

The smart glasses provide an immersive experience for the user. While wearing the assisted reality smart glasses, the onsite technician can send, receive, or open and view documents on the glasses. The wearable technology provides a direct "you-see-what-I-see" link to the expert from the knowledge hub, who can then remotely guide the onsite technician to perform intricate tasks by accurately guiding them through each step of their work. The experts, at their end, are able to screenshot and zoom in on problem areas and can share schematics or drawings with live annotations where required.

Often at remote sites, there are general technicians present, but they are not specialized and/or accredited to work on more complex systems. For example, air conditioning is essential on remote sites, and losing it for an extended period of time can be detrimental to the quality of life for employees on site. There is typically an HVAC technician on site, but they are not qualified to work on roof air exchange units. Many times, it takes several days for a specialized technician to reach the site. In this scenario, a virtually available specialist can help diagnose and troubleshoot issues. Often with spare parts on site, the issue can be fixed without a technician ever having to travel the site.

Another example where AR is applicable for remote sites is wastewater treatment plants. Issues with treatment plants have the potential to close an entire camp should critical parts stop functioning. AR glasses allow specialized technicians the ability to dial in and assist.

The Remote Technical Assistance Powered By Smart Glasses provides benefits for facilities management onshore as well, particularly with sites across multiple states and varying regulations. A cost-efficient centralized team can perform the initial diagnosis and guide the onsite team to fix issues. If greater onsite expertise is required, the appropriate state-accredited subject matter expert can be called in when required.

The smart glasses technology was developed with feature-rich commercial off-the-shelf Realware glasses and AMA's XpertEye remote assistance software, both of which satisfy energy industry needs.

The Realware glasses operate on Android 8.1.0 and the WearHF hands-free interface with a 2.0 GHz 8-core Qualcomm Snapdragon 625 chipset with Adreno 506 GPU (OpenGL ES 3.1 & OpenCL 2.0). They have 16 GB of internal storage, 2 GB RAM and a MicroSD slot that supports a maximum 256 GB card. They are Bluetooth and Wi-Fi enabled, and they come with a 3,250 mAh Li-Ion rechargeable, field swappable battery. The glasses weigh 380 g and are ruggedized IP66, MIL-STD-810G, 2-m drop tested. The boom arm adjusts six ways for all head sizes and are left or right eye compatible. The display flips out of the way when not in use. The display has a 20-degree field of view, 1-m fixed focus 24-bit color LCD, 0.33-inch diagonal, outdoor visible, and WVGA (854×480) resolution. The glasses also have four digital microphones with active noise cancellation, accurate voice recognition even in 95 dBA of typical industrial noise and an internal 91 dB loudspeaker. The camera has 16-MP four-axis optical image stabilization, phase detection auto-focus with an LED flashlight and the capacity to video 1080p at 30 frames per second.

"Smart connected assets, condition monitoring sensors and software, and advanced data analytics platforms and solutions provide significant business value for industry operators."

–Stephanie Hertzog, CEO, Sodexo Energy & Resources – North America

The AMA XpertEye browser-based technology provides seamless remote assistance with smart glasses, a dedicated smartphone and external video sources. The combined product set provides energy customers with advanced telepresence using AR-capable smart glasses to share the view of a situation with another person(s) via live audio and point-of-view video. With this technology, companies can augment any skill gaps, reduce downtown, save travel time and realize ancillary benefits like reduced training time and a lower carbon footprint.

Because of the nature of the work, energy companies cannot take advantage of an entirely remote workforce afforded other types of businesses. The challenge of keeping remote camps and offshore platforms free of COVID-19 has presented significant challenges to producers. Remote Technical Assistance Powered By Smart Glasses can assist by reducing the number of potential exposures.

In the "Oil and Gas after COVID-19" article, McKinsey & Co. reported that the industry will continue to scale up technology, taking inspiration from some of the new approaches that have emerged from this pandemic. They believe it will be the catalyst to rethink the size and role of the functional teams, field crews and management processes needed to run an efficient oil and gas company. ✚

Sodexo Energy & Resources uses technology to improve technical maintenance for critical assets. (Source: Sodexo Energy & Resources)

The latest technologies emerging in the upstream oil and gas industry

Companies collaborate to create 2D, 3D real-time well visualization

Weatherford International Plc announced a collaboration with INT, an upstream data visualization provider, to offer real-time well visualization in both 2D and 3D. Weatherford will embed INT's IVAAP framework into the Weatherford Centro digital well delivery software, advancing its data visualization capabilities. The digital well delivery software offers workflows that integrate every element of an operator's well data, allowing team members from any global location to access, share and store all vital project information at any time.

Technology can help speed soil recovery after oil spills

After an oil spill or leak, it is important to act fast. If the oil has gotten into soil, scientists need to rapidly assess how much oil there is and how far it has spread. It is a costly and time-consuming process. A team at University of Nebraska-Lincoln found a new method using technology called Vis-NIR spectroscopy that is faster and cheaper.

The traditional methods for analyzing these soils are done in the laboratory and involve multiple steps. It requires collecting samples from the spill site and then taking them off site for analysis. The Vis-NIR spectroscopy technology works by sending wavelengths of energy at a sample and measuring what is absorbed or reflected. Different chemical substances do this very specifically based on their makeup, so it is able to tell scientists a lot about a sample. The data they receive from the technology have to be compared to a model. They found they could construct accurate model samples mostly in the laboratory, with only a few samples from the site needed. Adding just a few field samples, rather than relying solely on them, is a process called spiking. This reduction of time and labor necessary at the oil spill site makes this new method rapid and cheap.

During spiking, the data from the field samples are added into the original model. This helps customize the model to make it more accurate for the specific location.

Researchers use spectroscopy to quickly and cheaply analyze soil samples. Accessories used to scan a soil sample include a puck, sample and contact probe. (Source: Nuwan Wijewardane, University of Nebraska-Lincoln)

The cost of the VisNIR-based method is just a few dollars per sample, compared to the traditional cost of $50 per sample. Additionally, rather than taking days or weeks to get results, the results are almost instant. The tool can also be taken right into the field to speed up the overall project.

Using quantum gravity sensors down boreholes

Experts in quantum cold-atom sensors are delving deep underground in a new project aimed at harnessing quantum gravity-sensing technology in harsh underground borehole environments. The Gravity Delve project, funded by Innovate UK, brings together academics from the UK Quantum Technology Hub Sensors and Timing, which is led by the University of Birmingham and Nemein Ltd., with the aim of investigating the benefits and challenges associated with using quantum gravity sensors down boreholes. Quantum gravity sensors based on atom interferometry are already being developed for use in the oil and gas sector. Quantum cold-atom sensors designed to operate on the surface will be able to detect and monitor objects beneath the ground better than any current technology. Nemein is developing borehole deployed equipment primarily focused on energy harvesting and environmental sensing. The new technology will enable the quantum sensor developed by the University of Birmingham to venture out of the laboratory and into the extremely harsh downhole environment.

Borehole applications to be investigated in the project will include carbon capture and storage (CCS) as well as hydrocarbon and geothermal reservoirs. Existing techniques for reservoir optimization include conventional microgravity, electrical and nuclear logging. These techniques, however, are limited by sensitivity, resolution and cost. Gravity Delve is investigating how a commercially relevant quantum device could replace or enhance current technology to optimize CCS reservoirs, minimize the environmental impact from hydrocarbon extraction and enhance the transition from fossil fuels to renewable energy such as geothermal. The project will develop a design for a borehole quantum cold-atom gravity sensor as well as the associated harsh environmental packaging and ancillary equipment. According to the project leaders, this will lead to the first cost-effective and efficient method deep borehole quantum sensor deployment.

Alliance provides integrated, open architecture software to maximize asset potential

Halliburton and Honeywell announced a collaboration to maximize asset potential, reduce execution risk and lower the total cost of ownership for oil and gas operators. The collaboration will leverage Halliburton Landmark's DecisionSpace 365 E&P cloud applications and the Honeywell Forge industrial analytics software to deliver insights about oil and gas assets. Together, the companies bring deep domain expertise in subsurface and surface operations with the latest digital innovations to help operators address operational efficiency, asset productivity and risk across their business. Operators will be able to maximize asset value by creating a digital twin on an integrated and open architecture that connects and models the supply chain from reservoir to point of sale.

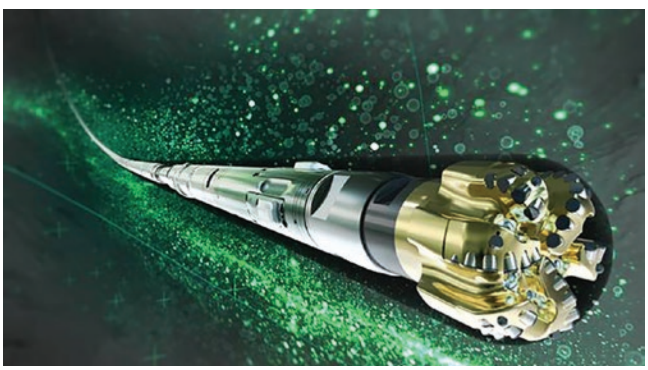
They will also be able to increase production, minimize opex/capex and reduce operational risks by streamlining processes from downhole to surface controls, including digital solutions for improved subsurface insight. Additionally, the collaboration can offer optimization of total asset and enterprise performance using real-time monitoring and remote operations.

App provides market insights and transparency

Online valuation and data provider, VesselsValue, has released its first official app. The free app is designed to ensure users can quickly obtain market insights and reinforces the company's proposition of making markets transparent and accessible. The app allows users to view current market, demolition and newbuild values for every vessel including company fleet values within the database. It also allows users to search the extensive VesselsValue database for any vessel or company fleet in the world. The app provides an interactive graph that features historical values and vessel transactions. Users can also view the specific details of each vessel (e.g., builder, flag, size, features and more). VesselsValue plans to expand the app's functionality and add additional features over the coming months. The app covers all ship types on the VesselsValue platform, including cargo ships, offshore vessels and passenger vessels, among others. The app is available on iOS and Android platforms.

New rotary steerable service for high-performance drilling

Baker Hughes has released its new Lucida advanced rotary steerable service, which integrates hardware, software, automation and remote connectivity to help oil and gas operators drill faster and deliver more precise, higher-quality wells. The service is designed to maximize directional drilling performance and well productivity by incorporating advanced electronics and near-bit sensors that enable drillers to more precisely guide bottomhole assemblies (BHAs). The Lucida service's integrated BHA includes a customized drill bit and high-strength connections to maximize penetration rates. The BHA also includes near-bit sensors to gather more downhole data and multi-chip module electronics, which have been tested extensively at temperature cycles approaching 400 F to provide a step change in reliability in more demanding drilling environments. The service's 16-sector gamma-ray sensors are situated close to the bit and provide real-time formation data that enable quick decisions to navigate the reservoir more precisely. Lucida's automated wellpath trajectory control system integrates both azimuthal and inclination hold modes with continuous proportional steering to automatically correct wellbore trajectory for formation trends.



The Baker Hughes Lucida advanced rotary steerable service integrates hardware, software, automation and remote connectivity to help oil and gas operators drill faster and more precisely. (Source: Baker Hughes)

New DC/DC converter designed for extreme environments

WAGO has released its new 12 to 24 VDC DIN Rail mountable converter for extreme conditions. This XTR DC/DC converter has conformal coating, which provides increased effectiveness against harsh environments. It can be used in a wide range of temperatures from 40 C to more than 70 C and is suitable for extreme applications. Other features include reverse polarity and short circuit protection, which prevents problems with mis-wiring, as well as 95% efficiency at full load, which reduces energy loss and provides full ampacity without derating. These converters are useful in environments that require extreme testing procedures and can provide up to 3 Amps.✚

The XTR DC converter has conformal coating. (Source: WAGO)

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****.*

1 Wyoming

Results from a Niobrara well were announced by Samson Resources Co. The 34-3031 39-74 NH Allemand Fed initially flowed 2,413 bbl of 49°API oil, with 4.375 MMcf of gas and 1,224 bbl or water per day. The Hornbuckle Field was drilled in Section 30-39n-74w in Converse County, Wyo., to 22,326 ft (12,207 ft true vertical depth). It was tested after 47-stage fracturing with a shut-in casing pressure of 3,000 psi during testing on a 28/64-inch choke. Production is from a perforated zone at 12,298 ft to 22,061 ft.

2 North Dakota

An Upper Three Forks venture in Dunn County, N.D., initially flowed 5,172 bbl of 41°API oil, 3.785 MMcf of gas and 4,884 bbl of water per day. Marathon Oil Co.'s Ritter 34-12TFH well was drilled in Section 12-146n-94w. The Bailey Field discovery was drilled to 21,287 ft (10,761 ft true vertical depth) and produces from perforations at 11,114 ft to 21,154 ft. Gauged on a 64/64-inch choke, the flowing casing pressure was 1,200 psi.

3 New Mexico

A Wolfcamp well in Eddy County, N.M., was tested flowing 4,544 bbl of oil, 10.925 MMcf of gas and 9,581 bbl of water per day. Oxy USA Inc.'s Corral Fly 35-26 Federal Com 036H is in Section 2-25s-29e. The Purple Sage Field well was drilled to 20,483 ft (10,364 ft true vertical depth). Tested on a 37/64-inch choke, the shut-in casing pressure was 1,600 psi, and production is from a perforated zone at 10,537 ft to 20,387 ft.

4 Oklahoma

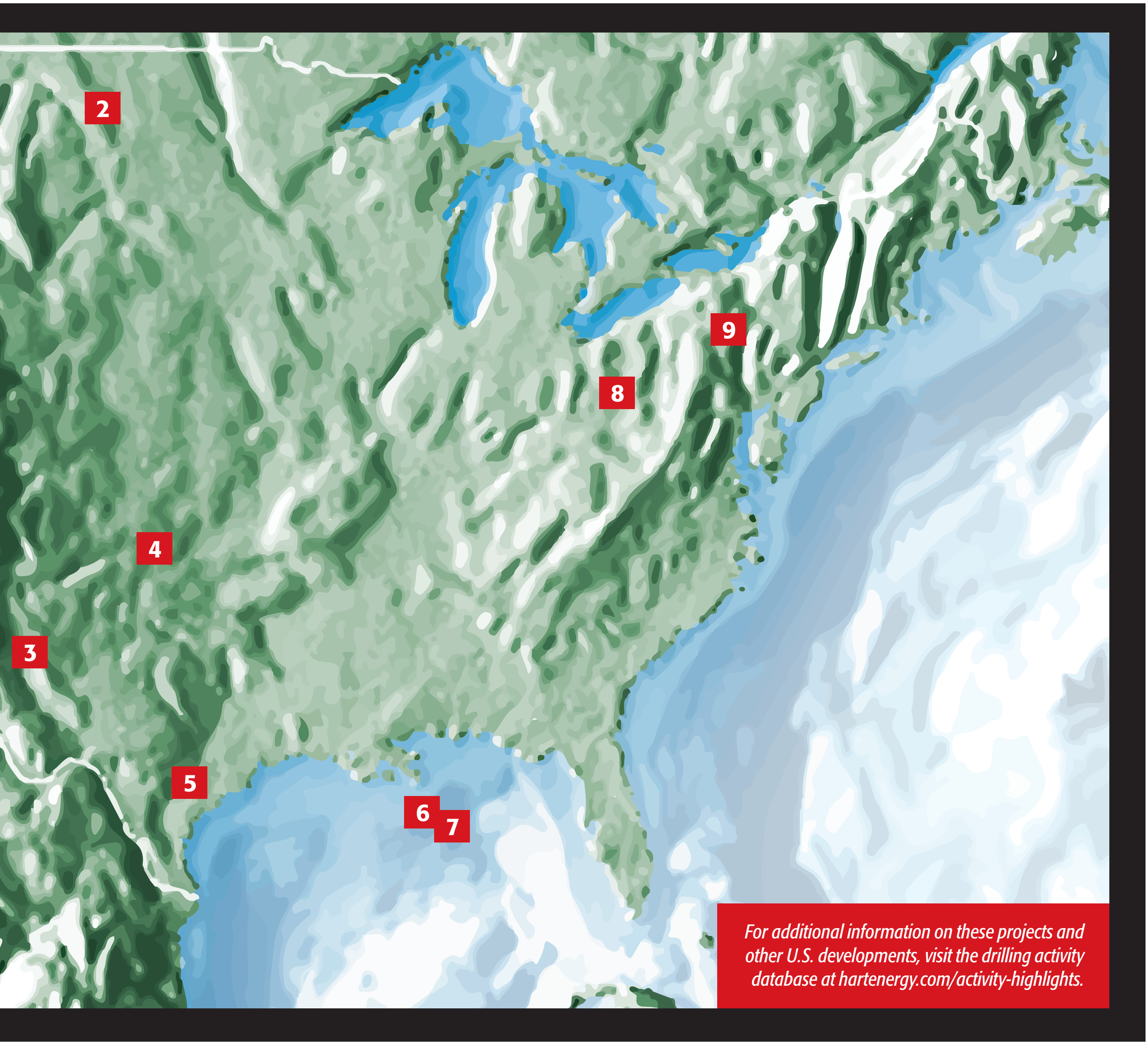
Mewbourne Oil Co. announced results from a Cherokee discovery in Ellis County, Okla., at Goldfinger 21/28 BO 1HR. The Grand West Field discovery initially flowed 402 bbl of 45°API oil, 490,000 cf of gas with 1,123 bbl of water daily from perforations between 10,310 ft and 19,459 ft. Located in Section 21-18n-24w, the venture was drilled to 19,692 ft (10,222 ft true vertical depth). It was tested on a 20/64-inch choke, and the flowing tubing pressure was 2,200 psi.

5 Texas

An Austin Chalk-Sugarkane Field completion was reported by Ageron Energy. Located in Karnes County (RRC Dist. 2), Texas, Bolf AC Unit 1H flowed at a daily rate of 1,022 bbl of 39°API oil, with 975,000 cf of gas and 588 bbl of water. It is in Erasmo Seguin Survey, A-10, and was drilled to a total depth of 13,835 ft (10,412 ft true vertical depth). Tested on a 24/64-inch choke, the flowing tubing pressure was 1,160 psi and the flowing casing pressure was 60 psi. Production is from perforations between 10,880 ft and 13,502 ft.

6 Gulf of Mexico

A Beacon Offshore Energy Miocene discovery was completed in Mississippi Canyon Block 794. The company's #0SS003S0B OCS-G34909 ST00BP00 flowed at a daily rate of 6,152 bbl of 30.6°API oil, 11.905 MMcf of gas with 18 bbl of water. Production at the 23,275-ft well is from perforations in



a Miocene zone at 22,765 ft to 22,886 ft. The Claiborne Field well was tested on a 49/64-inch choke, and the flowing tubing pressure was 7,883 psi. Claiborne Field was discovered and initially developed in 2017 by LLOG.

7 Gulf of Mexico

An Upper Miocene discovery was announced in Mississippi Canyon Block 934 by Shell Oil Co. The #0A006S1B OCS G07976 initially flowed 11,995 bbl of 27°API oil, with 10,000 cf/d of gas with no reported water. It was drilled to 18,620 ft (17,826 ft true vertical depth). Gauged on an 88/64-inch choke, the flowing tubing pressure was 4,963 psi, and production is from perforations at 18,423 ft to 18,465 ft.

8 Ohio

A Utica Shale discovery in Jefferson County, Ohio, flowed 38.403 MMcf of gas and 148 bbl of water per day. Ascent Resources' Faldowski 6H was drilled in Section 14-8n-3w in Limestone Field to a total depth of 20,912 ft (9,762 ft true vertical depth). Production is from an acidized and fractured zone at 10,065 ft to 20,736 ft.

9 Pennsylvania

Two Bradford County, Pa., Marcellus discoveries were announced by Chesapeake Operating Inc. The Herrick Field wells were drilled from a drillpad in Section 7, Laceyville 7.5 Quad, Wyalusing Township. The Brown Homestead 106HC well flowed 44.24 MMcf/d of gas. It was drilled to 18,120 ft (7,251 ft true vertical depth). The shut-in casing pressure was 3,414 psi, and production is from a perforated zone between 7,508 ft and 18,106 ft. The Brown Homestead 5HC well produced 48.644 MMcf/d of gas. It was drilled to 17,314 ft (7,248 ft true vertical depth). The shut-in casing pressure was 3,434 psi, and production is from fractured perforations between 7,237 ft and 12,299 ft. ✚

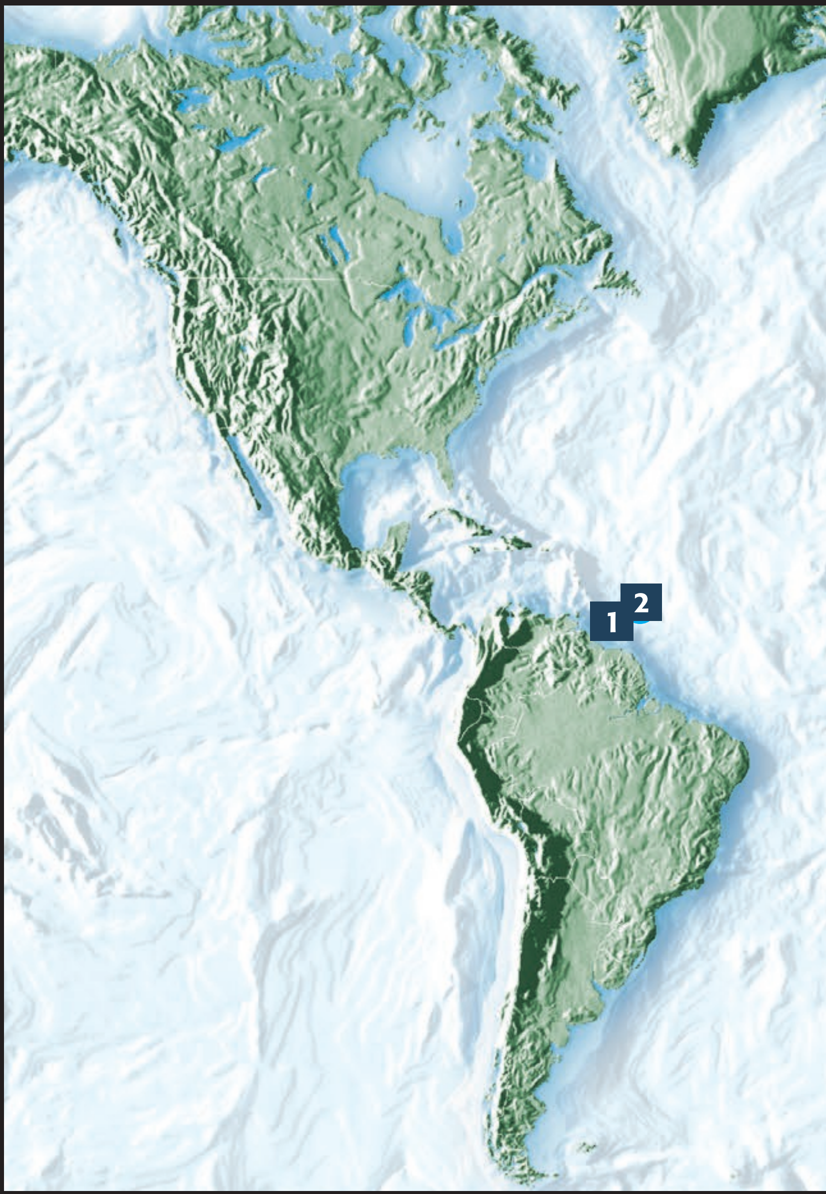
–By Larry Prado, Activity Editor

1 Guyana

Exxon Mobil announced two additional reservoirs in the Stabroek Block offshore Guyana. The additional reservoirs are adjacent to and southeast of the Yellowtail Field discovery well. According to partner Hess Corp., these are the 17th and 18th oil discoveries on the block. The new findings increase the recoverable resource base to more than 8 Bboe. The most recent well, Yellowtail-2, was drilled about 1 mile southeast of Yellowtail-1 to appraise its size, and it found the two new discoveries adjacent to the discovery reservoir and below it. Drilling operations were recently suspended due to the COVID-19 pandemic, but operations are continuing at exploration well Redtail-1, which is northwest of Yellowtail-1. The reported net production from the Liza Field averaged 22,000 bbl/d of oil in the second quarter of 2020, but the field hit 120,000 bbl/d in the third quarter after the commissioning of water injection equipment and bringing gas injection fully online.

2 Suriname

A discovery was reported in offshore Suriname's Block 58 by Apache Corp. The Kwaskwasi-1 well was drilled to 6,645 m and hit 278 m of net oil and volatile oil/gas condensate pay in multiple stacked targets in Upper Cretaceous Campanian and Santonian intervals. The shallower Campanian interval contained 63 m of net oil pay and 86 m of net volatile oil/gas condensate pay. Samples indicate between 34°API and 43°API oil. The deeper Santonian interval contains 129 m of net hydrocarbon reservoir. After completion operations are done at Kwaskwasi-1, the rig will be moved to drill Keskesi East-1. Apache has identified at least seven distinct play types and more than 50 prospects within the thermally mature play fairway.



3 Norway

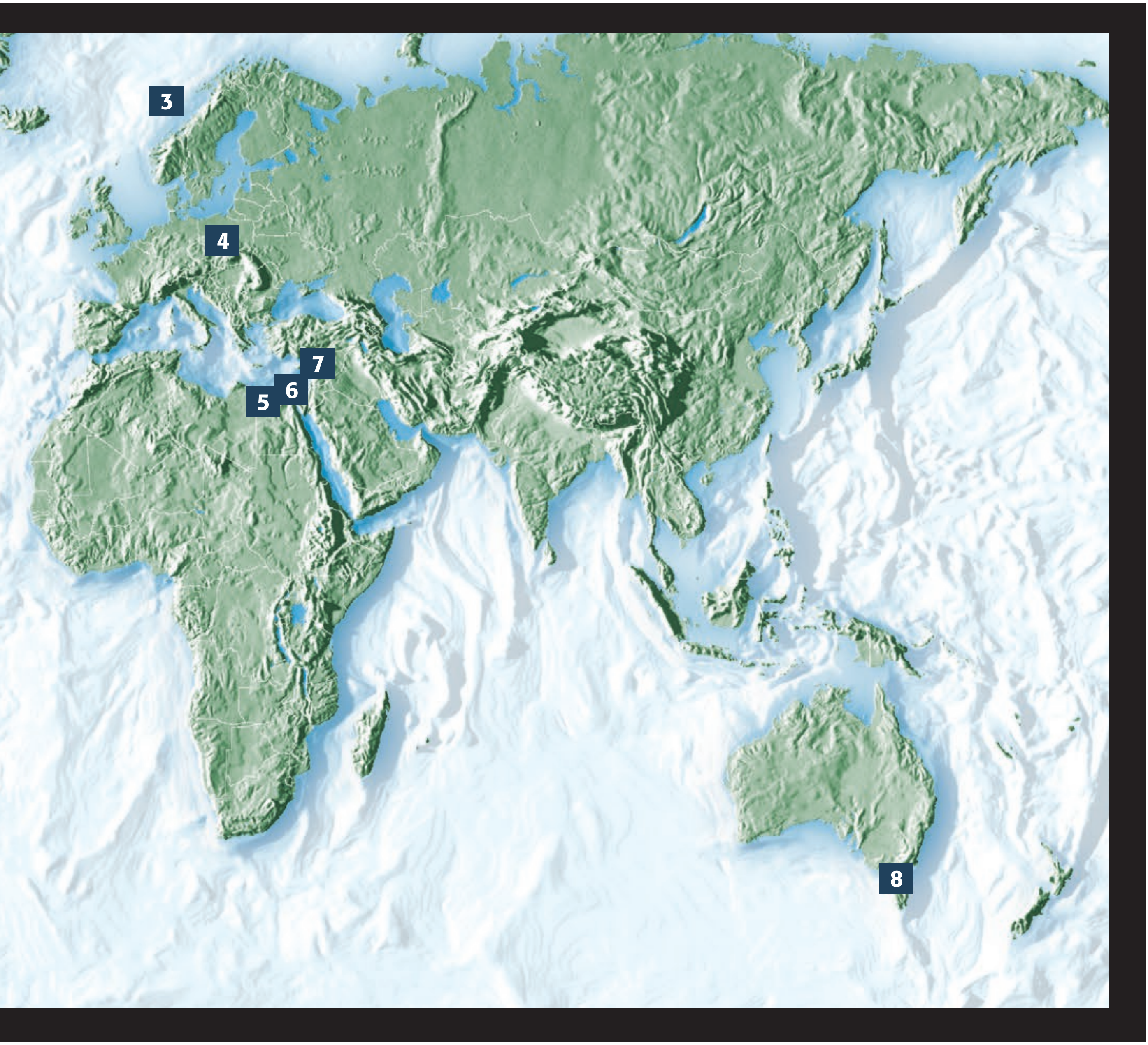
Neptune Energy has confirmed the commercial discovery of oil at the Dugong prospect in PL882 in the Norwegian sector of the North Sea. The volumes are estimated to be in the range of 40 MMboe to 120 MMboe. The discovery has significantly de-risked another prospect in the license estimated by Neptune at 33 MMboe and an estimated total resource potential in PL882 to as much as 153 MMboe. The Dugong prospect consists of two reservoirs at a depth between 3,250 m and 3,500 m. Area water depth at the site is approximately 330 m, and it is close to production facilities. Discovery well 34/4-15 S and the downdip sidetrack 34/4-15 A proved oil in the Viking and Brent Groups of the prospect. These are the first exploration wells in PL882. The well will be plugged and abandoned. Neptune Energy is the operator of PL882, Block 34/4 and 34/4-15 S with 40% interest in partnership with Concedo (20%), Petrolia (20%) and Idemitsu Petroleum (20%).

4 Poland

Polish Oil and Gas Co. completed another well in the Mielec–Bojanów fields at Korzeniówek-2K. Together with the previous appraisal well in the area, Korzeniówek-1, it will add approximately 9.5 Bcf/year of gas to the company's gas output. Both discoveries are in Debica County and produce from the Carpathian Foredeep Basin (Miocene).

5 Egypt

In the Western Desert in the Southwest Meleiha Concession, Eni announced a discovery in the Faghur Basin. The SWM-A-6X well was drilled to 15,800 ft and encountered 130 ft of net oil pay in Paleozoic sandstones of Dessouky. It was tested flowing approximately 12,000 bbl/d of oil and is about 130



km north of the Siwa Oasis in the basin. The well was already placed onstream with an output of 5,000 bbl/d of oil.

6 Egypt

Eni announced a gas and condensate discovery at the Bashrush 1 prospect in the North El Hammad Concession in the Egyptian sector of the Nile Delta in the Mediterranean Sea in Block 7. The discovery well was tested flowing about 32 MMcf/d of gas. The test was constrained by equipment capacity and is projected to be capable of an output of up to 100 MMcf/d of gas with 800 bbl/d of condensate.

7 Israel

Zion Oil & Gas has received drilling plan approval from the Israel Ministry of Energy for Megiddo Jezreel 2 on the 99,000-acre Megiddo-Jezreel license area in northeastern Israel. The well has a planned depth of 4,000 m. According to the company, the rig delivery has been delayed due to COVID-19 and restricted visa issuance within Israel for Zion's rig crews.

8 Australia

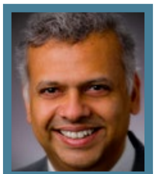
A gas discovery in offshore Australia's Otway Basin was reported by Origin Energy Ltd. at Thylacine-1. The well is in Tasmanian permit T/30P. Preliminary estimates of in-place reserves may be more than 600 Bcf and may exceed 1 Tcf. The 281-m gross gas column is in the Cretaceous Waarre Sand. Additional testing and exploration are planned. +

–By Larry Prado, Activity Editor

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

On The Move

PEOPLE


Saligram

Weatherford International Plc has selected **Girish K. Saligram**, previously COO at Exterran Corp., as its next president and CEO. Saligram's appointment, which includes a seat on the Weatherford board, takes effect Oct. 12. The top position has been vacant since early June following the resignation of former CEO **Mark A. McCollum**.

Hurricane Energy Plc has appointed **Antony Maris** CEO and executive director.


Walker

Lundin Energy AB has named **Nick Walker** president and CEO, following **Alex Schneiter's** decision to step down from the position. This will become effective Jan. 1, 2021. Walker has been COO of Lundin Energy since 2015. **Daniel Fitzgerald** has been appointed COO, effective Jan. 1. Fitzgerald is currently COO of International Petroleum Corp.

Ithaca Energy Ltd. has appointed **Bill Dunnett** CEO, taking over the role from his predecessor **Les Thomas**.


Pierce

Scientific Drilling International (SDI) has named **Pamela S. Pierce** its CEO and president, a position she has held on an interim basis since May. Pierce joined SDI's board of directors in June 2011 and was lead director for the past year. She will continue to serve as a member of the board of directors.

SeekOps Inc., a developer of advanced sensor technology for the energy sector, has strengthened its leadership team with the appointment of **Iain Cooper** as CEO.


Broussard

Abrado, a provider of downhole milling tools, has selected **Jason Broussard** as president and CEO. He will be based at the company's office in Broussard, La. With two decades of experience in upstream well operations, Broussard joins Abrado from Wellbore Fishing & Rental Tools, where he was senior vice president of operations. Prior to that, he held several management positions at Schlumberger (four years) and Baker Hughes (11 years).

Penn Virginia Corp. announced the concurrent retirement of **John A. Brooks** and appointment of **Darrin J. Henke** as president, CEO and director of the company.

Whiting Petroleum Corp. has appointed **Lynn Peterson** CEO, effective as of the company's anticipated emergence from chapter 11, which is projected to occur on Sept. 1. Peterson succeeds **Bradley J. Holly**, who will resign effective at that time to pursue other interests following the company's restructuring. Peterson will also join the company's board of directors.

International Petroleum Corp. has named **William Lundin** COO, effective Dec. 1.

Brian Cothran has joined Venture Global LNG Inc. as COO.

Quantum Energy Partners tapped **Sebastian T. Gass** from Chevron Corp. to lead the private-equity firm's digital transformation as CTO.

Battalion Oil Corp. has appointed **Kevin Andrews** executive vice president, CFO and treasurer, replacing **Ragan Altizer**, who plans to retire from the oil and gas industry.


Gattei

Francesco Gattei has taken up the role of CFO at Eni. Gattei is tasked with supporting the CEO in developing and implementing Eni's economic and financial strategy during the phase of accelerating the company's decarbonization plan.

Blueknight Energy Partners LP has appointed **Matthew R. Lewis** CFO.

Matthew DeNezza has joined Crusoe Energy Systems Inc. as CFO.

PBEX Resources LLC, a privately held oil and gas operating company, has promoted **Tom Taccia** to president.

Bryan Milton, president of Exxon Mobil Fuels & Lubricants, retired Sept. The board of directors has appointed **Ian Carr** president of Exxon Mobil Fuels & Lubricants Co. and elected him as vice president of Exxon Mobil Corp.


Milne

Sercel-GRC has named **William H. 'Willie' Milne** vice president, major accounts and operations. Milne will also be appointed to the Sercel-GRC Strategic Leadership Team. Based in Tulsa, Okla., Milne will be responsible for growing relationships with U.S. domestic oilfield service companies and developing new business with clients in the artificial lift sector. He will also oversee the sales administration and customer service departments.

ChampionX Corp. has appointed **Byron Pope** to the newly created role of vice president of ESG and investor relations.


Hermansen

Jōb Industrial Services, an engineering, procurement and construction company serving the oil and gas industry, has promoted **Steve Hermansen** to vice president of engineering and **Lisa Tyree** to vice president of sales and marketing.

GoExpedi, an e-commerce, supply chain and analytics company, has named **Noel Connolly** senior vice president of digital strategy.

The Plaza Group, an international petrochemical marketing firm, has promoted **Jose Flores** to executive vice president.

BCCK Holding Co., a provider of in engineering, procurement, fabrication and field construction services, has appointed **Thai Pham, P.E.** senior process engineer. Pham will be located in BCCK's office in The Woodlands, Texas, and will be responsible for supporting proposals and technology developments across the company.

WAGO has promoted **Clayton Windsor** to product manager of DIN rail mount terminal blocks.

Total Lubricants USA Inc. has appointed two new additions to its sales team: **John Neucere** as the new district sales manager and **Zachary Wells** as the technical sales representative.

Sparrows Group has appointed **Ali Hassan Al-Kharari** as the company's first Saudi Arabia general manager.

Renewable Energy Group Inc. has hired **Trisha Conley** to serve as vice president of people development.

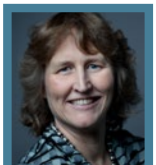
International SOS has appointed **Carolyn Taylor** as head of mental health, resilience and wellbeing to strengthen its expertise in this field, which is an increasing issue for the offshore energy workforce.

GeoPark Ltd. has appointed **Somit Varma** a new independent member of the board of directors, filling an existing vacancy.

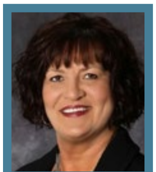
Flotek Industries Inc. has welcomed **Harsha V. Agadi** to its board of directors. He will also serve as the chair of the compensation committee.

GEOSPACE Technologies' **Michael J. Sheen**, senior vice president, CTO and executive director, will retire from the board of directors, effective February 2021. Additionally, **William H. Moody (Hank)** retired from the board of directors Sept. 30, and **Charles H. Still (Hank)** retired from the board of directors June 30. With these changes, the board will be downsizing and will eliminate the director seats held by Still and Moody. **Thomas L. Davis** will replace Still as the lead independent director.

Rolake Akinkugbe-Filani and **Robert Erlich** have joined the African Energy Chamber's advisory board for 2020 and 2021. Akinkugbe-Filani will be advising and supporting the African Energy Chamber within its investment and energy transition committees. Erlich will be advising and supporting the work within the exploration committee.


Taylor

Flowserve Corp.'s board of directors has elected **Carlyn Taylor** as an independent director and a member of the Audit Committee and the Corporate Governance & Nominating Committee of the board.


Hardwick

The board of directors of New Jersey Resources, a provider of natural gas and clean energy services, has elected **Susan Hardwick** to the board. Hardwick currently serves as executive vice president and CFO of American Water.

Xcel Energy has elected **Patricia L. Kampling** as a new board member.

IHS Markit has appointed **Gay Huey Evans** OBE an independent director to its board. She will also join the company's audit committee.

McDermott International Inc. has tapped **Andrew F. Gould**, the former head of Schlumberger Ltd., to serve on its board of directors.

COMPANIES

Schlumberger New Energy, a new Schlumberger business, and **Thermal Energy Partners** have entered into an agreement to create **STEP Energy**, a geothermal project development company. STEP Energy will leverage its partners' expertise to develop efficient and profitable geothermal power generation projects, providing an opportunity to support a reliable supply of clean energy.

Kemper Valve & Fittings (a Caterpillar company) has introduced a mobile command center that can operate from a customer's site, providing the benefits of reduced downtime, quality work and lower operator safety risks. Kemper's command center is equipped with lifting devices, power generation, compressed air and a closed-loop recirculation system.

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On The Move

Oxy Low Carbon Ventures, a subsidiary of **Occidental**, and **Rusheen Capital Management**, a private-equity firm, have formed a development company, **1PointFive**, to finance and deploy Carbon Engineering's large-scale direct air capture technology.

Baker Hughes Co. agreed to sell the surface pressure control flow business unit in its oilfield equipment segment to **Pelican Energy Partners LP** for an undisclosed amount on Sept. 10. The sale follows comments CEO Lorenzo Simonelli made recently about downsizing Baker Hughes' oilfield services and equipment portfolio in preparation for the energy industry's transition to a low-carbon future.

BP Plc agreed on Sept. 10 to acquire $1.1 billion in interests in existing U.S. offshore wind developments from Norway's **Equinor ASA**. The acquisition marks BP's entry into offshore wind and follows a new strategy that sees the British oil major accelerating its shift away from fossil fuels to achieve its ambitions of net-zero emissions by 2050. +

AD INDEX

The intersection of sustainability and digital

Meeting the challenge of sustainable operations requires embracing innovation and driving high performance.

Lees Rodionov, Schlumberger

Demand from the global community for our industry to employ a more sustainable method of providing access to energy continues to grow. While the global pandemic prompted a drastic change in the way we work, our industry was already undergoing a significant transformation. We have been working to answer the global call to action introduced by the U.N. with the Sustainable Development Goals. We have moved beyond simply meeting an expectation—we are committed to building sustainable operations across the entire E&P value chain.

Meeting this challenge requires embracing innovation and driving high performance, and doing so more safely and sustainably than in years past. Schlumberger is focused on creating technology that unlocks access to energy in this new environment. Customer centricity, digital enablement and sustainability are all elements of our strategy. We see the intersection of the three as an opportunity to steer a transformational change to our industry's operational footprint.

To do this correctly and fully realize sustainability ambitions, the industry must address the entire E&P value chain, starting at the planning stages. This includes managing the environmental footprint, including emissions, throughout the life cycle of our sourcing decisions, in addition to properly managing logistics, facilities, operations and, ultimately, the use of technology by operators.

Schlumberger is leveraging its digital investment internally while incorporating sustainability into engineering and operational practices, in addition to working closely with suppliers. This allows us to mitigate risk, enhance efficiency and more proactively reduce harmful environmental impacts from our operations. For example, we can complete remote digital inspections and prognostic health monitoring of field equipment, which decreases necessary visits to the well site, simultaneously reducing emissions and safeguarding workers.

Another example is how we integrated smart systems throughout the operational logistics workflow in Saudi Arabia to reduce the number of partially loaded trucks. Insight gained from that analysis enabled us to lower the logistics mileage driven, reducing vehicle-related emissions in Saudi Arabia by 21% over just two quarters (fourth-quarter 2019 to second-quarter 2020).

For our customers, Schlumberger can eliminate manual operations and downtime through the use of intelligent Industrial Internet of Things (IIoT)-enabled systems. The incorporation of edge computing—for example, through Agora, a Schlumberger startup venture focused on delivering edge computing and IIoT solutions to the oil and gas industry—enables production engineers to quickly analyze rod pump condition data to take corrective actions with no delays. This allowed one operator to increase production by 5% and reduce driving to the well site by 5,500 miles per month.

Additionally, by evaluating customer operations from site preparation through to production, we are able to model environmental metrics (e.g., emissions, waste, water, etc.) during key upstream and midstream activities. Doing so aids in understanding the environmental trade-offs of various operational choices during the planning stages.

By combining our digital domain and technological expertise with our leadership in sustainability, we are driving high-performance sustainably jointly with our customers and suppliers. As the global community calls upon our industry to deliver safer and more sustainable means to provide access to energy, we must leverage digital enablement to deliver more sustainable operations and to positively impact the communities where we live and work. +

Editor's note: *Lees Rodionov is the global director of sustainability with Schlumberger.*

(Source: Schlumberger)