



Rapid Rise of REMOTE OPERATIONS

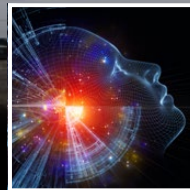
Have remote operations earned a permanent place in the oil field?



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Halliburton
Labs



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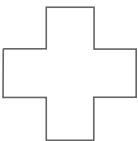
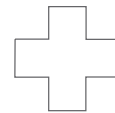
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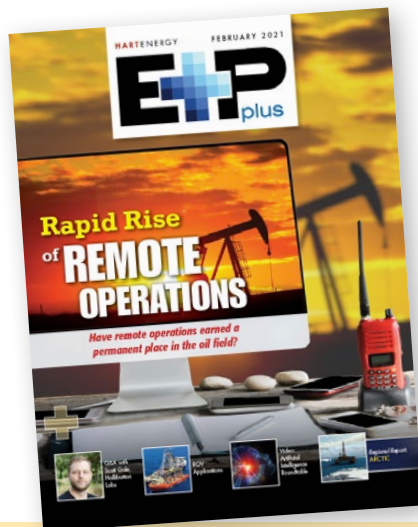
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About The Cover: Restricted movement due to global lockdowns has pushed oil and gas companies to reimagine operations and embrace remote technologies faster than ever. (Cover photo courtesy of Marc Morrison/marcmorrisson.com and Shutterstock.com; Cover design by Melissa Ritchie; Bottom images from left to right courtesy of Halliburton, C-Innovation; agsandrew/Shutterstock.com; and vitstudio/Shutterstock.com)

Coming Next Month: The March cover story will focus on water management solutions and will include interviews with Saudi Aramco, the Produced Water Society (PWS), Bedrock Automation, SitePro and XRI. This issue also will feature a roundtable video on water reclamation and reuse with PWS, Oilfield Water Logistics and WaterBridge. The Executive Q&A will feature an exclusive video interview with Superior Energy Services CEO David Dunlap. The Company Spotlight will highlight STRYDE, a new seismic technology startup. The Regional Report will cover the Bakken.

As always, E&P Plus will include its exploration, drilling, completions, production and offshore features in every issue. While you're waiting for your next copy of E&P Plus, be sure to visit HartEnergy.com for the latest news, industry updates and unique industry analysis.

E&P Plus (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Advertising rates furnished upon request. All subscriber inquiries should be addressed to E&P Plus, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. Fax: 713-840-1449; custserv@hartenergy.com. Copyright © Hart Energy Publishing, LP, 2021. Hart Energy Publishing, LP reserves all rights to editorial matter. No article may be reproduced or transmitted in whole or in parts by any means without written permission of the publisher. Federal copyright law prohibits unauthorized reproduction by any means and imposes fines of up to \$25,000 for violations.

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Haynesville Shale ‘private rejuvenation model’ takes spotlight

By *Velda Addison, Group Senior Editor*

An upstream oil and gas expert with IHS highlights the Haynesville Shale in a discussion covering markets, basin life cycle and the new economic model.

Analysts discuss growing pains facing US tight oil sector

By *Mary Holcomb, Associate Editor*

Similar to real-life growing pains, “it’s awkward and it’s painful,” but the U.S. tight oil sector is heading toward a healthier era, Wood Mackenzie analysts say.

EQT launches pilot to produce ‘responsibly sourced natural gas’

By *Emily Patsy, Senior Managing Editor, Digital Media*

EQT will seek to produce “responsibly sourced natural gas” from select wellpads by using continuous methane emission monitoring devices provided by pilot partner Project Canary.

Economics behind up-spacing trend in Permian Basin

By *Velda Addison, Group Senior Editor*

Spacing is a key piece of the puzzle for oil and gas companies looking to boost free cash flow.

Guyana-Suriname Basin tops oil exploration watch list

By *Velda Addison, Group Senior Editor*

Some drilling results, however, show the basin is not without risk for oil and gas exploration companies.

Oceaneering CEO Rod Larson talks energy transition

By *Velda Addison, Group Senior Editor*

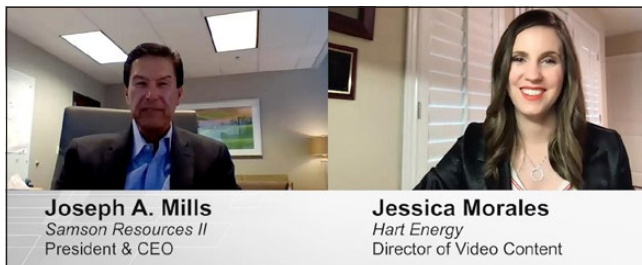
The oil and gas industry should be part of the conversation, given some of the expertise it brings to the table, according to Oceaneering CEO Rod Larson.

HART ENERGY VIDEOS

By *Jessica Morales, Director of Video Content*

Exclusive look at Samson Resources II sale with CEO Joe Mills

Bankruptcy, a global pandemic and a successful sale—Samson Resources II CEO Joe Mills has been through it all over the years. Hear this industry veteran discuss his optimistic mindset plus how he thinks the oil and gas business will need to adapt to face the future in this interview with Hart Energy’s Jessica Morales.



Future of oil and gas investments under Biden’s climate policy

The U.S. needs substantial investments in production to maintain current oil consumption, says Paul Goydan, Houston-based head of Boston Consulting Group’s North American energy practice, in an interview with Hart Energy’s Faiza Rizvi.

Leslie Beyer talks PESA, AESC merger

Former PESA President Leslie Beyer talks to Hart Energy’s Len Vermillion about the combination of PESA and AESC to form The Energy Workforce & Technology Council.



What updates to Colorado SB-181 mean for oil producers

New regulations will add further strain on oil and gas producers in Colorado, Jamie Davidson, asset performance management expert with Vysus Group, told Hart Energy’s Faiza Rizvi.

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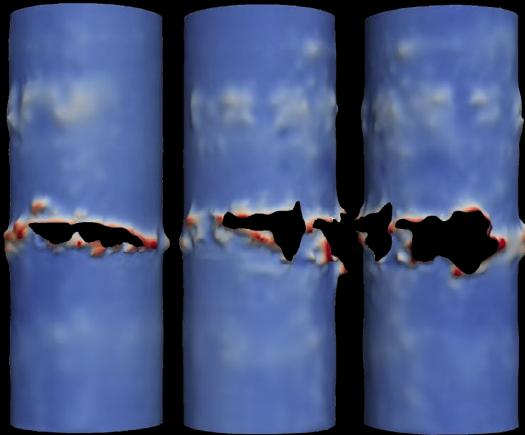
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ACOUSTIC IMAGING TECHNOLOGY

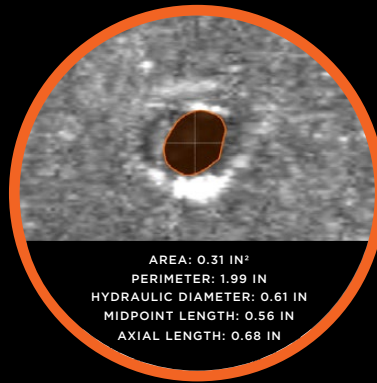


DarkVision's high resolution acoustic imaging technology gives you the ability to see inside your wells regardless of fluid clarity or condition. The HADES™ platform captures and delivers three dimensional data with unprecedented detail for all completions optimization and well integrity applications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

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AREA: 0.31 IN²
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 MIDPOINT LENGTH: 0.56 IN
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High Resolution 3D Images of Post-Fracture Perforations



150 °C
302 °F



103 MPa
15,000 psi



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Memory or
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As I
See It

Why it's time to speak up



(Source: Shutterstock.com/Hart Energy)

The industry can't allow its narrative to be owned and told by others.

In December 2020, I had the chance to interview Adam Anderson, CEO of Innovex Downhole Solutions. That was shortly after he became somewhat of a viral sensation among oil and gas professionals for a letter he wrote to the CEO of VF Corp., the company behind the popular outdoor apparel brand The North Face.

Anderson wasn't happy that his order for 400 jackets with his company logo was declined because The North Face said it wouldn't put an oil and gas company logo on its co-branded products. It was a curious stance considering the company makes its money by selling products made from nylon, a petroleum-based product.

Fed up, Anderson pointed out a number of facts and misrepresented truths in the decision, and his story was covered by KOSA-TV in Midland-Odessa, Texas, sparking an uproar by members and supporters of the industry, including U.S. representative Dan Crenshaw.

When I talked to Anderson, his frustration extended beyond The North Face. He was dismayed by our own industry's willingness to accept criticism of its existence, when in fact oil and gas have contributed countless benefits to the development of our modern society and will only continue to do so.

"I guess everyone gets themselves wound up in the ESG world and wants to apologize for what we do," he told me. "It's a problem. Leaders in our industry have become focused on this idea of what we do is a 'necessary evil.'"

I can't really say it better than that. We are living firmly in an anti-fossil fuel narrative that figures to only grow under the current makeup of Congress and the Biden administration. There's no doubt that the worst thing oil and gas executives can do right now is continue to deny the industry has issues with emissions, diversity and community relations. But what the industry also can't do is allow the narrative to be owned by others.

During Hart Energy's recent virtual [Executive Oil Conference](#), I chatted with Anton Rushakov, senior consultant with Global Affairs Associates, which specializes in ESG reporting and messaging. We talked about the idea that producers in the Permian Basin, in particular, have a real chance to take the lead in showing the world the tremendous progress the industry has made on flaring, carbon capture and more.

You'll get tired of hearing me talk about ESG through 2021 I'm sure, but understand it's not a fleeting trend. Your livelihood and those who work for and with you will depend on mastering it.

But back to Anderson's point. It's not only about ESG these days. It's vital that the industry show its worth to the future of society, to be part of it and continue to be a leader of modern development.

Anderson was informed by his distributor at the time of his denial by The North Face that the company lumped oil and gas in with tobacco companies and pornographers as companies it wouldn't want to use in co-branding. Do we really want the world to think of petroleum products like that? Of course not.

I know, you know and many out there know that oil and natural gas have ushered people out of poverty, led to the industrial revolution, made our society more mobile, helped feed the poor and treat the sick, and more.

The problem is there are many more who do not know. The only way they ever will is if industry leaders get together and start speaking up for themselves.+

Len Vermillion



Len Vermillion
Editorial Director
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**Read the full
interview with Adam
Anderson, CEO of
Innovex Downhole
Solutions, [here](#).**

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QA

Halliburton's Scott Gale provides insights into new lab program

Clean energy incubator program gives startups a head start.

Brian Walzel, Senior Editor

As many of the world's leading oil and gas producers commit to carbon neutrality, the service industry is moving rapidly to provide the tools needed to help those companies get there. After all, operators cannot get there on their own—they need the tools and technologies that help reduce emissions and push forward new energy sources into the mix.



(Source: Halliburton)



In this exclusive video interview, Scott Gale, executive director of Halliburton Labs, discusses the program and its goals with Hart Energy's Brian Walzel.

In an effort to fuel that drive, Halliburton recently launched its Halliburton Labs program. Halliburton Labs serves as a type of incubator initiative that gives participating companies access to Halliburton's laboratory facilities. According to the company, Halliburton Labs serves as a collaborative environment where entrepreneurs, academics, investors and industrial laboratories work together to advance clean, affordable energy.



Scott Gale

Companies selected to participate in the program will have access to technical expertise from Halliburton as well as its business network. In exchange, Halliburton takes a 5% equity ownership in the company.

"For early-stage, clean energy companies to achieve their growth targets, they require capital, technical and operational expertise, mentorship, access to lab space and the ability to demonstrate that they can scale their technologies," the company told E&P Plus. "Halliburton Labs brings these capabilities and resources together to support commercial success."

In this exclusive video interview, Scott Gale, executive director of Halliburton Labs, spoke with E&P Plus about the program, its goals and why Halliburton felt this program was necessary as the industry moves into a new era of low carbon intensity. +



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(Source: Varel Energy Solutions)

Varel Energy Solutions CEO shares strategies and insights

CEO Derek Nixon discusses the company's new direction after recent reset.

Brian Walzel, Senior Editor

In November 2020, Varel International Energy Services (VIES) announced a new path forward, which included a new brand renamed Varel Energy Solutions (VES). According to the company, the “major reset” includes “a redefining vision for business growth.” The new strategy was announced three months after the company received a multimillion-dollar investment from Blue Water Energy. The deal brought on Derek Nixon as the company's new CEO.

Nixon worked for 12 years at VIES. Prior to taking on the role at VES, he served as the vice president of downhole products (DHP). He joined Varel as a field salesman in 2006, later becoming regional manager before transitioning to DHP in 2014.

Nixon recently joined E&P Plus to discuss the company's new strategy and how oilfield service (OFS) companies can thrive in a price- and demand-challenged environment.

E&P Plus: Varel recently announced a “major reset” in its branding and its operations. Can you explain what that means?

Nixon: While Varel's been around for a very long time—going back to 1947 all the way to today—it's what we refer to as a little bit of an untold story at times. I know people know of Varel and know we offer drill bits.

And when they think of Varel, they think of drill bits. We also have the DHP brand. So it's really the formal bringing together of both brands as we go off on this new path. It's understanding what you're good at and keying into those key competencies to be able to really drive the brand forward and create value for shareholders.

E&P Plus: And will this reset include new products and service offerings? If so, what would those be?

Nixon: Yes, absolutely. We are actively looking at many deals. We have a good slush fund, so to speak, that's actively looking at making any deals that make sense. We look to expand on our completion portfolio. So things like toe sleeves and potentially frac plugs, casing flotation systems, packers, these sort of tools along with the stage tools make a lot of sense to us.

E&P Plus: What can the industry expect to see from Varel over the coming year?

Nixon: I think we're extremely active in getting the new brand out there [and] getting the new messaging out there. When we look at the purpose itself, it's just to create impact and be part of a winning team. Who doesn't

want to do that? It's making sure we have the right people on board and the right people to create value for our customers, both E&P and service companies moving forward. Everybody says that the key differentiators are people. But we'd like to take it a little bit farther than that and say really it's the relationships between our people, both internally and externally, that drive the value for the business. People are always a core competency, but it's understanding that everything that we do moving forward is about solving a problem for the service company or E&P company alike.

E&P Plus: How have the demands from your customers changed over the past year?

Nixon: It's shifted, largely geographically. One of the key strengths we have is a large worldwide network that we do business in, from the Middle East to Asia to Europe and North America as well as Latin America. But our revenue shifted to more of a 70-30 split, international versus domestic now, whereas historically it'd be more around a 50-50 split.

E&P Plus: What might you be looking for in a potential acquisition?

Nixon: Everybody's seeing right now, but there are a lot of deals to be had. It's finding deals that fit and go back to that core competency of what we want to do and how we want to be placed in the market. The main M&A activities we're looking for... we're looking for businesses that have, it doesn't have to be huge eval but positive eval right now.

Free cash flow is obviously a must and then synergies. What sort of synergies can we find between the organization that we're integrating into our footprint? And how quickly can we develop it?

We have the global platform ready, offices everywhere around the world, and the sales and operations infrastructure. So what can we take into that platform and really grow the business with it?



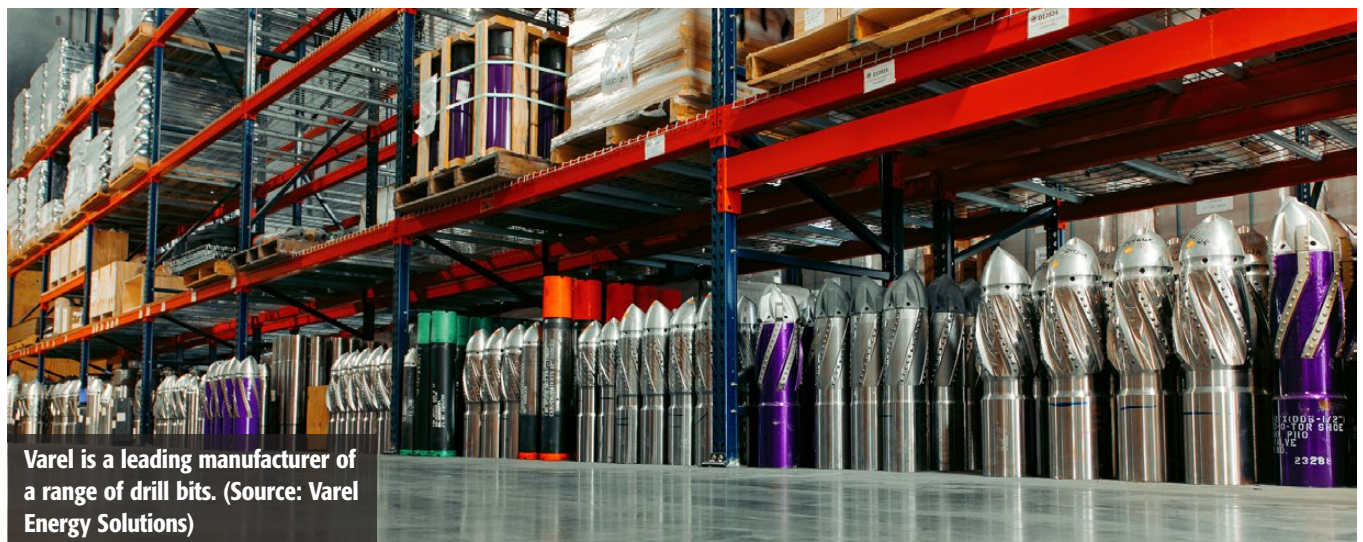
"We have a good slush fund, so to speak, that's actively looking at making any deals that make sense."

—Derek Nixon, Varel Energy Solutions

E&P Plus: How do companies like Varel and other OFS companies thrive in the low demand and low price market we're in?

Nixon: It's doing the simple things right now [and] concentrating on things that we can control. There are so many things outside of what we do every day that we can't control. We can't control the oil prices. We can't control the pandemic that's happening. So I think really just focusing on the business [and] getting back to just simple business [is key]—selling to good customers and making sure we're getting paid on time, and using our inventory value to help drive cash flow.

When we look back at this year [2020], the year has been extremely challenging. But it's been a good year from a business standpoint. When we bought the business back in March [2020], we didn't know what was going to happen. But we were planning for change anyway, and we wanted to change up the business [and] the approach. So this has really fast forwarded that a little bit, and it's really going to allow us to go back to retooling the industry. +



Varel is a leading manufacturer of a range of drill bits. (Source: Varel Energy Solutions)



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Conferences

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


In surveys, our attendees always cite two principle benefits from business conferences. They value *programming* – the topics addressed, by whom, and "lessons learned" – and they value *networking* – collaborative interactions with fellow

professionals. Our goal is to inspire new business ideas and opportunities for every participant in any of our events.

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

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

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VIRTUAL CONFERENCE



Feb. 16, 2021

VIRTUAL CONFERENCE



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Nov. 2-3, 2021
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Rapid Rise of REMOTE OPERATIONS

Restricted movement due to global lockdowns has pushed oil and gas companies to reimagine operations and embrace remote technologies faster than ever.

Faiza Rizvi, Associate Editor

The year 2020 will be remembered for many reasons: a global pandemic, an economic crisis, a historic price war, negative oil prices—the list is endless. But despite the cloud of setbacks that overshadowed the oil and gas industry last year, digital transformation was a silver lining that accelerated at a pace never seen before.

Call it adaptive mode, survival strategy or just plain necessity; oil and gas companies, which were already making steady progress automating operations, accelerated acceptance of remote technologies during the pandemic when workforces were grounded and a low-price environment pushed businesses to do more with less.

“2020 will be remembered in part as the year digital transformation went fully mainstream in the energy sector,” Brad Barth, chief product officer with InEight, told E&P Plus. “As businesses adapted to the pandemic, the corresponding shift to remote work served as a jolt to the status quo. The result was a nearly industrywide embrace of cloud technology, digitalization and remote work more deeply than ever before, keeping projects moving despite unprecedented challenges.”

In what could be the industry’s next leap toward digitalization, major service companies continue reimagining operations to adjust to a leaner fracking market. Remote drilling, for instance, has seen an uptick over the pandemic period when workforces were grounded and complex drilling challenges were solved remotely by domain experts.

“It’s pretty amazing that the majority of our drilling work is taking place remotely,” Paul Madero, vice president of drilling services with Baker Hughes, told E&P Plus. “See, the beautiful thing about remote operations that most people don’t understand is that once you open that digital world, your ability to deploy these tools accelerates because now you’re very comfortable with it. It’s really kind of like when we all started using the internet. At first, we didn’t really know what it was, and when you start to realize its capabilities and the productivity that it can unlock, it’s tremendous.”

He continued, “This year alone, we’ve had over 50 new customers across more than 12 countries adopt remote operations. So it gives you a bit of a breadth of the adoption rate we continue to see,



(Photo courtesy of Marc Morrison/marcmorrison.com and Shutterstock.com; Design by Melissa Ritchie)



“We are unlikely to reverse back to the old ways of working simply because people are now seeing and getting used to the advantages of remote operations, which are much faster, more efficient and have safety benefits.”

—Alexander Boekhorst, Shell

and we’re really excited about what the future holds for remote operations at Baker Hughes.”

‘Here to stay’

Analysts unanimously agree that post-pandemic success for oil and gas companies means reducing costs and increasing productivity. Therefore, getting comfortable with remote application of skills has become critical.

The question is, will remote operations continue to thrive even after the pandemic?

“Remote operations are here to stay,” according to InEight’s Barth. “The pandemic has accelerated trends that were already well established, not just in the energy sector, but across all

major industries. The necessary shift to remote led many organizations—including some of the biggest players in the energy sector—to accelerate their move to the cloud, but the writing has been on the wall for years: organizations that are successful with digital transformation can unlock benefits like remote project management, more efficient collaboration, better visibility and lower IT costs.”

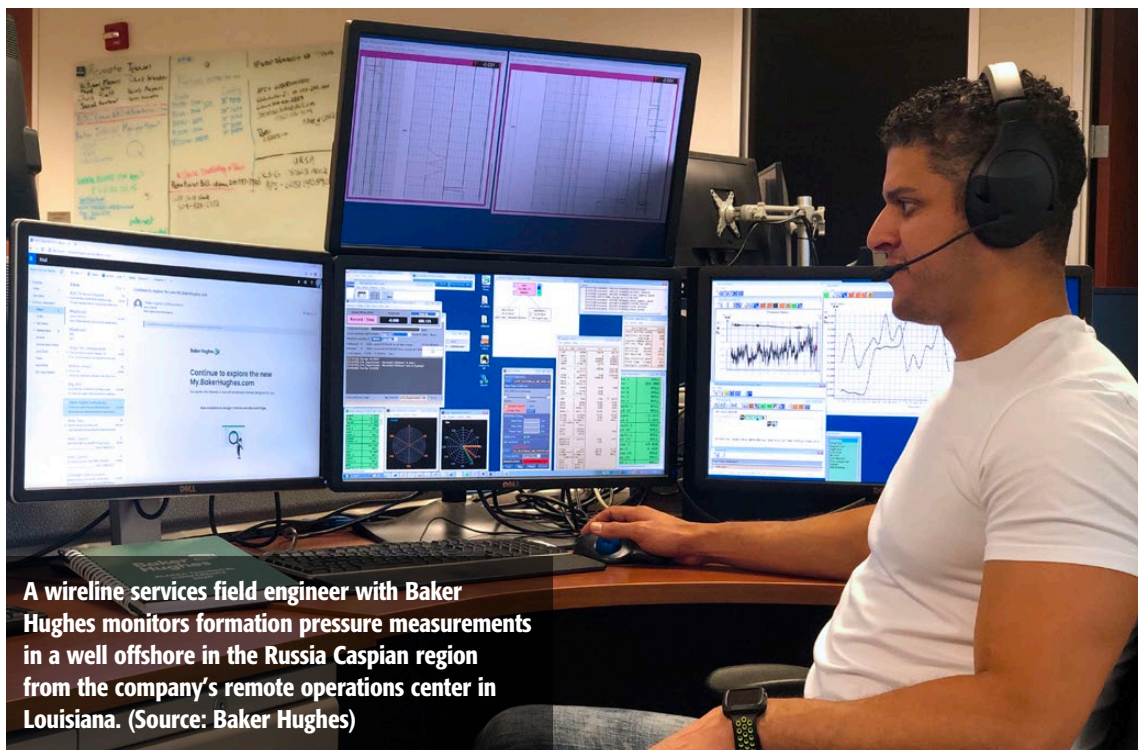
Others expressed similar sentiment.

“This year, we have seen a huge uptick in remote operations, and I expect it to continue,” said Alexander Boekhorst, vice president of digitalization and computational science with Shell. “We are unlikely to reverse back

to the old ways of working simply because people are now seeing and getting used to the advantages of remote operations, which are much faster, more efficient and have safety benefits. There is no need to fly people around or get close to drilling operations.”

Boekhorst continued, “Shell has been using remote technologies for about two decades. However, we have seen this trend accelerating recently, part of which is because of necessity.”

Discussing remote technologies that have seen an increase in deployment rate this year, he said there has been a huge uptick in the use of Shell’s automation system called Shell WellVantage. This real-time connection transmits data from



A wireline services field engineer with Baker Hughes monitors formation pressure measurements in a well offshore in the Russia Caspian region from the company’s remote operations center in Louisiana. (Source: Baker Hughes)

the drilling rig to specialists and drilling engineers. He added that the company has incorporated advanced artificial intelligence (AI)/machine learning (ML) solutions in the system to provide much faster insights, optimize drilling operations and increase efficiency.

Over the past few months, Shell also has doubled down on the use of augmented reality (AR).

"This year, we have seen a tenfold increase in the use of virtual rooms that are powered by AR," Boekhorst said.

He discussed the increased use of AR devices mounted on helmets, which an on-field worker can use to get real-time assistance via a video call, allowing the remote expert colleague to essentially see through their eyes and offer guidance remotely. Hundreds of these devices are being used in more than 30 locations.

He added that predictive maintenance is another area that has seen an uptick in activity.

"We have seen a massive increase in its deployment. Over 4,000 pieces of equipment are under direct predictive maintenance using 800,000 sensors. We can monitor and forecast issues with valves, compressors [and] pumps before they happen, and that is growing really fast. We have 23 assets in total under predictive maintenance monitoring with a huge amount of data supporting that," Boekhorst said.

Future of work

As the oil and gas industry accelerates its embrace of remote drilling and fracturing, the changes are expected to reshape the workforce and change the workplace permanently.

InEight's Barth outlined three essential steps that energy companies need to take to enable the future of work in their organizations:

First, companies need a cloud-based software platform that is powerful enough to serve as a single source of truth for collecting and analyzing data from all of the various roles involved

both internally and externally, while also being adaptable enough to meet the changing needs of a business as it grows. A cloud-based, subscription model for software also enables rapid ramp up and ramp down of usage as needed to reflect market conditions.

Second, with information overload being a very real risk, companies need to identify what information and key performance indicators are most critical for reporting and dashboards as well as for benchmarking. The time and money spent in the course of doing something

Upward momentum in remote operations



In this exclusive video for E&P Plus, Hart Energy's Faiza Rizvi interviews two senior executives from Baker Hughes: Paul Madero, vice president of drilling services, and Shan Jeegatheeswaran, vice president of digital for OFS.

Jeegatheeswaran said the upward momentum in remote operations will continue to unlock opportunities and values, adding that remote operations is a "launch pad" that will shape the future operations of the oil field.

"The technical architecture being built for automated operations will lead to innovations that we don't even consider today," he said.

"Remote operations means different things to different people," Madero added. "On the upstream side, what we're really talking about when we say remote operations is truly moving the activities and functions of jobs in the traditional sense that used to be done on the rig or the well site back in the remote operating centers, where you have the same amount of control that you did before."

Madero also highlighted three key areas to be considered for successful remote operations: state-of-the-art physical equipment required to capture and transmit data, advanced software that provides data channels, and the workflow.

"Remote operations are not just limited to drilling," he said, adding that it extends to the full wellbore architecture from drilling to productions and completions. "This year, due to some of the challenges caused by the pandemic, we've been able to activate liner hangers remotely, we've also got a very long legacy of being able to optimize artificial lift systems, which have a direct correlation to daily production."

Discussing the advantages of remote drilling to increase operator efficiencies, Madero said remote operations provide the opportunity for better collaboration, which is critical in the current environment. +

A shift toward autonomous operations



In this exclusive video interview with E&P Plus, Weatherford executives discuss how they deployed remote technologies to effectively manage operations during the pandemic.

Joe Isaac, global product line vice president of liner systems and cementing products with Weatherford, explained how the company has been increasingly using AccuView, a remote installation support service and system that transmits secure, real-time information between personnel on the platform rig and the subject matter experts.

"Today we run hundreds of jobs on AccuView, mostly in our casing exit business. About a year and a half ago, we started using AccuView for the liner systems business as well," he said. "With all that in place, we were actually quite prepared for what the pandemic brought on."

In July 2020, Weatherford remotely installed a 16-inch liner hanger on an offshore platform in Sakhalin Island, Russia, during the COVID-19 lockdown. Remote training and monitoring procedures enabled the successful installation of the liner hanger system, cementing products and tubular running services.

Manoj Nimbalkar, global vice president of automation production and software with Weatherford, applauded the industry's efforts in overcoming automation-related challenges. He pointed out that not too long ago, operators were unwilling to share their data due to poor cybersecurity, there were connectivity issues and several remote technologies were still in their infancy.

"What we're seeing now is improved connectivity, improved trust factor in data sharing from operators because of the improvement in cybersecurity... I think the market is shifting more toward autonomous operations," Nimbalkar said. +

should result not just in an outcome but also in captured knowledge that contributes to improvement for the next time.

Third, companies need to design and implement a change management plan and organization commitment to ensure a successful transition and instill a culture of collaboration and transparency. Too often, projects

with the potential to transform a business for the better get derailed and their value diminished by a resistance to change and the tendency to revert to old ways in moments of stress.

Where do people fit in the equation?

Pablo Avogadri, partner and associate

director with BCG, foresees an inevitable reskilling of the workforce in the coming years. While other industries have attracted millennials and are more "digitally ready" for market recovery, he said the oil and gas industry historically faces a skills gap.

"If you look at the demographics of the oil and gas industry, there is clearly a generation gap, which is making reskilling tough. When you talk about remote operations, we must work on upskilling and efficiency of the workforce. In order to shift the power from the field to the remote centers, it is important to change the way people work."

According to Stuart Harris, group president of digital transformation with Emerson, people are being replaced with sensors for effective asset management.

"If you're going to remove people from the operations to work remotely, then by necessity you need alternative eyes and ears for the process, and that comes in the form of sensors," he said.

He added that Emerson uses wireless non-intrusive battery-powered sensors that become the "eyes and ears" of the production process, which are not only used for typical process measurements around pressure, temperature, level and flow, but also for measuring corrosion, acoustic monitoring and toxic gas detection.

"These measurement technologies become very, very important as you start to take people out of the operations," Harris said.

Breaking the cultural norms

Baker Hughes' Madero underlined that the industry needs to break down cultural norms and adopt change management to advance in the area of remote operations.

"The biggest challenge is us," Madero said, adding that humans are creatures of habit and consistency. "Having been in the industry for over 15 years, the one misconception I've noticed in the industry is that some-



“We’ve certainly seen that the drive toward remote and integrated operations has accelerated as a result of the pandemic. It’s very in line with the new kinds of operating challenges that oil and gas producers are facing.”

—Stuart Harris, Emerson

how physical presence equates to enhanced control of the outcome. But the truth is, that’s no longer the case.

“Through the workflows, through the ecosystem that we’ve built, through the blueprint that we have embedded in our technology for the last 20 years, our ability to drive more consistent outcomes is really coming through. So it’s really just trying to overcome those cultural norms of

believing that you physically need someone in front of you for enhanced control. And I think what you saw in 2020 is that we’re proving that’s no longer the case.”

Madero also pointed out that remote operations have hit the “tipping point,” citing that more than 50% of Baker Hughes’ operations were carried out remotely in 2019, which increased to 80% in 2020.

Underlining speed and integration as two major benefits of automation, he said the ability to use AI and ML continues to accelerate, which has improved the speed, quality and consistency of decision-making, thereby optimizing operations in a much shorter cycle time. Madero also discussed that the increasing shift in automation will lead to integrated operations. With a “digital backbone”

By the
Numbers

AI’s impact on oil and gas

Artificial intelligence (AI) operations in the oil and gas industry were valued at **\$2 billion** in 2019 and are expected to reach **\$3.8 billion** by 2025, a CAGR of 10.9%.

15% to 25%
reduction in total
maintenance costs with AI

92% of oil and gas companies are either investing in AI or plan to in the next two years.

AI predictive maintenance can reduce unplanned downtime by **20% to 50%**

Up to **10%** improvement (or 1 trillion extra barrels of oil) in the global average underground recovery by using an AI analytical approach

~27 days of unplanned downtime per year is what the average offshore oil company experiences, which can lead to annual losses from **\$38 million to \$88 million.**

Automation trends and opportunities



STUART HARRIS
GROUP PRESIDENT OF DIGITAL TRANSFORMATION
EMERSON

FAIZA RIZVI
ASSOCIATE EDITOR
E&P PLUS

In this exclusive video interview with E&P Plus, Stuart Harris, group president of digital transformation with Emerson, discussed the accelerating trend of remote operations, its challenges, opportunities and future trends.

"We've certainly seen that the drive toward remote and integrated operations has accelerated as a result of the pandemic. It's very in line with the new kinds of operating challenges that oil and gas producers are facing," Harris said.

He pointed out that automation can be used a strategic lever in driving down project costs, which is much needed at a time when producers are looking for innovative ways to cut costs.

"When it comes to what we can do as an automation company to help change the cost position of the operating model regardless of what the oil prices are, we actually have a project execution methodology and leverage automation in an approach that we call project certainty," Harris said. "And what we have demonstrated is that with some of these technologies and approaches, we can use automation as a strategic lever to affect the cost of the whole project. So while automation might only be 1% to 4% of the total project costs, we have demonstrated that it can actually impact 10% or more." +

supporting field operations, there will be more multiskilling and less people on the field, supported by experts in the remote operation centers, he said.

Future trends

Discussing the future trends of remote operations, Shell's Boekhorst said he expects to see a contin-



"2020 will be remembered in part as the year digital transformation went fully mainstream in the energy sector."

—Brad Barth, InEight

ued uptick in the usage of AR and drones in data collection as well as the deployment of more advanced solutions in the area of AI and ML for data processing.

"New technologies offer the opportunity to increase both cost and operational efficiency," he said. "From our forecast of energy assets, remote technologies will expand production optimization and in real time steer the process control system to more optimal settings. Remote operations also reduce the CO₂ production per unit of energy produced; there is an example of how it helps in efficiency of operations."

According to Emerson's Harris, the next step in remote operations will be the widespread adoption of autonomous operations—using technology to enable automated decision-making.

"Often times, I think our industry intermixes remote operations, integrated operations and autonomous operations; sometimes those terms get used synonymously. In actual fact, they've each got distinct value propositions, and as we work with customers, what we're seeing is depending on what their priorities and business goals are, it skews more to one or the other. And we find that most companies are looking at the combination of these three ideas as an operating model for the future."

He added that oil and gas companies should adopt this new operating model to face the challenges of current market environment.

"As we think about reducing greenhouse emissions and the regulations that the industry is facing, if we can use new ways of work, especially autonomous operations, and leverage cloud-based technologies and wider digital transformation technologies, there is a synergistic effect here between some of the new ways of working and the business challenges that the industry faces," Harris said. +



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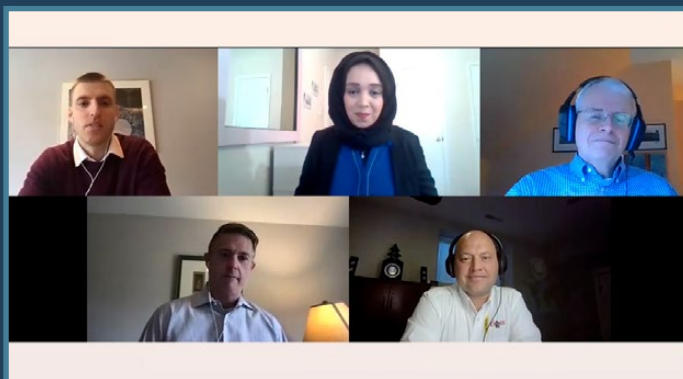
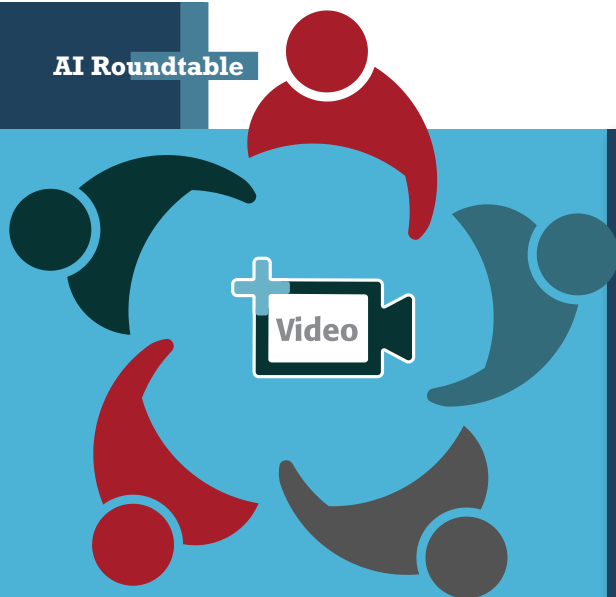
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In [this](#) roundtable discussion with Hart Energy's Faiza Rizvi, senior executives with RigER, Ambyint, Validere and Actenum Corp. discuss how AI, machine learning and analytics are shaping the future of the industry.

How AI is driving oil and gas market recovery

AI technologies can play a key part in the transformation of the value chain of the oil and gas industry.

Faiza Rizvi, Associate Editor

In an exclusive roundtable discussion, senior executives with four energy tech companies discuss how the downturn has accelerated the need to adopt new technologies and how artificial intelligence (AI), machine learning and analytics are shaping the future of the industry.

"The pandemic has changed the mindset of the executives, and right now everyone understands there is no way to run business without digitalization. More and more executives are considering digital transformation as the number one step," said Michael Maltsev, CEO and president of RigER.

"What I've been hearing since 2004 is the importance of digitizing the oil field, and it's just a never-ending story," added Owen Plowman, vice president of business development with Actenum Corp. "Because of the downturn, executives are really starting to examine areas in their organizations where they had not really thought about efficiency gains before."

SPEAKERS:

- **Michael Maltsev**, CEO and president, RigER
- **David Zahn**, COO, Ambyint
- **Dr. Ian Burjess**, co-founder, Validere
- **Owen Plowman**, vice president of business development, Actenum Corp.

JUMP TO A TOPIC:

- Downturn and the adoption of AI (0:48)
- AI and cost efficiency (4:10)
- AI and the workforce (8:51)
- Challenges in implementing AI (15:37)
- Upcoming trends in AI (18:55)

Addressing the impact of AI on the workforce, Dr. Ian Burjess, co-founder of Validere, said the oil and gas industry needs to be

equipped with skilled workers in the area of data analytics.

"What's really powerful with the combination of [oil and gas] operations and AI is the abundance of scientific data," he said. "There is an incredible demand for people that really understand the scientific method."

Ambyint COO David Zahn said 2020 saw a strong focus on new technologies that drive value and, consequently, there was a strong acceptance in edge computing among oil producers.

"We did a survey of over 30 operators a year and a half ago to find out what their edge computing strategy was, and it was really quite nascent ... there weren't any well-defined use cases beyond basic data analytics," he said. "We believe that 2021 will see edge computing come more to the floor. Last year was focused on new technologies that will help drive value, and also there are specific use cases that edge computing can help with." +



A home for North American hydrocarbons

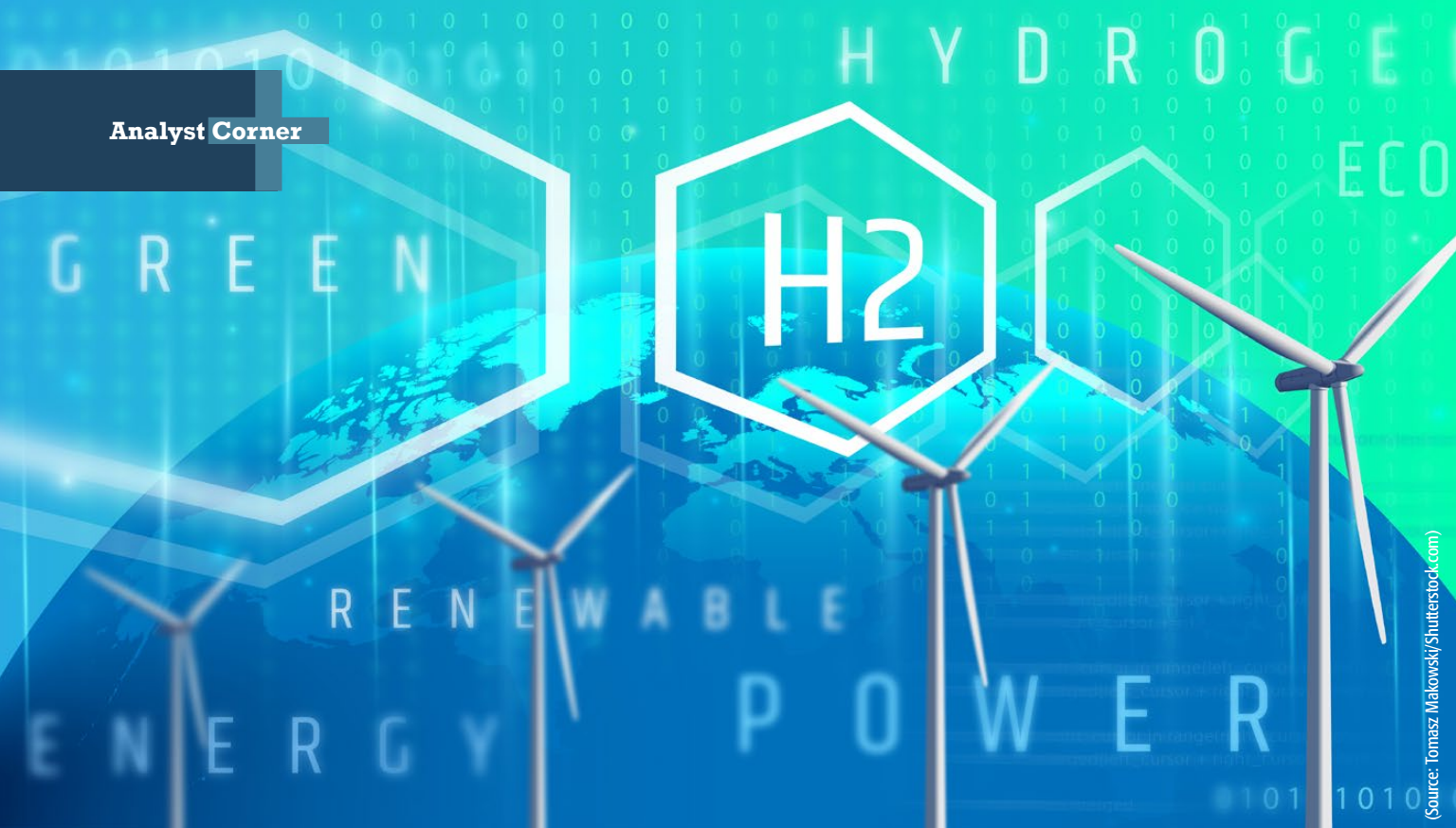
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Opinion: Energy transition and why an electric car is not the solution

It is time for the U.S. to take the lead in transitioning to a hydrogen economy.

George H. Lugin I, Hall Maines Lugin

Japan has been an early mover toward a hydrogen-based economy. Its roadmap includes developing a hydrogen supply chain, increasing the use of hydrogen across different sectors, promoting hydrogen technological innovation and public buy-in, and promoting an international hydrogen collaboration. The Paris Accord was a big driver, as was the Fukushima Daiichi disaster. The latter event resulted from natural causes (e.g., earthquake and tsunami) releasing radiation into the atmosphere and radioactive isotopes into the Pacific Ocean. Remember news of radioactive debris washing up on the shores of Washington?

The Japanese plan was thus born of the mother of all invention—necessity. While the U.S. hydrocarbon industry does not have that imminent necessity, it would be wise to pay attention and get on board before the train leaves the station.

And here is the point: it is the transition that requires America's famous innovation.

The first issue is changing a deep-rooted hydrocarbon U.S. mindset, which author Bryan Burrough famously wrote about in *The Big Rich*, to the simple truth that a transition away from hydrocarbons is coming.

The second issue is focusing the right people on what the ultimate renewable energy solution will be.

The third issue—the most complicated yet most important—is beginning the transition from hydrocarbons to hydrogen, the ultimate renewable now. The U.S. is no Japan, so we learn from it but do not copy it.

Changing the mindset

Spindletop created something that seems to have ingrained the value of hydrocarbons in generations of not just Texans, but all of the U.S. over a certain age. Despite headlines, don't think for a minute that California or the East Coast are not included. Companies and capital markets on the coasts have and still do make great fortunes off hydrocarbons. California has some of the largest fields in existence that have been pumping for more than 100 years. We still see can't lose deals almost every day from Texas to California to South America to Indonesia. For example, Exxon's Guyana Payara Field will begin production in 2024 and is expected to produce 220,000 bbl/d of oil from an estimated \$9 billion in development costs.

Hydrocarbons are going nowhere fast without government intervention, which is happening in the most developed nations. Initiatives in the EU are likely as significant as in Japan. Even so, this will not effec-



“U.S. oil and gas companies need to reinvent themselves as true energy companies and use their world-leading innovative talent to face the inevitable changing energy world.”

— George H. Lugin IV, Hall Maines Lugin

tuate change at the top fast enough. What will be social sentiment from the young. You see it on trading platforms such as Robinhood, in social media groups and even in the lower average age of politicians each year. The world is more connected, and that has brought with it more power to the youth and less to the aged establishment. So, change the mindset and get on the train before it leaves.

Hydrogen endgame

What is the renewable energy endgame? Hydrogen—the most abundant element in the universe and the energy used by nature. Solar, wind and even geothermal all exist because of the sun, which, like every other star, is a massive fusion reactor. Without diverting to a discussion of Nebula Theory, the sun’s hydrogen undergoes a fusion reaction that unleashes light and heat (the same thing at different wavelengths), which radiates to the earth. This in turn allows plants and animals to grow, the wind to blow and even the earth to spin (as well as dissipate heat from its core).

It is a hydrogen endgame. The only question is how fast can the U.S. get there and do we let other economies (whether single or a bloc) beat us? Of course, this question does not need an answer. For those familiar with Moore’s law—predicting the number of components on an integrated circuit (chip) would double every two years—you may know we can thank this rapid pace of innovation for everything, from smartphones to cheap laptops and GPS.

America is the world’s innovator. That innovation needs to be focused on the hydrogen transition.

And there is the rub. How do we transition to a dominant hydrogen-based energy economy? The hydrocarbon infrastructure is vast and aging. Most automakers have already started down a battery EV path instead of fuel cell EVs, and most non-integrated oil and gas companies only want to drill for hydrocarbons.

Navigating supply and storage roadblocks

Most see storage and transportation of hydrogen as the major roadblock, but we already store and transport similarly volatile substances.

Advancement in materials has already led to safe storage and transportation of hydrogen. Again, American innovation is the key, but we need the necessity.

Generation of hydrogen is another perceived roadblock. There are many ways to do this, some are green and others not so much. Green hydrogen is generated from renewable sources, so no greenhouse gases (GHGs) are generated in the process. Most people think of electrolysis, by which water is separated into hydrogen and oxygen using electricity. This process is green if the electricity comes from renewable sources like wind or solar. But the efficiencies are not there when compared to hydrocarbon electrical generation. This amounts to another innovation issue and frankly one that has a solution staring us in the face: biomass gasification.

Gray and blue hydrogen are also promising as existing infrastructure can be utilized. Gray hydrogen is generated from hydrocarbons but emits GHGs in the process. Blue hydrogen is also produced from hydrocarbons, but the GHGs are captured and injected back into the ground as opposed to being released to the atmosphere.

Another encouraging technology is direct recovery of hydrogen from existing oil sands (commercial or abandoned). The details are complex, but the process involves heating the remaining hydrocarbons and water in situ to break apart the molecules (thermolysis). The lightest element—hydrogen—can then be recovered from the wellbore leaving the other elements underground.

U.S. oil and gas companies need to reinvent themselves as true energy companies and use their world-leading innovative talent to face the inevitable changing energy world. Make no mistake, this transition will take decades and involve technologies yet to be invented. But green is coming. +

About the author: George H. Lugin IV is the shareholder, director and president of litigation law firm Hall Maines Lugin, P.C. Lugin’s expertise is grounded in a mechanical engineering degree, registration as a patent attorney and hands-on experience as a practicing engineer at NASA’s Johnson Space Center in Houston.



CoreSpec Alliance provides mercury intrusion capillary pressure testing. (Source: CoreSpec Alliance)

Generating value from drill cuttings

William Hagan, Stratagraph; David Hume and Allen Howard, PetroScale Reservoir Solutions; and Michael Santiago, CoreSpec Alliance

A new reservoir analysis software delivers an evaluation for cuttings, logs and drilling data to improve reservoir characterization.

Conventional cores, or whole cores, are solid cylinders of rock that can be brought to the surface as a single piece. These cores are used to model reservoir behavior to optimize production, based on the analysis of core porosity, permeability, fluid saturation, grain density, lithology and texture. However, the process of obtaining and analyzing cores is a notoriously costly one, calling for rig time, crew mobilization to site and subsequent analysis.

Drill cuttings, on the other hand, are removed from wells and brought to the surface in drilling mud and are often examined to make a mud log of the

subsurface materials penetrated at various depths. Even though cuttings are basically the same material as cores, many operators have traditionally been suspicious of drawing reliable data and conclusions from drill cuttings.

The Cuttings Alliance, a consortium of Stratagraph, CoreSpec Alliance and PetroScale Reservoir Solutions, is working on shifting that attitude. The aim of these oil and gas service companies is to offer their clients information worthy of a coring job for a smaller price.

Collaboration

Stratagraph has been delivering mud logging, geosteering and wellsite super-

vision for more than 50 years, whereas CoreSpec's specialty rock property testing goes beyond traditional cuttings analysis to create unique datasets. PetroScale uses geoscience, engineering and applied data analytics to determine reservoir and geomechanical properties. Within the Cuttings Alliance, Stratagraph is responsible for collecting a representative sample of the formation that has been drilled through, and PetroScale and CoreSpec handle all geophysical and geomechanical modeling.

Together, the team developed a process that provides true insight into a well to help the production model and inform future completion work in the same field.

With the industry shifting in recent years toward long horizontal drilling, operators are increasingly finding traditional core samples less meaningful, derived as they are from one distinct spot that may end up 7,000 ft away, laterally, from the continuation of the wellbore. Because cuttings are a natural byproduct of the drilling process, the Cuttings Alliance has devised a process that merely calls for the operator to collect what they already have—drill cuttings.

From that point on, the Cuttings Alliance manages all logistics and works together as one entity to bring mud logging, cuttings analysis and sophisticated well interpretation under one roof to reduce costs and improve well productivity in the field.

New analysis software

In recent years, myopic businesses have sold vast amounts of data into the oil and gas industry to a point where operators have acquired archives of data that are not realizing any return on investment. Operators either do not have time to action the data or they lack back-office personnel to use the data to produce executable decisions to optimize operations. If the data were properly harnessed, operators could derive better understanding of their reservoir, which in turn equates to better

fluid and proppant programs, more efficient fracs and higher well productivity.

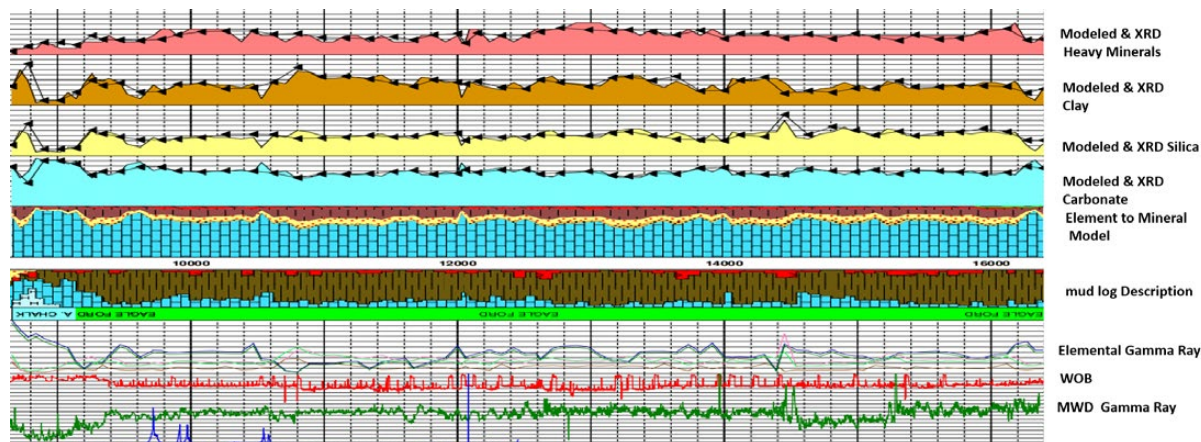
Since modern day operators possess reams of data but often lack the means of interpretation, RockProp was developed. This new software delivers analysis for cuttings, logs and drilling data. With traditional formation evaluations, an operator has to approach three different vendors: a mud logging company, a laboratory for sample analysis and a data interpretation service. Alternatively, by engaging with the Cuttings Alliance, the operator is afforded more control over its cuttings analysis workflow. The operator has access to a one-stop shop managing the migration of the cuttings from the well site to the laboratory and interpretation in a fully streamlined process, billed on a turnkey basis to further help operators predict and manage costs.

This approach improves overall process efficiency and creates an opportunity to remove three separate entities and their associated mark-ups and variations in quality standards to deliver meaningful, relevant and actionable information. At the end of their engagement with the Cuttings Alliance, the operator is not just provided with more data, but rather a set of conclusions that advise on which data are important and relevant to improve the operator's completions and evaluations going forward.



Stratagraph has logged more than 2,500 wells across Texas since 2005. (Source: Stratagraph)

Many operators have separate programs and budgets for mud logging, cuttings analysis and interpretation. RockProp brings these services together into a single product to save time and money while providing a sophisticated interpretation to improve reservoir characterization. RockProp combines log and drilling data with physical properties measured from cuttings to output reservoir parameters. Mineral models, total porosity, effective porosity and bound versus mobile fluid estimates are



The RockProp log, when combined with drilling data and physical properties measured from cuttings, enables an accurate output of reservoir parameters. (Source: Cuttings Alliance)



CoreSpec Alliance is fully equipped and capable of providing clients with geological and petrophysical measurements. (Source: CoreSpec Alliance)

obtained. This provides an assessment along vertical or horizontal wellbores that is independent of log models, which can be used to refine 2D and 3D reservoir models, improve geosteering, optimize completion designs and better characterize well potential.

In practice in the US

The Cuttings Alliance formed a relationship with an Eagle Ford operator that was able to supply the team with extremely useful data. Instead of analyzing broadly spaced samples, the operator had analyzed every sample. As a result, the Cuttings Alliance was able to validate its mineral model, along with its porosity and fluid models, by looking back and comparing the results to what the operator actually did, observing a match in the two and devising a set of recommendations as a result. By engaging closely with the operator and demonstrating the model, the Cuttings Alliance was able to prove the validity of the method.

As the whole process matures, fewer samples will need to be taken, bringing down associated costs even further.

More recently, the Cuttings Alliance has engaged RockProp in vertical wells

in the Delaware Basin area of the Permian Basin: an area with complex petrophysical issues. The operator has, to date, invested significant expenditure on wireline logs and other types of measurements to understand nuances and variability within its pay sections. By deploying the RockProp service in this case, the operator expects to save approximately \$200,000 per well, with the data providing even more value at the completion phase.

Future development

Frac and completion jobs can represent up to 70% of the costs of the well. If an operator can save one or two frac stages at least, they could save upward of \$500,000.

RockProp is in the early phase but will serve as an enhancement or even a replacement to extremely expensive logging programs in appraisal and development assets from a reservoir characterization perspective. This interpretive deliverable will be rounded out with innovation in the geomechanics space as well, where a reservoir is addressed from a mineralogical perspective and with data that would impact completions. Reducing

pressure on an operator's completion budget is an ongoing area of development, with the goal of obtaining additional information from RockProp analysis of the cuttings and developing completion fluid programs from the data, enabling clients to cut their fluid budgets significantly.

In the current economic environment, there is hesitation about expenditure on scientific analysis. As such, fewer rock samples are being taken for direct measurement and calibration. Although less data can be derived from cuttings in comparison with a whole core, experience has demonstrated that when coupled with secondary calibration data or mud logging data, a strong model can be built to the extent that the cuttings can be used to improve engineering solutions and remove a tremendous amount of cost from drilling operations.

Essentially, the Cuttings Alliance creates a workflow and a program that can help operators reduce costs, while still maintaining the quality of data that are required to properly develop an asset. +



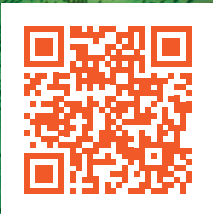
Stratagraph's experienced logging crew is working on a job in Zavala County, Texas. (Source: Stratagraph)

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Getting your arms around environmental, social and governance (ESG) issues can be quite a task. As one observer noted, current criteria used to evaluate ESG issues are “highly diverse on a massively complex subject.” ESG issues have never before claimed such importance. Public companies, no matter in what sector they may operate, “ignore this at their peril,” according to Pavel Molchanov, an energy research analyst at Raymond James & Associates Inc.


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The testing of Reelwell's DualLink took place at the NORCE Ullrigg. (Source: Reelwell)

Digital downhole technology enables better drilling decisions with data and power

Ian Silvester, CEO USA, Reelwell

The focus on a reliable solution for powered and wired drillpipe has been a significant challenge for the drilling industry.

Constant technological innovation in the oilfield drilling sector has driven the industry forward over the years. Through advancements in PDC bits, high-specification drilling rigs, MWD, LWD and rotary steerable tools, technical changes have helped evolve drilling efficiency, performance and well placement.

Despite these advancements, the focus on a reliable solution for powered and wired drillpipe has long been a significant challenge for the drilling industry.

Even with recent technical advances

within the sector, the industry continues to look for further improvements in the efficiency, quality and the overall consistency and reliability of the well construction process. With benchmarking against historic performance metrics—and greater use of digital twin models and automation—there is a growing need for higher resolution data from downhole.

Reelwell's DualLink powered and wired drillpipe is a digital drilling technology. Wired pipe enables the real-time transfer of information from downhole to surface at a faster rate

than the traditional methods. The increased transfer speed enables the operator to assess the downhole conditions instantly, optimize drilling processes and adjust to drilling dysfunctions immediately. This means that drilling time is reduced as problematic zones and time-consuming mitigation efforts can be avoided, saving rig time in the range of 7% to 15% and cutting associated rig emissions. With increased access to data, well placement within the pay zone is also improved, potentially increasing hydrocarbon recovery by 20%.

Testing

Designed for full and easy integration into a rig, DualLink integrates easily into existing drilling rig systems and can be handled in the same way as a regular drillpipe. Reelwell has undertaken qualification and field-testing of the system at rig sites in Stavanger, Norway, and Houston. The company also recently announced its successful customer demonstration of DualLink, a move which has supported the commercialization of the technology.

Working with its partners at Equinor, Aker BP, DNO Norge, The Research Council of Norway, Nabors Industries, DP-Master and Edge Energy, Reelwell undertook a full-scale demonstration of its powered and wired drillpipe.

Reelwell had the potential to connect downhole with surface and that's exactly what the company was able to show.

With performance testing taking place toward the end of 2020 at the NORCE Ullrigg rig, Reelwell was able to show the drillstring, consisting of 96 joints/3,058 ft of DualLink pipe, performed without failure for more than 80 hours operating with in hole, drilling granite down to 4,213 ft.

Not only that, but the test results illustrated high-speed bi-directional telemetry at more than 61,000 bps, power transmission of up to 500 W from surface to the battery-less bottomhole assembly (BHA) downhole and 100% uptime reliability of telemetry and power transmission.

This testing included pipehandling, racking, running in hole and real-time transmission of high-speed drilling mechanics, surveying and logging data via DualLink during drilling and tripping. Compatibility to power and communicate with the BHA tool fleet of a major service company was



The testing of Reelwell's DualLink shows the powered and wired drillpipe being run in hole. (Source: Reelwell)

proven during the demonstration, with runs including Reelwell's along-string tools and direction and inclination measurement tools.

The DualLink demonstration illustrated the reliability, high-speed telemetry and that the power of DualLink can and will connect downhole and surface, enabling the next generation of drilling tool development.

A point of comparison

DualLink differs from current wired pipe technologies, which use a cable connected at either end of the drillpipe within the drilling fluid, as Reelwell's braided conductor is combined with an insulating material and bonds to the inside diameter (ID) of each pipe, helping to reduce the potential for failure. The transceivers in use are optimized for the transmission requirements of the system and do not require signal boosters/repeaters. Also, the low-complexity pipe connectors are self-cleaning and field replaceable, without impacting on the drillpipe's integrity.

DualLink offers a real step change in visibility by supplying high-resolution

real-time data and imagery. Drilling decisions regarding well control, hole cleaning and drilling dynamics performance can all be made instantly with accurate information at hand, supporting the accurate placement of the wellbore and reducing lost time.

Overcoming engineering challenges

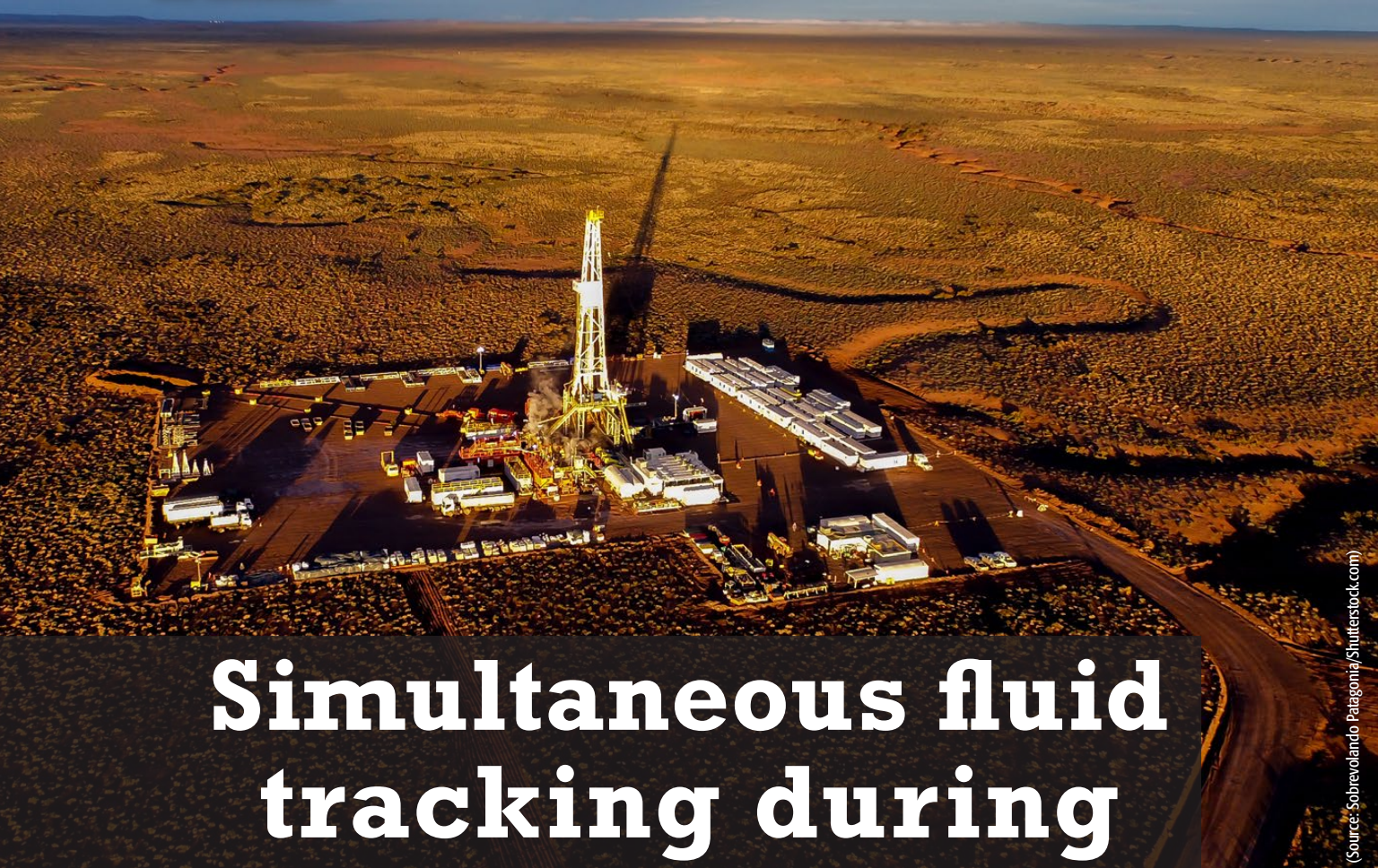
Reelwell's engineers knew activity should center on removing the communication and power path away from a single wire in the mud flow path to the surface ID of the pipe.

From there, the applications of multiple wires in the braid, rather than one or two in a cable, meant there was now a reliable, redundant path for power and data transmission. By making sure there was minimal impact to the threads and structural integrity of the drillpipe itself, it meant DualLink could be handled as a normal pipe while at the rig site, without technical limitations.

A key feature of the success was the introduction of robust, field replaceable connectors. This minimized the chance of damage. It also meant that if damage did occur, maintenance costs and downtime for repairing the assets would be reduced. +

With increased access to data, well placement within the pay zone is improved, potentially increasing hydrocarbon recovery by 20%.

Editor's note: Joining Reelwell in early 2018, Ian Silvester is CEO.



(Source: Sobrevolando Patagonia/Shutterstock.com)

Simultaneous fluid tracking during completions operations

Sam Young, Deep Imaging

A new and advanced workflow images fracturing fluid placement in real time.

The oil and gas industry would benefit from innovations that improve the recovery of hydrocarbons. In response to the current economic downturn, operators are seeking viable ways to alleviate risk and have more certainty on the return.

Many existing monitoring methods rely on seismic, an outdated procedure that commonly takes weeks or months to view processed results. Other indicators, such as production, tracers, FMI logs and pressure gages,

give operators plenty of information about the success or failure of the frac stages, but retroactively.

New technology has been developed to track fluid during fracturing operations in real time. Using a controlled-source electromagnetic (CSEM) tool, a signal response from the frac fluid can be imaged, giving operators a bird's eye view of their frac stage while it is happening. The real-time aspect of this technology allows operators to respond quickly

to undesired events, preventing a loss in production.

What is CSEM and how does it track fluid?

The application of CSEM relies on the principal behaviors of electromagnetics (EMs). The difference between the electrical conductivity of the fluid and background geological formation creates a signal response that images the fluid-filled fracture network. Although this method is applied on the surface,

well casing increases this response with mutual inductance, which results in a powerful EM signal. The signal strength depends on the introduction of the fluid into the surrounding geology—the higher the EM signal, the more frac fluid has been introduced into the area or path of least resistance.

This method seamlessly integrates with well operations. A transmitter consists of a large dipole that is grounded parallel to, and directly above, the lateral of the wellbore of interest. The transmitter system removes the surface noise sources such as pipelines, rail lines or other local metallic structures.

Receivers are placed alongside the transmitters and consist of two grounded wire sensors that sample at very high rates to increase the signal-to-noise ratio. To isolate and highlight the signal response caused by the frac, a baseline signal is recorded before the start of the frac and then subtracted from the overall response. This results in a clear signal from the frac fluid.

Figure 1 shows a real example of the components in the field. The goal of the survey design is to have the array laid out as densely and efficiently as possible while avoiding areas with surface structural impediments such as pads, residences or highways.

How to see the data in real time

Processing and imaging are performed simultaneously using in-house software. Advancements in this process over the past year have led to an expedited workflow that results within a couple hours after a frac stage ends. The receivers stream the data during the stage recording directly into the mobile office servers, where it is processed for quality control. Imaging is then performed simultane-

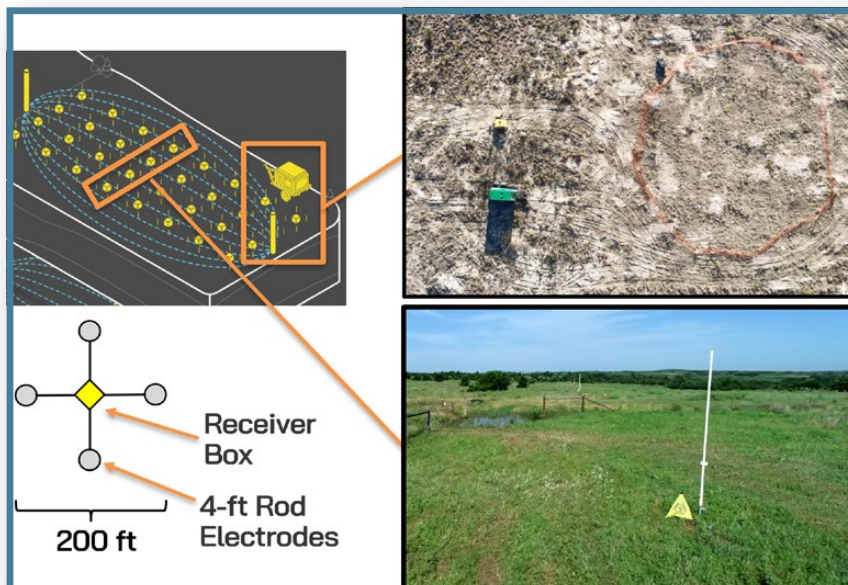


FIGURE 1. In this survey layout of the surface CSEM system in the field, the upper right image shows the transmitter and the lower right image is a close-up of the receiver station. (Source: Deep Imaging)

ously by a geoscientist and delivered to the client via a cloud-based web portal. Clients receive a map view motion picture of the stage signal areas with detailed analytics of fracture half-lengths, total areas and azimuths observed.

Case study

In September 2020, Deep Imaging, a service provider of surface-based EM frac imaging, performed a successful real-time survey. The company tracked fluid for multiple frac stages within 3 hours after each stage ended and generated results for one stage within 1 hour. The survey layout covered one well with receivers placed to cover the expected frac half-length of the completions design. Extended coverage was placed to the east to help analyze the extent of intra-well communication with the second well on the pad. There were also parent wells to the west.

Stages were monitored using an array of 80 receiver locations.

The primary objective was to prove testing could be done within a target time. The focus was also on the characterization of the stimulated reservoir area. The client was interested in analyzing well and stage spacing effectiveness, wellbore azimuth information and any potential unknowns such as plug failures or well casing integration issues. Deep Imaging's CSEM technology provided such analysis.

What was observed?

Stages were processed and delivered within 3 hours of the previous stage. The data quality was excellent, leading to various conclusions about the completion design:

1. **Wellbore azimuth information:** The frac stages were nearly symmetrical with some bias to the east. Since many stages display asymmetry, the bias observed gave confidence that these stages were spaced appropriately.
2. **Fluid tracking:** Stage overlap

Using a CSEM tool, a signal response from the frac fluid can be imaged, giving operators a bird's eye view of their frac stage while it is happening.

was calculated and quantified the overlapped area (Figure 2a). The results showed that 67% of the frac stage signal did not overlap with other stages, whereas 34% of stages overlapped with at least one other stage. The total percentage of the effective stimulated area of all frac stages was about 75% of what was expected by the client relative to the estimated stimulated rock area. This gave the client insight into the current design's stage efficiency.

- 3. Completions unknowns:** No detrimental frac effects were observed nor indications of plug failures from abrupt, north-south signal migration. Also, an aforementioned eastern signal bias was observed despite the parent wells to the west. Although depletion effects were expected, the interaction between child wells created a stress-conduit effect where previous nearby stages from the opposing well created a path of least resistance.

All processes of the frac stage are viewed together in a summarized snapshot in Figure 2b. This figure also includes the frac completion curves corroborated alongside the EM signal. These curves indicate how the signal behavior correlates with completion stage progression. EM signal strength indicates the perturbation caused by the frac fluid in the system and its extent. Not only do these indicators show real-time qualitative information, but they are also further quantified to make more impactful and thoughtful operational decisions.

The way ahead

With fracturing operations becoming increasingly complicated, it is imperative that more meaningful data be used to make decisions in real time. As machine-learning algorithms advance, more fluid dynamics information must be input to improve predictions.

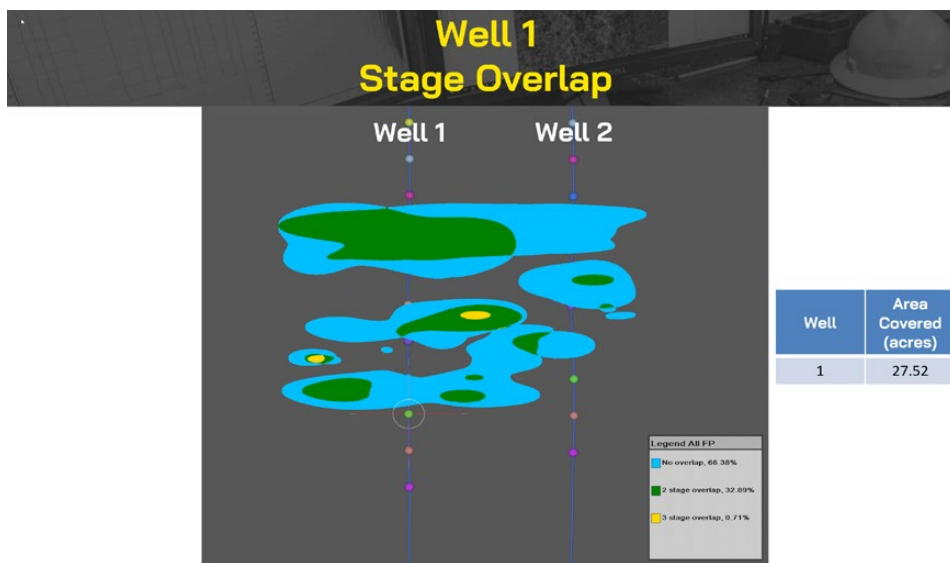


FIGURE 2a. A map view displays the signal calculating the area covered and percent overlap throughout the five stages. (Source: Deep Imaging)

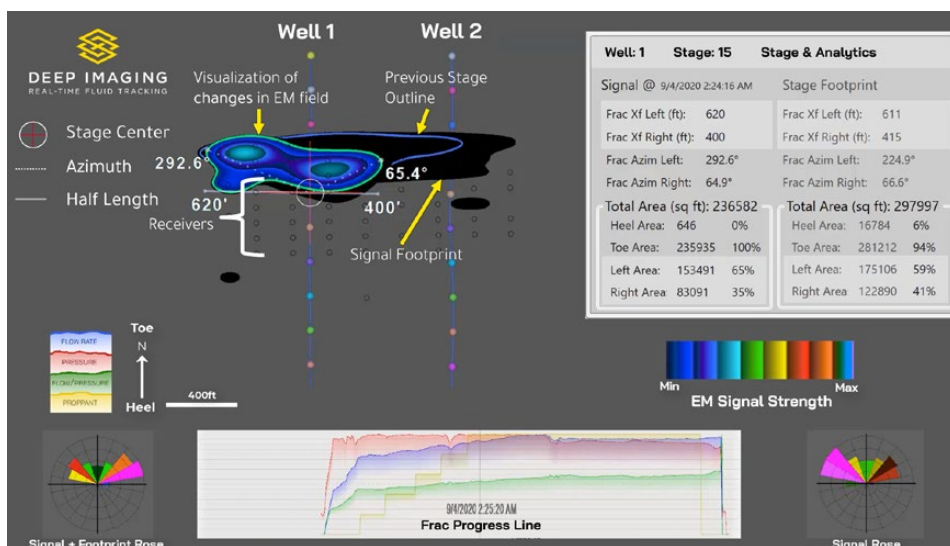
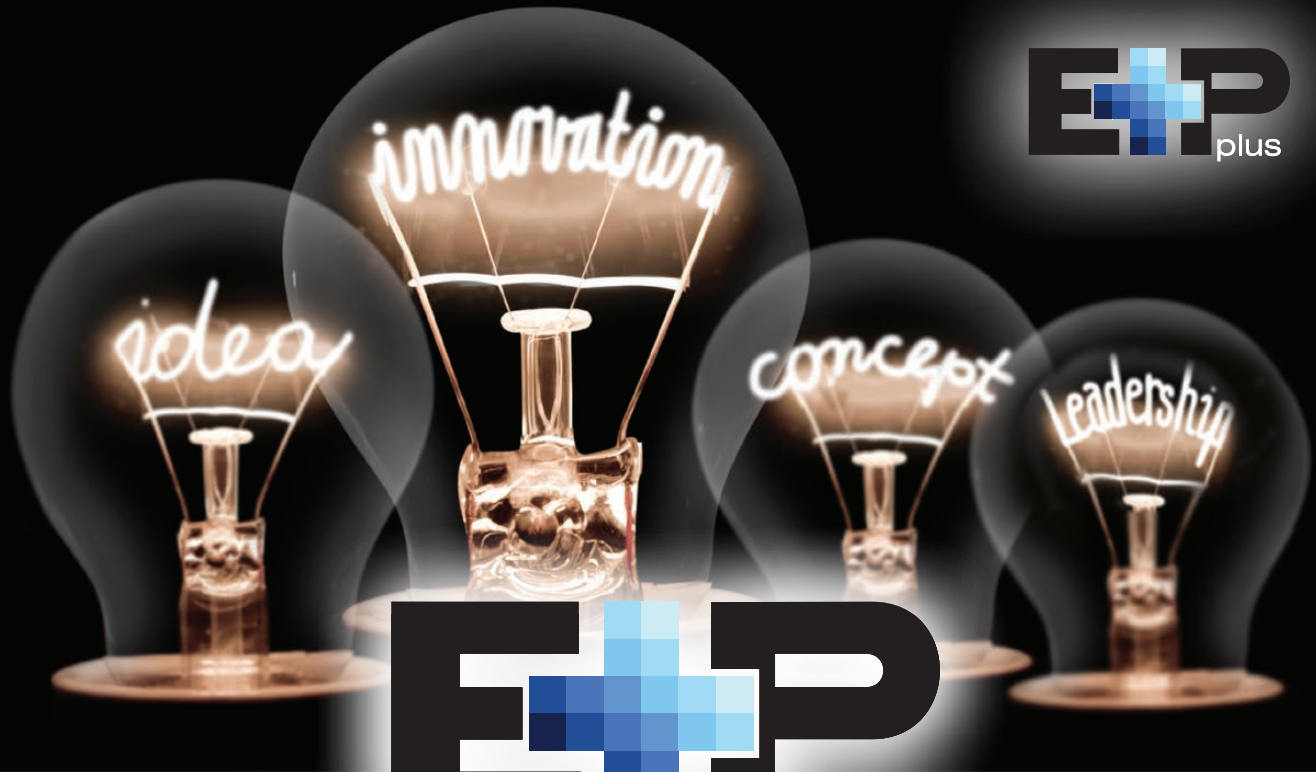


FIGURE 2b. Total analysis performed on a stage is shown. The frac signal strength is displayed using an RGB color bar to represent the signal intensity. The frac azimuth and length is calculated and displayed on the Stage and Analytics table. Frac azimuth is further visualized as a rose diagram, where the signal footprint is a representation of the area signal reached throughout the frac period. (Source: Deep Imaging)

Deep Imaging recently reached a milestone in the application of its improved technology. Data were successfully collected in real time while the client's objectives for reservoir characterization were also met. This technology meets an industry need

and is poised to make more breakthroughs alongside other advancements in real time. +

Acknowledgement: The author would like to thank Michelle Dano for her assistance in editing this article.



40 Under Forty Awards

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Deadline for submission is **March 31, 2021**

Identifying effective vapor recovery methods



Jeff Wilson, EcoVapor

How do tank recovery and vapor tower recovery systems stack up?

Effective tank vapor gas management is a critical component for achieving environmental performance goals and improving wellsite safety. The current practice of flaring tank vapors produces emissions of greenhouse gasses (GHGs) and volatile organic compounds (VOCs), increasing permit requirements and negatively impacting ESG performance.

This article covers three primary methods of managing tank vapors and analyzes their relative advantages with respect to achieving environmental goals, impacts on operational processes and economics.

Tank vapor management methods

Flaring at upstream oil and gas production sites has come under increased scrutiny. A report released in 2020 by the Railroad Commissioner of Texas Ryan Sitton estimated that 5% of producing wells in Texas lack access to pipelines, and the gas volumes flared in Texas in 2018 have been estimated at 650 MMcf/d.

Although occurring in lower volumes, flaring of high-Btu tank vapor is also common, even at sites connected to gas pipelines. Factors driving tank vapor volumes include pressure reductions (flash vapor), working

(Source: Leonid Ikon/Shutterstock.com)

Gas Flows to VRU System (Mscf/d)

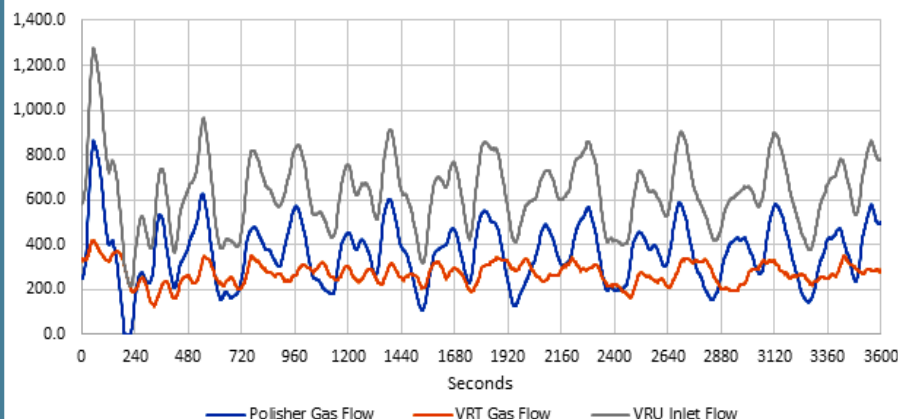


FIGURE 1. The blue line plots volumes from a “polisher” (a heated separator), volumes captured by the VRT just before the tanks are in orange, and volumes handled by a VRU are in gray. The wide variability in gas volume has a compounding effect, creating challenges in managing tank pressures, minimizing emissions and venting. This variability, combined with the fixed capacity of a VRT, can result in low retention time and reduced capture efficiency. (Source: Mesa Applied Technologies)

and breathing effects, and recovery of truck loading vapors. Flaring these NGL-rich vapors generates emissions of regulated substances and represents a significant loss of economic value. It is common for multiwell pads to generate upward of 300 Mscf/d of tank flash gas—an energy equivalent of 120 bbl/d.

There are three primary methods of managing these low-pressure vapors: flaring, partial capture before the storage tanks and full capture from atmospheric storage tanks.

Flaring

Flaring of site vapor usually requires a low-pressure flare or enclosed combustor device (ECD). These devices often have a destruction rate of VOCs exceeding 95% (typically 99% for C1-C3 and 98% for C4+), and the primary combustion products are CO₂, water and NO_x.

VOCs and NO_x are precursors for ozone formation in the presence of sunlight. Because ozone is a federally regulated “criteria pollutant,” flaring at large production facilities in regions designated by the EPA as non-attainment for ozone may require the operator to secure a Title V air permit, which is time-consuming and expensive.

There are a number of reasons to use flares or combustors, with low capex being the most common. Oxygen contamination in the atmospheric tanks is another reason since pipeline tariffs usually specify no more than 10 ppm of oxygen in sales gas.

Partial capture

An alternative to flaring is to use a vapor recovery tower (VRT) to capture as much of the vapor as possible prior to liquids entering atmospheric storage tanks, avoiding oxygen ingress. VRTs generate incremental revenue from capturing a portion of the otherwise wasted gas product.

VRTs are not without their drawbacks. Variability in vapor flow presents several challenges. Vapor volumes are a function of well production volumes, oil composition and temperature, surface equipment, and operating pressures, among other factors. In addition, liquids separation is never perfect, and oil volumes in produced water tanks also generate flashing vapor.

The problem of flow variability can be seen in Figure 1, which estimates flows at several different points in separation at an eight-well pad. A common design issue is that VRTs are initially undersized. The lack of capac-

ity results in low retention time, which lowers capture efficiency.

Since the VRTs only process the oil, flash vapor from produced water, working and breathing vapors in the tanks, and tank truck vapors have to be handled separately and are typically flared. Field data indicate that VRTs commonly capture 60% to 80% of the total low-pressure vapor volume at a pad.

Full capture

Total capture of low-pressure vapor requires recovery from the storage tanks. Limiting the effectiveness of tank capture methods, however, is the presence of oxygen in the tank headspace. As previously noted, oxygen levels are typically restricted by pipeline specifications.

One method for managing oxygen levels in storage tanks is the use of a gas blanketing system. Gas blanketing systems have been used for many years to mitigate explosive risks and have had some success in meeting pipeline limits for oxygen. Modern blanketing systems employ pressure transmitters, solenoids and programmable logic controllers.

However, maintaining the sequential system of pressure set points in a modern gas blanketing system in

Function	Tank Recovery (ZerO ₂)	Vapor Tower Recovery
Capture flash vapors from oil – generate revenue from waste	✓	✓
Prevent oxygen from fouling recovered gas stream	✓	✓
Separation of liquids from gas	✓	✓
Require use of VRU	✓	✓
Reduce emissions	✓	✓
100% Oil Tank Vapor Capture	✓	✗
Produced Water Tank Vapor Capture	✓	✗
Tank Truck Vapor Capture	✓	✗
Simultaneous Recovery from Tanks And Other Low-pressure Vessels (i.e. ULPS, H/T, etc.)	✓	✗
Control of tank pressure minimizing venting	✓	✗

FIGURE 2. There are a number of functional similarities between capture with a VRT and capturing directly from the tanks, but there are also some key differences. (Source: EcoVapor)

ounces per square inch is challenging. The increased operational complexity often requires operators to dedicate maintenance personnel specifically to the setup, maintenance and repair of tank hatches, vapor recovery units (VRUs) and flare/ECD inlet valves.

A second option for tank capture is the use of an oxygen removal unit downstream of the tanks. Instead of attempting to find and control the myriad sources of O₂ ingress, this technology removes all oxygen from the entire vapor stream and ensures all of the site vapor meets pipeline requirements. This equipment typically has 99%+ uptime with the capture efficiency of the entire system limited primarily by the VRU.

There are a number of functional similarities between capture with a VRT and capturing directly from the tanks, but there are also some key differences (Figure 2).

Comparison of capture methods

Emission profiles for the three capture methods were estimated using a volume of 300 Mscf/d. The estimate was prepared using a recovery efficiency of 75% for partial capture, a flare destruction rate of 98% and VRU uptime of 95%.

The results demonstrated that tank

capture incorporating oxygen removal equipment downstream of the storage tanks resulted in the lowest emissions of GHGs and regulated substances.

Case studies

A major independent producer operating in the Powder River Basin evaluated vapor capture via a VRT versus tank capture using oxygen removal equipment. In the trial, each configuration was run for nearly 80 days, and vapor that was not captured was flared.

Results gathered by the producer are summarized in the table below.

The tank capture method resulted in a 37% reduction in flaring and incremental sales of rich-Btu gas. The tank capture method also employed a scrubber upstream of the oxygen

removal unit, resulting in a 3% increase in crude oil sales as compared to the VRT case.

The operator estimated that the NPV of the tank capture configuration was approximately twice that of the VRT.

In another case study, Shell installed oxygen removal units at its central processing facilities in 2018 to reduce low pressure vapor flaring. While Shell has not disclosed the economics generated by the 32 units, the company reported that the resulting reduction in flaring reduced methane emissions in 2020 by the equivalent of 32 metric tonnes from 2018 levels.

In a 2020 case study, an operator in the Denver-Julesburg Basin discovered that the routine flaring of tank vapors was resulting in emissions levels requiring expensive and stringent air permits. Installation of oxygen removal equipment and capturing vapor directly from the tanks was credited with a 94% reduction in flared volumes. The value of the captured gas assuming a value of \$2.50/mcf exceeds \$23,000 monthly.

Conclusion

Emerging technologies for capturing tank vapor gas provide operators the opportunity to significantly mitigate flaring. Tank capture using oxygen removal equipment has proven to generate the greatest emissions reductions from all sources, with favorable economics and improvement in safety for operators and site equipment. +

Two-well Pad on a Horizontal Shale in the Powder River Basin		
	Partial Recovery with VRT	Tank Recovery with O ₂ Removal
Oil Production (bbl/d)	1,091	1,125
Vapor Capture (Mscf/d)	137	188
Recovery Efficiency	73%	98%
Vapor Btu/Scf	2,104	2,665

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Deadline for submissions is July 30, 2021.

Contact **meainfo@hartenergy.com** with any questions.

Cloud-based approach to enhancing production operation efficiencies

Brandon Cavallaro, Aron Hallquist and Colin JB Smith, Schlumberger

As the industry seeks opportunities to extract the most value from existing assets, cloud-based systems provide an opportunity for increasing production and enhancing operational efficiency.

Globally, oil and gas executives are focused on enhancing value from existing resources. This approach applies to all aspects of the industry, including human capital, physical assets and data. This is particularly important in production operations, where resource utilization drives unit cost efficiency and project economics.

Legacy software approaches are not well-equipped to manage today's connected oil fields where single wells can generate 100,000 datapoints per day. Data management challenges arise from the sheer volume and complexity of acquired data. Asset teams spend

significant resources contextualizing data to extract meaningful value, which lengthens the time from data acquisition to field actions.

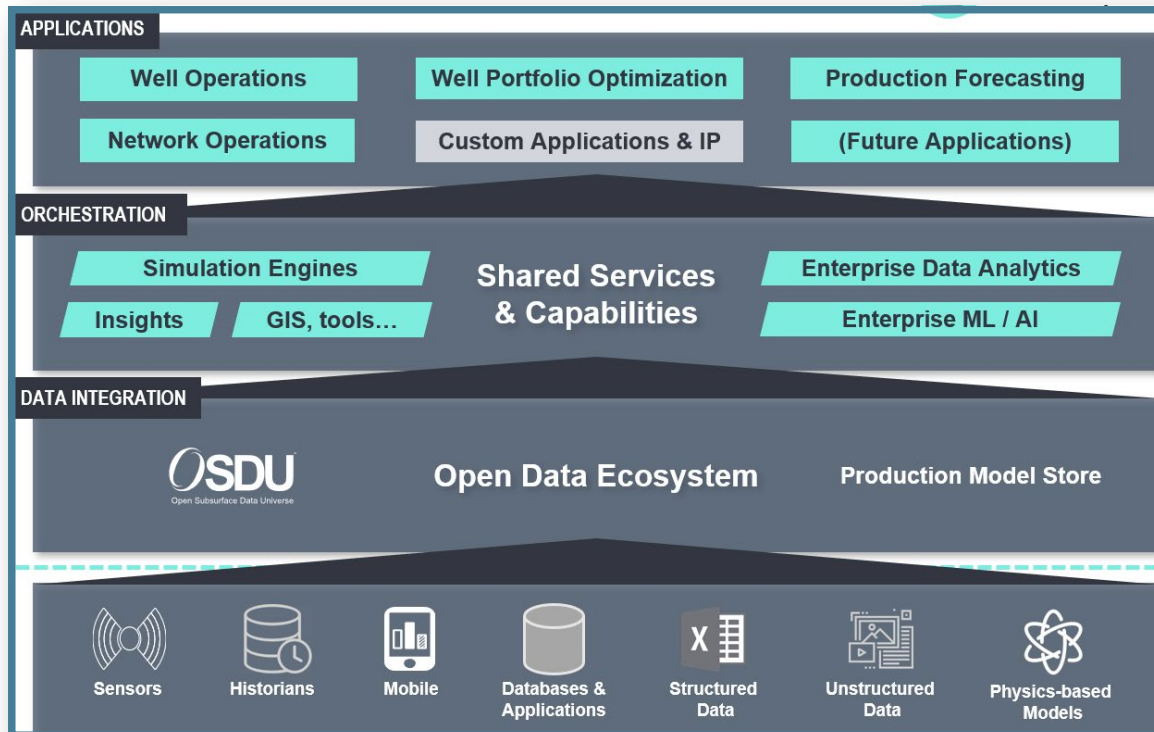
Today's oil field requires an approach that leverages cloud computing to transform production operations by streamlining data management. This empowers asset teams to concentrate on higher-value tasks and enables more agile and dynamic decision-making.

Unifying production operations via the cloud

According to market surveys, up to 70% of an engineer's day could be spent on low-value data manipulation. Tasks

such as preparing and cleansing, then duplicating data between systems for diagnostics and analysis are time-consuming, error-prone and redundant. However, production operations inefficiencies related to human capital data access can be improved with digital solutions. Even further value can be realized through improved data integrity, consistency and standardization across the production operations landscape in scalable cloud-based solutions.

The ProdOps tuned production operations system, a cloud-native tool built on the DELFI cognitive E&P environment, is designed to help operators better manage data and unify asset teams.



With a robust, open data foundation and a data infrastructure and ingestion framework, the ProdOps system brings together live and contextualized data from structured and unstructured sources. (Source: Schlumberger)

The system provides a clear single data access point that can be utilized for confident decision-making. With automation of engineering best practices at scale, the system brings together disparate work processes to improve decision quality and accelerate time to decision or action. The system provides continuous intelligence to engineers, highlighting priorities and key focus areas. As a result, operators avoid slow or poor decisions, unplanned downtime, unnecessary interventions, deferred production and more.

The outcome is production gains and cost reductions. Cloud-based solution net gains, however, are far greater than traditional approaches because decision-making is enabled by more data and faster automated insights. Insights are derived using data-driven techniques, physics-based models and hybrids, which are a combination of both. Through the system's ability to continuously learn, value-generating insights are self-improving as data

access grows. Further human capital efficiencies are achieved as engineering effort focuses not on data quality, but rather on problem solving and exploring new opportunities. The engineer is better equipped to do so with on-demand access to the latest operational data and auto-calibrated models that are enhanced by advanced data science tools and techniques for routine diagnostics.





The cloud-native system unifies production operations by driving integration, collaboration, automation and openness for asset teams. By connecting to and aggregating data and models from proprietary and third-party sources, manual data-gathering and contextualization activities are eliminated. In addition, the system serves as a single environment to review and analyze performance, to assign and track tasks, and to drive transparency and collaboration among teams.

Rapid decision support is driven by combining data and physical models,

which enables standardization of automated best practices. Further, the system provides capabilities to develop algorithms, tools and applications that leverage integrated machine learning, artificial intelligence and physics-based models to develop standardized best practices. As an open data infrastructure, operators can connect to these best practices from virtually any source.

Traditional digital oilfield solutions are typically bespoke, difficult and costly to maintain—and relatively hard coded in most cases. To overcome these challenges, the ProdOps system provides a means of extracting more value from preexisting infrastructure through quick and easy connections to data and models. Additionally, software updates are performed automatically, which eliminates the burden and cost associated with maintaining traditional production systems.

Built on extensive domain expertise and two decades of digital oilfield experience, the cloud-native system

Well operations Optimization through continuous monitoring and automated identification of operational issues		Used to see and understand causes for underperformance. Enables proactive management with automated insights that provide a pipeline of recommendations for actions at the right time.
Network operations Guided well-network optimization, risk and opportunity identification		Validates production optimization at a field level through integrated well and flow simulation to reduce downtime. Automated insights expose production issues and enhancement opportunities.
Production forecasting An automated, evergreen pipeline of forecasts		Automatically identifies wells that require updates and conducting batch runs to rapidly update large well counts. Supports a wide range of industry-standard forecasting techniques.
Well portfolio optimization Rapid automated screening of workover and intervention candidates		Identifies candidates for workovers and interventions with a systematic approach that consolidates data from a range of systems and sources. Asset teams are guided by automated processes and integrated economics.

The cloud-based tuned production operations system contains production-focused applications for well operations, network operations, production forecasting and well portfolio optimization. (Source: Schlumberger)

delivers a robust data foundation with an industry-proven data infrastructure and ingestion framework. Further, the technology brings together live, contextualized data from various structured and unstructured sources, including Internet of Things (IoT) sensors, production volumes and documents, all of which are used to derive insights.

Insights can be used to support remote operations by augmenting IoT/edge acquisition and control capabilities for equipment surveillance and the optimization of field systems. The infrastructure and data model innately understands what a well network is, in addition to understanding the operational measurements. Taking scalability a step further, open APIs allow operators to build their own solutions from the level of individual calculations and algorithms to extensive tools and applications.

Production applications

The cloud-based tuned production operations system contains various production-focused applications. The well operations application is used by engineers to see and understand causes for

underperformance. The network operations application, which incorporates integrated well and flow simulation, validates production optimization at a field level and reduces the likelihood of downtime.

One operator is utilizing ProdOps as their long-term digital system to manage more than 6,000 wells. The operator is utilizing the system to aggregate enterprise-wide production data to digitalize and automate production surveillance as well as to optimize artificial lift performance and surveillance. The system was selected on the basis of the customer's drive for operational and organizational efficiency—specifically around achieving goals of significant production increases and decreases in intervention spend.

The production forecasting application provides evergreen well forecasts. One operator is utilizing the application to generate, maintain and streamline the sharing of forecasts, resulting in a reduction of its forecasting process from six months to less than three weeks for more than 2,000 wells.

The well portfolio optimization application helps operators identify produc-

tion enhancement candidates, which is typically a manual-intensive and repetitive process. The application flags a ranked list of opportunities for idle well reactivation and identifies opportunities for artificial lift optimization, behind-casing opportunities and more.

In one application, an operator significantly reduced the time it spent to perform and review well candidates, with 89% time savings compared with the previous manual approach. The time reduction and the elimination of routine work activities resulted in cost savings of 88%.

Cloud-enhanced production

As the industry seeks opportunities to minimize expenditure and extract the most value from existing assets, cloud-based production systems provide an integral solution for increasing production and enhancing operational and organizational efficiency. The cloud-native ProdOps system serves as a vehicle for digitalization with a unified environment that brings clarity to complex, scattered and disconnected operational data and processes to establish a single source of truth. +



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The *MV Island Venture* prepares to perform riserless light well intervention in the GoM. (Source: C-Innovation)

Problem solving in the field with ROVs

Michael MacMillan, C-Innovation

Over the years, the ROV industry has seen many iterative advances in technology, changing the role and modern capabilities of remote vehicles in subsea operations.

As the subsea market changes, inspection, maintenance and repair (IMR) work is more typically performed on a call-out basis. Consequently, the use of ROVs also has transformed over the years. Today, ROVs are utilized as a resource that is more valuable and complex than merely a subsea camera and instead play a key role in the efficient maintenance of subsea equipment. As a result, ROVs are now expected to remain subsea for a long duration of time and must be able to withstand the demands of the harsh environment as well as perform a number of technologically advanced tasks.

Operators of subsea assets demand reliability and availability in their

operational ROVs, which can be utilized safely and efficiently to complete their work scopes. Most recently, the integration of a subsea control systems interface into the ROV has been a milestone serving to dramatically reduce operators' costs.

C-I's Augmented Reality and Mid-Water StationKeep systems provide a robust, systemwide platform utilizing sophisticated ROVs equipped with sensor capacity. These systems enable operators to utilize ROVs as the control system rather than having larger assets on location for those services, saving the operator unnecessary expenditure in the process. Furthermore, the advancement of modular

ROV systems allows quick diagnoses of issues and rapid repair times. The ability to monitor sensors more closely, set alarm parameters and track data has provided the industry with a platform that helps maintain offshore equipment better than before.

The ability to respond to a client with a full solution, operating as a single point of contact, reduces the cost to the client and also minimizes risks by dealing with a single subcontractor. By adopting this large-scale, single solution approach, work scopes (e.g., tree installations, hydrate remediation, survey operations and IMR, which used to take up to a year to plan) can be achieved in less than a month.

Installing stem clamps using an ROV

Recently, C-I completed the installation of several stem clamps for bp beneath the Mad Dog spar in the Gulf of Mexico (GoM) utilizing its *MV Dove* IMR ROV. C-I was engaged by bp early in the project life cycle to provide input into the design of the subsea hardware and installation capabilities of the ROV, which would face limited access to the installation location beneath the facility.

Throughout the planning process, several risks were mitigated for C-I and bp assets by modifying the ROV. This included armouring with Lexan polycarbonate, design of new manipulator mounting subframes to extend the reach of the manipulators by 12 inches and installation of enhanced manipulator controls systems. The C-I project team engaged with the ROV operations groups, offshore managers and tooling group to evaluate the risks involved with the execution of the project. The project was a success and was completed 10 days ahead of bp's schedule.

Opening valve using only ROV power

A large international operating company in the GoM requested C-I to open an FS2 fluid loss isolation barrier valve using only ROV power. The drilling and completion rig had already moved off site. Therefore, a high cost and even higher impact to the remaining drilling and completion schedule would have been incurred to bring it back just to actuate the valve in question. Ultimately, C-I designed, built and deployed a subsea tree controls interface system, which leverages the existing infrastructure and technology of the ROV systems.

Estimated cost savings were \$3 million per well when compared to accomplishing the same with a rig and riser. The client considered the procedure to be a huge success and a long-term solution to an otherwise expensive task. This procedure can

easily be repeated across other wells and operators in this region.

Future work

Some of C-I's most recent awards and extensions for work with a large GoM energy investor include an extension of the well intervention vessel services contract for the *Island Venture*, providing riserless light well intervention for mechanical and hydraulic stimulations of deepsea assets.

Additionally, C-I has been awarded a four-year extension of an IMR services agreement, which is an all-inclusive contract including vessel, ROV, survey, engineering and project management for field expansion projects, jumper installations, subsea tree installations, facility underwater inspections in lieu of dry docking, commissioning of new assets for field expansion projects and general field support.

Value in consolidating services post-2020

In a market where the oil price is unstable and operating costs are high, efficiency becomes a priority. As work

dynamics have changed across the world, so has the dynamics within the offshore oil and gas industry.

In this new era, it is vital to deliver services more quickly and efficiently than ever before without compromising on quality. By combining project management, engineering, procurement, service and personnel into a single source contract, more inclusive offerings can be obtained at the same price structures, securing long-term, more predictable profitability.

Furthermore, by uniting services and offering complete packages to the end user, a single contractor, such as C-I, can maintain a higher utilization rate, enabling projects to be completed more efficiently than ever before. This single source solution approach makes it much easier to identify and implement the best solutions to the wide array of complex problems that are often encountered offshore.

There will continue to be demand for a complete, economical solution under one operating umbrella in the coming years as the industry adapts to the myriad shocks experienced in 2020. +

The *MV Island Performer* sets up for a jumper installation in the GoM. (Source: C-Innovation)





Enabling remotely operated surveys with reliable data and communications

Ryan Larsen, Oceaneering Survey Services

Remotely operated surveys reduce personnel on board, decrease HSE exposure and reduce overall project costs.

It has long been a dream for offshore energy explorers to go where many have not gone before. That means searching for oil and gas deposits in deeper waters and farther from shore than previously charted.

Many issues arise from these special projects: safety, time and cost. Keeping offshore workers safe in harsh, remote environments is of the utmost importance as operators strive to maintain the same (or better) exploration results.

The prolonged downturn in the oil and gas industry, coupled with

an ongoing global pandemic, has increased the difficulty of normal operations. It is a necessity to reduce offshore personnel so that essential staff members can do their jobs unhindered and safely social distanced. Remote solutions can boost worker safety and improve environmental conditions.

Remote operations make it easy to reduce mobilization and logistics costs. Subject matter experts (SMEs) can work from a dedicated onshore base and safely and intelligently communicate with personnel on the rig or vessel.

Since 2004, Oceaneering has been at the forefront of remote piloting and control technology, which allows subsea vehicles, such as ROVs, to be piloted from shore rather than onboard vessels and rigs. Recent advances in offshore communication networks are ensuring that resident ROVs and AUVs are a trustworthy option for carrying out offshore operations. Advanced subsea vehicles are benefiting from increased 4G offshore coverage along with faster, stable and more cost-efficient satellite communications. Additionally, more

offshore facilities feature installations with direct fiber-to-shore connectivity allowing lower latency and higher fidelity connections.

Oceaneering has invested in Remote Control Monitoring Stations (RCMS) in Houston and Lafayette, La., for its remote survey operations. An SME working from an onshore base can lend expertise and remotely monitor multiple projects from one location. These onshore bases also enable customers to safely view operations from anywhere in the world and further reduce the need for expert personnel to be located offshore to monitor or troubleshoot operations.

The ROS system

Oceaneering's Remotely Operated Survey (ROS) system can be used to execute exploration work, FPSO vessel hookup, plugging and abandonment, development, and re-latch and re-spud activities. The company also conducts remote inertial jumper metrologies, remote inertial marker buoy sets and remote monitoring of Acoustic Doppler Current Profiles (ADCPs) data.

Reliable data and communications between the rig or vessel and the onshore base are the backbone of the ROS system. The required bandwidth is determined by project scope, and



Onshore-based personnel observe ROS operations from a dedicated RCMS in Houston. (Source: Oceaneering)

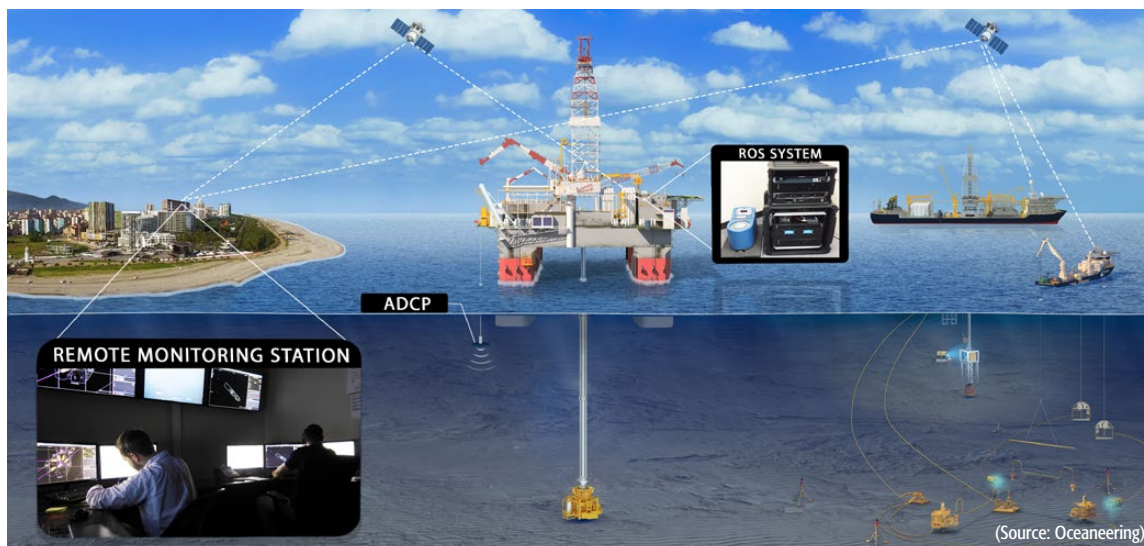
some operations can be run with as little as 256 kbps of bandwidth on the rig or vessel's existing internet access.

However, when the campaigns are more advanced, such as jumper metrologies, more data bandwidth is necessary to conduct remote monitoring operations and maintain constant contact with the dynamic positioning officer, ROV pilots and party chiefs.

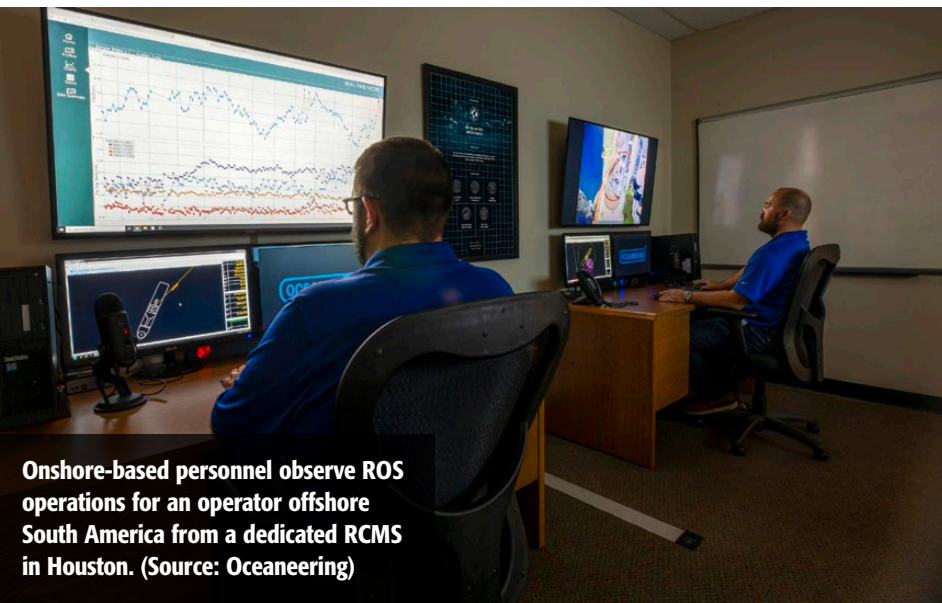
With jumper metrology, getting the correct distance between point

A and point B (e.g., from well site to manifold) is critical. By using inertial technology, the ROV will fly back and forth to secure the distance, and that calculation will be used by engineers to produce jumpers to fit to the exact space available.

Subsea marker buoy sets are launched directly from the rig as it comes onto location. Four markers are placed down, and then the conductor is set down in the middle of the buoys.



(Source: Oceaneering)



Onshore-based personnel observe ROS operations for an operator offshore South America from a dedicated RCMS in Houston. (Source: Oceaneering)

This acts as an “x marks the spot” so the rig can drill on the correct location. All of this is done remotely without having to send out additional surveyors.

Oceaneering can apply ADCPs on ROS campaigns as well. ADCPs enable the ability to monitor flow of currents past a vessel or a rig. Underwater currents can be extremely harsh, almost like rivers or spinning hurricanes called eddies; currents of 4 to 6 knots can hinder operations. The ADCP provides the ability to see what is happening on the rig but also monitor the current flow underneath.

The system provides the drilling team with real-time data, which can be reported back to the National Oceanic and Atmospheric Administration’s National Buoy Center, which in turn uses the data to create oceanographic current maps. Oceaneering’s cross-trained ROV crews offshore lower the equipment overboard when data are needed to be acquired.

Keeping offshore workers safe in harsh, remote environments is of the utmost importance as operators strive to maintain the same (or better) exploration results.

First ROS campaign

In 2016 Oceaneering was approached by a major U.S. operator to find a long-term, cost-efficient positioning solution for offshore drilling moves. The operator sought a way to improve safety while also reducing costs. The solution Oceaneering proposed would provide the customer with 24/7 remote access from shore to the rig.

Oceaneering executed a one-day survey of the operator’s rig and then mobilized and installed its equipment on board in a three-day period, one week after the initial survey. The rig move occurred over a two-day period, and a preliminary field report and certified location plat were delivered in 48 hours. This allowed the operator to identify the final well position, close out drilling permits and continue field development planning.

The ROS package included two Oceaneering C-NAV3050 GNSS receiv-

ers with precise point positioning correction service, one gyrocompass, one GNSS heading sensor, one survey navigation supplemented with in-house software applications, one survey remote access and communications package with internet security.

Testing the waters off South America

In 2019 Oceaneering was contacted by a different operator to provide integrated rig services for a drillship it intended to use for a three-well campaign offshore South America. Oceaneering mobilized an ROS system, ROV and ADCP system for the campaign in summer 2019. The drillship then transited to the drilling location where it began operations in the early fall of that year.

Having the ROS system installed onboard supporting survey operations provided the operator more than 52% in actual project operational savings as compared to conventional operations. The operator saved 96 personnel onboard days as the campaign extended to a fourth well. These savings do not include other potential cost savings from logistics of crew and equipment, lodging and meals. The pandemic also has provided extra savings on quarantining costs of crew that would have normally been required in a conventional operation.

The operator went on to conduct successful drilling campaigns offshore South America into 2020.

New milestone

In 2020 Oceaneering achieved its biggest milestone yet for ROS, conducting its 100th rig move and recording 150,000 hours of operations with 99.9% uptime. Advancements in these areas will enable operators to rethink the way they conduct offshore work. To date, Oceaneering has 13 active ROS systems in use around the world with additional units in production to meet growing demand. +

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New drilling and completions technologies

As companies look toward market recovery, these new drilling and completions technologies will help producers boost efficiencies and streamline operations.

Drill bit with concave-shaped cutting elements reduces drilling costs

Smith Bits, a Schlumberger company, has released the StrataBlade concave diamond element bit, which is designed to improve the ROP in a wide range of rock types while withstanding impact damage often associated with drilling interbedded formations. The StrataBlade bit incorporates new geometry Strata concave diamond elements across the bit face, which increases cutting efficiency and results in higher instantaneous ROP with the same operating parameters. In deep lateral wells where weight transfer to the bit is a challenge, the StrataBlade bit drills with higher ROP when compared with traditional PDC bits with flat cutters. Improved cutting efficiency also means a better torque response at the bit for conformance to directional plans. The bit has undergone field testing in North America, specifically in the Haynesville and the Appalachian Basin. In the East Texas Travis Peak and Cotton Valley formations, the StrataBlade bit enabled an operator to eliminate two bit runs while drilling to 10,000-ft measured depth with an average ROP increase of 28% compared to direct offset wells.



The StrataBlade concave diamond element bit features Strata elements strategically placed along the bit face. (Source: Schlumberger)

New electroplating coating to protect drilling equipment from wear and corrosion

Honeywell has entered into an agreement to allow industrial coatings provider Moore's Industrial Service Ltd. to distribute and apply its new electroplating coating for use in demanding conditions within the oil and gas industry. The new coating is applied using a electroplating chemistry that protects the surface of components within a drilling string from abrasion and corrosion. Honeywell's new offering provides several advantages compared with incumbent coating solutions, including up to three times more wear resistance than Chrome. The new coating is harder than before, while also being more durable and less expensive than other offerings. This enables customers to extend their drilling hours and lower total operating costs. Within the oil and gas industry, this coating will be used on tools for drilling, such as mud motors, piston housings, mandrels and cavity pumps. It will allow them to run longer without unnecessary or unplanned failures that lead to operational stoppages.

Company to develop AI tool to support offshore drilling efforts

Norwegian oil services company Applied Petroleum Technology (APT) has received research funding to develop an artificial intelligence (AI) tool that can dramatically change how oil companies utilize biostratigraphic services to plan drilling programs and evaluate and assess hydrocarbon wells. Biostratigraphy is the dating of rocks with the help of fossils that is obligatory for all exploration wells drilled on the Norwegian Continental Shelf. It is used to help understand the subsurface geology and correlate sections in wells both within fields and on a larger regional scale. The Norwegian Research Council has awarded APT a grant to develop an image digitalization and AI technique and associated software to modernize and improve microscopic analysis to find, identify and quantify the fossil content. The latter is utilized in the planning of drilling programs, evaluation and assessment of wells during the offshore drilling process.

New hydraulic dual choke unit offers increased value to drilling applications

CORTEC has released its new CX-HB3.0 Hydra-Balance Choke and Panel System, which offers drilling operations an increased level of value and functionality within MPD, underbalanced drilling and other drilling set-point applications. This new system has been designed to provide higher levels of accuracy, ease of use and field-friendly serviceability for end users seeking a simple set-point solution. The Hydra-Balance system is designed to exceed the level of response and precision of many existing options within the market. CORTEC has concluded

an extensive round of both in-house validation and infield operational trials. The CX-HB3.0 system features a main HPU/HMI control panel with remote HMI panel integration and offers a set-point accuracy of +/- 25 or less psi, operating pressure range up to 2,500 psi and maintains a compact footprint that maximizes weight and space savings.



CORTEC's CX-HB3.0 Hydra-Balance Choke and Panel System is a hydraulic dual choke unit that can be controlled via a compact remote panel, which is installed in close proximity to the driller. (Source: CORTEC)

Biosurfactant technology boosts initial completion oil production

Locus Bio-Energy Solutions (Locus BE) has released SUSTAIN, a newly developed green technology that is optimizing initial oil production in completions and slowing declines. The biosurfactant is formulated using biosurfactants with multifunctional properties for hydraulic fracturing that require as little as 1/50th of the dosage rate of traditional completions surfactants, significantly lowering costs. SUSTAIN helps oil operators boost IP and sustain those higher rates for longer periods to maximize operator profitability and EUR, which all work to increase the return on investment of unconventional wells, which is a must in today's capital-challenged operating environment.

SUSTAIN's biosurfactants can penetrate the smallest shale rock nanopores that other treatments cannot reach, mobilizing otherwise immobile oil and enhancing recovery in unconventional tight formations where pore throats are extremely small. Locus BE's biosurfactants are less than 2 nm in diameter, significantly smaller than any other competing technologies, which increases penetration in the reservoir during hydraulic fracturing. Unlike traditional chemical surfactants, up to 50% of SUSTAIN's biosurfactants are adsorbed in shale reservoirs and slowly desorb over time, providing continued long-term mobilization of oil after flowback. These ultralow effective dosage rates also ensure that SUSTAIN will continue to contribute to boosting production performance for months after application.

Company enters completions segment with launch of new splice tool

Ace Oil Tools has launched its Ace Splice Clamp (ASC) to the completions market. Allowing multiple lines to be spliced with a single clamp, the ASC is a sub-less downhole product that protects the control lines during completion. Combining the functionality of a shrouded crimp clamp for locking flatpacks with a splice sub into one single product, the ASC accepts a flatpack control line assembly. The design protects bare control lines and houses the splice blocks. The "one design fits all approach" of the ASC means that operators have the ability to utilize different vendors for the various products required and can still utilize the ASC to house all combinations.

New electric tool simplifies fishing operations

Wellgrab has secured the Research Council of Norway funding to support the launch of its new fishing tool called the Wellgrab Electric Release Fishing Tool (WERFT). The WERFT performed two operations in 2019 with WERFT version 1. The next-generation WERFT version 2 is scheduled to launch in the second quarter of 2021. The WERFT consists of a basic module and an accompanying tool pack with several special features. The concept combines several functions into one tool. With a combined control and communication system, it enables safer and more cost-effective fishing and pulling operations. Further, by pairing digital capabilities with a versatile, multifunctional tool, the WERFT drives safer and more cost-effective fishing operations. Current mechanical tools are often operated by the service operator pulling up or running down the wireline to which the tool is attached. When the geometry of the well is complex, this mechanical control is not precise causing unwanted mis-runs or failure. Designed to increase safety, the WERFT is controlled and activated from the surface, meaning that at the touch of a button, the operator can easily connect to or from any object that has to be fished out. The tool is applicable for retrieving plugs, all fishing operations and for relocating downhole assemblies. +

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.





(Source: Larry Prado, Hart Energy)

Arctic exploration continues

Unfortunately, during the past year, a number of major banks announced they would not finance major Arctic development projects.

Larry Prado, Activity Editor

According to the U.S. Energy Information Administration (EIA), the Arctic could hold about 22% of the world's undiscovered conventional oil and natural gas resources.

The area above the Arctic Circle encompasses about 6% of the Earth's surface area. While the Arctic is about the size of the African continent, most of the resource area is oceanic. About 33% of the Arctic is occupied by land. Another 33% of the Arctic consists of offshore continental shelves located in less than 500 m of Arctic Ocean water. The remaining 33% of the Arctic is in Arctic Ocean waters deeper than 500 m.

The 2008 U.S. Geological Survey Arctic assessment estimated a total oil and gas resource of 412 Bboe, with 78% of those resources expected to be gas and NGL. The composition of undiscovered Arctic hydrocarbons is largely determined by the West Siberian Basin and East Barents Basin, which hold 47% of the undiscovered Arctic resources, with 94% of those resources being gas and NGL.

Jurisdictionally, the Arctic contains portions of eight countries: Canada, Denmark (Greenland), Finland, Iceland, Norway, Sweden, the U.S. and Russia. Finland and Sweden do not border the Arctic Ocean and are the only Arctic countries without jurisdictional claims in the Arctic Ocean and adjacent seas.

Large oil and gas fields (500 MMboe or more of recoverable oil and gas) are crucial to future oil and gas development—the cost of developing oil and gas fields in the Arctic is so high that large fields are initially necessary to pay for the infrastructure required to later develop the smaller oil and gas deposits. Costs are unusually high because of the extraordinarily harsh environment, long supply lines and limited civilized habitation.

For example, the Prudhoe Bay Field with 13.6 Bbbl of recoverable oil made the construction of the Alyeska Oil Pipeline commercially viable. Without Prudhoe Bay Field, it is likely that the smaller Alaska North Slope oil prospects, such as [Pikka](#), [Icewine](#), [Alpine](#) and others, would not have been developed.

In addition, ConocoPhillips has made significant discoveries at its Willow, Harpoon and Narwhal prospects as well as other finds in Caelus Energy's Smith Bay, Repsol/Armstrong Energy's Horseshoe discovery and Pantheon Resources' Talitha project and Alkaid prospect.

Large Arctic oil and natural gas discoveries began in Russia (1962) and in the U.S. with the Alaska's Prudhoe Bay (1967). Approximately 61 large oil and natural gas fields have been discovered within the Arctic Circle in Russia, Alaska, Canada's Northwest Territories and Norway. Fifteen of

these 61 large Arctic fields have not yet gone into production; 11 are in Canada's Northwest Territories, two in Russia and two in Arctic Alaska.

Of the 61 large Arctic fields, 43 are in Russia and 35 (33 gas and two oil) are located in the West Siberian Basin. Of the eight remaining large Russian fields, five are in the Timan-Pechora Basin, two are in the South Barents Basin and one is in the Ludlov Saddle.

US

Shell Oil announced plans in 2020 to resume offshore Alaska oil and gas exploration at its West Harrison Bay license in the Beaufort Sea just offshore from the National Petroleum Reserve. The company is looking for partners to explore the 86,400 acres in its 18 leases.

In its five-year plan, Shell plans to conduct seismic studies to update geological data and finalize well and reservoir design in 2021-22 and expand exploratory drilling in 2023-24. The prospect area sits atop the popular and shallow Nanushuk, one of the most promising formations on the western part of the North Slope.

The Trump administration recently announced plans to open the Arctic National Wildlife Refuge (ANWR). Previous efforts by various U.S. administrations to open ANWR for oil exploration have resulted in legal battles, and it is expected to be challenged again in the courts by a coalition of environmental groups and Alaska Natives.

ANWR is the U.S.'s largest wildlife refuge and home to a large variety of species of plants and animals, such as polar bears, grizzly bears, black bears, moose, caribou and wolves.

Russia

Russia's Rosneft announced the discovery of a new oil and gas field, Novoogennoye, on the border of the Krasnoyarsk Territory and Yamal-Nenets autonomous region, and it is estimated to have 146 MMbbl of oil and 1 Bcf of gas.

Rosneft recently reported the discovery of large gas reserves in two locations in the Kara Sea that are estimated to contain approximately 45 Tcf of gas in the two new reservoirs.

Russia is pushing for greater development of the risky Arctic ventures despite western sanctions placed against the country for its invasion of Ukraine and Crimea. Earlier in 2020, Russian President Putin approved tax exemptions to stimulate Arctic upstream oil and gas development.

In June 2020, approximately 5 MMgal of diesel fuel spilled from a power plant storage tank near Norilsk in Siberia onto a road and into the Ambarnaya River. President Putin declared a state of emergency and ordered lawmakers to strengthen environmental legislation. The accident is the second largest in modern Russian history in terms of volume and was only exceeded by a crude oil spill in the northwestern region of Komi that took place over several months in 1994.

Norway

Norway planned to open nine frontier areas in its latest licensing round to expand exploration in the Arctic. Norway's Ministry of Petroleum and Energy and the Petroleum Directorate offered 136 blocks in eight

regions of the Arctic Barents Sea and one in the Norwegian Sea. Environmental groups immediately filed a suit against the licensing, and it will be heard before the country's Supreme Court. The lawsuit also accuses the government of failing to keep its pledges to slash greenhouse-gas emissions under the 2015 Paris climate agreement.

Canada, Greenland

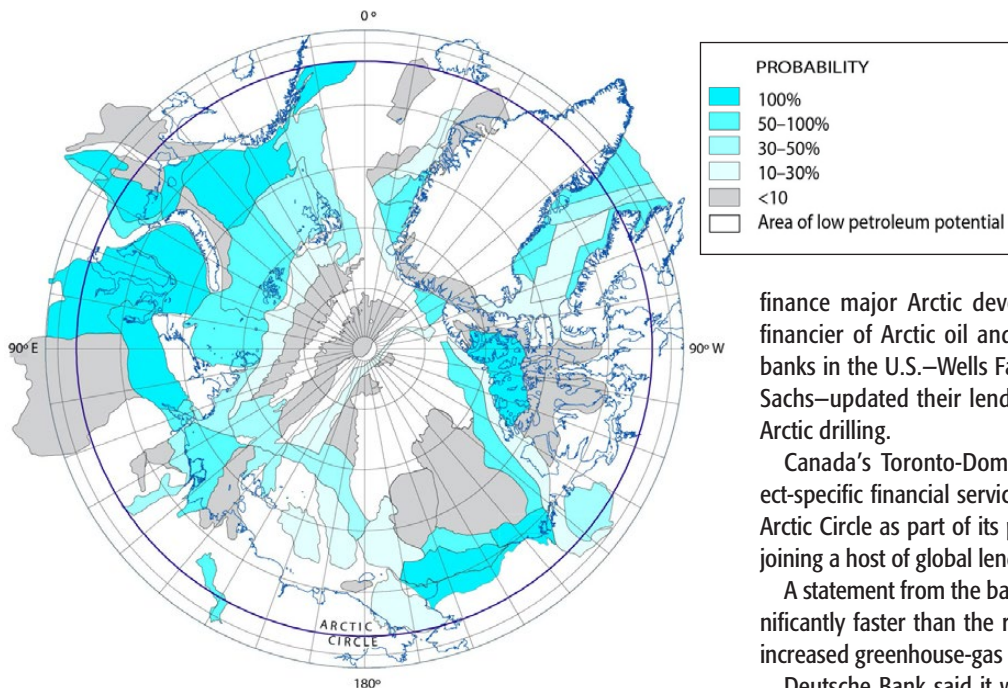
The exploration outlook is less optimistic for Canada and Greenland, where a mixture of very high costs, reluctance to use public funds and particularly harsh conditions will prevent a significant buildup. Canadian policymakers have long considered improving port and other transport infrastructure in their Arctic territories, but high costs

This 1983 drilling rig operation took place near Alaska's Colville River Delta. (Source: Larry Prado, Hart Energy)





Drilling rig heater units (left) and snow removal equipment (right) are shown operating at the Colville River Delta site in 1983. (Source: Larry Prado, Hart Energy)



Assessment units (AUs) in the Circum-Arctic Resource Appraisal are color-coded by assessed probability of the presence of at least one undiscovered oil and/or gas field with recoverable resources greater than 50 MMboe. Probabilities for AUs are based on the entire area of the AU, including any parts south of the Arctic Circle. (Source: 2008 USGS Fact Sheet)

have thus far hampered their efforts and restrained government spending is expected to continue limiting infrastructure buildup in Canada.

Financial challenges

During the past year, a number of major banks announced that they would not finance major Arctic development projects, including the largest financier of Arctic oil and gas, JP Morgan. Four of the six largest banks in the U.S.—Wells Fargo, Chase Bank, Citi Bank and Goldman Sachs—updated their lending policies to exclude financing for new Arctic drilling.

Canada’s Toronto-Dominion Bank said it will not provide project-specific financial services for oil- and gas-related activities in the Arctic Circle as part of its plan to get to net-zero emissions by 2050, joining a host of global lenders in taking similar action.

A statement from the bank noted, “The Arctic Circle is warming significantly faster than the rest of our planet, which poses the risk of increased greenhouse-gas releases and further warming.”

Deutsche Bank said it will no longer finance any new projects in the Arctic region or oil sands projects. By the end of 2020, the bank intended to review all of its existing business activities in Europe and the U.S. with regard to clients’ diversification plans in coal power and end coal mining support by 2025. +

Editor’s note: This article was written in early January.



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Alaska North Slope simulation study

Research reviews the impact of rheology models on the injection profile and recovery improvement of horizontal well polymer flooding in a heavy oil reservoir on Alaska's North Slope.

Jianqiao Leng, Mingzhen Wei and Baojun Bai, Missouri University of Science and Technology; Randall S. Seright, New Mexico Petroleum Recovery Research Center; Yin Zhang, University of Alaska Fairbanks; David Cercone, National Energy Technology Laboratory (U.S. Department of Energy); and Samson Ning, Hilcorp Alaska LLC

The Alaska North Slope (ANS) is estimated to contain 20 Bbbl to 30 Bbbl of heavy oil. However, the development pace of that resource has been quite slow due to the high costs of development and the low oil recovery efficiency using conventional waterflood and EOR methods. Even after three decades of development efforts by multiple operators, the total heavy oil cumulative recovery from all ANS fields just reached 255 MMbbl, which was less than 1% of the total heavy oil in place in 2019.

The University of Alaska Fairbanks is leading a project being sponsored by the U.S. Department of Energy National Energy Technology Laboratory (NETL) and Hilcorp Alaska LLC. The project is a four-year field pilot project entitled, "First Ever Field Pilot on Alaska's North Slope to Validate the Use of Polymer Floods for Heavy Oil Enhanced Oil Recovery (EOR)."

The objective of the project is to improve the oil recovery efficiency by polymer flooding in the Schrader Bluff heavy oil reservoir on the ANS. Polymer flooding has been widely applied to decrease the driving phase mobility and improve the sweep efficiency for conventional oil reservoirs. Recent theoretical results and field results have proved the

effectiveness of this technology in viscous and heavy oil reservoirs. The current field pilot tests of the project also have shown encouraging results in the EOR performance of polymer flooding.

Many laboratory experiments and simulation studies have been conducted to understand the mechanisms behind the optimistic results in pilot tests in different environments. This paper will focus on the effect of polymer rheology on polymer flooding performance in ANS heavy oil reservoirs that are developed with horizontal well.

The use of horizontal wells for EOR in heavy oil reservoirs has increased in recent years. As the target formations in the ANS are relatively close to permafrost, steam generation is prohibitive considering the heat loss and environmental requirements. Thus, polymer flooding has been recommended and applied in the target heavy oil formation.

Although many simulation studies have been conducted on the rheology model effect of polymer flooding, the results are for the vertical well system and lack applicability for the current horizontal well projects. Thus, to examine the rheology model effect on polymer flooding efficiency with the horizontal well system in heavy oil

reservoirs, the project demonstrates how hydrolyzed polyacrylamide (HPAM) apparent viscosity correlated with polymer concentration, formation

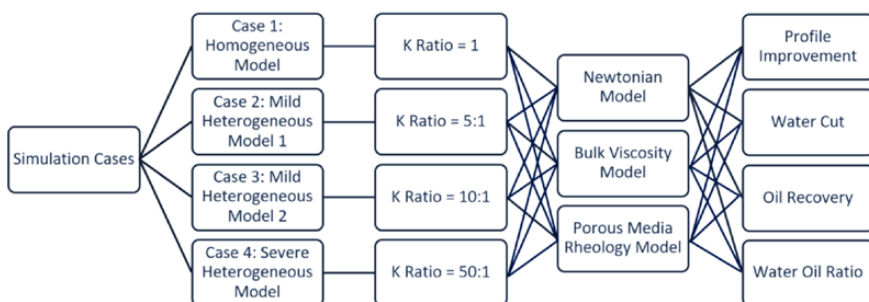


FIGURE 1. The flow chart depicts the simulation design for model heterogeneities, polymer rheology models and objective functions. (Source: NETL)

permeability, porosity, saturation condition and flow velocity. A large variation of formation heterogeneities (K ratio ranges from one to 50) was considered for sensitivity analysis. Incremental oil recovery, water cut reduction, injection profile improvement and water-oil ratio (WOR) also were considered to examine the polymer flooding efficiency.

Simulation model description

To reduce the noise of other influencing factors and to analyze the detail effect of polymer rheology modeling on the polymer injection profile, sweep and oil recovery, all simulation runs were conducted in an areal conceptual model containing two horizontal laterals—an injector and a producer.

The horizontal model is located at 3,930 ft true vertical depth. The model contains a vertical high-permeability channel extended from injector to producer. Thus, the model contains two different permeabilities. The reservoir characteristics are listed in Table 1. The relative permeability was measured by laboratory experts using sandpack coreflooding from Schrader Bluff NB Formation.

Laboratory experts also measured a residual resistance factor of 1.4 (ratio of core permeability before polymer and after polymer flooding), which was caused by polymer adsorption. However, in this study, because the adsorbed polymer is not expected to interfere with the effect of polymer rheology, it is assumed the polymer adsorption does not reduce permeability significantly.

Simulation design

In a homogeneous reservoir, medium to high shear rates usually only exist near the wellbore. In a heterogeneous reservoir, shear rates also can elevate greatly in high-permeability zones or channels. As a result, this study implemented four heterogeneity cases for each rheology model, Figure 1.

The study discussed the polymer flooding simulation while considering the rheology influence in horizontal wells. Consistent with previous theoretical analysis, the simulation results presented the variations of polymer flooding efficiency by using the bulk viscosity model and the apparent viscosity model at relatively high flow rates with the linear flow in parallel horizontal well systems. The sweep was largely increased if the shear thickening was considered in the rheology model. Simulation of HPAM non-Newtonian rheology using bulk viscosity can greatly underestimate the prediction results of real porous media performance of polymer flooding, and application of the apparent viscosity model shows great benefit for this case study of heavy oil polymer flooding using horizontal wells in terms of profile control, sweep improvement and WOR reduction.

Simulation results for this case study

The apparent viscosity response can provide sufficient resistance for the driving phase in channels where velocity is commonly very high but keep a moderate resistance in matrices where velocity is relatively lower. With this mechanism, the apparent viscosity model makes HPAM polymer eligible for conformance control in horizontal well polymer flooding.

TABLE 1. Numerical Reservoir Model Characteristics

Reservoir Properties	Value
Length, I	2,000 ft
Width, J	2,000 ft
Thickness, K	10 ft.
Initial Reservoir Pressure	1,750 psi
Initial Reservoir Temperature	89 F
Model Top Depth	3,930 ft
Grids Dimensions	100*100*1
Grid Block Size	20*20*10
Porosity	23.6%
Swi	0.17
Sor	0.35
Oil Viscosity	286 cP
Water Viscosity	1.07
Low- and High-permeability Contrast	1:5, 1:10 and 1:50
Crossflow, Ki:Kj	1
Polymer Adsorption Capacity	28 µg/g
Well Constraints	Value
Injection Rate	1,500 bbl/d
Producer BHP	600 psi
Well Radius	0.4 ft
Operations	Value
Polymer Initiation Time	80% water cut at producer
Polymer End Time	100% water cut at producer
Injection Profile Observation Time	After 1 FPV polymer injected

(Source: NETL)

Secondly, polymer flooding effectiveness was strongly influenced by reservoir heterogeneity.

In addition to the optimal recovery stage by waterflooding in heavy oil, polymer flooding can provide an extended period of optimal recovery with low WOR. For higher heterogeneity cases, this extended period was very limited for the bulk viscosity model but increased dramatically for the apparent viscosity model.

Lastly, the application of the apparent viscosity model in simulation shows significant benefit for the case study in heavy oil polymer flooding using horizontal wells to improve the sweep, reduce the WOR, overcome the negative effect by heterogeneity and extend the economic production. +

Editor's note: This article is a condensed version of "Impact of Rheology Models on the Injection Profile and Recovery Improvement of Horizontal Well Polymer Flooding in a Heavy Oil Reservoir on Alaska's North Slope: A Simulation Study," submitted to the U.S. Department of Energy's National Energy Technology Laboratory. More information on the project can be obtained at netl.doe.gov.

1 Wyoming

A Turner Sand completion in K-Bar Field was announced by EOG Resources Inc. The Campbell County, Wyo., producer well, #558-0820H Broadhead, was tested flowing 1,443 bbl of 43.7° API oil and 968,000 cf/d of gas. It was tested on a 128/128-inch choke with a flowing tubing pressure of 3,820 psi and a flowing casing pressure of 168 psi. The venture was drilled to 21,163 ft (10,630 ft true vertical depth). Production is from a perforated zone between 10,892 ft and 21,145 ft.

2 New Mexico

In New Mexico's Lea County, Tap Rock Operating reported results from a Lea County, N.M., Bone Spring discovery in an unnamed field. Located in Section 33-24s-35e, #134h Gipple Federal Com was drilled to 22,465 ft (12,146 ft true vertical depth). It was tested flowing at a 24-hour rate of 2,127 bbl of oil and 1.897 MMcf of gas with no reported water. Gauged on a 36/64-inch choke, the flowing casing pressure was 2,300 psi. Production is from a perforated zone at 12,217 ft to 22,323 ft.



3 Texas

A horizontal Val Verde Basin-Woodford Shale well was completed in Vista Grande Field by Brahman Resource Partners LLC. Located in Pecos County (RRC Dist. 8), Texas, #1H King of the Hill 33 initially flowed 665,000 cf of gas and 129 bbl of 52°API condensate through perforations at 13,516 ft to 16,912 ft. Located in Section 33, Block 102, J.H. Gibson Survey, A-1902, it was drilled to 17,261 ft (13,711 ft true vertical depth), and the nearly 1-mile long lateral bottomed to the southwest in Terrell County (RRC Dist. 7C) in Section 37, Block 102, J.H. Gibson Survey, A-1671 with a plug-back depth of 16,976 ft. Gauged on a 13/64-

inch choke, the flowing casing pressure was 2,275 psi, and the shut-in casing pressure was 4,300 psi.

4 North Dakota

Two high-volume Squaw Creek Field-Middle Bakken wells were reported by WPX Energy Inc. in McKenzie County, N.D. The wells were drilled from a pad in Section 25-149n-95w. The #24-13-12HD Omaha Woman produced 7,542 bbl of 42°API oil, 3.76 MMcf of gas and 4.032 bbl of water per day. It was drilled to 26,706 ft (11,106 ft true vertical depth). It was tested on a 64/64-inch choke with a flowing casing pressure of 2,400 psi. Production is from a

Middle Bakken zone at 11,491 ft to 26,539 ft. The offsetting #24-13-12HC Omaha Woman was drilled to 26,825 ft (11,115 ft true vertical depth). It flowed 6,883 bbl of 42°API oil, 5.112 MMcf of gas and 3,240 bbl of water per day. Gauged on a 64/74-inch coke, the flowing casing pressure was 3,200 psi, and production is from perforations at 11,552 ft to 26,669 ft.

5 Gulf of Mexico

In Alaminos Canyon Block 857, Shell Oil Co. completed a Middle Miocene well. The #0GB007S0B OCS G17571 ST00BP00 was drilled to 23,300 ft, and it produced 3,513 bbl of 35.5°API oil and 2.12 MMcf of gas



per day. Production is from a perforated zone between 19,813 ft and 20,967 ft. It was tested on a 57/64-inch choke with a flowing tubing pressure of 2,779 psi. Additional completion information is not currently available.

6 Ohio

Ascent Resources announced results from a Utica Shale discovery in Jefferson County, Ohio. The #3H Thompson initially flowed 29.01 MMcf of gas per day for perforations at 9,454 ft to 21,231 ft after 68-stage fracturing. The Jewett Consolidated Field venture is in Section 24-8n-3w and was drilled to 21,354 ft (9,082 ft true vertical depth).

7 West Virginia

HG Energy completed two Marcellus Shale discoveries in Harrison County, W. Va. The wells were drilled from a pad in Union Dist., Milford West 7.5 Quad and are in Jane Lew Weston Field. The #2H Stickle has a total depth of 20,309 ft (6,731 ft true vertical depth). It was tested producing 21.48 MMcf of gas per day from a perforated zone at 7,151 ft to 20,175 ft after 47 stages of fracturing. The #6H Stickle initially flowed 13.08 MMcf/d of gas. Drilled to 17,050 ft, the true vertical depth was 6,758 ft, and it was also fracture-stimulated in 47 stages with production from perforations at 7,490 ft to 16,911 ft.

8 Pennsylvania

A Wyoming County, Pa., Marcellus Shale discovery was tested flowing 44.752 MMcf/d of gas. Chesapeake Operating Inc.'s #4H Trowbridge was drilled in Section 9, Laceyville 7.5 Quad, Windham Township. The Mehoopany Field well was drilled to 12,639 ft (7,128 ft true vertical depth). It was tested after 24-stage fracturing, and production is from perforations at 6,830 ft to 12,624 ft. +

—By Larry Prado, Activity Editor

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

1 Mexico

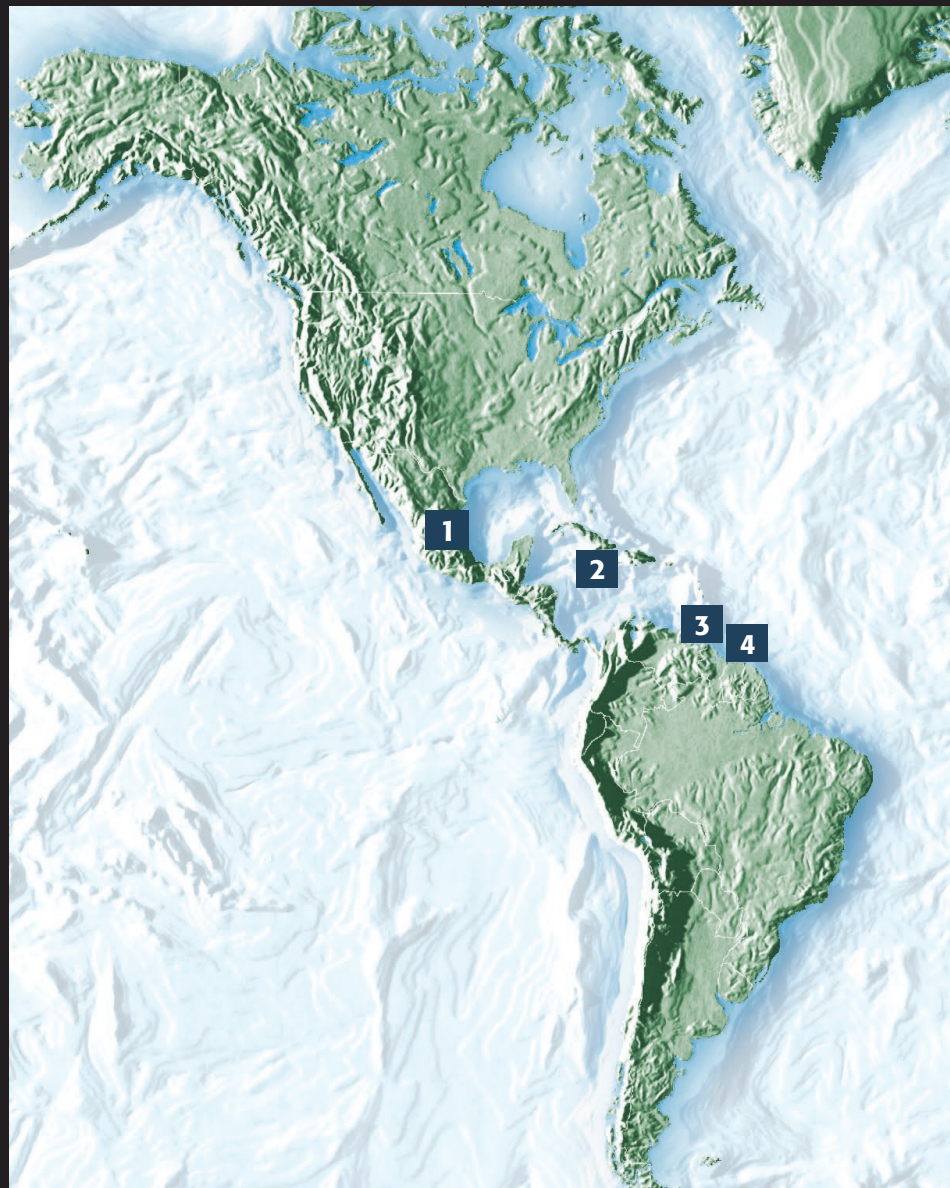
Pemex has received permission to explore the onshore Tampico-Misantla Basin in southeastern Mexico in the states of Tamaulipas, San Luis Potosi and Veracruz. Pemex will explore for unconventional shale-based resources. Exploration wells will be drilled and tested in mature fields. With the development of additional resources, the country's present production could increase by about 300,000 bbl/d to about 1.9 MMbbl/d in 2021 and 2.4 MMbbl/d by 2024. According to the country's National Hydrocarbons Commission, Mexico's unconventional resources amount to an estimated 67.8 Bboe, of which approximately 32 Bboe are in the Tampico-Misantla Basin.

2 Jamaica

A new prospective resource report for United Oil & Gas indicates unrisks, mean prospective resources of more than 2.4 Bbbl of oil across 11 prospects and two leads in the Walton Morant license offshore Jamaica. The report noted that the gross, unrisks mean prospective resource estimate for the Colibri Prospect is 406 MMbbl, which was compiled with an updated reservoir model based on a pre-stack depth migration study from a 3D seismic dataset acquired and processed in 2018 to 2019. Eleven wells have been drilled to date (nine onshore and two offshore) with 10 having hydrocarbons show.

3 Trinidad

Touchstone Exploration completed an exploration well at #1-Cascadura Deep in the Ortoire Block onshore Trinidad. The well was drilled to a total depth of 8,303 ft, and drilling operations were suspended due to high-pressure gas zones encountered. The venture hit a total sand thickness of 2,100 ft in multiple, stacked thrust sheets in the Herrera section. Wireline logs indicated gas pay totaling approximately 1,315 net ft in four unique thrust sheets from a depth of 5,455 ft to total depth. In addition, an aggregate 1,007 net ft of gas pay was identified in the overthrust sheets, an increase of about 20% com-



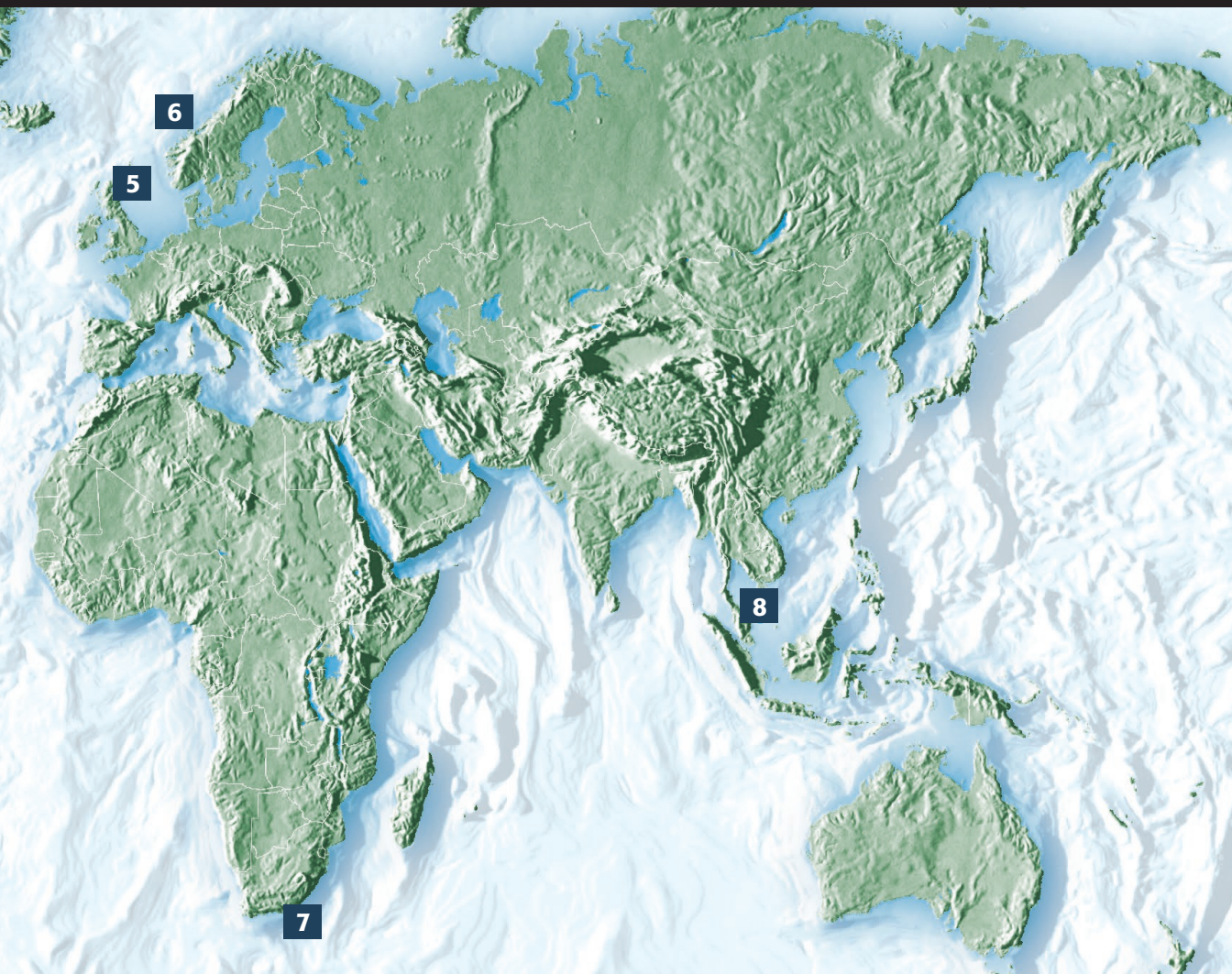
pared to the #1ST1-Cascadura discovery, and additional gas pay of about 308 net ft was encountered in two previously untested Herrera thrust sheets below the sands observed in #1ST1-Cascadura.

4 Suriname

Petronas has announced a hydrocarbon discovery in offshore Suriname's Block 52 at exploration well #1-Sloanea. The exploration well was drilled to 4,780 m and encountered several hydrocarbon-bearing sandstone formations with good reservoir qualities in Campanian. Further evaluation is planned to determine the full extent of the discovery.

5 UK

Jersey Oil & Gas announced a comprehensive subsurface evaluation across its licensed acreage. The study identified a significant new prospect, Wengen, in P2170, directly west of the producing Tweedsmuir Field. Four of the Greater Buchan prospects have been matured to drill-ready status: Verbier Deep; Cortina NE (J64); Wengen (P2170) and Zermatt (P2497). The prospects have an aggregate P50 prospective resource of 222 MMboe, which includes upside potential to Cortina NE. An exploration well is planned for 2022.



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

6 Norway

Equinor announced results from an offshore Norway discovery in PL 263 D. The wildcat well, #6407/1-8 S, is east of the Maria Field. The objective of the well was to prove petroleum in reservoir rocks from the Middle Jurassic Age (Garn and Ile) formations. The well encountered the Garn with a thickness of about 85 m, with reservoir rocks of moderate to very good reservoir quality. A 9-m gas column was encountered in Lange (Late Cretaceous), and there were three thin sandstone layers totaling 4 m with poor to moderate reservoir properties. Preliminary estimates place the size of the discovery to about 5.65 MMcf of recoverable oil equivalent. It was drilled to a vertical depth of

3,518 m and was terminated in Ile. Area water depth is 295 m. Additional testing is planned. This is the first exploration well in PL 263 D.

7 South Africa

Total announced drillstem test results from the #1X-Luiperd discovery in Block 11B/12B in the Outeniqua Basin offshore South Africa. The venture intersected 85 m gross sands with 73 m (net) good quality pay in the main target interval. It was drilled to 3,400 m in 1,795 m of water. Gauged on a 58/64-inch choke, the well flowed 33 MMcf of gas and 4,320 bbl of condensate per day (about 9,820 boe/d). The Paddavissie Fairway in the southwest corner of the block now includes

both the Brulpadda and Luiperd discoveries, confirming the prolific petroleum system.

8 Indonesia

Medco Energi completed the #1-West Belutum exploration and appraisal well in the Indonesian sector of the South Natuna Sea in Block B. The venture encountered an unreported amount of hydrocarbon resources after five drillstem tests. Additional testing and evaluation are planned. The company previously announced commercial exploration success in Block B, and the wells will be developed in 2021 to 2022 along with the prior development of the Hiu Field. +

—By Larry Prado, Activity Editor



PEOPLE



Rød

Norwegian oil company Vår Energi has appointed **Torger Rød** CEO. Rød will succeed **Kristin F. Kragseth**, who has recently accepted the position as CEO of Petoro, the management company for the Norwegian state-owned oil and gas interests.

Seadrill Ltd. has named **Reid Warriner** COO and **Leif Nelson** CTO.

Well-SENSE has appointed **Annabel Green** CEO.

Stratagraph has named **Ashby Pettigrew** president.

Amplify Energy Corp.'s interim CEO, **Martyn Willsher**, will permanently assume the positions of president and CEO.

Enverus has appointed **Manuj Nikhanj** president.



Stewart

Ashtead Technology, an integrated subsea technology and services company, has appointed **Ingrid Stewart** CFO.

Premier Oil Plc said Jan. 25 that **Alexander Krane** would take over as CFO, as a reverse takeover of the company by private equity-backed Chrysaor Holdings Ltd. is set to complete in first-quarter 2021. Krane will replace **Richard Rose**, who will step down as interim CEO and finance director of Premier Oil.

Ithaca Energy Ltd. has named **David Crawford** CFO.

EOG Resources Inc. has promoted **Ezra Y. Jacob** to president.

Infrastructure Networks Inc. (iNet), a remote communications provider to the industry and government in the continental U.S., has promoted **Brian Keefover** to vice president and general manager of the Permian Basin. **Morten Hagland Hansen** has joined iNet as senior vice president of engineering and networks.



Leach

Tim Leach has been appointed to ConocoPhillips' board of directors and executive leadership team. Leach, previously Concho's chairman and CEO, has joined ConocoPhillips as executive vice president of the company's Lower 48 operations.



Hasås

Morten Hasås has joined Kongsberg Digital as senior vice president for Maritime Simulation. Previously CEO of Scantech Industries, Morten has held top management positions at ScanSense, Scanmar and Kongsberg Maritime.



Cockerill

EnerMech has appointed **Paul Cockerill** regional director for the Middle East and Caspian as it seeks to further grow its foothold across the upstream, downstream and petrochemical sectors in 2021. Cockerill replaces **Steve Jones**, who has been named as Enermech's Southern European general manager, as the company looks to grow and further diversify its presence across the region.



Jones

ChampionX has appointed **Mohammed Al-Khalifa** to the newly created role of general manager of Saudi Arabia to spearhead the region for further growth in 2021.



Yeoman

MRDS Group has appointed **Craig Yeoman** finance director. With nearly 30 years' commercial, corporate finance and banking experience, Craig is well known across the U.K. and international industry landscape.



Slaughter

Corrosion Resistant Alloys, a manufacturer of high-grade corrosion resistant alloy tubes, has selected **Tom W. Slaughter** for a business development and advisory role.



Howlett

Xodus Group has appointed **Natasha Howlett** to lead an in-house emissions management division, which will support clients' emissions reduction initiatives around the world.

The appointment is a part of the company's investment in expanding their emissions team to support clients and the wider energy industry in achieving its net zero goals.

Brent Smolik, a former executive with Noble Energy, has been elected to Marathon Oil Corp.'s board of directors.



Hill

The International Association of Oil & Gas Producers has welcomed **Iman Hill** as its new executive director. She will succeed **Gordon Ballard**, who has stepped down following his five-year tenure.



Conn

Oxford Flow has named **Iain Conn** non-executive director, as the company embarks on further growth and diversification.

On The Move



COMPANIES

H&S Valve, Ignition Systems and Controls, Global Compressor and Potemkin have combined to form the new organization called **Global Compression Services**. The new solutions provider is a one-stop shop for natural gas compressor equipment parts and services for operations across the globe.

Saudi Aramco and **Baker Hughes** have announced the formation of **Novel**, a 50:50 joint venture to develop and commercialize a broad range of non-metallic products for multiple applications in the energy sector.

Motive Offshore Group, a specialist in marine equipment fabrication and rental for the back-deck and beyond, has announced the acquisition of **Flowline Specialists**, subsea equipment experts, for an undisclosed figure.

ConocoPhillips Co. has completed its acquisition of **Concho Resources**, following approval by shareholders of both companies.

Husky Energy announced in early January that the transaction to strategically combine with **Cenovus Energy** has closed.

Devon Energy Corp. and **WPX Energy Inc.** have announced the successful completion of their previously announced all-stock merger of equals. The combined company will operate under the name **Devon Energy** and will be headquartered in Oklahoma City.

AqualisBraemar ASA has successfully completed the acquisition of 100% of the shares in **LOC Group**, thereby creating an even more complete service provider to the upstream oil and gas industry. +

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Industry headwinds mandate technology collaborations

Current E&P technology needs a significant pivot in the way applications are developed and delivered.

Duane Dopkin, Emerson Automation Solutions

The oil and gas (O&G) industry is at a significant inflection point where the force of market headwinds, cost pressures, environmental challenges, knowledge attrition and geopolitical uncertainty have converged. Fortunately, the confluence of potentially disruptive technology has landed on the industry at the same time. Collectively branded as “digital transformation technology,” cloud computing, edge technology, machine learning (ML), artificial intelligence (AI), workflow automation, and Internet of Things (IoT) and data analytics are now part of every O&G company’s mindset, roadmap or even current portfolio. The timing seems perfect. So what is the problem?

Many of the commonly used commercial E&P software applications developed by technology providers for the O&G industry were developed in the 1980s and 1990s. These applications progressively evolved into huge monolithic systems, rich in functionality but equally rich in complexity. While these applications have undergone many upgrades and refreshes in their long histories, they lack many of the characteristics and requirements of an agile digital transformation ecosystem and a new way of working that is more conducive to a rapidly changing O&G industry.

Native cloud applications, complemented with a rich set of web and cloud services, provide agility in development, delivery and adoption. However, disaggregation of the application monoliths into more granular components that can exploit a new ecosystem and new economic delivery models takes considerable time. In the meantime, these monolithic applications have been made available to cloud users through a much simpler but less flexible “lift and shift” model.

Data sizes, data diversity and a plethora of proprietary data formats pose another huge challenge to practicing geoscientists and engineers. This challenge is not new; however, it has been exacerbated by the requirements of the industry for more and better digital data (e.g., new surface and subsurface geological and geophysical data). It also has been exacerbated by the sheer volume of proprietary data that have created data management issues, data integrity issues and workflow issues not readily solved by cloud providers alone.

Additionally, rapid decision-making requires continuous streams of real-time data and information from sensors to monitor results, maintain equipment, drive production decisions and manage field operations. These data must be directed to monitoring platforms, analyzed with diagnostic web-based dashboards and integrated with other data (IoT).

E&P data are not only large and diverse, they are complex, often multidimensional, structured and unstructured, and irregularly sampled

across data types. Although analysis of these data appears to be highly suitable for ML and AI methods, off-the-shelf or open source AI and ML algorithms require effort to adapt them to E&P data to solve classification, prediction or analysis problems. Data cleaning, preparation and the lack of sufficient data to train a neural network can deter application. Integration with physics-based models also might be required to achieve desired speed to decision and quality outcomes.

This short summary of the state of current E&P technology, data and ecosystems provides a backdrop for the need for a significant pivot in the way software applications are developed and delivered and the way data are aggregated and consumed. These are not the only issues facing the O&G industry. There are many others, including the use and adoption of open systems and open data that favor democratization of technology over siloed technology development and delivery. Open standards and open ecosystems, however, require high levels of cooperation between all O&G stakeholders to allow the industry to do more with less.

Collaborations between O&G companies and technology providers have always provided a business model and pathway for solving problems. Historically, however, these collaborations have been limited to solving highly focused issues involving proprietary technology and business problems. More point-to-point collaborations of this type will not make a dent in the challenges described above.

The collaborations that are being formed today by O&G companies and technology providers aim to address industry headwinds and hyper-cost efficiencies. These collaborations are occurring between cloud providers, technology specialists (AI/ML), E&P software application providers, alternative energy providers, data storage providers, high-performance computing suppliers and O&G companies. Common themes critical to these collaborations are openness, sustainability, scalability and efficiency.

On their own, these collaborations are not sufficient to overcome the technology challenges faced by the O&G industry. A common understanding and sharing of macro and micro requirements from domain experts as well as a joint understanding of the respective business models of collaborating companies are necessary for a successful outcome. The encouraging news is that these collaborations are forming and proceeding with force. +

About the author: Duane Dopkin is the executive vice president of geoscience, E&P software, with Emerson Automation Solutions.