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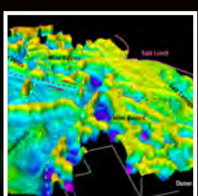
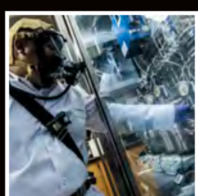
E+P plus

Digitalization

A guide to building a legacy

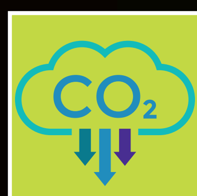


Marine Seismic



H_2S Management

Offshore Wind



Emissions Reduction

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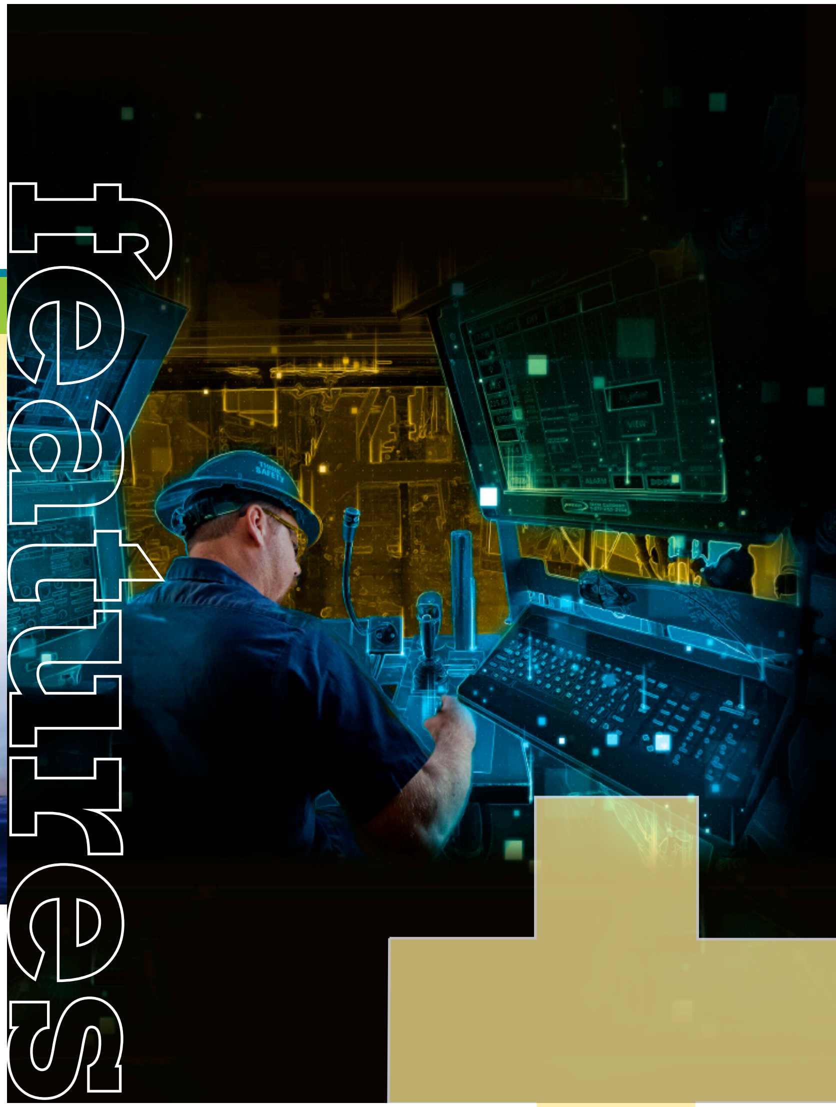
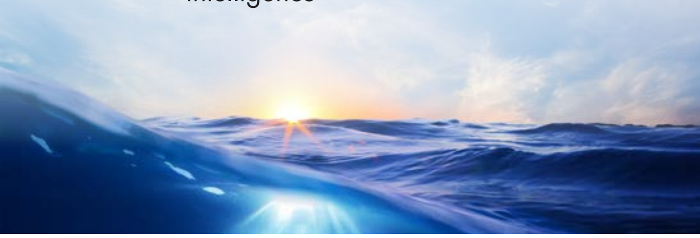
features



Cover Story: Digital Journey Guide

Exploration: Marine Seismic



Production Optimization

Production: Flow Control/Monitoring

Offshore Wind

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

About The Cover: In this month's cover story, industry leaders showcase how the integration of intelligent infrastructure can be a transformative business strategy for long-term success. Pictured, Devon employees use rich data visualizations to make wellsite decisions, improving operational efficiency. (Cover image courtesy of Devon Energy; Cover design by Alexa Sanders; Bottom images from left to right courtesy of PGS; ChampionX; and Shutterstock.com)

Coming Next Month: Starting June 1, E&P will publish via a newsletter every Tuesday, which allows us to share more content in a timelier manner rather than operating months ahead of schedule like we have done with a monthly publication.

Essentially, instead of distributing E&P in the format you see now in this final monthly issue, subscribers will receive a weekly HTML newsletter. Our readers have responded better and requested the HTML format. Simply put, we're doing this because you asked and we listened!

The content you receive in this new newsletter will be the same original content you receive now, only more of it. For additional details, read the column by Editorial Director Len Vermillion in this edition's **As I See It**.

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As I
See It

E&P's next chapter

Keeping up with the trends, a change in distribution is coming soon.

It was the height of the COVID-19 pandemic in summer 2020 when we announced E&P magazine would go fully digital and rebrand as E&P Plus. At the time, receiving printed magazines at your offices was rather difficult given that many of you, like us, had set up shop in home offices. To better serve our readers, we created a new digital version of E&P that could be delivered directly to your email. In addition, the move let us add multimedia content in the form of videos, infographics and more.

It was an innovation for our long-standing print publication brought about by the COVID-19 pandemic coupled with a historic oil price crash. But while COVID-19 seems to have turned a corner in the U.S., many of the solutions brought about to deal with it are becoming permanent. That includes remote work habits and the digital preferences of our readers.

The name of this column is "As I See It" but it may as well be called "As *You* See It." You've seen E&P in a digital format. You've seen it delivered directly to your email. You've seen its interoperability with HartEnergy.com and our video center. You told us you want us to keep it that way.

For the past nine months, we've teamed with a vendor to produce a new type of E&P as an experiment. But we want to give you even more. So we are simplifying the delivery to direct E&P readers to HartEnergy.com, where we will house the content in a branded E&P section for easy-to-find content. And we'll be delivering more of the same great content you've come to know from our same cadre of editors and writers and, of course, extensive contributions from the industry.

Beginning in June, we will cease publishing this experimental version of E&P Plus you are reading now and replace it with a weekly HTML newsletter under the original E&P brand. The content you receive in this new newsletter will be the same original content you receive now, only more of it.

Avid readers of E&P have watched this publication go through an evolution since its first issue in the late 1990s. Like the technology developers of the oil and gas industry, we're not afraid to push the envelope and make things better and more efficient as time goes on.

E&P isn't going anywhere, except directly to your inbox. We look forward to continuing to serve the industry and, as always, I welcome your feedback on our latest endeavor. +

Len Vermillion

Len Vermillion
Editorial Director
lvermillion@hartenergy.com

The name of this column is "As I See It" but it may as well be called "As *You* See It."

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(Source: Frank's International)

Frank's International on safety and digitalization

President & CEO Michael Kearney discusses its upcoming Expro combination, automated solutions and the industry's long-term focus.

Ariana Hurtado, Senior Managing Editor, Publications

Founded in 1938, Frank's International has been around to see more than a few industry cycles.

The global oil services company provides a broad and comprehensive range of tubular running services, tubular fabrication, and specialty well construction and well intervention solutions with a focus on complex and technically demanding wells.

Oklahoman Frank Mosing originally founded Frank's Casing Crew in Lafayette, La. "His dedication built this local tubular running services startup into a publicly traded international company providing specialty cementing technologies, downhole service tools, drilling technologies, hammer and slot recovery services, and large OD tubulars and connectors around the globe," Frank's International President & CEO Michael Kearney said.

In March, Frank's International and Expro Group, a privately held international energy services company, announced the companies' intent to combine in an all-stock transaction expected to close in the quarter ending Sept. 30, according to a company news release. Upon closing, the combined company will assume the Expro Group name and will retain the Frank's brand name for its well construction solutions.

"We are in the process of combining with Expro Group to better serve our customers with a broader offering and technological capabilities across the well life cycle, with the greater scale and financial strength to support our long-term success," Kearney said.

In an exclusive interview with E&P Plus, Kearney dives deeper into this recently announced combination, overcoming industry and pandemic-related challenges, and its current R&D projects.

"Digitization, automation and intelligent machine learning are all core to the future of our industry."–

– Michael Kearney, Frank's International

E&P Plus: Based on the recent announcement of the combination with Expro Group, how does that affect the path forward for the combined organization?

Kearney: Our anticipated combination with Expro Group will only bolster our plans. This transaction will create a more resilient company with even more financial strength and the ability to capture more opportunities in a cyclical market. While Expro provides well access, well flow optimization and well intervention services, Frank's offers tubular running services, tubular fabrication, cementing equipment, drilling tools and specialty well construction solutions. This means our companies' service offerings are largely complementary, so we can offer a full suite of solutions across the well life cycle.

We will also have exposure to global offshore and onshore markets, plus a healthy balance between customers' capital and operational spending. If you underpin all of this with a very strong balance sheet and enhanced liquidity position, it adds up to resiliency, service quality and innovation. This is what excites me about this proposed transaction.

E&P Plus: How has Frank's International been able to optimize its business during these challenging times?

Kearney: Frank's International operates in approximately 40 countries on six continents and provides diversified products and services across both onshore and offshore markets. This broad offering and wide footprint allow us to meet our customers' complex needs across the globe. In the wake of COVID-19 and other economic impacts, our customers have turned to our unique digital, automated and integrated solutions that directly address the new safety and efficiency challenges our customers are facing. As we have further diversified our assets and revenue, we have maintained a strong balance sheet, which has served us well during the pandemic.

E&P Plus: What is the No. 1 challenge your clients are facing in the field right now?

Kearney: Our priority has been to support our customers' safety, and that is even more paramount in these challenging times. This is followed closely by the need to increase efficiencies at the rig site to save on rig and other operational costs. Our digital, automated and intelligent solutions address these concerns. Reducing the number of personnel on board (POB), especially in the red zone, reduces inherent risks and costs not only at the rig site but also on road, helicopter, plane and marine travel. It also reduces the equipment footprint on the rig and maintenance downtime. For example, our CENTRI-FI technology consolidates the controls for our tubular running equipment into one single, remotely operated digital tablet, which allows for increased efficiency and safety for our personnel.

E&P Plus: Does the company have any R&D projects in the works right now? Will you be releasing any new technologies to the market this year?

Kearney: R&D is at the core of Frank's capabilities, from digitizing our connection make-up solutions to our automated casing equipment and intelligent software applications. Our technology continues to enhance safety and efficiency for our customers. In fact, enhancing technology is a core component of our proposed combination with Expro Group. Once combined, our R&D function will be further strengthened and will allow us to participate more in energy transition and contribute to a lower carbon future. We have proven to be leaders in technological development and expect to announce new technologies as they become available.

E&P Plus: As a leader yourself in the oil and gas industry, what do you see as the path forward from here?

Kearney: The industry is extremely resilient and creative, solving some extremely difficult challenges to provide affordable energy to the world. Digitization, automation and intelligent machine learning are all core to the future of our industry. That has been and will continue to be our focus for the long-term and is key to unlocking additional safety and efficiency gains. In this current environment, we know that our strong balance sheet, coupled with our culture of innovation, will enable us to continue to invest in our people, operations and technology. +

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Devon employees use rich data visualizations to make wellsite decisions, improving operational efficiency. (Source: Devon Energy)

Digitalization:

A Guide to Building a Legacy

Industry leaders showcase how the integration of intelligent infrastructure can be a transformative business strategy for long-term success.

***Mary Holcomb**, Associate Editor*

The oil and gas industry has reached another tipping point, and staying innovative has become imperative to building resiliency. The challenges brought on by the pandemic have taught industry leaders that even the smallest digital steps can be transformative.

While consistency has never been a term synonymous with the oil and gas industry due to fluctuating prices, some leaders have mastered coexisting with unpredictability. Some have not. And an elite group of others have uncovered the golden nugget to surviving through it all: digital innovation.

Industry heavyweights Chevron Corp. and Devon Energy Corp. and newcomer Hibernia Resources III LLC have accelerated their organizations by prioritizing a strong digital strategy. By investing in advanced analytical functionalities to produce new insights and optimize operations, these upstream players have established valuable roadmaps for digitizing at any scale.

Chevron: 'Technology is in our DNA'

The energy sector has become increasingly focused on digitizing, and looking at Big Oil's digital transformation can provide a helpful blueprint for smaller operators.

Industry leader Chevron Corp. has powered a 141-year legacy in oil and gas by betting on digital in its infancy, exploring emerging technologies to unlock value across its oilfield assets.

"Technology is in our DNA, which is the genesis for where we are today on our digital journey," said Frank Cassulo, Chevron's chief digital officer. "In the early 2000s, we started thinking about tools and applications that could help digitize the oil field to unlock value. From that point in time, we've matured significantly to the point that today we're moving into a cloud environment."

In 2018 the global energy provider received a push from CEO Michael Wirth to apply digital solutions at scale to improve the velocity of how it delivers business outcomes. That executive-level mindset shift has transformed Chevron into a sophisticated enterprise of smart machinery, cloud-based solutions and digital analytics.

"We believe capitalizing on new and emerging technologies is a differentiator," Cassulo said. "In today's environment, digital is accelerating at a rapid rate, and we see that technologies such as computing, cloud sensors and other algorithms are really growing and expanding in our business in a way that we can harness data in a manner to help drive improved business insights."

By 2020 Chevron reshaped its entire digital footprint to strengthen its commitment to deliver higher returns and lower carbon.

"We're actively working on upscaling our organization and building fluency and digital capabilities within the workforce at all layers of our organization from leadership through frontline workers," Cassulo said.

Power of collaboration

One venture that has been transformative to the business has been strategic partnerships within the technology sector, according to Cassulo.

In 2017 Chevron inked a seven-year partnership with Microsoft Corp. to build its knowledge of cloud technology via the Azure platform. The deal established Microsoft as the company's primary cloud provider, accelerating the application of advanced technologies—like the Internet of Things—to drive performance and improve efficiencies.

"With the partnership, we'll not only leverage the cloud but also cloud computing, data analytics and other capabilities that they offer on their Azure platform," he said.

Recently, Chevron combined forces with Microsoft and Schlumberger to develop a groundbreaking carbon negative bioenergy in Mendota, Calif. The plant will covert agricultural waste biomass into a renewable synthesis gas that is expected to remove about 300,000 tons of CO_2 annually.

"We view partnerships as enablers," Cassulo said. "For example, bringing together Microsoft and Schlumberger has the ability to unlock potential that none of the companies could do alone. So uniting three companies with incredible talents and capabilities really solves some of the most complex problems in our industry."

Utilizing technology as a differentiator has helped Chevron keep a competitive edge across all its assets, especially in the Permian Basin. The ingenuity of the organization's workforce—paired with advancements in horizontal drilling and

TCO utilizes data analytics and automated performance monitoring to improve returns. (Source: Chevron Corp.)

hydraulic fracturing—has increased its shale and tight oil production.

"One of our largest development opportunities has been in the Permian Basin," he said. "So we view technology and digital as a way to continue improving our ability to compete in the Permian. We've used tools to automate workflows. We've improved well performance, and we've even got into data insights that help us with capital allocation and our prioritization process, positioning us as a leader in the shale and tight oil community."

According to Cassulo, the company has leveraged technology like artificial intelligence (AI) and machine learning to reduce the uncertainty of its subsurface characterization of reserves classifications in the Permian.

"Our opportunity lies in applying it and continuing to innovate at the edge," he added. "I think AI and machine learning have been helpful in terms of the massive amounts of data that we capture each and every day in our business and being able to use that data to drive and inform better decisions at speed."

Additionally, Chevron has integrated geofencing within its Tengiz oilfield operations and implemented digital initiatives to train its workforce at its offshore environments like the Gulf of Mexico.

"A category of digital that I think is really interesting involves putting in safeguards to protect our employees and improve the safety of our operations," Cassulo noted.

While the focus has been improving its technical side, the company has adopted functions to upgrade its internal systems like moving its HR platforms to a cloud-based system.

"A lot of our procurement systems are cloud-based," he said. "Some of the basic fundamental business aspects have been transformed by just simply having access to large scale cloud environments, so digital is really permeating all of our business."

Strategy for success

To experience similar success, Cassulo advises operators newly on their digital journey to focus on scaling up and building the capabilities to solve problems at speed.

"We're in the middle of a transformation where we're thinking about the cross-collaboration of our business units across and focusing on the enterprise value first versus discrete business segment value," he said. "That's the power behind it…getting to unlock the true potential of a company is through collaboration and then applying technology and digital solutions at scale."

Chevron's delivery model has been to deliver at a velocity—combined with an agile mindset—that has never been done at this scale before, he noted.

"There's a cultural component to it, and then organizationally there's setting up the right structure to help deliver that," Cassulo said. "The bottom line, and the way I view digital today, is that it's integrated into just about everything we do. Digital doesn't stand alone. It's an integrated way of delivering solutions across our business."

The supermajor plans to double down on digital acceleration efforts with the intention of providing cleaner, more reliable and affordable energy.

"We see digital as really unlocking the full potential of our company," Cassulo concluded.

Field employees use streaming data delivered to their mobile device, making their jobs more efficient. (Source: Adobe Stock/ Devon Energy)

Devon Energy: 'More technically sophisticated'

Devon Energy Corp. has maintained an active role in leveraging new technologies to accelerate its business operations.

The shale producer was an early adopter of Big Data architecture like real-time streaming, software solutions and deep learning infrastructure, which have all helped solidify the operator's competitive edge in today's upstream field.

Following the acquisition of several companies in 2010 and its transition from an international operator to focusing purely on U.S. land operations, Devon's digital journey became a bigger priority, according to Trey Lowe, Devon's vice president of technology.

"We had a cultural alignment many years ago," Lowe said. "One of the very first foundational things that we had to do was to collect data the same way across the entire company whether someone was in the field in South Texas, in the Delaware Basin or western Oklahoma. We gained alignment early in the journey, which allowed us to start building more advanced and impactful tools on top of our collected data over the last several years."

Good data

The first undertaking was a companywide data cleanup and governance initiative, and during that period Devon began preparing all its data in centralized data warehouses. This effort ensured that its experts and decision makers were provided high-quality, reliable data.

Soon after, the company implemented decision support centers (DSCs) in core producing areas for its operations. The DSCs stream real-time data from producing wells back to field teams that then utilize the information to optimize performance and lower operating costs.

"Throughout that time, we were becoming more technically sophisticated," Lowe said. "We saw this as the next step to differentiate ourselves from our peers and take our technical knowhow and excellent set of engineers and scientists and provide them with the toolkit to make decisions faster. We had some very forward-thinking leaders, and they helped guide the ship and get us started down that path."

Initially, the premise of the DSCs was to promote wellsite productivity and reduce downtime. Over time, Lowe said the organization realized it could make better decisions across the entire enterprise if it had good data and provided a transparent and accessible avenue to the data for its engineers and geoscientists.

All of Devon's assets are now highly instrumented and automated, resulting in more than 90% of information being digital, according to Lowe.

"We continue to execute on that plan and it's guided our migration and helped us identify and prioritize our efforts the last several years," he said.

Real-time analytics

Devon has seen the biggest benefit from analyzing real-time data on the production side, Lowe said. Similar to the DSCs, a well construction center (WellCon) was developed to optimize drilling and completions operations on Devon's wells.

WellCon applied analytics to real-time drilling control and geosteering as well as completion and flowback operations. With this technology, engineers and geologists improved out-of-zone footage and sidetracks, and it optimized hydraulic fracturing operations.

Lowe said advanced analytics

and remote monitoring have also boosted asset performance, improved decision-making, lowered costs and optimized efficiencies across the organization.

From its producing fields, Lowe said well downtime improved by up to 50% and flaring emissions reduced by nearly 60%.

"In the drilling organization, we continue to break records almost every month on costs per foot and the footage per day with successes across all of our drilling rigs," he said. "On the fracturing side, we are now at such an efficiency level that we have pumping operations running more than 21 out of the 24 hours in a day, which is a major improvement of over 100% from four to five years ago when we started down this path."

With these insights, Devon developed its Sealed Wellbore Pressure Monitoring technology (SWPM), a fracture diagnostic tool designed to help E&P companies maximize cluster efficiency. Essentially, the software monitors fracture growth and the fluid volumes between treated wells by tracking the pressure response in nonperforated wellbores.

"We had new inventions that came from that data. Specifically our Sealed Wellbore Pressure Monitoring was a direct result of one of the real-time data initiatives combined with our innovative culture," he said.

Learning new capabilities

"Today we're deep into image analytics and computer vision," Lowe said.

Cognitive analytics using AI, machine learning and deep learning is an area of opportunity that Devon is actively exploring.

"We are trying to understand how we can push models to the edge," he said. "For example, advancing our drilling rigs and fracturing operations so that they can either interface directly with the equipment on location or provide deeper insights to the people making decisions."

Lowe said making subsurface data available, uniform and accessible across the company has been a recent challenge, particularly with its geoscience and reservoir engineering data. Devon is working on deriving further insights from its seismic and other subsurface data by leveraging AI and combining it with operational data.

"Both of those are fertile grounds for further development," he added.

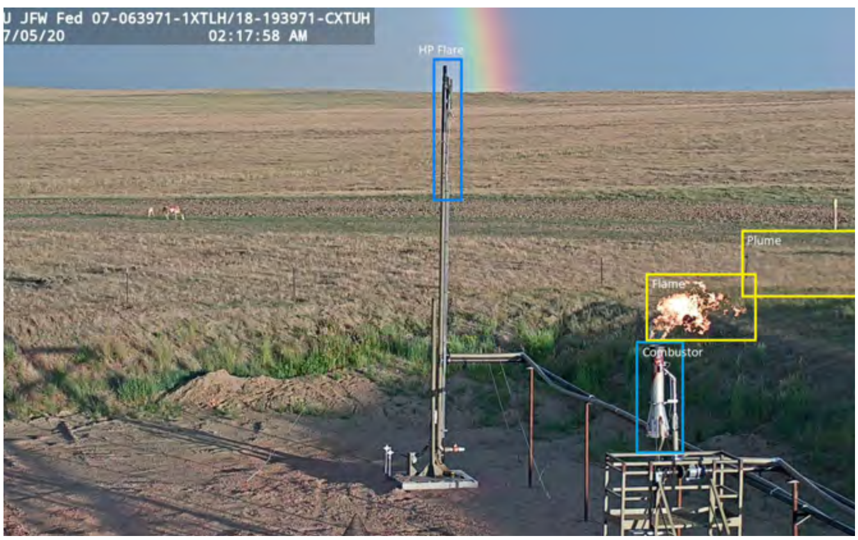
In January 2021, Devon closed its merger of equals with WPX Energy and became a top U.S. unconventional company operating in five basins with premier acreage including more than 400,000 net acres in the Delaware Basin. Now going through a large-scale integration, Devon has inherited WPX's portfolio of legacy solutions, including digital transformation initiatives the company had pursued prior to the merger.

"WPX had an innovation team, and we're working on some pretty innovative products across the company that are going to be incorporated very nicely into the things that legacy Devon developed," Lowe said. "A great example is in real-time fracturing data, where Devon had done a lot of work developing algorithms and visuals with the data in-house, and WPX spent a lot of effort and time trying to understand the architecture of how you run analytics at the well site."

Lowe added, "Those two are so complementary that it's been great getting our teams together and taking the learnings from both companies. It's going to be a win that we can accelerate with pushing the models that we've created in-house back to the well site. We're all really excited about that."

Moving forward, Devon plans to continue its digitization journey by sticking to its system of prioritizing innovative ideas and being deliberate in scoping out tangible benefits, Lowe said.

"We're going to continue building things for our field operations so we can make faster decisions based on data," he said. "We're going to be nimble and agile on what we approach and what we tackle next, and we're definitely really interested in applying digital technologies into improving ESG initiatives across the company, so that's going to continue to be a focus for us and our future."



Wellsite video is analyzed in real time using AI, converting images to actionable data. (Source: Devon Energy)

Hibernia Resources: 'Major gains for us'

In the early innings of automation, Houston-based E&P Hibernia Resources LLC's selective vetting of digital enhancements has helped the company capture impressive results across its well sites.

"You have to be really intentional in the types of technology you take on," said James Gray, Hibernia's vice president of reservoir engineering. "It can't be technology just for the sake of technology. At times we're acquiring more data than we have the manpower to process so we ought to be deliberate about the value of information we're obtaining and ensure it is actionable."

Hibernia Resources' frac stack is shown on its three-well Hartgrove pad in western Reagan County, Texas. (Source: Hibernia Resources)

Fracture optimization

In 2019 the Permian-focused producer entered an agreement to trial Cold Bore Technology's SmartPAD completions optimization system. Using a combination of sensors and proprietary state detection algorithms, the technology tracks operations directly at the wellhead and connects all onsite service companies to a trusted source of formatted and timestamped operational data.

"We found Cold Bore better captured the parallel inter-related activities associated with multiwell frac ops," Gray said. "It also does a better job categorizing downtime and productive time by the minutes and seconds than the standard well reporting platforms we traditionally relied on."

By November 2020, the producer digitized 100% of its completion operations on its well pads thanks to the early success of the trial.

Across Hibernia's six pads, the company replicated double digit percentage reductions in non-pumping time across multiple sequential pads, reduced non-pumping time from an average of 8.91 hours per day to 4.19 hours per day, reduced its 2020 campaign by 15 days saving over $300,000 in fixed costs and maintained 100% onsite safety.

"Cold Bore came in with their sensors and a dedicated hands-on location that consistently categorized each activity in a useful and detailed way," Gray said. "We were able to look at any specific part of our operations and see how we've performed, how long it has taken us to execute that particular stage or step of the operation through time, and see where we've progressed."

Since multiwell pad fracs can be a month or longer, being able to shave off any time on frac jobs can make a world's difference for any company, according to Gray.

"With where we are on our journey as we scale up, and as we go to more wells per pad and longer lateral lengths, those little efficiency gains will save even more days on those operations," he added.

Drawing off that success, Hibernia plans to trial simul-frac this year, which is a two-well stimulation technique gaining popularity across horizontal wells in U.S. shale. The trend has awarded some producers slashed completion times.

In January 2021, Rystad Energy reported that the approach represented 8% of all well completions in the U.S. onshore sector during fourth-quarter 2020.

Hibernia's first simul-frac commenced in April. Gray said if the expected efficiencies are realized, the company will consider employing it on 70% of this year's program and 90% to 100% of their 2022 program.

A workover rig drills out frac plugs on Hibernia Resources' six-well UL Boss Hogg pad in central Upton County, Texas. (Source: Hibernia Resources)

"That could be a big step change for us," he said. "Going forward we're planning six additional well pads and more 3-mile laterals, so efficiency gains that before would've shaved hours and days could now shave days and weeks on our most ambitious projects. Major reductions in time from first spend to first production is the objective, and digitizing the completion data will become even more important as the rate of execution increases."

Prioritizing data

The next big task on Hibernia's digital journey involves improving its data management process.

Currently, Hibernia utilizes SCADA sensors and equipment on its wells and batteries to collect its data. However, the company is moving away from spreadsheets and working on getting its streams of data into a central location.

"We've got companies that acquire the data for us on their own individual platforms that we can view our data on, which is very handy," Gray said. "But aggregating that data into our own production accounting software and then into a central database that the rest of the organization can leverage is huge."

With the data in a consistent format, he said various applications and workers of different disciplines could leverage the data faster, helping speed up the workflows and prevent Hibernia "from spinning our wheels."

Additionally, the company sophisticated its internal business operations with the implementation of Microsoft's business analytics service Power BI. The software collects unrelated sources of data into coherent, interactive visualizations and business intelligence capabilities.

Gray said the unified data allows the organization to do production reports and accounting surveillance, which is "a core part of our business."

A workover rig drills out frac plugs on Hibernia Resources' six-well UL Boss Hogg pad in central Upton County, Texas. (Source: Hibernia Resources)

Cold Bore's SmartPAD technology provides a full analytics overview of key performance indicators. (Source: Cold Bore Technology)

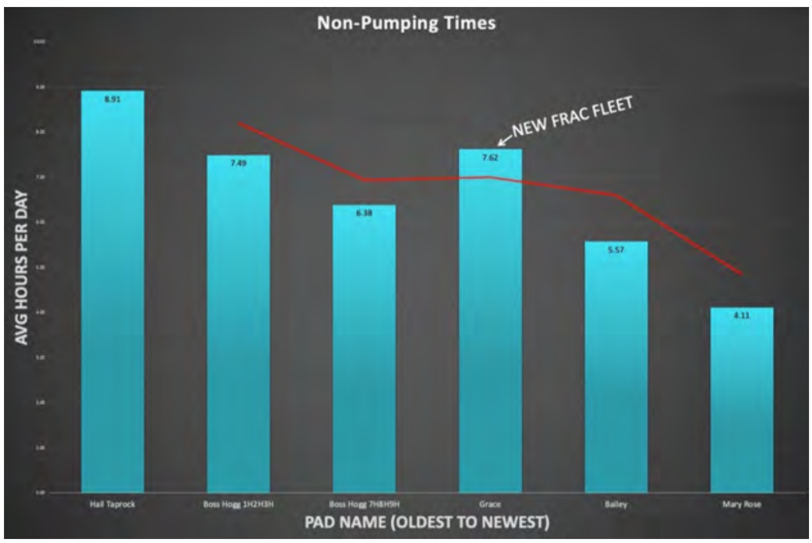
Staying relentless

Gray noted that while on its digital path, Hibernia has learned the value of incorporating technologies that larger operators either ignore or are fortunate enough to have a team to focus purely on that issue.

"As a growing company, some of the established processes that the large companies probably take for granted can be major gains for us," he said. "When we're able to implement improved accounting surveillance or standard operating procedures in the field, that's the kind of stuff

Cold Bore President & CEO Brett Chell coordinates with an engineer at a Permian field site. (Source: Cold Bore Technology)

Currently, Hibernia utilizes SCADA sensors and equipment on its wells and batteries to collect its data. However, the company is moving away from spreadsheets and working on getting its streams of data into a central location.



Hibernia cut non-pumping time by more than 50% on pads during 2020. (Source: Business Wire)

that can pay dividends for growing companies like Hibernia."

Hibernia intends to keep an optimistic approach to new technologies, and Gray anticipates continued success by remaining dedicated to one of the organization's core philosophies: it's not technology for the sake of technology.

"Emerging companies shouldn't explore technology just because it's cutting edge," he said. "They should relentlessly pursue technology that offers a clear path to help you do your job better, faster or safer. It's an approach that benefits all stakeholders." +

(Source: Shutterstock.com)

Derisking presalt prospectivity in the deepwater Campos Basin

Improved velocity model accuracy affords improved image quality, illumination and depth accuracy of the subsurface structures found within the presalt play.

Hermann Lebit, John Cramer, Jeffrey Tilton,
Yermek Balabekov *and* ***Joao Victor Lima****, PGS*

The outer Campos Basin remains an underexplored domain of the prolific Brazilian hydrocarbon provinces exemplified by super-giant discoveries in the adjacent Santos Basin and in the inner segment of the Campos Basin.

The growing interest in extending the various proven petroleum systems and associated play types into the external Campos Basin is consequentially being answered by PGS with an ongoing non-exclusive program of high-quality GeoStreamer 3D multisensor seismic acquisition, including the recording of gravity and magnetic data. This multiyear program will aid industry evaluation of newly offered acreage, extending the exploration opportunities of the deepwater Campos Basin.

Exploration potential of the post-salt and the prolific presalt section will be presented here in light of the imaging results and the forthcoming Brazil bid round.

New seismic data for Campos Basin exploration

PGS recently completed the acquisition of 15 600 sq km of multisensor 3D seismic data over the deepwater section of the outer Campos Basin offshore Brazil. New data are combined with existing 3D seismic data using multi-azimuth processing to enable optimal imaging particularly of the presalt architecture in this prolific hydrocarbon basin. The program is in line with the forthcoming licensing rounds (Concession Round 17 and 7th Sharing Round), aligns with the demand for optimized seismic imaging of the presalt reservoirs and illuminates the underlying petroleum systems.

In addition, it provides the industry with reliable seismic imaging for appropriate exploration risk mitigation and potential drilling hazard assessment in this emerging deepwater basin.

Campos Basin subsurface setting

The survey covers the entire outer passive margin section of the Campos Basin including large parts of the outboard allochthonous salt edge (Figure 1). Based on the character of the salt architecture and associated structural settings, four major domains have been established. Gravity-driven, thin-skinned tectonics along the basin's subsiding passive margin, caused prolonged salt movements, which contributed to the formation of these salt structural domains (Figure 1).

An inboard area called the Salt Roller domain refers to the updip zone of post-rift extension that affected the Aptian evaporites and overlying Albian carbonates.

Extension is evident by a network of listric normal faults rooting into the regional decollement along the base of the evaporites. The domain name refers to the predominant salt concentration in triangular-shaped bodies at the footwall of the extensional faults.

The most prolific and giant oil and gas fields of the Campos Basin (e.g., Roncador, Marlim, Jubarte, etc.) reside in the Upper Cretaceous clastic sequences above this salt domain, which might be sourced, at least partially, from presalt hydrocarbon kitchens. Amplitude analysis within the program area revealed similar evidence for hydrocarbon reservoir potential within the postsalt sequence. It further includes promising presalt discoveries near the inner high of the rift system. These are characterized by well-imaged, sag-phase, layered, depositional signatures on-lapping onto tilted fault blocks related to the Lower Cretaceous rifting stages of the margin.

The sag-phase basins contain the rich Barremian source rock sequences while the structural highs are critical for the deposition of the prolific presalt reservoirs, comprising high porosity shallow-water carbonate buildups. The latter are predominantly formed of high energy marine to lacustrine Coquina facies limestones, stromatolitic mounds and sometimes travertine. The drilled sag-phase signature extends beyond the inner high and an adjustment regional ramp, which drops the base of the evaporate sequence over a series of rift-related normal faults (Figure 1).

h structural highs next to stratified sag-basin fills, continues underneath the subsequent two outer salt domains and opens additional exploration running room, where the newly acquired 3D seismic dataset will support exploration and drilling risk mitigation.

Presalt objectives under the Albian Folds and Salt Mini Basins

The Albian Folds domain (Figure 1) is characterized by an intense corrugation at the top of the Aptian evaporite sequence and affects the Albian carbonates. The fold structures quickly dampen against intra-formational unconformities within the Albian carbonate sequence and are caused by early shortening instabilities that appear to be linked to extensional fragmentation of the same sequence at the updip salt roller domain. A line of salt walls, which document the prolonged salt inflation (Figure 1), today separates both domains. Salt movement becomes the dominant condition in the adjacent Mini Basin domain where salt walls and reactive diapirs separate an array of deep mini basins filled with post salt sediments (Figure 1). A few salt bodies transition into active diapirs and reach shallow levels below the mud line, while some of the mini basins are grounded with their Albian sequence against the presalt formation.

Underneath the Mini Basin domain, an approximate North-South trending outer structural high reveals a series of potential presalt reservoirs, more than a half dozen locations already identified by the industry as potential

PGS Campos Basin 3D Seismic Program

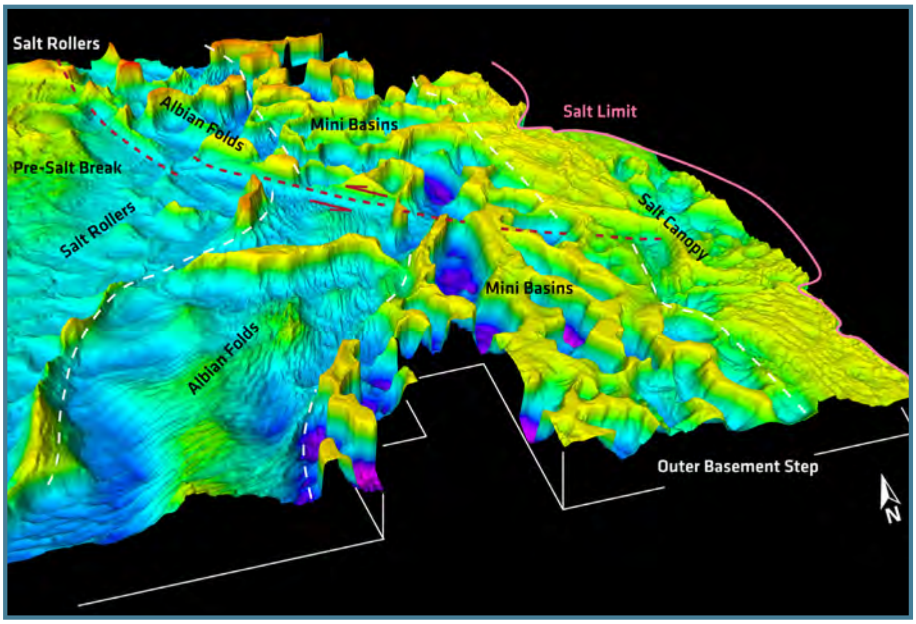


FIGURE 1. Relief of top Aptian evaporites in the deepwater Campos Basin illustrate the major salt tectonic domains (outlined by white dashed lines) and their displacement along a regional sinistral strike-slip fault (red dashed line). Cold colors represent deep, partially welded mini basins. The limit of the allochthonous salt canopy is captured in part by the new 3D seismic acquisition program. (Source: PGS)

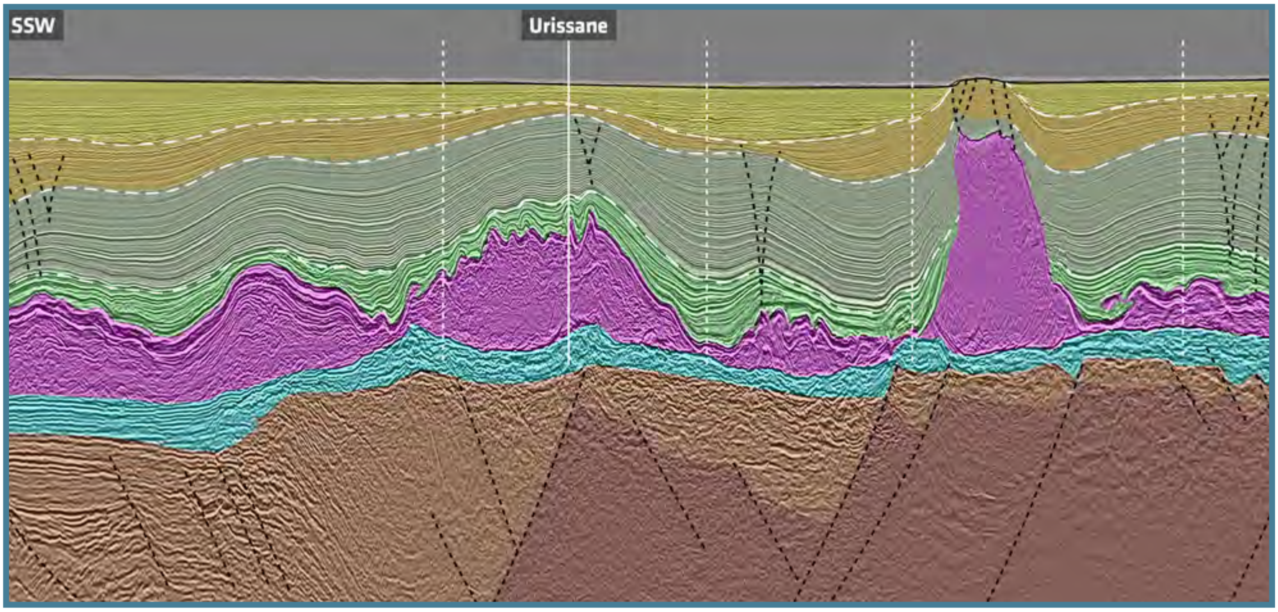


FIGURE 2. A legacy 3D KPSDM seismic profile along the outer presalt high illustrates post-salt, salt and presalt stratigraphy. Higher quality seismic imaging is required for forthcoming drilling campaigns and appropriate characterization of these promising presalt reservoirs. A recent presalt test by Petrobras (Urissane) and several other permitted presalt well locations are indicated on the graphic. (Source: PGS)

drilling targets (Figure 2). A recent presalt test by Petrobras and partner Exxon Mobil on the Urissane prospect is expected to confirm a working petroleum system and the extension of the presalt play concept into the deepwater sector of the Campos Basin. Petrobras filed a hydrocarbon oil show report to the Brazilian regulator ANP in early first-quarter 2021 on this first outer Campos Basin presalt well.

The Outer High and the edge of the salt basin salt kinematics

The outer high forms the proximal shoulder of a l basement graben, underneath thick salt accumulations of the Mini Basin domain (Figure 2). The graben's distal shoulder images a significant, 1,000-m to 2,000-m basement step that is fragmented by NE-SW trending sinistral transfer fault zones. This basement step likely marks the limit of the passive margin rift system and reveals frequent magmatic features such as sill-like intrusions along the salt base. Beyond the outer basement step the evaporites form an allochthonous salt canopy (Figure 1) that gradually climbs over (possible) Upper Cretaceous deep marine sediment sequences. Analog subsalt plays are well described from other salt basins such as the Northern Gulf of Mexico where significant subsalt discoveries are documented. A portion of this area is included in the acreage offering by ANP in the upcoming Brazil 17th Bidding Round and is covered by the new 3D program.

The geophysical data cover the complete salt kinematic system from the proximal, updip extension to distal compression and salt inflation, including salt mobilization into canopies at the outermost section of the passive margin. It also illuminates the interaction with the underlying rift architecture. The resulting salt kinematics have several implications for hydrocarbon exploration including the top seal assessment for underlying hydrocarbon reservoirs, while the salt architecture impacts seismic wave propagation and therefore the fidelity of the presalt imaging of the reservoirs and their associated petroleum systems.

Advanced seismic technology for presalt imaging

The new data offers a step change in image quality of the emerging Campos presalt play.

Full waveform inversion driven depth velocity modeling of the post-salt, layered evaporate (salt) and presalt sections has provided more accurate velocity model updates by leveraging the full seismic wavefield (reflections and refractions) recorded in these long-offset (10 km) multi-azimuth data. Improved velocity model accuracy affords improved image quality, illumination and depth accuracy of the subsurface structures found within the presalt play. The results will support any future exploration drilling and subsequent reservoir characterization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Chris Beyer
chris.beyer@edfenergyna.com
281-653-1068
Ben Rich
ben.rich@edfenergyna.com
281-653-1736

HSCV10610A allowed the operator to restart production on shut-in wells. (Source: ChampionX)

Increasing efficiency and reducing total cost of ownership in H_2S management

Scavenger helps maintain product stability and enables carbon management.

***Dr. Malcolm Todd and Michael O'Brian**, ChampionX*

H_2S is a highly poisonous, flammable and corrosive chemical compound often encountered during oil and gas exploration and production activity. Due to its hazardous nature, H_2S levels must be closely monitored during offshore operations to assure personnel safety and productivity.

In addition to health and safety concerns, the extremely corrosive nature of the colorless gas can result in significant damage to wells, production equipment and pipelines if not managed effectively. If an efficient method to control H_2S is not implemented, it can lead to considerably reduced production, with only sweet wells able to be produced.

H_2S scavengers are low-hazard, non-corrosive specialized chemical compounds that remove sulfide species. They have become the standard method for offshore operations and are typically injected directly into the sour production. Due to the potentially large volumes required, the scavenger is transported offshore in chemical tote tanks so it can be injected directly or bunkered into facility tanks.

A major global operator recently experienced difficulty managing H_2S levels in a gas export line on one of its North Sea assets. The incumbent product was working efficiently, but due to the amount and concentration of H_2S being treated, it required six to seven tons of product per day. With limited onboard fixed storage and the remote location of the asset, the amount of scavenger required to meet the demand was limiting full production. The storage of chemicals on deck was also affecting other activities and had the potential to negatively influence an upcoming drilling campaign.

ChampionX was contracted to create and deploy a highly concentrated scavenger which would reduce the amount of chemicals required while delivering a more sustainable and efficient solution.

Evaluating the challenge

H_2S scavenger tote tanks can take up significant space on an offshore platform, creating logistical issues and requiring regular movement for continued supply. On this particular asset, up to two 1,000-

gal tanks were swapped daily to meet the demand. Economically, the current operation had resulted in expenditure of around $3.5 million per year. Further, with approximately 2,500 tons of product being moved annually, this had a significant impact on the asset's carbon footprint, which the operator was keen to reduce.

The winter months in the North Sea also created further challenges, as logistics can face significant delays due to harsh weather and high sea states, which meant a safety stock of scavenger was required on deck. To host 21 days of the product offshore, the operator required 30 tanks, which covered a substantial part of the platform's laydown area. This was a key issue to resolve, as the space was required for essential equipment for planned drilling and well operations.

The incumbent solution was also having a considerable impact on the asset's production activities. The high volumes of H_2S being produced from some wells had resulted in them being shut in, as the platform could not host the amount of scavenger required to treat them all. At its peak, the E&P organization had 4,500 bbl/d of deferred production associated with H_2S management.

Devising a sustainable solution

Having discussed the supply challenges with the operator, ChampionX found that increasing the activity of the product could reduce the handling requirements. The company began lab testing to create a bespoke, highly concentrated H_2S scavenger, which would reduce the volume required and allow the operator to unlock production from the shut-in wells.

A team of five chemists at the company's laboratories in Aberdeen, UK, began the initial formulation and testing to devise a more concentrated product, one which would show increased scavenging capacity and, critically, maintain product stability. The process took around one year, with long-term stability and compatibility testing conducted to ensure the product was stable and solids did not form at varying temperatures. Testing was also conducted to confirm the chemical continued to perform optimally.

Materials compatibility was a vital element to be considered in the development. When H_2S scavenger is injected into oil and gas processes, it comes into contact with numerous vessels and components, depending on the asset, so the chemical cannot negatively affect the materials. As part of the product commercialization, ChampionX tested the new product on a range of rubbers and metals across varying standards, which are commonly found in the oil field. Once the final chemical formulation was devised, necessary OSPAR and Centre for Environment, Fisheries and Aquaculture Science (CFAS) certifications were secured.

Reducing carbon footprint, increasing efficiency

Upon successful final testing, the company deployed its high-activity HSCV10610A scavenger product to the operator's platform for definitive field testing.

Once implemented, HSCV10610A delivered annual cost savings of more than $1 million to the client through improved performance over the incumbent product, while continuing to meet

ChampionX's laboratory in Aberdeen conducted testing to create a high-activity H_2S scavenger. (Source: Champion X)

Due to its hazardous nature, H_2S levels must be closely monitored during offshore operations. (Source: Champion X)

the same gas export H_2S concentrations.

The reduction in chemical volume of 1.25 million litres decreased the tank changeovers and its associated tasks, resulting in two man-hours per shift saved. This amounted to an annual resource benefit equivalent of $64,000 in terms of lab tech man-hours.

The new scavenger further delivered a 70% reduction in the number of H_2S scavenger tote tanks shipped: a yearly saving of $162,000 in tank rental. It also freed up 3.5% (23m^2) of all available vessel space per sailing. The reduction in volumes of chemical being transported significantly reduced road and sea transport costs and avoided the production of 231 metric tons of CO_2 per year, drastically reducing the operator's carbon footprint.

The adoption of HSCV10610A allowed the operator to re-start production on the previously shut-in wells, significantly increasing production by up to 4,500 bbl/d.

Implementing this high-activity chemical also allowed the pipe deck to be reclaimed before an essential drilling campaign and was a key step to freeing up platform laydown space for other operations.

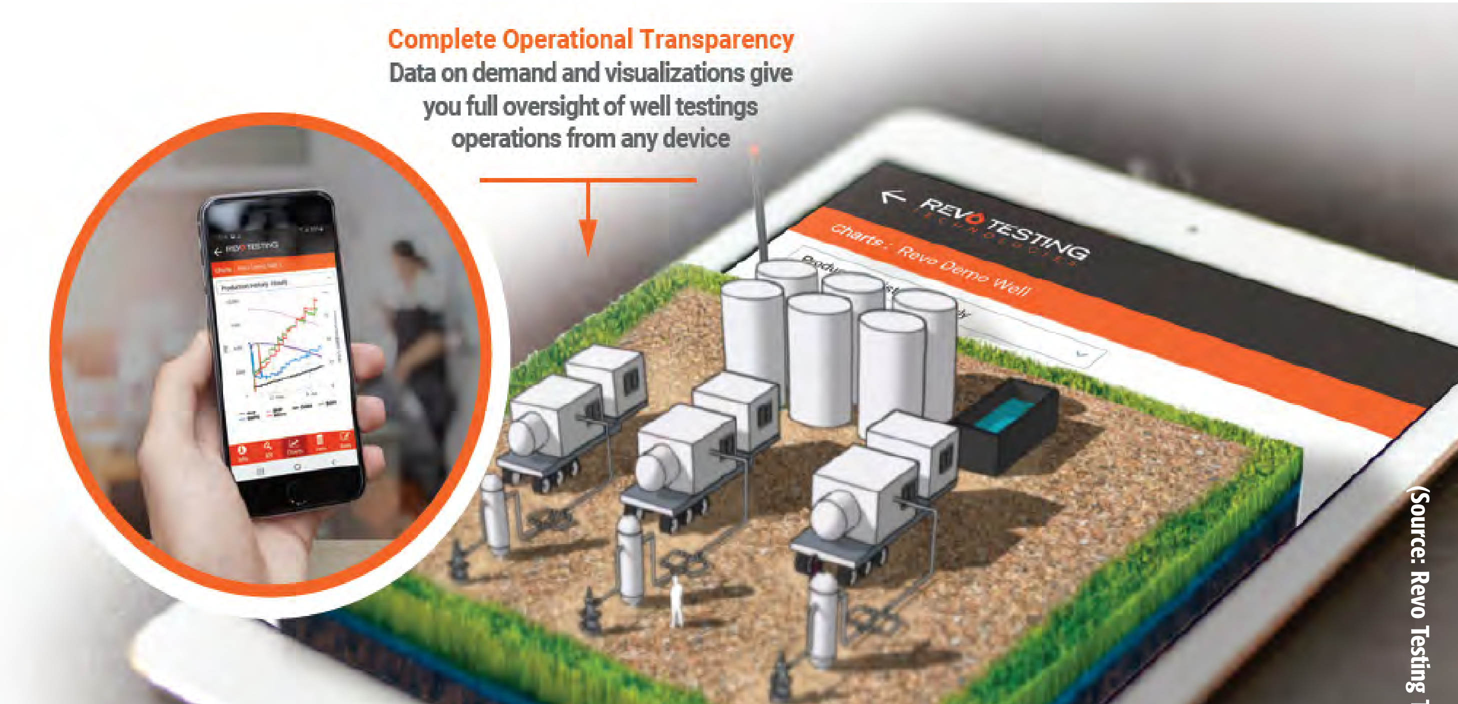
The operator continues to utilize ChampionX's product HSCV10610A, and the highly concentrated solution has become an industry standard in the North Sea.

Supporting the net-zero journey

The removal of H_2S is a common issue in the oil and gas industry, and there are various methodologies for its remediation which have their own associated expenditures and challenges. It is essential that solutions ensure the health and safety of those on board, in addition to maintaining crude value and maximizing production.

However, as the UK continues its journey towards net zero, it is no longer enough to create solutions which simply offer efficiencies. Sustainability and reduction of carbon footprint must be prioritized. ChampionX's bespoke scavenger demonstrates how investment in research and development, coupled with a clear view to deliver an environmental solution can garner significant results for the sector. +

ChampionX devised a highly concentrated scavenger that significantly reduced the volume required. (Source: Champion X)



(Source: Revo Testing Technologies)

Measuring well performance

Improving drawdown management with automated analysis can enable efficiencies and cost savings.

***Adam Swartley**, REVO Testing Technologies*

The push for a more digital oilfield has led to the creation of numerous software tools to take advantage of newly available real-time well data. The waterfall of data that is now being captured has resulted in the need for productivity solutions to help engineering teams focus on the conclusions provided by the data, not data management itself. Engineers now have a variety of options to help them visualize and analyze data during just about every point of a well's life. However, one segment has been left behind on the path to a digital oilfield--unconventional well flowback and well testing.

Early-time flowback data provides one of the first glimpses of valuable information to manage a well's drawdown and evaluate reservoir responses and well performance. Yet many in the industry are not leveraging this data to optimize their completions and well production. One of the primary reasons being the poor data quality traditionally being captured during this period, often making analysis difficult or even impossible. Additionally, the fact that this data is still typically recorded manually and sent in an email or text message makes using and managing the data a time-intensive process.

Instead, simple production targets, drawdown limits or even rules of thumb are often used to manage the well startup. Most engineers don't have the time or expertise to spend their days compiling and analyzing flowback data to optimize their choke and drawdown management.

Revo Testing Technologies has recently released the Revo iQ software package to solve these problems and give operators the opportunity to effectively manage this crucial period of a well's life. The system helps modernize flowback operations and give engineers the tools they need to tailor a drawdown strategy to every well, without spending all day sorting through flowback reports.

Flowback digitalization

For many operators unconventional flowback data management has fallen behind almost every other part of a well's life. Text message chains, periodic emails and difficult-to-use Excel files are all part of the archaic processes that most operators still utilize to manage their flowback data. Add to that data errors or missed reports from flowback hands in the field and it is easy to see why it has been simpler to just use a standard basic strategy on every well.

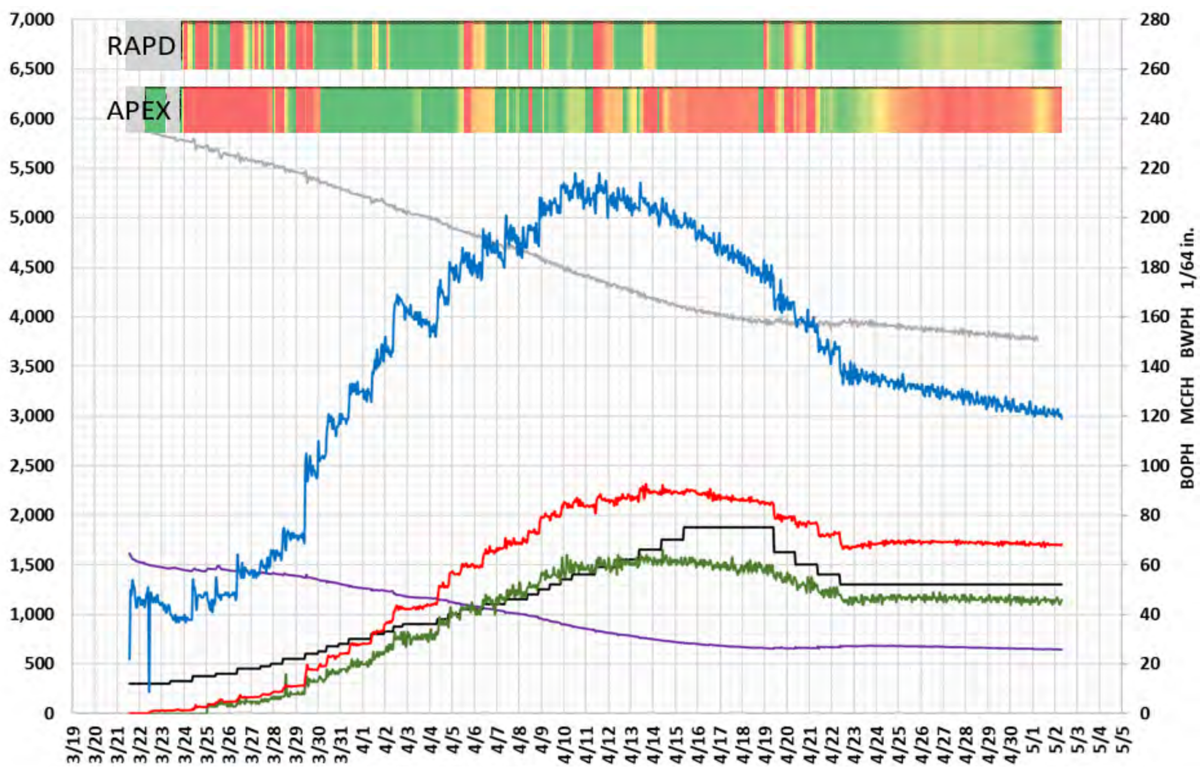
With Revo iQ, data is streamed live from the field to a PC or mobile device so that well result updates are instantly available. Data can be captured by Revo's automated flow testing hardware, existing SCADA equipment, or by service provider in the field as soon as they take their measurements. Well information is all stored in the cloud and can be connected back to internal databases or any other software packages. Rule-based alerts can be setup to push to a mobile device notifying the user of production milestones, potential measurement issues, well performance changes or any other monitoring metric.

Automated well performance diagnostics

Modernizing and simplifying the process of ingesting and monitoring raw data is only the first step toward realizing the full potential of flowback. The raw data is useful, but only gives basic indications about how to manage the choke to efficiently draw down the well.

It first must be understood how bottomhole pressure (BHP) is changing during initial the production period. To accomplish this, Revo built a series of real-time BHP calculations into Revo iQ systtem allowing the ability to model BHP on a wide variety of well types. The BHP data and rate data is then used in two new tools to automate the analysis of flowback data, RAPD and APEX. These tools can be used to flow a well back as fast as possible while maintaining the effectiveness of the completion and reducing damage to the reservoir. The goal of the automated analysis is to allow operators to stay in this sweet spot of increasing production as fast as possible, without damaging the reservoir.

RAPD performs an automated analysis on every data point to determine how fracture conductivity is changing over time and from one choke change to the next. Analytical models are matched automatically to each transient to understand changes in conductivity. The analysis results are then fed into gauges and colored histograms showing how performance is changing throughout the flowback



The graph depicts two wells in the Eagle Ford, Well A and B, and their cumulative gas production comparison. (Source: Revo Testing Technologies)

period. RAPD gives operators the ability to let well results drive choke management allowing the drawdown strategy to be tailored to every well. The APEX tool works alongside RAPD to help operators to understand how current well performance compares to peak performance.

Case study: Improving drawdown management

An Eagle Ford operator reported high sand rates during flowback and lower long-term production on wells with high initial rates. The operator decided to perform a comparison test to determine how effective Revo's system was versus their current procedures. Well A utilized Revo's optimized flowback strategy and Well B utilized the operator's standard strategy.

The customer utilized Revo iQ and Revo's engineering team to develop an initial choke management strategy to reduce early proppant flowback. The RAPD and APEX tools were then used to manage the choke and drawdown over the course of the flowback. Well A initially came on at a lower choke size, but was then opened quicker and to a larger choke as confinement stress increased with proper drawdown management.

The optimized flowback strategy resulted in a reduction in sand production of 42%, eliminating the need for additional sand management equipment, thereby decreasing the cost of the flowback. In addition, the Revo optimized flowback helped Well A achieve a 53% increase in cumulative production.

New applications

Now that RAPD has been proven to optimize drawdown in real time, the software is being testing for edge applications for automated choke systems and automated artificial lift systems for full-field drawdown optimization. This will give operators the ability to optimize both surface and subsurface systems in real time. +

Maintaining high metrological performance for the life of the well

A cost-efficient approach to expanding the flowmeter operating envelope for wells in production decline.

***Alexander Zhandin**, Schlumberger*

Maintaining high-accuracy flow rate metering for the life of the well is critical for maximizing reservoir productivity and planning an intervention strategy. The ability to accurately measure oil, gas, and water flow rates, preferably in real time, enables operators to make better-informed production decisions with key information about well dynamics.

To accurately capture production flow, multiphase flowmeters are sized for specific flow rate ranges before installation. However, as wells mature and production inevitably declines, the differential pressure (dP) across the venturi section of a multiphase flowmeter may become so low that flow rate accuracy is difficult to maintain. The dP measurement provides raw information about the momentum of the flow and is closely related to the mass flow rate of the fluid going through the meter. For wells in production decline, dP readings may be outside the standard meter operating envelope, directly affecting the flow rate measurement accuracy.

Whereas conventional wells typically experience a gradual decline over decades of production, unconventional wells generally see a much sharper drop within the first few years, accompanied with water cut and fluid property changes. Particularly for North America land applications, operators need a quick, cost-efficient solution to enable continuous high-accuracy multiphase flow rate data for wells in production decline.

FIGURE 1. The low-rate extender insert is installed across the venturi section of a multiphase surface flowmeter. (Source: Schlumberger)

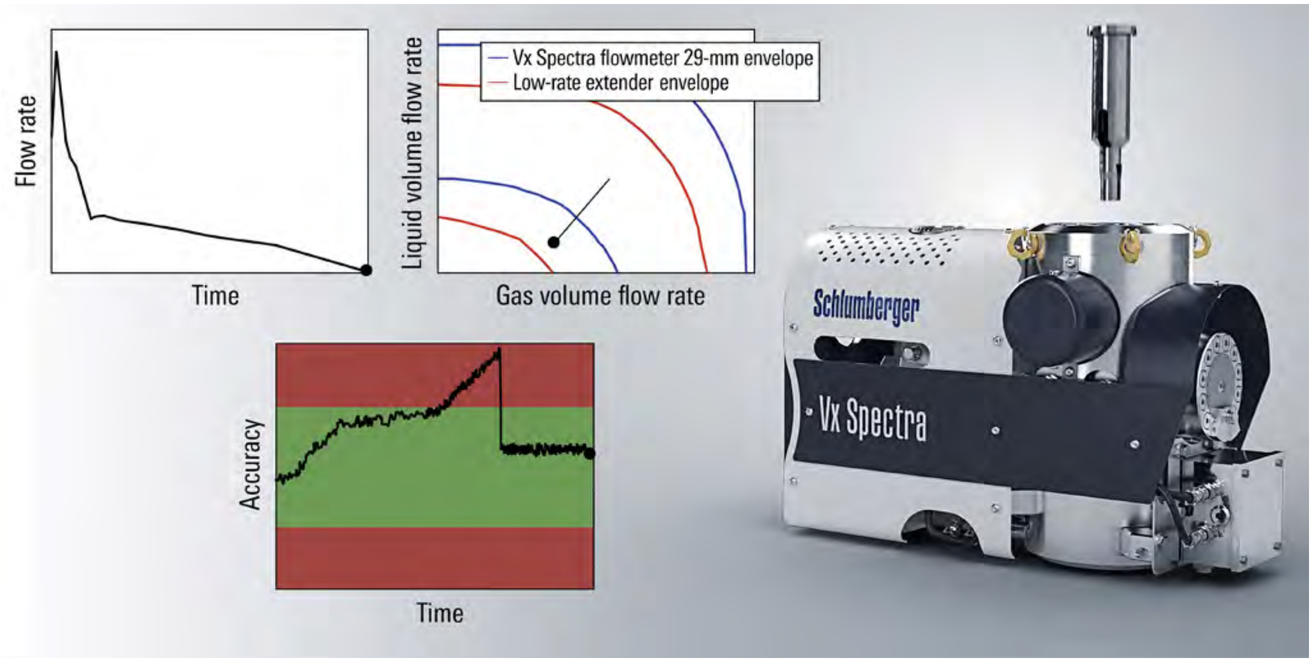


FIGURE 2. The illustration demonstrates the expanded operating envelope of the surface multiphase flowmeter by installing a low-rate extender insert. The low-rate extender maintains metering accuracy for wells in production decline. (Source: Schlumberger)

Conventional approaches to maintaining high metrological performance

Venturi sections with a 29-mm size address midrange multiphase metering at the majority of oil production fields. Typically, meters are replaced for a smaller size to increase the turndown ratio and thus operational metering envelope in depleting wells. However, this approach strains capex and increases nonproductive time (NPT).

Furthermore, the practice of installing a separator to act as a metering device has proven to be both capex- and opex-intensive. Operators have found it challenging to manage the optimal turndown ratio, a process that requires constant attention and places timing demands on personnel to service equipment. Separators also require continuous control over various moving parts to maintain the operational integrity, requiring more maintenance. Moreover, with unavoidable solids buildup during production, it becomes necessary to regularly empty the separators as they slowly fill with solids, especially as production rates decline. These are challenges that advanced surface meters such as the Vx Spectra surface multiphase flowmeter have resolved by its lack of moving parts and incorporating drain passages to flush the pressure membranes and the passage through the venturi when clogged. This enhances the surface multiphase flowmeter performance and reduces intervention time.

Expanding the operational envelope

By combining full-gamma spectroscopy and high-frequency flow rate and phase fraction measurement at a single point in the venturi throat, the surface multiphase flowmeter ensures accurate, repeatable and real-time flow rate measurement without phase separation. For wells in production decline, a solution that expands this same metering accuracy and real-time insights can help operators make improved decisions.

Instead of replacing the field infrastructure, retrofitting an existing 29-mm surface multiphase flowmeter is a new solution for achieving more cost-efficient high-accuracy metering in depleting wells. By installing a lightweight, compact insert across the venturi section of the flowmeter, operators can reduce both the capex and NPT associated with conventional methods and ensure more continuous flow rate measurement and data insights for the life of the well. Typically, installation takes less than half a day, as opposed to two days with replacing for a new, smaller meter.

The multiphase surface flowmeter provides robust measurement over a large range of gas volume fractions (GVFs), with a turndown ratio over 10 for a fixed GVF. Because the insert reduces the cross-sectional area at the venturi throat, the turndown ratio increases by at least two times, thus expanding the measured dP to accommodate for low flow rates. This increased operating envelope results in high-accuracy flow rate measurement for wells in production decline, eliminating the need to replace the existing meter. In addition to the increased turndown ratio, flow rate accuracy is maintained due to an updated flow model that describes the multiphase flow through the unique cross-sectional shape formed by the low-rate extender insert at the venturi throat. Extensive validation in a multiphase flow loop under a wide variety of flow conditions has demonstrated the effectiveness and accuracy of the insert solution. The low-rate extender insert also does not interfere with the gamma ray beam, thus maintaining the same photon count rates and consequently phase fraction and water cut accuracies.

Case study: Maintaining flow rate accuracy in the Permian

Field tests in U.S. unconventional oil and gas wells demonstrate the usability and robustness of the low-rate extender insert to deliver reliable, high-quality multiphase data for wells in production decline. An unconventional shale well in Texas was brought online in 2019, and production started to gradually decline. Within six months, liquid production decreased by half, and gas production decreased by 25%. Due to production decline, the well's low flow rate was outside the installed flowmeter's operational envelope. The field's operator was faced with needing to replace the existing 29-mm flowmeter for a smaller size to maintain dP values above the low limit and operate in the working envelope for metering accuracy.

To avoid infrastructure changes, lost production time and additional costs, the operator chose to retrofit the existing surface multiphase flowmeter with a low-rate extender. The insert was installed for a trial test in June 2020. After installation in the venturi cross-sectional area, the measured dP increased by more than four times—expanding the operational capacity of the existing 29-mm flowmeter and resulting in more accurate flow rate measurement.

The flow rate measurements were compared with production separator data in real time, and the flowmeter metrological specifications and operating envelope were proven to be maintained. The operator saved capex and NPT by running the same flowmeter for an extended period, accommodating the flow rate changes from an initial high production to steep production decline and demonstrating the low-rate extender's capability to maintain high-accuracy metering for the life of the well.

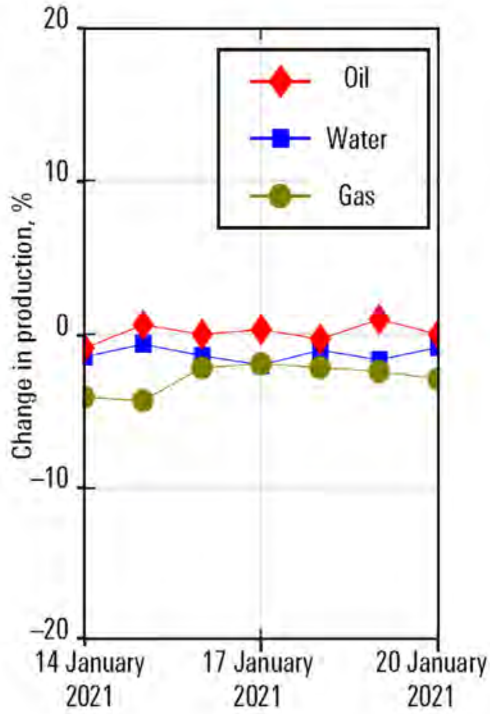


FIGURE 3. For an operator in Texas, production separator data confirmed the surface multiphase flowmeter retrofitted with the low-rate extender maintained high metrological performance. (Source: Schlumberger)

Obtaining continuous, accurate multiphase flow dynamics enables delivering reliable production data for accurate production profiling.

Efficiently optimizing production for the life of the well

The low-rate extender insert provides a cost-efficient solution to expand the operational metering envelope by optimizing existing field infrastructure instead of replacing equipment. This method significantly reduces capex and NPT while maintaining the flowmeter's high metrological performance for wells in production decline. Operators can also further reduce production downtime by including the low-rate extender insert during the initial meter installation to proactively plan for production and flow rate changes as wells mature.

Obtaining continuous, accurate multiphase flow dynamics enables delivering reliable production data for accurate production profiling. The low-rate extender insert maintains this reliability for the life of the well, providing operators with the measurements they need to efficiently manage and optimize their production. ✚

(Source: Subsea Europe Services Gmbh)

Optimizing data acquisition to reduce maintenance costs

Developments in hydrographic survey technology can support the growing demand for ad hoc marine surveys in and around offshore wind farms.

Andres Nicola, *Nicola Offshore GmbH; and* ***Sören Themann,*** *Subsea Europe Services GmbH*

Due in part to the early industry acceptance of new technologies and methodologies for planning and deployment over the past decade, the cost per KwH of energy produced by offshore wind farms continues to fall. With offshore wind energy now more than economically viable, the industry must work even harder to optimize operations and maintenance (O&M) to ensure costs to the end-consumer stay low, while meeting the inevitable extra demand on capacity coming from price competitiveness.

Cost reduction programs are more essential for energy companies and offshore wind farm operators than ever, and it's clear that the squeeze will tighten as the industry looks toward a future of much larger and more powerful wind turbines, located farther from shore. This development is a direct result of the need to deliver on strict carbon reduction plans as guided by the Paris Agreement and the U.N. Sustainable Development Goals. As an example of the pressures faced by the offshore wind industry, the U.K. government's commitment of reaching 30 GW installed capacity by 2030 was subsequently amended to 40 GW, with a target of net zero carbon emissions by 2050.

Sector growth and stability will depend upon innovation in the design of wind turbines, new installation processes and digitalization for operational safety and efficiency. And while large technology and offshore service companies will be in the spotlight, cost reductions will also come from countless smaller players, working across the entire offshore wind farm value chain. Projects as simple to grasp as torque monitoring on bolts or as complex as AI-powered robotics to crawl turbine blades looking for cracks may solve hundreds of potential pinch points where time and money can be saved.

Unforeseen circumstances

Optimizing the acquisition of marine data that enable subsea engineering and maintenance can also influence the O&M bottom line. The requirement for an accurate view of the seabed and the water column is present from the planning stages throughout the entire life cycle of a wind farm, and as such, marine survey is a visible cost center. Planned surveys are an established and accepted cost with a predictable impact on budgets, but marine data are increasingly needed on a more urgent or ad hoc basis due to unforeseen circumstances that are impossible to budget for in advance.

Such circumstances might include the loss of an expensive tool or piece of important equipment over the side of a vessel during turbine installation or subsea inspection, maintenance and repairs. Additionally, especially in the North Sea, unexploded ordinance (UXO) leftover from World War II can regularly cause work to stop on offshore wind farms. In both scenarios, the cost of nonproductive time (NPT) from extended vessel charter, equipment hire and crewing costs as well as late and non-completion penalties demands a fast resolution to the problem at hand.

With wind farms often located 30 km to 50 km from shore, the project owner generally looks to small but fast vessels of opportunity that can get on site quickly for what is usually only a short survey. But while such vessels are usually readily available for hire in most commercial ports, acquiring and installing the right hydrographic equipment for the survey and finding the expertise to operate it can take days or weeks, all the while the cost of NPT continues to rise.

Often referred to as gap-filler surveys, these projects are usually defined by the need for industry standard multibeam echosounder (MBES) solutions with little notice prior to the day of the survey. This demands a certain flexibility in the logistics chain, which too often isn't available. Even clearly urgent projects can be forced to wait while the equipment needed is located and delivered from another country or even continent.

Cost reduction programs are more essential for energy companies and offshore wind farm operators than ever, and it's clear that the squeeze will tighten as the industry looks toward a future of much larger and more powerful wind turbines, located farther from shore.

Simplified deployment

Simplifying the deployment and use of expensive, complex MBES systems has proven a successful starting point to enabling more cost-effective gap-filler surveys. Significantly, the design of a new integrated Hydrographic Survey System (iHSS) has made adding precise survey capabilities to any vessel of opportunity much easier. Able to acquire data to the new IHO S-44 Exclusive Order standards, the iHSS is a ready to mobilize solution based on MBES' made by R2 Sonic, workstation, software, inertial navigation system and flexible mounting.

With stocking efforts to ensure availability, an iHSS can be virtually anywhere in Europe next day and mobilizing the system generally takes less than an hour on most vessels as it comes preconfigured with all components already integrated. It features an all-in-one pole mount design with multibeam transceiver, Inertial Motion Unit and GNSS antennas in one reference frame, which simplifies installation even further and reduces potential errors from inconsistent or wrong offsets, contributing to the iHSS' ability to deliver data of the highest quality.

The combination of technical solution, standardized workflows and streamlined logistics means that short jobs, long transit times and high-quality data are no longer a contradiction in terms for the marine survey world. This was shown in an earlier contract when marine survey company Nicola Engineering GmbH was tasked by an offshore wind service company to carry out a rapid survey to locate and identify a small feature on the seabed in the North Sea. Rather than wait for a large, slow commercial survey vessel to become available in the area, Nicola Engineering turned to Dutch shipyard and charter company ProMarine BV to mobilize a small, fast survey boat with relevant offshore permits already in place.

The combination of the iHSS, a fast, class-approved survey boat and skilled operators met the requirement for a high-resolution MBES to survey the target—a small subsea feature approximately 1 m in length in water depths exceeding 30 m. The project was completed within two days of Nicola Engineering receiving its brief, and the survey was finished in a single day out of a small port in the Netherlands. Mobilization and calibration of the whole system took about two hours. The iHSS successfully located and identified the feature quickly and at a considerably lower cost than using a commercial survey ship.

The iHSS arrives preconfigured to simplify and expedite installation on any vessel of opportunity. (Source: Subsea Europe Services Gmbh)

Autonomy platform

The vision behind the iHSS is that service companies and subcontractors can quickly add industry standard survey capabilities to any vessel of their choosing (or any vessel that's available in urgent situations). The technology integration reduces complexity to a point that the system is almost plug and play, which contributes to expediency in getting vessels and equipment to a survey site quickly and cost effectively.

The technology integrations have also made operating the iHSS easier when compared to standard MBES systems. Marine survey expertise and training are still needed to use the iHSS, but the integrated nature positions it as a platform for introducing more automation and ultimately enabling autonomous operations. Onboard expertise is integral to conducting marine surveys and post processing, but with the iHSS, AI-powered autonomy may one day deliver results to the same standard that professional surveyors can achieve today.

The combination of technical solution, standardized workflows and streamlined logistics means that short jobs, long transit times and high-quality data are no longer a contradiction in terms for the marine survey world.

Fleets of unmanned vessels conducting autonomous survey operations on wind farms with monitoring and management by marine surveyors on shore have the potential to deliver significant O&M cost savings. The vision is long-term. For today, the iHSS concept and Nicola Offshore, the marine survey company it helped to create, are simplifying, specializing and lowering the cost of on-demand marine surveys. These developments may be low-ley in the overall theme of offshore wind farm opex, but nonetheless they do play a part keeping the cost per KwH of wind energy on its downward trend. +

Latest upstream technologies

The latest advances in upstream technologies include a supercomputer for exploration, equipment to lower emissions, additive manufacturing services and more.

New thermoplastic pipe to reduce corrosion risks, lower emissions

Baker Hughes has released its next-generation Onshore Composite Flexible Pipe to address the corrosion and cost of ownership challenges with conventional steel pipe for the energy, oil and gas, and industrial sectors. The flexible, lightweight reinforced thermoplastic pipe offers an economic and environmentally superior alternative to resource-intensive onshore steel pipes for optimizing the core structure of flowline and oil and gas pipeline networks. A key feature of the pipe is its proven spoolable design, making it easier, faster and more cost-effective to transport and install versus steel pipe, reducing installed costs by more than 20%. Installation also requires fewer onsite support facilities and heavy vehicles, de-risking operations, taking up less width on a pipeline right-of-way and reducing environmental impact on surrounding land. Baker Hughes' Onshore Composite Flexible Pipe offers an economic solution for the transport of CO_2 and hydrogen as well as the conversion of existing infrastructure to carry gases. In addition, the pipe's noncorrosive materials can withstand contaminants without requiring chemical inhibitors, corrosion monitoring and inspection, or disruptive repair work, significantly reducing opex.

The new Onshore Composite Flexible Pipe offers lower cost of ownership, reduced corrosion risks and lower manufacturing emissions compared to traditional pipes. (Source: Baker Hughes)

Supercomputer to open up new horizons of exploration

Saudi Aramco and stc have released Dammam 7, a supercomputer that presents new opportunities in both exploration and development and enhances Aramco's decision-making on exploration and investment decisions. This is the next step in Aramco's digital transformation, complementing a suite of advanced technologies that are reshaping core operations, driving efficiencies and reinforcing its industry leadership in geoscience.

Developed at Dhahran Techno Valley in partnership with Solutions, a subsidiary of stc Group, and CRAY, a Hewlett Packard Enterprise subsidiary, Dammam 7 has 55.4 petaflops of peak computing power, allowing it to process and image the world's largest geophysical datasets.

Named after the first oil well discovered in Saudi Arabia, the Dammam 7 supercomputer's sophisticated imaging and deep-learning algorithms will allow it to run very detailed 3D earth models, improving the company's ability to discover and recover oil and gas while reducing exploration and development risks. It will further enhance decision-making for exploration and development of conventional and unconventional hydrocarbon resources as well as guide future investments in production and resource allocation.

Complete suite of digital solutions for monitoring corrosion

Emerson has released a complete corrosion and erosion monitoring portfolio with digital capabilities and full integration with the Plantweb digital ecosystem through the new Rosemount 4390 series of corrosion and erosion wireless transmitters and Plantweb Insight Non-Intrusive Corrosion application. The monitoring portfolio turns existing offline corrosion probes into online tools to monitor for the risk of corrosion or erosion in oil and gas processing. The new Plantweb Insight Non-Intrusive Corrosion application for non-intrusive corrosion monitoring complements the existing suite of Plantweb Insight applications, enabling comprehensive corrosion and erosion analysis at the end-user's desk.

When instrumented with inline probes, changes in corrosion risk can be detected in minutes, enabling sites to take corrective actions before damage occurs. The Rosemount 4390 series of corrosion and erosion transmitters leverage WirelessHART for reliable and robust data retrieval and work with Emerson's inline probes that measure the corrosive and erosive nature of the fluid and provide early risk detection for a site. The Plantweb Insight Corrosion applications allow users to access and analyze data from pipe thickness monitoring sensors and inline probes at their desk and gain real-time advanced analytics to assess the risk and impact of corrosion or erosion on the asset or plant.

Operators can drive plants to their maximum capability and avoid costly incidents with a fully integrated corrosion and erosion monitoring suite of software and service solutions. (Source: Emerson)

New additive manufacturing service specification to support digital transformation

DNV has released a new service specification document with the aim to support stakeholders across the additive manufacturing (AM) value chain to ensure AM products, assets and systems are safe and efficient. The specification can support the global oil and gas industry to adopt AM technology for gaining cost and efficiency benefits while maintaining safety. AM—the industrial equivalent of 3D printing—is an emerging technology that uses 3D model data to fabricate parts, enabling, among other benefits, significant cost and time savings. AM could help avoid long, expensive production shutdowns and reduce supply chain carbon footprints. Building trust in printed parts is key to unlocking this potential. The new service specification is being launched to define DNV's AM qualification scheme and provide the basis for obtaining and retaining DNV statements and certificates for the endorsement of facilities and digital products/services, qualification of manufacturers, build processes, parts and part families, AM machine(s) and equipment and AM personnel.

Companies combine digital forces to optimize inventory

Royal Dutch Shell and Equinor will develop the next generation of Shell Inventory Optimiser , a solution that leverages advanced analytics on historical data to optimize operational spare part inventory levels. Building on news of the recent Strategic Alliance with Shell, Microsoft will be supporting Shell and Equinor with the co-development of the tool, which runs on Microsoft Azure.

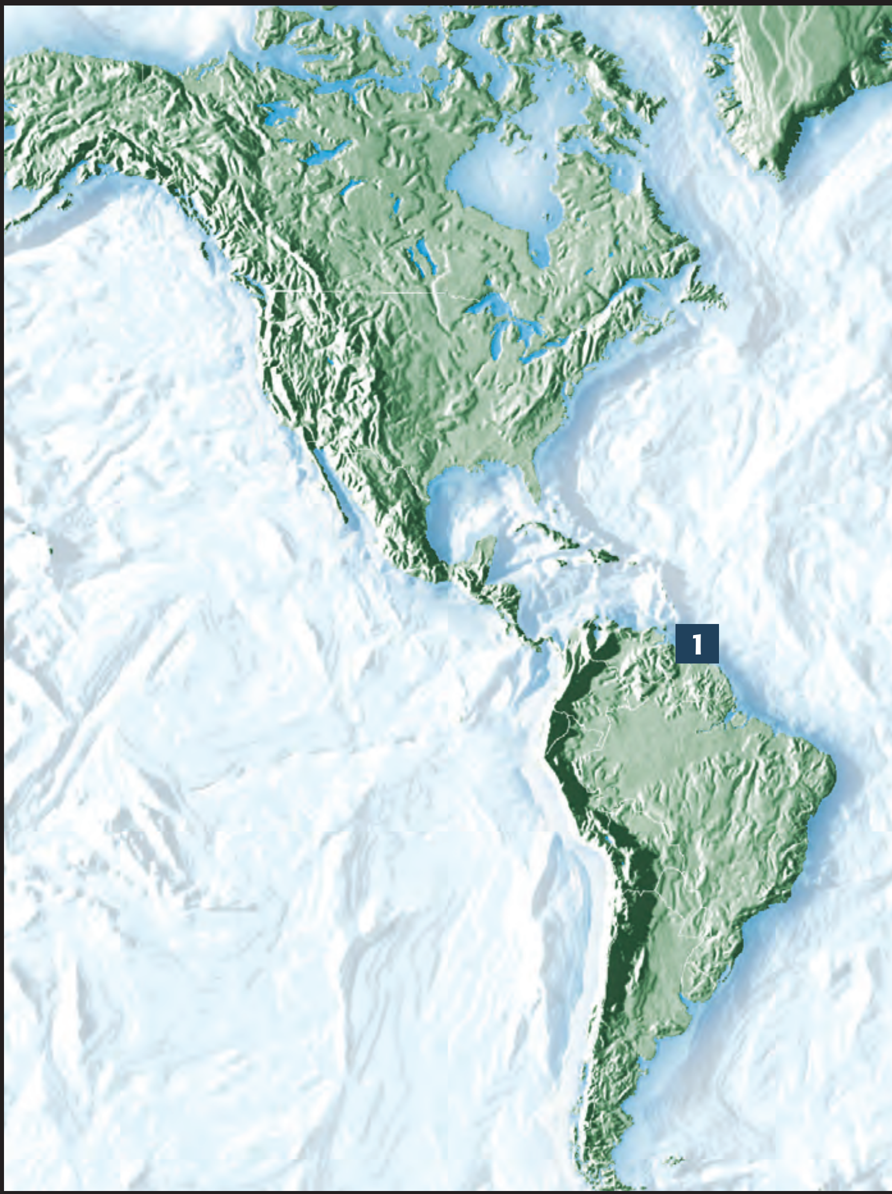
The goal is for energy companies to have better control over available equipment and to optimize stock levels. Since first deployment in 2017, this proprietary solution has been deployed across Shell's Upstream, Manufacturing and Integrated Gas assets globally, generating millions of dollars in value through optimized stock levels. The tool integrates Microsoft Azure Machine Learning, Azure Databricks and Azure Datalake and will see the tool enhanced with new features to further optimize the algorithm, driving the recommendations and an improved user experience. Both Equinor and Shell users will benefit from these new features. For Equinor, this tool could reduce inventory inflow with as much as 13%, which could save millions. The collaboration is the first of a series of planned co-innovation initiatives across the wider energy value chain including themes such as maintenance, production optimization and supply chain management, which are in development.

The co-development project will be run through a joint engineering team with digital and discipline specialists from Shell, Equinor and Microsoft. (Source: Equinor)

OFS management solution for small businesses

Managers of small companies are sometimes unable to identify what's happening in every area of their business. They may, for example, not know how much equipment they have available or get lost in scheduled jobs and paper tickets. RigER has released its RigER: Start, an oilfield services (OFS) and equipment rentals (OFR) management software for small businesses. Designed specifically for small OFS/OFR businesses, RigER: Start comes with all essential functions that an operations management software must have including a simplified setup and configuration process, standardized quote to invoice workflow, and a low-risk/high-benefit advantage of the package licensing option. The RigER: Start configuration includes management software for purchases, inventory management, sales, field operations and invoices. The software also will include management reports and dashboards to provide insight into the operational key performance indicators, including equipment utilization, job cost analysis and client performance. ✚

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 Guyana

Results from an independent prospective resource study and report were announced by Frontera Energy and CGX Energy for the offshore Guyana Corentyne North Area, Corentyne Main Area and Demerara blocks. A total of 32 prospects were identified in the study in both blocks (27 in the Corentyne Block and five in the Demerara Block): the unrisked volume is 6.089 MMboe and the risked volume is 1.09 MMboe. The prospects are oil (64%), gas (28%) and the remainder condensate (8%). An exploration well in the Corentyne block at #1-Kawa is planned in the second half of 2021 and will target a stratigraphic trap in Campanian-Santonian-aged rocks. In the Demerara block, exploration well #1-Makarapan will be targeting an Aptian stratigraphic prospect on the block.

2 UK

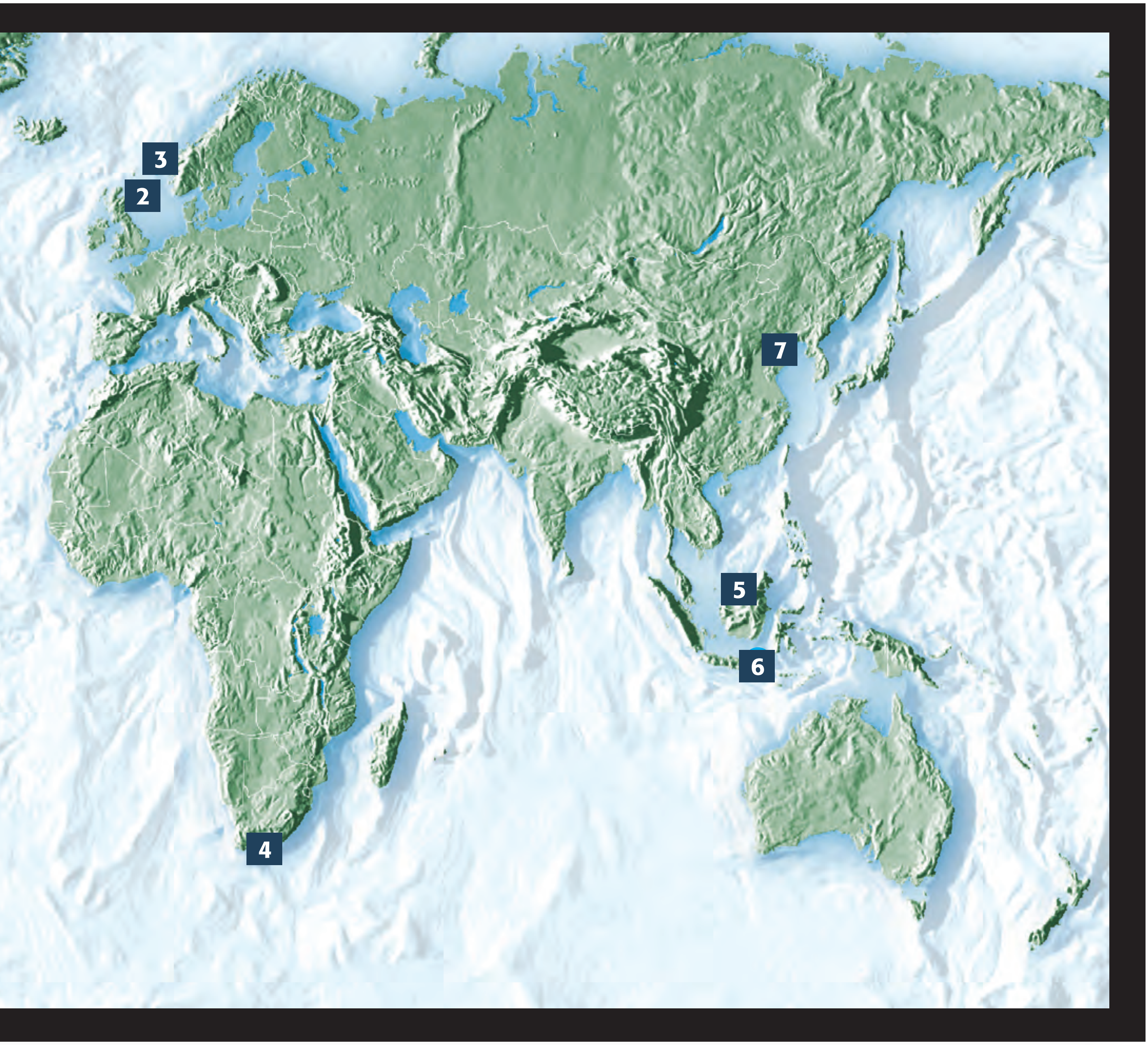
Neptune Energy is planning a four-well development test in the U.K. portion of the North Sea. The Seagull prospect will be in PL1622, Block 22/29C. Seagull is expecting to produce 50,000 boe/d (gross). The prospect is a HP/HT development. The proven and probable gross reserves are estimated at 50 MMboe. Neptune is the operator of Seagull and PL1622 and Block 22/29C.

3 Norway

Equinor announced an oil and gas discovery about 18 km southwest of Troll Field in PL 923. The target for exploration well #31/1-2 S was to prove petroleum in the Middle Jurassic Brent and Cook. The #31/1-2 S encountered a 145-m gas column (Etive and Oseberg) and a 24-m oil column. The sandstone reservoir was 50-m thick with good reservoir quality. In addition, a 6-m, oil-bearing sandstone with moderate to poor reservoir quality was found in the upper part of Dunlin. It was drilled to 3,555 m and bottomed in Jurassic Amundsen. The target for #31/1-2 A was to delineate the discovery made in Brent. The well hit good quality sandstones with good reservoir quality in Etive and the upper part of Oseberg. The lower part of Oseberg contained sandstone with moderate to poor reservoir quality. An estimated total of 41 m of effective sandstone reservoir was found in the two formations. The well proved 12 m of oil in Etive and a 17-m oil column in Oseberg. The Cook formation proved to be water-filled in both wells. Well #31/1-2 A was drilled to 3,876 m and bottom in Cook. Recoverable resources are estimated 44–69 MMbbl of oil equivalent. bbl of oil equivalent.

4 South Africa

Tower Resources announced updated resource estimates following interpretation of the reprocessing of additional 2D seismic data covering the Algoa-Gamtoos license, offshore South Africa. The company's reprocessing work encompassed 4,500 km of 2D seismic data already collected and also further data acquired from the Petroleum Authority of South Africa, including tie lines from Brulpadda to the Algoa-Gamtoos area. The results indicate a deeper level slope (as seen at Brulpadda) and three separate reservoir targets—a shallow section estimated at an unrisked Pmean recoverable resource of 470 MMboe, a previously unidentified deeper slope section with an unrisked Pmean recoverable resource of 231 MMboe and a previously unidentified basin floor fan section has an unrisked Pmean recoverable resources of 710 MMboe. In addition, a submarine fan complex in the shallow-water Gamtoos area



of the license was identified during the survey, which is estimated to contain an unrisked Pmean recoverable resource of 135 MMboe. The Algoa-Gamtoos license is located adjacent to Total's Blocks 11B/12B, where Total has made discoveries in excess of 1 Bboe.

5 Malaysia

PTT Exploration and Production announced a shallow-water gas discovery at the first exploration well, #1-Dokong, in Block SK417 off the coast of Sarawak, Malaysia. The venture was targeting gas in the sandstone reservoir and was drilled to 3,810 m. The well encountered a gas column of more than 80 m. A second exploration well will be drilled later in 2021 as part of the exploration campaign.

6 Indonesia

Petronas announced an oil discovery in the offshore Java North Madura II Production Sharing Contract in Indonesia. Exploration well #1-Hidayah was drilled to 2,739 m. In encountered an oil-bearing carbonate buildup with good reservoir qualities in Ngimbang Carbonate. It was tested flowing approximately 2,100 bbl/d of oil with good crude quality. Additional testing is planned. Petronas is also the operator for the Bukit Tua oil and gas field offshore East Java.

7 China

China National Offshore Oil Co. has announced a large oil and gas discovery at #13-2 Bozhong in Bohai Bay. The venture was drilled in the southwestern ring of the Bozhong Sag in Bohai Bay. Area water depth is approximately 23 m. The well was drilled to 5,223 m and encountered oil pay zones with a total thickness of approximately 346 m. It initially flowed about 1,980 bbl of crude and 5.25 MMcf of gas per day. ✚

–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

Chesapeake Energy Corp. announced the departure of CEO **Doug Lawler** and tapped **Mike Wichterich** to lead the company in the interim. Lawler had served as president, CEO and as a director on the Chesapeake board since June 2013.

David M. Turk has been sworn in as the Deputy Secretary of the U.S. Department of Energy by Secretary of Energy **Jennifer M. Granholm**.

VAALCO Energy Inc. has named **George Maxwell** CEO.

Oasis Petroleum Inc. has named **Daniel E. "Danny" Brown** CEO.

TMC Compressors has appointed Christian Ness CEO. Ness succeeds industry veteran **Per Kjellin** as part of a planned generational change. Kjellin will continue working for TMC as adviser in the company's business development team. He will also join the company's board of directors.

Enteq Upstream, the oilfield services technology and equipment supplier, has appointed **Andrew Law** CEO, succeeding Enteq founder **Martin Perry**.

O'Neill

Woodside Petroleum Ltd. named its development and marketing head **Meg O'Neill** as acting CEO after longtime boss **Peter Coleman** decided to step down a little earlier than planned.

Antero Resources Corp. has announced the retirement of **Glen Warren**, who helped co-found the Appalachia shale producer alongside its current chairman and CEO Paul Rady.

Permian Basin operator Ring Energy has promoted **Travis Thomas** to CFO, succeeding **Randy Broaddrick**, who held the role since its reverse merger with Stanford Energy in 2012.

Dr. Peter Waller will become CFO of the Flender Group, a global supplier of mechanical and electrical drive systems. He succeeds **Dr. Ulrich Stock** who will resign from his position as CFO of the Flender Group by mutual agreement.

ProPetro Holding Corp. has promoted **Sam Sledge** to president. Sledge, who joined ProPetro in 2011, currently serves as the company's chief strategy and administrative officer.

Kosmos Energy has promoted **Tim Nicholson** to senior vice president and head of exploration. He will replace Tracey Henderson, who has left the company to pursue other interests.

Additionally, **John Shinol** has been promoted to senior vice president and chief geoscientist.

Crowley Maritime Corp. has promoted **Alisa Praskovich** to vice president of sustainability, where she will orchestrate Crowley's ESG activities across its diverse business offerings and operations globally.

Akselos has appointed Shell Venture's **Michiel Van Haersma Buma** vice president of customer success.

BCCK Holding Co. has appointed **Brian Petko** senior vice president of engineering.

Validere has appointed **Kayla Ball** senior vice president of products. **Ben Tao** was named senior vice president of marketing, **Jana Shelford** was named vice president of talent and culture, and Jesse Shouldice was appointed vice president of business development.

ASCO , a global integrated logistics and materials management company, has appointed **Craig Revie** general manager of its specialist lifting division, NSL.

Stephen

Ashtead Technology has named **Scott Stephen** to head its increasing activities in renewable energy. In the newly created role, Stephen will oversee the firm's growing presence and enhance its service offering to support the global renewables market.

Justet

Composite pipe technology company Strohm has promoted **Caroline Justet** to support its international growth ambitions as the oil and gas industry progresses toward cleaner energy production.

Denbury Inc. has appointed **Nikulas Wood** as senior vice president. Wood will head the Denbury Carbon Solutions team.

Bill Webb has been promoted to vice president within the Environmental and Construction Professional Practice of RT Specialty.

EnBiorganic Technologies, a provider of patented turnkey autonomous systems for the natural, biological treatment of wastewater, has appointed **Joyce Stroot** to its R&D team as senior technologist.

Beginning on June 1, **Hans-Peter Siebenhaar** will take over the responsibility for communications at OMV as senior vice president.

Oil and Natural Gas Corp. Ltd. has announced that its finance director, **Subhash Kumar**, has assumed the additional post of chairman and managing director of the company.

COMPANIES

Dräger has opened a new facility in Gonzales, La., further strengthening its presence in the Gulf Coast. The new location offers Dräger's full portfolio of safety products and its enhanced offering of rental and safety services for the oil, gas and chemical industries.

Dresser NGS, a provider of metering, electronics, instrumentation, flow control, distribution repair products and overpressure protection devices, has rebranded as **Dresser Utility Solutions**.

Pioneer Natural Resources Co. is buying **DoublePoint Energy LLC** in a deal valued at $6.4 billion, less than three months after completing its purchase of fellow shale driller **Parsley Energy Inc.** as it expands in the U.S. Permian Basin.

Enverus has acquired **Energy Acuity**, a provider of power generation and power delivery market data with specific expertise in renewable energy.

Noble Corp. has announced the completion of its acquisition of **Pacific Drilling Co. LLC**.

Six One Commodities Global LLC (61C Global), a natural gas and power merchant backed by Pinnacle Asset Management LP, announced on April 26 the acquisitions of **Vega Energy Partners Ltd.** and **WGL Midstream Inc.**

Bluewater, a private equity company, announced April 28 that it has sold **px Group**, having transformed the business during its five years of ownership to a market leader operating energy and energy transition assets throughout the U.K.

SPOC Automation, a family of companies specializing in variable speed drive automation and inverter technologies, has launched its newest company, **SPOC Grid Inverter Technologies Inc.**

AD INDEX

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E&P plus

Senior Vice President of Events and Media/E&P Publisher
RUSSELL LAAS
Tel: 713-260-6449
dwest@hartenergy.com

Vice President of Sales
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

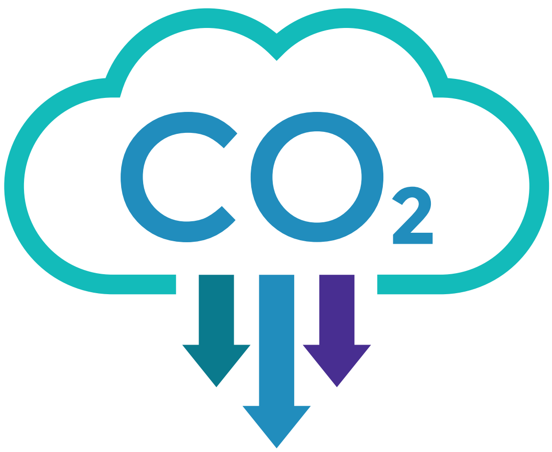
Targeting natural gas emission reductions

Performance-based guidelines are key to reducing methane emissions.

Richard Hyde, ONE Future

Natural gas plays a critical role in providing much needed energy to nearly 179 million Americans every day. It is a key driver in fueling the country's economy, and its demand will not diminish, even in a net-zero carbon economy. Natural gas powers more than half of the country's commercial buildings and is the largest source of reliable electricity generation—38%. Natural gas is plentiful, affordable and reliable; the growing use of natural gas in the U.S. has reduced the nation's methane emissions and lowered household heating and cooking costs.

According to the EPA, total methane emissions from natural gas systems declined 24% from 1990 to 2018. Annual methane emissions from natural gas distribution systems declined 73% from 1990 to 2018, even while natural gas utilities added more than 769,000 miles of pipeline to serve an additional 20 million Americans. Yet more is expected of the industry.



Following the 2020 election, one of President Biden's first actions was to sign an Executive Order directing the EPA to propose rules addressing methane emissions.

Our Nation's Energy Future (ONE Future) is a coalition of more than 40 of the largest and most engaged natural gas companies, all focused on reducing methane emissions to a level that ensures the sustainability of natural gas. The core belief of the coalition is that it does not view this as a one or two sector issue; this is a supply-chain issue. Together, we must become more efficient in delivering each molecule of natural gas from production to consumption while minimizing leaks.

While we share President Biden's view that methane emissions need more attention, we do not agree that a prescriptive, or one-size-fits-all, regulatory approach will be effective.

Instead, ONE Future strongly believes that regulations that take a performance-based approach will always be more successful because setting a performance target allows every company the flexibility to deploy and target capital where it will be most effective in reducing emissions. This is important because studies show the majority of emissions come from a small fraction of sources.

ONE Future also believes performance-based regulations encourage knowledge sharing and technology innovation. The coalition's members have established best practices such as engineering of facilities, well design, supplier selection and enhanced operational procedures. These practices partnered with technology innovation have led to lower emissions.

In fact, ONE Future member companies have successfully utilized this performance-based approach over the last several years. We set a goal of achieving a 1% methane intensity level, or 99% methane efficiency, by 2025. Methane efficiency is how efficiently a molecule of gas can be moved from production to consumption. Coalition members have achieved our goal in each of the years that we have reported. Our latest report shows that our methane intensity, based on 2019 data, was one-third of 1%. In other words, members are 99.67% efficient in delivering a molecule of gas from the rig to the burner tip.

Identifying targets for performance-based approach

One of the keys to a performance-based approach is to set a target. If the EPA were to follow the Paris Agreement, what target could be utilized for the natural gas supply chain?

One option is the International Energy Agency's (IEA) STEP Current Policies Scenario, designed to estimate what total emissions and associated temperatures would be if the world pursues a decarbonization path consistent with existing carbon emission reduction pledges. Interim goals are set using a 70% emissions reduction by 2025 and a 90% emissions reduction by 2030, with a net-zero goal by 2050.

Using IEA production data and EPA emissions data, the target would be approximately 00.33% for 2025, a target that ONE Future's members have already achieved, and they continue to work to attain further reductions.

ONE Future's results show that a performance-based approach works, today and tomorrow, and it is a step in the right direction. +