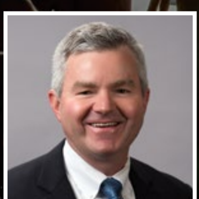
HARTENERGY SEPTEMBER 2020

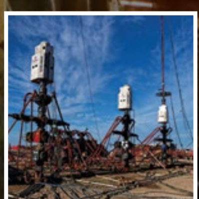
E+P plus

The Other Side

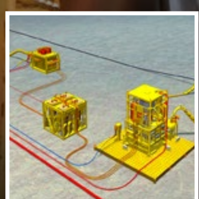
As the oil and gas industry regains strength, companies could emerge anew



Q&A with Clay Williams

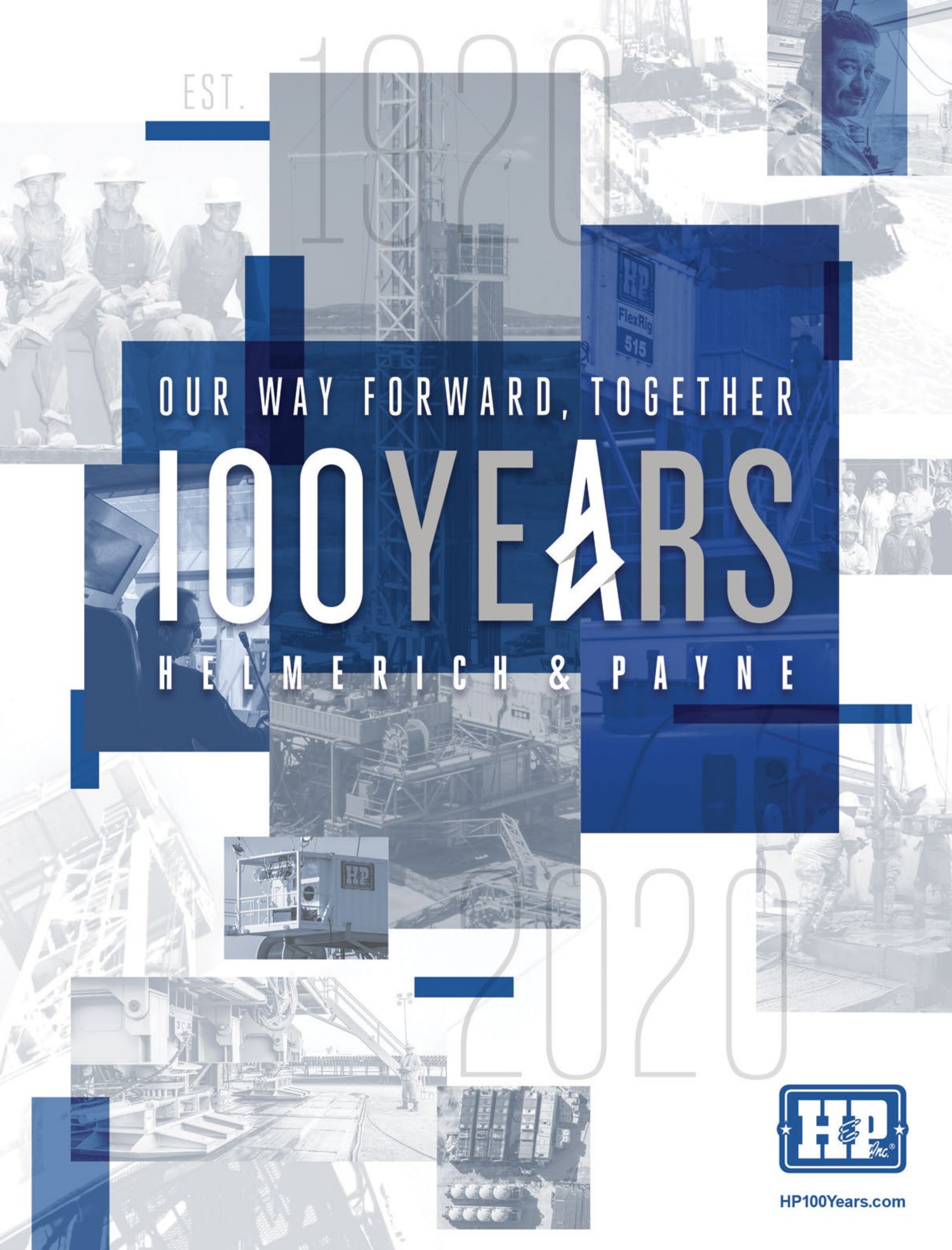


Completions Automation



Innovation Spotlight

2020 MEA Winners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1616 S. VOSS ROAD, STE 1000
HOUSTON, TEXAS 77057
P: +1 713.260.6400 F: +1 713.840.0923
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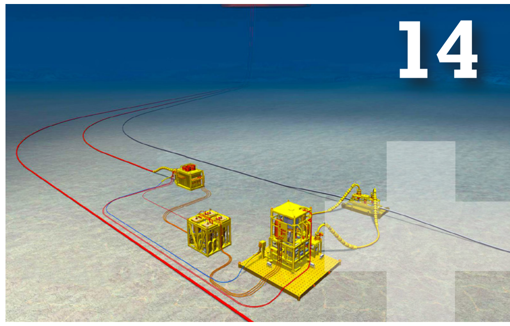

About The Cover: As the world recovers from the COVID-19 pandemic, energy demand is slowly picking up. Energy companies around the world are evaluating their assets and operations to ensure they emerge in the best possible position to capitalize on a new era of oil and gas production. *(Cover photo courtesy of Marc Morrison/marcmorrison.com; Bottom images from left to right courtesy of National Oilwell Varco, Downing USA, TechnipFMC and Hart Energy; Cover design by Alexa Sanders)*

Coming Next Month: The October issue's cover story will focus on ESG. The Executive Q&A will feature an exclusive video interview with Baker Hughes Chairman and CEO Lorenzo Simonelli, and the Regional Report will highlight South America. As always, **E&P Plus** will include its exploration, drilling, completions, production and offshore features in every issue. While you're waiting for your next copy of **E&P Plus**, be sure to visit **HartEnergy.com** for the latest news, industry updates and unique industry analysis.

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New methane 'heat map' to help oil companies reduce emissions

By Mary Holcomb, Associate Editor

A new digital tool set for release later this year by Geosite will provide the oil and gas industry with actionable satellite imagery for the detection of high-methane emissions events.

Buffalo Bills owners' blank-check company raises $300 million

By Darren Barbee, Senior Editor

Terrence M. Pegula joins other NFL owners, most notably Dallas Cowboys owner Jerry Jones, in making large new investments during a stagnant time for the oil and gas industry.

Texas takes steps to reduce flaring in oil sector

By Velda Addison, Group Senior Editor

Changes would include reducing the amount of time an operator may get an administrative exception to flare natural gas.

Experts expect tough second half ahead for oil sector

By Velda Addison, Group Senior Editor

Oil and gas companies face continued market volatility despite an already historic year so far.

Exxon Mobil, Chevron adjust in Permian Basin amid market volatility

By Velda Addison, Group Senior Editor

The supermajors are focused on specific developments and improving efficiency in the Permian Basin as market conditions recover.

Tokyo Gas takes first majority stake in US shale producer

By Darren Barbee, Senior Editor

Tokyo Gas will pay about $620 million as it increases its ownership in Castleton Resources, a U.S. shale gas operator focused on being a consolidator of E&P assets in the Ark-La-Tex region.

HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

WPX Energy's Clay Gaspar talks Permian outlook, ESG, tech

Clay Gaspar, president and COO at WPX Energy, provides an in-depth look at the shale producer's outlook for the Permian and Williston basins along with the importance of ESG.

Advisers coauthor book to help upstream companies process risk

Risked Revenue Energy Associates President and Founder Wayne Penello and Managing Director Andrew Furman preview their book, which was released Aug. 11.

Grant Thornton's Bryan Benoit talks oil industry recovery

After a rough second quarter that included a historic collapse in oil prices, Bryan Benoit, a principal with Grant Thornton Financial Advisors who also leads the firm's energy advisory practice, says he's starting to see green shoots ahead for the industry.

ESG roundtable: Is oil and gas ready for the expectations, opportunities?

If the industry wants continued capital investment, it will have to up its game. Our virtual panel discusses what you need to know to be ready for increased scrutiny and requirements of an ESG future.

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ACOUSTIC IMAGING TECHNOLOGY

DarkVision's high resolution acoustic imaging technology gives you the ability to see inside your wells regardless of fluid clarity or condition. The HADES™ platform captures and delivers three dimensional data with unprecedented detail for all completions optimization and well integrity applications - whether it's perforations, sliding sleeves, FCDs, casing integrity, scale buildup, wellhead integrity, or wellbore restrictions.

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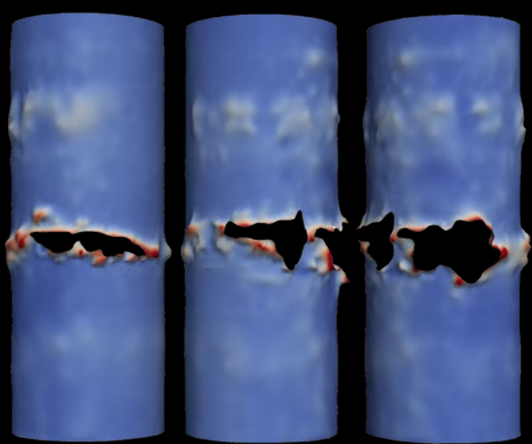
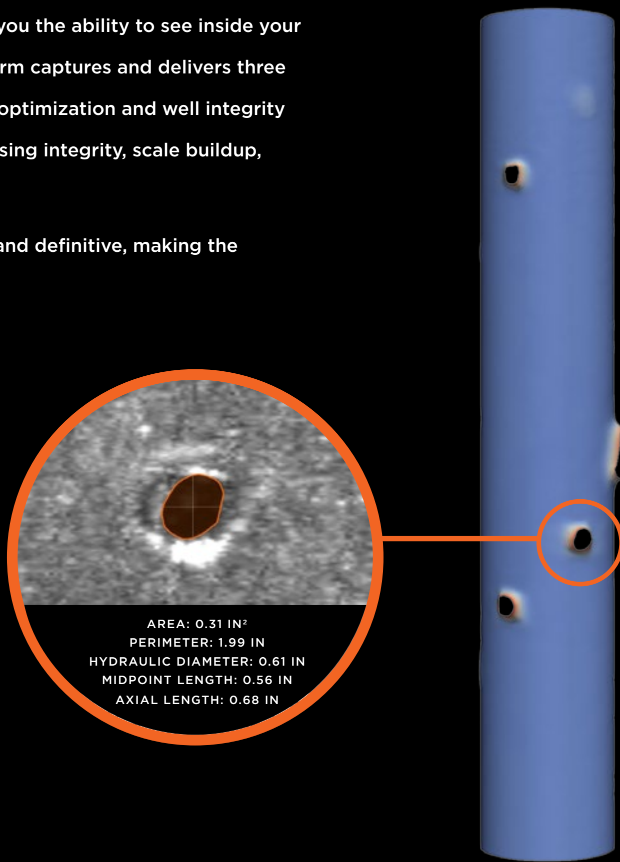


High Resolution 3D Images of Casing Breaches at Plug Depth



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As I See It

Slow down or accelerate?

We are launching E&P Plus for a new era of oil and gas.

It was Independence Day in the U.S. when it hit me. Not a backyard firework, although I did have to dodge a few wayward bottle rockets. I was struck by an epiphany that the COVID-19 pandemic isn't a time to feel sorry for ourselves; it's a chance to embrace a future we probably already saw coming, even if it's hard to admit sometimes.

This notion got into my head with a simple answer to a question I posed to my family. I pondered what the holiday shopping season would be like this year given crowded stores are unlikely. The answer I got from a niece was matter-of-fact and telling. "I haven't done Christmas shopping in a store in two years," she said.

Retail job losses are a serious problem we're facing, but shopping has already mostly gone digital and will continue to do so. It's a tough reality to face, but there's opportunity in change.

We see similar things happening in the oil field. Much of our technology and production content has transitioned to stories about the digital oil field, drones, artificial intelligence, data gathering and how their growing presence in the industry lets producers accommodate lower breakeven prices and, of course, manage through price fluctuations.

Let's not mince words. This year's double whammy of COVID-19's effect on oil demand and $40 oil brought on by an ill-timed muscle-flexing contest by Saudi Arabia and Russia in the spring has increased the need to be creative, nimble, fast and, in many cases, digital. This is not the time to put future plans aside; it's a chance to accelerate them.

The E&P team, and Hart Energy as a whole, have always been with you in good times and bad, and we'll continue to do so. Some things never change. While the industry's service sector faces a battle like it's not faced in recent memory, we feel its pain too. While producers ponder cost efficiencies and possible consolidation, we understand their plight.

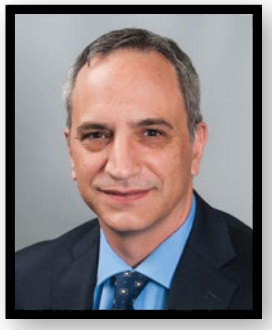
As many of you already realize, we're here to help you with quick, accurate and easily accessible information. Our goal remains connecting you to solutions. We also realize the future of operations is likely to be different, and you'll need to find those solutions much more efficiently.

That's why we are launching **E&P Plus** for a new era of oil and gas. We're digital, and we're faster. We're nimble this way, and we want you to get the latest information on trends, new technology and data when you need it. We're also putting you in more direct contact with the industry executives and analysts who have fed us information for so many years. We've added video interviews and interactive charts to the mix, for example—things we wouldn't have been able to offer you in a static print product.

Of course, **E&P Plus** is more efficient as well. We're operating on shorter lead times, which means our content is fresh and new, with the added benefit of being updated even after publishing. We're integrating **E&P Plus** with HartEnergy.com, which means you'll be able to access updated content and data whenever you need it, wherever you're working from these days.

We're excited to launch **E&P Plus**, and we hope you enjoy it. +

Len Vermillion



Len Vermillion
Editorial Director
lvermillion@hartenergy.com

We're excited to launch E&P Plus, and we hope you enjoy it.

Read more commentary at
HARTENERGY.COM

BCG's low-carbon strategy for upstream players focuses on reducing their carbon footprint while providing financial value to companies in the low-price environment. (Source: Leonid Ikan/Shuterstock.com)

How upstream players can decarbonize with positive returns

A company's detailed road map outlines how to design a cost-effective decarbonization strategy.

Faiza Rizvi, Associate Editor

Despite a rebound in oil prices, resurgent waves of the COVID-19 show the industry's recovery remains fragile. In addition to dealing with the volatility of the near-term market environment, upstream companies face a longer-term challenge of reducing emissions, with growing pressure from regulators, investors and other stakeholders. Although many upstream companies have made considerable progress in meeting climate change goals, they will have to play a bigger part going forward as stakeholder pressure and expectations continue to rise.

Boston Consulting Group (BCG) has outlined a cost-effective approach, which offers to shrink a company's carbon footprint and strengthen its social license to operate and increase revenue growth.

"The industry is facing a challenging time. Upstream players are making spending cuts, and it is likely they will focus on core operations and avoid making additional investments," Thomas Baker, managing director and partner with BCG, told E&P Plus. "That being said, we think there is still a role for decarbonization, and in fact, the current environment creates an important opportunity to potentially accelerate these activities. Many of these measures can be cost-effective and provide lower capex, improved output and have a financial benefit for the players."

Objectives

To design an effective decarbonization strategy, BCG suggests it is crucial the company meets regulatory requirements of the country in which it operates.

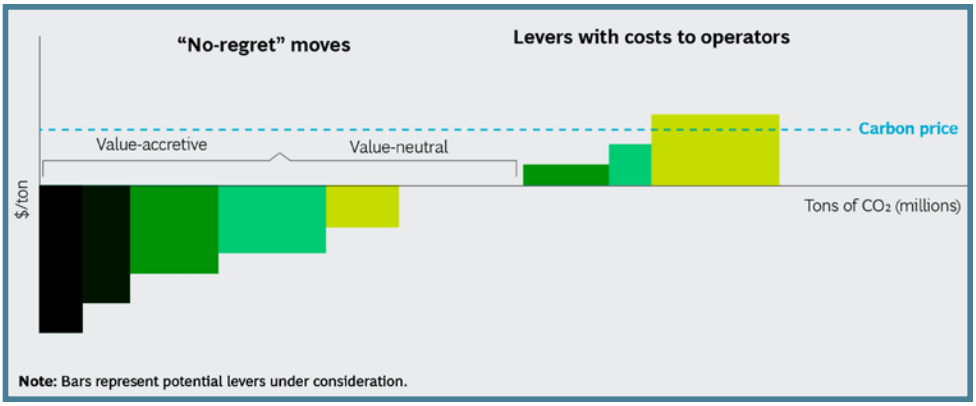
"Regulatory environment is a critical piece in decarbonizing the oil and gas sector," said Ilshat Kharisov, managing director and partner with BCG. "What we've seen working effectively is when regulatory bodies work together with oil and gas companies to figure out the most economical solutions to decarbonize. In areas such as the EU and California, where regulations are progressive, we have seen great examples of bold actions taken by companies to reduce emissions and carbon footprints. Regulatory bodies will need to work with oil and gas companies to figure out best opportunities to steer investments in carbon capture to achieve climate change goals."

While the EU has clearly established carbon-pricing schemes and net-zero emissions targets, carbon emission rules in the U.S. vary considerably from state to state. For instance, California's Low Carbon Fuel Standard Program incentivizes upstream players to produce low-carbon intensity crude oils. Other local regulations, such as fracking bans in New York and water-disposal policies in Pennsylvania, have a strong impact on company operations in those states.

In addition to meeting regulatory requirements, BCG's strategy also stresses the importance of communication with key stakeholders to ensure the strategy is tailored to suit the needs of the company, which should adopt transparency while setting low-carbon goals and establish a tracking mechanism to monitor progress over time. An effective decarbonization strategy should also ensure the company retains its social license to operate, which demands active engagement with its stakeholders. The plan should include involvement of communities through job creation and communicating to them the local environmental effects of the business.

Companies should also discuss low-carbon policies and sustainability goals with current and potential employees to attract and retain top talent.

A cost-effective plan to decarbonize operations must also identify business opportunities that emerge as a result of meeting climate goals. BCG has outlined possible opportunities that include initiatives that leverage a company's core business and capabilities, such as the monetization of project management capabilities or offering a new technology as a service, such as solar assets, hydrogen fuel as well as carbon capture, utilization and storage (CCUS). Companies could also acquire conventional assets and manage them in a way that reduces the assets' carbon intensity.



Once decarbonization levers have been identified, BCG ranks them according to efficiency, financial impact and other relevant factors. (Source: BCG)

BCG's strategy emphasizes "value-accretive" decarbonization that is tailored to each company's set of constraints and opportunities. One of the most important goals while designing a low-carbon plan is to identify potential new revenue sources, while providing financial value to companies.

For instance, BCG designed a decarbonization plan for a U.S.-based upstream operator focused on the acquisition of low-carbon assets, adoption of energy-efficient measures aimed at optimizing operations and reducing costs, realization of new revenue streams based on regulatory incentives and the launch of step-out businesses. Once fully implemented, the strategy increased the company's enterprise value by 30% and put the company on course for a roughly 90% reduction in its carbon emissions by 2040.

Approach

According to BCG's findings, most companies could reduce their carbon emissions by 10% to 20% without a negative impact on the company's return on investment. Also, many companies could further slash their emissions by 30% to 40% while still maintaining a positive internal rate of return, depending on the type of assets the company owns and the regulatory mandates where it operates. BCG's outline for reducing a company's carbon footprint is based on a company-specific approach tailored to suit each player's operating environment, assets and regulatory constraints.

Instead of targeting emissions of individual hydrocarbon streams, BCG suggests companies should focus on cutting the overall carbon intensity of their operations, which has proven to be the most efficient approach for companies in reducing net emissions.

After outlining the goals, the company should evaluate external factors such as population, demographic shifts and societal concerns about climate change and the environment. External factors also include regulatory constraints, incentives to grow acceptance, usage of green technologies, and progress toward carbon pricing and related schemes.

Once external factors have been evaluated, BCG explores different phases of the company's value chain to identify opportunities of reducing carbon emissions. For instance, the exploration phase should reflect the growing importance of low-carbon-intensity assets in a portfolio.

As Kharisov explained, "Investments made at the exploration stage are typically long-term. Therefore, it is a very critical to look at the carbon intensity of the crudes and study regulatory developments as well as the final requirements, expectations and the economics of those oil fields."

For instance, in California, where oil reserves are highly carbon-intensive, unless the current oil and gas companies start decarbonizing actively, there is no business case to produce crudes actively over the next 10 to 15 years.

"I think carbon intensity of the crudes will play a critical role in portfolio decisions over the next few years. We can already see major moves like divesting high-carbon-intensity assets from major oil companies' portfolio as a way to reduce their carbon footprint. As this happens, we might see some of those assets being stranded," Kharisov added.

During the design and sourcing phase, BCG suggests companies could realize decarbonization goals by applying lean principles and tools to asset operations, electrifying operations where possible and using remote control centers. Upstream players can create incentives for suppliers to reduce their emissions footprint by employing carbon as a key metric in vendor selection and evaluation.

Lastly, in the operations phase, decarbonization levers include optimizing operational cycle times, improving fleet performance and routing, using zero-carbon electricity, improving energy efficiency, reducing flaring and methane leakages, and installing CCUS technologies.

Once available measures across the value chain are identified and their efficiency is determined, BCG combines these measures with key social, regulatory and market trends to produce a ranking of potential decarbonization actions the company could take.

"In our study, we call these actions the 'no regret' moves, whose implementation provides negative cost for the company," Baker said. "In our experience working with operators, these moves could reduce up 25% to 50% of emissions and ultimately support companies in the low-price environment." +

Q&A

NOV's CEO shares his insights on the industry's path forward

Clay Williams
Chairman, President and CEO, NOV

Clay Williams discusses the future of onshore and offshore oil and gas development, the impact of the energy transition on oilfield service providers and more amid the challenging energy climate.

Jennifer Presley, Executive Editor

A focus of this month's issue of E&P Plus is on what the oil and gas industry will look like as it moves forward into a post-pandemic world. It is a world that is a little bit different than the one the predecessors for the company that would become National Oilwell Varco (NOV) witnessed more than a century ago.

Clay Williams, the chairman, president and CEO of NOV, recently provided E&P Plus with an exclusive video interview in which he shared his views on the way forward for oilfield service companies.

"Our industry is going to have to put up better financial returns, but above all, we're going to, most importantly, make sure that we're adding value to the operations of oil and gas companies because they're facing similar challenges," he said. "If the value that we bring to their operations isn't tangible and demonstrable, they can't afford to pay for it. And so all of us, I think, across oil and gas broadly are going to have to head to a world where we're more efficient and better at what we do."

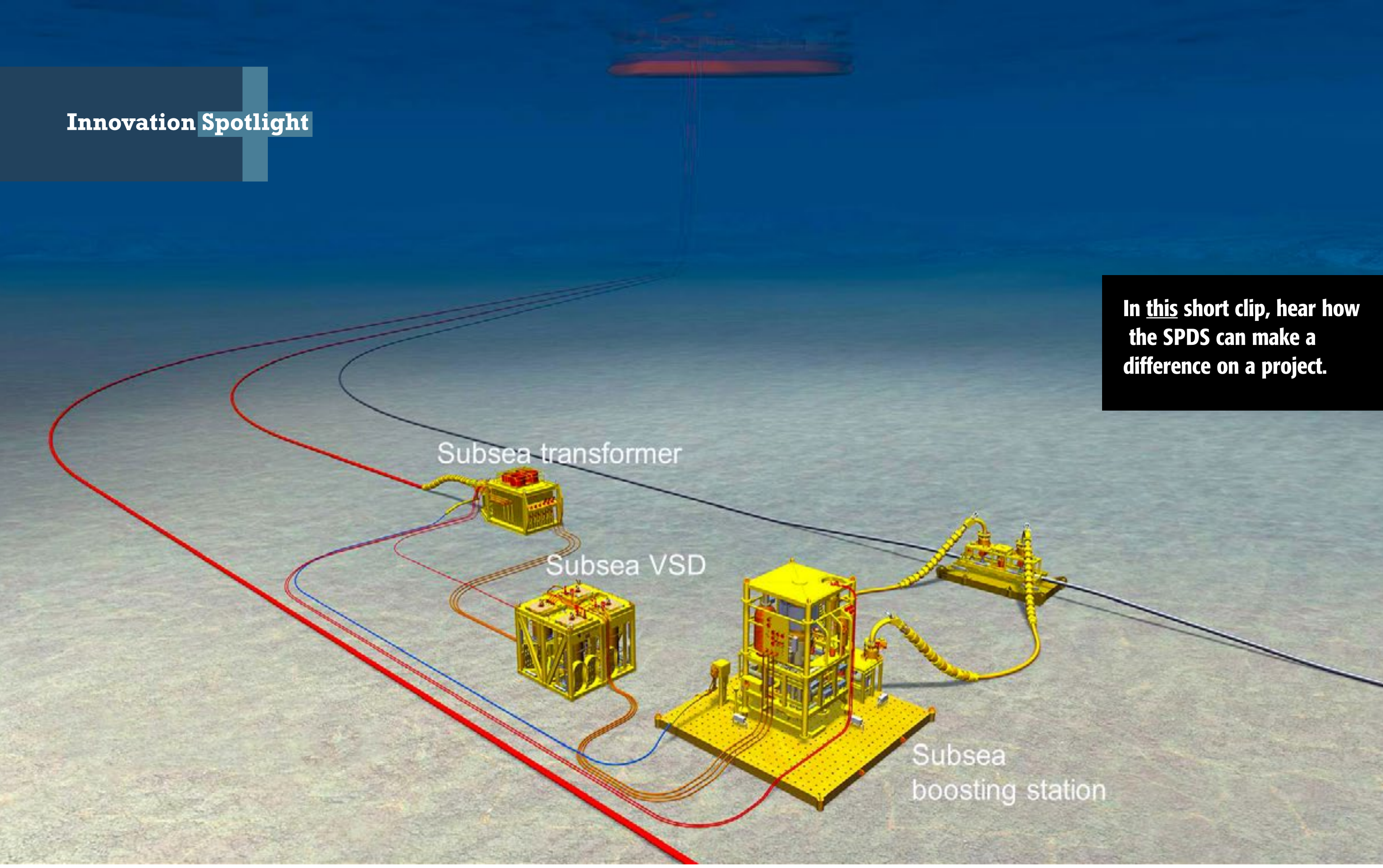
In this exclusive video interview, NOV CEO Clay Williams discusses the energy industry's recovery post-pandemic.

"All of us across oil and gas broadly are going to have to head to a world where we're more efficient and better at what we do."

– Clay Williams, NOV

He shared the company's efforts and its role in the current energy climate, the impact of digital on accelerating the energy transition and more in the interview. Williams also noted for those just getting started in the industry that while it has seen its ups and downs, it is essential to remember there is always another side.

"We're going to see prosperity return. We're going to get busy again. And so I would tell you hang in there. This is going to get better, and you'll look back at this time and realize that you probably grew more through the downturn than you may fully appreciate right now," he said. "But when I look back on my own career…I credit the downturns and the tough times that I went through for really making me who I am." +



In this short clip, hear how the SPDS can make a difference on a project.

TechnipFMC shares insights on its 2020 OTC Spotlight on New Technology winning system

Eduardo Cardoso, director of subsea processing technologies, discusses the company's Subsea Power Distribution Station, the future of subsea power generation and more.

Jennifer Presley, Executive Editor

Today's smartphones have more processing power than the computing system NASA used to put a man on the moon and bring him home more than 50 years ago. The shared similarity is that without a steady supply of electric power, each would be a useless block of assembled raw materials.

On land, at sea or on the seabed, the challenge of providing a steady supply of electrical power to thirsty industrial consumers is a global one. For the oil and gas industry, the shift from topsides operations to subsea operations is underway. Ensuring safe and reliable subsea operations requires a safe and reliable source of electrical power.

Eduardo Cardoso, director of subsea processing technologies with TechnipFMC, discusses the company's Subsea Power Distribution Station (SPDS)—a 2020 Offshore Technology Conference Spotlight on New Technology award winner—the challenge of powering subsea systems and more in this E&P Plus inaugural "Innovation Spotlight."

E&P Plus: What is the Subsea Power Distribution Station?

Cardoso: The TechnipFMC Subsea Power Distribution Station comprises a variable speed drive [VSD] and transformer that are placed on the seabed, along with power-receiving umbilicals connected to a topside generator.

Each subsea processing system requires a pump for either injection or boosting, and every pump is driven by an electric motor that requires continued changes in the frequency of the power that is feeding the pump. When process dynamic changes happen in the system, the pump

needs to respond accordingly and change its speed. To change the speed, we need a VSD, which is the central piece of our SPDS.

Another piece of the SPDS is the transformer. The transformer matches the umbilical transmission voltage levels to the VSD voltage. It`s installed upstream the VSD and downstream the umbilical. These two pieces, VSD and transformer, are typically found on the topside. By relocating them to the seabed, we are decreasing the overall cost of the system while making it more reliable.

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

Cardoso: In addition to relocating the system to the seabed, our SPDS is scalable and modular. Each module of the VSD delivers up to 1.5 MW of power. So, if you want to build a 6-MW subsea power station, then you can add more of the modules in parallel to add up to 6 MW.

Current technologies available for subsea power distribution aim for higher power systems, for example 6 MW and up for compression systems. We saw that there was a need for a cost-effective option on the smaller applications projects that were cost-constrained overall and developed the SPDS to meet that need.

"As we learn more about the benefits and limitations of subsea power distribution, people will be more willing to entertain subsea-to-shore technologies."

– Eduardo Cardoso, TechnipFMC

E&P Plus: With the focus currently on doing more with less and making incremental advances on brownfield operations with new technologies, what role does the SPDS perform?

Cardoso: The difficulty that we have now is mainly on operating platforms, where there is a limited amount of space and small number of people to execute the work. The real estate is, many times, not available on the platform for a power distribution system, and the cost associated with accommodating the necessary structural upgrades can be substantial.

The SPDS is a very good fit, especially with brownfields, because it overcomes these challenges faced topside. In fact, we can reduce boosting costs by up to 60% on brownfield projects with the SPDS.

E&P Plus: Did the project design start with a fresh sheet of paper, or was it the combination of the best of other technology projects?

Cardoso: It's a mixture of both. We had the freedom to find a creative solution for the problem, but in search of the core issue, we understood that we also had to address costs, reliability and serviceability. We could have started from scratch. There's a lot of brilliant minds all over the world that would have loved to work on a problem like that. Still, we understood that it would be better for us to piggyback on existing technologies, experience and successes in the industry, and try to bring all of those into one program.

In this brief clip, TechnipFMC's Eduardo Cardoso discusses the importance of collaboration in these challenging times and how the SPDS team is coming together to innovate and create further advances.

That's why we partnered with WEG, an electrical motor and technology company, to get access to all of their learnings on the 1,000-plus units they have already sold into the land market. We then adapted their technology to the subsea environment, which is our area of expertise.

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

Cardoso: I see electrification growing. I like to say that, for example, YouTube was available way before high-speed internet was available. You had the video capability, but the infrastructure wasn't ready to stream videos at fast speeds. Subsea electrification is to subsea processing as high-speed internet is to YouTube. I can see electrification as an enabling technology for subsea processing.

As we learn more about the benefits and limitations of subsea power distribution, people will be more willing to entertain subsea-to-shore technologies. There will be decisions associated with AC versus DC as distances start to grow. There are advantages to both sides. I think that after 150 kilometers, the industry will start weighing pros and cons. Besides distance, power demand is critical as well. For example, if you have a big subsea production facility with all kinds of subsea equipment, the question of which type of transmission is more economical—DC or AC—will have to be considered further.

At the end of the day, when all of those technologies are more mature further down the road, then the industry will start thinking of offshore power generation and how to make it economically viable. +

Exploration for clastic stratigraphic traps

Explorers must recognize whether they have the right tools and processes to explore effectively for commercial finds.

Graeme Bagley and **Edwige Zanella**, Westwood Global Energy Group

Over the last decade, more oil and gas was discovered in stratigraphic traps than any other trap type, and excelling in stratigraphic trap exploration is now the key to top quartile exploration performance. Historically, hydrocarbon prospects in clastic stratigraphic traps have been considered difficult to identify and high risk to explore, but success rates have been improving with better geological models and use of geophysical direct hydrocarbon indicators (DHIs).

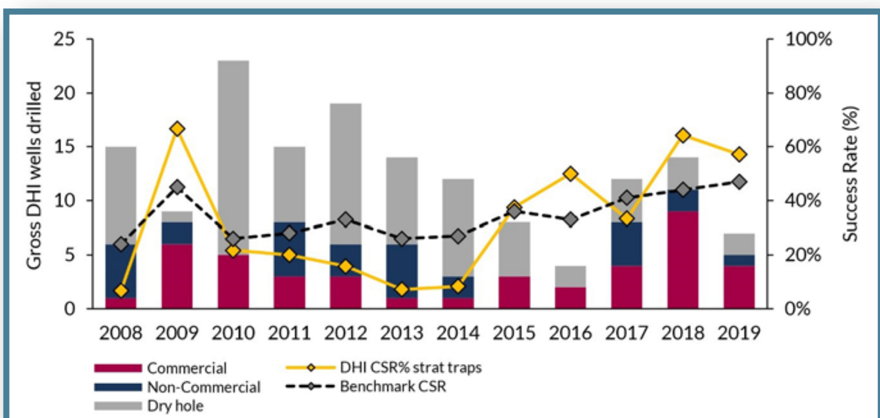
Westwood analyzed stratigraphic trap exploration between 2008 and 2019 in 66 basins and in 113 different plays. It found that the proportion of exploration targets reported as involving stratigraphic traps increased from 12% in 2008 to 30% in 2019. Commercial success rates (CSRs) also have increased, with the average CSR of 50% achieved between 2017 and 2019, double that of the previous nine years. Stratigraphic traps had a larger average discovery size of 280 MMboe, and a lower drilling finding cost of 0.5 $/boe, compared to other trap types during this period. The evidence shows they are not higher risk than other traps, contrary to many explorers' preconceptions.

Defining stratigraphic traps

Stratigraphic traps in clastic sediments are formed when reservoir sands are encased in sealing mudstones. Pinch-out traps are the most targeted clastic stratigraphic traps and involve the lateral and updip pinch-out of channels and lobes, or pinch-out of sand bodies by onlap onto an underlying unconformity. Stratigraphic traps also can be formed by erosional truncation, where the reservoir is sealed by younger mudstones infilling an erosional topography. Another kind of stratigraphic trap is formed by injectites, where unconsolidated sands are injected, post-deposition, into overlying mudstones forming dykes and sills.

Stratigraphic traps in clastic sediments can be formed in different tectonic settings and in different parts of the systems tract from fluvial to deep water, where there is a rapid transition from permeable sandstone to an impermeable facies. The major focus of stratigraphic trap exploration in the 2008-2019 period was Cretaceous- and Tertiary-aged deepwater turbidite complexes located in passive margin settings, which have delivered 31 Bboe of discovered commercial resources.

In the last 10 years, about 80 Tcf of gas (13 Bboe) has been discovered in stratigraphic traps in the Rovuma-Rufiji Basin offshore Tanzania and Mozambique, while another 24 Tcf of gas has been found across the continent in the MSGBC Basin. Stratigraphic traps contain more than 6 Bbbl of oil in the Suriname-Guyana Basin and over 2 Bbbl of oil in the Colville Basin in Alaska. Other prolific basins with significant numbers of stratigraphic traps include the Nile delta, Sarawak, Sergipe-Alagoas and the Tano basins. There have been notable failed stratigraphic trap campaigns as well in the Carnarvon, Sierra Leone-Liberia and Central North Sea basins from which important lessons have been learned.



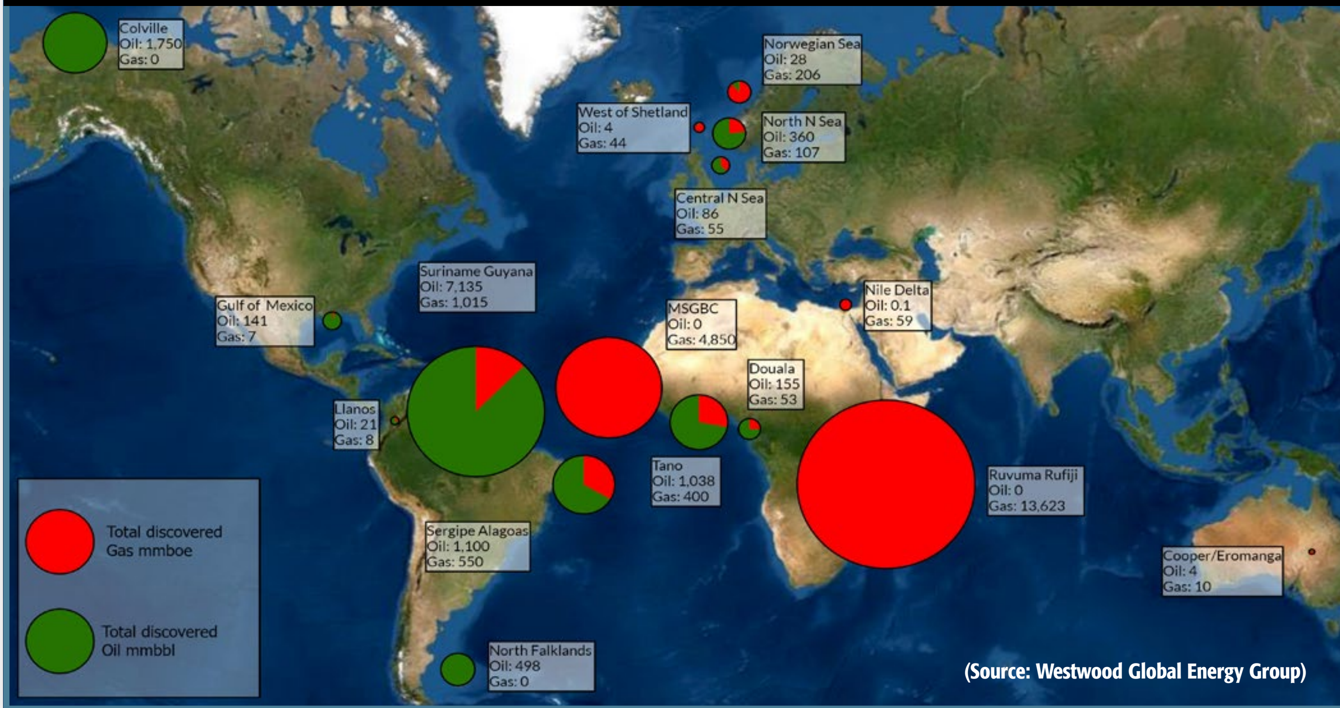
The chart depicts exploration success rates in DHI stratigraphic trap prospects by year. (Source: Westwood Global Energy Group)

Lessons learned

Westwood's analysis has shown that there are two key factors that have led to an increase in the success rate of stratigraphic traps. The first is a better understanding of the geological setting where stratigraphic traps form.

Within turbidite systems, the location of the stratigraphic trap on the depositional slope and the detailed architecture of the slope can have an impact on the chance of commercial success. Traps located on the lower slope to basin floor had the highest success rates in the 2008-2019 period and delivered the largest discovered volumes. Additionally, slopes that were graded with

Resources discovered in stratigraphic traps since 2008



little preexisting topography performed better. Lower slope settings are conducive to the stacking of multiple stratigraphic traps vertically offering a higher resource density, resulting in the need for fewer development wells, lower costs and a greater chance of commercial success.

In the Cretaceous Nanushuk play of the Colville Basin in Alaska, stratigraphic traps have been formed in a series of low-stand wedges, where high-quality marginal marine sandstones and sealed by overlying shales deposited with next transgression.

The second key factor that has led to improved performance of stratigraphic traps is the role of geophysical DHIs, which have long been the Holy Grail for explorers, providing a means to predict discoveries ahead of the drill bit using information obtained solely from seismic data.

Seismic reflections are created at the boundaries between layers in the earth where the physical properties of the rocks and the fluids contained within those rocks change. The seismic response can be different, depending on whether the pore space in a rock is filled with water, oil or gas. The change in the observed response may be used to infer the presence of hydrocarbons rather than water in some instances. Stratigraphic traps are often very subtle and may be difficult to observe on seismic data. In some cases, the first indication of a potential stratigraphic trap prospect is the presence of a seismic anomaly, which can be a DHI.

Westwood has analyzed the success rates of exploration prospects reported to have DHIs interpreted pre-drill globally since 2010. Thirty-five percent of stratigraphic and combination traps (i.e., those traps that contain both structural and stratigraphic elements) recorded by Westwood were reported as being DHI-supported, compared to only 11% of purely structural traps. In stratigraphic trap prospects, amplitude anomalies and amplitude-versus-offset anomalies were the most frequently reported DHIs, contributing 55% and 32% of the number reported respectively, with amplitude conformance comprising only 9% of the reported DHI types and flat spots just 2%.

Over the entire 10-year period reviewed, the average commercial success rate for stratigraphic traps reported to be supported by the presence of a DHI was 28%, less than the commercial success rate for all stratigraphic traps, with or without DHIs. The DHI-supported prospect success rate was particularly poor in the 2011 to 2014 high oil price period suggesting that many seismic anomalies were mistakenly interpreted as DHIs.

The overall commercial success rate for stratigraphic traps increased from about 26% in 2013 to 47% in 2019, but the turnaround in performance has been even better for those supported by DHIs. The success rates for stratigraphic traps with DHIs reached a nadir in 2013 with a CSR of just 7%. It has since shown a dramatic improvement, reaching a peak in 2018 of 64% with successes in Alaska, Romania, Norway, Colombia and Guyana.

Stratigraphic traps are not inherently more risky than other trap types. The key is for explorers to recognize whether they have the right tools and processes to explore effectively for commercial finds. This requires a sound geological model integrating the trapping element into the entire petroleum system analysis, supported by reliable geophysical calibration and the effective use of analogue data. +

The Other Side

As the world recovers from the COVID-19 pandemic, energy demand is slowly picking up. Energy companies around the world are evaluating their assets and operations to ensure they emerge in the best possible position to capitalize on a new era of oil and gas production. (Source: Marc Morrison/marcmorrison.com)

As the oil and gas industry regains strength following a tumultuous second quarter, companies could emerge anew.

Velda Addison *and* ***Brian Walzel****, Hart Energy*

No one had seen anything like this.

Unlike previous downturns, no amount of bracing could save some oil companies from bankruptcy or falling into the arms of peers with stronger balance sheets.

With an oil price war between OPEC+ brewing and a pandemic spreading across the world, the oil and gas industry buckled under the pressure of slowed demand as travel came to a near halt in the spring. Oil prices nosedived. Producers shut in production. Previously trimmed budgets got even thinner, and operators and service providers alike laid off thousands.

The situation, however, appears to have improved—at least as of late summer. Stay-at-home orders intended to slow the spread of COVID-19 eased, and production cuts brought supply and demand closer to balance. Oil prices stabilized around $40/bbl after falling into negative territory.

Yet, the damage is evident, and the potential for more disruption and demand destruction exists.

Planning for the next chapter in the predictably unpredictable oil and gas sector could seem like a tall order—not knowing which direction attempts to slow the global pandemic could swing demand.

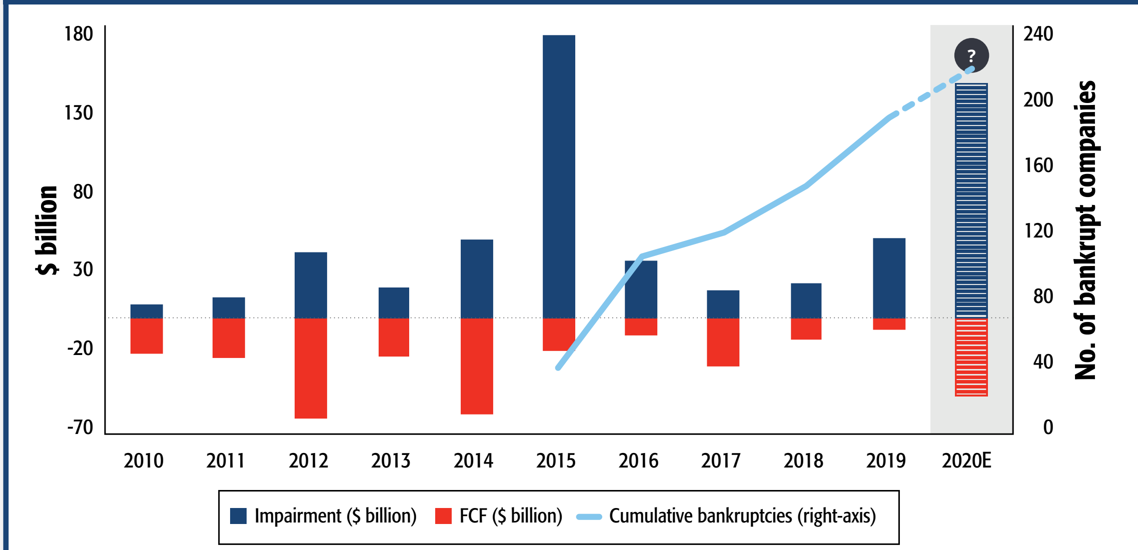
However, today's market turmoil has not blinded executives from long-term company goals. It may have even shed more light on specific paths different types of companies are taking, evidenced by where capital is being directed.

As the industry picks itself up from another fall, technology—which helped drive U.S. shale production to new heights—could focus on autonomous, digital and remote applications, some say.

Given shale's steep production decline and investor sentiment, conventional assets could return to the spotlight as the energy transition keeps natural gas and renewables on the radar long term. Meanwhile, the inevitability of consolidation and bankruptcies could mean quality acreage in key basins could become available.

While no one knows how energy companies will look post-pandemic, many agree that those that do survive will emerge looking a bit different. For an industry that oftentimes evolves at the pace of sea change, the coronavirus pandemic might indeed force an acceleration.

"Without fundamental change, it will be difficult to return to the attractive industry performance that has historically prevailed," McKinsey & Co. stated in a May report on the post-COVID-19 oil and gas industry. "On its current course and speed, the industry could now be entering an era defined by intense competition, technology-led rapid supply response, flat to declining demand, investor skepticism, and increasing public and government pressure regarding the impact on climate and the environment. The question of how to create value in the next normal is, therefore, fundamental."



Profitability of the US Shale Industry (Upstream)

Note: Bankruptcy numbers are available from 2015 onwards.
Source: Capital IQ database; Haynes & Boone oil-patch bankruptcy monitor; Deloitte.

The U.S. shale industry saw net negative free cash flow of $300 billion, impaired more than $450 billion of invested capital and has seen more than 190 bankruptcies since 2010. (Source: Deloitte)

Making 'real money'

Even prior to the COVID-19 outbreak and OPEC+ price war that crippled the industry, oil and gas producers, particularly those operating in unconventional development, faced mounting debt issues. Operators found that expensive shale wells showed significant IP but fell off sharply after only a few months, resulting in shortfalls in expected production, and therefore investor returns. As a result, lenders became skeptical and companies responded by slashing their budgets and honing in on only their best assets.

Now, with budgets cut even further and investors looking elsewhere, companies are focusing almost exclusively on their assets that generate cash flow.

Chevron reduced its 2020 capital guidance from $20 billion to $14 billion following the onset of the COVID-19 pandemic and the price war between Saudi Arabia and Russia.

"The focus has really been on short-cycle capital. So capital that was addressing long-term production or long-term value, we largely sustained that," Chevron CFO Pierre Breber told E&P Plus. "We certainly took haircuts across everything, but the disproportionate reductions were really in the short cycle."

For Chevron, that meant cuts across its unconventional assets in the Permian Basin and Loma Campana in Argentina's Vaca Muerta Formation along with its base business in San Joaquin Valley, infill drilling projects and in West Africa.

The company reported an $8.3 billion loss in the second quarter, writing down $5.6 billion on oil and gas assets amid the downturn. Chevron wasn't alone. So did majors including Eni, Royal Dutch Shell and Total—to name a few. According to IHS Herold, the oil and gas industry cut spending by $24.4 billion in 2020 compared to 2019.

"A growing number of investors are questioning whether today's oil and gas companies will ever generate acceptable returns," McKinsey & Co. reported.

For tight oil investments to create value, companies should earn a return on capital employed above 10%, according to James West, senior managing director with Evercore ISI.

Yet, "this industry has proven an inability to do that, particularly in tight oil, particularly in U.S. shale," he told Hart Energy in a video interview.

Despite pushing U.S. oil production up to about 13 MMbbl/d in January, the U.S. shale industry didn't fare so well in other areas.

Deloitte data show the industry impaired more than $450 billion worth of invested capital, reported net negative free cash flows of $300 billion and has filed more than 190 bankruptcies since 2010.

Deloitte doesn't have a hurdle rate in mind for an acceptable tight oil return on invested capital, seeing how a global pandemic can destroy demand.

However, "the hurdle rate is going to definitely be impacted if we look at statements from the likes of BlackRock and others," Duane Dickson, Deloitte's vice chairman and U.S. oil, gas and chemicals leader, told E&P Plus.

Sustainability will also probably factor more into the return equation, he added.

Investors have not deprioritized

sustainability, according to BlackRock, a New York-based investment management company. The firm voted against the management of 53 companies, including 37 energy companies with a combined market cap of nearly $408 billion globally for their "lack of progress on climate, across carbon-intensive sectors" in its 2020 proxy season.

McKinsey & Co. offered that the model for value creation has been led by the supermajors, which focus on scale, strong balance sheets, best-in-class integrated portfolios, advantaged assets and superior operational abilities.

"Basin leadership has also long been a source of distinctiveness and value creation in oil and gas. Similarly, low-cost commodity suppliers with first-quartile assets have also thrived," the company reported.

As Allen Gilmer, founder of industry analyst Enverus, explained, there are several opportunities for nonmajor oil companies to find value. He pointed out that major oil companies became major oil companies because they developed quality assets in many places, which led to a variety of cash flow opportunities in both oil and gas. Companies capable of doing multiple tasks and doing them well mean they can make "real money," Gilmer said.

So, who is going to be focused on making real money? The majors? Privately owned companies?

"That's not to say that they can't take on debt," Gilmer added. "But I do think that they definitely need to be focused on how they can make real money and how they do so in an environment that has a fair amount of alpha and beta, with regard to the underlying commodity price of that which they produce."

Assessing the short and long cycles

Not all companies went into this downturn and pandemic as strong as their peers, with some having much stronger financial positions and far better assets.

"Companies with the strongest balance sheets and the greater number of options are the ones that are focusing on repositioning," Deloitte's Dickson said, adding others may need to find a partner or restructure.

Moving forward, the industry also will get a better sense of the role of shale.

"Longer term, is shale an asset that's easy to turn on and turn off or not?" Dickson said.

Supermajors have found turning their shale assets off is the initial approach to cauterize the wounds that price and demand destruction have wrought. The short-cycle economics for shale offer operators, particularly those that are highly diversified, the option of cutting costs during a downturn without risking long-term financial success.

Even those that are not diversified were forced to curtail their only revenue stream by shutting in production. The slow but steady uptick in demand this summer, coupled with global supply cuts, has allowed those producers to cautiously bring wells back online.

Treadstone Energy Partners II holds about 40,000 acres in the Austin Chalk trend. Founder Frank McCorkle said the company essentially shut down production at the onset of the pandemic.

"We shut in a majority of our production for a couple of months, and we're just now starting to ramp our production back up," he said. "We aren't at full production and probably won't be at full production until the end of the year. We did that because selling oil at such a low price is just value-destructive to our company. We didn't have to sell oil, and we didn't see a need to sell it at extremely low prices."

Among the lessons that operators can take away from this downturn is a firm understanding of their short-cycle and long-cycle capital commitments, and which of their assets and projects offer financial flexibility during price volatility. But the ability to flex capital between assets is only possible with a diversified portfolio.

"You need to have the types of projects and the types of investments and asset classes that allow you to do that," Breber said. "And that tends to be unconventional, the infill drilling types of activities where you can withdraw capital, preserve that cash and really save the production for when prices respond and produce when prices are higher."

Looking ahead, West believes the U.S. shale industry will eventually shrink.

"It'll be a smaller group of companies, smaller production than we peaked out at late last year," West told Hart Energy, "and we do think that the incremental barrels that are going to be needed for demand growth over time will come from international markets rather than the shale market."

Global oil demand could rise 400,000 bbl/d from its outlook in June to 92.1 MMbbl/d, according to the International Energy Agency (IEA).

Oil prices are also a factor.

Although WTI prices have seemingly stabilized in the $40/bbl range, Enverus' Gilmer expects prices to settle at about the $50/bbl range by the end of the year. If prices continue to climb, the world could be facing more oversupply issues.

"The biggest issue that we have here is when the price of oil reaches $60 to $65 WTI. We have the infrastructure and we have the capability of adding a million barrels a day, year over year and for several years," Gilmer said. "And that is something that's going to be really hard for the planet to get around. And it's relatively quick to come online. So we believe that that's the buffer on the upside."

Recent experiences combined with shale's steep decline and investor sentiment may even drive some U.S. shale players toward conventional assets in search of higher returns.

"I wouldn't be surprised to see some companies that really drove into shale and sold off some of their international and offshore assets go back into the international markets [and] go back to the offshore," West said.

Turning to technology

Cost reductions have been a primary focus for oil companies and service providers for at least the past few years. Such cuts have come both in the field with operational improvements and in boardrooms through downsizing and asset sales. However, that will only get companies part of the way in further cutting costs, Deloitte's Dickson said.

When the shock fades and market resets, technology will likely be something the industry will crave more. The real change Dickson expects to see is more agility.

"I think we're going to see signs that the industry itself will develop greater agility by way of technology," Dickson said, referencing digital productivity tools. "They bring in more machine learning, artificial intelligence, ability to train people faster [and the] ability to make decisions better and quicker. That translates to better processes and better profit velocity that's possible."

Digital technologies will become more normalized in the energy space, he said.

The recovery track for the shale industry could also require bringing disruptive technologies like nanotechnology together with tracer analytics, microseismic monitoring and other advanced analytics, according to Deloitte. In a report, the firm suggested operators team up with vendors to automate and digitize operations to realize savings, shorten value chains and create pathways for the energy transition.

Following the last downturn, the industry saw remarkable efficiencies gained in completion designs, particularly in the number of fracked stages per lateral and proppant usage. But by many accounts, those efficiencies have leveled off, especially in proppant loading. Now that the industry is emerging from yet another downturn, the environment is likely ripe for more efficiencies, such as in production optimization.

Enverus' Gilmer believes opportunities also exist in better reservoir evaluation.

"I think efficiencies can really be found in understanding your reservoirs, really understanding what you can do with those," he said. "That's why right now I like private companies because they are not punished for doing experiments, looking to see how they can expand their production and expand their reserve base. And there's probably no one magic recipe. It's going to come down to capital discipline, which is something that has been sorely lacking in the industry for a while with regard to things that are not necessary."

However, Gilmer explained that the responsibility of more efficient operations lies not only with producers but also with service companies.

"We have a lot of really smart people in this industry that are building tools and ideas in the oilfield services," he said. "But it's incumbent for them to be able to show how it improves either oil cuts, costs or improves return either above and beyond. The ROI has to be pretty clear."

As companies adjust, they are also mindful of how they position themselves in the market. That, Dickson added, is being driven by discussions around sustainability and diversification.

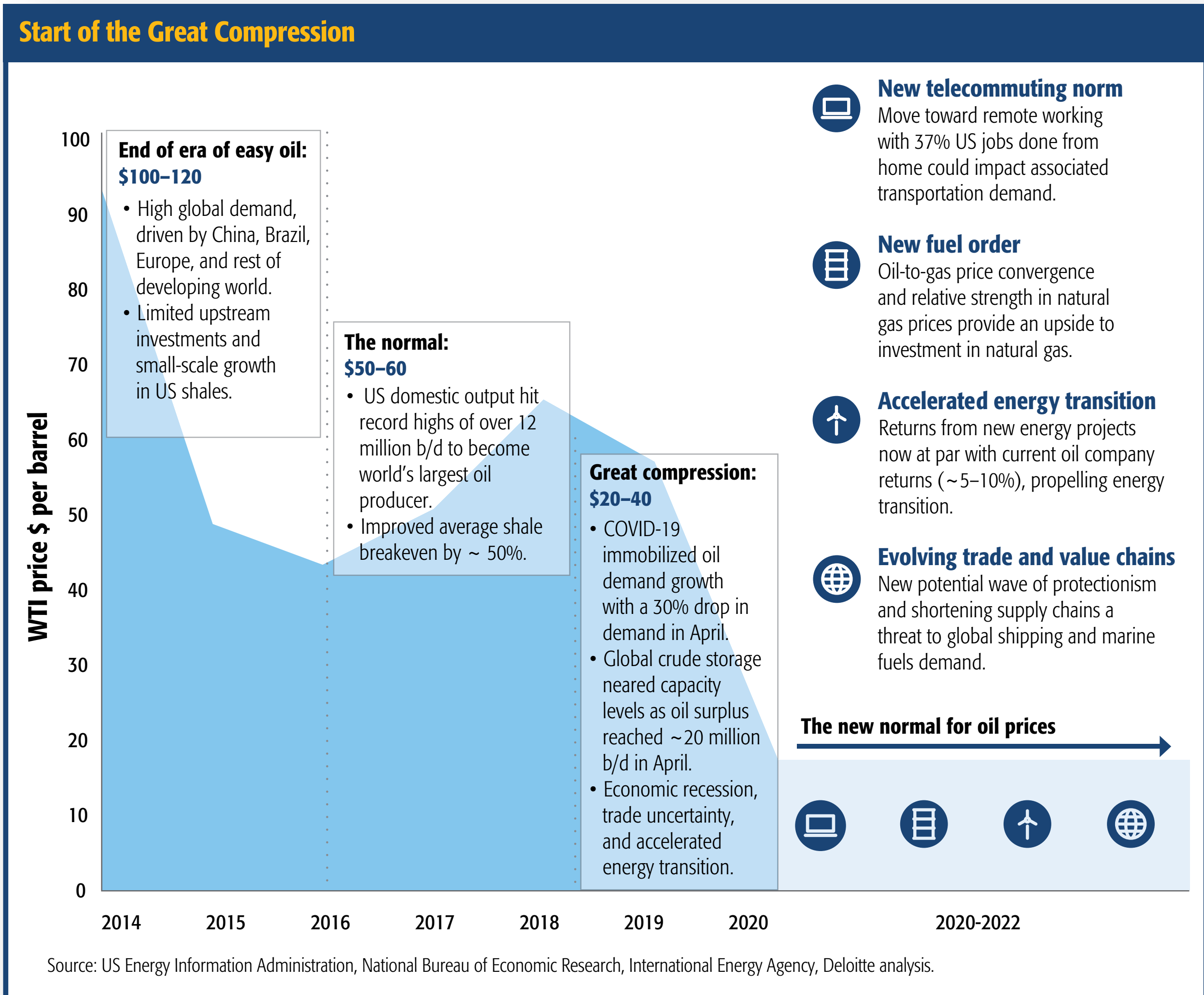
The transition fuel

A common belief among analysts is that the oil and gas industry—both operators and service providers—faces a crucial challenge: evolve or perish.

Gilmer likened the current industry environment to that of biological evolution, in which an organism dies if it does not adapt and evolve. McKinsey & Co. shared similar sentiments.

"The winners will be those that use this crisis to boldly reposition their portfolios and transform their operating models," the analyst stated in its May report. "Companies that don't will restructure or inevitably atrophy."

One of the weaknesses of the U.S. shale industry is that a lack of diversification, whether it be in a company's production mix or its acreage positions,



The global demand for oil demand may not return to pre-pandemic levels soon as a result of remote telecommuting, relatively stable and stronger prospects in natural gas, decapitalized and stable business profile of new energies, shortened supply chains and regionalization of trade. (Source: Deloitte)

(Source: Marc Morrison/marcmorrison.com)

can leave them vulnerable to sudden and sharp market variances.

Varying opinions exist among industry experts on the current role of natural gas as it pertains to value creation. Although, as a long-term fuel source, most agree natural gas will play an important part in the energy mix.

The IEA forecasts natural gas demand will fall by 4% this year, contributing to lost growth of about 75 Bcm/year between its 2019 and 2025 forecast period. However, global gas demand is expected to grow on average 1.5% per year during that time, surpassing 370 Bcm annually in 2025.

Enverus sees future opportunities for natural gas in a post-pandemic environment with demand possibly reaching pre-COVID-19 levels relatively quickly.

"I know a lot of analysts are saying, 'As we bring more production back online and the associated gas gets back online, that we'll quickly find ourselves in an oversupplied situation once again,'" Gilmer said. "We don't think that. We're pretty bullish on natural gas at this point. Our guys are saying that they definitely believe that we're going to see $3.50 prices in natural gas. We're not as bullish with regard to oil."

Having both oil and gas—universally seen as the transition fuel in the energy transition—in portfolios gives optionality, said Kate Hardin, executive director of the Deloitte Research Center for Energy & Industrials.

There has not been movement among U.S. shale players, for example, from oil-dominant plays into natural gas plays considering the recent downturn was demand-driven, but a Deloitte survey of executives shows company strategies are relying more heavily on gas or doing more with the gas produced.

Still, there are challenges.

Even before COVID-19, the natural gas market faced significant oversupply, weakening prices and causing some operators, like Chevron, to reassess their natural gas assets. According to the IEA, data covering half of global demand suggest that gas consumption fell by more than 3% in first-quarter 2020, and supply failed to respond accordingly.

Plus, there are earnings to think about.

In December 2019, Chevron exited its western Canada Kitimat gas export project. That same month, Chevron said it would divest its Marcellus assets, which the company acquired in 2011 in a $4.3 billion purchase of Atlas Energy Inc.

Those projects "just don't compete for capital" in the current market, Breber said.

"[Natural gas is] a very good business. The demand side is good, but there are a lot of folks adding to supply, and we need to increase our returns on capital. Chevron and the industry do," he added. "The only way to do that is to be very disciplined with your capital. Only invest your capital, the shareholders' capital, in the highest return projects, and right now, and maybe in the short to medium term, that's not where natural gas projects are."

Chevron may have shed some natural gas assets, but its move to buy out Noble Energy will give the company a substantial natural gas position in the Mediterranean Sea.

Weighing moves based on financials, ESG and investor concerns, and short- and long-term energy needs amid market volatility is a delicate balance.

Looking at moves taken during the second quarter, the height of the oil price war and COVID-19 turbulence, increasing divergence among energy companies is clearly visible for Keith Myers, president of research with the U.K.-based Westwood Global Energy Group. Myers said he has never seen a bigger divergence in how companies see the future in his more than three-decade tenure in the business.

"The leaders in changing the paradigm at the moment are the European majors that have been announcing how they're realigning their business to be compatible with the Paris agreement goals," Myers said during a July webinar.

The role of sustainable energy

While there is little to suggest oil and gas won't be significant contributors to meeting future energy needs, producers and service providers are implementing goals in technologies and operating methods that work toward established sustainability goals.

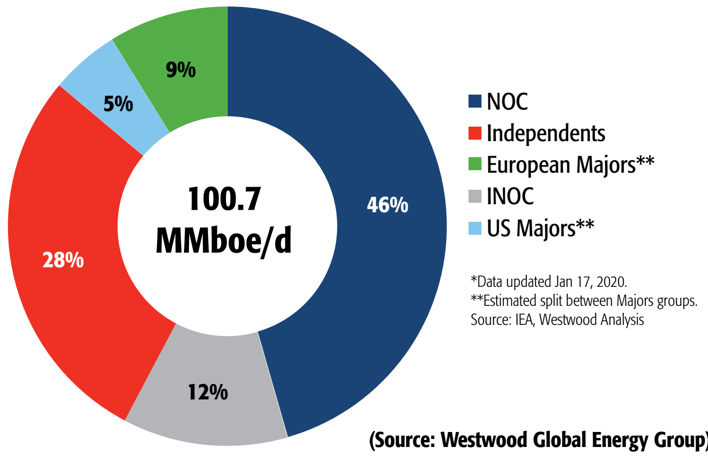
"Across the spectrum of energy companies, some are preparing for a growth-oriented, renewable energy focused future," Deloitte's Dickson said. "Others are preparing to be the low cost, strong brand, last competitor standing because it's going to be a very, very long time before the economy changes away from the way we provide fuels and move around."

When it comes to new energy investments, however, time can be a deterrent.

Royal Dutch Shell's strategy is focused on the transition to a low-carbon future, but company executives are aware of the challenges.

"It takes a tremendously long time getting from the very first commercial application of a technology to it being 1% of the energy mix," Royal Dutch Shell CEO Ben van Beurden said during a discussion with IHS Markit Vice Chairman Daniel Yergin. "It tends to take 25 years in our sector."

2020 Oil Production by Company Type*



(Source: Westwood Global Energy Group)

Diverging Views on the Energy Transition

Company Type	Approach to the Energy Transition	Alignment with Paris
European Majors	▪ Ambitious net zero targets ▪ Covering operations and combustion of products (scope 1,2 &3) ▪ Restructuring to align with Paris Agreement	
Independents	▪ Diversity of views. Focus on reducing emissions from operations (scope 1&2)	
US Majors	▪ Taking a more risk management approach ▪ Focus on operations emissions ▪ Testing robustness of portfolio against low demand future	
National Oil Companies & International National Oil Companies	▪ NOCs currently contribute 58% of global production and hold c.65% of global reserves. ▪ NOC ambitions around sustainability are unclear.	

Source: IEA, Westwood Analysis

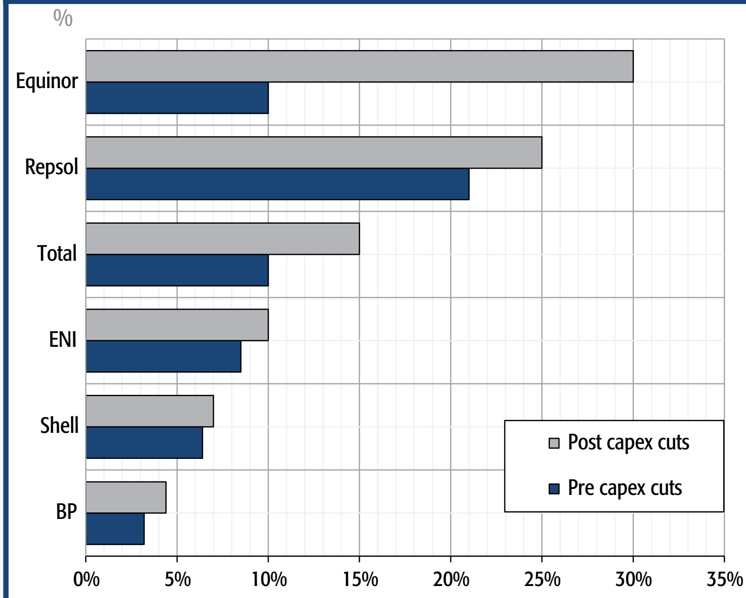
Aligned Neutral Misaligned

(Source: Westwood Global Energy Group)

European majors are leading by realigning businesses to become compatible with Paris agreement goals, while U.S. majors are taking a more risk management approach, examining the robustness of their portfolios to oil demand forecasts consistent with 2 C (35.6 F) of warming, Myers said.

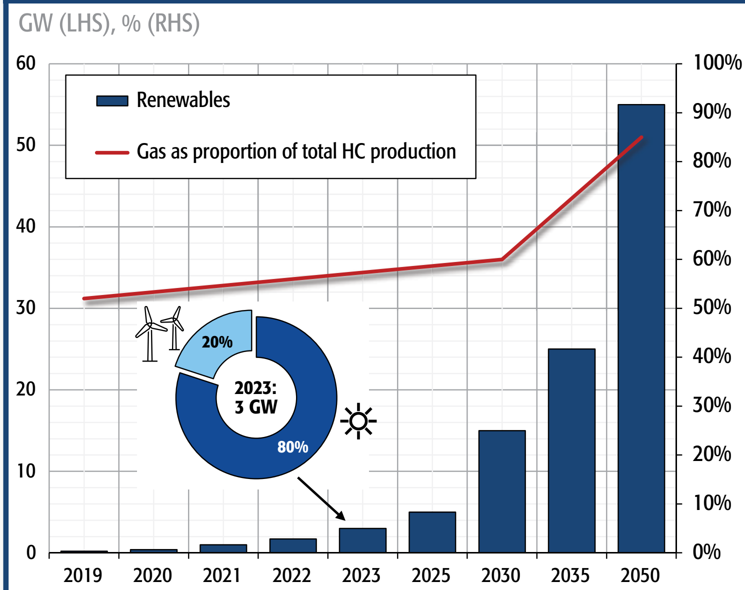
Plans of the independents run the gamut.

Percent of 2020 Capex Attributable to Low-carbon Investments



(Source: Westwood Global Energy Group)

ENI Installed Renewables Capacity & Gas Percent of Upstream Production



(Source: Westwood Global Energy Group)

"There's a huge diversity of views on the future from those [independents] that are ignoring the issue completely to those that are trying to address the issue but with a focus on Scope 1 and 2 [emissions]," Myers said, "because if you're an independent, there's not a lot you can do about Scope 3."

As defined by the U.S. EPA, Scope 3 greenhouse-gas (GHG) emissions result from activities from assets that the reporting company doesn't own or control but indirectly impacts its value chain. Scope 2 emissions are indirect emissions from sources owned or controlled by the company, while Scope 1 emissions are direct emissions from sources owned or controlled by the company.

The specifics, however, are not clear yet.

"What we're not yet seeing is the details of what this means for the industry and where investment's going," Myers said.

Indication may lie in where European majors chose to cut spending in recent months.

"Pre the COVID pandemic and the oil price crash, renewable investments were mainly 10% or less" of European majors' capital budgets, Myers said. "But post the cuts, you can see that the percentage has grown. So, the renewables were protected from the cuts that the upstream took."

Norway's Equinor, Spain's Repsol and France's Total have dedicated the highest percentages of their capex to low-carbon investments. bp, which is transitioning from an international oil company to an integrated energy company, said in August it aims to increase such investments tenfold to about $5 billion annually as the company strengthens its portfolio with renewables, bioenergy, hydrogen, and carbon capture, use and storage.

Targeting carbon neutrality by 2030, Equinor said it aims to increase its renewable energy capacity tenfold by 2026 as it grows within the wind and solar segments. Repsol has its sight on net zero emissions by 2050, while Eni has set a fixed 2050 absolute emissions reduction target of 80% covering all of its products.

Size is key to a company's strategy, Deloitte's Hardin said.

Larger companies can have a longer reach with an international presence and ability to invest in new business models, she said, noting such companies have the wherewithal to invest in solar, wind or even electric vehicles.

"For the smaller companies, North American independents, for example, what we've seen over time, is there is more of the classic health, safety and environment play, which they have been reporting in their documents for a while," Hardin said, adding they are tracking and working to lower emissions and water usage. "Some companies have been making their sustainability reports public since before the Paris agreement."

Speaking during the company's second-quarter investor call, Equinor CFO and executive vice president Lars Christian Bacher said that as the company looks to further diversify its production mix, particularly in arenas such as offshore wind power, it looks to do so with a focus on quality assets that provide a solid return.

"If we're entering into a business, onshore, offshore, oil, gas, deep water, shallow water, renewables or not, it has to be among the good assets," Bacher said. "In my mind, people too often are having a vertical line between assets, whether you should invest in one category or the other. For me, it's a horizontal line. Everything above a certain good return, I'm very eager to look at and see if we can get it if it's among the best ones. That also goes for onshore positions. Whether we will enter and when and where, that remains to be seen."

Chevron is aiming to lower its oil net GHG emission intensity by up to 10% and natural gas net GHG emission intensity by up to 5% by 2023. The company is also looking to reduce net methane emissions intensity by 20% to 25% and reduce net flaring intensity by 25% to 30% by 2023.

Speaking with E&P Plus, Breber said he expects the energy transition to take "decades," and the energy transition is "a long-term question" but will still be relevant post-pandemic.

"[The energy transition issue] will be there when we're on the other side of it," Breber said. "Right now we're in the middle of it. The effort that we're taking to address climate change and the energy transition, which are really addressing long-term value, those are largely sustained."

He acknowledged that any focus on energy transition and renewables amid the current climate is "in the backdrop" but remains a component of the company's long-term value strategy.

"When we think about long-term value, we do think about the investments that we're making that will bring on oil and gas production in years," he said. "Because we don't know, well, we don't even know what's going to happen six months from now."

Opportunities in acreage

Low prices often equal opportunity, particularly on the M&A front. With the inevitability of sell-offs and bankruptcies, deals are likely there to be had, and acreage in key basins could become available.

But for smaller operators like Treadstone, identifying the most economic basins and opportunities rather than the most popular ones is a key factor in possible acreage growth.

"We've always avoided the really popular basins," McCorkle said. "The Permian, the Bakken, not because they are bad, but because they've gotten way overpriced. I think there is still a challenge in some of those where people have gotten in for such a high price. I think seeing mergers, particularly for public companies or larger private companies, could happen because they're doing it on a like-for-like basis rather than trying to lay out cash for assets that have been bought at too high of prices to start with."

However, one challenge facing smaller companies, especially those that operate in less-popular resource plays but in highly coveted basins, is the cost of acquiring acreage. Such opportunities likely only make financial sense in a higher oil price environment.

"We're primarily focused on the Austin Chalk in the oil window, which most people have avoided," McCorkle said. "The challenge with that is often people put a lot of money into the Eagle Ford resource play below the Austin Chalk, so it makes acquiring the Austin Chalk a bit challenging. People want to get paid a lot for their resource plays and location. It's not economic until you get into a much, much higher oil price."

Although bolt-on acreage might be available, the key is to acquire properties that allow for the development of longer laterals, Gilmer said.

"Having acreage, just the raw number of acres is not very telling, but the ability to put long laterals [is what's important]," Gilmer said. "Long laterals being 10,000-ft-plus laterals really, really, substantively improves the value of that average. Not all acres are equal. Because the difference in some cases between a 4,000-ft lateral and an 8,000-ft lateral can be the difference in a 15% or 20% internal rate of return and a 100% rate of return."

McCorkle echoes that sentiment, saying that when Treadstone does look to add acreage, it does so to enhance the company's ability to extend its lateral length in the Austin Chalk.

"We usually focus on very contiguous acreage or acreage that is along our boundary that we can drill into from our acreage," he said. "And the primary reason for that is the lateral length. It's much more challenging to make an economic development with 3,000-ft to 5,000-ft laterals any more than it is to get to 8,000-ft to 10,000-ft lateral lengths. Obviously, that's truer in some reservoirs more than others, but for the most part, added lateral length is more economic."

Chevron cut second-quarter 2020 spending in the Permian Basin by 75% compared to the first quarter, and it reduced its operating rig count to four with one completion crew. (Source: Chevron)

Finding normalcy

Deloitte is tracking three areas to gauge how the industry shapes up in the near and longer term: COVID-19 containment and recovery, economic recovery, and energy demand.

"It's hard to say exactly where we're going to end up after the disruptions that we've seen," Hardin said. The next normal will likely be a lower demand environment, she said, possibly with more price volatility.

According to Deloitte, the global industry may evolve to include new telecommuting norms, regionalized trade and supply chains, and a new fuel order.

During the worst of the pandemic in March and April, power demand dropped 10% to 15% in some of the hardest-hit regions, and vehicle traffic fell by 40% to 50% compared to pre-COVID-19 levels, impacting demand for gasoline and other fuels, before picking back up, Hardin said. The world is also awaiting the return of air travel, which she said remains sluggish.

"We have seen a real decline in jet fuel demand post-COVID-19," Hardin said.

Dickson observe that jet fuel demand might never return to pre-COVID-19 levels.

Whether the pandemic changes when the world reaches peak oil demand also remains to be seen. Decarbonization, however, is expected to slow long-term oil demand growth.

As energy companies await normalcy in new forms, agility and flexibility with an ability to grow production capacity to meet long-term demand are key to staying competitive, according to Deloitte's midyear industry outlook.

"In the coming months, [producers] should balance the trade-offs between short-term cost-cutting and long-term investments so they are best positioned for the future," Deloitte said. "Even if energy demand drops in the coming year and the energy mix begins to change, the long-term demand for energy overall will likely continue to grow."

Data from the IEA showed global oil demand was down 16.4 MMbbl/d during the second-quarter 2020 compared to a year ago. Lockdowns related to the pandemic were behind the drop. Improvement is expected in the second half of the year.

Natural gas markets, which have seen depressed prices, also face continued headwinds with power demand falling, including in Europe, and renewables displacing LNG imports in parts of the world, according to Deloitte.

However, "fuel switching could dictate the recovery" and "natural gas still has a role to play in providing energy security in a lower-carbon world and can underpin economic growth in many developed and developing economies," Deloitte said in an outlook, referring specifically to the power sector.

For the industry to not just recover from the current downturn but thrive in a new post-pandemic reality, companies will likely need to evaluate their assets, identifying what provides true returns and what generates cash, while also appeasing sentiments toward a more environmentally friendly approach to energy production.

Breber said Chevron is well positioned for a post-pandemic industry with a low-teens net debt ratio and a strong balance sheet, but he noted that many other companies in the industry are more highly leveraged.

"In an industry where your revenue can decrease 50% almost overnight, that's not a capital structure that I think makes a lot of sense for shareholders," Breber said. "This is the third time in 10-plus years this has happened, so you don't have to go back to ancient history books to have learned this lesson. Coming out of this we should see better capitalized companies and companies with stronger balance sheets that can weather the price volatility that we've seen in the past, and we're very likely to see in the future." +

2020 Meritorious Awards

for Engineering Innovation

An expert panel of judges has selected the top 25 industry projects that open new and better avenues to the complicated process of finding and producing hydrocarbons around the world.

The E&P Plus editors and staff proudly present the winners of the 2020 Special Meritorious Awards for Engineering Innovation (MEAs), which recognize service and operating companies for excellence and achievement in every segment of the upstream petroleum industry. The pages that follow highlight 25 winners picked by an independent team of judges.

The winning technologies represent a broad range of disciplines and address several challenges that pose roadblocks to efficient operations. Winners of each category are products that provided monumental changes in their sectors and represented techniques and technologies that are most likely to improve artificial lift, drill bits, drilling fluids/stimulation, drilling systems, exploration/geoscience, formation evaluation, HSE, hydraulic fracturing/pressure pumping, intelligent systems and components, IOR/EOR/remediation, marine construction and decommissioning, nonfracturing completions, subsea systems and water management.

This year some of the brightest minds in the industry from service and operating companies entered exceptionally innovative products and technologies that have now been measured against the world's best to be distinguished as the most groundbreaking in concept, design and application.

The awards program recognizes new products and technologies designed by companies and people who understand the need for newer, better and constantly changing technological innovation to appease the energy-hungry world.

The panel of judges comprised experts in business, engineering and the sciences representing operating and consulting companies worldwide. Each judge was assigned a category that best utilized his or her area of expertise. Judges whose companies have a business interest were excluded from participation.

E&P Plus would like to thank these distinguished judges for their efforts in selecting the winners in this year's competition.

An entry form for the 2021 MEAs competition is available at HartEnergy.com/mea. The deadline for entries is Jan. 31, 2021. +

2020 MEA JUDGES

Ben Bloys
Chevron

Mike Forrest
Exploration Consultant

Richard "Dick" Ghiselin, P.E.
Qittitut Consulting LLC

Nancy House
Integrated Geophysical Interpretation Inc. LLC

David Johnston
Differential Seismic LLC

Nelson Oliveros
Integrated Energy Services, Petrofac

Bill Pike
KeyLogic

John Thorogood
Drilling Global Consultant LLP

Scott Weeden
Consultant

ARTIFICIAL LIFT WINNER

SCHLUMBERGER

REDA CONTINUUM EXTENDED-LIFE ESP PUMP

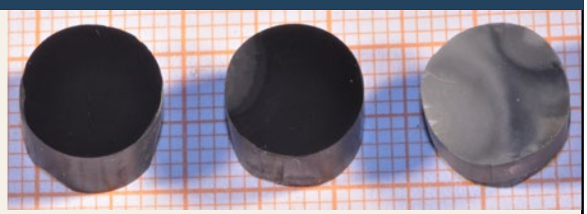
Challenging flow characteristics such as steep flow declines and solids and gas production often exceed the capabilities of conventional electric submersible pumps (ESPs), leading to failures, lost production and reduced runlife. The REDA Continuum extended-life ESP delivers a step change in lift, efficiency, lifetime and power consumption in unconventional and conventional wells with low and slug flow, solids production, frequent stops and starts, and production uncertainty. The result is a significant increase in operators' ability to produce more oil for longer. The latest Continuum pumps feature an enlarged balance chamber, optimized balance holes and rugged washer designs to limit upthrust and downthrust wear when production exceeds or drops below expectations. Designed for 5½-inch or larger casing sizes, the pumps can handle 200 bbl/d to 7,000 bbl/d, enabling faster drawdown and greater IP compared with the natural flow. +

A newly enhanced Continuum pump mitigates stress on the pump during slugging and gas production as flow declines, delivering a step change in lift, efficiency, lifetime and power consumption. (Source: Schlumberger)

DRILL BITS WINNER

SAUDI ARAMCO

ULTRASTRONG CATALYST-FREE PDC



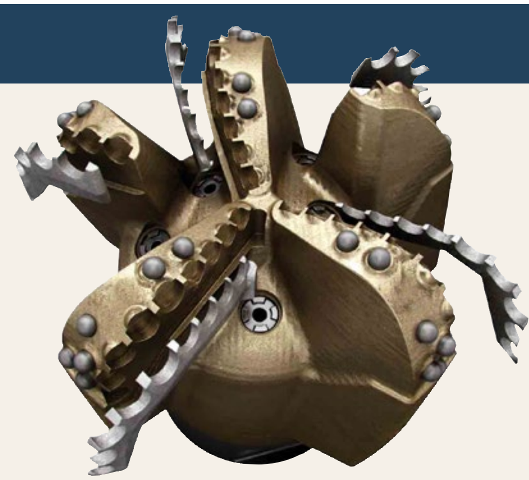
Cutters made from the ultrastrong catalyst-free PDC material feature the highest thermal stability and oxidation resistance at temperatures up to 1,200 C in air, more than 600 C higher than that of commercial PDC cutters. (Source: Saudi Aramco)

Polycrystalline diamond compact (PDC) drill bits are essential drilling tools for oil exploration and drilling. Drilling in hard, highly abrasive and interbedded formations is a difficult challenge for today's PDC bits. Current PDC cutter technology does not provide sufficient wear, impact resistance or thermal stability to achieve the final goal of a single run to drill the entire interval. The weakness in the current technology is due to the use of unavoidable cobalt catalysts needed to bind the diamond grains that compose the PDC cutting structure.

Saudi Aramco's ultrastrong and catalyst-free PDC material has been successfully synthesized for the first time, setting a new world record as the hardest diamond material to date, according to the company. Its wear resistance is 300% higher than that of the best diamond materials used in the industry. The thermal stability and oxidation resistance of the PDC cutter also broke the industry records by an increase of about 600 C.

In a case study, catalyst-free PDC with ultrahigh wear resistance was successfully synthesized under an extremely high pressure of 16 GPa and ultrahigh temperature of 2,300 C for the first time. The wear resistance, hardness and thermal stability were symmetrically evaluated. The results showed that the new material possesses an exceptionally high wear resistance of more than 300% higher than that of the best commercial PDC materials used in the industry. The material also broke all the diamond indenters during the hardness testing, indicating the world's hardest material to date. +

DRILL BITS WINNER



Aegis Armor Cladding is applied directly to the bit blade, improving cutter protection and delivering increased erosion resistance compared with conventional hardfacing. (Source: Smith Bits, a Schlumberger company)

SMITH BITS, A SCHLUMBERGER COMPANY

AEGIS ARMOR CLADDING

In the polycrystalline diamond compact (PDC) bits market, drillers have the choice of two bit-body options: tungsten-carbide matrix PDC bits and steel-body bits. While steel-body bits incorporate geometries that are more conducive to efficient cuttings evacuation, they are less resistant to erosion when compared to matrix PDC bits. Even with the addition of conventional hardfacing, steel-body bits lack the durability needed to withstand the harsh downhole environments of most drilling applications.

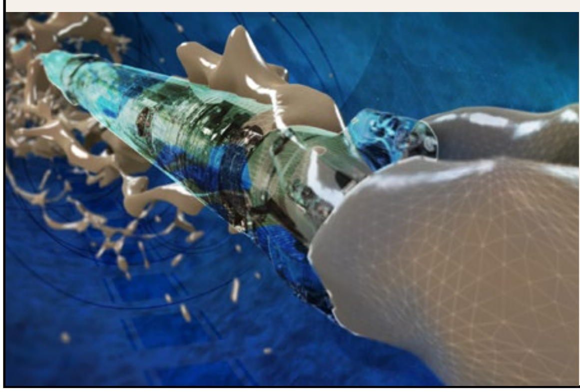
Aegis Armor Cladding comprises individual strips of a tungsten-carbide material applied to the blade face of steel-body drill bits using an electron-beam additive manufacturing process. Aegis Armor Cladding increases bit erosion resistance by 400% and strength by 40% when compared to conventional matrix PDC bits. This new type of PDC bit construction enables drillers to realize the benefits of steel- and matrix-body bits, so they no longer have to sacrifice drilling performance based on the limitations of conventional bit bodies. Aegis Armor Cladding has undergone extensive field testing, accumulating more than 70 runs worldwide. +

DRILLING FLUIDS/STIMULATION WINNER

BAKER HUGHES

DELTA-TEQ LOW-PRESSURE-IMPACT DRILLING FLUID

In challenging offshore wells, pore pressure, fracture gradient and complex geometry combine to create a narrow operating window. Numerous operational problems—such as excessive surge pressures, pressure spikes due to pump initiation pressures, complicated equivalent circulating density (ECD) management and the inability to effectively control drilling parameters—can result in costly and time-consuming events.



Baker Hughes has released the DELTA-TEQ low-pressure-impact drilling fluid, a nonaqueous formulation, to enable operators working in narrow pressure windows to meet their drilling objectives by significantly reducing the risks associated with this activity. The typical solution to drilling in narrow pressure windows has been the use of a low-ECD drilling fluid. The DELTA-TEQ fluid has the ability to manage hydraulic impact by maintaining the right viscosity in the right areas of the well for optimal hole cleaning and penetration rates without putting excess pressure on the formation. Like a "viscosity clutch," it engages viscosity at low shear rates and disengages at high shear rates. +

Featuring an advanced formulation of specialized clay and polymers, the DELTA-TEQ fluid creates a nonprogressive gel structure that reduces hydraulic impact with a rapid-set/easy-break profile. (Source: Baker Hughes)

DRILLING FLUIDS/STIMULATION WINNER

TETRA TECHNOLOGIES

TETRA CS NEPTUNE FLUID SYSTEMS

For complex, high-pressure wells, operators need a dense completion fluid system that contains neither zinc nor cesium formate, yet is environmentally sound and commercially viable. Zinc brines are classified as marine pollutants, restricted in the Gulf of Mexico (GoM) and prohibited in the North Sea, Brazil and elsewhere. The cesium salt used in cesium formates is now prohibitively expensive due to depletion of its ore reserves in the world largest mine in Central Canada.

TETRA developed the suite of TETRA CS Neptune completion fluids as an alternative to zinc brines and cesium formate. Meeting environmental regulations for the GoM, North Sea and other regions, the high-density, clear brines have a neutral or alkaline pH and approach the densities of zinc bromide and cesium formate, yet they're free of zinc, formates and solids.

TETRA CS Neptune fluids can be formulated with densities up to 17.5 ppg and can be blended using standard clear-brine equipment. They are stable at elevated temperatures and during storage. The fluids are compatible with most elastomers and metals, pose low risk of corrosion and can be designed to perform at low temperatures and high pressures without crystallization. +

TETRA CS Neptune fluids are versatile, as they can be formulated as low-solids, reservoir drill-in fluids and reclaimed for reuse using standard equipment. (Source: TETRA Technologies)

DRILLING SYSTEMS WINNER

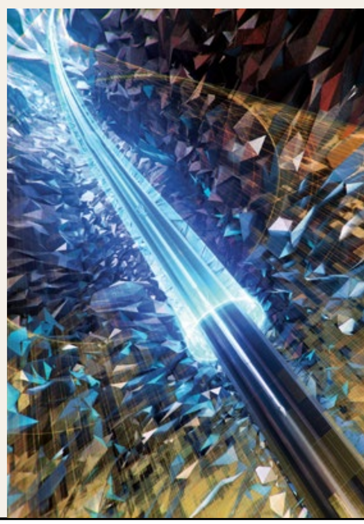
GYRODATA

OMEGA^X SOLID-STATE SURVEYING SYSTEM

Directional drilling is not always an easy proposition. The challenges inherent in modern wells are many, including multistratigraphic, interbedded rock layers with varying levels of hardness; harsher downhole conditions with higher pressures and temperatures; long laterals and extended-reach drilling applications; and more.

One path to address these challenges involves gyroscopic survey technology. Gyrodata initiated a comprehensive R&D program to develop a solid-state gyroscopic technology that uses an advanced new sensor package to measure the earth's rotational rate, precisely and accurately determining inclination and true north.

This technology powers the company's Omega^X system, an all-attitude, solid-state drop gyro surveying system that integrates two independent, three-axis sensor probes. The sensor package and electronics, including memory and data processing, are only 19 inches long, significantly reducing the overall length of the bottomhole assembly. The system can operate to 302 F with no time limitation, making it ideal for use in applications with harsher downhole conditions. Omega^X seamlessly collects surveys during pipe connection, eliminates mass unbalance error and reduces the ellipse of uncertainty by a wide margin versus traditional gyro systems and MWD surveys. +



The Omega^X system is an all-attitude, solid-state drop gyro surveying system that integrates two independent, three-axis sensor probes. (Source: Gyrodata)

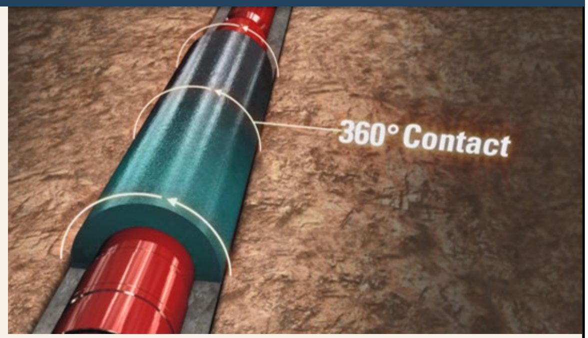
DRILLING SYSTEMS WINNER

WEATHERFORD

AlphaST SINGLE-TRIP OPENHOLE CEMENT AND SIDETRACK SYSTEM

Weatherford's AlphaST Single-Trip Openhole Cement and Sidetrack System cements, anchors and drills in one trip. This capability saves days of rig time compared to current conventional whipstock systems that require two trips to kick off a sidetrack.

In one trip, the AlphaST system can convey cement, if necessary, anchor the whipstock and immediately kick off a lateral. Instead of using a cement for sidetracking, the system uses a packer, which eliminates re-cementing and redrilling operations associated with plug failure. The system also enables drilling past a fish, straightening crooked holes and bypassing collapsed boreholes. The system consists of an injection production packer (IPP), which takes the place of a cement plug for anchoring purposes. The IPP anchor enables positioning the lateral departure in the openhole wellbore without the need for a false bottom or cement barrier. The system also incorporates a specially designed flow tube, a low-angle whipstock and a twin-mill drilloff bottomhole assembly (BHA). The flow tube conveys cement to create a barrier in the original wellbore. The single-angle 3-degree whipstock creates a smooth transition into the sidetrack without steps or ledges, which enables the use of drilling BHAs with short-tooth or polycrystalline diamond compact style bits. ✚



A lead mill and a flex mill are part of the whipstock assembly and attached to the string with shear bolts. (Source: Weatherford)

EXPLORATION/GEOSCIENCE WINNER

SAUDI ARAMCO

SPICERACK

Saudi Aramco's SpiceRack is a multiyear research collaboration project with EXPEC ARC and Seabed GeoSolutions to design, develop, manufacture and commercialize a highly productive, fully robotized and cost-efficient solution for seafloor seismic acquisition. This type of seafloor acquisition incorporates robotized AUVs for the deployment, recording and retrieval of seismic seafloor sensors.

Conventional seafloor seismic acquisition is using seismic sensors positioned on the seafloor that are either attached to cables/ropes or are cableless nodes. For the cable type deployment and retrieval, multiple vessels are required, making the cost of these type of surveys prohibitively expensive. For the deployment and retrieval of nodal sensors, an ROV is required, increasing the total duration of such surveys and thus increases significantly acquisition costs.

Alternatively, SpiceRack is a disruptive technology that uses robots and automation for the deployment and retrieval of AUVs as seismic sensors. By automating seafloor acquisition, a cost reduction of 30% and increase in productivity of 50% is expected. SpiceRack, by using automation and robots, creates a more efficient and safer operation to produce high-resolution subsurface images. ✚

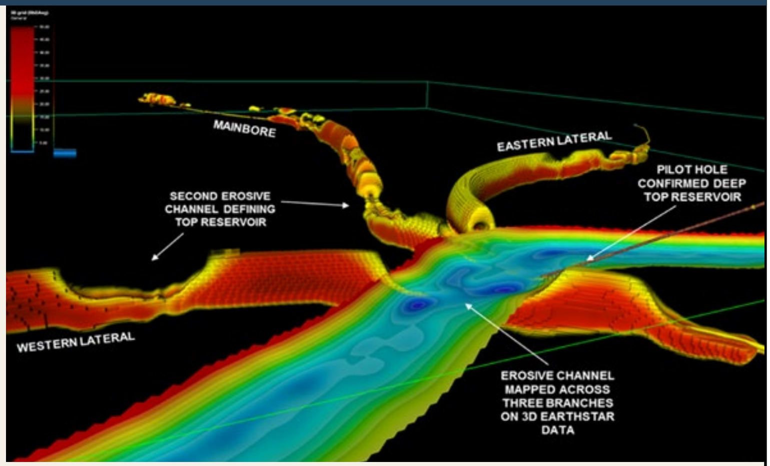
Saudi Aramco used the SpiceRack technology as part of an industry-first experiment using 20 AUVs for seafloor seismic acquisition. The next deployment plans to use 200 AUVs in seafloor seismic acquisition. (Source: Saudi Aramco)

FORMATION EVALUATION WINNER

HALLIBURTON

EARTHSTAR ULTRA-DEEP RESISTIVITY SERVICE 3D INVERSION

Halliburton's EarthStar Ultra-Deep Resistivity Service 3D Inversion makes electromagnetic field measurements around the borehole while drilling and converts them into a 3D model of the geological structure using an advanced, mesh-based, computational inversion method. The 3D model of the reservoir allows operators to see a realistic representation of the true reservoir structure, which helps them to make informed well-placement decisions and obtain a far better understanding of the shape, size and productivity of the reservoir.



The 3D inversion capability from the EarthStar service will have a significant impact in the E&P industry due to its ability to reveal structural details that would otherwise have been overlooked. (Source: Halliburton)

The EarthStar service illuminates and maps reservoir and fluid boundaries, with a proven capability to map these features up to 225 ft from the wellbore, extending the sensitive range up to 10 times farther than was previously possible. +

FORMATION EVALUATION WINNER

WEATHERFORD

INTELLIGENT CONVEYANCE SYSTEM

The Weatherford Intelligent Conveyance System (ICS) advances autonomy and communication in openhole logging to improve operational outcomes. Designed to convey Compact logging tools to total depth (TD), the ICS applies to horizontal wells, slant rigs and remote locations.

Currently, most openhole logging jobs use a hydromechanical system. Although highly reliable with very few failures and a greater than 95% operating efficiency, the hydromechanical approach lacks two-way communication between the engineer at the surface and the downhole tools. The ICS was designed to provide the same reliability while improving on tool communication and memory capabilities. The ICS uses two-way communication, including drillpipe rotation to communicate to the downhole tools and pressure pulses to reply for the uplink. The other ICS differentiator is the downhole memory sub that acts as a logging robot that autonomously sends out commands to open the caliper, record data, communicate with the surface and mitigate potential fault conditions for more reliable log acquisition. The memory sub divides tasks into two different levels according to the level of intelligence needed. +

The ICS is designed to save time and provide detailed information to the surface so clients can make informed decisions. (Source: Weatherford)

HSE WINNER

CRUSOE ENERGY SYSTEMS INC.

DIGITAL FLARE MITIGATION

The Digital Flare Mitigation (DFM) system by Crusoe Energy Systems Inc. deploys modular, mobile, energy-intensive data centers directly to well sites to consume natural gas that would otherwise be wasted through flaring. Scalable to millions of cubic feet per day at each location, the system provides a badly needed beneficial use for associated gas, facilitates regulatory compliance with gas capture requirements and achieves a 30% to 40% reduction in CO_2-equivalent greenhouse-gas emissions, plus significant air quality and visual impact improvements versus open flaring. DFM systems are commissioned in a matter of days and can remobilize to new sites as gas volumes decline through well maturation. Relative to other flare mitigation technologies, Crusoe's system represents a complete and scalable solution for the operator's associated gas stream that is economically attractive. In many cases, the DFM system is delivered at low or no cost. For projects with sufficient scale, term and supply redundancy, Crusoe can provide gas revenue to operators where no revenue existed before, while simultaneously delivering critical regulatory and environmental compliance value.

Crusoe operates 10 DFM systems across North Dakota, Montana, Wyoming and Colorado. (Source: Crusoe Energy Systems)

Crusoe installed the first DFM system in the Powder River Basin of Wyoming in January 2019 and grew to 10 deployments over the following year. Each of Crusoe's deployments helps an upstream operator reduce natural gas flaring in the field and simultaneously provides a low-cost energy source for compute processes running in Crusoe's data centers. +

HSE WINNER

FRANK'S INTERNATIONAL

RACK BACK CONSOLE

To reduce the risk of dropped joints or stands of pipe during rack back operations, Frank's International has developed the Rack Back Console, a specialized control console designed to control pneumatic elevators and spiders building double, triple or quad stands for racking back in the derrick. Although these programmed functions can be controlled electronically, mechanical programming with pneumatic logic allows working on the rig floor without the need for costly hazardous area certifications. The Rack Back Console programming will allow only the correct tool (elevator or spider) control valve to be activated at each operational step of the tubular stand building process, thereby preventing the tool from being activated out of operational sequence. The Rack Back Console automatically resets each stand building cycle based on the number of steps required to complete a double, triple or quad tubular stand. It also includes both run and pull modes for building and laying out stands. This feature allows the operation sequence to be reversed in the event the tubular stand must be disassembled.

The Rack Back Console was first successfully deployed in January 2019 to rack back a variety of stands on a multiwell project for a major operator on a dual-activity drillship in the Gulf of Mexico. The Rack Back Console successfully ran more than 180 stands with several wells. +

The Rack Back Console incorporates visual indicators to inform the control panel operator of the current sequential step of the console's program. (Source: Frank's International)

HYDRAULIC FRACTURING/PRESSURE PUMPING WINNER

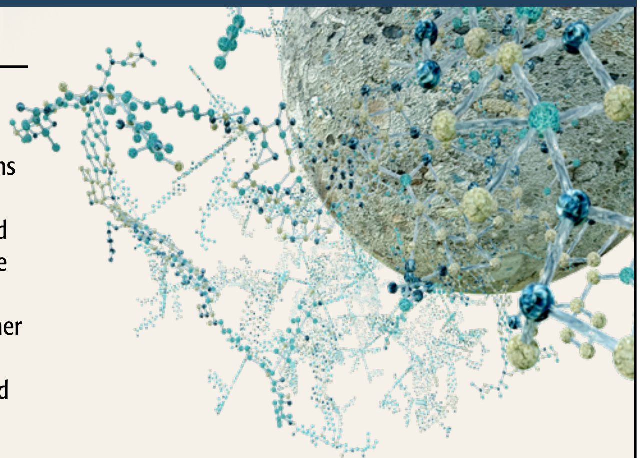
BJ SERVICES

THINFRAC MP FRICTION REDUCER

BJ Services' ThinFrac MP friction reducer is a fluid solution for the effective extraction of hydrocarbons from unconventional reservoirs. It is designed to provide pumping efficiency, complex fracture networks and precise breakability to increase production and improve operational efficiencies.

ThinFrac MP is a cost-effective polyacrylamide polymer friction reducer with superior proppant-carrying properties. This synthetic engineered polymer provides rapid hydration in 8 to 10 seconds, delivering instantaneous friction reduction. Due to its viscoelastic properties, it provides superior proppant transport capabilities in slickwater fracturing operations to deliver the proppant to the fractures. Because of its high molecular weight and rapid hydration, it delivers greater pipe friction reduction at lower loading.

Operators have seen as much as 85% reduction in pipe friction pressure, which has proven to lower hydraulic horsepower and surface equipment requirements. The polymer friction reducer is compatible with freshwater, brines and low-pH fluids. +



The molecular structure of ThinFrac MP allows a clean, efficient break with little to no formation or proppant pack damage. (Source: BJ Services)

HYDRAULIC FRACTURING/PRESSURE PUMPING WINNER

NINE ENERGY SERVICE

BREAKTHRU CASING FLOTATION DEVICE

Nine Energy Service's BreakThru Casing Flotation Device is a technologically advanced barrier designed to float casing across long lateral runs to the toe of the wellbore.

BreakThru works by running casing to a predetermined depth based on wellbore modeling using two fewer connections and two fewer thread sets than conventional casing flotation devices. Then fluid is pumped into the casing above the barrier, creating the force necessary to push the casing all the way to target depth.

Once the casing is fully landed, additional fluid accumulates until it reaches the activation pressure needed to disintegrate the barrier into fine, sand-like particles.

These fine particles are easily circulated out through sleeves, toe valves and float equipment, eliminating the need for a debris trap, fluid flushes or extra trips to retrieve device pieces.

As a result, operators can begin pumping cement immediately, saving time and generating increased efficiencies. BreakThru's durability provides a reliable seal under the extreme temperatures and axial loads encountered during run-in, yet reliably shatters once the casing is landed. +

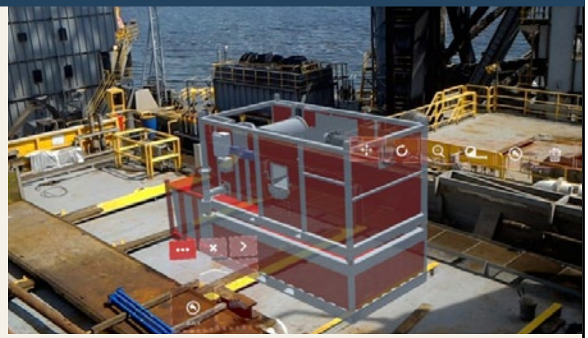
Without a debris trap or landing collar taking up space on the string, BreakThru enables operators to gain access to the full wellbore. This means they gain exposure to the pay zone sooner, saving rig time, eliminating the costs of extra threads and a landing collar, and boosting ultimate recovery. (Source: Nine Energy Service)

INTELLIGENT COMPONENTS WINNER

HALLIBURTON

IMERSIV AUGMENTED AND VIRTUAL REALITY SOLUTIONS

Conventional offshore rig site surveys typically take weeks. With the new Imersiv Augmented and Virtual Reality Solutions from Halliburton, operators can save at least two days of rig time and improve the accuracy of rig surveys and audits for offshore solids control and fluid management. Using a Microsoft HoloLens, users can digitally overlay precise 1:1 scale 3D models of equipment onto existing physical rig spaces while concurrently performing high-resolution scans of the respective rig space and access routes. This combination delivered by Imersiv Augmented and Virtual Reality Solutions enables users to promptly identify obstacles that can impede installation and ensure the selected equipment conforms to the operator's rig design and processing requirements in real time, increasing levels of confidence. Survey experts no longer have to travel across time zones to a rig, which could add days or weeks of non-productive time (NPT) and significant cost overruns. Now these same specialists can provide remote survey assistance to multiple operations in different parts of the world, without ever having to leave their office. The end result is lower operating costs, reduced headcount, less NPT and lower risk. +



The scanned equipment is loaded into an application on the Hololens and can be accessed through voice or gesture commands. Users can then manipulate and place 3D holograms of separation equipment in real space, with all clearances virtually measured to help ensure optimal placement. (Source: Halliburton)

INTELLIGENT COMPONENTS WINNER

SIEMENS

ADDITIVE MANUFACTURING FOR FOSSIL-FREE COMBUSTION IN GAS TURBINES

As a fuel source, hydrogen is well positioned to meet the market demands for low-emission gas turbines with dry low emission (DLE) combustion systems. The turbines incorporate the latest generation of DLE burner, which efficiently burns hydrogen or hydrogen/fuel gas mixes to lower CO_2 and NO_x emissions. In recent years, the development effort has been accelerated by incorporating additive manufacturing (AM) techniques to enable rapid design, prototyping and manufacturing. Prototypes produced by AM are delivered faster than by conventional manufacturing, which makes testing of different components more efficient and reduces testing and development time by as much as 75%. AM also delivers 60% faster repairs of components like burner tips, 40% to 50% lower lead times for spare parts and complete burner sets, and an essentially limitless flexibility in the design of new parts.

AM enables the design of gas turbine components in support of the decarbonization of the oil, gas and power generation industries. (Source: Siemens)

Siemens' medium-size gas turbines run on a wide range of fuel specs. The model SGT-800 gas turbine runs with up to 50 vol-% H_2 in the fuel mix, the SGT-700 with up to 55 vol-% H_2 and the SGT-600 with up to 60 vol-% H_2. The ultimate goal of delivering a 100 vol-% H_2 is closer to realization, thanks to promising test results of a single burner operating on 100 vol-% H_2 in Siemens Clean Energy test center in Berlin. +

INTELLIGENT COMPONENTS WINNER

U.S. WELL SERVICES

POWER PATH

U.S. Well Services' (USWS) PowerPath provides 13,800-volt electrical power to remote pads that can be several miles away from the turbine generator. This advancement in technology allows the turbine to rig into one location and feed the electricity to multiple pads using a micro-grid, therefore decreasing the mobilization time between pads. This micro-grid and centralized location for the turbine also eliminates the need for each pad from having existing field gas pipelines to it before the wells are stimulated or having to truck CNG or LNG to each location during the frac job. PowerPath is not limited to only frac operations. Operators can utilize PowerPath to power other oilfield equipment such as drilling rigs when developing acreage within a concentrated area. USWS first deployed the PowerPath technology in June 2019 to successfully provide power to a remote hydraulic fracturing operation 2.5 miles away. The technology allows power generation to be centrally located among five hydraulic fracturing pads and to transmit power miles away via overhead lines to onsite Clean Fleet pumping equipment. Utilizing high-voltage electricity allowed the power to be sent multiple miles without power losses that come from low- and medium-voltage systems. +

U.S. Well Services' PowerPath system shortens the mobilization time between pads and eliminates the need to run gas lines to each pad prior to the fracturing job. (Source: U.S. Well Services)

INTELLIGENT SYSTEMS WINNER

BEDROCK AUTOMATION

BEDROCK OPEN SECURE AUTOMATION

Bedrock Open Secure Automation (OSA) is a high-capacity control system with built-in cybersecurity. The authentication and encryption capabilities that had previously been available only in military and aerospace electronics are embedded into Bedrock's control system platform. To overpower this digital defense-in-depth, rogue code would have to pass through numerous authentication and encryption steps occurring in real time on all parts of the system electronics. This is not a practical possibility. The modules are further protected against cyber intrusion by encasement in sealed anti-tamper metal and a pin-less backplane, which also delivers extreme electromagnetic and thermal hardening for real-world reliability. OSA encompasses PLC, RTU, DCS and EFM capabilities, but it augments them with the cybersecurity and higher performance necessary to remain competitive. By making security built-in, Bedrock OSA has removed the cost of cybersecurity as a barrier to deploying IIoT architectures. +

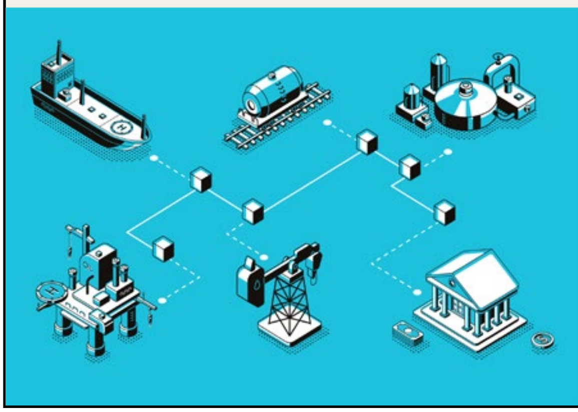
The Bedrock OSA product family provides high-performance PLC, RTU, DCS and EFM capabilities augmented with the built-in cybersecurity and communications necessary to remain competitive in the digital age. (Source: Bedrock Automation)

INTELLIGENT SYSTEMS WINNER

DATA GUMBO CORP.

GUMBONET

Data Gumbo Corp.'s GumboNet blockchain-based network automates smart contracts and transactions for industry leaders by utilizing the combination of distributed ledger technology with contract terms confirmed with operating field data. In providing a single, industry-agnostic immutable record of truth across participants, GumboNet solves long-standing issues of trust and data inaccuracies to reduce barriers associated with doing business. By forging trust between stakeholders, automating transactions and mitigating contract leakage, GumboNet is significantly changing how businesses transact. Old World business methodologies often include processes modeled on paper trails, isolated corporate views, rigid IT infrastructure, siloed systems, enterprise resource planning and transactional friction. With Data Gumbo, this approach is replaced by operational transparency, contractual flexibility and frictionless transactions. As a simple, intuitive and subscription-based blockchain network, companies are freed from building and sustaining standalone, siloed blockchain technologies that require resources and continuous oversight. ✚



GumboNet has been adopted for a water haulage pilot program by the Offshore Operators Committee Oil & Gas Blockchain Consortium. (Source: Data Gumbo Corp.)

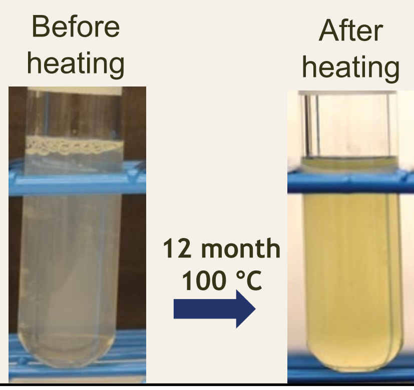
IOR/EOR/REMEDIATION WINNER

SAUDI ARAMCO

NANO-ENCAPSULATED RESERVOIR CHEMICAL TREATMENTS

More than 50% of hydrocarbon resources in subsurface reservoirs are unrecoverable by current operations. Chemical EOR is one of the most promising and widely studied methods to help recover remaining hydrocarbons. Successful EOR formulations need to be low cost and accessible at large quantities.

Saudi Aramco has developed a nano-surfactant technology that offers a one-step highly economic process for stabilizing and target-delivering hot brine-incompatible surfactants. The developed nano-encapsulation technique extends the use of a large variety of reservoir chemical treatments that are otherwise inoperative in high salinity and temperature reservoirs. At the same time, it improves their performance and depth of penetration as well as reduces the amount of chemicals needed without affecting performance. The method was inspired by formulations widely used in nanotechnology for medicine and successfully translated into the oil field by a multidisciplinary team of scientists and engineers. Studies demonstrated that this method of nano-encapsulation of surfactants represents one of the industry's first formulations that can be scaled up and synthesized in the field, can be used for various applications in reservoirs with various salinity and temperature brines, and provides high-efficiency mobilization of the remaining oil. ✚



Nano-surfactant is persistently stable in high salinty and temperature. (Source: Saudi Aramco)

IOR/EOR/REMEDIATION WINNER

WELL-SENSE

FIBERLINE INTERVENTION SYSTEM

Well-SENSE's FiberLine Intervention (FLI) System is designed to deliver faster, smarter well intelligence. The technology has demonstrated efficiency gains and the rapid acquisition of high-quality, richer downhole data compared to conventional wireline methods. FLI is a self-contained, portable system using a pressure containing "launcher" connected to the wellhead. It deploys the probe into the well, which lays bare optical fiber to total depth. The fiber gathers instant, distributed data simultaneously across the entire length of the fiber-optic cable. Temperature and acoustic profiles can be captured, plus any changes over time, resulting in a rich picture of the complete well. As it does not rely on wireline, slickline or coiled tubing for deployment, results are obtained faster, more economically, using less personnel with reduced wellsite personnel on board, footprint and operational risk. FLI operations on average can take up to 3 hours of logging, compared to up to 24 hours for single-point wireline logging.

Just one Well-SENSE engineer is required to transport and operate FLI. Its lightweight, compact size means it is delivered to the well site in the back of a truck or via a small shipping box. This opens up new opportunities, allowing operators to acquire data from more challenging, less accessible wellsite locations, such as unmanned offshore satellite platforms with little or no deck space.

As a plug-and-play system, FLI is ready for rapid implementation. It takes just one person about 30 minutes to an hour to rig up, while rigging down is almost immediate. The probe is sacrificial or retrievable depending on the client's preference. Compared with onshore data acquisition in the US, FLI could offer up to 50% to 75% cost savings, whereas this can potentially reach 90% in the offshore environment, depending on the application. +

The FLI technology can contain single-point sensors in its probe to deliver "active" real-time measurements that complement the distributed sensing. (Source: Well-SENSE)

MARINE CONSTRUCTION & DECOMMISSIONING WINNER

SCHLUMBERGER

CEMFIT HEAL FLEXIBLE SELF-HEALING CEMENT SYSTEM

Schlumberger's CemFIT Heal flexible self-healing cement system helps ensure well integrity from drilling to abandonment, providing a competent annular pressure seal and protecting against hydrocarbon leaks and sustained casing pressure (SCP). Using the CemFIT Heal system eliminates SCP at the construction phase and minimizes risks and operational challenges at decommissioning. Conventional cement systems expand after setting only in the presence of water coming from the formation; however, these systems cannot self-heal subsequently if the cement matrix is damaged. The CemFIT Heal system heals upon interaction with hydrocarbons, improving cement bonding and sealing micro-annuli that can cause unwanted gas migration. A low Young's modulus enables it to withstand cement sheath stresses from drilling, perforating, stimulation treatments, and temperature and pressure changes, which help prevent cement sheath failure. +

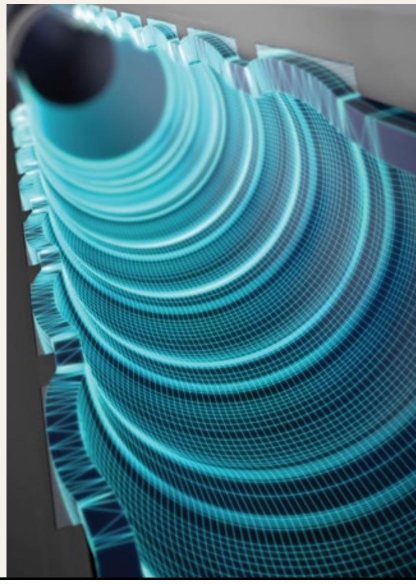
Conventional offshore well cement barriers (left) can develop cracks and micro-annuli after pressure changes and other stresses. The CemFIT Heal system (right) responds to any contact with oil or gas by automatically repairing and sealing itself, eliminating SCP and adding options to simplify plug and abandonment. (Source: Schlumberger)

SUBSEA SYSTEMS WINNER

SCHLUMBERGER

CASING RECONNECT METAL-TO-METAL, GAS-TIGHT CASING REPAIR SYSTEM

Schlumberger's Casing Reconnect Metal-to-Metal, Gas-Tight Casing Repair System is a cost-effective remediation system for well operations. The system seamlessly replaces stuck or damaged casing and provides a robust seal for the life of the well, keeping drilling programs on schedule and securing well integrity for plugging and abandonment operations. The Casing Reconnect system enables cutting and pulling casing anywhere between the wellhead and the stuck point. Replacement casing is then run with a Casing Reconnect system to the receptacle on the bottom—correctly spaced out with the casing hanger. The casing stump is then morphed into the Casing Reconnect system receptacle to rejoin the two strings with a high axial-load-bearing, metal-to-metal seal. The system accommodates excess swallow at the connection, simplifying space out for correctly landing the hanger. The system is ISO 14310 VO-rated and contains no moving parts. The full-axial-load-bearing reconnection tool uses Metalmorphology metal-to-metal sealing and anchoring technology. +



The Casing Reconnect system eliminates sidetracking and fishing operations, keeping drilling programs on schedule. (Source: Schlumberger)

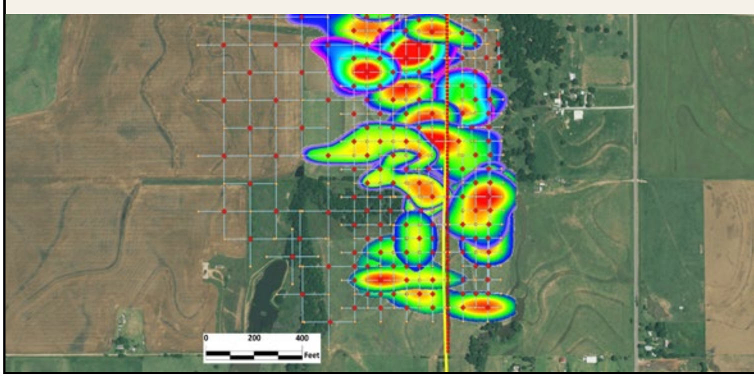
SUBSURFACE COMPLETIONS WINNER

DEEP IMAGING

DEEP IMAGING REAL-TIME FLUID TRACKING

E&Ps were successful at developing highly productive well designs and then inadvertently spaced them too closely together. Despite technological advancements, teams can't precisely evaluate how much rock was treated during a frac, nor can they effectively identify completions issues and whether they were successful in mitigating them.

Deep Imaging offers a real-time system for tracking fluid as it's pumped through the wellbore and out to the fracture tips during a completion job. While seeing stages form in real time, operators are validating models and successful stages while identifying, fixing or avoiding problem stages as they occur. By spotting issues at inception, companies are reducing waste and boosting well productivity. Look-back efforts to improve well models are important, but well inventories are too valuable to make adjustments solely on the next well. In one example, a customer discovered how to save up to $1 million on future wells by reducing the number of frac stages per well without impacting performance. +



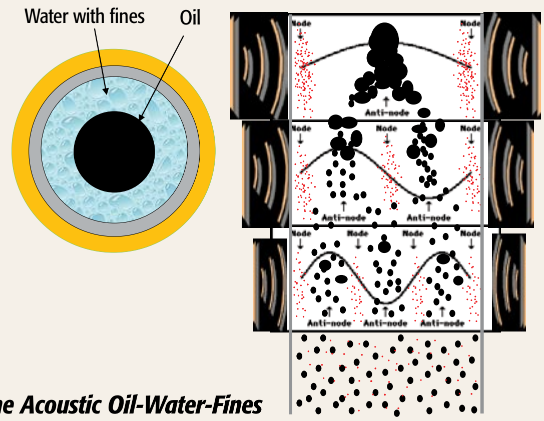
With the fluid tracking system, deployment does not require access to the well pad. A current is transmitted that creates an electromagnetic (EM) field in the subsurface. During a frac stage, the injected fluid alters the EM field, which is measured at the surface. (Source: Deep Imaging)

WATER MANAGEMENT WINNER

SAUDI ARAMCO

ACOUSTIC OIL-WATER-FINES SEPARATION

Saudi Aramco's Acoustic Oil-Water-Fines Separation system separates minute amounts of small oil droplets and solid particles from flowing fluid streams without intervention. The three-phase separation technology can be used to reduce the volumes of water produced from mature oil and gas reservoirs and pumped to the processing plants by several orders of magnitude. It reduces the costs for pumping and treating massive volumes of produced water as well as the health and environmental hazards associated with handling large volumes of produced water. Because of its ability to separate minute volumes of oil and particles, the technology can be utilized in treating produced water prior to injection into the disposal wells, reducing the risk of contaminating groundwater aquifers. The acoustic separation tool increases the oil-to-water ratios in producing wells and also reduces the risk of pore clogging and formation contamination should water be reinjected back in the formation. The tool also can be utilized as a surface separation system to reduce the volume of produced water prior to reaching the gas-oil separation plant (GOSP), thus costs of reconfiguring the GOSP to accommodate increased water cuts. +



The Acoustic Oil-Water-Fines Separation concept separates oil and fines simultaneously with no flow intervention or pressure drop. (Source: Saudi Aramco)

Shearwater's marine vibrator BASS is lowered into the water for testing. (Source: Shearwater)

New marine vibrator offers a more efficient and eco-friendly seismic source

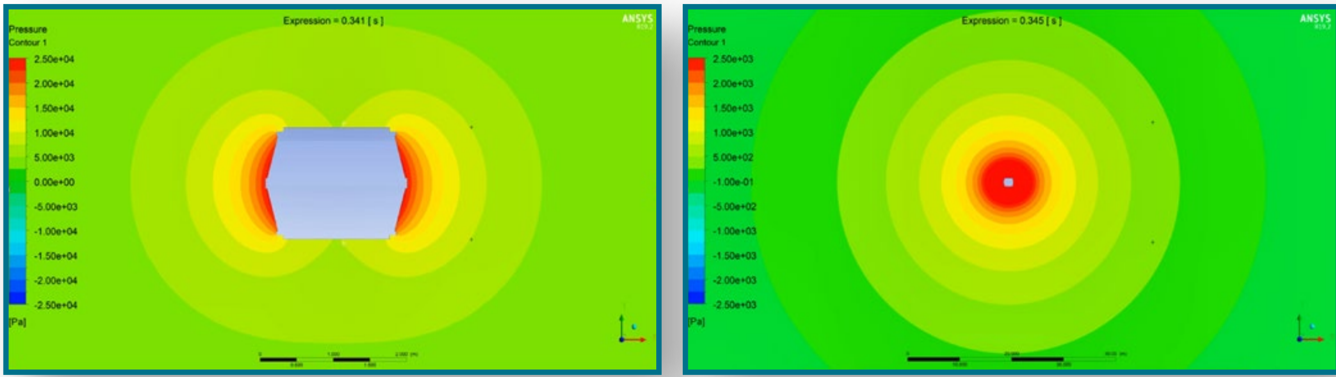
Marine vibrators provide less environmental impact and better data.

***Sara Amar**, Shearwater; and **Peter Hanssen**, Equinor*

Active seismic acquisition is one of the first key steps in the exploration for new oil and gas reserves and is also fundamental in the effort to optimize the development and production of existing oil fields. It uses seismic waves emitted by sources at discrete locations, and some of that energy is reflected back from layers in the subsurface to tens of thousands of recording sensors. The data are then processed to give an image of the subsurface, which is later analyzed by geologists to identify commercial deposits of hydrocarbons.

A typical marine seismic acquisition is conducted using airgun source arrays towed behind a vessel. Such a source typically comprises about 30 single airguns of different volumes, all firing at the same time to produce a sharp acoustic peak. The principle technology of airguns has not evolved much since the 1970s when it replaced the use of dynamite, and airguns stayed inherently inflexible by nature.

It is very challenging to shape the energy spectrum of an airgun source to suit a particular geological application, which means that in most cases the source ends up emitting more energy than what is required for seismic imaging as well as energy at higher frequencies than those used to form the final seismic image. The marine vibrator system has the capability to emit the same energy as an airgun source, but it distributed over time and over a precisely chosen frequency range. Therefore, it is con-



Computational fluid dynamics simulations enable the measurement of the pressure field at all positions from the source. The left panel shows the pressure field at the near-field positions (less than 100 m), while the right panel shows the pressure field at far-field positions (up to 500 m). (Source: Shearwater)

sidered less damaging and disturbing to marine fauna.

Environmental awareness

Increased environmental awareness and the resulting restrictions have motivated new efforts toward the development of marine vibrators as an alternative to airguns. Swept-frequency marine vibrators are one way to reduce levels of sound impact to the environment and to satisfy any restrictions. In the past, marine vibrators have been found to be deficient in energy output, especially at low frequencies. The achievable energy spectrum was found to roughly match the airgun energy spectrum at higher frequencies, but it failed to match it at low frequencies.

An alternative approach is to design the sweep to generate just enough energy at each frequency to create the required signal-to-noise ratio for imaging the target area in depth. Therefore, it is a necessity for any marine vibrator operation to not only avoid unused energy transmissions but to be able to move this excess energy to useful lower frequencies. Unlike airguns, vibrators allow the exact definition of which frequencies should be emitted for a specific geological setting and the survey target.

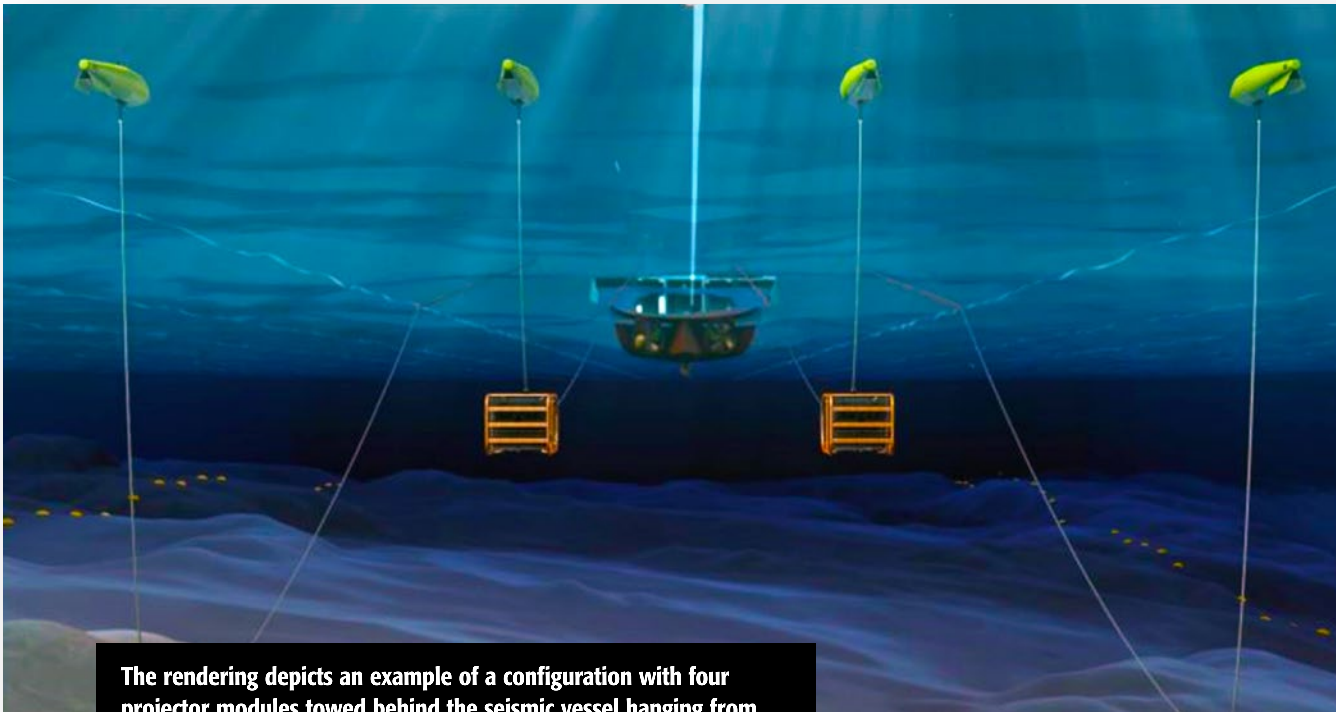
A main challenge that presents itself is achieving the required low frequency output with a practical and reliable marine vibrator. Sweeping at low frequencies requires a large volume of water displacement as the pressure output depends on the second derivative of the volume displacement. This leads to a roll-off in output as the driving frequency is reduced. An in-depth trade-off analysis shows that using a hydraulic-based drive technology enables the marine vibrator to reach low frequencies down to 3 Hz. Hydraulics can produce extremely high forces and enable fast actuation, while precisely controlling the phase and amplitude. Furthermore, hydraulics are reliable commercial components and are used widely in various industries such as aviation and robotics.

BASS system

To develop a commercially viable marine vibrator source, Shearwater has considered the Broadband Acoustic Seismic Source (BASS) system as a whole and designed it in a way that provides optimal functionality and interaction of all supporting subsystems that will handle, operate and maintain the projector modules. The projector modules are the units towed in the water, designed to be able to emit a specific waveform. Shearwater has reduced the dimensions of a BASS projector module to about 2 m-by-2 m-by-3 m and its weight to about 5,000 kg. This makes it possible to handle multiple projectors on the back deck of a standard seismic vessel and tow them behind the vessel in a flexible source geometry based on the survey requirements. A small seismic source vessel will be able to tow up to eight BASS projector modules in parallel, reproducing the output of a standard airgun source and still have space for multiple replacement modules on board.

So far, only the ability to avoid emitting superfluous higher frequencies has been discussed here, but because the vibrator also sweeps the seismic energy over time, the sound pressure level (SPL)

Increased environmental awareness and the resulting restrictions have motivated new efforts toward the development of marine vibrators as an alternative to airguns.



The rendering depicts an example of a configuration with four projector modules towed behind the seismic vessel hanging from floats. The units are deployed at different depths and do not have the same alignment behind the vessel. (Source: Shearwater)

is significantly reduced, reducing the acoustic footprint from thousands of pops to something comparable to a constant whoosh next to a street. Additionally, one can also moderate the sound exposure level (SEL) at will, which is a measure of how much energy is sent out over a certain time duration. Frequency content, SPL and SEL are measures of environmental impact, and these can be customized precisely with the BASS.

Swept-frequency marine vibrators are one way to reduce levels of sound impact to the environment and to satisfy any restrictions.

Next to the environmental advantages of a marine vibrator, the precise control of the phase of the seismic signal provides the means to obtain a significant efficiency advantage compared to an airgun system.

By utilizing advanced processing techniques, combined with a smartly designed source geometry tailored to the survey area, the source productivity is expected to greatly increase. The main enabler of the productivity increase is the directivity of the BASS, making it possible to unlock gradient-source processing capabilities as shown in the case of ocean-bottom nodes (OBN).

Full-azimuth OBN surveys are considered to be the gold standard in terms of image quality and the ability to accurately characterize reservoir properties. Despite their superior quality, less than 40% of all seismic acquisitions are on the ocean bottom, mainly due to cost. One reason for the high cost of seabed acquisition results from the long acquisition times in the field, and consequently the vessel costs. Modeling shows that the BASS marine vibrator system can potentially reduce the acquisition time and the overall survey cost.

The BASS marine vibrator system will enable global E&P companies to operate with lower impact to the environment, which may be particularly important in areas with busy or narrow acquisition windows due to other marine activities, such as commercial fishing. Marine vibrators are a potential game changer because they address three important objectives: more efficiency, less environmental impact and better data. ✚

References available upon request.


eDF

(Source: Marc Morrison/marcmorrison.com)

Drilling motors reimagined with system-focused design

A new motor helps increase power and performance to complete longer laterals faster and with greater control.

***Shashi Talya**, Halliburton*

Operators strive to drill faster and more reliably regardless of the drilling environment. This has increased the demand for more power generation by a mud motor. For shoe-to-shoe drilling performance and improved total well delivery, it is vital for the focus to be on the motor as a system. Historically, the focus on motors has been to improve performance of individual sub-systems or components with little focus on overall system performance. As a result, one of the trends is that the power section has outpaced the rest of the motor in terms of torque capability and horsepower.

With advances in elastomer technology and power section design, the industry has developed high-performance power sections that can run at higher flow rate and higher differential pressure resulting in increased horsepower. The transmission and bearing section has now become the weaker link in the chain along with the motor connections. A true system level design requires consideration of the overall bottomhole assembly (BHA), such as motor only or motor-assisted rotary steerable system (RSS); applications (vertical only, curve and lateral, or lateral only); downhole temperatures; and drilling parameters. A clear understanding of the loads on the BHA in various applications and rig constraints in terms of flow rate, pressure and torque capability is critical to ensuring a successful drilling campaign.

Designing a new motor

In 2019 Halliburton introduced its Motors Center of Excellence (MCE), located in Houston and Dammam, Saudi Arabia, to combine specialized engineering and manufacturing capabilities to customize motor designs for specific basin challenges. This allows Halliburton to take full ownership of drilling motor design, manufacturing and repair, which accelerates differentiated products, reduces manufacturing time, repairs, maintenance costs and inventory, and transforms the business model from product focus to service delivery.

The MCE was formed to think of the motor as a system within the BHA and bring together established competencies in system analysis and design, tribology/bearing technology, elastomer chemistry and drive train design. The MCE includes two new power section stator reline facilities that are equipped with state-of-the-art technology and equipment and use proprietary processes for adhesive application, elastomer injection and curing. The laser technology provides high-resolution inspection to assure quality control that the end product meets design intent and customer needs.

With this system focus, the NitroForce high-torque, high-flow motor was developed as an optimized overall system of the power section, transmission and bearings. The system's key enabler is the use of advanced BHA modeling at the system and sub-system level to match power section and transmission to optimize motor performance with a goal of reliably delivering shoe-to-shoe drilling performance.

The NitroForce motor improves ROP by providing the highest horsepower and by enabling a higher weight on bit (WOB). The high flow rate, stronger transmission design and high-strength elastomers work together to increase bit speed and torque output, which increases power. Halliburton's mud-lubricated polycrystalline diamond compact thrust bearing design withstands higher thrust loads, enabling a higher WOB. The specific power section configuration is designed to maximize reliability and horsepower while ensuring that the transmission, bearings and connections are designed to meet the requirements of the system performance.

The matched system of the motor provides optimized performance and reliability, with a power section and lower end that are designed to work together. Both the power section and lower end have a high flow rate to ensure that hole cleaning is not restricted by tool design. The motor delivers longer runs with less wear by using the Charge high-performance elastomers (HPEs) and the stronger transmission, power section and bearings. Developed in the MCE, the durability of the Charge HPE improves reliability and increases the life of the stator so the motor can drill farther. It has low hysteresis (internal heat generation) while drilling with reliable rubber-to-metal bond and high abrasion resistance. The NitroForce motor transmission design and bearing technology enables the ability to operate at high flow and high torque.

The NitroForce motor improves ROP by providing high horsepower and enabling a higher WOB. The high flow rate, stronger transmission design and high-strength elastomers work together to increase bit speed and torque output, which increases power. (Source: Halliburton)

Drilling longer laterals

Reducing the limitations of conventional motors enables greater flexibility in well planning and BHA design. The extended life of the NitroForce motor enables longer laterals—those more than 10,000 ft—to help reduce costs by drilling with fewer runs and tools. Operators can reduce runs further by drilling the curve and lateral in one run with a fatigue-resistant transmission and more reliable bearings. These stronger bearings also withstand higher side loads to enable higher doglegs.

In the U.S. Midcontinent region, the NitroForce motor was able to drill 10,000 ft in one run to achieve a record with 30% more ROP of 105 ft/hr in the basin. In Canada, a matched system BHA with a proprietary NitroForce power section design delivered the lateral in a single run, when historically it used to take three BHAs to deliver the well. Using a systems approach, a matched motor with a bit was designed with the motor configured to deliver increased power and torque. This enabled completion of the lateral in one run as compared to multiple trips that increased the cost of drilling shoe to shoe. The matched system reduced lateral drill time by more than 25%.

In a motor-assisted RSS application in the U.S., the NitroForce motor outperformed the competition to drill the fastest well and set a new ROP record consecutively, which reduced six days of rig time.

For an operator in the Middle East, the challenge was to improve drilling performance and reduce trips. The team worked closed with the customer to come up with an engineered solution that included a motor-assisted RSS. The NitroForce motor powered an RSS to drill more than 19,000 ft with consistent shoe-to-shoe drilling, and it set a new ROP record in the area run over run for three wells. The operator reduced well time by six days from authorization for expenditure with zero nonproductive time.

By developing a true system level design with the NitroForce motor, Halliburton can provide increased power and performance to complete longer laterals faster and with greater control to help operators drill more consistent wells to increase their production. +

Formation evaluation returns to the surface

Hybrid mud logging is a major step change in providing quantitative data in near-real time without increasing personnel.

Simon Hughes, Geoffrey Cave *and* ***David Tonner****, Diversified Well Logging*

(Source: Yesenia Rodriguez/marcmorrison.com)

Formation evaluation at the wellsite was initially carried out by geologists examining cuttings and formation gas collected from the mud stream and "lagged" to bit depth, a practice known as mud logging or surface logging. Over the years, technological advances and economic viability allowed ever more complex downhole measurement tools to be created and run. These MWD and LWD tools determine several formation properties and have become uniquely associated with formation evaluation.

In today's business climate, upstream oil and gas companies are increasingly focused on capital efficiency and return on investment (ROI). Delivery of an acceptable ROI to private and public investors is currently challenging in unconventional plays. However, these challenges also apply offshore with its high cost operations, the focus on trimming budgets, reduction of nonproductive time (NPT) and risk, and getting the best data at the best price.

By reinventing mud logging through the development of robotic solutions and advanced software for the collection and analysis of drilled cuttings, including real-time geochemistry at the well site, Diversified Well Logging (DWL) is providing a tool to help operators achieve better capital efficiency and ROI. As a result, high-resolution quantitative data at low risk and cost are available for geologists and engineers, meaning that formation evaluation can return to the surface.

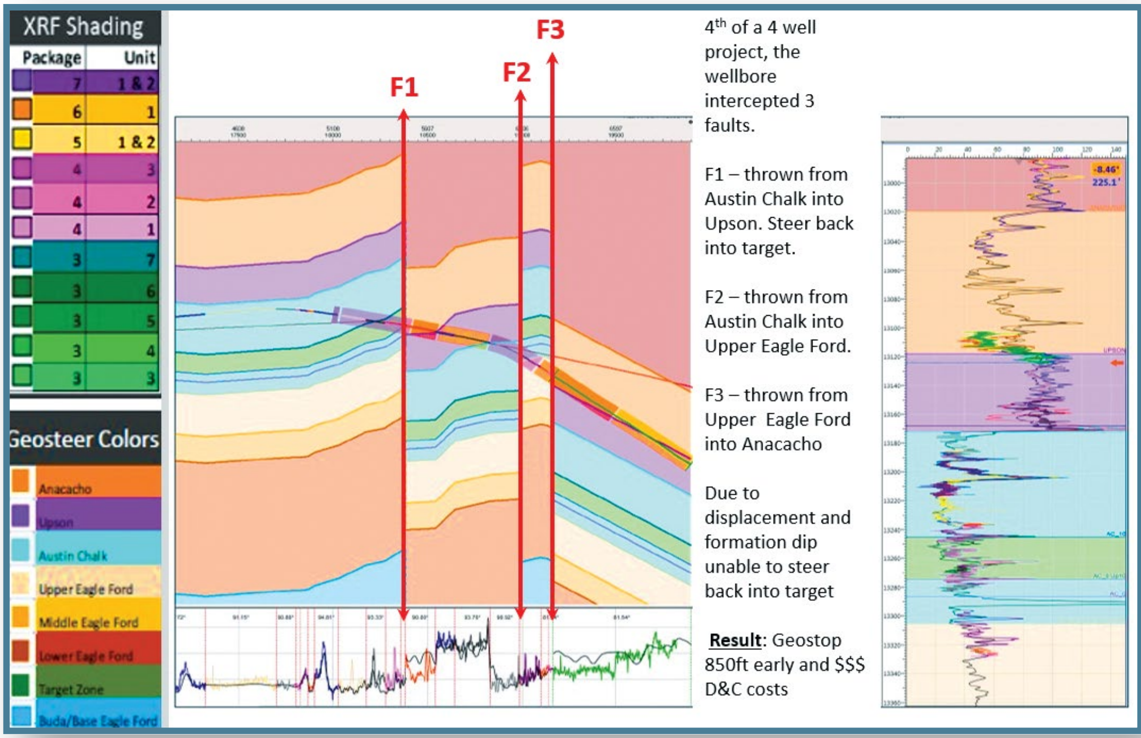
Reinventing mud logging

Reinvention of mud logging was necessary to meet the need for quantitative data on depth while also being representative of the interval sampled at a higher resolution. The technology also needed the same number of people at the well site and to meet the requirement to provide more value and reduce risk. The result of these needs is hybrid mud logging (HML).

Using drill cuttings and benchtop portable X-Ray fluorescence (XRF) instruments, rigorous laboratory quality control procedures can be applied to provide near-real-time elemental rock measurements. Combined with drilling data, formation gas and artificial intelligence (AI) methods, including machine and deep learning, an important window into the subsurface is now available.

This evolution from qualitative sample analysis to quantitative elemental, mineralogical and chemostratigraphic interpretation allows in real or near-real time

- Accurate stratigraphic wellbore positioning;
- Improved understanding of depositional environment and provenance;
- Improved understanding of reservoir quality;
- Facies characterization;
- Modeled mineralogy;
- Estimation of clay composition;
- Relative grain size indication;
- Cavings ID related to wellbore stability;



A real-time XRF elemental analysis provides independent geosteering interpretation, is able to differentiate between two carbonate rich formations and determines the throw across multiple faults and aids the decision whether to steer back into the target or TD the well early. (Source: Diversified Well Logging)

- Drilling hazard mitigation (chert beds);
- Integration with gas data for fluids ID, compartmentalization and connectivity;
- Quantitative formation evaluation and correlation;
- Geosteering (or elemental/chemosteering);
- Improving drilling efficiency;
- Avoiding geohazards and reducing NPT; and
- Optimizing landing targets or casing points.

Elemental gamma ray

With real-time quality control of the samples and data, problems related to on-depth sample representation and contamination are resolved immediately at the well site rather than weeks or months later in a laboratory. To confirm that samples are on-depth, the elemental gamma ray (EGR) is calculated and compared with MWD/LWD gamma ray (GR) when available. The EGR is calculated from the elemental values of uranium, thorium and potassium derived from XRF analysis of the drilled cuttings. With case histories from many wells onshore and offshore, confidence in the EGR is high. Many case histories have shown excellent coherence with downhole GR giving operators the confidence to drill on with EGR when the MWD/LWD tool has failed.

The importance of depth control is increased when geosteering through tight target windows. Unconventional production depends on drilling long lateral wells in the right place through formations that are perceived to be relatively homogenous, with only downhole GR as the steering and formation evaluation tool. HML, EGR and GR are used as corroborative datasets for the geosteering team and, more importantly, the elemental data are used to fingerprint lithological packages allowing chemosteering. Given the XRF provides 25 to 32 elements and an almost infinite number of elemental ratios compared to a single measurement, such as total GR, this permits differentiation of lithological packages that might appear the same for GR alone. With the high cost of LWD, real-time elemental data provide the fidelity of formation evaluation that enhances geopositioning, detects and avoids geohazards, and provides a rich source of data for cost-effective improvements in drilling and production efficiency for every well drilled.

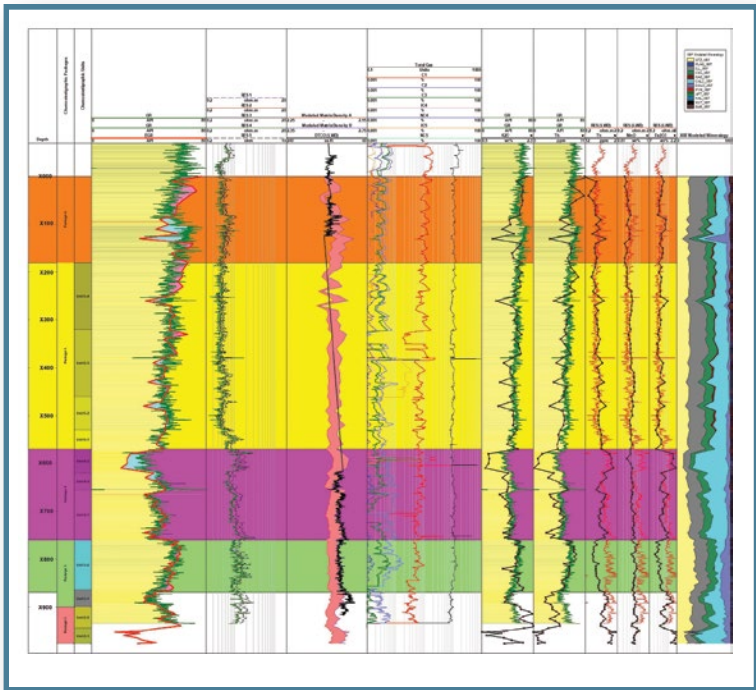
Case history 1

Using HML's real-time elemental data enabled an operator to successfully geo-stop a well that had faulted 200 ft out of the Austin Chalk into the overlying Anacacho Formation. The magnitude of the fault and formation dip after the fault determined it was not possible to steer the wellbore back into the target before the planned total depth of the well. With average drilling and completion costs in this area estimated to be in the $8 million to $10 million range, considerable savings were realized.

Case history 2

Expanding on the value of surface MWD and formation evaluation, and by using real-time quantitative elemental data combined with AI software, a South Texas operator was prompted to reevaluate its formation evaluation program. Where traditional mud logging was used only infrequently—one well per pad—following a trial of HML, the operator found it was able to use the data to predict hydraulic fracturing efficiency without the cost and time of running microseismic and fiber-optic measurements. The power and utility of quantitative geological data combined with innovative software led the operator to deploy HML on all wells in South Texas for 2020.

Vast amounts of information can be garnered from rocks and gas collected at the surface while drilling. XRF elemental data are used to model mineralogy, total organic carbon, matrix density and estimate parameters such as bulk density and porosity. This is all achieved without the cost and risk inherent in running downhole tools. Downhole tool acquisition costs from wireline and LWD are estimated to be in the range of $14 billion annually, according to Spears and Associates. While downhole tools can fail with loss of data, become stuck or lost in hole, elemental data from cuttings are always available for formation evaluation. With advanced software, synthetic logs can be created for advanced geological, geomechanical and petrophysical use.



Real-time chemostratigraphy provides the confirmation of stratigraphic position to identify the casing point ahead of a major pore pressure regression, eliminating a potential bit trip in the Gulf of Mexico due to failure of crucial LWD tools. (Source: Diversified Well Logging)

Case history 3

HML was recently used in the Gulf of Mexico to identify a crucial casing point at the Cretaceous-Paleocene boundary, which marks a major pressure regression due to the presence of impact breccias and depletion. During the drilling operation, the LWD tool failed with loss of real-time sonic, resistivity and GR data over a 1,600-ft section. Confidence in the EGR and chemostratigraphic location allowed drilling to continue without tripping for a new tool. Sonic data were lost from the memory data as well. The matrix density modeled from elemental data showed coherence with the sonic log prior to tool failure and with the new tool on the next bit run. The matrix density modeled from the elemental data filled in the missing interval. Certain elements were seen to correlate with resistivity throughout the hole section. Possible reasons for these correlations and links to factors governing pore pressure are being explored.

Next step transformation in mud logging

Higher-resolution sampling is achieved with DWL's robotic mud logger. The Robologger can collect and store samples every 2 minutes, providing quantitative rock composition at greater depth resolution than is possible with humans. The tool provides consistent sample collection, 24/7 in all weather and lowers HSE risk and carbon footprint by reducing the number of personnel required at the well site. Current development will integrate a laser induced breakdown spectroscopy device into Robologger for real-time elemental cuttings analysis.

Drilled cuttings and mud gas provide a physical sample of the subsurface. With quantitative elemental analysis and EGR, users can be confident that the samples are on depth and representative. These two factors are one reason why the industry has historically been reluctant to utilize the full potential of drilled cuttings. With the focus on cost and reduction in risk, HML is a major step change in providing quantitative data in near-real time without increasing personnel. With automation and robotics integrated with the power of AI and deep learning, the Robologger will be the next step transformation in mud logging by providing high-resolution, quantitative sample collection and analysis in real time with a reduction in personnel. This surface MWD provides high-resolution, quantitative data in real time at reduced risk and greater value and helps the industry achieve better capital efficiency and ROI. +

Reducing flat time in the field

An offline cementing system saves an E&P company eight hours of cycle time and about $32,000 per well.

Brandon Dodge, *Weir Oil & Gas*

While multiwell pad drilling offers many advantages, operators often find themselves relying on traditional methods that prevent them from experiencing the full benefits this approach can provide. New technology that reduces flat time can unlock deeper cost savings and efficiencies operators have been waiting for.

Traditional extraction methods involve drilling down vertically from a new pad into a single well. This requires a rig to be disassembled, hauled to the next pad and then reassembled—even if the new well site is just a few feet away. Relocating a rig requires several days, hundreds of thousands of dollars and constructing an entirely new drilling pad, along with all the equipment and infrastructure that goes with it, making it costly to the operator and the environment.

Multiwell pad advantages

Multiwell pad drilling enables operators to achieve economies of scale to shorten cycle time and increase rig productivity, which is why it has become the new norm in North America land operations. Instead of building multiple four-acre locations to drill, complete and produce horizontal wells, multiwell pad drilling allows operators to tap into different layers of shale at various levels of the subsurface at one time from one location, reaching multiple reservoirs and formations more efficiently. Multiwell pad drilling enables multiple wellbores to be drilled from one drilling pad, cutting down on the amount of space and the number of rigs needed for an operation, while increasing the number of wells, and potentially the amount of resources, those wells can reach.

(Source: Evgeny_V/Shutterstock.com)

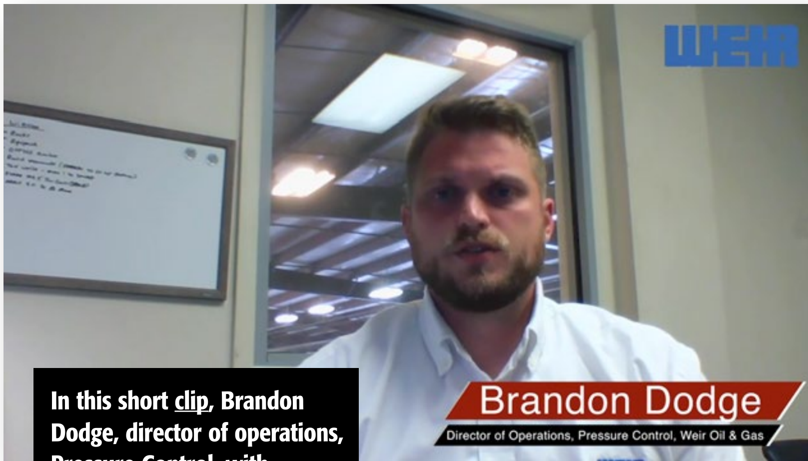
Multiwell pad drilling is the multitasker of oil and gas production. There are simultaneous operations happening at one time. While an operator is perforating one well, they may be performing wireline on another well. Operations are completed in batches. These simultaneous operations can save hundreds of hours and thousands of dollars. What used to cost $10,000/hour using conventional methods, now costs about $3,000/hour with multiwell pad drilling. The overall cycle times and cost of drilling the well are dramatically reduced.

While multiwell pad drilling offers several compelling advantages, it can also create expenses for operators as field crews wait on site for their turn to perform their specific work. Production delays and increased planning can increase the complexity of employing multiwell pad drilling and can increase labor costs.

Benefits of batching

The batch nature of multiwell pad drilling enables certain operations to be taken offline without affecting the overall economics or cycle time of the operation. Operators can skid over to the next well to begin rigging up while another well is cementing casing strings offline, for example. Taking cementing offline presents a viable option for operators to reduce nonproductive time (NPT), optimize drilling efficiency and reduce cycle time. Weir Oil & Gas' Offline Cementing system gives operators valuable drilling time as it removes cementing from the critical path.

When taking cementing offline, the openhole section is drilled and casing is run to total measured depth and hung in the wellhead. The rig then skids to the next well, begins rigging up and drills the next openhole section. While the rig is setting up on the next well, the cementing can be performed on the previously drilled or cased well section.



In this short clip, Brandon Dodge, director of operations, Pressure Control, with Weir Oil & Gas, discusses offline cementing.

Case study

Taking cementing offline can prove extremely fruitful, especially when it can be performed with both surface and production casing. A South Texas E&P company realized it was experiencing a significant amount of NPT due to waiting for cement to set. In an effort to reduce flat time, optimize drilling efficiency and reduce cycle time, the E&P company enlisted the use of the offline cementing system to take cementing operations safely off the critical path.

Weir designed and installed a compact, reliable and safe system that met cellar height requirements and attached it to the company's S-29 Lock Ring Wellhead to enable offline cementing for production casing. It is a tool-free, eight-minute setup that eliminates the need for BOP configuration adjustments and enables testing isolation in the backside of the well for greater security and well integrity.

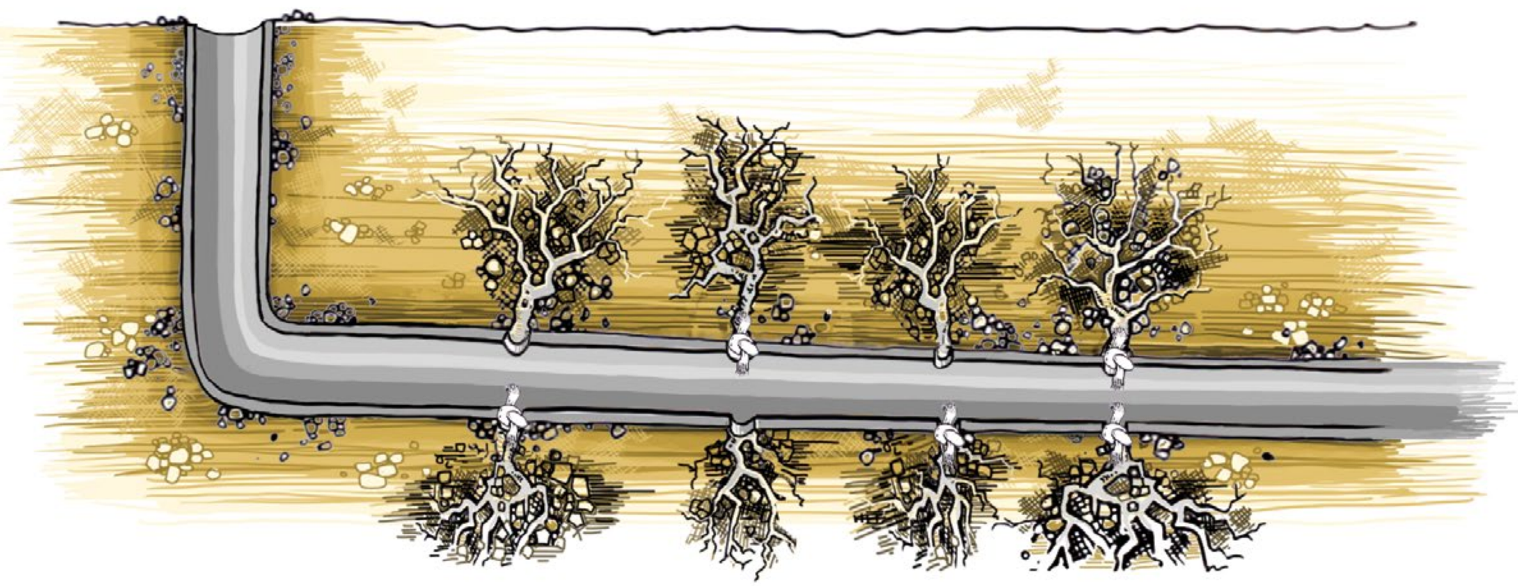
Once installed, the company's cementing crew successfully connected its cement head to the system and completed the cementing operation. The offline cementing system resulted in a significant reduction in NPT and cost savings. The E&P company saved 8 to 10 hours of cycle time and about $32,000 per well with this solution. The offline cementing system also enabled the E&P company to manage crews with pinpoint accuracy, eliminating the typical NPT that is common in multipad drilling as crews wait for each other to complete each operation.

As companies seek to further reduce capex, taking advantage of automations (e.g., offline cementing) is more crucial than ever. Eliminating the NPT that occurs while field crews wait for their turn on site can create substantial cost savings and efficiencies.

Taking cementing offline can prove extremely fruitful, especially when it can be performed with both surface and production casing.

Today's climate is encouraging operators to challenge traditional approaches to see and do things differently—to take advantage of automation. Taking a systems-wide viewpoint helps unlock greater efficiencies and savings. By thinking in systems, not silos, improvements are identified that can impact the entire operation. Offline cementing is one of those improvements that can have positive ripple effects across a site.+

PERF PODS SEAL AT A 1:1 RATIO



SlicFrac®
Zonal Isolation

Thru Tubing Solutions' SlicFrac diverting technology is the only diverter that will seal off irregular shaped holes making it the ideal solution for new completions and re-frac operations.

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

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

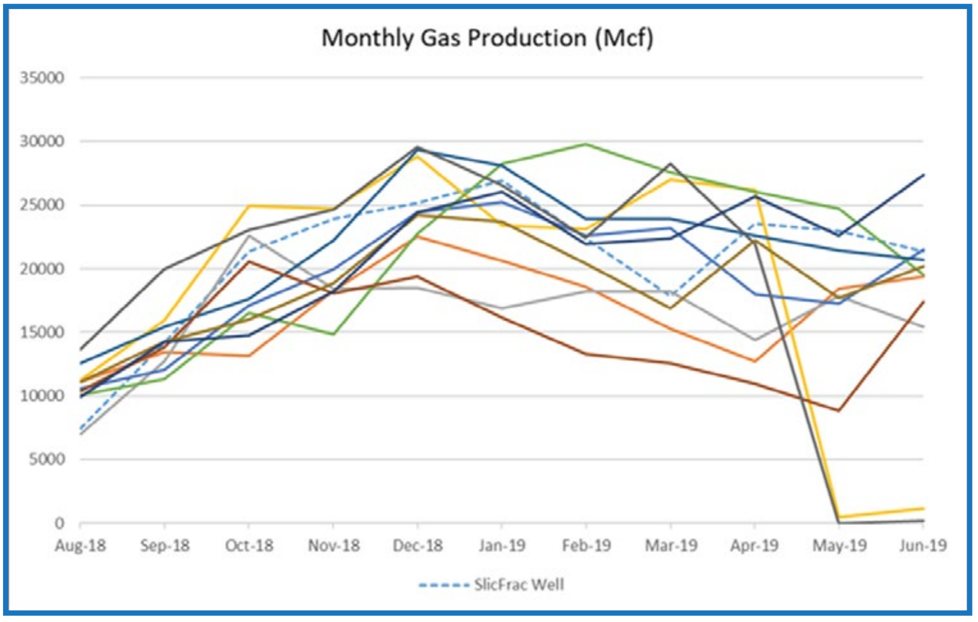
SlicFrac Benefits:

- *Reduce or eliminate bridge plugs*
- *Reduce overall completion costs*
- *Mid-stage diversion for maximum cluster efficiency*
- *Eliminate bashing on offset wellbores*
- *Block flow at the perforation in the casing*
- *Perf PODs form to geometry of irregular shaped holes*

Replace Frac Plugs with **SlicFrac**

Incorporating Perf PODs as an alternative to frac plugs for zonal isolation allowed the operator to complete the wellbore as designed, despite casing limitations.

Due to multiple casing ID restrictions, a customer in the DJ Basin required an alternative solution to isolate intervals and effectively stimulate the entire lateral.



The customer replaced all frac plugs with **SlicFrac** Perf PODs, deployed between each frac stimulation to isolate and divert the flow to the next interval of perforations. By isolating each perforation the customer was able to efficiently stimulate the entire lateral; attaining more reservoir contact with improved perf cluster efficiency. **SlicFrac** Perf PODs were deployed to divert fluid from the dominant perforations and provide breakdown of the less dominant or under-stimulated perf clusters within each interval.

For this 55 stage completion, degradable Perf PODs were deployed from surface maintaining isolation for the entirety of the 10 day frac stimulation. **TTS'** Standard Milling BHA was used post frac to cleanout residual sand and circulate the wellbore clean before putting the well onto production.

By replacing frac plugs with **SlicFrac** Diversion, the customer was able to effectively stimulate the entire wellbore as designed, while reducing overall completion costs and eliminating the risks associated with setting and removing reduced OD plugs. The chart above shows production of the well where **SlicFrac** was used in comparison to other wells in the field; the production is higher than many of the wells and continuing to trend upward.

Visit www.SlicFrac.com to see how SlicFrac can optimize your well!

FSCS can help improve frac efficiencies, increase completion rates and reduce costs per well. (Source: Downing USA)

Automating well completions

A new system reduces stage-to-stage transition time from 45 minutes to less than 3 minutes while ensuring the safety of personnel.

Tim Marvel *and* ***Austin Johnson****, Downing USA*

The plug-and-perf (PNP) technique is the most prevalent completion method in North America's shale and tight oil plays. The method provides the ability to pinpoint fracture locations with perforating guns, adjust stage spacing during the completion, achieve zonal isolation between stages and complete 100 or more stages in a horizontal well.

While preferred versus the sliding sleeve method, the traditional PNP method is highly inefficient and requires personnel to work at height in the red zone. Traditional wireline tool deployment requires three steps.

First, the working valve on the frac tree is shut down manually by a red zone operator. The wireline operator picks up the gun assembly and suspends it over the frac head and the red zone operator. Next, the red zone operator installs the wireline lubricator, which is pressurized using a backside pump. The frac iron is then pressure tested. If successful, the working valve is opened and the wireline tools can be lowered into the well. If the test is unsuccessful, more time is required to find and repair leaks in the iron. Using conventional methods, this entire process takes up to 45 minutes. The use of a latch or wellhead connection unit might reduce the time by 25 minutes.

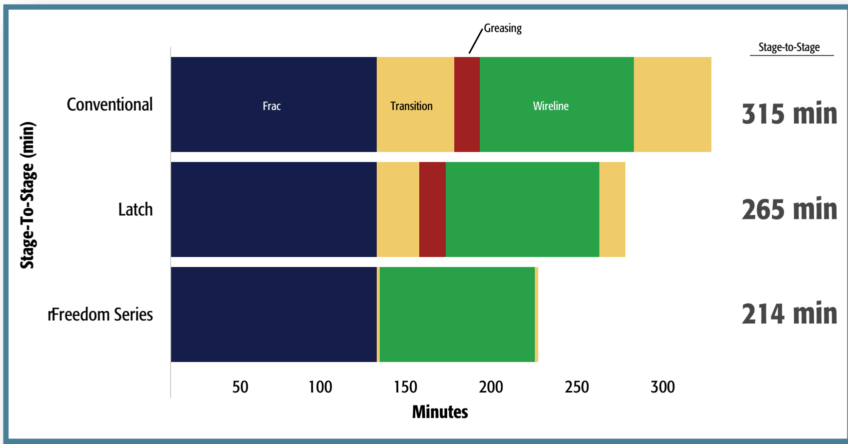
Removing the wireline string after perforating and transitioning to fracturing the next stage is equally time-consuming, again taking up to 45 minutes depending on the efficiency tools employed. The process begins with the red zone operator closing the working valve manually, releasing the lubricator and bleeding off the pressure. At this step, closing the valve accidentally on the wireline can cut the wireline, resulting in a costly fishing job of at least a day of nonproductive time (NPT). If a ball is to be dropped, the red zone operator drops it onto the swab valve and then installs the frac head cap. The frac iron is then pressure tested. If successful, the red zone operator manually opens the swab valve, releasing the ball down the wellbore until its seat onto the frac plug, at which point pressure pumping begins.

Improving completions

The downturn in the oil and gas industry highlights the need for the efficiency enabled by automated technology. Downing's Freedom Series Completion System (FSCS) lowers well completion costs through surface efficiencies and reduced labor costs and creates safer well sites. The FSCS was designed to improve the efficiency, safety and costs of PNP operations.

The integrated system is located between the frac head and lubricator. It comprises a multichambered valve, a quick-connect latch and an automated ball dropper. The hydraulically actuated valves create three chambers that are operated via a computer from a control cabin or remotely via the cloud. The quick-connect latch enables the lubricator to be attached to the frac tree without personnel working at height in the red zone. With the FSCS, the lubricator can simultaneously attach to the quick connect latch while the well is pumping.

In addition, using Downing's FS Pump Station, the lubricator is prefilled during the flush cycle, enabling a transition of a few seconds before the wireline is sent downhole.



Comparing stage-to-stage well times, conventional and latch methods lag behind the FSCS wells, mostly because automation has shortened the transition times. (Source: Downing USA)

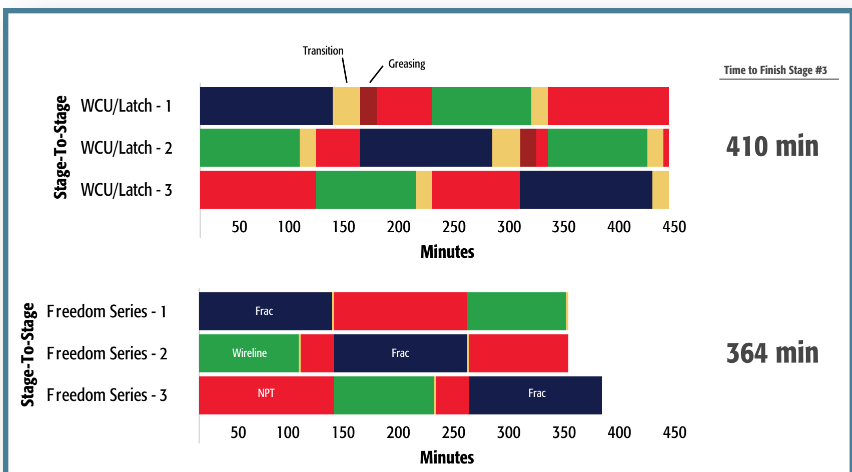
At each stage, the system's multichamber system equalizes pressure between the surface/lubricator and the well, enabling wireline conveyed tools, balls and collets to pass easily between the surface and the well without operating the lower master valve and without pressuring down and repressurizing the flow iron.

Downing's FSCS lowers well completion costs through surface efficiencies and reduced labor costs and creates safer well sites.

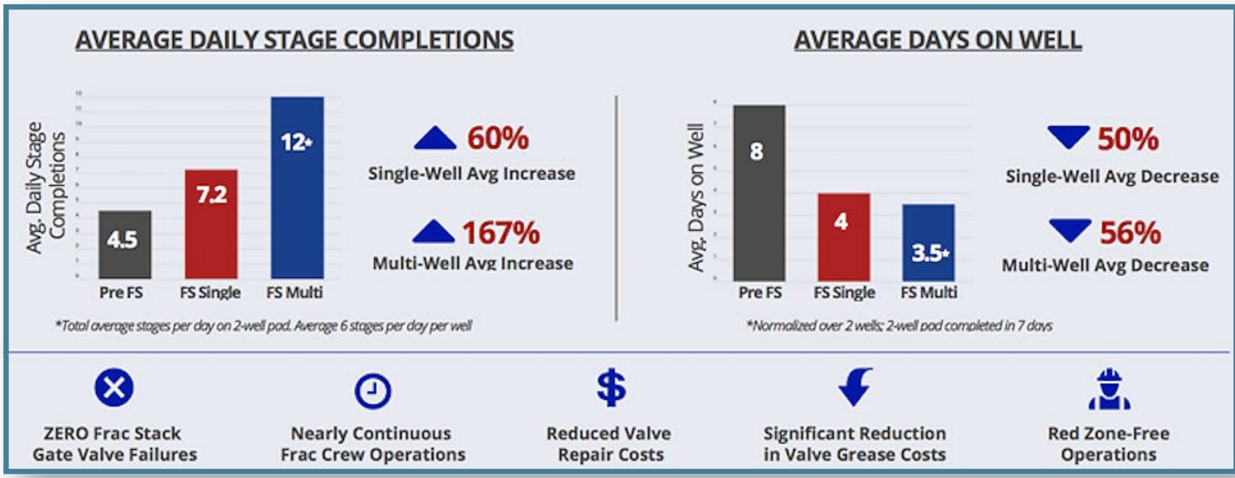
The system provides a dual barrier to control well pressure so the lubricator can be latched to the wellhead and prefilled while pumping proceeds, compressing stage-to-stage time. The FSCS reduces transition time from 45 minutes to less than 3 minutes, significantly compressing the stage-to-stage time. Quick transitions enable continuous pumping operations on zipper fracs, helping operators significantly increase their pump efficiency.

Additional savings

With the FSCS, wireline tools are run in and out of the well without opening and closing the lower master valve, significantly reducing repair costs and greasing requirements up to 90% in single wells and 50% with zipper operations. Moreover, because the FSCS provides a dual barrier for well control, one hydraulic valve can be removed from the frac stack, further reducing height as well as the cost of the stack.



In a study, stage completion times were compared. The FSCS saved significant time in stage-to-stage comparisons, 364 minutes compared to 410 minutes. (Source: Downing USA)



In a recent study, average daily stage completions using FS Single resulted in a single well average increase of 60%, while using the FS Multi provided a 167% average increase. The FS Single and FS Multi also beat the eight-day average days on a well, yielding a 50% decrease on a single well and a 56% average decrease using the FS Multi on multi-wells. (Source: Downing USA)

There is no need to depressurize the frac iron between stages, as required when using the gate valve to contain well pressure when using the FSCS. Because the frac iron does not need to be repressurized, no testing is needed and pumps do not need to be primed, allowing pumping to quickly resume on the next stage after the transition. In addition, frac iron leaks are reduced from the reduction in pressure cycling. And, given that gate valves are cycled only a few times during the entire job, the chance of a gate valve failure and the subsequent replacement time (up to 12 hours of NPT) is significantly reduced.

iControl's intelligent design detects valve position, ensuring valves remain closed if equalization is not detected, eliminating the risk of accidental pressure release.

Downing reports that the FSCS has completed more than 7,500 stages across 180-plus wells without experiencing a gate valve failure on the frac stack.

Completions automation

The FSCS establishes an automation platform on the well site for adding additional services to further compress stage-to-stage time, reduce potential safety hazards and lower well completion costs. With onsite personnel representing the largest potential safety concerns and added completion cost, attention was focused on automating the remaining frac stack processes and integrating these into the FSCS.

FS iControl was developed to automate the control and greasing of all hydraulic frac valves, eliminating the need for onsite service techs to operate and grease valves.

Integrated with the system workflows, iControl seamlessly operates the zipper hydraulic valves as part of the transition process. During this transition, valves are automatically and precisely greased to manufacturer's specifications, eliminating potential human error and red zone operations. The exact amount of grease put into each valve is recorded and time-stamped, available to the operator in real time.

In addition, iControl's intelligent design detects valve position, ensuring valves remain closed if equalization is not detected, eliminating the risk of accidental pressure release. Finally, with only one accumulator needed on location for up to a four-well zipper frac, the operational footprint is reduced versus conventional greasing manifolds, minimizing equipment costs and further improving safety.

Real-time analytics

All sensor data are streamed to the cloud in real time. The system incorporates real-time data analytics that provides a comprehensive picture of the operational efficiency. With time-stamped data, analytics and automated milestones from proprietary algorithms, comparing operational efficiency day to day, job to job and crew to crew are readily available.

Job summaries and charting enable individual job analysis or trending across multiple jobs, enabling an operator to quickly modify operations and improve completion efficiency. With a built-in application program interface, data can readily be streamed into an operator's data aggregation platform.

Finally, the system includes remote operations center support providing live backup and intervention in conjunction with the operator. Remote operations capabilities include cameras enabling inspection of wirelines, check lines and equipment. +

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A technician opens a valve at the end of fracturing operations on a Midland Basin well. (Photo by Tom Fox, courtesy of Oil and Gas Investor)

Managing negative fracture interactions with far-field diverters and liquid chemical tracers

The effectiveness of far-field diverters was evaluated by a Permian Basin operator using tracers.

***Sudiptya Banerjee**, Tracerco*

For operators developing shale reserves, determining an optimal infill well strategy can be technically challenging and plagued by multiple sources of uncertainty. Even under the best circumstances, multiple reservoir properties combine to create a complex blend of matrix permeability, natural faults and fractures, and landing interval properties that make ideal placement highly variable from pad to pad—especially within stacked reservoirs.

While heterogeneity in the reservoir cannot be controlled, multiple strategies have been created to mitigate the risk of placing infill wells close enough for negative fracture interactions, instances where overlapping stimulated areas between wells undermines the economic value of one or both assets. These mitigation techniques almost exclusively focus on preventing fracture linkage, either by limiting fracture growth or by controlling the direction of propagation.

In cases where parent well production has significantly depleted the reservoir, stimulation of infill wells frequently results in a higher degree of asymmetric fracture growth, with fractures propagating toward depleted and previously fractured zones surrounding the parent well rather than stimulating previously unexploited reserves. An optimal mitigation strategy redirects the energy of hydraulic fracturing toward more even fracture growth and a more distributed, rather than longer, fracture itself. Yet the selection of an optimal mitigation strategy is not clear cut, particularly when individual pads deal with unique heterogeneities and natural fracture outlays.

To this end, diagnostic tools provide significant value in determining which completion strategy and the possible combination of mitigation techniques best align with an operator's technical needs and economic drivers. A Permian Basin operator evaluated the effectiveness of far-field diverters at controlling fracture growth and limiting interwell communication between child and parent wells. Liquid chemical tracers were used to establish and quantify flow from and between wells and determine if a novel diversion strategy was preventing negative fracture interference.

Building a tracer test of far-field diverters

A tracer study was constructed around 10 horizontal wells in the Spraberry trend. Eight of these wells were newly

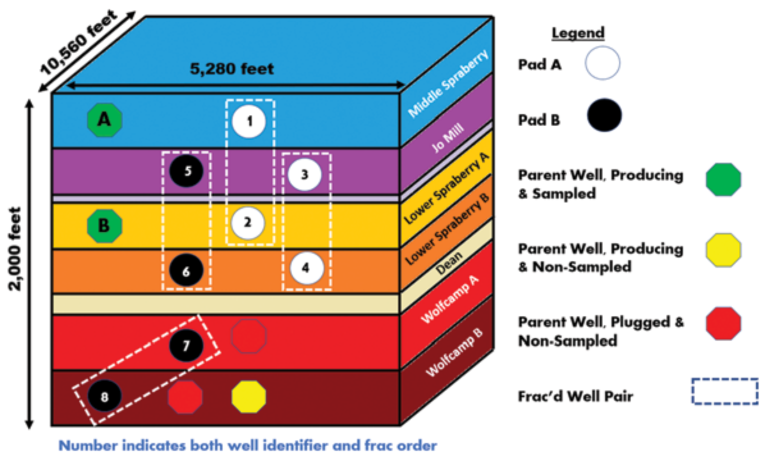


FIGURE 1. The graphic displays relative placement of parent and child wells as well as frac order (not to scale). (Source: Tracerco)

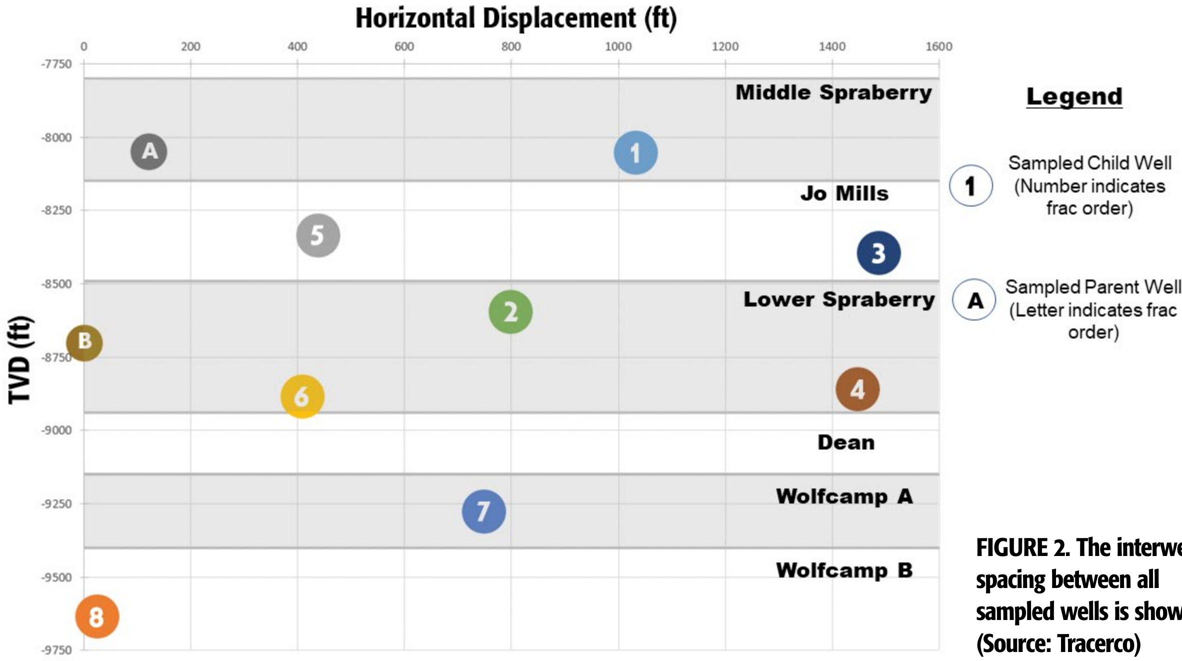


FIGURE 2. The interwell spacing between all sampled wells is shown. (Source: Tracerco)

hydraulically fractured infill wells, grouped into two pads and spread across the Middle and Lower Spraberry, Wolfcamp A and B, and the Jo Mill intervals. Two nearby parent wells also were monitored for possible interwell communication with the child wells. Figures 1 and 2 provide a reference for the relative placement of all 10 wells.

Each infill well was completed in a manner typical for the area; a slickwater stimulation program, using a combination of 100 mesh and 40/70 sand, was used to zipper frac well pairs.

Table 1 provides a summary of the stimulation program used for the infill wells.

To compare the use of far-field diverters against a baseline stimulation, Wells 1, 2, 5 and 6 were divided into four treatment zones. In the case of these four wells, stages 1-4 were treated with both a liquid oil and water tracer but no diverter to provide verification of flow from the toe of the well. Stages 5-12 were treated with a second oil and water tracer pair but again no diverter. Stages 13-20 were treated with a third unique oil and water tracer pair alongside a far-field diverter. The remainder of the lateral did not see the use of tracers or diverters. In the case of child wells 3, 4, 7 and 8, the first 20 stages were treated with liquid water tracers, liquid oil tracers and diverter.

To further protect the parent wells from negative fracture interactions, Parent Wells A and B were shut in for a period of time to restore the depletion zone surrounding them prior to fracturing the child wells. Parent Well A also saw an injection of water to prepressurize the near wellbore area and provide additional protection from child fracture growth into its drainage area. Three additional parent wells exist within the Wolfcamp A/B and in proximity to Well 7, but these wells could not be sampled over the course of the study. However, the depletion effects of these three parent wells are expected to affect fracture growth direction during the stimulation of the child wells.

Over the span of 200 days, samples were collected from the eight child and two parent wells and analyzed for the presence of the injected tracers. When tracers were recovered from the same well that saw their injection, the combination of tracer concentration and production history generated a mass

Well Identifier	Stages	Lateral Length (ft)	Proppant Intensity (lb/ft)	Fluid Intensity (bbl/ft)	Average Fracture Rate (bpm)
Infill Well 1	54	9,880	2,000	48	94
Infill Well 2	55	10,000	2,000	48	94
Infill Well 3	66	9,950	2,000	51	95
Infill Well 4	66	9,930	2,000	50	94
Infill Well 5	55	9,900	2,000	48	95
Infill Well 6	55	10,010	2,000	48	94
Infill Well 7	67	9,990	2,300	56	94
Infill Well 8	67	10,050	2,600	72	94

TABLE 1. This summary provides key stimulation design properties for each infill well. (Source: Tracerco)

Stages 1-4	Treated Well		Production Wells								
			Well 1	Well 2	Well 3	Well 5	Well 6	Well 7	Well 8	Parent A	Parent B
		Well 1	***0.25***	0	2.47	0	0	0	0.31	0	0
		Well 2	0	***0.85***	0.24	0	0.24	0	0	0	0.33
		Well 5	0	0	0	***0.19***	0	0	0	0	0.15
		Well 6	0	0.21	0	0	***0.83***	0.24	0	0	0.12

Stages 5-12	Treated Well		Production Wells								
			Well 1	Well 2	Well 3	Well 5	Well 6	Well 7	Well 8	Parent A	Parent B
		Well 1	***0.15***	0	0	0	0	0	0.3	0.15	0
		Well 2	0	***0.1***	4.28	0	0	0	0	0	0
		Well 5	0	0	0	***0.16***	0	0	0	0.13	0
		Well 6	0	0.39	0.1	0.93	***0.82***	0	0	0	0.83

Stages 13-20	Treated Well		Production Wells								
			Well 1	Well 2	Well 3	Well 5	Well 6	Well 7	Well 8	Parent A	Parent B
		Well 1	***0.39***	0	0	0.1	0	0	0.65	0	0
		Well 2	0	***0.81***	0.13	0.13	0	0	0	0	0.13
		Well 5	0	0	0	***0.23***	0	0	0	0.28	0.29
		Well 6	0	0	0	0.14	***0.13***	0	0	0	0.19

FIGURE 3. A heat map illustrates the mass percent recovery of tracer injected recovered from sampled wells in the study. (Source: Tracerco)

balance that revealed how much of the oil and water production came from each of the three treated zones. When a tracer was discovered in the production fluid of an offset well, its presence evidenced an intermingling of stimulated reservoir volumes (SRVs) that allowed for tracer migration to occur.

Study results

Establishing diverter effectiveness was centered on the tracer behavior of Wells 1, 2, 5 and 6. These four wells placed zones treated with diverter alongside untreated zones, allowing the effects of diversion to be compared to a baseline established by the same well. Heat maps are provided in Figure 3, showing the migration of water tracers among the sampled wells. Compare the heat map distribution of stages 1-4 and stages 5-12; for the two zones that did not see diverter use, tracer migration trends are largely identical. The variations that do exist are relatively small, such as the worst of the interwell communication occurring between wells 1 and 3 for the toe-most stages and between Wells 2 and 3 for stages 5-12. Given that Wells 1 and 2 are a zippered pair, this is not a meaningful distinction.

For Well 6, interwell communication favors its nearest offset—Well 5—for stages 1-4 and switches to its next nearest offset well—Well 7—for stages 5-12. Where communication with a parent well occurs, it nearly universally occurs with Parent Well B that was not prepressurized. Where diverters were used, there is definitive and measurable change in the growth of the fracture network surrounding the child wells. Diversion successfully restrains the high overlap in the stimulated area surrounding the Well 1 and Well 2 pair and Well 3. In place of strong growth in an easterly direction, a more symmetric network grows to both the east and west of the zippered well pair. However, due to the closeness of well spacing, this substitutes strong communication with Well 3 with less extreme, but still problematic, communication with Wells 3 and 5.

Diversion did not prove effective in preventing fracture network growth toward depleted zones within the reservoir. Though tracer results are suggestive that diverter use may increase cluster efficiency and provide a more even distribution of fracture fluid through each perforation during fracturing, the improvement was insufficient to significantly change the likelihood of negative fracture interactions (Figure 4).

Where diverted stages could be compared to non-diverted stages, it was often observed that the non-diverted stages had higher or comparable recovery of injected oil.

An analysis of the oil tracers suggests other trade-offs might exist when using this particular diverter. Where diverted stages could be compared to non-diverted stages, it was often observed that the non-diverted stages had higher or comparable recovery of injected oil tracers (Figure 5). Since the mass recovery of oil tracer is an effective proxy for oil production from these zones, the recovery rates raise

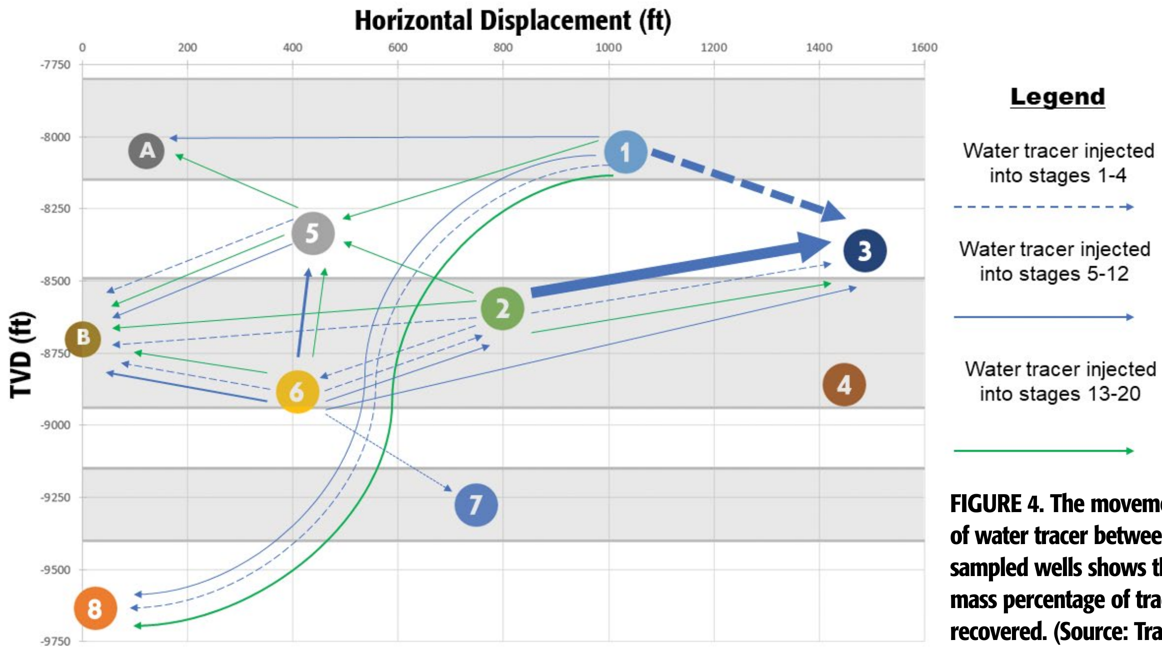


FIGURE 4. The movement of water tracer between sampled wells shows the mass percentage of tracer recovered. (Source: Tracerco)

concerns that the diverter has a near-field effect that is negatively effecting oil production from the treated well.

In fracturing infill Wells 1 and 2 first, the operator attempted to create a pressure barrier that prevented fracture growth from Wells 3 and 4 to preferentially grow toward either the depleted parent wells or the newly drilled wells of Pad 2. Once Pad 2 was in turn stimulated, Wells 5 and 6 were stimulated first in the hopes that energy reserved in the reservoir post-fracturing would also shield the remaining wells from the stress effects originating in the depletion zone. Managing stimulation order did prove effective in mitigating negative fracture interactions for the remaining child wells in this study; the tracer behavior of Wells 3, 4, 7 and 8 illustrated very low levels of tracer migration and only to the nearest offset wells. Communication with the two depleted parents was essentially eliminated.

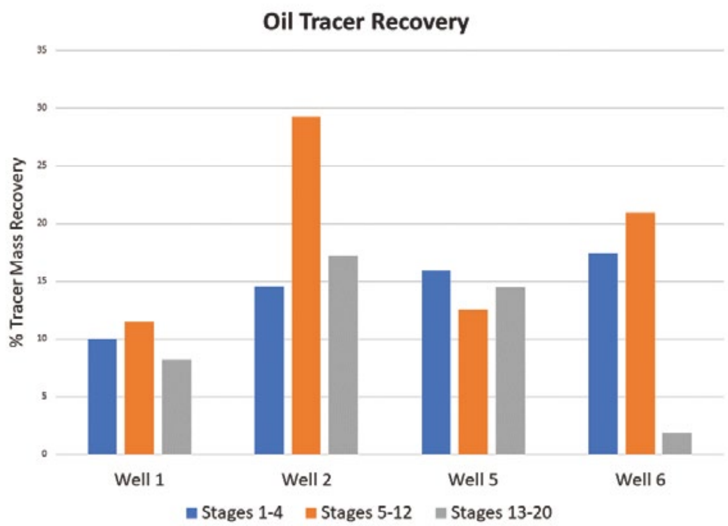


FIGURE 5. The chart depicts recovery of oil tracers from zones untreated and treated by diverter. (Source: Tracerco)

Conclusion

The use of liquid chemical tracers allowed for a rapid, cost-effective method to evaluate far-field diverters within the Spraberry trend. In using these markers to trace interwell oil and water movement, it was observed that without diverters, the planned stimulation program generated a far-field fracture system, meaning these stage fractures had an extended connection to the reservoir, which overlapped the SRV of its neighboring offsets.

In stages where far-field diverters were used, asymmetrical growth of this far-field fracture system was curtailed but introduced new problems. In creating a more even fracture network around child wells, the use of diverters ensured that negative fracture interactions occurred more often but with slightly diminished magnitude. The use of diverters also notably penalized oil production. Where well spacing was increased or frac order could be managed, the operator achieved comparable or better mitigation of overlapping SRVs and so the future use of diversion was abandoned for their Spraberry field development.+

(Source: petroleum man/Shutterstock.com)

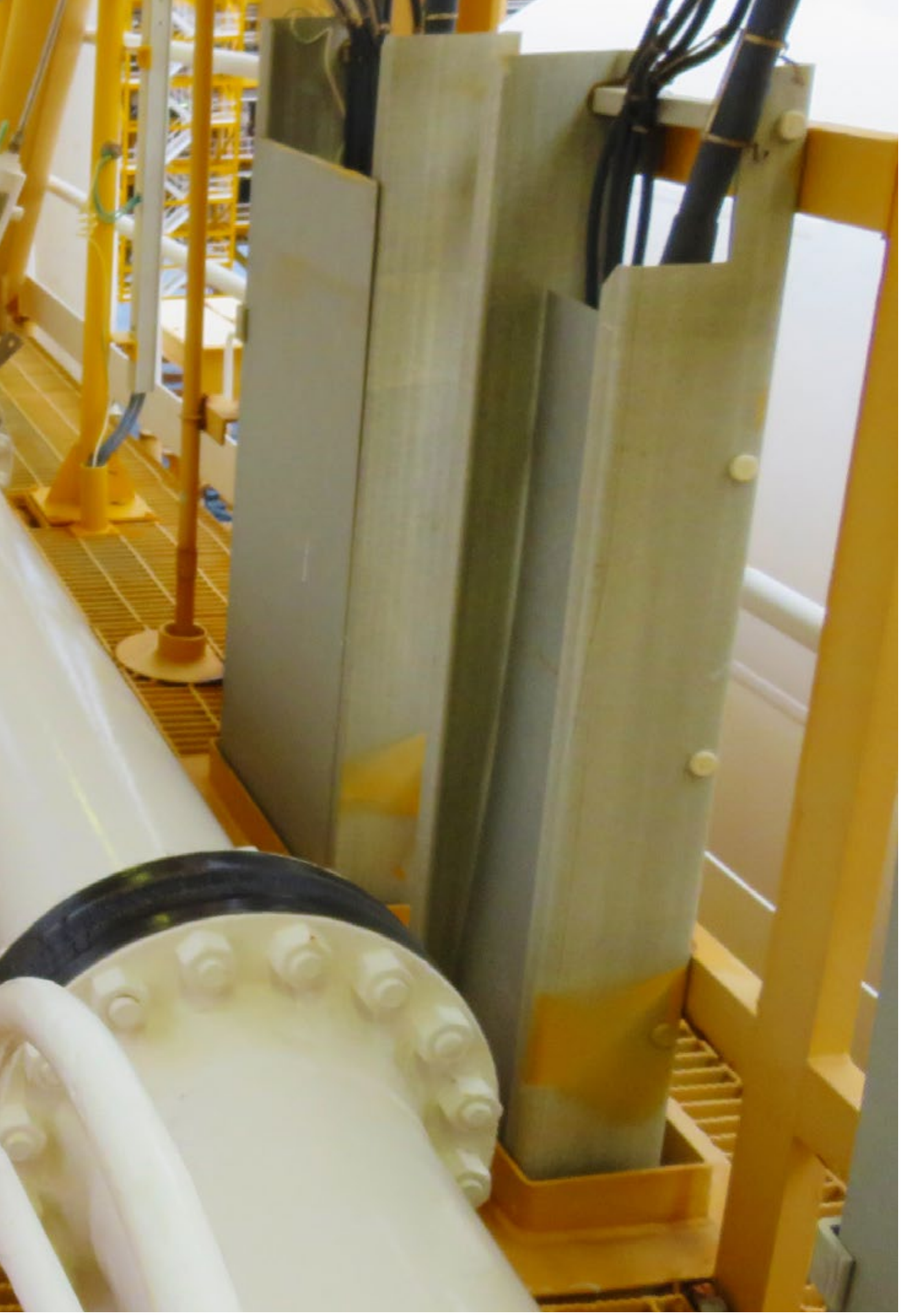
Managing H_2S recovery using analytics

Reduce emissions by improving sulfur recovery unit performance with self-service industrial analytics.

***Julian Pereira**, TrendMiner*

Oil and gas (O&G) companies are continuously striving to optimize overall equipment effectiveness, performance and profitability within a highly volatile and regulated environment. Several of those regulations are coming from an increasing industry effort toward the reduction of emissions that affect both health and the environment. Initiatives are growing from industry and governmental groups. For example, O&G companies that operate in the U.K. Continental Shelf are stepping up to reduce carbon emissions to net zero by 2050 in the U.K. Another example is the decarbonization efforts led by the European Commission, which aims to initiate the transition toward "a climate neutral economy" by 2050. This will require the active involvement and investment of different industry, technology and governmental sectors for mid- and long-term solutions.

To start getting results today, it is key to take advantage of underutilized



data in combination with process expertise that is already in place. Aim to improve process workflows to have a better and more efficient emissions control and reduction.

There is an increasing need to exploit the large set of data being generated from sensors, instruments and assets. Traditional methods of Big Data solutions require complex IT projects and data scientists to build and maintain models. Aside from being costly and time-consuming, this way of working can also create resource bottlenecks in the organization and underutilize the process and asset experts. Turning big industrial data into actionable information might seem like a huge task, but self-service industrial analytics makes it easy for process engineers to optimize the processes by themselves. Results are delivered fast, directly into the hands of the process experts who can really provide meaningful interpretations to the data, allowing them to uncover insights at all levels of production, improving day-to-day decision-making.

Improving performance

Sulfur recovery units (SRU) are becoming more and more important not only due to the rising demand for sulfur in various applications but mainly due to the increasing concern and number of regulations around emissions control and climate change. SRUs typically include burners, catalytic stages, most of the time a Superclaus unit and a tail gas incinerator. The Claus process partially burns the H_2S. It then converts catalytically the H_2S and the CO_2 combustion products to elemental sulfur and water vapor. One of the most important process key performance indicators is sulfur recovery. Low process efficiency (in this case, lower than 99.2) results in lower sulfur recovery and unprocessed and unwanted H_2S and sulfur dioxide emissions.

Analyzing the data

A prerequisite for data analytics is to have the data readily available through a live connection to the historian for automatically visualizing the tags in user-friendly trend views. The next step is to start the data exploration and searching for specific process events in the SRU throughout multiple years of data. With the use of modern self-service industrial analytics software, the process expert can focus on discovering the periods of low-sulfur recovery over the last two years.

The process expert will search for and visualize the low recovery periods, focusing on the H_2S content behavior. The sulfur that is recovered has a high dependency on the H_2S content that is measured before the Superclaus unit; whenever the H_2S online analyzer has sudden increases, the sulfur recovery rate will decrease. In this use case, the search showed 15 periods of low recovery, out of which nine presented a similar increase pattern of the H_2S content—even when the content value was still under the content target of 0.8% vol, which

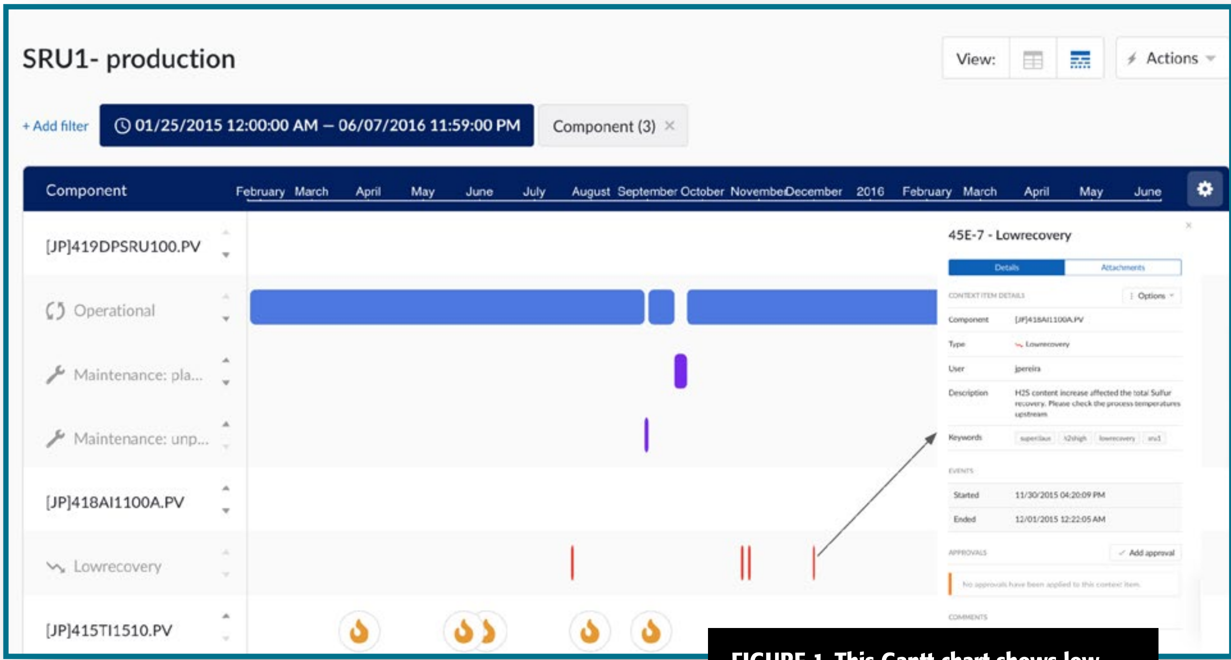


FIGURE 1. This Gantt chart shows low recovery periods longer than 20 minutes, in combination with other operational contextual information to speed up root cause analysis. (Source: TrendMiner)

was typically managed by a feedback control system to recover the plant's sulfur at maximum efficiency.

The process expert decided to set up a monitor to follow the pattern of sudden increases of the H_2S content independent of the absolute value. Through patented pattern recognition technology, the process expert was able to identify particular behaviors for periods longer than 20 minutes. By saving the search, the H_2S content behavior can be monitored in real time. Each time a user-configurable percentage of similarity is matched, an alert via email is sent to the operator for taking appropriate measures to control the process.

Context accelerates analysis

The created monitor, running in the background, can be used to capture specific low-recovery events, which can be combined with other operational contextual data from other systems. The Gantt chart view (Figure 1) gives the users a quick overview of information from the manufacturing execution system for operational status of the unit in combination with maintenance periods, operator manual entries of high skin temperature in the reactor furnace and automatic logins coming from the monitor of the sudden increase of the H_2S content.

All this information can be used to create an analytics-driven production cockpit (Figure 2). Looking at a timeframe set by the user (in this case one week) containing the live status of the H_2S content as an alert, a quick overview is provided to all relevant time-series data following the Sulphur recovery in MT/D (megatons per day), the total steam production in lb/h as well as several temperature measurement upstream of the Superclaus. Lastly, the operator has access to a counter that shows the history of the behavior of the H_2S content alert for a determined period of time.

In this use case, with the dashboard in place for the control room, an increase of H_2S was detected for more than 20 minutes, triggering the H_2S status alert. During the shift handover, it was decided to further investigate the issue with the self-service analytics software. Just with one click on the alert tile, the engineers move to the time-series data universe to start a root cause analysis with the time frame and tags of interest available.

Since the issues are not immediately clear by using the tags around the H_2S content analyzer, it is decided to look further upstream. Instead of trial and error, the self-service analytics software can suggest root causes through using the recommender engine. In this use case, the recommender engine suggests a strong negative correlation between the operating temperature of the first Claus unit and the H_2S content value. An immediate call to action to bring the process and the recovery back is to check fluctuations in the sulfur flow and steam around the first Claus unit and/or increase the process of its inlet process gas temperature.

Closing the analytics loop

With the low operating temperature of the first Claus unit identified as the root cause for the increase in the H_2S content and therefore low-sulfur recovery during the last shift, it is then time to look into the last four events of H_2S increase that happened throughout the last week. Looking into the data for those periods, lets the expert conclude that there is a more consistent problem with the operating temperature of the first Claus unit. A deeper analysis of the flow measurement and control loops tuning takes place, but no immediate deviation is spotted.

As a complement for the consequent process discussions, a quick look by using the recommendation engine for all four periods confirms a hypothesis that the root cause could then be on the utility side (steam) of the SRU unit. In comparison with the process side of the unit, the utility side is frequently neglected in both the details of the conceptual design and in the normal day-to-day operation.

The process team then focuses on looking at a heat loss in the steam side, and after a couple of field checks, it is found that there is a problem with one of the steam traps. This resulted in the creation of a monitor set on the operating temperature of the first Claus unit with the recommendation for the operator to look into the steam side. More particularly, the steam traps around it to manually check the temperature measurement at the inflow of the trap and at the condensate side of the trap. As an extra outcome of the analysis, it is decided to double check the preventive maintenance program for the steam trap.

The self-service analytics tool has helped the process expert to easily visualize and monitor the process, assess the size of the problem, drill down to a series of root causes and finally set up a monitor to prevent the issue from happening in the future. There was no need for a long multi-disciplinary data analytics project, the process engineers could easily do all the data analytics themselves, including the use of contextual data from other business applications and easily create a production cockpit to monitor, control and improve the process. In this way, it helps reduce emissions, maintenance costs and production losses. ✚

Aim to improve process workflows to have a better and more efficient emissions control and reduction.

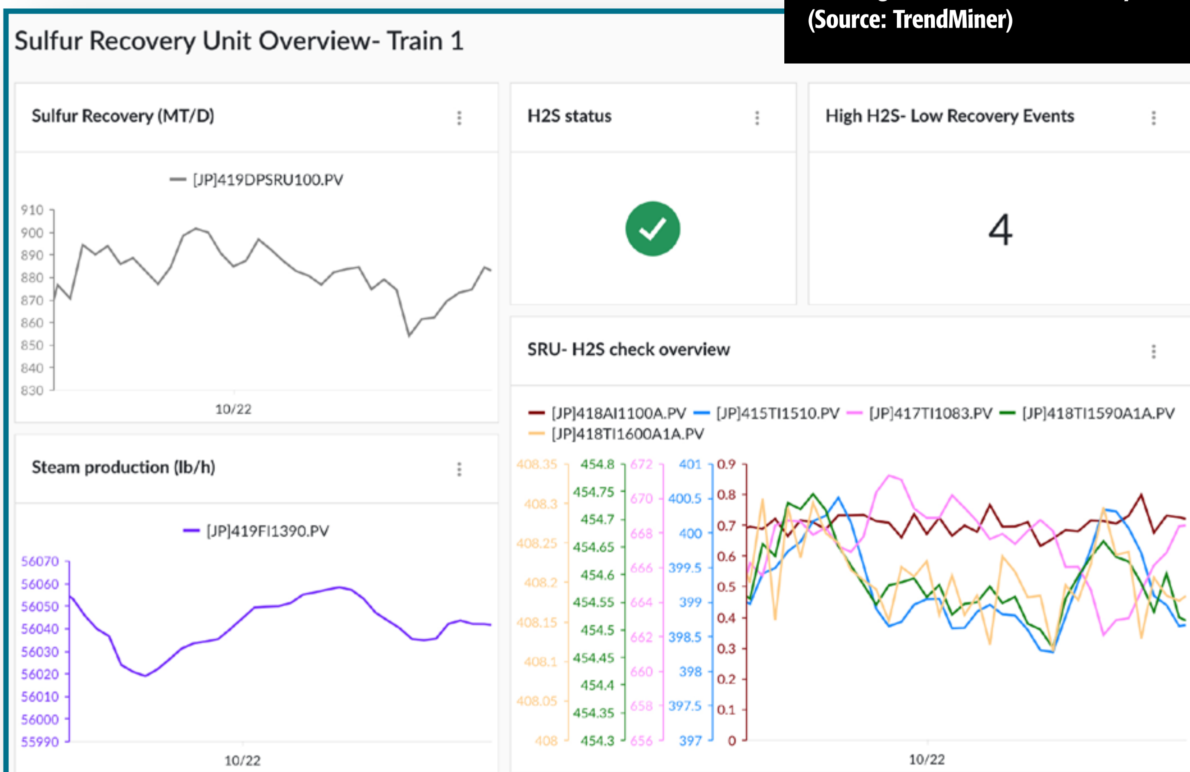


FIGURE 2. An SRU production cockpit visualizes the operational performance of the unit, including the alert tile showing four low-sulfur recovery events. (Source: TrendMiner)

A VFD controls a rod pump. (Source: SPOC Automation)

Innovative evolution of variable frequency drives

Can new variable frequency drives restore profitability to oil and gas production?

Bobby Mason *and* ***Ted Wilke****, SPOC Automation*

At the start of the year, few predicted the turmoil that 2020 would inflict on the oil and gas industry. Oversupply and the collapse of demand created historic stresses on oil and gas prices. Long-term predictions for oil prices remain decidedly unoptimistic, and this low-price environment is the industry's foreseeable future.

In response, producers are looking to squeeze every dollar from their budgets in both capex and LOE. Everyone it seems, producers as well as suppliers, are in a fight to survive.

Extraordinary cost of production

It requires an enormous amount of energy to extract and move a barrel of oil or gas from the ground. In fact, energy costs are a huge percentage of most producers' LOE. According to the U.S. Energy Information Administration, the oil and gas business consumes 2.5% of all distilled petroleum products. Anything that can lower those costs directly impacts the bottom line.

Another significant cost is the inefficiency of the people tasked with monitoring and maintaining the system: the traditional pumpers. How many thousands of pumpers are driving around the West Texas desert or the plains of North Dakota in their pickup trucks checking every well site, collecting production data but not necessarily doing anything to increase production? All those miles. All those hours on backcountry lease roads and only occasionally putting their expertise to work. The traditional way of managing wells is an incredibly inefficient process. Automation through the use of variable frequency drives (VFDs) is rapidly changing the equation.

Driving up efficiency, driving down costs

In response to the new pervasive low-cost environment, producers are clearly pushing for the greater integration of automation technology into both upstream and midstream applications in a bid to push the threshold for profitability to attainable levels. For years, automation has provided a sustainable way to lower lifting costs. But when oil prices are high, producers tend to only worry about pumping as much and as fast as possible, so not everyone felt the need to integrate technology into their processes. But when oil prices linger at historically low levels, those cost savings might be the difference between pumping profitably and losing money on every barrel—or between surviving and going out of business.

And while in the historical context of the industry, the low-voltage VFD is a relatively modern invention, the drive's value to both process improvement and cost reduction is increasingly critical.

One of the most significant benefits that VFDs bring to the oil field is the reduction of energy costs required to run each pump. By reducing kWh usage, eliminating power factor penalties and helping producers avoid peak-demand charges, VFDs can save between 10% and 35% on energy costs per pump. That alone is compelling for most producers.

The benefits of automation go beyond energy savings, however. The VFD does more than monitor pump and well conditions; it automates the mechanical response to those changing conditions.

Obviously, the oil field is hard on mechanical equipment. The heat, cold and dust all take a toll as well as the incredible stresses at play in the typical pumping system. At any given time, thousands of things can go wrong, from overheated bearings to shaft alignment to slowing flow rates. Drive automation recognizes these issues and can initiate either automated or human responses before a small issue becomes the kind of larger problem that shuts down production.

So, for instance, if a rod pump hits pump off, the VFD can slow the motor, slowing the pump, rather than shutting it down completely, allowing the reservoir to refill before returning to normal production speed. The producer maintains production and also eliminates the significant costs of shutting down and restarting the pump. By slowing and not stopping, sand is maintained in the fluid column, reducing pump damage. VFDs also eliminate the mechanical stresses that inevitably lead to expensive workovers. By slowing the pump production rate to match the reservoir inflow rate, system stresses go down and equipment life expectancy goes up. So assets run longer, they last longer and they require less unscheduled maintenance.

The next generation of drives, currently under development, will amplify all of that by incorporating a number of new innovations. Historically, pumps run on either gas engines or electric motors.

Innovations under development, though, will allow producers to incorporate both fuel types in a hybrid solution, allowing them to alternate in real time between fuel types to take

A pumper checks electric submersible pumps and well conditions in West Texas. (Source: SPOC Automation)

A bank of VFDs controls an electric submersible pumps site. (Source: SPOC Automation)

Three VFDs in a midstream water site control an array of horizontal pumps. (Source: SPOC Automation)

VFDs in a midstream water application operate outside of Midland, Texas. (Source: SPOC Automation)

advantage of the most cost-efficient source. In many applications, these hybrid drive technologies go beyond saving energy. They also reduce CO_2 and other emissions as well as noise and vibration, an important benefit to companies pushing toward carbon-neutral goals.

Another innovation under development is the electrification of the drive—turning the drive into a power source, storing power and running off of a battery during times of peak electrical charges or source anomalies. These innovations will increase production by decreasing the idle time of the pump.

Next-generation drives will integrate more sensors into the process to provide more production data and more insights into the performance of each pump and each well. These data will be critical elements as more companies push predictive maintenance and other automation initiatives throughout their processes, making the drive the hub at the pump level.

These data will inform better production decisions, allowing more nuanced automated responses to changing conditions. The next generation of drives won't just do what they are told in given circumstances; they will identify and "call for action" whenever an issue with the motor arises. So if a bearing or rotor is failing, the drive will identify the issue and either take action automatically or notify the pumper of the problem and the specific actions that they need to take.

Equally important, the enhanced data the drives will collect will inform better business decisions, helping producers make more profitable decisions on new investments and asset allocation.

It will change the way pumpers work. Because they have insights into the performance of each well, pumpers will increasingly schedule site visits to problem wells or to their most profitable fields. Their work becomes proactive; they move from an expense to part of the solution that keeps production running. Instead of being measured in wells managed, they can be measured in extra barrels produced. And then, by eliminating all of those thousands of unnecessary miles on the road, there is the ancillary benefit of helping the business run cleaner.

It is a reality in this business that people come and go. And with them, too often, goes a significant chunk of a company's institutional knowledge, specifically knowledge about the performance of individual wells and entire fields. A drive with information being brought up to SCADA provides a historical record of every event related to every well. That record can be invaluable when making long-term plans and especially as technology pushes toward predictive failure initiatives.

The technology exists today to help producers do more for less. Innovations in oilfield automation will continue to drive down the viable profitability point, helping producers not just survive the new reality but thrive as well. +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Advances made in P&A of subsea wells

A subsea wellhead retrieval tool delivers quick wellhead recovery, minimizes opex and reduces rig time.

Jeffrey Toulouse, *Weatherford*

FIGURE 1. The Weatherford MOST Plus tool provides safe, single-trip wellhead recovery operations with minimal damage. (Source: Weatherford)

Well abandonment is a crucial and inevitable stage in the life cycle of all wells. While many in the industry have historically viewed decommissioning as an expenditure without financial return, this view is rapidly changing due to progressively stringent regulatory requirements and heightened ESG awareness. The higher operational costs and risk associated with offshore operations makes the permanent abandonment of subsea wells a worthy challenge, especially when the full scope of project logistics, vessel day rates, costs associated with the number of personnel on board and full suite of services is factored in.

As an increasing number of fields reach the end of their productive lives, and countries impose stringent regulations aimed at restoring the seabed to an undisturbed condition, subsea plug and abandonment (P&A) technologies are gaining traction. Time spent on subsea wellhead recovery is often the biggest determinant of the cost of an abandonment campaign, and hence the rightful area of focus for a value hungry industry.

There are two different approaches to well abandonment and wellhead recovery in the subsea environment, and both involve internal cutting of the surface and conductor casings, followed by recovery of the wellhead by internal or external latching.

Wellhead recovery systems evolution

First developed in 1992, the MOST (mechanical, outside-latch, single-trip) tool represents the world's first one-trip subsea wellhead cut and recovery system. This field-proven system has performed more than 1,600 successful wellhead recoveries across every offshore basin in the world in water depths ranging from 26 m to 3,031 m. Featuring an external latching system, the system protects the internal surfaces of valuable recovered wellheads to preserve them for possible future use. The rugged versatility of the system has also enabled its use in a rigless P&A campaign through umbilical deployment and pairing with an abrasive jet cutting head.

The newly released second-generation MOST Plus system includes several technologies that improve tool capabilities and performance. This latest release packages a newly designed tension-cut mandrel, non-rotating flexible stabilizer (NRFS), large-diameter cutter and high-angle knives to provide pulling capabilities up to 1 MMlb, and record-breaking rotary cutting depths of 600 m. Deeper cutting depths are achievable by adding a precision mud motor.

The system latches and releases to inspect the cutting knives and confirm the cut without the need for tripping. The external latch protects the internal wellhead sealing profiles from damage, while also providing superior lateral support for the wellhead assembly to eliminate any lateral whipping that might impede cutting. An additional fail-safe feature enables releasing the outside latch by ROV, if required. Swarf

(Source: Lukasz Z/Shutterstock.com)

buildup is prevented through a design that allows for a much larger flow area within the wellhead (Figures 1 and 2).

The design of the MOST Plus tool consists of minimal parts. The MOST Plus housing engages with, latches onto and retrieves the wellhead once the casings and conductor are cut. The main components of the housing include an uppermost bonnet, a grapple housing and wellhead grapple arms. Other parts consist of compression springs and pivot pins, which help the grapple arms latch firmly onto the external wellhead profile eliminating any damage to the internal seal areas and increasing the likelihood of salvaging or reusing the retrieved wellheads. The increased clearance afforded by the external latch design allows greater strength and less chance of a tool failure by allowing the cuttings and swarf to flow out of the tool and away from the working mechanism.

The MOST Plus system can recover the majority of wellheads deployed in the market today. The design of the revised grapple-arm geometry and next-generation housing provides active engagement with the exterior of the wellhead profile, thereby increasing pulling capabilities up to 1 MMlb. Several versions of grapple arms enable appropriate selection to match the wellhead profile. Another important attribute of the next-generation housing is the emergency release feature that allows an ROV to quickly disengage the MOST system from the wellhead by removing release pins, if required in a contingency (Figure 3).

FIGURE 2. The conductor after a cut-and-pull operation with MOST Plus is shown. (Source: Weatherford)

The tension-cut mandrel incorporates a spring clutch system, which allows the transfer of selectively applied torque when latching or releasing from the wellhead and during cutting operations. Integrated into the tension-cut mandrel, a robust polycrystalline diamond bearing delivers superior performance and extended life in the severe service environment associated with subsea cutting applications.

The MOST Plus system also features a newly developed and propriety NRFS. The flexible stabilizer blades can pass through the wellhead inner diameter (ID) restriction and then expand against the larger ID of the casing to be cut, giving an effective casing range of 18⅝ inches to 22 inches. Once through the wellhead, the NRFS positively engages the ID of the casing, centralizing the cutter assembly and improving performance during casing-cutting operations while the stabilizer blades naturally dampen lateral vibration. The combination of the stabilizer blades with the unique marine bearing eliminates metal-to-metal contact, and lateral vibration significantly reduces damage to the cutter knives, improving cutting performance and saving valuable rig time.

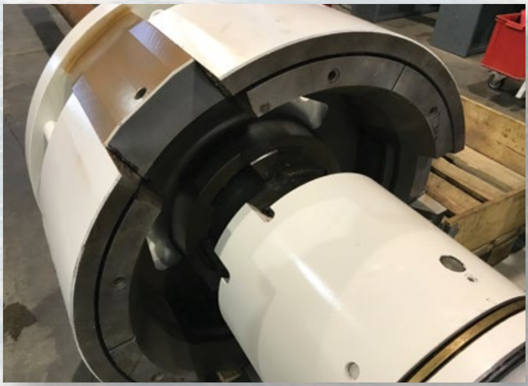

FIGURE 3. The grapple arms and set/release 'J' lugs for the MOST Plus system are shown. (Source: Weatherford)

A newly developed large diameter M-24 cutter further reduces the possibility of an eccentric cut. The geometry of this cutter provides additional stabilization, which equates to more efficient cuts and reduced operating times. In addition to the new cutter, new knives have an aggressive high-angle profile that reduces contact area with the conductor casing by more than 25% of standard straight knives and reduces the total amount of material removed from the casing to complete the cut. The knives also include an aggressive two-blade contact cutting geometry and special tungsten carbide inserts to further increase cutting efficiency (Figure 4).

FIGURE 4. The wellhead assembly and 36-inch by 22-inch conductor casings are retrieved from a Norwegian Continental Shelf field. (Source: Weatherford)

Operations

The MOST Plus system has successfully performed numerous offshore jobs in the Norwegian section of the North Sea, Norwegian Sea and Barents Sea at water depths ranging from 109 m to 416 m. The casing and conductor strings configurations were 20 inches by 30 inches, 21 inches by 36 inches, or 22 inches by 36 inches. The tool assembly on each job included the next-generation MOST Plus tool housing, tension-cut mandrel or a mud motor, NRFS, large-diameter cutter, and high-angle knives.

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The MOST Plus system demonstrated its operational effectiveness with reduced cutting times compared to traditional cut-and-pull operations, even in large heavy-wall conductors. The breakthrough design of the NRFS and large-diameter cutter increases stabilization and minimizes vibration during cutting. The reduced surface vibration eliminates the need for derrick inspections after the cutting operation, saving several hours of valuable rig time compared to traditional cut-and-pull operations.

The average cutting time observed with the MOST Plus represents more than a 50% reduction in cutting time compared to traditional techniques used for cutting 18⅝-inch to 36-inch conductors.

Executing abandonment campaigns successfully in a safe, efficient and environmentally prudent manner is critical to the reputation of the service provider and operator alike. +

Trelleborg Firenut jet fire protection for bolted connections is subjected to fire testing. (Source: Trelleborg Offshore)

Fire protection and safety for offshore topside structures

Passive fire protection will be key to mitigating the risk effects of fire, saving lives and assets.

Tony Westerlund *and* ***Isabelle Strømme****, Trelleborg Offshore*

As the offshore industry continues to push the limits when it comes to extending the life of assets and supporting operation in increasingly harsh conditions, the need for reliable and durable solutions that deliver proven performance has never been greater.

The focus on technical safety in oil and gas production is continuously increasing, with an expectation that all products and solutions are tested, qualified and certified to relevant regulations and standards. Companies need to be committed to designing high-performance, robust and reliable solutions that will improve safety and protect people, equipment, critical components and structures in the most demanding environments.

Fires in offshore or onshore installations can lead to immense destruction, making the uses and understanding of the properties of passive fire protection (PFP) materials crucial. PFP is typically used in defined areas highlighted in project-specific design accidental load specifications and is required to meet blast and fire requirements.

A wide range of PFP materials is available in the market, including syntactic phenolic resin-based coating, elastomer-based coatings, epoxy systems, cementitious protection, mineral wool wraps and insulation, and fireproof cladding, as well as concrete products.

As the properties of each material vary, finding the most effective material and technical solution for a project is crucial. Factors to consider when choosing the right material include the potential source of a fire, its possible duration, temperature and blast, along

The Trelleborg Offshore Jet Fire test rig undergoes material qualification testing in Norway. (Source: Trelleborg Offshore)

with qualifications, certificates and material properties.

The objective of PFP is to prevent or mitigate the serious consequences of fire:

- Prevent escalation of fire to adjacent areas;
- Ensure a temporary refuge is intact for a specified amount of time;
- Protect people from the fire (heat and smoke) and make escape or evacuation possible;
- Protect essential systems and equipment; and
- Maintain structural integrity for a set period.

Elastomer materials

Elastomer-based PFP products and systems are well suited for protection against corrosion and fire scenarios. The most extreme fire scenarios are cellulose, hydrocarbon, jet fire and high heat flux—all distinctive to topsides offshore. Elastomer materials can be used alone or in various combinations to meet specific requirements.

Corrosion under insulation is a serious form of localized external corrosion that occurs in insulated carbon and low-alloy steel equipment. This form of corrosion happens when water is absorbed by or collected during the insulation process. The advantage of using elastomer-based materials for PFP is the excellent steel substrate bonding properties offered, providing additional corrosion protection.

Testing of PFP materials

Offshore projects require elastomer materials that show excellent fire protection properties in accordance with relevant authorities, regulations and standards.

Hydrocarbon testing fire, or pool fire, is a fire fueled by hydrocarbon compounds (oil and gas), having a high flame temperature up to 1,000 C within 5 minutes, achieved almost instantaneously after ignition. The heat rises to 1,100 C shortly thereafter, following a given temperature curve in accordance with a standard. Fire resistance tests designed to determine the resistance to jet fires of PFP materials and systems. The material's performance in tests gives an indication of its behavior in a jet fire.

Specialized extended jet fire testing, also referred to as high heat flux, is performed in a much larger chamber allowing increased temperatures of 1,300 C to 1,400 C, with higher heat flux (350 kW/sq m) and allows testing of larger specimens.

Qualification tests are typically performed at accredited fire test laboratories in accordance with set standards and certified by a third-party approval institute. The most common type of testing is the performance of project-specific sequential testing, combining the different fire scenarios, including blowout, jet fire, pool or hydrocarbon fire.

Using elastomer-based PFP materials

PFP elastomeric materials used as deck protection ensure water repellence, flexibility and noise reduction, minimizing corrosion effects by protecting anti-corrosion systems. The prevention of fire escalation between partitions is essential. Due to its flexibility, elastomer-based PFP materials can be applied to any surface, flooring, walls or roofing, and it is mounted with a chemical or mechanical bond. The systems ensure water repellence, flexibility, noise reduction and minimize corrosion effects by protecting anti-corrosion systems.

Fires in offshore or onshore installations can lead to immense destruction, making the uses and understanding of the properties of passive fire protection materials crucial.

Protection between partitions, escape tunnels and routes are also an important part of any total protection solution. Elastomer-based PFP seals offer a flexible connection between rigid metal sections. Capable of handling large displacements, they connect modules, maintaining a fireproof partition, absorbing misalignments, angular deviations and eliminating concentrations of stress. Elastomer-based seals used in escape tunnels and door seals offer protection of door frames and connecting fire-safe escape areas.

The benefits of elastomeric seals include the

- Elimination of the propagation of vibrations, dynamic loads and deviations caused by a fabrication process;
- Customization to fit any shape and size to suit individual project requirements; and
- Installation on a variety of structures with bolting.

In areas where drainage is required, elastomer-based seals can be made as a drain gully that supports the design of a closed deck, eliminating the need for fireproofing of process deck structures. Drain gullies allow spillage from process modules to drain, eliminating the requirement for multiple drainage boxes and integrated overflow.

Vikodeck is designed to offer surface protection against blast, jet and pool fire in harsh offshore oil and gas environments. (Source: Trelleborg Offshore)

Risers

Oil and gas export risers, flexible risers and pipes have the potential risk of being exposed to blast and fire, together with corrosion under insulation. Using elastomer-based PFP for risers can combine corrosion protection with blast, jet and pool fire properties as well as mechanical protection. Elastomer coatings on risers as corrosion protection is an extremely robust solution, widely recognized as the most effective method for riser corrosion protection, particularly in the highly corrosive splash zone area where the elastomer coating is chemically bonded to the substrate.

Pipe penetrating through partitions increases risk in the event of a fire, allowing a fire to spread between areas.

An elastomeric pipe penetration seal acts as a water- and gas-tight shield against both blast and fire. Suitable for a wide variety of different size and shape applications, penetration seals close the pipe penetration and allow movement of the pipe during operation.

Nuts and bolts

Installations can be exposed to leakages of flammable and/or explosive substances, and severe operating conditions increase the likelihood of leakages, with the majority originating from flanges or fittings. Bolts can easily lose their load-bearing capacity when exposed to heat and are subject to pretension, with the load carried by the threads. When threads (bolt and nut) are heated sufficiently, the nut will disconnect and leakage will occur. PFP of bolts and flanges is an important part of any installation, and they can be protected in several ways. The most common is to build a PFP box around the flanged connection, focusing the protection on covering the most critical area, explicitly covering the bolts and nuts to extend service life in the event of a fire.

Developments in elastomeric materials allow nuts and bolts to be directly covered with molded material, providing a lightweight, space-saving solution that is easy to apply, offering improved levels of protection.

Conclusion

Elastomer-based PFP products are maintenance-free, watertight, resistant to ozone, seawater and UV-light as well as suited for use in harsh and cold environments, absorbing and preventing stress and strain transfer within structures.

While the oil and gas industry continues to push limits when it comes to extending the life of assets and operation in even harsher environments, PFP will be a key to mitigating the risk effects of fire, saving lives and assets. +

(Source: Shutterstock.com/Hart Energy)

Digital transformation in the oil patch's back office

Streamlining the billing processes can help companies thrive in tough times.

Marcus Wagner, AcctTwo

With the perfect storm of the COVID-19 pandemic and the recent collapse in oil prices, the pressure has never been higher for oil companies to cut costs to survive. Though these past few years the industry has seen rapid advances in tech innovation and application in drilling and services, the adoption of new technologies in the back office has lagged due to risk aversion and failure of many finance leaders to understand the benefits of modern technology, specifically true cloud accounting. With the accelerating waves of the retirement of the older generation and the emergence of younger leaders who grew up in the digital age, service companies are beginning to see that full-scale digital transformation has gone from optional to urgent.

An example of this trend can be seen at Silvertip Completions, a Midland-based provider of wireline and pumping solutions to the Permian Basin. When CFO Kyle Kirk joined the company three years ago, he had a vision that challenged traditional thinking about how finance operations should be set up. Having entered the labor force in 2000, he started his career at the same time software first began moving to the cloud.

Kirk and his colleagues began a search for modern, cloud-based software that automates customer-facing processes of sales and operations, and integrates with back-office accounting systems to streamline the order-to-cash cycle, accelerate cash flow and keep administrative expenses low. Having selected FieldFx by LiquidFrameworks for their front-office solution, they turned to AcctTwo to guide them through their implementation of a modern financial application and integrate the two systems for maximum efficiency.

"Most companies, especially oil and gas service companies, are constantly under pressure from both internal customers, such as operations personnel, executives and owners, and external customers to provide more datapoints beyond 10 years ago [as well as] more timely data—gone are the days of invoices or data provided in weeks—and more efficient data without additional costs," Kirk said.

"No accounting system has an oil and gas-friendly front-end field ticketing and billing system that accommodates the point-in-time, detailed data collection needed by most companies, especially oil and gas service companies. Service companies are no longer providing simple invoices like we were a decade ago. We are expected to provide data that detail what happened every step of the process and track efficiency metrics, process exceptions and resolutions. Without a front-end system like FieldFX, companies are relegated to tracking data in separate flat-file systems such as Excel or Access. Meaningful reports have to be created by hand, combining the Excel data with accounting system data, which makes reports time-consuming, prone to error and difficult to repeat."

Power of modern cloud software

LiquidFrameworks' FieldFx is a mobile field operations management solution that organizes and manages jobs, quotes, field tickets, equipment, contracts and more for sales and operations. Implementing this system has enabled Silvertip to capture real-time data once, at the source and have those data flow through their systems in an automated way. This allows access to data immediately and avoids the need for manual, redundant data entry.

"FieldFX allows us to capture almost every imaginable piece of data recorded at a well site. We have eliminated almost all paper from our field personnel," Kirk said. "We have also moved from each of our field engineers and supervisors needing laptops to using tablets, cutting our computing cost in about half. We have near-real-time data without an FTE having to manually enter it. We know what happened in the field, both good and bad, almost immediately."

Transforming the back office

Though things were working well in capturing all the field data, Kirk needed to integrate the FieldFX front end with a modern accounting system on the back end to fully realize the power of an integrated order-to-cash process. Kirk turned to Houston-based AcctTwo, a provider of cloud-based financial management software and managed accounting services. AcctTwo has helped more than 1,000 companies move their accounting systems to the cloud to leverage the value of digital transformation and set the stage for the next wave of technology innovations.

Moving to a modern, cloud-based financial management system like AcctTwo's Sage Intacct provides the benefits of better process automation and anywhere, anytime access to data.

Cloud software enables the software provider to provide rapid updates across the entire customer base, speeding up the pace of innovation and allowing customers to get access to the latest technology innovations at all times. Moving to the cloud is just the first step of many in the digital transformation journey. AcctTwo uses robotic process automation to automate processes both for their customers as well as for their own internal operations, and it is working with Sage Intacct on their artificial intelligence beta program.

Integration results

By integrating the front-office sales and operations system with the back-office accounting and billing system, Silvertip is able to generate its customer invoices faster, speeding up the cash collection cycle and reducing billing errors.

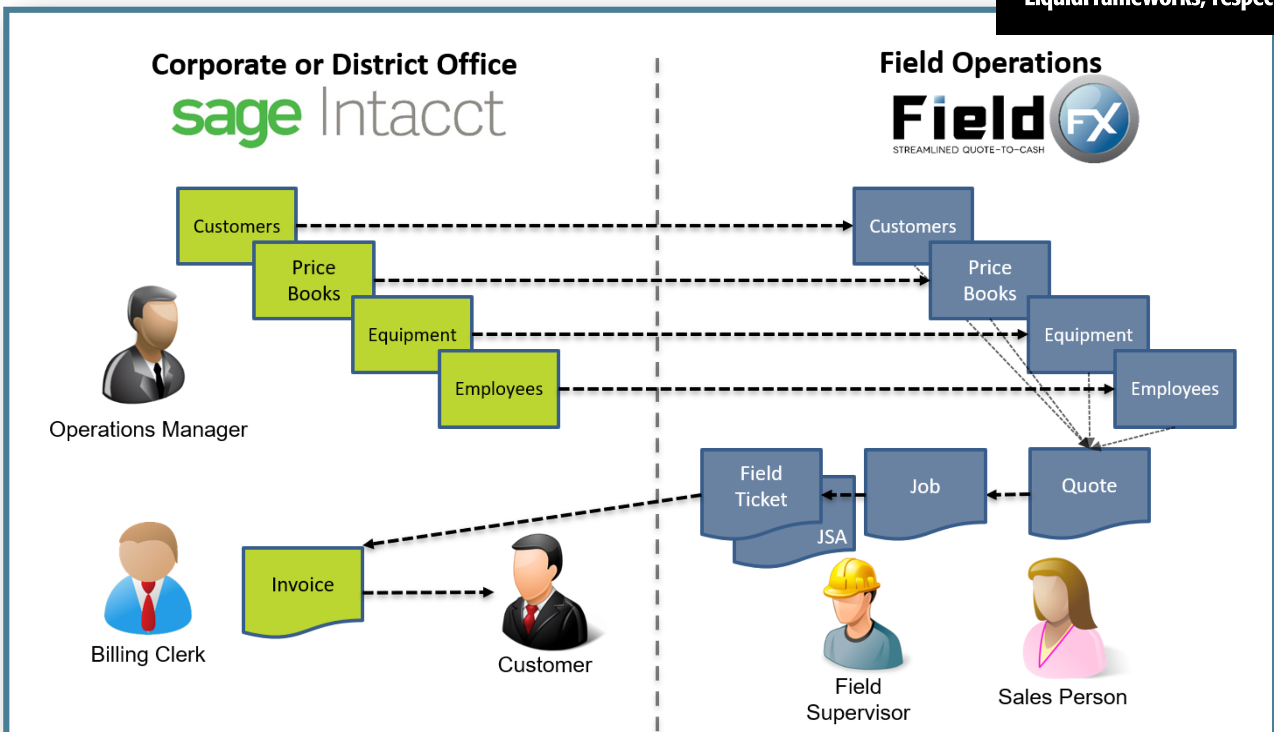
"The implementation of FieldFX, coupled with AcctTwo's integration between FieldFX and Sage Intacct, has been the largest and most successful advancement of our vision to automate manual processes wherever possible," Kirk said. "The programs have allowed a seamless, efficient flow of data from the field to the accounting system. This implementation has eliminated one FTE during a time when resources are significantly constrained due to low oil prices. Now we are reviewing and evaluating data instead of entering data. Even when we get back close to 100% utilization, we should not have to add any additional FTEs to accommodate field tickets, billing, etc."

Digital transformation has yielded big benefits for companies in numerous industries over the past 10 years.

He said the average days to invoice have decreased by about two days. They are currently using the data to develop unit-level costing to better track profitability by unit and activity "as customers love to change products and processes on the fly," he said.

Kirk added, "FieldFX and Sage Intacct are both simple, effective, yet powerful systems that together have greatly increased our ability to measure our operations, both for ourselves and our customers."

Digital transformation has yielded big benefits for companies in numerous industries over the past 10 years. Oilfield services companies that embrace these changes like Silvertip Completions will not only be able to survive the current and future crises but also thrive. +



This graphic illustrates how the Sage Intacct and FieldFX systems work together to tightly integrate and automate order-to-cash processes. (Source: AcctTwo Shared Services LLC. Sage Intacct and FieldFX logos are trademarks of Sage Intacct and LiquidFrameworks, respectively.)

FIGURE 1. The digital twin is a virtual image of an asset, maintained throughout the life cycle and easily accessible at any time. (Source: DNV GL)

Trusting digital twins to deliver value

Digital twins are a rapidly developing technology widely expected to become a significant contributor to the future management of major industrial sites.

Kjell Eriksson, DNV GL - Oil & Gas

The concept of what many understand today as a digital twin has been around for several years under many guises, from model-based optimization to structural reanalysis systems. Recent developments in digital technology have enabled these virtual depictions of systems or physical assets to be used in decision-making processes and other activities that had not been possible in the past.

While the definition of what a digital twin is and what it is not is relatively wide, the consensus is that it allows system information to be available to predict performance through integrated models with the purpose of providing decision support.

Rather than think of a digital twin as a monolith, DNV GL believes it should be considered a collection of elements or components, of various levels of sophistication, each with their own distinct role and function (Figure 1).

Digital twins are still in the early stages of their evolution. Their early development focused on a series of standalone features to inform decision-making during asset design phases. As the market and technology matures, it is expected their sophistication will increase significantly, eventually being dominated by either prescriptive or even autonomous functional elements.

"We have never been in a position where we can create more and better data than today," explained Per Myseth, head of data services, data management and analytics with DNV GL. "Likewise, we have never been able to combine and analyze information in more advanced ways than we have at present. As this technology evolves, it is vital to combine the criticality and the use cases of the digital twin to fully understand the quality and all the components in it."

Trust on trial

Companies designing and manufacturing hardware across the oil and gas value chain must prove the safety, quality and integrity of components, equipment and assets through recognized quality assurance principles. However, no standard process exists to provide the same mechanism of trust and value for the digital representation of a physical asset and its behavior.

As oil and gas operators demand proof that digital twins can be trusted and deliver value over time, DNV GL, in partnership with TechnipFMC, has developed a methodology for qualifying the quality and integrity of the technology.

Built upon DNV GL's recommended practice (RP) for technology qualification, DNVGL-RP-A2031 aims to bring a level playing field to the sector's varying technical definitions of, and expectations of, digital twins. It will set a benchmark for oil and gas operators, supply chain partners and regulators to establish trust in digital twin-generated data for performance and safety decision-making in projects and operations.

The methodology is being piloted on two subsea field development projects. Operators and the supply chain wishing to participate are still welcome to contribute in what will ultimately be a new RP, encompassing definitions of the digital twin, to data quality and algorithm performance.

Realizing true value from virtual reality

The major challenge when implementing new digital technologies is the same as when novel hardware technologies were introduced two decades ago. How can you trust that it works when the technology hasn't been used before? Building trust in the quality and integrity of digital twins is key to extracting maximum value and, subsequently, to its adoption.

Oil and gas companies are increasingly utilizing the technology to bring asset information from multiple sources together in a single and secure place, connecting 3D models with real-time field data during the operation phase.

For example, in October 2019, Kongsberg Digital, a subsidiary of KONGSBERG, signed a $10.5 million contract scope to digitalize the Nyhamna facility, a gas processing and export hub for Ormen Lange and other fields connected to the Polarled pipeline. The Kognifai Dynamic Digital Twin will be continuously updated with integrated information reflecting the status of the facility in real time. As technical service provider at Nyhamna, A/S Norske Shell will be equipped with the ability to simulate scenarios and uncover new options for optimization of its real-life counterpart.

Petoro was established to create the highest possible value and achieve the highest possible income to the state interest in petroleum activities. It has substantial holdings across 213 production licenses in 34 fields in the Norwegian Continental Shelf, including ownership in the Nyhamna gas export facility.

While encouraged by the advance of digital twins, Roy Ruså, chief digital officer with Petoro, is concerned by a lack of sector openness for alternative solutions to its possibilities and pitfalls, leading to distrust on the capabilities.

"They [the supply chain] are even solving problems that customers don't know they have. The suppliers are much more valuable than we apparently appreciate because we tend to tell the supplier the solution or what they should do," he said.

Developing a twin is challenging, but success does not necessarily mean making value from it.

"We need stronger emphasis on change management," he said. "While the quality of the digital twin could be OK, there is often too little focus on the change process and preparing the people that are going to use it in practice."

Data quality, the digital platform, change management for implementing and maintaining a change process, and data management, are just a few of the factors that Ruså believes need to be in place to make digital twins more trustworthy and less troublesome.

As part of its digital transformation, TechnipFMC has developed Subsea Studio, a digital solution that transforms conventional studies into ultrafast digital field development (Figure 2).

The ambition is to seamlessly connect with the integrated engineering, procurement, construction and installation phases and the integrated life-of-field phases unlocking the full potential of an integrated digital thread.

"We are transforming into a more data-centric way of working," said Erlend Fjøsna, TechnipFMC's head of innovation and digital partnering.

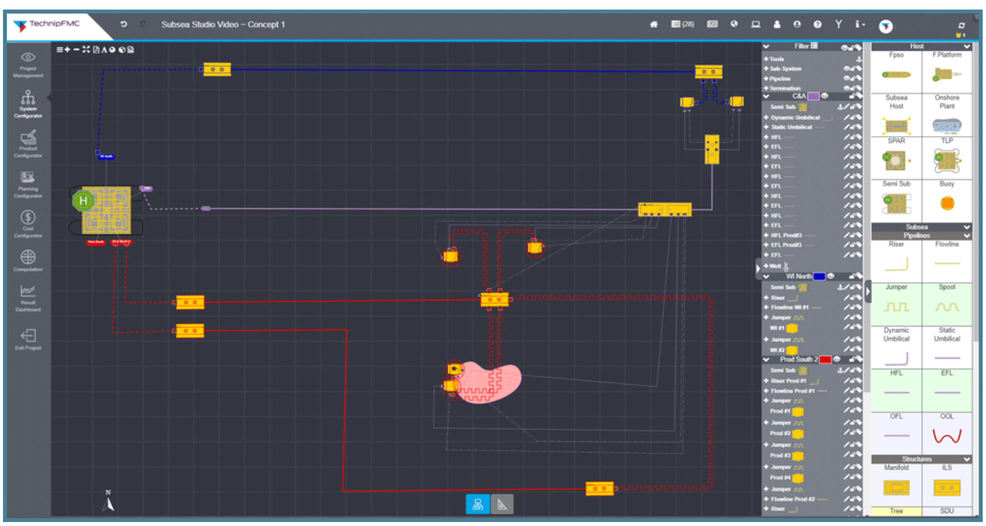


FIGURE 2. Subsea Studio enables engineers to work faster in one collaborative space and leverage a single source of truth to configure any type of development. (Source: TechnipFMC)

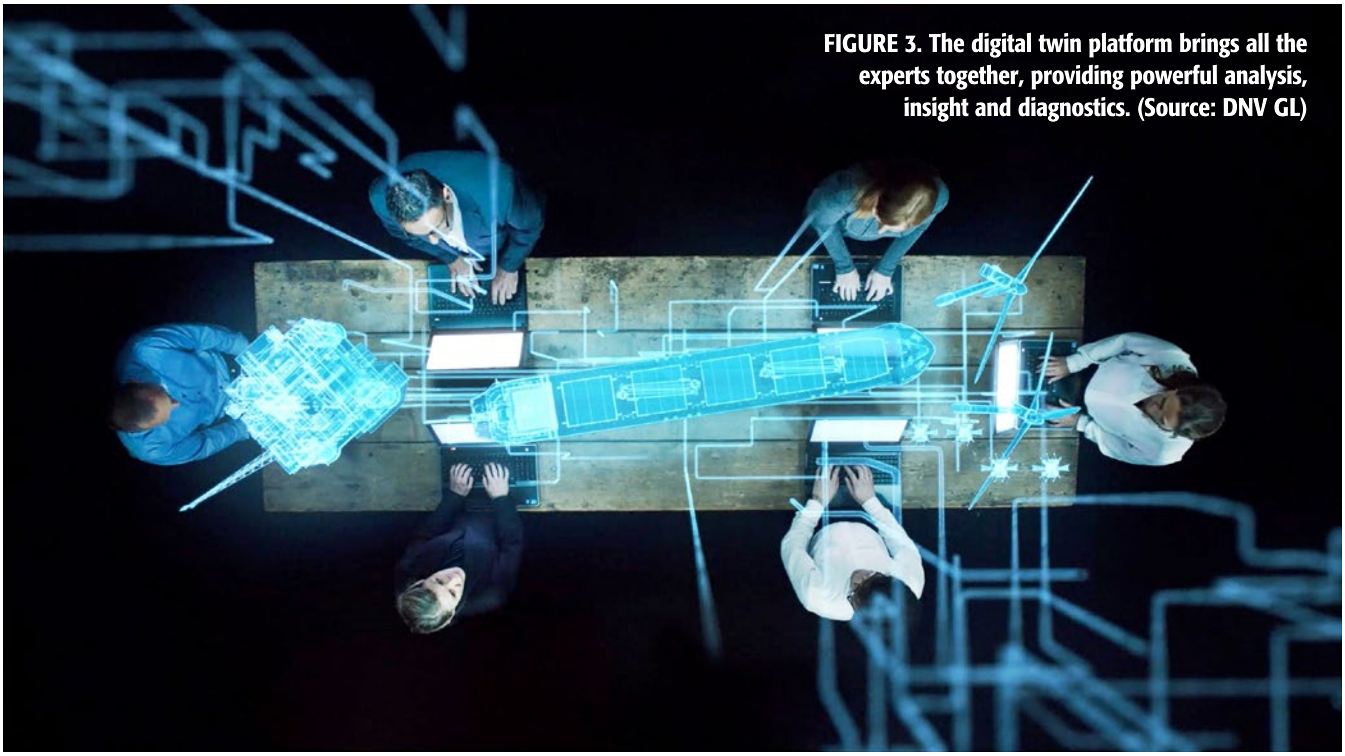


FIGURE 3. The digital twin platform brings all the experts together, providing powerful analysis, insight and diagnostics. (Source: DNV GL)

"The digitalization debate is now more centered on what value is created and how we can leverage our domain knowledge to deliver that value—not only to maintain it over time but to ensure interoperability and a trusted digital thread between various parties. Digital twins hold the promise of having significant or even huge cost savings. It is an ongoing journey, and we see already the benefits brought by those new ways of working."

A digital twin should be considered a collection of elements or components, of various levels of sophistication, each with their own distinct role and function.

Reliability through maturity

Digital twins are a rapidly developing technology widely expected to become a significant contributor to the future management of major industrial sites. The digital twin market is estimated to grow from $3.8 billion in 2019 to $35.8 billion by 2025.

DNV GL's Technology Outlook 2030, a research report identifying transformative technologies in key industries, highlights a digital value chain run by machines and algorithms as a prevailing trend for the oil and gas industry in the decade ahead. The research predicts cloud computing, advanced simulation, virtual system testing, virtual/augmented reality and machine learning will progressively merge into full digital twins, which combine data analytics, real-time and near-real-time data on installations, subsurface geology and reservoirs.

The use of twins and trust in their accuracy can be significantly increased by ensuring that data and information reflect the most up-to-date condition of the physical asset. To ensure the performance of digital twins matches expectations, organizations involved require a structured, systematic approach (Figure 3).

To support the industry achieving its goals of high-quality trustworthy digital twins, DNV GL has published two frameworks as important building blocks. In April 2017, the data quality assessment framework DNVGL-RP-0497 was published to perform quality assurance across three areas:

1. An organization's capabilities to create and maintain high-quality data;
2. Measuring the quality of data; and
3. Assessing the risk of using the data.

Three years later, DNVGL-RP-0510 was published. This methodology assures the process of making, testing, deploying, maintaining and monitoring data science solutions based on data-driven methodologies like machine learning and artificial intelligence.

Solving the digital trust challenge will be key to its adoption, its acceleration to use at a greater scale and its acceptance as an accurate, valuable and trusted technology. +

Digital service delivers real-time operational data and insights

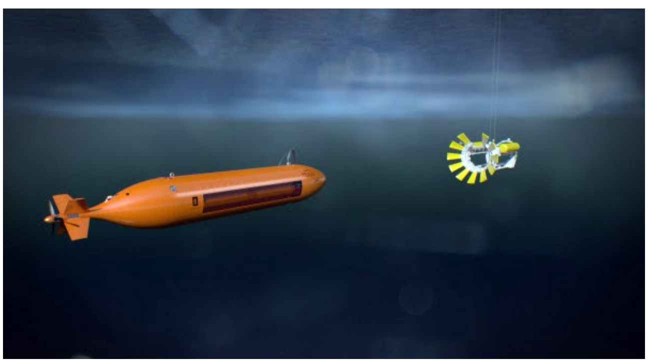
Schlumberger has released its Performance Live digitally connected service that optimizes remote wellsite operations control while improving safety, efficiency and footprint. The service includes technology and domain expertise within a digital ecosystem, leveraging cloud-based applications and automated data workflows through a secure and robust data network. The Performance Live service provides customers with instant access to data and collaboration with domain experts, enabling faster, more informed decision-making for directional drilling, well logging, formation testing and other oil and gas operations. Automated end-to-end workflows simplify tasks that eliminate redundancy and deliver consistent service.

Software monitors workers' safety in real time

Honeywell has released Safety Suite Real Time, new software to help industrial facility operators and safety managers monitor workers' exposure to gas, weather and certain physiological conditions in real time to help prevent incidents and quickly respond to emergencies. The software, which integrates into plant operations, connects wirelessly to gas detection devices to enable centralized monitoring of assets and workers. The software is designed to help eliminate manual processes, assist with regulatory compliance, maximize accuracy and efficiency, and minimize safety costs. Safety managers can use the platform to monitor workers on the job site and view gas readings, alarms, compliance statuses and more on a map-based display viewable from the command center or any internet-connected device. Safety managers can track live situations as they occur, determine personnel locations and detect issues early to help avoid bigger problems and instantly notify workers via SMS messaging to clear the area.

New system increases efficiency, improves safety of AUVs

Kongsberg Maritime has released the Launch and Recovery System (LARS) for its HUGIN range of AUVs. After evaluating techniques and procedures in depth, Kongsberg Maritime developed an optimal solution to have the LARS operating from midships, with the release and capture of HUGIN marine robots occurring beneath the sea surface. Launching and recovering AUVs under water, away from the splash zone, lessens the possibility of damage, while midships deployment averts any likelihood of AUVs being run over by the launch vessel. An added benefit of the LARS' subsea capabilities is that the launch and recovery processes can be carried out in much higher sea states, reducing the risk of weather damage to marine robots, while also boosting productivity to deliver significant cost savings. The design allows AUVs to be deployed from a hangar or container, and multiple robots may be managed from a single LARS.



Kongsberg Maritime's LARS can be installed into an AUV hangar on a platform supply vessel, facilitating a broad range of subsea tasks. (Source: Kongsberg Maritime)

Online program offers on-demand well control training

Well Control School has launched the SMART knowledge retention program, a new online well control training aid designed to give learners access to exclusive curriculum through a web-based subscription service. SMART delivers more than 400 individual training videos with customizable programs that cover every learning objective required by industry standards. The SMART library allows subscribers to easily review missed objectives at their own pace by using a keyword system linked to specific training goals. The program also gives training administrators complete control of assembling multiple micro-courses while coaching and evaluating individual learners in real time to ensure an optimal outcome whether they are in the oil field or the classroom. The SMART program is designed for individual companies, university petroleum engineering programs, government agencies and insurance companies focused on oilfield coverage.

Subscribers of Well Control School's SMART training program can access more than 400 training videos. (Source: Well Control School)

Educational web series focuses on proppants

Hexion Oilfield Technology Group has launched Proppant Talk, an educational web series posted weekly on their LinkedIn showcase page. The short videos are focused on proppant-related issues in hydraulic fracturing. Topics covered include proppant flowback, fines generation and migration, effects of cyclic stress and more. Hexion has been releasing these videos to keep members of the industry informed and entertained during the COVID-19 crisis and downturn in oilfield activity.

Contact tracing tool to ensure worker safety

Blackline Safety Corp. has released a new contact-tracing tool for industrial businesses, which makes it easy to proactively monitor a business' social distancing effectiveness and trace person-to-person contacts if an employee tests positive for COVID-19. Such active measures help to improve employee confidence and morale, knowing that the business has further control over the health and wellbeing of every worker. Blackline has launched its new Close Contact report, which is immediately available to all current and future customers in its cloud-hosted Blackline Analytics software. This new report supports users of G7 safety wearables during work hours, to map the close interactions between employees. After hours and off the worksite, Blackline's Loner Mobile smartphone app is available to provide complete tracing coverage for businesses and their personnel. Blackline's Close Contact report and other contact tracing tools comply with the strictest privacy regulations and allow businesses to respect the privacy of the employee while keeping them safe.

Updated versions of reservoir characterization software enhance the user experience

CGG GeoSoftware has released new versions of its cloud-ready reservoir characterization and petrophysical interpretation software. All applications across the entire GeoSoftware portfolio now run on both Azure and AWS platforms. The newest releases, Jason 10.1, Hampson-Russell 10.5 and PowerLog 10.1, also offer advances in machine learning and artificial intelligence (AI) as well as streamlined connections to Python ecosystem notebooks.

Jason 10.1 enhancements include further expansion of the drag-and-drop functionality of files and viewers. The Jason Workbench offers a consolidated Progress Overview, an all-in-one window without distracting popups. Time-to-depth conversion in Jason DepthMod is faster and requires fewer steps. Velocity refinement can occur over all geologic layers simultaneously.

HampsonRussell 10.5 offers multinode processing (MNP) on Windows in addition to Linux, powerfully speeding up processing projects. Initial tests of MNP Windows indicate 3.5 times faster project speeds when using four MNP nodes rather than a single node.

PowerLog 10.1 offers Automatic Depth shifting, an AI capability that calculates depth shifts for a variety of well log datasets to a measurement that is known to be on depth, important for generating log correlations and valid petrophysical computations. Many of PowerLog's usability enhancements are client-driven and enable users to easily generate interpretations and optimize well completions.

In-bit sensors deliver performance measurements to maximize drilling efficiency

Halliburton Co. has released its Cerebro Force in-bit sensors that capture weight, torque and bending measurements directly from the bit to improve understanding of downhole environments, optimize bit design and increase drilling efficiency. Built on Halliburton's in-bit vibration sensing platform, Cerebro Force utilizes downhole data to reduce or eliminate surface measurement uncertainty and inefficiencies caused by bit design, bottomhole assembly and drilling parameter selection. Through the Design at the Customer Interface (DatCI) process, Halliburton's local network of drill bit experts collaborate with operators to customize bits for basin-specific applications and will use data from Cerebro Force to inform new designs and optimize parameters for efficient and precise drilling.

Remote piloting capability for ROVs

Forum Energy Technologies has developed and demonstrated the ability to remotely operate work-class and observation class (Perry and Sub-Atlantic) ROV systems between an offshore vessel and a remote location. This new capability brings major opportunities to adapt operational practices in response to the latest industry drives as cost savings and reductions in HSE risks can be realized through reducing offshore crew sizes. Continued development in software efficiencies, which reduce the effect of network latency coupled with increased availability and reliability of the global 4G network, has now allowed Forum to offer remote operations on its full range of ROV systems. Forum's ICE and subCAN remote operations suites provide a robust means of piloting vessel or platform-based systems from an onshore control facility via a wired, 4G or satellite connection. +

The system upgrade components are manufactured and delivered from Forum's U.K. facility in Kirkbymoorside, Yorkshire. (Source: Forum Energy Technologies)

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****.*

US Highlights

1 Alaska

A Prudhoe Bay, Alaska, recompletion was reported by bp Plc. The 03-27A Prudhoe Bay Unit is in Section 11-10n-15e in Umiat Meridian. The discovery was tested flowing 839 bbl of oil, 6.952 MMcf of gas and 7,693 bbl of water per day from Sadlerochit perforations at 10,375 ft to 13,000 ft. It was drilled to 13,133 ft (8,794 ft true vertical depth).

2 Wyoming

EOG Resource Inc. announced a Mowry and a Niobrara completion at a Johnson County, Wyo., drillpad in Section 12-47n-78w. The 53-1201H Orbit flowed 889 bbl of 51°API condensate, 2.712 MMcf of gas and 1,777 bbl of water daily from Mowry. It was drilled to 20,684 ft (11,368 ft true vertical) and is producing from a perforated zone at 11,654 ft to 20,592 ft. Gauged on a 32/64-inch choke, the shut-in casing pressure was 1,733 psi. About 40 ft to the west, 61-1201H Orbit initially flowed 803 bbl of 45.4°API oil, 749,000 of gas and 777 bbl of water daily from Niobrara. Drilled to 19,115 ft (9,929 ft true vertical depth), production is from perforations at 10,252 ft to 19,058 ft, and it was tested on a 26/64-inch choke with a flowing casing pressure of 1,182 psi.

3 New Mexico

Three Red Tank Field discoveries were announced in Lea County, N.M., by Oxy USA. The Bone Spring producers were drilled from a pad in Section 30-22s-33e. The Avogato 30-31 State Com 032H was drilled to 22,125 ft (11,948 ft true vertical depth). It initially flowed 4,742 bbl of oil, 7.824 MMcf of gas and 8,256 bbl of water per day from perforations at 11,850 ft to 22,031 ft after 51-stage fracturing. The Avogato 30 31 State Com 024H was drilled to 21,078 ft (10,961 ft true vertical depth). It was tested flowing 1,492 bbl of oil, 1.704 MMcf of gas and 1,190 bbl of water per day from fractured perforations at 10,610 ft to 20,985 ft. The Avogato 30 31 State Com 025H was drilled to 20,988 ft (10,785 ft true vertical depth), and it produced 2,127 bbl of oil, 2.664 MMcf of gas and 9,976 bbl of water daily from perforations at 10,572 ft to 20,896 ft.

4 Oklahoma

Citizen Energy III completed a horizontal Cherokee discovery in Oklahoma's Caddo County. According to IHS Markit, Bowling 1H-21-16 flowed 72 bbl of 50°API oil, 4.585 MMcf of gas and 559 bbl of water per day from acid- and fracture-treated perforations at 12,567 ft to 19,419 ft. Gauged on a 16/64-inch choke, the flowing tubing pressure was 4,695 psi. It was drilled to 19,474 ft in Section 21-10n-10w to a proposed true vertical depth of 12,550 ft. The 2-mile lateral bottomed to the north in Section 16. There had been no previous horizontal drilling in the Anadarko Basin township, which borders Canadian County on its north side.

5 Gulf of Mexico

In Walker Ridge Block 584, Exxon Mobil Corp. announced results from a Wilcox discovery. The company's 1JU106S0B OCS G20351 was drilled to 31,910 ft (29,185 ft true vertical depth). It produced 9,278 bbl of 24.7°API oil, 1.058 MMcf of gas and 125 bbl of water per day from perforations

between 30,672 ft and 31,630 ft. Tested on a 56/64-inch choke, the flowing tubing pressure was 8,037 psi.

6 Gulf of Mexico

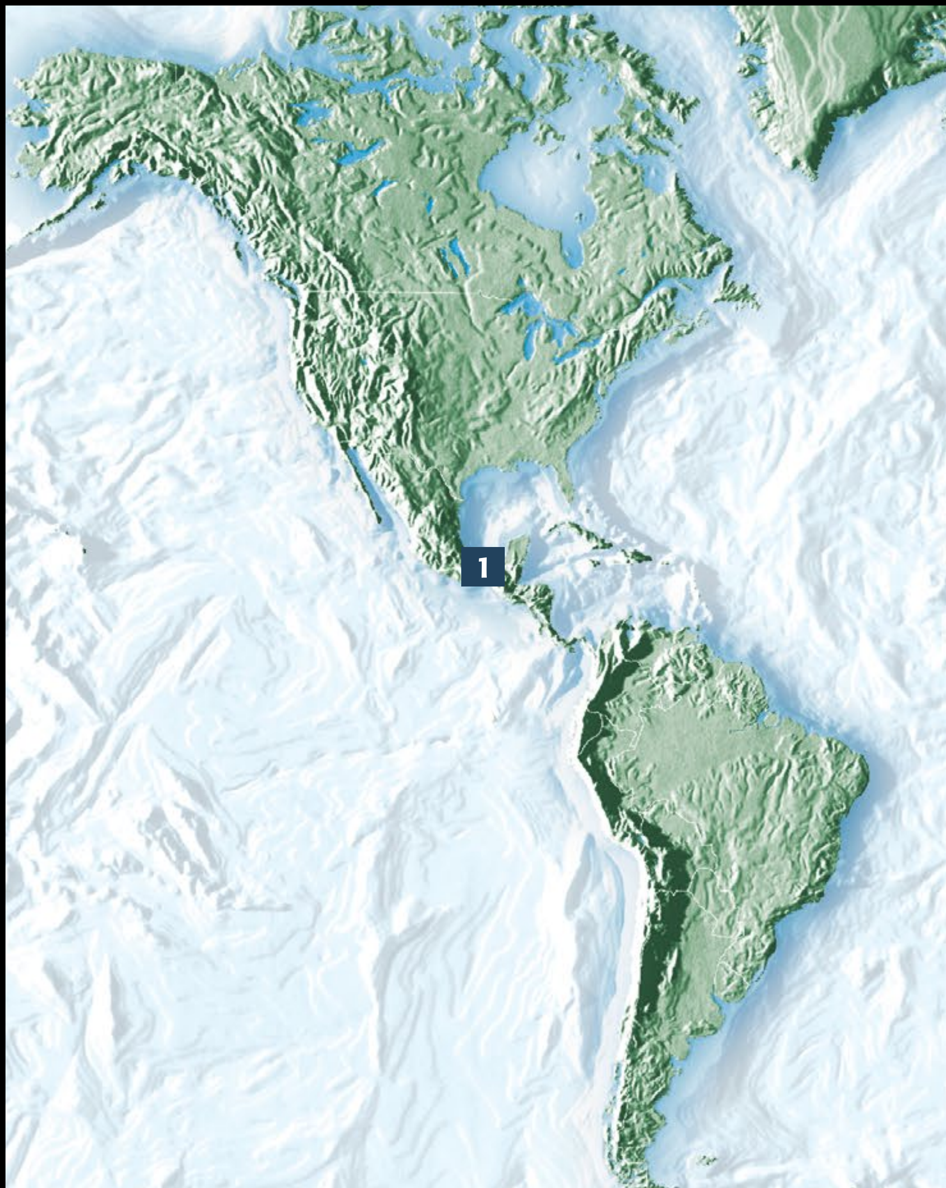
Deep Gulf Energy III announced a Mississippi Canyon Block 214 discovery at 002S0B1 OCS G24059. The well flowed 11,070 bbl of 32.8°API oil, with 19.936 MMcf of gas and 83 bbl of water per day. Production is from Upper Miocene perforations at 16,215 ft to 16,245 ft. It was tested on a 36/64-inch choke with a flowing tubing pressure of 5,058 psi. The well was drilled to 17,835 ft (17,548 ft true vertical depth).

7 Pennsylvania

Five Fayette County, Pa., Marcellus Shale wells were completed by Chevron Corp. at a Luzerne Field pad in Section 2, Carmichaels 7.5 Quad, Luzerne Township. The Yoder 1H was drilled to 18,266 (7,920 ft true vertical depth) and flowed 3.803 MMcf of gas with a shut-in casing pressure of 4,619 psi. Production is from a perforated zone at 8,592 ft to 18,043 ft. The Yoder 2H was drilled to 17,268 ft (8,000 ft true vertical depth) and flowed 3.402 MMcf of gas per day from perforations at 8,406 ft to 17,043 ft with a shut-in casing pressure of 4,585 psi. The Yoder 5H was drilled to 16,899 ft (8,100 ft true vertical depth) and produced 3.571 MMcf of gas per day from perforations at 8,641 ft to 16,701 ft. The Yoder 6H was drilled to 18,201 ft (8,000 ft true vertical depth) and produced 5.906 MMcf/d of gas from perforations at 8,341 ft to 15,665 ft with a shut-in casing pressure of 4,425 psi. The Yoder 10H was drilled to 16,834 ft (8,000 ft true vertical depth) and was tested flowing 2.657 MMcf/d of gas from perforations at 8,739 ft to 16,600 ft with a shut-in casing pressure of 4.171 psi. +

—By Larry Prado, Activity Editor

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



1 Mexico

Pemex has received a permit to drill an exploratory test at appraisal well 2DEL-Quesqu in onshore Tabasco. The appraisal well be drilled in an 'S' trajectory toward an Upper Jurassic Kimmeridge (JSK) play, and the planned depth is 6,730 m. The well site is in AE-0053-4M-Mezcalapa-03 within the Cuencas del Sureste. Pemex expects to encounter gas and condensate in total resources of 62 MMboe.

2 UK

UK Oil & Gas has received a permit to drill and test the Loxley-1 Portland gas exploration/appraisal well in the PEDL234 license area. A sidetrack well, Loxley-1z, also has been permitted. The company plans to appraise the Portland gas accumulation, which was originally discovered in 1982 by ConocoPhillips about 8 km to the west at Godley-1 Bridge.

3 Norway

Neptune Energy made a hydrocarbon discovery in the Norwegian sector of the North Sea in PL882 at exploration well Dugong-1. Depending on testing results, a sidetrack may be drilled to further define the extent of the discovery. Area water depth is 330 m, and production is from a zone at 3,250 m to 3,400 m. Neptune Energy is the operator of PL882, Block 34/4 and Dugong-1.

4 Norway

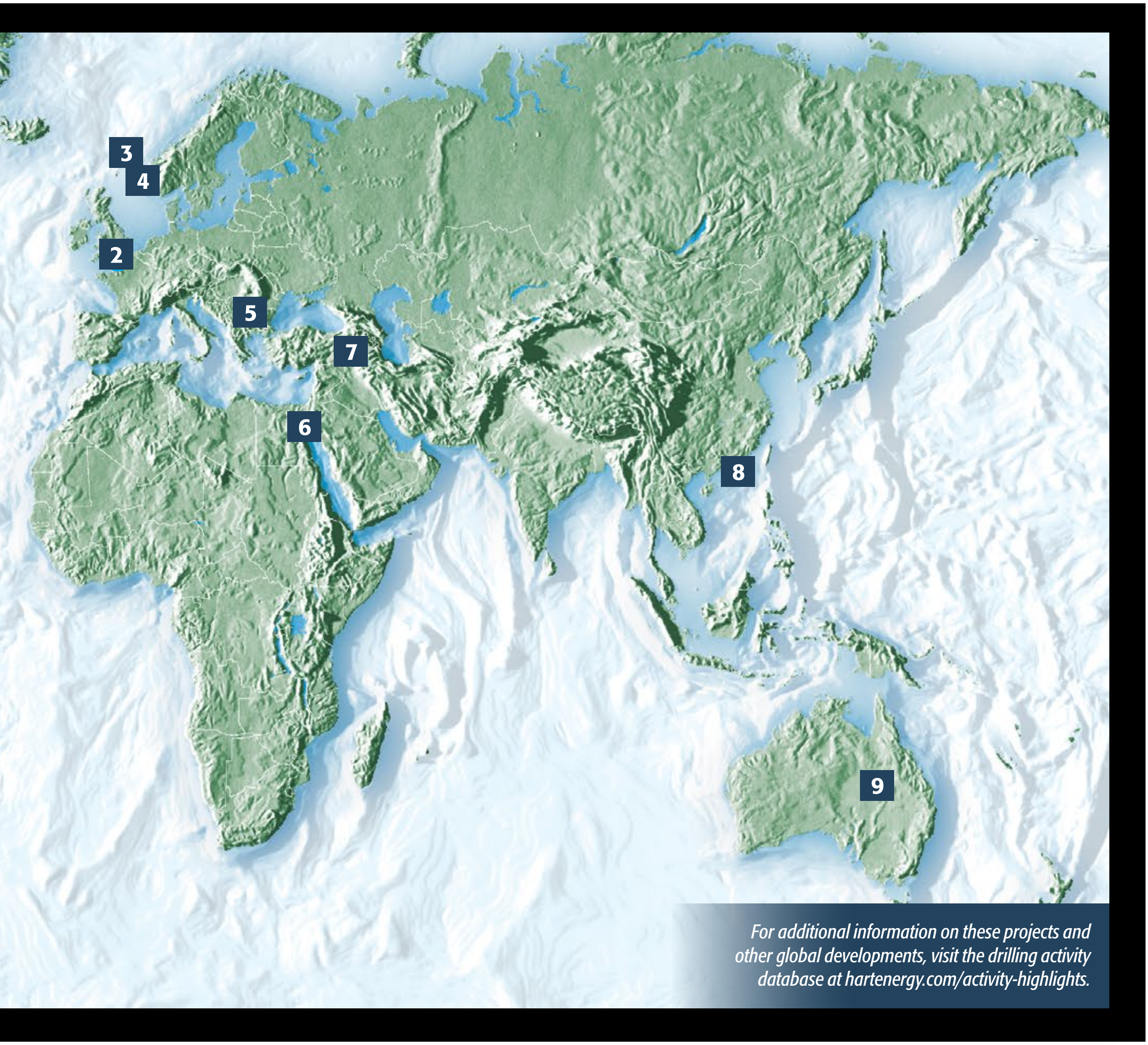
Equinor has completed wildcat, 30/2-5 S in the Norwegian North Sea. The venture encountered a gas column of about 160 m in Brent Group (Tarbert, Ness, Etive and Rannoch), of which 60 m make up an effective sandstone reservoir. Ness has 30 m of sandstone with poor-to-moderate reservoir quality, while Etive has 15 m of sandstone, primarily of moderate quality. The Tarbert has 10 m of sandstone with poor-to-moderate reservoir quality, and Rannoch has 5 m of poor-quality sandstone. Preliminary estimates indicate the discovery between 3 MMcm and 10 MMcm of recoverable oil equivalent. This is the first exploration well in PL878; it was drilled to 4,390 m and area water depth is 142 m.

5 Romania

ADX Energy completed exploration well Iecea Mica-1 in onshore Romania's Iecea Mare production license. The well encountered gas across three zones with a combined total of 20 Bcf of 2C contingent resources. Testing at the Pannonian Basin well will concentrate on the PA IV sand (Pliocene), which is a proven reservoir and has the greatest upside reserves potential of the three hydrocarbon-bearing reservoir intervals intersected in Iecea Mica-1. The company is planning a high-resolution 2D seismic program is 2020.

6 Egypt

Cheiron completed an oil discovery in Egypt's southern Gulf of Suez at exploration well GNN-4 in the Geisum and Tawila West Concession. The venture initially flowed more than 2,000 bbl/d of oil. The discovery contains an estimated 260 MMbbl of oil in place. Two additional wells are planned in the southern area of the discovery. Later, the development focus will shift to the northern area of the discovery. This is the first completion in Nukhul in the Geisum area and will open up further exploration potential, both within the concession and in the neighboring acreage.



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

7 Turkey

Trillion Energy has announced evaluation results from the Zagros Basin Derecik exploration licenses in the Hakkari area of Turkey. According to the company, the basin extends from Iraq into Turkey to include the Derecik licenses, which are now near several major producing oil fields in northern Iraq, including the Bijell, Atrush, Swara Tika and Swara Tika East fields. Rhe Derecik Blocks have identical stratigraphy as the Zagros Field block in Iraq, with Cretaceous and Miocene compression. The Balkayalar-1 has a planned depth of 2,560 m in an anticlinal, four-way closure containing Jurassic and Triassic reservoirs. The Derecik-1 has a planned depth of 3,493 m, which is also an anticlinal four-way closure containing Cretaceous, Jurassic and Triassic reservoirs.

8 China

Chinese National Offshore Oil Corp. has announced a discovery in the eastern portion of the South China Sea at Huizhou 26-6. According to the company, it is expected to become the first mid- to large-sized condensate oil and gas field in the shallow-water area of the Pearl River Mouth Basin. The well is in Huizhou Sag in the Zhu 1 Depression of Pearl River Mouth Basin. Area water depth is approximately 113 m. The well was drilled to 4,276 m and encountered oil and gas pay zones with a total thickness of about 422.2 m. During a flow test, it initially produced 2,020 bbl of oil and 15.36 MMcf of gas per day.

9 Australia

Vintage Energy is fracturing and preparing to flow test exploration well Vali-1 ST1. The ATP 2021 venture will be fractured in six stages—five in the Patchawarra and one in the deeper Tirrawarra/Basal Patchawarra section between 2,810 m to 3,140 m. The program will measure total stabilized gas rates, downhole reservoir pressure and individual formation gas flow contribution. The certified gross 2C contingent resource is 37.7 Bcf of gas (18.8 Bcf net). ✚

—By Larry Prado, Activity Editor

PEOPLE

Kjetel Digre has been appointed CEO of Aker Solutions.


Sistrunk

Aera Energy LLC's President and CEO **Christina Sistrunk** has elected to retire, effective Oct. 1. Succeeding Sistrunk will be **Erik Bartsch**, currently the vice president of Safety and Environment, Integrated Gas and New Energies with Shell. As part of his transition into Aera, Bartsch will initially assume the role of COO and CEO designee. On Oct. 1, he will become Aera's fourth president and CEO.


Chell

Cold Bore Technology Inc. announced that **Brett Chell,** the company co-founder and president, has assumed the role of CEO. Former CEO **Blair Layton** has moved to the role of CFO.

After Sanchez Energy Corp. emerged from its financial restructuring and Chapter 11 as privately held Mesquite Energy Inc., **Cameron W. George** was appointed interim CEO, executive vice president and CFO. In addition, the company's board of directors comprises **Nathan H. Van Duzer**, **Wilson B. Handler** and **Harry F. Quarls**.


Conkle

In connection with CARBO Ceramics Chapter 11 emergence, **Don Conkle** has been promoted to CEO. He joined the company in 2012 as the vice president of sales and marketing and has 34 years of leadership and industry experience.

Contango Oil & Gas Co. has promoted **Farley Dakan** to president. **Wilkie Colyer**, previously Contango's president and CEO, will continue serving as CEO. Additionally, **Chad Roller** has been appointed senior vice president and COO, while **Chad McLawhorn** will serve as senior vice president, general counsel and corporate secretary of the company.

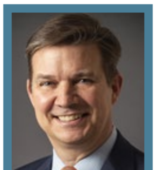

McLawhorn

Siemens Gamesa Renewable Energy has named **Beatriz Puente** CFO, effective Dec. 1. **Lars Bondo Krogsgaard** and **Juan Gutiérrez** have been appointed CEOs of the Onshore and Service business units, respectively. Gutiérrez assumed his new role Aug. 15, and Krogsgaard will join Siemens Gamesa on Nov. 1.

Tallgrass Energy has named **Crystal Heter** COO.

Comet Ridge Ltd. has appointed **Phil Hicks** CFO.

Flotek Industries Inc. has welcomed **Michael E. Borton** as CFO.


Williams Jr.

Forum Energy Technologies Inc. has named **D. Lyle Williams Jr.** executive vice president and CFO. He will succeed **Pablo G. Mercado**, who has resigned to pursue other opportunities. Additionally, **Neal Lux** has been named executive vice president of operations.


Conway

Andrew Conway has joined tech firm Xergy as CTO, leading the Proteus development team in Karachi, Pakistan. Conway's appointment comes two months after **Nigel Filer** joined Xergy as an investor and CEO. Xergy also has appointed **Scott Michie** business development director.

McDermott International Ltd. has appointed **Tareq Kawash** senior vice president for its Europe, Middle East and Africa region.


Thillerup

Xodus Group has appointed **Alexander Thillerup** U.S. renewables vice president. He will head up a new office in Boston as the company looks to grow its offshore wind services across North America. Thillerup will be supported by **Jamie MacDonald**, who is relocating from Xodus' headquarters in Aberdeen, U.K., to take up the position of director of operations.

AqualisBraemar has promoted **John Harris** to regional managing director of the Southeast Asia region.

Vacuworx has welcomed **Charlie Cunningham** as senior director of sales.

Gillian King, vice president of Europe, Russia, Commonwealth of Independent States and the Africa region with Tendeka, has joined the board of the Oil and Gas Technology Center.


Oetjen

Martin Oetjen has been appointed to the executive board of MAN Energy Solutions. He will be responsible for the Supply Chain and Production division. Oetjen has already been responsible for the Supply Chain role since January 2020 as chief representative of the company.

West Texas Resources Inc. has appointed **Danilo Cacciamatta** to the company's board of directors.

GeoPark Ltd. has named **Sylvia Escovar Gomez** an independent member of the board of directors.

COMPANIES

BluEnergy is a new company committed to enabling oil and gas companies to leverage their existing asset base to create low carbon energy streams.

Rovco, the provider of ROV services to the offshore energy industry, has opened a new office and operational base in Edinburgh, Scotland, to serve its current portfolio of offshore renewable and energy projects.

OleumTech has opened a new office in Midland, Texas, which will primarily serve as a training facility to accommodate and support customers in the region.

Xodus Group has opened a new office in Boston, as the company looks to grow its offshore wind services across North America.

JDR, a global subsea cable supplier and servicer, has begun construction of a new U.S. headquarters in Tomball, Texas.

Kværner ASA and **Aker Solutions ASA** have entered into a merger plan, whereby the two entities will join forces to create a new supplier company focused on low-carbon oil and gas production and accelerating growth in renewable energy industries. The name of the new company will be Aker Solutions ASA.

Kongsberg Digital has acquired **COACH Solutions**, a supplier of software solutions for vessel performance and monitoring. The new company will be named **KONGSBERG COACH Solutions**. +

AD INDEX

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E&P plus

Publisher
DARRIN WEST
Tel: 713-260-6449
dwest@hartenergy.com

Global Sales Manager
HENRY TINNE
Tel: 713-260-6478
htinne@hartenergy.com

Executive Director of Conference Marketing
BILL MILLER
Tel: 713-260-1067
bmiller@hartenergy.com

Executive Director—Digital Media
DANNY FOSTER
Tel: 713-260-6437
dfoster@hartenergy.com

Director, Business Development
CHANTAL HAGEN
Tel: 713.260.5204
chagen@hartenergy.com

United States/Canada/ Latin America
1616 S. Voss Road, Suite 1000
Houston, Texas 77057 USA
Tel: 713-260-6400
Toll Free: 800-874-2544
Fax: 713-627-2546

Advertising Coordinator
SUSET MEDEROS
Tel: 713-260-4637
iosubmission@hartenergy.com

Subscription Services
E&P Plus
1616 S. Voss Road, Suite 1000
Houston, Texas 77057
Tel: 713-260-6442
Fax: 713-840-1449
custserv@hartenergy.com

Boosting productivity in an era of E&P belt tightening

E&P companies must resist the urge to retreat from innovative technologies.

David Zahn, Ambyint

Today's economic climate is punishing those who are operationally or capital inefficient. The 226 bankruptcies from January 2015 to May 2020 lays this truth to bare. The focus for those seeking to avoid a similar fate and survive an extended period of tight capital markets and low, volatile oil prices is on improving cash flow. At the heart of most E&P efforts is strengthening margins through production optimization and other cost reduction opportunities—in many cases through headcount reductions.

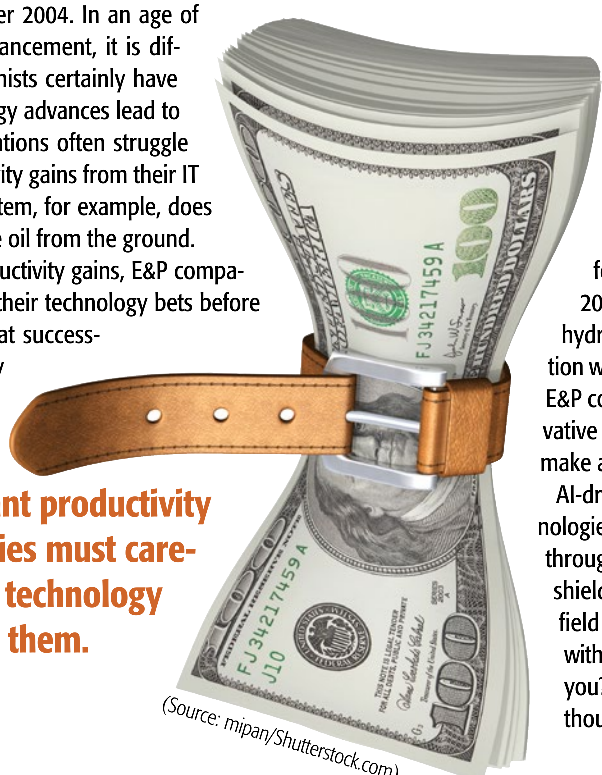
Prior to today's economic climate, there were already too many wells and too few people to manage them. Operations groups are now stretched even thinner as they focus on ensuring production goals are met. A day filled with data analysis and fighting fires, unfortunately, does not allow much time for other important activities, such as production optimization. The challenge for E&P companies then becomes how to get more out of their existing workforce.

The truth is that real productivity growth is difficult to achieve. At a macro level, the U.S. saw growth decline from 2.1% to 0.6% over the decade after 2004. In an age of significant technological advancement, it is difficult to fathom why. Economists certainly have theories, but not all technology advances lead to greater productivity. Corporations often struggle to achieve requisite productivity gains from their IT spend. A new back-office system, for example, does not help a company get more oil from the ground.

To achieve significant productivity gains, E&P companies must carefully consider their technology bets before placing them. Companies that successfully boost field productivity and the number of wells managed daily per engineer display similar patterns in how they evaluate and adopt technology. There are three such patterns to consider:

1. ***Augmented workforce and processes:*** Simply speeding existing processes rarely moves the needle in efficiency and productivity gains. Automating repetitive, manual tasks and transforming processes through disruptive technologies, such as artificial intelligence (AI), create significant cost savings and revenue enhancement opportunities. Companies that do so will see more wells managed and optimized on a daily basis.
2. ***Demonstrable proof points:*** Innovation has a dark side—the bleeding edge—where technologies have not stood the test of field deployments. In an environment of capital constraints where bad decisions have high opportunity costs, companies must invest in deployed technologies that show measurable value.
3. ***Six months or less payback:*** The demands of improving cash flow mean investing in solutions that have much shorter paybacks than traditionally sought. Aim for technologies or terms that have a positive return on investment in less than six months.

To achieve significant productivity gains, E&P companies must carefully consider their technology bets before placing them.



(Source: mipan/Shutterstock.com)

Technological change

We are an industry that has benefited greatly from technological change. Ours is only one of four industries to have doubled growth in the last 20-plus years, primarily due to the rapid adoption of hydraulic fracturing technologies. We embrace innovation when it changes the game. In tough economic times, E&P companies must resist the urge to retreat from innovative technologies and instead look for ones that can make a difference.

AI-driven production optimization is one of these technologies. It gives the field back at least 25% of their day through real-time actionable information, reduces windshield time and allows companies to cover the entire field of assets. It is the very definition of doing more with less in a short payback period. Is AI on the table for you? If not, why is AI already adopted successfully on thousands of wells across every major basin today? ✚