HARTENERGY
APRIL 2021

E+P plus

ESG in Oil & Gas:

Searching for Answers

Q&A with TGS CEO Kristian Johansen

Permian in the Middle East?

Gas-lift Technology

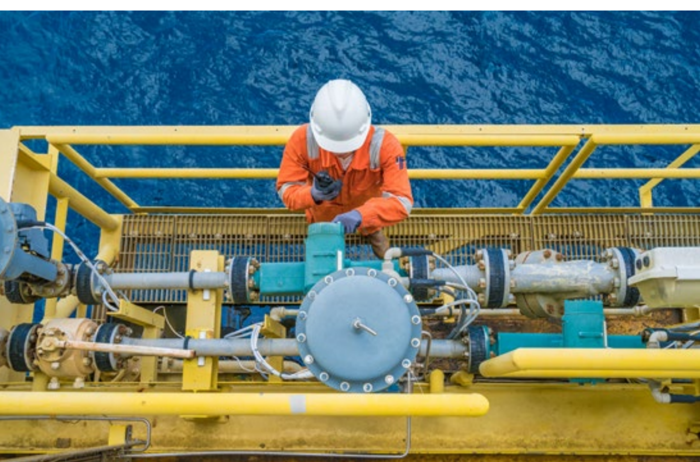
Appalachia Analysis

E+P plus

April 2021 + Vol. 96 + Issue 4

A Hart Energy Publication

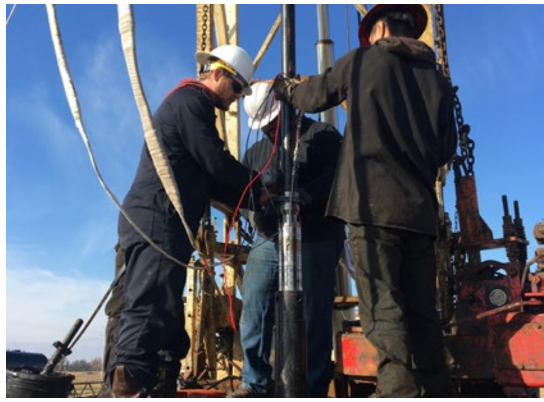
HARTENERGY.COM



E&P plus

1616 S. VOSS ROAD, STE 1000
HOUSTON, TEXAS 77057
P: +1 713.260.6400 F: +1 713.840.0923
HartEnergy.com

departments



About The Cover: Building an ESG case and presenting the right evidence to stakeholders across the value chain has become a riddle wrapped in a mystery inside an enigma for producers and service providers in oil and gas. So how are they setting about solving it? (Cover images courtesy of Shutterstock.com and Hart Energy; Cover design by Melissa Ritchie; Bottom images from left to right courtesy of TGS; ADNOC; Upwing Energy and DenPhotos/Shutterstock.com)

Coming Next Month: The May cover story will provide readers with a digital journey guide on the who, what and how of digital field development. It will feature interviews with Devon Energy, Chevron and Hibernia Resources, among others. The Executive Q&A will highlight an exclusive video interview with Oceaneering CEO Roderick Larson, and the Company Spotlight will feature a Q&A with Michael Kearney, chairman, president and CEO with Frank's International.

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.

E&P Plus (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Advertising rates furnished upon request. All subscriber inquiries should be addressed to E&P Plus, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442, Fax: 713-840-1449; custserv@hartenergy.com.

Online Content+

Exclusives Available Only Online
Subscribe at **HartEnergy.com/subscribe**

Oilfield service companies embrace energy transition
By Velda Addison, Group Senior Editor
Some of the largest oilfield services companies in the world such as Schlumberger, Baker Hughes and Halliburton are 'enablers of the transition' to cleaner forms of energy, an analyst said during Evercore's Global Energy Outlook in late March.

Survey: Oil and gas CEOs 'very confident' about sector's growth
By Faiza Rizvi, Associate Editor
A majority of CEOs in the energy sector are also eager to lock in the sustainability and climate change gains made by oil and gas companies during the pandemic, according to a recent survey by KPMG.

Total, Iberdrola CEOs discuss renewables in new energy landscape
By Velda Addison, Group Senior Editor
All types of renewables will be needed to help reach carbon emissions reduction targets, the CEOs say.

How oil and gas can navigate its own net-zero roadmap
By Joseph Markman, Senior Editor
The energy transition is moving at a fast and furious pace, and the oil and gas industry not keeping up presents its own series of risks, including alienating investors and falling behind in recruiting talent.

Latin American producers position for energy transition
By Velda Addison, Group Senior Editor
Executives from Ecopetrol, Petrobras and Pemex in Latin America share insight on how their companies are adjusting and the role of natural gas in the energy transition during CERAWeek by IHSMarkit.

HART ENERGY VIDEOS
By Jessica Morales, Director of Video Content

Oil and gas industry isn't going away anytime soon
Vicki Knott, CEO of Crux OCM, told Hart Energy's Faiza Rizvi the oil and gas industry is not dying and fossil fuels are in fact needed for a smooth energy transition.

COGA's Dan Haley on The North Face, oil and gas in society, Colorado's production future
In launching its 'Fueling Our Lives' campaign to educate the public on the role oil and gas plays in society, the Colorado Oil & Gas Association gave an interesting award to The North Face following viral criticism of the outdoor apparel company. Dan Haley, president and CEO of COGA, joined Hart Energy's Len Vermillion to talk about the dubious award and his thoughts on VF Corp.'s, parent company of The North Face, stance on co-branding with oil and gas.

How FERC's new chair will impact the oil industry
FERC will align with President Biden's climate goals, but the energy transition cannot be done 'on the backs of oil and gas workers,' Ken Irvin, co-leader of global energy practice with Sidley Austin, told Hart Energy's Faiza Rizvi.

View more exclusive video interviews at HartEnergy.com/videos

25 INFLUENTIAL Women IN ENERGY

2021 Women In Energy Virtual Conference
From ESG to the energy workforce to capital investment, the Women In Energy honorees discuss it all during Hart Energy's Women In Energy virtual program. Watch the on-demand sessions at hartenergyconferences.com/women-in-energy!

DARKVISION

HOUSTON, TEXAS

CALGARY, ALBERTA

+1.800.218.1902 • WWW.DARKVISIONTECH.COM • SALES@DARKVISIONTECH.COM

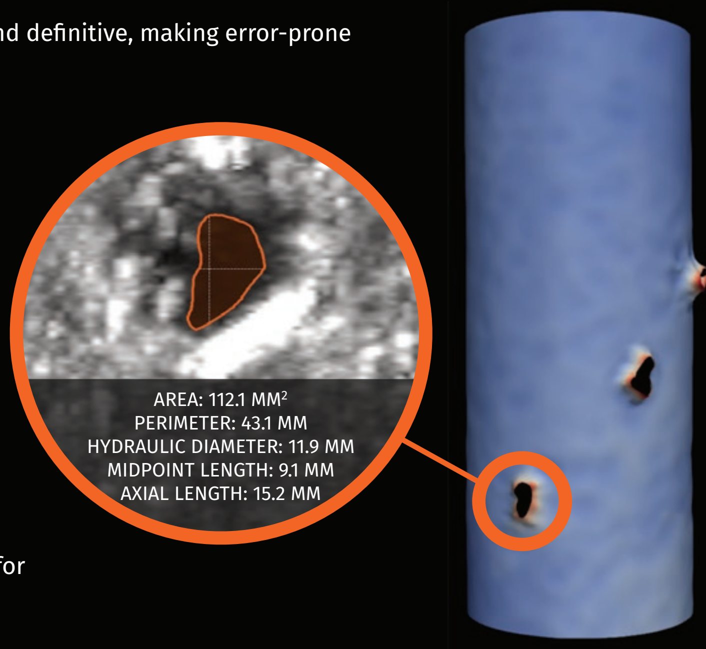
H·A·D·E·S

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 3D 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.

DarkVision's dimensionally accurate 3D renderings are intuitive and definitive, making error-prone interpretation of ambiguous data a thing of the past.

- Evaluate **casing integrity** and **perforation erosion** in one run.
- Save on clean out costs. **No fluid flushing** required.
- **Submillimetric resolution** for precision perforation erosion measurements.
- Full circumferential scanning and **30,000+ ft logging capacity** for comprehensive **single-run scans**



150°C 302 °F	103 MPa 15,000 psi	0.25 mm 0.01 in	Fluid Agnostic	Memory or Real Time

As I
See It

Placing a priority on exploration

Discovering new resources is vital for meeting future demand.


(Source: donvictorio/Shutterstock.com)

It's no secret that even before the pandemic knee-capped the industry last year, oil and gas exploration was mired in its own downcycle. With the notable exceptions of Guyana and Africa, major discoveries in more traditional and productive basins like the Gulf of Mexico and U.K. Continental Shelf have been few and far between.

And with many analysts predicting a peak may come soon—or relatively soon at least—it's fair to wonder if we've seen peak exploration as well. Considering the early stages of the energy transition evolution the industry currently finds itself in, it would be unwise to discount the role exploration can play.

Natural gas is widely seen as the transition fuel in the energy transition. However, exploration for natural gas has so far not reflected this view. According to a recent report issued by Westwood Global Energy Group, 32% of high-impact wells drilled between 2011 and 2019 targeted gas prospects, with the highest portion coming in 2019 when 45% of wells targeted gas. In its report, Westwood claimed that there is no evidence that this year will see more drilling plans targeting gas.

"In fact, 2021 is expected to see the lowest proportion of high-impact exploration wells targeting gas in more than a decade," Westwood stated.

One reason for this, however, is that the industry has already produced more natural gas than it needs as a result of high-producing oil-heavy wells also generating natural gas. According to Westwood, about 36 Bboe of gas discovered between 2008 and 2016 remains in the ground without plans for development.

The noticeable decline in exploration isn't only limited to gas projects. According to Rystad Energy, exploration needs to speed up "significantly" if the oil and gas industry is to meet future demands through 2050.

"To meet the global cumulative demand over the next 30 years, undeveloped and undiscovered resources totaling 313 billion barrels of oil need to be added to currently producing assets," Rystad reported.

The demand for oil may well be tapering off, and by most accounts it isn't likely to reach pre-COVID-19 levels. But that doesn't mean producers should abandon trying to find new resources. Meanwhile, service companies in the exploration field are steadily bringing new technologies to the market that make identifying pay zones more efficient and more effective.

COVID-19 has effectively up-ended the oil and gas industry, and companies across the value chain have examined and reexamined their operations with the goal of being as financially efficient as possible. Concurrently, the energy transition has gained steam and put natural gas into focus. The demand for natural gas will be there, even if it might not be long term for oil. Now it's up to the producers to find it. +

Brian Walzel
Senior Editor
bwalzel@hartenergy.com

Exploration needs to speed up significantly if the oil and gas industry is to meet future demands through 2050.

Read more commentary at
HARTENERGY.COM


WATERBRIDGE

Video

In this exclusive video interview, TGS CEO Kristian Johansen discusses the company's New Energy Solutions business unit and how data management can play a role in the energy transition.

Q&A

TGS CEO Kristian Johansen talks energy transition

Data-driven upstream service company diversifies to meet energy transition demands.

Brian Walzel, Senior Editor

Despite the exploration market in upstream oil and gas experiencing what TGS CEO Kristian Johansen has described as a "deep cyclical trough," exploration companies, like so many others in the oilfield services (OFS) sector, are learning to adapt. In many cases, such as for TGS, adaptability includes diversification into avenues of the energy transition and increased focus on ESG.

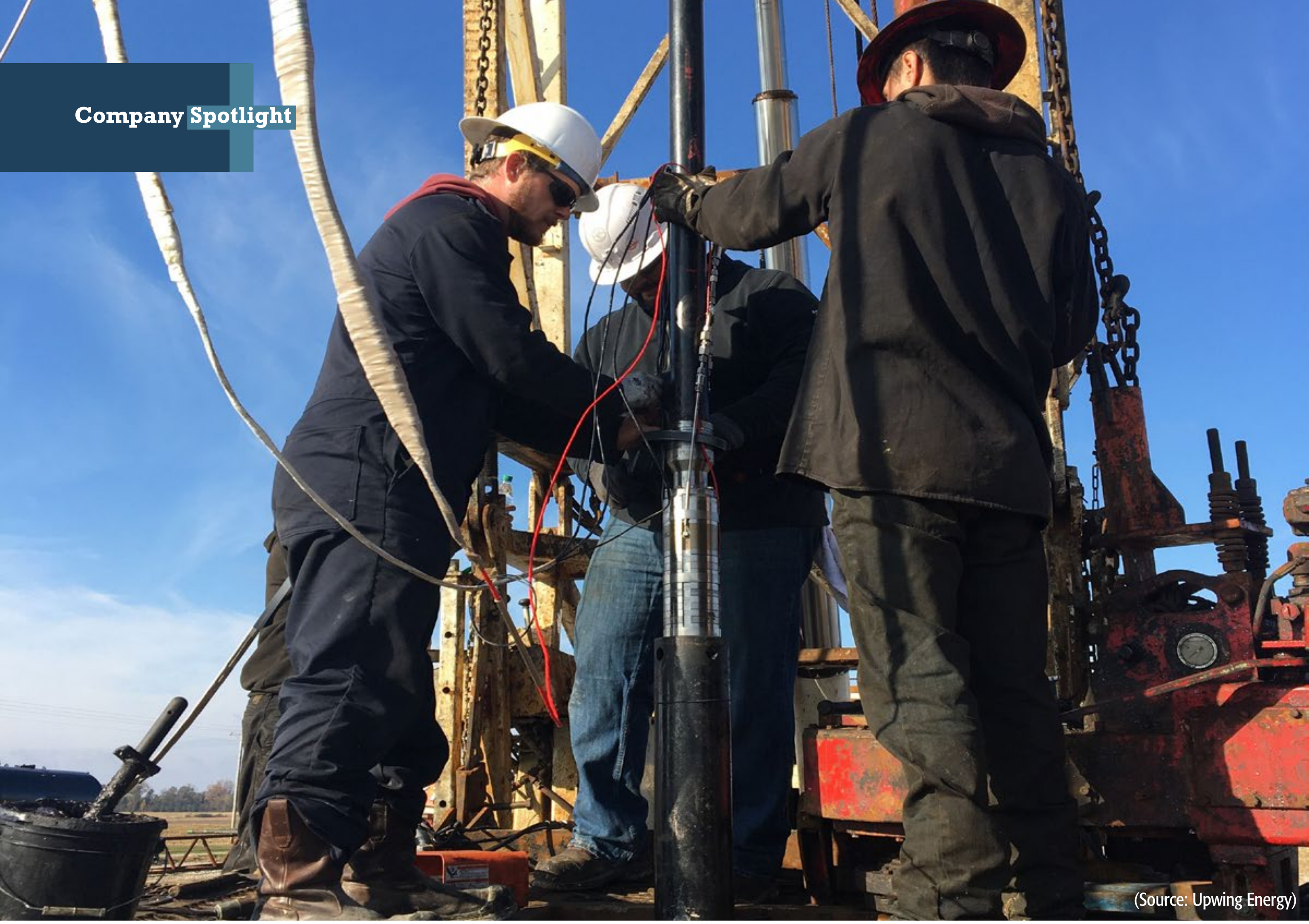
TGS, self-described as an energy data and intelligence company, launched its New Energy Solutions (NES) business unit in February. The new component of the company aims to provide data-driven applications and solutions for wind energy, carbon storage, geothermal and deepsea minerals.

"Over the past few years, we have seen an increasing interest for our data and insights from other industries besides the oil and gas industry," Johansen said. "By establishing our NES business unit, we are preparing our non-oil and gas offering for future growth."

Johansen recently sat down for an exclusive interview with E&P Plus where he further discussed NES and how data management can play a role in the energy transition. He also discussed offshore development trends and how the OFS sector can thrive in a new environment with depressed demand and limited new development. +

"Over the past few years, we have seen an increasing interest for our data and insights from other industries besides the oil and gas industry. By establishing our NES business unit, we are preparing our non-oil and gas offering for future growth."

Kristian Johansen, TGS



(Source: Upwing Energy)

Filling the gap in gas-lift technologies

Upwing Energy CEO Herman Artinian shares details about the company's evolution, how its technologies work and the state of the artificial lift industry.

Brian Walzel, Senior Editor

Spun out of Calnetix Technologies, a California-based company producing machinery and power generation technologies, Upwing Energy emerged in 2011 as it developed its Subsurface Compressor System (SCS). Over the next decade, Upwing developed, tested and trialed its SCS, leading to a funding initiative in 2018 from Equinor Technology Ventures and Cooper and Co. The initiative helped accelerate the development of the downhole gas compressor.

Simultaneously, Upwing developed its Enhanced Production Simulator, a tool that analyzes conventional and unconventional wells and calculates the incremental producible reserves based on specific parameters.

Upwing Energy CEO Herman Artinian recently talked with E&P Plus about the company's evolution, how the company's technologies work and the state of the artificial lift industry.

E&P Plus: How did the company get started? What was the inspiration?

Artinian: Upwing Energy is an innovative offshoot of Calnetix Technologies. Calnetix is a high-speed technology incubator that identifies strategic opportunities to enable new applications in various industries. Calnetix is very familiar with the oil and gas sector, as it introduced the first high-speed permanent magnet subsea pump to the industry through another one of its subsidiaries, Direct Drive Systems, which was acquired by FMC Technologies in 2009.

While demonstrating waste heat recovery systems in oil and gas fields in 2011, Calnetix became more familiar with oil and gas field operations and identified the need for more advanced artificial lift technologies to extract more hydrocarbons from existing assets.

The company created a strategic initiative to develop a subsurface compressor prototype to prove the concept of downhole compression. With the successful proof-of-concept field trials, Upwing Energy was formed.

E&P Plus: What did you feel was lacking in the artificial lift industry that Upwing could provide?

Artinian: Artificial lift for natural gas does not exist today. The best operators can do is deliquefy the well as it becomes liquid loaded. However, in reality, this is a means of life support rather than a way to enhance production. The SCS decreases the reservoir pressure to levels that are not possible today. This significantly increases production and recoverability.

From an engineering and physics standpoint, we knew we could make subsurface compression work, but we didn't know for certain what a huge difference in production it would make and how the reservoir would respond until we did our trials. The data only available from our tool are shedding new light on the available reserves and opening up new production strategies for E&Ps in both conventional and unconventional formations.

Subsurface compression provides another huge win from an environmental standpoint as well. Unlike surface compression, there is no risk of leaks into the environment, and there is a significant savings in carbon emissions. In fact, over 9 million tons of CO_2 equivalent can be offset by removing a wellhead compressor and replacing it with an SCS. In addition, operators can take advantage of the fact that we are a certified carbon neutral supplier.

E&P Plus: How is what Upwing offers different from what's on the market?

Artinian: It is completely unique. There are no other subsurface compressors available in today's market. We were well-suited to address this market demand due to our unique technology and extensive background in high-speed systems that stem from Calnetix.

Upwing is positioning itself as a service company that will enable operators to increase production and recoverability instead of just selling a tool. Upwing will evaluate the assets and take the lead on deploying and operating its advanced systems for a monthly fee. This reduces the capital requirements for an operator and puts the responsibility on Upwing for the equipment.

E&P Plus: With operators shifting from the mode of "production at all costs" to "generate cash flow," how does that impact the artificial lift business, and how do you adjust?

Artinian: It is significantly more cost effective to produce more from existing assets than developing new ones. The SCS increases the rate of production by 20% to 200%, resulting in higher cash flow. It also increases the rate of recovery by 20% to 70% due to lower pressure well abandonment, resulting in a larger balance sheet. Lastly, it removes liquids due to higher velocity gas within the wellbore and reservoir with its hybrid multiphase compressor, eliminating the need for topside liquid pumps and wellhead compressors, resulting in a lower cost of production. So, in a sense, we are reinventing the artificial lift business for operators to align with this transition.

"Over 9 million tons of CO_2 equivalent can be offset by removing a wellhead compressor and replacing it with an SCS."

– Herman Artinian, Upwing Energy

E&P Plus: Explain how the Enhanced Production Simulation works and how that can benefit producers.

Artinian: Up to now, there wasn't a need to develop enhanced production simulation simply because artificial lift for gas wells did not exist. The operators had to work with the given reservoir pressure and produce as much as possible. Now that we can alter the reservoir pressure and create a drawdown to decrease it up to 80%, the demand for more enhanced tools is eminent. Upwing has developed unique in-house tools to be able to evaluate and predict production when the SCS is deployed.

The Enhanced Production Simulation (EPS) developed by Upwing incorporates reservoir and wellbore characteristics, the wellhead conditions and the SCS operating ranges to predict incremental production. The simulation utilizes both an analytical approach and a numerical simulation to converge the results. Because the SCS enables deliquification at the wellbore (and therefore multiphase production), it is important to keep the velocities above critical along the production tubing.

Customers can input commonly known well data, including wellhead pressure, wellhead temperature, bottomhole temperature, inflow performance relationship, pipe length, pipe ID, pressure ratio and fluids composition, to simulate the increased gas-flow rate and additional recoverable reserves with a subsurface compressor. The simulations also provide insights on how to plan completion geometry and leverage the capability of subsurface compression to maximize the production gain potential.

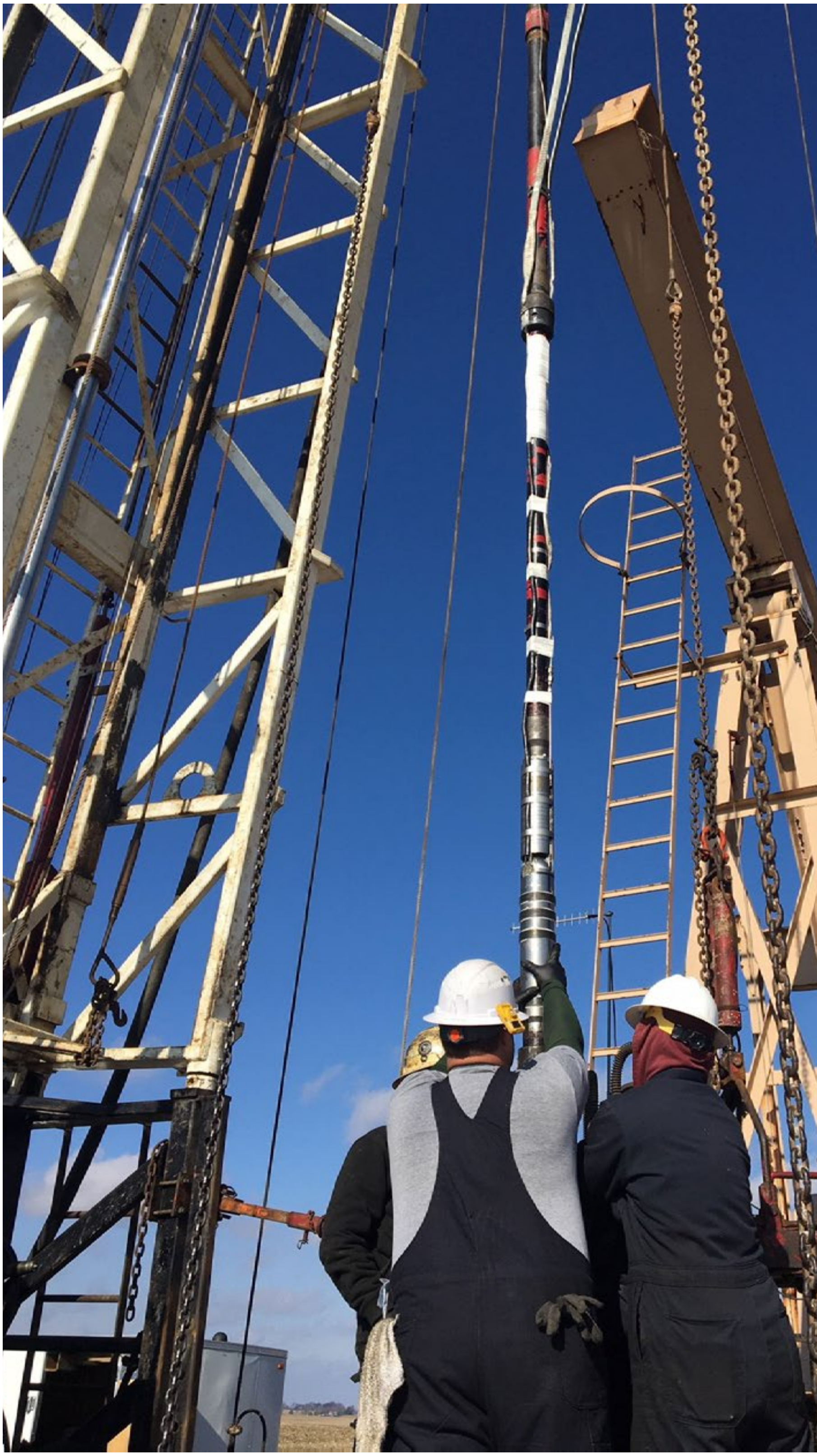
The SCS optimizes both the compressor parameters and the completion geometry to maximize the production. This process is constantly monitored and calculated via internally developed autonomous controls to adjust the speed and the torque of the compressor as there are pressure changes in the gathering lines as well as production fluid density changes. This is all possible due to the significant amount of new data now available through the SCS.

E&P Plus: The company has been recognized for its SCS. Talk about how that works and what makes it unique in the industry.

Artinian: The SCS increases gas production and recoverable reserves by decreasing bottomhole flowing pressure and causing higher reservoir drawdown. It also carries liquids to the surface by creating higher gas velocities throughout the vertical and horizontal wellbores and prevents vapor condensation by increasing the temperature of the gas when exiting the compressor.

The subsurface compressor consists of two main components—a high-speed hermetically sealed permanent magnet motor with magnetic bearings and a hybrid wet gas compressor. These two components are coupled by a magnetic coupling that conveys torque from the hermetically sealed motor to the compressor with no mechanical shaft or seals, so there is no need for a motor protector to isolate the motor from downhole fluids. The SCS' protector-less architecture provides an extremely reliable rotating solution for lower total cost of ownership and can also be applied to oil recovery. The topside variable frequency drive controls the motor at high speeds without any speed sensors.

Upwing's SCS is the only downhole turbomachinery that can maximize gas and condensate production, recoverable reserves, gas-in-place recovery efficiency and liquid unloading at the same time. All of these benefits can be realized in any type of formation and wellbore geometry in both the onshore and offshore environments regardless of where the well is within its life span. +



An SCS is run in the hole, which will result in optimization of both the compressor parameters and the completion geometry to maximize the production. (Source: Upwing Energy)

ESG in Oil & Gas:

Searching for Answers

Building an ESG case and presenting the right evidence to stakeholders across the value chain has become a riddle wrapped in a mystery inside an enigma for producers and service providers in oil and gas. So how are they setting about solving it?

(Source: Shutterstock.com and Hart Energy/Melissa Ritchie)

***Len Vermillion**, Editorial Director*

If you want answers to ESG in oil and gas, be prepared to join the search party. The answers are hard to decipher, mainly because ESG in oil and gas remains something far from a black-and-white issue with unquestioned solutions. Collectively, the work is being done; it's just that there isn't really one right way, one right measurement or one all-encompassing goal between all three prongs of ESG—as of yet.

"There's a different answer between the E, the S and the G," admits Sean O'Donnell, managing director with Quantum Energy Partners, one of the largest private equity investors in oil and gas. "Private equity has always had the 'G' figured out pretty well in terms of ownership, alignment and control. You're seeing the conversation in the public market change to catching up on having ESG-oriented scorecards."

So, the money wants ESG to be a big part of the oil and gas industry. That's a well-documented fact that satisfies *why* producers and oilfield service (OFS) providers are scrambling to get their ESG-friendly operations and reporting in order. Just take a look at these articles featured in various Hart Energy media:

- *ESG Takes Root*
- *Energy ESG: Building a Case for an ESG Ready Future*
- *EOR Tech to Help Oil Producers Reach ESG Goals*
- *Q&A: Why ESG Investing Will Impact Oil and Gas in 2021*
- *Why ESG is Here to Stay for Oil and Gas Industry*

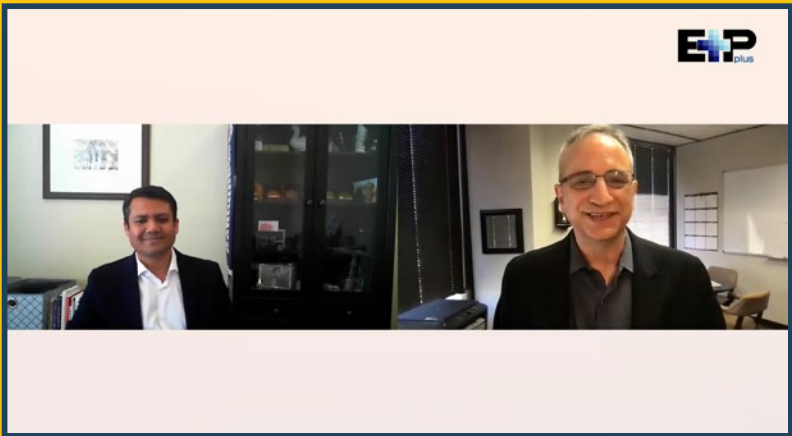
But the *what* and the *how* remain the enigma. That's not to say there hasn't been progress toward finding the right solutions, particularly in the area that has dominated headlines, politics and Wall Street for the last couple of years.

"The real push over the last 24 months for the industry has been a step-function kind of change on the E," O'Donnell said. "It's on methane, in particular."

O'Donnell pointed out the green shoots of metrics for measuring methane mitigation as a catalyst for progress.

"The technology and the operational protocols are now well understood and available," he said.

ESG and well production



Nishant Jha, director of Well Production Systems with Schlumberger, talked with Hart Energy's Len Vermillion about reducing emissions at the well site. View the full interview to hear his thoughts.

"There's also been a refinement of reporting that upstream companies should be focused on. Three years ago, four years ago, there were 1,100 different measurements for ESG."

That thought probably makes your head spin. Clearly, that's too daunting of a task for any large major to figure out, let alone a small independent oil and gas E&P. However, O'Donnell said the metrics that matter most have come to the forefront over the last two years.

"The technology and the ability to capture those data, and the ability to quality control those data, and the ability to have meaningful baselines that are common across companies that—in the last 12 months—have been what's really started to develop," O'Donnell said. "Investors can start to make relative value decisions."

Building the case

When it comes to presenting their cases to investors, oil and gas producers rely on the help of the service sector. Luckily, the OFS sector is keenly aware of the importance of ESG in oil and gas. Many have developed their own operations and R&D with ESG in mind.

"For us, it's embedded in our vision and purpose," said Lees Rodionov, Global Director - Sustainability, Schlumberger. "The vision is we will define and drive high performance sustainably. The purpose is we create amazing technology that unlocks access to energy for the benefit of all."

But more importantly, Rodionov said, is that the drive to reach ESG in oil and gas starts at the top and needs to be embedded in the standard operations of a company, whether it is a service company or producer.

"If it's off to the side, I think it's hard to manage that triple bottom line they talk about in sustainability—balancing the financial, environmental and social priorities," she said.

Schlumberger has developed a comprehensive program to address the need for ESG in oil and gas. While she said there is, of course, a strong emphasis on emissions and addressing the industry's role in climate change, the company's priorities also address the need for meaningful opportunities to all stakeholder groups: employees, customers, investors and the communities in which it works.

"In layman's terms, what this is about is taking emissions out of the whole oil and gas value chain—so operations, supply chain, the technology that our customers use—and then also growing our low-carbon businesses outside oil and gas," she said. "In addition, it's creating a space for diverse, inclusive, fair local opportunity."

To Rodionov's point, ESG is far from a singular focus on climate change; however, in 2021 emissions figures to be the biggest issue for the oil and gas industry, particular in light of a new administration in the U.S. hellbent on reining back in regulations that proliferated in the Obama era, and an ongoing charge toward net-zero in the EU and other parts of the world.

"Our strategy addresses both our historical core portfolio as well as those new avenues for growth in the carbon neutral space," she said.

Before service providers like Schlumberger can offer help to producers through their services and technologies, they have to address their own carbon footprints. Schlumberger has done that, Rodionov said. Its own ESG program addresses the carbon intensity of its own supply chain, operations, and products and services. But it also addresses the carbon intensity of the technology itself.

"The methodology we've adopted to address both the opportunities and the [financial and physical] risks that climate change presents is the TCFD [Taskforce for Climate-related Financial Disclosures] methodology," she said. "This seems to be the one that there's some conversion on as a best practice inside the investment community."

"We just want to be as efficient as we can and find that sweet spot in planning between environmental impact and the financial and social impact."

–Lees Rodionov, Schlumberger

Rodionov said Schlumberger has committed to a science-based target and will submit it this year. The target will manage the high-carbon parts of the value chain mentioned earlier.

"Going through the process of setting the target has been really beneficial because it has given us a deep understanding of our footprint in terms of where the emissions are coming from, where we can impact and what's going to have the most impact," Rodionov said.

She added that the company is committed to using those science-based targets to help its clients reduce their emissions as well.

Presenting the evidence

What producers will need to pass on when seeking to satisfy tenders is a holistic value chain with ESG needs buttoned up. Rodionov said that starts at home for the service suppliers.

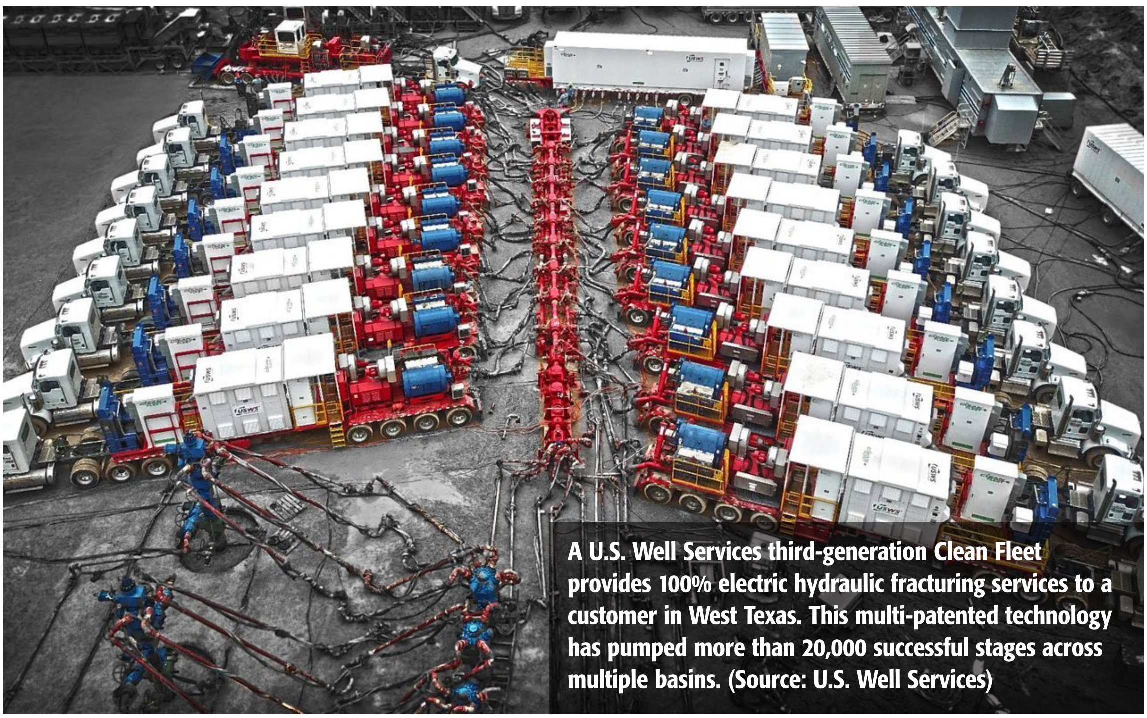
"If I talk about our footprint [and] our operations, we're looking at the fuel and power we consume primarily in our vehicles and our facilities," she said. "So, our tactics for reducing emissions in this space are going to be primarily technology-centric around our fleet of 13,000 light vehicles that we would convert to electric. We have facilities that consume diesel and electricity that we would convert to renewable. And then we'd also look for opportunities to drive waste out of the system."

Rodionov admits that the vast majority of Schlumberger's emissions fall in the things it uses to deliver operations and the technology itself.

"We have some high carbon inputs like cement, steel and chemicals, but it's also logistics, third-party equipment," she said. "The tactics for reduction in this space are going to be around strategic supplier partnerships, looking to partner with suppliers who have similar goals to ours."

Rodionov said leveraging digital technology is also a prime driver of reducing waste in the supply chain.

"We just want to be as efficient



A U.S. Well Services third-generation Clean Fleet provides 100% electric hydraulic fracturing services to a customer in West Texas. This multi-patented technology has pumped more than 20,000 successful stages across multiple basins. (Source: U.S. Well Services)

U.S. Well Services can utilize field gas, CNG or LNG to generate power for an entire frac fleet using a 30-MW turbine. (Source: U.S. Well Services)

as we can and find that sweet spot in planning between environmental impact and the financial and social impact," she concluded.

Creating a clean fleet

E-fracs are a seen as a way to significantly cut the environmental footprint of oil and gas wells. How do they compare to diesel and dual-fuel fleets?

In an industry that relies heavily on data, it only makes sense to put the data concerning ESG to the test. One area on the energy transition that gets a heavy dose of dialog these days is the idea of electric frac fleets, or e-fracs. But do they really make a difference in cutting emissions?

U.S. Well Services, a noted provider of electric fleets and Tier II & Tier IV diesel fleets, decided to put it to the test. The company brought in a third party to take measurements and collect data from its existing fleets in the field and the results show that measuring the company's CleanFleet versus diesel fleets emissions were indeed lowered "in every case," according to U.S. Well Services CTO Lon Robinson.

So electric fleets do cut emissions, the company concluded. "That's the story," Robinson said bluntly.

"We're the only company out there that's done this with real data from the field," said Matt Moncla, chief commercial officer for the company. "It is real data we know is right."

U.S. Well Services outlined its findings in a 40-page white paper titled *Clearing the Air: The Truth about Diesel, Duel-Fuel and Electric Hydraulic Fracturing Operations.* The white paper is authored by Robinson and Vanessa Hordijk, natural gas process engineer with U.S. Well Services.

"We decided we would do a deep dive study on our natural gas turbines and compare them to what we would get for operating with our diesel fleets," Robinson said. "We took some of our real operational data from a pad in the Permian. We took that data and we looked at the load profile of our turbine, and from that load profile we calculated the emissions using four of the most highly accepted calculation methods.

"We not only did it for each stage [there were 13], but we also did it between stages during the idling period of the turbine," he continued. "Then we took that same identical load profile and applied it to [different fleets]."

They compared Tier 2 diesel, Tier 4 diesel and a tier 4 dual-fuel.

"We had a really good apples-to-apples comparison," Robinson said. "In every simulation, our CO_2e emissions were less for the turbines."

Given the evidence, the question turns to whether or not there has been or will be adoption of e-fleets in places such as the Permian Basin. U.S. Well Services already works with several operators around the country including Range Resources, Royal Dutch Shell, Apache Corp. and EQT, all of which provided testimonials in the white paper.

U.S. Well Services has been using electric fleets since 2014. Robinson and Moncla said the company was the first to put a stage in the ground using electric fleets. The company is now on its fourth generation of CleanFleet.

Robinson added that during the COVID-19 downturn of 2020, all of the company's electric fleets stayed active.

"We are now getting to put more to work, but there has been continued interest in electric fleets," he added.

"Where we can't supply electric fleets, we're putting diesel back to work, but a lot of our customers are anxious to turn to electric fleets."

So in a world looking for things that will get investors' attention in an ESG report, e-fleets are ready for their star turn.

EQT made the comment in the white paper that since going electric, it's taken out 17 MMgal of diesel from its operations, Moncla said. "It's real," he added.

With natural gas seemingly on the uptick, Moncla said he believes their e-fleets are built for operations in places like the Haynesville.

"We have 3,000-hp motors, and we have precise control of our pumps," he said. "We're not fighting transmissions. We're not fighting gears."

Moncla said their equipment is built for that kind of work.

A third-generation U.S. Well Services Clean Fleet in the Appalachian Basin provides hydraulic fracturing services for a long-term customer. U.S. Well Services' first electric fleet was deployed in the Appalachian Basin in 2014. (Source: U.S. Well Services)

"Obviously, with the higher rates, higher pressures, that's more fuel burn," he said. "So it will be way more than half-a-million a month of diesel when you're talking Haynesville. It will be between $1 million and $1.5 million.

"We know once we show these operators what the fleet's capable of and the money they can save, that's going to be a great play for us," he said. +

(Source: Tereshchenko Dmitry/Shutterstock.com)

Streamlining STO

Tighter management of shutdown, turnaround and outage (STO) projects can save millions in maintenance costs. Here's a blueprint for doing STO more efficiently.

Hisham Gouda, SAP

The drive to capture every molecule of efficiency across every facet of an E&P operation has manifested in plenty of positive ways for oil and gas companies: stronger, faster return on capital investments, shorter development cycles, larger commodity margins, and the list goes on.

As heavily as E&P companies have focused on operational efficiency, there's one area that may still offer opportunity for substantial efficiency gains: shutdown, turnaround and outage (STO). While companies have spent millions to improve and reinvent processes, there's still room for them to optimize, accelerate and simplify STO. Some companies, as digitally mature as they may be in certain aspects of their operations, continue to manage STO organically rather than strategically, with a patchwork of sometimes ill-fitting point solutions that hamper their ability to optimize this critical area of their operation.

And it appears they are paying the price for doing so. SAP calculates that by taking a more integrated approach to STO, a company can shorten a shutdown by 5% to 10%. For a production site, SAP projects that would translate into savings of $3.5 million to $6.5 million for the entire shutdown period.

While these figures are hypothetical, potential savings of this magnitude are reason enough for companies to take a closer look at their STO practices and processes as well as the technologies they use to manage them.

Pain points

As tempting as it may be to leave STO alone, the ramifications—financial and otherwise —are too large to overlook. Not only can STO account for up to 50% of a plant's annual maintenance budget, it also can have a major impact on a company and its brand should there be an HSE-related incident. What's more, the loss of revenue and income during a shutdown can amount to multiple times the cost of the shutdown itself.

STO is fraught with potential pain points, as SAP has learned from a recent analysis conducted with McKinsey. That analysis, drawn from dozens of interviews with executives at 18 companies around the globe, highlights some of them.

If some of those pain points seem all too familiar, then a company's STO processes and the technology that underpins it could be ripe for scrutiny. The following sections highlight the best-in-class approaches and capabilities that SAP is seeing E&P companies deploy to tighten up their STO projects and capture efficiencies that go right to the bottom line.

Start with integration

Companies that are most efficient with STO tend to have one thing in common: their systems are fully and seamlessly integrated, enabling data and insight to flow freely among the various facets of the business touched by STO, throughout the entire process of scoping, planning, executing and project close-out. A patchwork of siloed systems driven by software that struggles to communicate can lead to uninformed decision-making, project bottlenecks, inefficient workforce deployment, safety issues and, ultimately, costly delays and less than desirable outcomes.

STO outcomes look much different when there's a fully integrated digital system to help guide the process—when HR, procurement, finance, budgeting and costing, project management, third-party scheduling tools and the like are connected and working from a single source of truth. So information about scope changes, materials, logistics and completion of work flows to relevant parts of the business to support end-to-end strategic planning, processes and decision-making.

With a high level of integration across systems, key elements of STO, including scoping, and planning around cost, materials and operations as well as tactical planning and scheduling become much more straightforward. A company gains the ability to evaluate scenarios and systematically optimize processes. They also benefit from improved collaboration and cooperation within and across teams and departments.

In short, integration is a game changer.

Mobile makes a difference

With mobile capabilities as part of the integrated system, real-time connectivity becomes a two-way street between onsite workers (i.e., internal personnel, contractors and subcontractors) and the enterprise. Mobile-enabled workers can access resources (e.g., training and troubleshooting) in real time to help them execute tasks. They also can report in-the-moment findings during scope discovery, receive new tasks and log task completion in the moment instead of having to traffic paperwork at shift's end.

Meanwhile, the enterprise can monitor workers remotely, tracking them with sensor-equipped wearable technology, informing them of plant conditions and sending them information relevant to the task at hand.

All this can result in a huge jump in worker productivity and workforce maximization.

STO pain-point map – foundation for solution packages

	Assess	Define	Prepare	Execute	Evaluate
Systems	• Missing portfolio view across assets to schedule STOs • Master data incomplete/inaccurate • Missing sources of scope items	• Manual scope collection and management • No possibility to evaluate scenarios and optimize them systematically • Master data incomplete/inaccurate	• Missing integration of 3rd-party systems for current information • Missing support for resource leveling and procurement	• Missing realtime tracking • No overview about progress/earned value • Missing interfaces between internal systems • Lack of usability	
Processes	• Underestimation of STO efforts • Different processes at each asset • Missing best practices/ standardization • Missing industry view of competition activities	• Lack of proper risk assessment for scope items • Inaccurate cost and time estimates	• STO scope is not frozen and additional work emerges • Changes are added by individuals	• No tracking/documentation of work and materials • Missing integration of regular tasks and STO • Inefficient motion of resources across plant	• Operational commissioning takes longer than expected due to rework
Resources		• Underestimation of logistics for resources • Missing trust to suppliers/contractors • Manual permission/ certificate evaluation • Contractors chosen with limited information	• Long lead times for material not considered • Missing possibility to reserve materials	• Missing willingness to track work • Lack of top-down control and insights into operational work • Lack of shortterm material management within plant	• Loss of materials that were not used • No documentation of experience with contractor • No evaluation of work that has been finished
Capabilities		• No sustainable team with experience of previous STOs	• No shared interest of stakeholders	• Missing knowledge base, experiences & right skills • Inappropriate training with systems • Lack of quality of supervisors • Collaboration barriers	• No documentation and dependency on individual knowledge

(Source: SAP)

Critical painpoint   Minor painpoint   No painpoint

Advanced modeling and predictive capabilities

The ability to quickly analyze data and model scenarios brings a new level of efficiency to asset performance management, speeding and strengthening decision-making throughout an STO project.

These tools are proving indispensable in generating risk, cost and time estimations for scope items and, more generally, in properly defining scope. iIn the STO world, a well-defined scope often leads to a positive project outcome with the ability to reduce STO duration by as much as 20%.

An execution control tower

Visibility into every aspect of an STO project is critical to a positive outcome. When decision-makers have the data right in front of them in a user-friendly digital environment—where they can access progress reports, details on next steps and real-time updates on HSE conditions; view key performance indicators based on real-time calculations; and assess the risk/cost/impact of potential scope and timeline changes—they're better equipped to make decisions on the fly. Rescheduling and replanning in real time become a reality.

Ultimately, having a highly connected control center can increase workforce efficiency, reduce overruns, avoid scope creep, tighten issue resolution and optimize resources, all of which positively impact project finances.

With higher levels of standardization and governance in projects, an E&P company not only can capture new efficiencies in those projects, it can focus on its core business.

Connectivity with suppliers, contractors and other external resources

Extending the seamless flow of data and insight as well as access to vital project information to key external players in an STO project is another way to improve overall project efficiency. Open connectivity with contractors enables them to access best practices, training resources and mobile apps for reporting on task status and plant conditions, among other items. And internally, key project supervisors and planners can keep close tabs on work progress and process adherence, and pass on change orders as they're approved.

A similar level of connectivity with the supply chain enables a company to maintain a firm grip on logistics, materials, potential supply bottlenecks and other factors that can impact a project.

Standardization and governance

The goal with STO should be to make each project more efficient than the one prior. This entails standardizing processes across assets and projects, developing and disseminating STO best practices, and generally capturing the learnings from each and every project so they can be applied to subsequent projects. Establishing standards, milestones and benchmarks, ensuring process adherence and building institutional knowledge, analyzing the quality of contractors' work—all of this is predicated on the existence of a readily accessible, simple-to-update knowledge base.

There's no need to reinvent the wheel with every STO project. With higher levels of standardization and governance in those projects, an E&P company not only can capture new efficiencies in those projects, it can focus on its core business. ✚

(Source: Oil and Gas Photographer/Shutterstock.com)

ADNOC expects to unlock 1 Bcf/d from the Ruwais Diyab Unconventional Gas Concession located 200 km west of Abu Dhabi city with operating partner Total. (Source: ADNOC)

Permian in the Middle East? UAE stepping up to replicate US shale boom

The UAE's unconventional resources show promising results, with production potential comparable to the most prolific North American shale plays.

Faiza Rizvi, Associate Editor

In November 2020, Abu Dhabi National Oil Co. (ADNOC) commenced gas production from its unconventional gas field—a milestone that helped the world's third largest oil producer inch closer toward its gas self-sufficiency goal by 2030.

In an exclusive interview with E&P Plus, Mohamed R. Al Zaabi, senior vice president of unconventional and exploration with ADNOC, discussed the tremendous potential of unconventionals in the United Arab Emirates (UAE) and his company's commitment to working with international partners to develop the UAE's capital city, Abu Dhabi's unconventional resources.

E&P Plus: Can you give us a macro outlook on the potential of Abu Dhabi's unconventional oil and gas resources?

Al Zaabi: Abu Dhabi has abundant unconventional oil and gas recoverable resources that will support ADNOC's drive toward gas self-sufficiency for the UAE and provide long-term energy security to the UAE and our global partners. As we continue to appraise our unconventional resources estimated at 22 billion barrels of unconventional oil and 160 Tcf of unconventional gas, we see very promising results, with production potential comparable to the most prolific North American shale oil and gas plays.

In addition, we see great prospects beyond this area including in our tight oil and gas reservoirs, which we are further exploring and appraising.

The potential for an unconventional oil and gas industry in the UAE is evident, and we are committed to working with international partners to develop Abu Dhabi's unconventional resources to mutually benefit the UAE, its people and our future international partners.

The development of this industry is underpinned by the UAE's trusted and reliable investment environment, our infrastructure and excellent geographical location.

E&P Plus: Is digitalization playing a key role in unlocking the unconventional reserves?

Al Zaabi: ADNOC is firmly committed to developing Abu Dhabi's vast unconventional resources and has allocated substantial capital to de-risk these resources over the past few years. This has enabled significant unconventional recoverable resource discoveries through our exploration and appraisal activities covering 25,000 sq km onshore.

Since we began exploring for unconventional resources, we have successfully customized North American unconventional technologies to Abu Dhabi's reservoir conditions. Doing this has expedited our learning curve, driven efficiencies and reduced our costs.

ADNOC is also using digitalization and artificial intelligence to turn our vast amount of operational information into data that we can use to harness efficiencies. For example, during the pandemic our remote operations monitoring capabilities have enabled us to maintain operations by managing real-time drilling and fracturing, providing sites with technical and decision-making support to bring online our unconventional wells.

The progress we make can be further expedited as we secure strategic value-add partners that bring advanced technology and capabilities as well as deep expertise in unconventionals.

E&P Plus: What are the opportunities for North American companies to tap into Abu Dhabi's unconventional resources?

Al Zaabi: When you look back, ADNOC launched its unconventional exploration and de-risking program in 2015. Since then, we have announced significant unconventional resources, completed a dedicated gas exploration campaign and produced first gas just two years after we announced the first unconventional gas concession in the Middle East.

This is just the beginning, and we know we cannot maximize the full potential of Abu Dhabi's unconventional resources alone. We need multiple operators or partners such as was required for U.S. shale basins.

There is huge opportunity for the growth of unconventionals in the UAE; the acreage is contiguous across an area exceeding 25,000 sq km with year-round accessibility, and the proximity to infrastructure and market is a plus in addition to a very efficient permitting process.

"This is just the beginning and we know we cannot maximize the full potential of Abu Dhabi's unconventional resources alone. We need multiple operators or partners such as was required for U.S. shale basins."

–Mohamed R. Al Zaabi, ADNOC

The flexible and customizable commercial terms and work program, allowing partners to work directly with ADNOC to tailor the terms and design of the development with the option to divide it into phases to maximize value and lower risk is also appealing to potential partners.

100% operatorship is another opportunity for international partners, which allows for a flexible and cost-focused operating model. Ruwais Diyab Concession is one example where ADNOC is a 60% nonoperating partner and Total holds a 40% stake but is the operator.

E&P Plus: Explain the role of unconventionals in ADNOC's broader upstream growth strategy.

Al Zaabi: Abu Dhabi's unconventional oil and gas resources will make a key contribution to the delivery of ADNOC's 2030 strategy. For example, unlocking unconventional gas will play an important part in achieving gas self-sufficiency for the UAE. Ruwais-Diyab, our unconventionals gas flagship project with our partner Total, has demonstrated the viability of quickly unlocking gas as we progress toward providing 1 Bcf per day from this concession before 2030.

We are also seeing promising production results across all our oil and gas exploration activities in the Al Dhafra region in the west of Abu Dhabi city where we are conducting sole risk operations.

To support ADNOC's unconventionals growth strategy, the Integrated Drilling Services [IDS] and fracking capabilities of ADNOC Drilling, ADNOC's start-to-finish IDS drilling business, will be instrumental in delivering our mandate to unlock the abundant, untapped unconventional oil and gas resources across Abu Dhabi.

As we progress toward ensuring a sustainable and more economic gas supply, we will benefit from our unconventional resources being located near ADNOC's Ruwais industrial area. This enables operations to leverage ADNOC's expansive existing infrastructure and enables efficient logistics and operational management while also providing the potential for the future growth of an unconventionals gas industry in the UAE.

E&P Plus: What, according to you, are some challenges that you face in the area of unconventional resource development, and how do plan to overcome those?

> **"As we progress toward ensuring a sustainable and more economic gas supply, we will benefit from our unconventional resources being located near ADNOC's Ruwais industrial area."**
>
> *–Mohamed R. Al Zaabi, ADNOC*

Al Zaabi: One key challenge when developing an unconventional oil and gas industry, especially in a conventional resources-rich country like the UAE, is the ability to produce at very competitive costs compared to conventional resources.

Fortunately, we have all the components to ensure unconventionals in the UAE become commercially viable and profitable. In addition to having a laser focus on cost reduction, our early field development economics, based on actual well production results, show competitive costs compared to early play entries in North America and in the region. Critically, our well performance and reservoir quality of our unconventional plays also show lower decline and potentially higher recovery factors.

The high-value acreage spanning across Abu Dhabi and our OFS [oilfield service] market will positively contribute to reducing the cost of unconventionals and creating synergies across our operations. Leveraging the expertise of our partners will also play an important role in cost reduction.

Our data show that when we reach full field development, our current costs will significantly decrease, and we expect they will be competitive even with the most commercial North American shale plays. +

Over the next decade, oil and gas activity in the Appalachian Basin will be strongly driven by available takeaway capacity and pipeline expansion. (Source: DenPhotos/ Shutterstock.com)

Appalachia and the race to capitalize on higher Henry Hub prices

Who can access spare Appalachia takeaway? This analysis takes a look at how pipeline takeaway capacity will determine which companies can grow production and on which midstream systems.

Amber McCullagh, Enverus

Over the second half of 2020, Henry Hub prices rallied from depths of pandemic lows, with the 12-month strip reaching the $3/MMBtu range for the first time since early 2019. But in Appalachia, the next two years will look very different from the last five, when consistent pipeline capacity additions facilitated average production growth of 3 Bcf/d annually. Now, with only one takeaway project under construction, subtler differences in midstream connectivity will drive which producers and gathering systems can access these higher prices outside the basin and which ones will be left to compete for limited in-region demand.

In short, the competition is set. So who will capitalize and tap higher Henry Hub prices this year?

Serving in-region demand

Demand in the Northeast, net of storage injections and withdrawals, averages ~17 Bcf/d annually but with ~3 Bcf/d of swing between the peak in February and low in October (Figure 1). Seasonally weak U.S. Northeast demand triggered ~2 Bcf/d of shut-ins last fall.

The lowest-cost acreage or best-capitalized producers are most able to serve Northeast demand, as in-region prices deteriorate with growing production causing marginal production to be priced out. Among operators with at least 50 wells put to sales since 2019, Chesapeake, Cabot, National Fuel Gas and Range Resources feature the lowest breakevens, while Cabot is the least levered of the public E&Ps. Major gathering systems positioned for growth include Williams' Susquehanna Supply Hub, Williams' Bradford Supply Hub, National Fuel Gas's Clermont Gathering, CNX's McQuay Area System and Equitrans' legacy Equitrans Gathering.

Northeast takeaway capacity

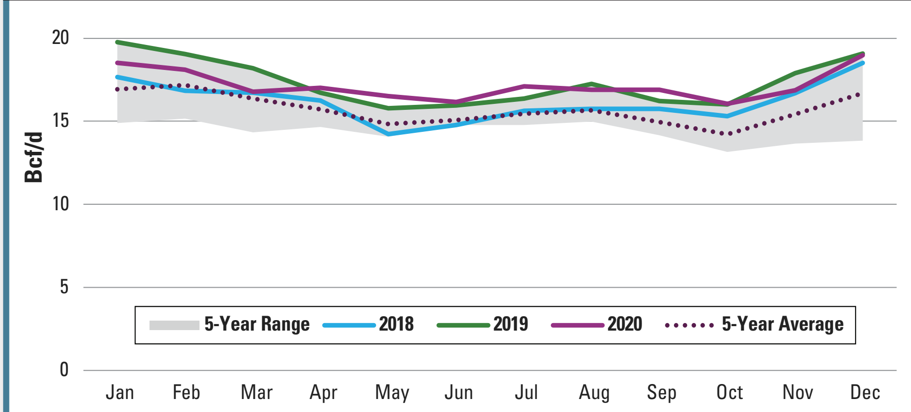
Most Northeast production does not stay in the Northeast, though. Takeaway capacity from the Northeast to other regions currently totals ~19 Bcf/d, growing as high as 21 Bcf/d once Mountain Valley Pipeline is completed.

The existing 19 Bcf/d of takeaway combined with the ~17 Bcf/d of in-region demand more than accommodates peak Northeast production of ~35 Bcf/d. However, last fall points to a possible future for Appalachian basis differentials, as in-basin prices collapsed to ~$1/MMBtu, despite ~1 Bcf/d of nominally available takeaway capacity. This disconnect reflects disparities in which gas can access this open capacity. Three routes—Tennessee Gas Pipeline (TGP) Zone 4, NEXUS and Rover—account for almost all of this available takeaway (Figure 2).

Implications for growth

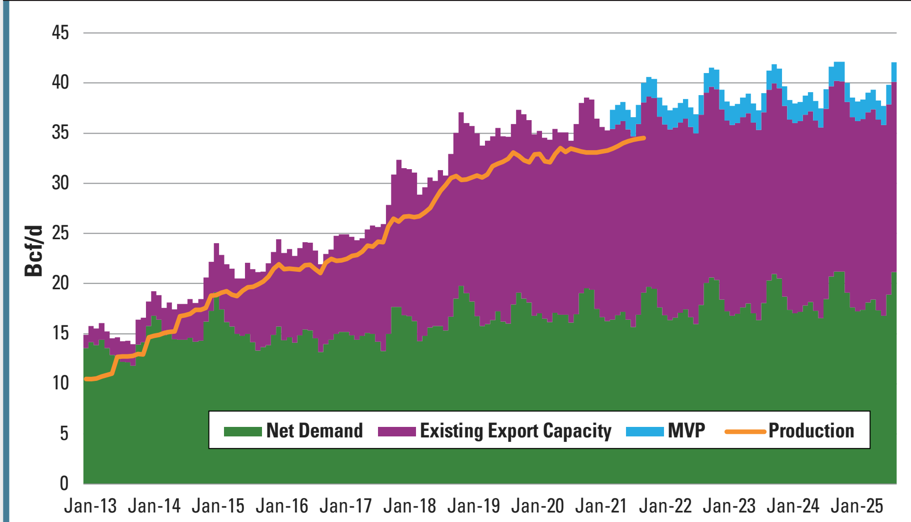
Operators with the right midstream connections to available takeaway

FIGURE 1. Northeast Net Demand



(Source: Enverus)

FIGURE 2. Northeast Supply, Demand, Takeaway and Prices



(Source: Enverus)

capacity have more sustainable growth options. In particular, these three pipelines mostly access Ohio volumes, so this acreage looks better positioned than acreage in Pennsylvania or the West Virginia panhandle with lower wellhead breakevens.

From 2014 to 2016, EQT (then a combined upstream, midstream and utility company) developed the Ohio Valley Connector expansion on its Equitrans Transmission system, taking West Virginia and Pennsylvania production to its Clarington, Ohio, interconnect with Rockies Express Pipeline and later with Rover. With difficult terrain in the Appalachian mountains around the Ohio River Valley, the project included only 50 miles of newbuild or looped pipe but a tariff rate of $0.30/MMBtu. Economics for pipeline expansions are often more favorable than for newbuild, but lining up commitments and building such a project would take at least three years.

Instead, intra-Appalachia basis spreads look likely to bring rigs back in Ohio and West Virginia in addition to Tier 1 Marcellus acreage, despite a ~$0.25/MMBtu difference in wellhead breakevens.

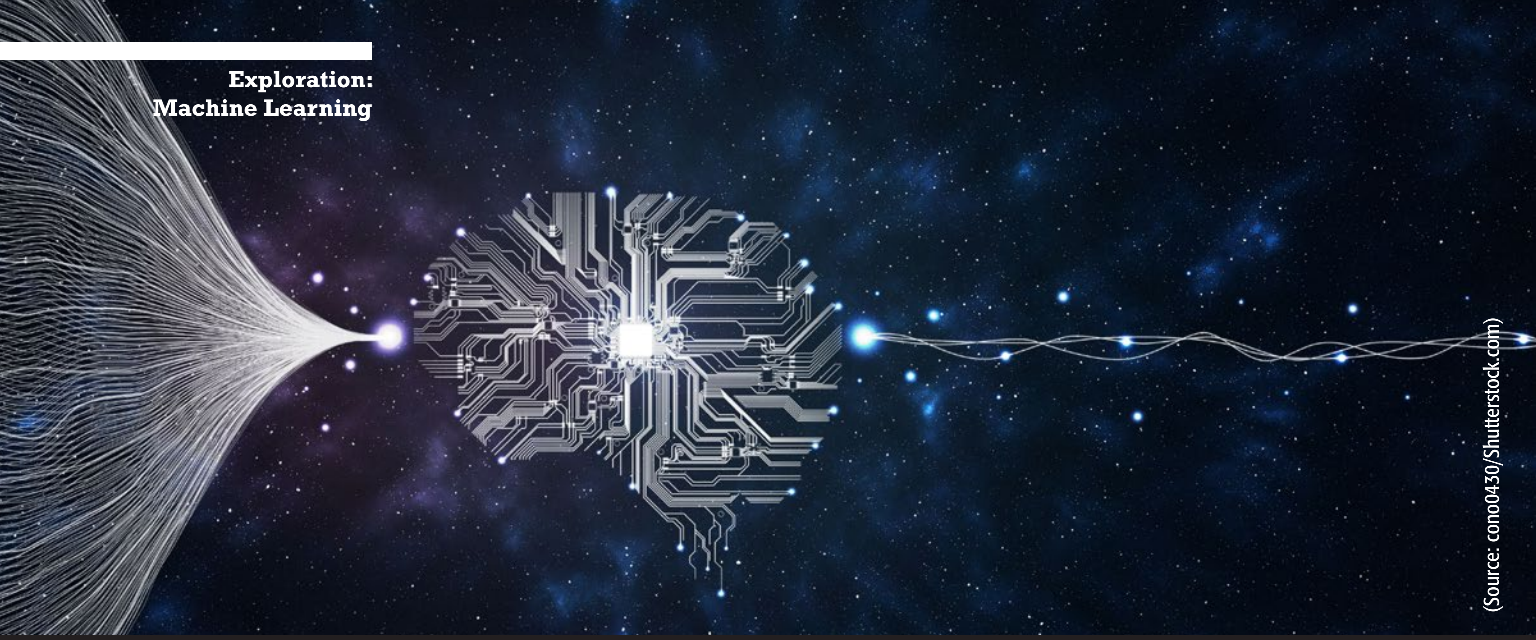
Since the beginning of 2019, Ascent and Gulfport drilled the most wells in the Utica South Dry Gas sub-plays. Of gathering systems, Energy Transfer's Ohio River System, Equitrans' Olympus Belmont Area, MarkWest's Ohio Gathering System, Antero Midstream's Utica Shale and Antero Midstream's Marcellus Shale feature less attractive wellhead breakevens versus the best systems in Pennsylvania but are better positioned for immediate growth due to advantageous connections to interstate takeaway.

In terms of transmission, the most attractive piece of unsold long-term capacity is the ~150 MMcf/d of NEXUS capacity that can source gas in core southwest Pennsylvania acreage via a TETCO capacity lease. However, the balance of unsold NEXUS capacity, with receipts at the Kensington processing plant for rich-gas Ohio production with ~$4/MMBtu breakevens, is unlikely to sell until a supply header project is built or NGL prices skyrocket.

Rover accesses lower-cost Ohio supply relative to NEXUS; therefore, we expect Rover to sell out of its long-term capacity before NEXUS does. On TGP, current flows exceed producers' contract capacity, but several consumers and marketers also contracted for capacity with receipts in northern Ohio. Filling this takeaway capacity may require upstream pipeline expansion.

Without question, the road map has changed in Appalachia. Whereas the last 10 years were marked by a race to prove up acreage and develop long-haul transmission, the next 10 years will be driven by existing infrastructure. Those upstream and midstream operators with the right connections and right-of-way stand to benefit from the higher Henry Hub prices in 2021 and 2022. +

About the author: *Amber McCullagh is a director with Enverus and leads the company's Midstream Intelligence team.*



(Source: cono0430/Shutterstock.com)

Reservoir characterization: combining machine intelligence with human intelligence

An integrated approach for reservoir characterization bridges the traditional disciplinary divides, leading to better handling of uncertainties and improvement of the reservoir model for field development.

***Fred Aminzadeh**, University of Houston*

Reservoir characterization is the process of assessing reservoir properties and its condition, using the available data from different sources such as core samples, log data, seismic surveys (3D and 4D) and production data. This is done in different stages of the E&P process from high grading reservoirs in exploration to their delineation for their development, as well as their description for optimum production to assessing their evolution in their stimulation for enhanced oil/gas recovery to extend their economic life.

An integrated approach for reservoir characterization bridges the traditional disciplinary divides, leading to better handling of uncertainties and improvement of the reservoir model for field development.

Among the main difficulties in reservoir characterization is the "SURE challenge." Figure 1 demonstrates the complications involved in integrating different data types with different scale, uncertainty, resolution and environment (SURE). The top left illustrates three key data types: core, well log and seismic data (referred to as a data pyramid). The base of the pyramid is the seismic with very large coverage but with limited resolution and lesser level of certainty. The top of the pyramid is the core data with very little coverage (only at a particular well location involving a fraction of the well) but with high level of certainty and resolution.

Effective integration of all the data types, in spite of the SURE challenge, is the objective of reservoir characterization. Artificial intelligence (AI) and data analytics (DA) can play key roles in offering solutions to the SURE challenge.

AI-DA has been gaining popularity in many aspects of E&P recently, and the expectation is that it will become an integral part of the tool box for many of our applications. DA, which is the systematic use of computational analysis of the data for making decisions, is an appropriate tool to address the need to deal with large amounts of data (Figure 1). The DA engine is energized by the power of AI and its machine learning (ML) and deep learning (DL) subsets. AI-DA may prove to be the exact medicine to address the SURE challenge.

The bottom right of Figure 1 shows a pyramid comprising different aspects of integration. Vast amounts

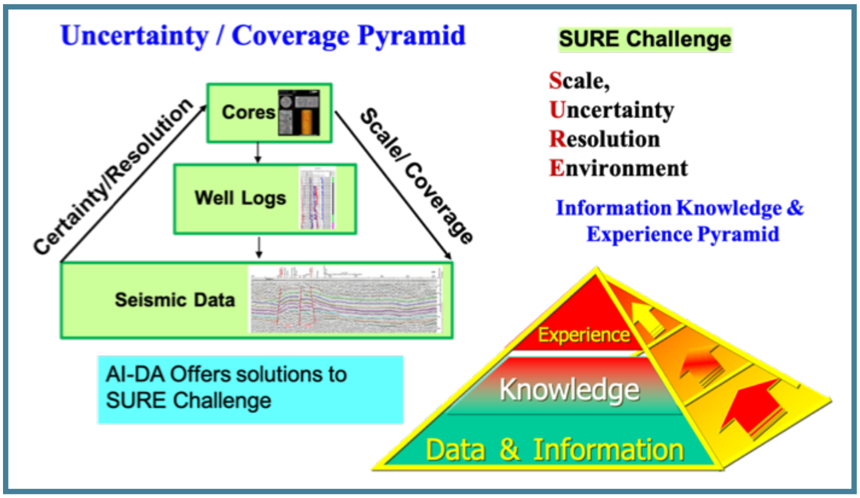


FIGURE 1. The SURE challenge highlights the difficulties in integrating data with wide ranging differences in terms of scale, uncertainty, resolution and environment. (Source: AIM-DEEP/University of Houston)

of Big Data with their 4V characteristics (volume, velocity, variety and veracity) need to be combined with technical knowledge and experience from domain experts to perform effective data mining and ultimately reservoir characterization. This requires designing a human machine interface, perhaps based on fuzzy logic and natural language processing to facilitate flow of data and information between the two.

An integrated reservoir characterization starts with collecting data from geological, petrophysical, seismic and engineering data. A multidisciplinary data analysis process creates a model of different reservoir properties including reservoir architecture, lithologies and facies. The geometry of the flow units is established (physical rock properties such as porosities and permeabilities of flow units). Three properties are related to the pore space:

- Porosity: the fraction of the entire volume part occupied by pores, cracks and fractures;
- Internal surface: the magnitude of the surface of pores as related to the rock mass pore volume and controls interface—effects at the boundary grain—pore fluid; and
- Permeability: the ability to flow fluid through rock pores.

Given different levels of uncertainty and other aspects of the SURE challenge, the estimates of reservoir properties should also be accompanied with their respective levels of uncertainty. This is derived from the calibration process and the extent of the match between estimated models with the ground truth (well/production data). This necessitates integration of physics-based and data-based approaches, also referred to as hybrid methods. Reservoir description is an iterative process from the input data to the process (e.g., well data, seismic data and production data). High-performance computers, both for their computing power and memory capacity, are crucial for performing data mining and iterations in a timely fashion, especially for real-time reservoir monitoring.

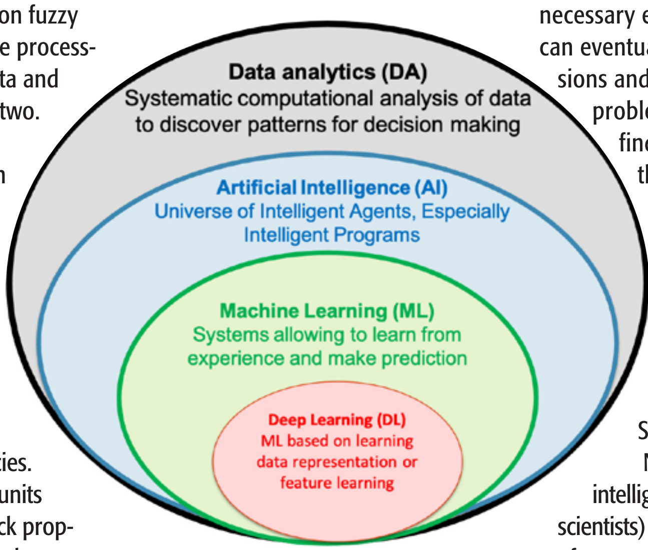


FIGURE 2. The graphic depicts the hierarchy of data analytics, artificial intelligence, machine learning and deep learning, all of which provide a new set of tools for E&P. (Source: AIM-DEEP/University of Houston)

AI-DA offers a natural toolbox for reservoir property estimation and their uncertainties. ML and DL methods perform much like a human brain. They can receive a variety of data from many different sources with drastically different characteristics and undertake necessary evaluations, and they can eventually make the right decisions and/or solve complicated problems. For example, DL finds particular features in the data that could be useful for classification of facies or prediction of different reservoir properties (Figure 2). They are well equipped to handle the issues highlighted under the SURE challenge.

Nevertheless, human intelligence (engineers and geoscientists) will always have a superior performance with qualitative data than computers that are better dealing with quantitative data. Thus, we should design effective human-machine interfaces to create hybrid solutions based on combining machine intelligence with human intelligence. +

Program bridges the gap between O&G and academia

University's program focuses on AI and data analytics technologies for energy E&P.

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

University of Houston's (UH) new AIM-DEEP program, which stands for artificial intelligence (AI), machine learning and data analytics for energy exploration and production, was launched to fill the gap between the ever-increasing advances in AI and data analytics and the growing demand for such technologies in various oil and gas and other energy-related applications.

"AIM-DEEP is expected to emerge as a unique platform to help speed up infusion of AI, machine learning and data analytics concepts into the energy exploration and production arena," said Fred Aminzadeh, professor and AIM-DEEP director with the University of Houston.

"AIM-DEEP will do this by bringing oil and gas operators, service companies, high-tech computer/data companies and academia together," he continued. "We want to benefit from various ongoing research on AI, not only in different departments at UH but also those of many other academic and research partners of AIM-DEEP. It will serve as a catalyst to break down the discipline, organization and industry versus academia boundaries to keep pace with the fast-evolving AI/data analytics technologies."

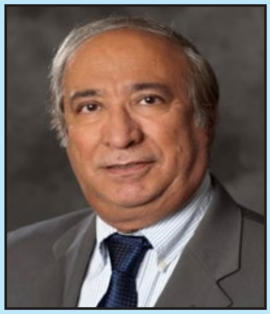
Aminzadeh recently detailed the university's AIM-DEEP program in a written interview with E&P Plus.

E&P Plus: What are some of the program's focus areas in the E&P sector of the oil and gas industry?

Aminzadeh: The program is focused on effective use of AI in different aspects of E&P. The top five focus areas based on the votes from the current and prospective sponsors are:

- Value addition of high-performance computing and AI for oil and gas applications;
- Intelligent seismic attribute analysis and reservoir characterization;
- Machine learning/AI/data analytics for production cost reduction of unconventional resources;
- Integrating physics-based and statistics-based approaches using AI and data analytics; and
- Digitalization: Getting the most value out of digital threads and digital twins in oil and gas.

E&P Plus: How is this program a catalyst for transformative changes in the areas of reservoir characterization and evaluation, 3D seismic and/or subsurface imaging?



Fred Aminzadeh

Aminzadeh: We expect to be a change agent in the way subsurface imaging and reservoir analysis is done. This will combine the power of AI and data analytics with the many advances in high-performance computing and memory (both physical and cloud/edge-based) to carry out modeling, imaging and simulation tasks more efficiently and faster in a cost-effective manner. We will help unleash the strength of AI and data analytics to address various Big Data challenges of the energy industry. The transformative changes resulting from more widespread use of AI and data analytics will be of the scale of the role horizonal drilling and hydraulic fracturing have played in the development of shale resources had in the last 20 years.

E&P Plus: What are the benefits of a membership with the AIM-DEEP program for those working with operators or service companies in the oil and gas industry?

Aminzadeh: With its hybrid structure, AIM-DEEP is not yet another university consortium. Its "BASE membership" provides cost-effective R&D on topics prioritized by sponsors. Other benefits include

a) Quick access to experts on machine learning at UH-AIM-DEEP and its academic and vendor partners;
b) Receiving software and other technical material on AI and data analytics;
c) Crossing discipline boundaries within UH and other partners; and
d) Filling the gap between the energy industry AI/data analytics needs and the capabilities available in other industries.

The "Individually Sponsored Projects," or ISP membership, provides the additional benefits of exclusive access to intellectual properties while honoring data confidentiality. ✚

For more information, visit https://aim-deep.petro.uh.edu or contact faminzad@centeral.uh.edu.

CONFERENCE & EXHIBITION

DUG HAYNESVILLE

LIVE from Shreveport!

May 26-27, 2021

Shreveport Convention Center
Shreveport, LA

Hart Energy's **DUG Haynesville Conference & Exhibition** will return to its standard in-person format, **May 26-27, 2021** at the **Shreveport Convention Center!**

This live program will provide a comprehensive view of activity in this dynamic region. Its exhibit hall promises unsurpassed opportunity to get face-to-face (appropriately masked) with major players and make valuable business connections.

FEATURED SPEAKERS

David Braziel · Doug Krenek · Raoul LeBlanc · Dylan LaBlue · Emily McClain · Matt Oehler · Chris Simon · Rob Turnham

Speakers confirmed daily. Visit website for updates.
DUGHaynesville.com

David Braziel
President
RBN Energy

Doug Krenek
President & CEO
Sabine Oil & Gas

Raoul LeBlanc
Vice President, Financial Services & North American Onshore
IHS Markit

Dylan LaBlue
Area Sales Director, DFW, Central & Southern
Baker Hughes Co.

Emily McClain
Senior Analyst
Rystad Energy

Matt Oehler
Business Development Manager
PropX

Chris Simon
Vice President, Business Development
Rockcliff Energy

Rob Turnham
President
Goodrich Petroleum Corp.

THANK YOU TO OUR FEATURED SPONSORS

Baker Hughes · Eastern Energy Services · GR Energy Services · Performance Proppants · Sierra Frac Sand, LLC · Sabine Oil & Gas · Rockcliff Energy

For information on attending, exhibiting or sponsorship, visit DUGHaynesville.com

Presented by: HARTENERGY

Hosted by: E&P plus · Oil and Gas Investor · MIDSTREAM Business

FIGURE 1. An example depicts a carbonate reservoir comprising a complex porosity profile with various types of fluids. This reservoir combines both fast and slow relaxing formation elements, and this is where having both T_1 and T_2 distributions become very important. (Source: Schlumberger)

Maximizing production from complex reservoirs

New high-definition NMR LWD technology helps improve well placement in complex clastic and carbonate reservoirs.

***Benjamin Rouanet and David Maggs**, Schlumberger*

In recent years, formation evaluation and well placement accuracy have become increasingly important to operators seeking to get the greatest return on investment (ROI) possible from their wells targeting highly complex carbonate and clastic reservoirs. LWD solutions have played a significant role in helping operators achieve this, especially since the introduction of nuclear magnetic resonance (NMR) LWD solutions within the past 20 years.

NMR is generally used for LWD applications when formation evaluation from standard measurements such as density neutron is not sufficient or accurate enough for a complete petrophysical and reservoir producibility evaluation. Using a combination of magnetic fields, the NMR tool can act directly on the formation fluid nuclei measuring their polarization time (T_1) or relaxation time (T_2). The NMR deliverables are then derived from the T_1 or the T_2 distribution at each depth. These deliverables include matrix independent porosity, pore size distribution, bound and free fluid volumes, pore fluid type, pore fluid characteristics and a continuous permeability estimate.

Today, the industry has access to many LWD options; however, the current industry LWD NMR solutions available are based either on the T_1 or the T_2 distribution, but not both. Simultaneous, real-time T_1 and T_2 distribution measurements ensure a complete understanding of the reservoir, regardless of its complexity. The MagniSphere high-definition NMR LWD service for slimhole applications (wellbores less than 6¾ inches) improves the operator's decision-making during this crucial stage of the well's life cycle. This new service applies an acquisition workflow that uses overlapping measurement sequences, enabling the industry's first simultaneous measurements of T_1 and T_2 distribution while drilling without compromising drilling performance. This delivers real-time petrophysical evaluation data, which are integrated into an intelligent processing workflow. The processed data provide operators with reservoir intelligence to identify producible hydrocarbons while drilling and enable precision geosteering, thus delivering ideal well placement required to maximize production.

LWD NMR challenges

NMR is one of the most complicated measurements made in the oil field today. Complex acquisition sequences are combined and repeated many times to cover the full measurement spectrum while ensuring low signal to noise (S/N) in the final measurement. Time-based acquisition sequences are performed as the NMR sensor rotates, moves axially with the drillstring and is subjected to associated shocks and vibrations. These environmental conditions must be addressed by the tool design or they can significantly affect NMR measurement quality.

There are two key challenges that LWD NMR services need to address for today's increasingly challenging drilling conditions:

- Measurement quality regardless of the reservoir complexity; and
- Sustained measurement quality in challenging environments without compromising the ROP.

Addressing these challenges is critical for any NMR service to successfully provide operators accurate reservoir evaluation and enable precision geosteering in the varied drilling conditions encountered around the world.

The high-definition NMR LWD service is designed to sustain a high-quality measurement in the most challenging drilling conditions for extended operating hours.

High-definition NMR LWD

The simultaneous acquisition of T_1 and T_2 distribution measurements is the main feature that addresses measurement quality.

The T_1 measurement responds better to large pores and grains, such as macroporous carbonate or high-porosity clastic formations, and light fluids such as light oil or gas. This measurement is also more tolerant of lateral motion effects that can occur while drilling.

T_2 measurements are optimum for the characterization of fast-relaxing formation components, such as shale, microporous carbonates and heavy fluids. The high-definition NMR LWD service uses 400-us echo spacing, which is the shortest of all current LWD NMR solutions, to ensure that the fast-relaxing formation components are accurately characterized. The 400-us echo spacing also enables high measurement density and higher vertical resolution.

The simultaneous T_1 and T_2 acquisition brings the additional benefit that the processing and interpretation workflow can be automated in real-time and recorded mode, ensuring consistent and reliable answers. Traditionally, the T_1:T_2 ratio is a single value user input. But when both T_1 and T_2 are available, it can be determined directly from the raw measurements as a variable across the full distribution range. This enables the NMR answers to be delivered directly from the acquisition system in real time for use in formation evaluation and geosteering applications (Figure 1).

Simultaneous T_1 and T_2 acquisition offers the possibility to characterize a wider range of fluid and rock fabric, and it also reduces user input during real-time acquisition. This ensures a repeatable high-quality NMR measurement regardless of the environment complexity.

To maintain measurement quality in challenging environments without compromising the ROP, the service incorporates the latest innovations in NMR sensor, digital and electronic design to ensure measurement reliability.

Higher tolerance to lateral motion is achieved with a newly engineered receiver, providing a more stable volume of investigation and two built-in sleeves that minimize antenna vibration. The antenna electronics also enable the tool to maintain an optimal S/N ratio in any type of environment, including very saline mud systems. These two features, combined with a compressed acquisition workflow, enable the service to deliver a quality measurement at fast ROP in harsh drilling conditions for extended drilling hours.

Case study

A national oil company in the Middle East completed a large number of high-definition NMR LWD service applications in multiple wells, accumulating high-quality, continuous LWD NMR data. This enabled an accurate evaluation of clastic and carbonate reservoirs by measuring permeability profile, macro- and microporosity volumes, pore size distribution and

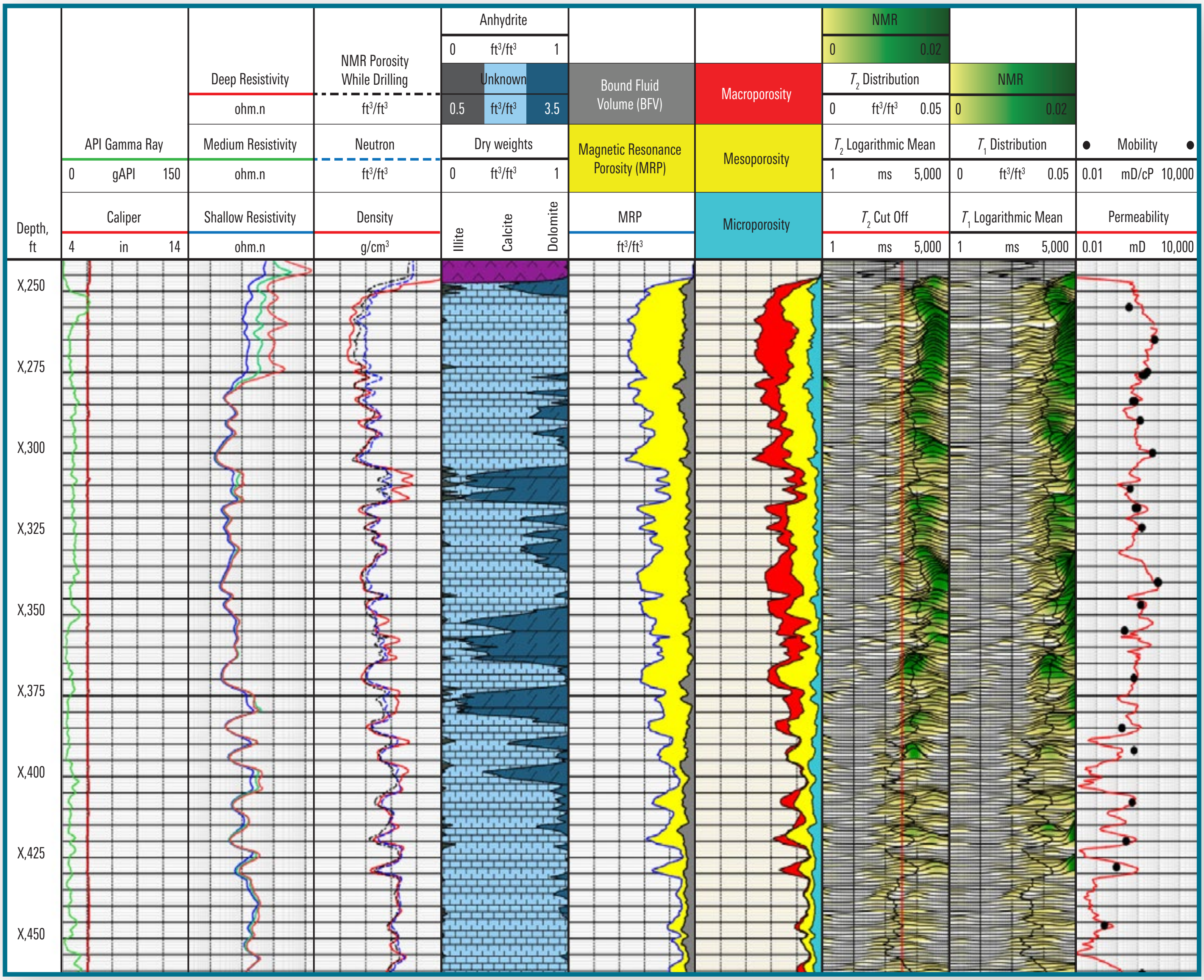


FIGURE 2. Service acquired continuous real-time NMR data, enabling accurate petrophysical-based well lacement while drilling in the Middle East. (Source: Schlumberger)

identifying the presence of various fluid types, such as light and heavy oil, tar or water.

Applications comprised multiple drilling environments, including exposure to lateral motion, shock and vibration, water-based and oil-based muds, and multiple bottomhole assembly configurations.

Figure 2 is a good example of NMR data acquired while drilling in one of the jobs. It features the continuous T_1 and T_2 distribution as well as the main NMR deliverables.

Conclusion

The simultaneous acquisition of the T_1 and T_2 distribution provides high resolution on the full relaxation time interval. Combined with the short echo spacing, this results in a robust and repeatable characterization of a wider range of fluid type and rock fabric that is well suited for complex and clastic reservoirs.

The high-definition NMR LWD service is designed and able to sustain a high-quality measurement in the most challenging drilling conditions for extended operating hours. The result is measurable ROI for LWD operations in complex reservoirs, as real-time, high-quality petrophysical data enables better decision-making on production strategy or well placement, which in turn can yield improved production performance. ✚

ELIMS, a division of Economy Polymers and Chemicals, developed a field-to-cloud chemical level monitoring system that was designed to improve the entire chemical supply chain. (Source: ELIMS)

Want more efficient field inventory visibility?

A new technology empowers companies to efficiently take inventory and asset management into the modern digital oilfield age.

***David Ludwig and Stewart White**, ELIMS*

In today's oil and gas industry, ESG efforts are top of mind, and it has become vital for the sustainability of operations. Optimizing the utilization of personnel and keeping them safe is paramount while their focus on higher value items also helps drive efficiency. In addition, support staff in remote locations are being spread across multiple site locations, increasing the number of variables they need to keep track of to ensure operations continue without nonproductive time (NPT). To achieve financial cost targets, more work needs to be done with fewer man hours, though safety and performance are priority. The advent of new specialized Internet of Things (IoT) applications is assisting with this transformation.

Chemical management on a frac site requires constant oversight. A modern frac site is limited in space, and the tanks that store chemicals are not large enough to store the entire volume necessary to complete the job, necessitating chemical replenishment to take place. This requires an understanding of current inventory, the rate of consumption and delivery lead time. All of these must be as accurate as possible to keep expense at a minimum. The process of checking the fluid level in the tanks is time-consuming and hazardous for field personnel. The communication between field personnel reporting inventory counts and the supply chain personnel managing replenishment orders is often inefficient. Task redundancy creates confusion, inaccuracies create waste and more man hours create cost and safety issues. All generating ESG concerns.

Gap in the market

The good news is there are currently a number of IoT-based fluid level monitoring devices available in the market that can help mitigate some of the efficiency losses and hazards. However, none of these devices where specifically built for this application and lack key features such as

- an onboard display for field personnel and delivery drivers, showing tank level, volume and temperature;
- a method to provide and visualize

data in the field—this is critical because there is often limited cell or internet connectivity; and

- a turnkey complete network/system that securely delivers data at the field level, cloud level (API) and through a user interface with tailored dashboards and analytics.

Perhaps the largest deficiency of these level monitoring devices is the timing interval that they report data. Commonly, data from these devices are reported about one to three times per day depending on how often the end user wants to replace batteries. This timing interval is too infrequent to keep up with the fast-paced nature of modern oil and gas operations. Managing chemical replenishment with stale data typically leads to chemical depletion/NPT or driver demurrage due to not enough storage to fit a delivery.

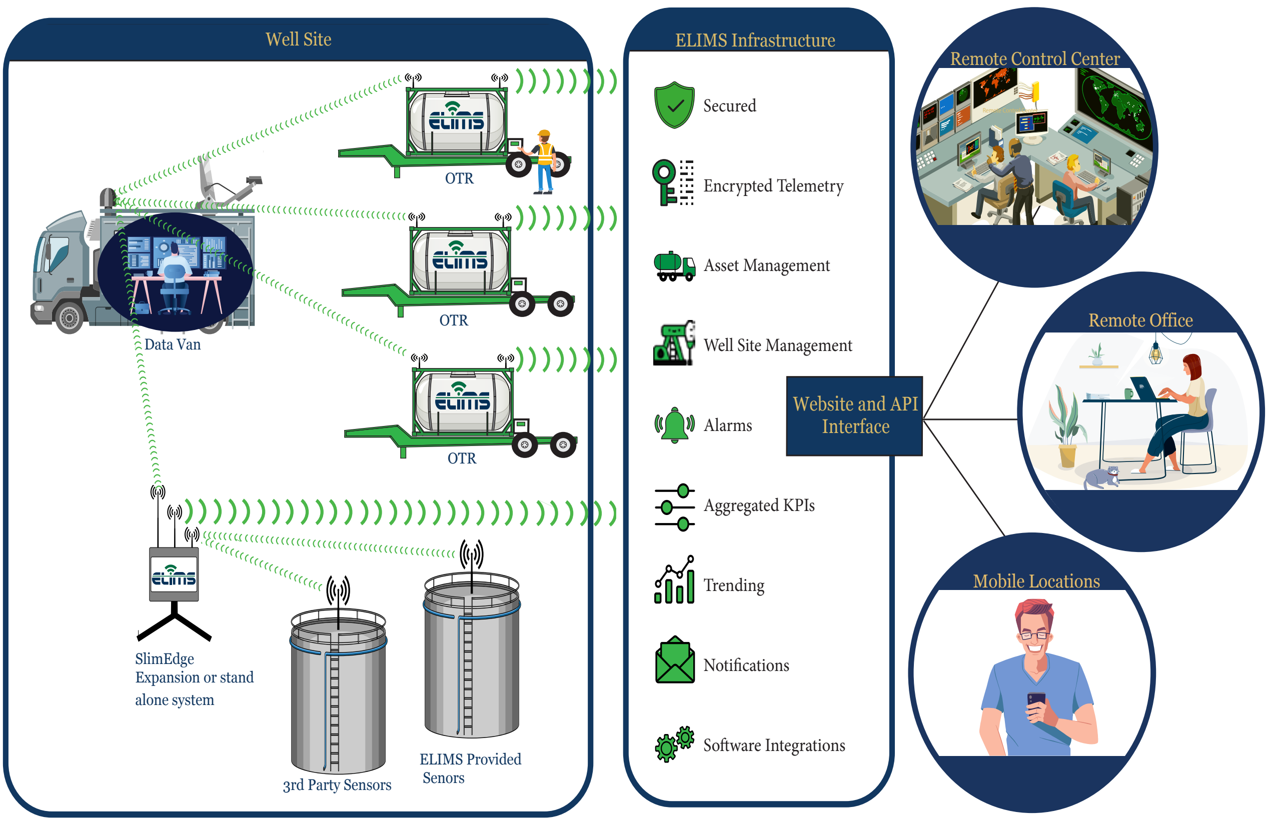
Field-to-cloud chemical level monitoring

ELIMS, a division of Economy Polymers and Chemicals, developed a system to solve this problem. The system is a field-to-cloud chemical level monitoring tool that was designed to improve the entire chemical supply chain. The field component called Over the Road, or OTR, is engineered with field personnel in mind providing multiple methods to visualize data and eliminating the need to climb on top of tanks to obtain fluid levels, fill, drain or vent the tank. The cloud component, CloudViewer, was designed for staff supporting field operations, ordering chemicals and scheduling assets logistics.

Additionally, all data are available to the customer for use in proprietary or third-party analytics and visualization tools. All components are carefully designed with safety, reliability and security at the forefront. The system has been engineered to achieve low cost, flexibility and even expansion to monitor other sensors outside of mobile tankage.

Data management

The field component of the system typically mounts onto an ISO tank/trailer and continuously gathers data from a high-accuracy fluid level sensor and GPS antenna to determine meaningful information. Tank volume is computed from the level data on the order of seconds rather than minutes or hours typically seen. From these data, advanced algorithms capture frac stage consumption figures and tank refill events among other reports. Tank level, volume and temperature are sent to the cloud system every 15 minutes. Stage and refill information are sent to the cloud immediately after their completion is detected.



ELIMS empowers companies to liberate their assets and data in a cost-effective and flexible solution designed specifically for the application and helps to painlessly bring operations into the modern digital age. (Source: ELIMS)

The GPS signal is used to report the position of the asset and determine if the system is in motion or stationary, allowing notifications to be sent indicating if the asset has arrived on site, is still en route, at a facility being reloaded or at a facility in standby status.

Tank level/volume visualization

Traditionally, field personnel complete a manual process called strapping, which determines the fluid level in the tank. This requires a person to climb on top of a 15-ft tank, open the man lid, stick an often warped or damaged wooden stick into the fluid, measure the fluid level on the stick, then correlate that measurement with an estimated strapping chart to determine the volume. This time-consuming process is often inaccurate, unsafe and must be completed frequently.

In addition, the chemical supply manager must actively keep track of the reported levels and make decisions on when to reorder.

OTR removes this process by continuously calculating the precise chemical volume. The system provides personnel multiple methods to view the tank information.

First, for field personnel, the onboard display shows chemical level, chemical volume, chemical temperature and system status data. Secondly, the system broadcasts a secured Wi-Fi signal that provides access to a local website where all tank parameters, deliveries, stages and other operational dashboards are provided. Since the visualization interface is a website, software does not need to be installed on computers or mobile devices used to connect to the system. The data that are visualized are updated every few seconds in near-real time.

Communications to the cloud

The method of sending secure data from the field to the cloud infrastructure has been a continually evolving component of the system. This aspect of the system is uniquely engineered to meet the challenges of the mobile nature of the application and the ruggedly remote locations where oil and gas is produced.

The first iteration of the cloud communications system included an IoT specific satellite terminal only. Since cellular devices and networks have grown tremendously, this has driven very competitive cellular data rates. Now cellular connectivity has been incorporated into the OTR system.

end users with different objectives can get the data they need quickly. The system also incorporates specific algorithms and analysis to help decrease the burdens of supply chain personnel so they can manage many job sites at a time.

The system utilizes text message and/or email to alert users of any number of parameters, including but not limited to chemical replenishment recommendations, high/low level alerts, temperature alerts, tank movement alerts, daily reports and refill completion reports.

As our industry moves toward viable ESG initiatives, turnkey local and cloud-based sensor data systems have become an increasingly popular choice to increase efficiency and safety.

However, through exhaustive field testing and development, it was observed that cellular connectivity drops off in many field locations in Texas, depending on location and interestingly time of day. It also drops off in mountainous regions of Colorado, Wyoming and Montana. These are all areas where oil and gas activity are focused. To provide the highest datastream quality, redundancy is required. Cellular connectivity is the primary strategy, and the system automatically reverts to satellite for very reliable 24/7 data communication. Also, the company is currently testing various other options to increase reliability of the datastream.

Functionality

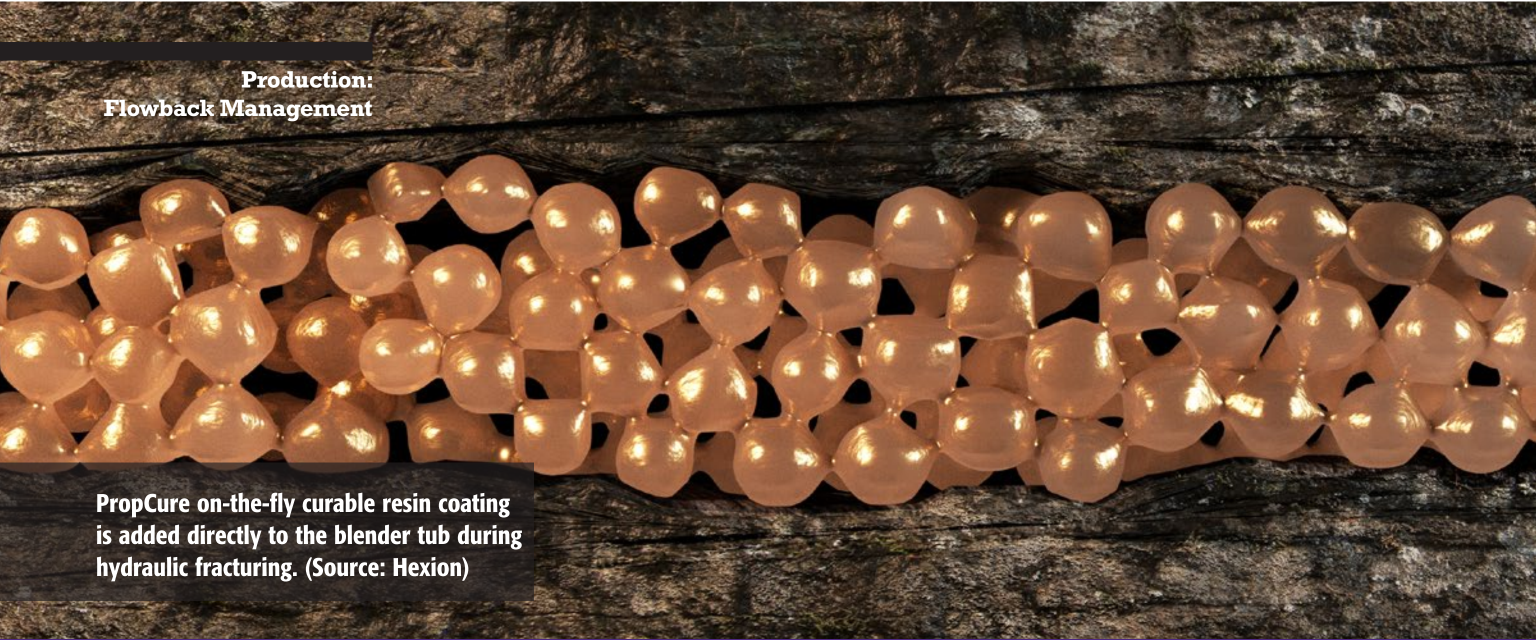
The CloudViewer is essentially the remote control center for the system. It's typically utilized by consumers of the information that are not located in the field. The CloudViewer includes various modules, dashboards and controls to operate, audit and manage chemical inventory and logistics.

The data collected from the field is mapped into related business models so

Upon initial setup of the system, ELIMS representatives work with customers to configure these actionable alerts. The system is flexible and can also handle custom application requirements. Built on micro services, additional custom logic can be added quickly and reliably without effecting other modules of the system.

All deliveries and consumption stages/events are visualized. Customers even use the data provided by the highly accurate level sensor combined with the extensively developed algorithms to audit third-party data such as delivery amounts and stage consumption. In addition, chemical utilization is also totalized in terms of total delivered, total used and, for those using the invoicing module, total invoiced.

It is also possible to store associated documents in the system. These documents can be associated with the asset (OTR trailer) or well site. BOLs, JSAs and other documents are typically stored in these locations.



PropCure on-the-fly curable resin coating is added directly to the blender tub during hydraulic fracturing. (Source: Hexion)

Keeping proppant downhole

On-the-fly curable resin coating controls proppant flowback and improves production.

Adam Harper, Hexion

Proppant flowback continues to be a challenge for operators in the oil and gas industry. It has been well documented how proppant flowing out of the formation can damage downhole and surface equipment once the wells are put on production. It is also well understood that production pathways for oil and gas can be restricted as proppant shifts into the wellbore and fractures pinch off near the wellbore. This can result in reduced EUR and potential long-lasting well damage. Traditional proppant flowback solutions have been an added expense that operators have a hard time incorporating into their overall budget, especially in a low oil price environment.

In 2018 Hexion launched its PropShield proppant flowback control additive. This liquid additive is added directly to the blender tub to coat the proppant as it is pumped downhole. This has proven to be a more economical solution compared to traditional means of proppant flowback mitigation. While PropShield additive has been pumped in hundreds of wells and remains in use, there are other challenges that operators have that were out of the original scope of development. These include proppant flowback control in high-temperature wells, improved crush resistance of the substrate, improved conductivity of the proppant pack and improved EUR.

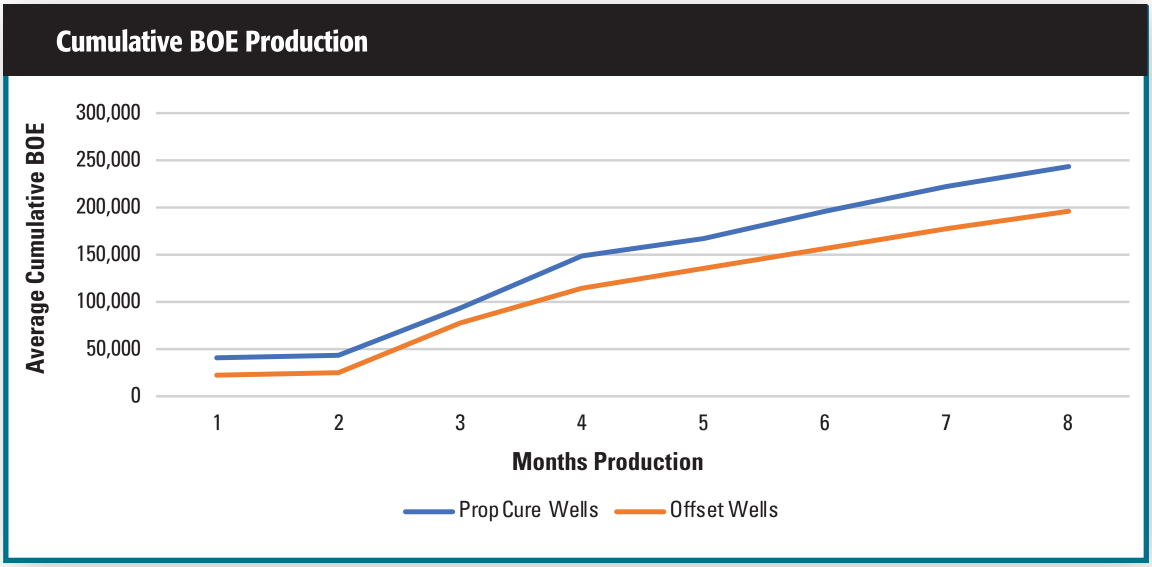
New technology

Hexion has since developed a new technology: PropCure on-the-fly curable resin coating. This coating allows operators to produce curable resin-coated proppants in the blender tub. PropCure has an affinity for the substrate, seeking it out in the blender tub while leaving the equipment clean. Once downhole, the coated proppant grains bond together and create a unified proppant pack. This provides proppant flowback control at high temperatures and high well flow rates; improved crush resistance and fines immobilization; and improved conductivity of the proppant pack.

Additionally, the coating has a tailored surface chemistry that alters the relative permeability of the proppant pack, allowing improved flow of hydrocarbons. Since it is a liquid additive, PropCure offers flexibility in job design and delivers significant savings compared to traditional proppant flowback control technologies.

Application

PropCure is a two-part system that arrives on location in isotainers or totes depending on the job size. The two components are pumped through standard liquid additive pumps (gear pumps) and combine in an inline static mixer that feeds into the blender tub. The two



A Bakken operator has experienced a 200-bbl/d improvement by using PropCure coating. (Source: Hexion)

components are pumped at a 1:1 ratio by weight. Once combined, the typical application rates are 0.5% to 1.5% by weight of sand (BWOS).

Job flexibility is a critically important feature of this technology. It can be used with any type or mesh size of proppant, including ceramic. PropCure can be added as a tail-in, lead-in, combination of tail-in and lead-in or pulsed depending on expected proppant flowback regimes. It can also be pumped during 100% of the stage as long as proppant is being pumped. Optimization of the job can take place once field, formation and flowback regime characteristics are fully understood.

Laboratory testing

Measuring bond strength has been an important aspect in the development of PropCure coating to ensure proppant flowback control can be achieved. The unconfined compressive strength (UCS) test was designed to assess the bond strength of traditional resin-coated proppants but has proven useful in validating the effectiveness of PropCure. All testing done to date shows that the additive provides outstanding bond strength that is comparable to a premium traditional resin-coated proppant and is effective over a wide range of temperatures (105 F to 350 F-plus).

Third-party conductivity testing was performed to ensure that fluids can freely flow through the coated proppant pack. Data show up to 10 times improvement in conductivity observed in the standard API conductivity test at 10,000 psi compared to the control of uncoated substrate. This improvement in conductivity can be attributed to fines encapsulation and reduced fines migration.

Crush testing was used to further test and validate the coating ability of the additive to reduce proppant fines. A 40/70 Northern white mesh sand was treated with a 1% BWOS PropCure coating and subjected to 10,700-psi closure stress. The same untreated sand was used as the control. The results of the test showed the coating reduced fines generation by 44%.

Oil flow rate testing was conducted to demonstrate how the tailored surface chemistry of the coating can alter the relative permeability of the proppant pack. In this test, treated proppant is packed in a test cell and saturated with oil. After full saturation, the rate of flow is calculated. Untreated proppant is used as a control. PropCure had a flow rate that was more than two times higher than the untreated control. Running this technology even at low concentrations could reduce or eliminate the need for additional surfactants because it is acting as a long-term surfactant coating on the proppant.

Field study

A Bakken operator ran a field trial on a seven-well pad comparing three wells that utilized PropCure to four wells that used 100% uncoated frac sand. These wells had a bottomhole temperature of 270 F, laterals of roughly 10,000 ft and an estimated closure stress of 8,000 psi. The proppant usage was 200,000 lb/stage at 40 stages for a total of 8 MMlb per well. The fluid system was slickwater for all wells in the dataset. The wells with PropCure treated the first 7.5% of the sand in each stage and the last 17.5% of sand in each stage. The dosage used for PropCure was 1% BWOS.

The operator reported that once the wells were put on production, there was no proppant flowback for PropCure wells while all of the uncoated offset wells continued to produce sand. Additionally, after eight months of production, it was communicated that the coating wells were producing on average 200 bbl/d more oil than the uncoated offsets.

The operator plans to continue to use the coating in their upcoming completions in the Bakken. Additional completions with multiple E&Ps are planned for most regions in North America in the coming months. +

Data-based inspections: It's time to get real

A winning combination of historical and real-time data can ensure optimum operability and profitability for aging assets.

***Christopher Blake**, IMRANDD*

For an oil and gas asset management company, maintaining and inspecting plant and associated equipment efficiently can often feel like a never-ending process. Whether it is contending with budget, time or bed space constraints, integrity teams are far too familiar with assessing, prioritizing and justifying their decision-making processes. In highly regulated locations such as the U.K. Continental Shelf, not taking the time to properly assess and understand an asset condition can be an exceptionally expensive gamble, which is why most operators pursue a risk-based inspection (RBI) methodology. But is this approach still fit for purpose in 2021?

Good quality RBI has its place in the asset management tool kit as it enables direct comparison of all the equipment under the metric of risk, irrespective of their damage mechanisms. For example, asset managers can use RBIs to compare the risk of corrosion on a piece of pipework against the risk of fatigue cracking to the deck integration on the skid for a pressure vessel. By incorporating feedback, such as material or equipment condition into the asset's profile, the recommendations will change over time. But it is this feedback loop

Even though offshore operators have been traditionally using historical data for asset integrity management, utilizing real-time data offers numerous benefits, and the insights continue to improve rapidly with the industry's growing digital capabilities. (Source: Oil and Gas Photographer/Shutterstock.com)

that can sometimes be the undoing of an otherwise sound asset integrity methodology.

The creep of human bias

Anecdotally, the industry has seen how human bias creeps into RBI strategies over time. Engineers lose confidence in the inspection readings and err on the side of caution. After a few inspections, this shifts the asset's risk profile further away from where it should be statistically. The profile becomes overly conservative, assessing probability based on engineering experience and past scenarios to the point of being toxic to the ethos of the very approach it was designed to deliver.

In other instances, the RBI strategy is primarily based on whether an incident has occurred within an organization or is a common issue within the industry, and it will only ever be based on historical or assumed data rather than what is happening in real time. Equally, much of the decision-making is made in isolation of what is happening in the plant's wider operations, meaning valuable operational insights, such as process data or system changes, are not incorporated. All in all, it is fair to say there is room for improvement in what is currently one of the most common integrity management processes used in heavy industries.

Holy Grail of asset integrity

Event-driven inspection based on predictive integrity management is the new Holy Grail for many asset managers. Rather than using traditional lagging indicators such as wall loss or visible corrosion, the responsibility is on using leading, real-time (or very near-real-time) data, such as process conditions including temperature and pressure, to drive inspection.

As an example, under one set of conditions, pipe X will degrade at a certain rate per annum. Those conditions are monitored using environmental and process data and log any events where these data deviate from the model's "business as usual" circumstances. At a given point in time, an alteration is made concerning the production fluids within the system, causing an increase in pipe temperature by 20 C. Because higher temperatures accelerate corrosion, this creates an event that must be accounted for and reviewed.

Modeling environmental and process data in this way improves accuracy and efficiency of inspection and intervention. By creating a data model based on the conditions and fluctuations that affect degradation rates and monitoring these conditions accordingly, operators can confidently improve investigative time to those components where conditions have changed.

Event-driven inspection is a method that is particularly relevant for scenarios where degradation mechanics and parameters are well understood and particularly beneficial for complex operations where the cost of traditional inspection methods add up quickly. If an operator can confidently monitor condition and only command inspections when absolutely necessary, substantial savings can often be made. However—particularly in older assets—the reality is sometimes a little less black and white.

There will always be risk-based integrity activity, as even the most accurate model will acknowledge bounds of error and predicted condition will begin to diverge from known condition over time at a rate based upon quality and availability of information. With event-driven inspection, asset managers will be concerned with curating/managing and validating their asset datasets.

One of the current outputs of IMRANDD's analytics software is that it identifies gaps in datasets in addition to predicting failures and identifying potential savings. These gaps can be viewed as blind spots. Identifying them is a good step in itself, which is moving from "unknown unknowns" to "known unknowns."

Gaining access to real-time data

Most operators have been collecting real-time data on asset operations for decades through sources such as sensors, production and chemical data, to name a few, but not actually using it in real time. However, recent advancements in data collection and analysis make this new Holy Grail of event-driven inspection possible.

All in all, it is fair to say there is room for improvement in what is currently one of the most common integrity management processes used in heavy industries.

First, the ability to use additional real-time datasets captured by different departments make predictive modeling more targeted and build up a better, more accurate and holistic view of an asset's condition.

Secondly, data no longer need to be manually curated before an onshore engineer attempts to try to interpret the detail. Instead, data are being screened, analyzed and validated continuously, providing the timeliest view of an asset's integrity and substantially reducing time to implement asset management decisions.

Finally, new software exists that can build complex models and analyze data separately helping to eradicate human bias entirely. Moreover, this approach does not require any hardware, simply an ability to think differently about the types of data from an asset that could be used to provide insights for the integrity management team.

Confidence in greater volumes

This last development is particularly important for event-driven inspection where the ability to handle large volumes of data seamlessly and sort errors from genuine data variations is a prerequisite for having confidence in recommendations. While many variations can be legitimately disregarded—be they from human error, a poorly calibrated kit or prevailing conditions—a handful will be legitimate indicators of failure. Operators need to be certain of which data can be excluded, which inconsistencies require further investigation and where gaps lie.

IMRANDD's forthcoming AIDA MAX will be one of the digital asset management solutions that can do just that, using machine learning to assist the build of its asset degradation models to power event-driven inspection. Built for engineers, by engineers, the new analytics software will bring critical, real-time or near-real-time insights to complement existing human checks and balances.

With this technology, data variations are separated out from the normal ranges to be analyzed with more scrutiny and eventually reincluded in models. Furthermore, given the volumes of data being handled, AIDA MAX will be able to identify and treat many data variations automatically without an engineer's intervention.

As example, where the data show pipe X's process conditions have changed, the model is then updated with this new information, changing the degradation model that now indicates a likely failure prior to the next planned intervention. The plan is updated based on this new leading indicator, which in turn informs the integrity team to inspect the affected area sooner.

While using historic data to make quantitative assessments has been a staple method for asset integrity management for some time, the benefits of utilizing real-time data are undeniable, and the insights harnessed continue to improve rapidly in line with the industry's growing digital capabilities. Operators stand to gain a more holistic view of their plant's operations and condition as well as greater confidence in their asset integrity management. Ultimately, this will lead us to adopt event-driven integrity and inspection where continuously updated degradation models allow operators to precisely predict integrity and make stronger commercial decisions. +

Data analytics and cloud computing technologies

With increasing focus toward remote operations, strategic adoption of cloud computing technologies will allow oil and gas companies to scale their data management and drive higher efficiencies.

Cloud-native analytics software for reliable reservoir opportunity identification

Emerson has released SpeedWise Reservoir Opportunity, a fully automated, cloud-native reservoir analytics tool developed in collaboration with Quantum Reservoir Impact. The software is unique in how it applies advanced algorithms, data mining and workflow automation to cut the amount of work required to identify field development opportunities from months to weeks. The comprehensive technology helps oil and gas companies achieve greater return on investment by shortening decision-making cycles and delivering better risk management. It features automated geoengineering workflows for identifying and ranking recompletion, vertical sweet spots and horizontal wells. By analyzing historical field performance and benchmarking against analog assets, the flexible framework picks the optimal parameters for the identification process, tailored to address the unique geological and engineering challenges posed by each field. Using SpeedWise Reservoir Opportunity, reservoir teams can break down multidisciplinary silos to help mitigate missing and incomplete data for more confident development planning. The software provides a secure cloud-based environment, resulting in much more efficient teamwork, where reservoir teams can collaboratively visualize and analyze ranked opportunities. Once ranked, results can be accessed through an interactive visualization dashboard for collaborative analysis and validation.

Speedwise Reservoir Opportunity applies advanced algorithms, data mining and workflow automation to cut the amount of work required to identify field development opportunities from months to weeks. (Source: Emerson)

ESG measurement tool solves sustainability data problem

Data Gumbo has released GumboNet ESG, a sustainability measurement technology that ties a company's operational data to ESG standards reporting. The result is real-time verifiable environmental performance monitoring, setting a new bar for transparency to satisfy investors, regulators and other stakeholders' desire for faster and better environmental impact data. GumboNet ESG utilizes the Sustainability Accounting Standards Board (SASB) framework with a specific smart contract to create automated ESG reports. Monitoring ESG measurement consumes human capital, time and financial resources without the guarantee of accuracy or repeatability. GumboNet ESG allows companies to automate reporting with the promise of accurate measurements from the field, simplifying historically inaccurate self-reporting practices and supporting standardization in accordance with SASB standards.

New service for well optimization benchmark

Ambyint has released a new service that gives E&P companies clear visibility into the relative impacts of their well optimization strategies and practices. The service benchmarks companies against the rest of the industry providing metrics and operational road map recommendations to improve bottom-line results. The Ambyint Well Optimization Assessment service is a four- to six-week engagement with E&P operations teams that reviews operational performance focusing on artificial lift optimization, work prioritization, well reliability, workflows, data utilization, reporting and performance metrics. These data feed an assessment report containing baseline data analysis supported with interviews, workflow value maps and a data systems framework to provide customers with essential insights that inform operational and digitalization strategies.

New user experience provides faster access to real-time information

Datagration's PetroVisor Knowledge Automation platform for oil and gas companies now has a new, intuitive user experience. The modern web interface provides users with easier and faster access to the critical real-time information they need to make better business decisions whether they are operating in the cloud, on-premise or utilizing hybrid environments. The new user experience is a natural addition to PetroVisor platform, which solves the "too much data, too little time" problem that plagues oil and gas operators. It delivers automated engineering workflows in real time to improve engineering and investment decisions, such as operational and capital efficiency. With this enhanced user experience, users can access more information faster without in-depth training and enjoy the benefits of a seamless experience. Some other new features and improvements include advanced 3D mapping.

These features make PetroVisor a comprehensive, collaborative environment for aggregating and analyzing data. With its user-defined workflows, users can connect people, systems and data with complete visibility to the end-to-end process—improving organizational and cross-domain workflows, automating technical and business processes, and mitigating risk—all on a unified platform.

National digitalization project to promote E&P potential

The Egyptian Ministry of Petroleum and Schlumberger have launched the Egypt Upstream Gateway, a project for the digitalization of subsurface information. This digital platform will also enable global access to the country's subsurface data, which is kept evergreen by enhancing legacy datasets through reprocessing and new studies. This digital initiative will be used to unlock the potential of Egypt's petroleum sector and promote the country's E&P potential worldwide. The Egypt Upstream Gateway provides digital access to more than 100 years' worth of accumulated national onshore and offshore seismic, non-seismic, well log, production and additional subsurface data under a single platform. These data, which empower de-risked decisions through the ability to explore multiple basins and evergreen data, can be accessed virtually from anywhere using the platform's online portal. In addition, the Egypt Upstream Gateway will host Egypt's upcoming bid round highlighting lease availability information to national and international investors worldwide.

Enhanced project management software provides intelligent solution

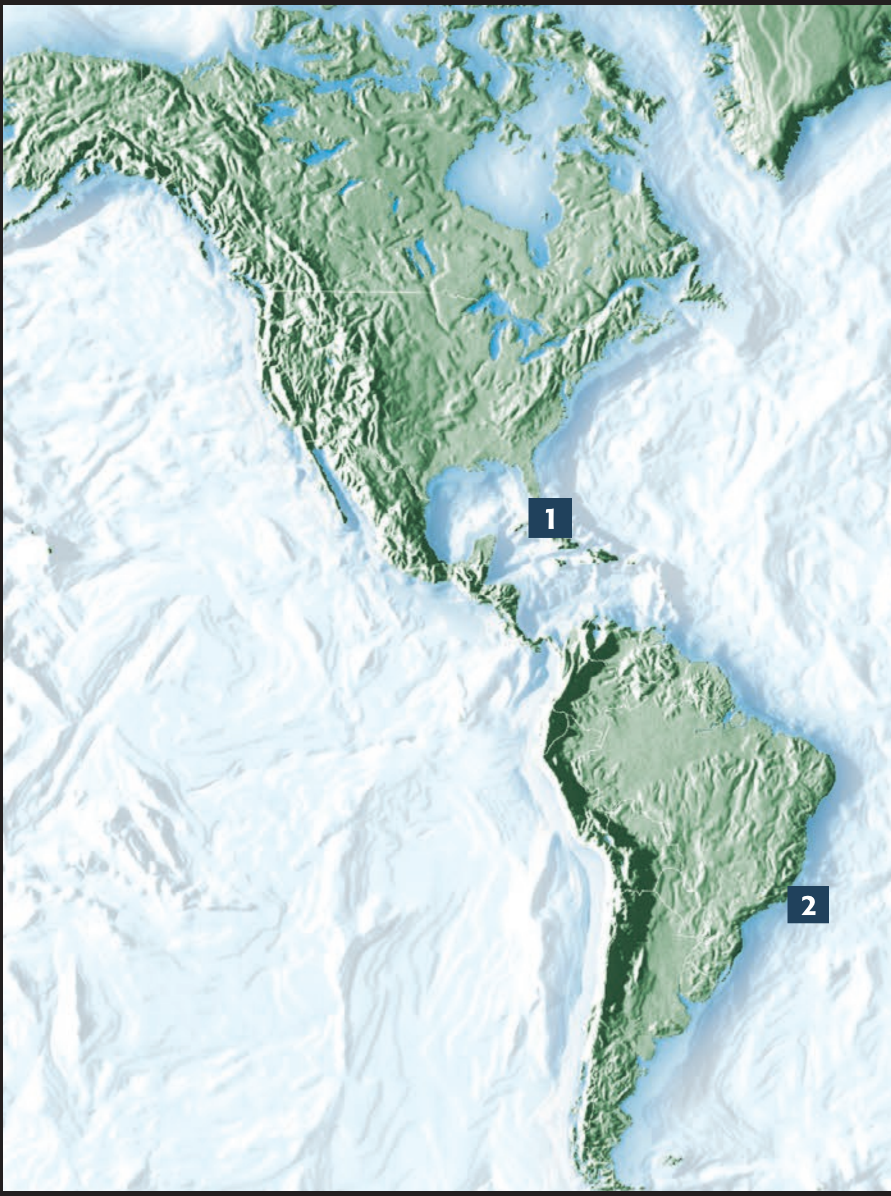
InEight Inc. announced enhancements to its planning, scheduling and risk offering to deliver an intelligent and multidimensional planning solution for capital projects. New InEight capabilities for total project risk management include Multiple Risk Mitigation Assignments and Tracking, which completes the cost schedule risk assessment and fills the gap between identifying threats and taking the right corrective measures by using artificial intelligence to intelligently recommend mitigation actions with the highest probability of success. In addition, Enhanced Risk Register allows better management of threats and opportunities with advanced categorization, tracking and analysis of risk across multiple projects and promotion of risk items previous to current projects. Moreover, InEight's Cost Risk integrates risk from two key pillars of project controls—cost and schedule—to provide total project risk analysis. If a schedule takes longer, it is likely to cost more. Breaking the silo between two critical aspects of a capital project can help reduce added costs.

Cloud-ready reservoir characterization technology to improve usability

CGG GeoSoftware has released new versions of its cloud-ready reservoir characterization and petrophysical interpretation software with enhancements that boost performance and improve usability. Jason Workbench 10.2 offers enhanced display options, upgraded QCs and monitoring, and more user-friendly interfaces. The Python machine learning ecosystem contains additional basic and advanced sample scripts and Jupyter notebooks, making it easier for clients to build their own workflows. Optimizing performance continues to be prioritized, particularly within its geostatistical reservoir characterization technology. The new features and functionality of HampsonRussell 10.6 include an interactive radon analyzer, an amplitude-versus-offset interpretation crossplot template and improved convenience in retrieving inversion models, greater parameter flexibility and a new inversion algorithm. PowerLog 10.2 for petrophysical interpretation offers improvements in handling Big Data, performance enhancements and data preparation automation for patching curves. A complete automated log editing workflow is available through a collection of modules, which includes Outlier Detection, Log Patching and Synthetic Curve Generation. As a critical part of PowerLog's workflow, Outlier Detection enables users to detect data spikes and anomalies and then replace bad data with patches or synthetic curves. The resulting high-quality curve data are essential in generating accurate interpretations, pore pressure predictions and for use in seismic inverse modeling.

Capabilities in the rock physics software also have been enriched with new rock physics models, regression, curve fitting and an enhanced interface. InsightEarth 3.6 now has new features, including the recently announced WellPath interactive well path planning technology. The WellPath QuickPlan workflow automates planning for large multiwell pads or platforms and builds all well plans simultaneously. ✚

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



1 Bahamas

Bahamas Petroleum encountered hydrocarbons at #1-Perseverance in the Cooper Block offshore the Bahamas. The well was drilled to approximately 3,900 m. It will be permanently plugged and abandoned. The exploration well had a planned depth of 4,800 m and was testing multiple potential reservoir horizons continuously through the Albian and Aptian aged formations, targeting P50 prospective oil resources of 770,000 bbl, with an upside of 1.44 Bbbl.

2 Brazil

Petrobras completed a Campos Basin hydrocarbon discovery in Block C-M-411. The #1-BRSA-1377-RJS (Urissane) was drilled in approximately 2,950 m of water, and it encountered oil in the presalt section of the reservoirs. Additional testing in the area is planned to assess the potential of the discovery.

3 UK

UK Oil & Gas has announced results from a report of the Loxley Portland gas discovery in PEDL234. The report indicates a a mean case, gross gas-in-place of 49 Bcf. According to the company, results further underline the estimate that the 48-sq-km Loxley geological structure contains significant gas volumes of about 4 Bcf to 5 Bcf per year on an energy equivalent basis. The company is planning to drill #1-Loxley in the second half of 2021.

4 UK

Eni has been awarded a new production license, P2511, in the U.K. sector of the North Sea. According to the company, P2511 encompasses approximately 340 sq km near the U.K./Norway maritime boundary. Area water depth ranges from 100 m to 130 m. The license includes blocks 9/23c, 9/24a, 9/27a, 9/28c and 9/29b for an initial exploration period of six years.

5 Norway

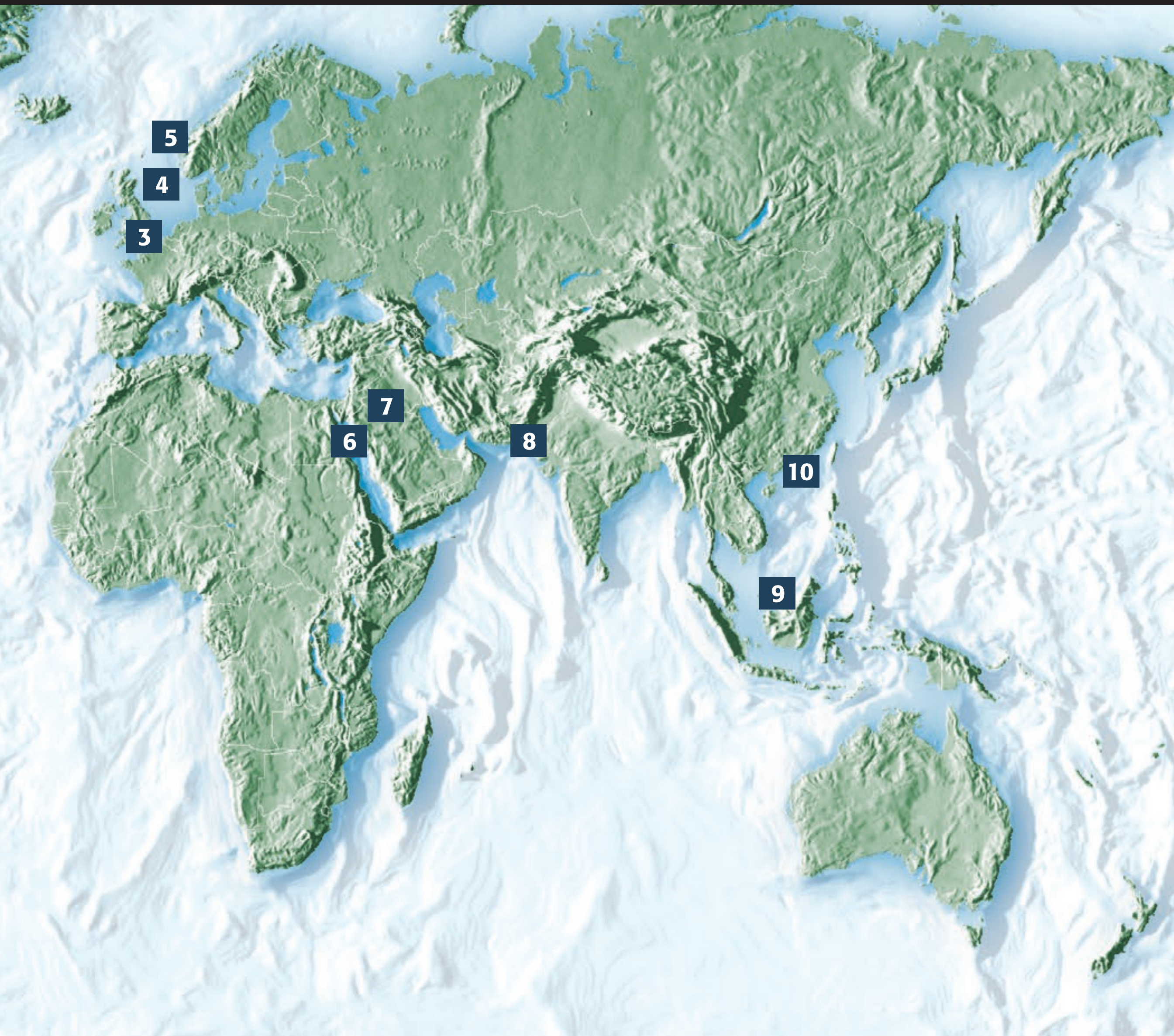
Equinor received a drilling permit from the Norwegian Petroleum Directorate for wildcat well #31/11-1 S in PL 785 S. The area in this license consists of parts of blocks 26/2 and 31/11, and it is south of Troll Field, which is one of the largest oil fields on the Norwegian Continental Shelf. This is the first exploration well to be drilled in the license.

6 Egypt

Ganoub El Wadi Petroleum Holding Co. (Ganope) plans to drill 11 exploration wells in the western portion of the Red Sea in Egyptian territorial waters. The exploration program in blocks 1 through 9 was recently approved by the Egyptian Minister of Petroleum and Mineral Resources. Seismic surveying is underway, and a second phase of surveying is planned from this year. Ganope anticipates an average total production of 27,600 bbl/d of oil.

7 Saudi Arabia

Saudi Aramco announced two new oil and gas fields in northern Saudi Arabia. According to the company, the new Abraq al-Toloul oil field in the Northern Borders Province flowed at a rate of 3,189 bbl/d of Arab light crude oil, with 3.5 MMcf/d of gas. Hadabat al Hajara gas field in the neighboring al-Jauf Province has a production rate of 16 MMcf/d of gas, along with 1,944 bbl of oil condensate, accord-



ing to country's energy minister. Aramco plans to estimate the total amount of oil and gas in the two fields, and it is drilling more wells to determine the boundary areas and capacities.

8 Pakistan

A gas condensate discovery was reported by Oil and Gas Development Co. at #1-Sial in Hyderabad District in Sindh Province, Pakistan. The well was drilled to 2,442 m. It initially flowed 1.146 MMcf of gas and 680 bbl of condensate per day from Lower Goru during testing on a 32/64-inch choke. The wellhead flowing pressure was 460 psi.

9 Malaysia

An offshore Malaysia gas discovery was announced by PTT Exploration and Production. An appraisal well, #2-Lang Lebah in the Sarawak SK 410B prospect, encountered a 600-m gas pay zone. Flow testing indicated it would produce 50 MMcf/d of gas. The well was drilled to a total depth of 4,320 m, and it is in the joint Malaysia-Indonesia venture area in the South China Sea off the island of Borneo. Additional testing is planned.

10 China

China National Offshore Oil Corp. announced a discovery in the Pearl River Mouth Basin in Huizhou Sag in Zhu1 Depression. According to the company, the discovery holds approximately 3.14 Bboe. The #1-HZ26 exploration well is in Huizou 26-6 Field. It was tested flowing about 2,020 bbl of oil and 15.36 MMcf of gas per day. The well was drilled in 370 ft of water to about 14,028 ft and hit approximately 1,385 ft of pay. It is one of the largest oil and gas fields discovered to date in the Pearl River Mouth Basin. +

—By Larry Prado, Activity Editor

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

PEOPLE


Granholm

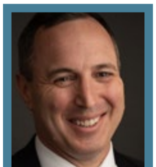
The U.S. Senate approved President Joe Biden's nominee, former Michigan Gov. **Jennifer Granholm**, to serve as secretary of the Department of Energy. Granholm will play a key role in implementing Biden's climate agenda.

Phillips 66 has named **Mark Lashier** president and CEO of Chevron Phillips Chemical Co.

ConocoPhillips has announced the retirement of **Matt Fox** as executive vice president and COO, effective May 1.

Superior Energy Services Inc. has announced the resignations of CEO **David Dunlap** and CFO **Westy Ballard**, who both resigned to pursue other opportunities. Superior plans to commence an executive search to identify a new CEO. **Michael Y. McGovern**, the chairman of the company's board of directors, has been appointed executive chairman and assumed the functions of the company's principal executive officer. **James Spexarth**, the company's chief accounting officer, will serve as interim CFO.

U.S. oil and gas producer California Resources Corp. has appointed interim CEO **Mark McFarland** head. McFarland, who has served on the company's board since its emergence from bankruptcy in October 2020, was appointed interim CEO in December, following the departure of **Todd Stevens**.

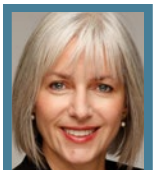

Warner

Crowley has promoted **Dan Warner** to CFO, consolidating Crowley Maritime Corp.'s enterprise-level financial strategy, resources and services under his leadership.

VAALCO Energy Inc. CFO **Elizabeth Prochnow** retired March 31. **Jason J. Doornik**, VAALCO's chief accounting officer and controller, will serve as principal financial officer until a new CFO is named.

Tidewater Inc., an owner and operator of offshore support vessels, has promoted **Sam R. Rubio** to executive vice president and CFO and **David E. Darling** to executive vice president and COO.

Total has appointed **Stéphane Michel** president of Gas, Renewables & Power and a Total executive committee member, a position previously held by **Philippe Sauquet**, who has exercised his retirement rights.


Kingham

Louise Kingham OBE will succeed **Peter Mather** as bp's U.K. head of country and senior vice president for Europe, effective in May. Mather, who has decided to leave the company at the end of the year, will continue in his nonexecutive role as chair of the bp Europe Supervisory Board.

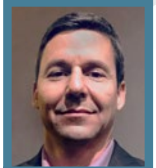

McBride

FourPhase, the solids and production performance specialist for the oil and gas sector, has appointed **Neil McBride** vice president of global business development as the company eyes further international expansion.

Percepto has appointed **Robert Mayfield** vice president of sales in North America.


Gonce

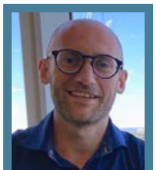
Danos has promoted **Justin Gonce** to general manager of onshore. In this role, Justin will lead the company's production services teams in the Eagle Ford, Marcellus and the Permian basins as well as the project services team in the Permian.


Webster

Twin Brothers Marine, a provider of heavy steel fabrication for the oil and gas, industrial, infrastructure and renewables industries, has named **Jason Webster** general manager.


Maússe

EnerMech has appointed **Celestino Maússe** to the newly created role of Mozambique country manager as the company seeks to expand its business as local activity ramps up.


Gray

Xodus Group has appointed **Alasdair Gray** head of late life and decommissioning in the Asia-Pacific following a significant increase of activity in the region.

Leonardo Machado has been named managing director of Maersk Training UK as the company looks to expand its offering to the North Sea energy sector.

The board of directors of Royal Dutch Shell Plc have named **Andrew Mackenzie** the new company chair with effect from the conclusion of Shell's 2021 Annual General Meeting, scheduled for May 18. Mackenzie will succeed **Chad Holliday** who will step down May 18 having served as chair for six years and as a board director since September 2010.

Exxon Mobil Corp. has appointed activist investor **Jeff Ubben** and former Comcast Corp. executive **Michael Angelakis** to its board.

Denbury Inc. has appointed **Cindy A. Yeilding** to its board of directors.

COMPANIES

Frank's International NV and **Expro Group** announced an agreement on March

11 to combine in an all-stock transaction expected to close in the third quarter. The combined company will assume the Expro Group name upon completion of the merger and be led by **Mike Jardon**, Expro's current CEO. The company will also retain the Frank's International brand name for its well construction solutions as part of the combination.

INEOS E&P AS, which is a part of **INEOS Energy**, has entered into an agreement to acquire the subsidiary **Hess Denmark ApS** for a total consideration of $150 million.

Percepto has announced a major strategic expansion in the North American market with new headquarters opening in Texas by the second quarter of 2021.

Pilot Water Solutions LLC (PWS) has acquired **Felix Water LLC**, complementing PWS' premier national water midstream footprint and creating one of the largest water midstream companies in the U.S.

Vysus Group, which was previously **Lloyd's Register**'s energy business, has acquired Norwegian-based software firm **Promaps Technology**, which has developed a software to ensure the security of energy supply and mitigates risk in power systems.

AqualisBraemar LOC ASA has entered into a definitive agreement for the acquisition of 100% of the share capital of **East Point Geo Ltd.** to strengthen its geoscience offering within the oil and gas industry.

Peloton has entered into an agreement to acquire **Cevian Technologies**, a cloud-based software company that specializes in real-time data acquisition, visualization and reporting tools for the completions industry.

IHS Markit's shareholders voted overwhelmingly to approve its merger with **S&P Global**. The merger is expected to close in the second half of 2021 depending on antitrust and regulatory approvals and satisfaction of other customary closing conditions. +

HARTENERGY APRIL 2021

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

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 Coordinators
CAROL NUNEZ
Tel: 713-260-6408
iosubmission@hartenergy.com

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

Rolling out a vaccine for oil and gas wells

Predictive modeling using digital technologies and data analytics will help reduce carbon emissions.

Mohamed Hegazi, TGT Diagnostics

If only we could inoculate subsurface wells against future integrity or flow issues it would be a dream come true. But there are many ways to proactively diagnose and keep them healthy and immune from unexpected "disease."

Never has health been more in the spotlight—the health of our communities and the health of our planet. The pandemic has elevated the world's focus on the environment and on driving down carbon emissions.

The energy sector has come under intense scrutiny as the world strives to tackle climate change. A major challenge is striking the balance between the continued need for fossil fuels, as part of a wider energy portfolio, while offsetting the associated carbon emissions.

Energy outlook

The *DNV 2020 Energy Transition Outlook* estimates that by 2050 oil and gas will account for 74% of the world's energy-related CO_2 emissions (Figure 1) and more than 80% emissions including CO_2 equivalents. Emissions from the entire oil and gas value chain is on course to fall one-third by 2050.

The oil and gas sector is not alone in its endeavor; many major world economies have set ambitious goals to reach net-zero emissions by 2050, some even sooner. It is no longer a solitary cause.

Proactive and predictive diagnostics

We are constantly reminded that it is important to visit the doctor for routine checkups to ward off potential issues and/or treat issues early. We all know that prevention is better than treatment. Staying healthy does not only apply to humans or businesses, but also to wells that produce, inject or store hydrocarbons.

The road to net zero has many paths, but keeping wells healthy through proactive monitoring, diagnosing and subsequent remedial work is not only a duty, it's good business. Furthermore, it would drastically reduce environmental fallouts as well as unplanned costs or reputational damage.

Well diagnostic companies, like TGT, can help. Application-led diagnostic products provide operators with the right information to act in advance and thus reduce potential emissions. A proactively diagnosed well has the best chance of staying healthy versus a well that is only diagnosed when problems start to appear.

Optimizing resources

But it's not only about catching leaks and holes, it is also about optimizing resources that can have a detrimental effect on the environment. An activity that has a huge potential for improvement is fluid injection into a well system to enhance reservoir pressure and hydrocarbon recovery. Thousands of barrels of

"Pursuing routine diagnostics of subsurface wells to detect potential issues before they escalate is common sense, but what's next?"

—Mohamed Hegazi, CEO, TGT Diagnostics

water are injected daily, but is the flow going where it should? On numerous occasions, TGT's diagnostics have revealed the actual path and volume of injected water is different to the expectation or the plan—and this is sometimes after years of operating. With these findings, operators can reduce the amount of wasted water, cut down on water transportation and treatment, and ultimately reduce their energy intensity and drive down their emissions.

Equally important are idle wells—wells that are either abandoned or neglected. Routinely diagnosing the integrity of these wells to provide assurance they are "quiet" is highly advisable. More often than not, there are signs of subsurface activity. These wells represent a potential emission source that may prove difficult to remedy if neglected further.

A focus in the pursuit of net zero is carbon capture and storage (CCS)—capturing CO_2 at the source, compressing it for transportation and then injecting it deep into a rock formation, where it is permanently stored. Routinely diagnosing the integrity of this storage facility to provide assurance that the plug is holding tight and that the CO_2 is not migrating to water reservoirs or the surface will become essential, if not a legal requirement.

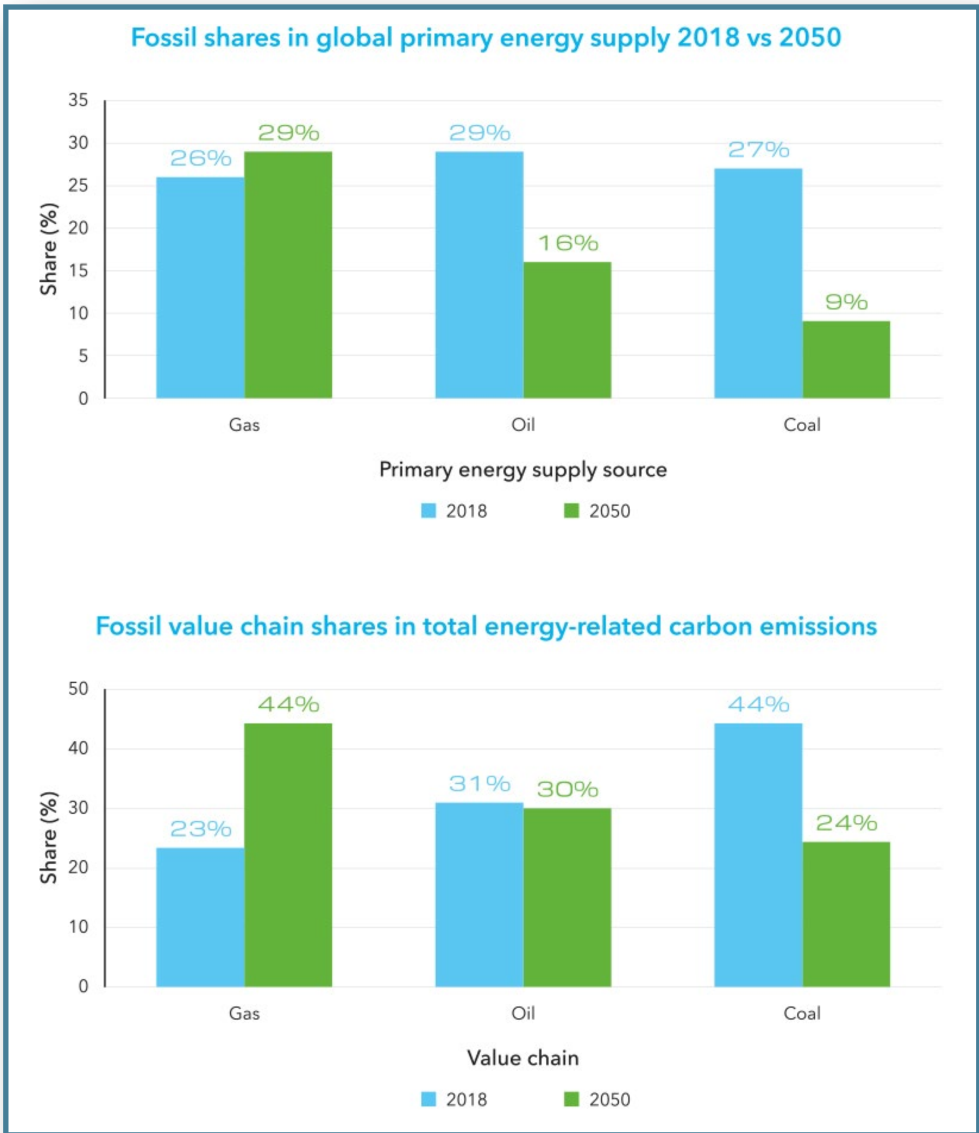


FIGURE 1. DNV GL predicts that oil and gas will still play key roles in the energy mix in 2050 when their value chains will account for most energy-related emissions. (Source: TGT)

Data are gold

Pursuing routine diagnostics of subsurface wells to detect potential issues before they escalate is common sense, but what's next?

Like many sectors, data are gold. With a wealth of diagnostic data at our fingertips, we can employ digital technologies and methodologies that predict when a diagnosis is needed or when a failure is imminent. With sufficient field or reservoir diagnostic data, we will be able to predict its behavior and failure modes with acceptable accuracy. Predictive modeling using digital technologies and data analytics will help reduce carbon emissions by boosting the energy efficiency of production.

It's good for the environment and for business to stay healthy. To do this, we need to have a bold and visionary mindset that encourages proactive well diagnostics and soon makes use of predictive diagnostics. ✚