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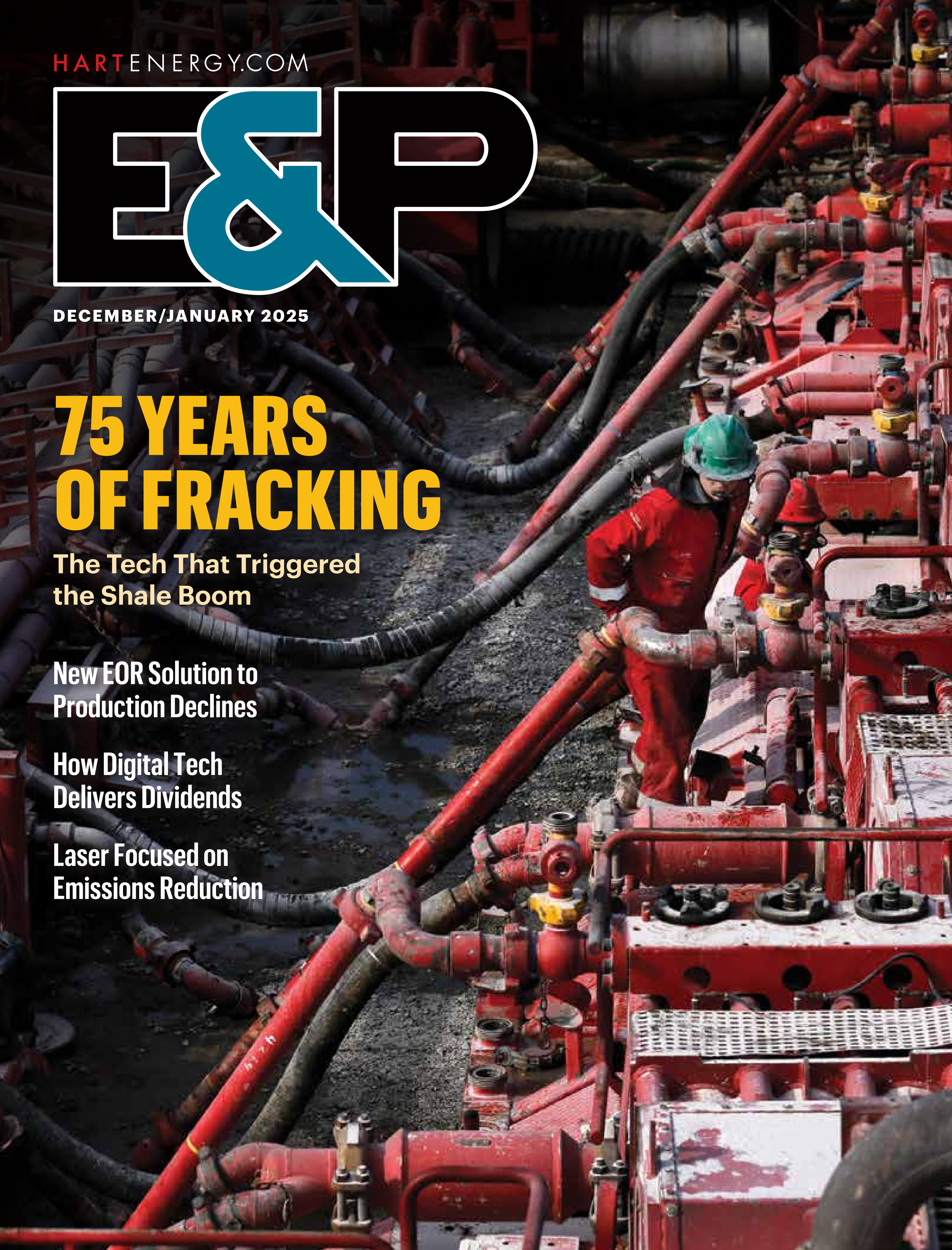

75 YEARS OF FRACKING

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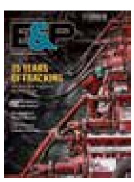
DECEMBER 2024 / JANUARY 2025 | VOLUME 99 | NUMBER 2



ABOUT THE COVER:
This image provided by Halliburton captures the complexity and power of fracking operations.

E&P (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX, and additional mailing offices. Subscription rates: 1 year (12 issues), US $149; 2 years (24 issues), US $279. Single copies are US $18 (prepayment required). Advertising rates furnished upon request. POSTMASTER: Send address changes to E&P, P.O. Box 3001, Northbrook, IL 60065-9977. Address all non-subscriber correspondence to E&P, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 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, 2025. Hart Energy Publishing, LP reserves all rights to editorial matter in this magazine. No article may be reproduced or transmitted in whole or in parts by any means without written permission of the publisher, excepting that permission to photocopy is granted to users registered with Copyright Clearance Center/0164-8322/91 $3/$2. Indexed by Applied Science, Technology Index and Engineering Index Inc. Federal copyright law prohibits unauthorized reproduction by any means and imposes fines of up to $25,000 for violations.

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CELEBRATING 75 YEARS OF THE FRAC

Halliburton and Stanolind Oil pioneered the hydraulic fracturing that led to the shale boom.

JORDAN BLUM | EDITORIAL DIRECTOR

The Legend goes that Erle P. Halliburton did not want to get into the hydraulic fracturing business at first.

The founder of the Halliburton Oil Well Cementing Co. was preparing both to retire and to take his company public when the potential came for Halliburton to pioneer hydraulic fracturing, and he initially saw risk and expenses rather than opportunity.

After some internal urging, Halliburton decided to invest in fracking with Stanolind Oil and Gas—the upstream arm of the Standard Oil Company of Indiana. They completed the first commercial job on March 17, 1949, in Oklahoma, helping set the course for the U.S. oil and gas boom of the 1950s and '60s and, eventually, the shale revolution of today.

As Halliburton and the industry celebrate the 75th anniversary of commercial fracking, history shows that those small, initial frac jobs—consisting of a single 75 hp pump producing 3.5 bbl/min—led to millions of fracs performed over the decades. Intensive fracking, when combined with horizontal drilling and seismic and digital technologies, pushed the U.S. back into the role of the world's biggest oil and gas producer. And the tools and technology continue to rapidly evolve.

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Erle P. Halliburton, photographed by Robert Yarnall Richie, 1940. Despite initial reservations—and plans for retirement—Halliburton took a risk on hydraulic fracturing and his company became the front runner for technology that would change the world.

"Outside of the industry, when I talk to generalist investors, people are totally clueless, and they think fracking is a brand-new thing," said Marshall Adkins, head of energy investment banking at Raymond James and a former field engineer. "When I tell people it's 75 years old, it just blows them away."

Halliburton Chairman, President and CEO Jeff Miller said he is proud of how hydraulic fracturing produced surplus energy resources, enabled global development and lowered costs.

"Halliburton's early involvement in the development of hydraulic fracturing methods, materials and equipment is an important part of

Stanolind secretly approached Halliburton Oil Well Cementing Co. early in the experimental phases to develop the well stimulation process that would eventually become fracking. The two companies partnered for the first fracture treatment in 1947.

HALLIBURTON

our legacy," Miller said. "It sets us apart from our competitors and propels us forward as we improve hydraulic fracturing execution and chemistry. Tight gas and shale would not be economically viable without hydraulic fracturing, and it accounts for a significant portion of production today.

"Technological advances in horizontal drilling and stimulation transformed the industry and positioned the U.S. as a leader in the production of hydrocarbons. Tight gas and the advent of massive hydraulic fracturing treatments were significant game changers in North America."

Tim Hunter

But it all began with Halliburton deciding in a post-World War II energy era that fracking was worth the money and effort.

Tim Hunter, Halliburton chief technical advisor with production enhancement, credits the company's then-chief engineer, Bill Owsley, as the chief advocate.

"Erle P. wasn't necessarily eager to do the experimentation. The cementing business was the heart of the company, and it was an expensive venture to step into something risky," Hunter said. "Owsley was the one who pushed it over center and eventually got Erle P. to buy in and convinced him to do it.

William Owsley

"I think that's interesting. Here's the big opportunity in front of you and the big fork in the road. Do you take the opportunity or not? Halliburton took it, and look where we are today."

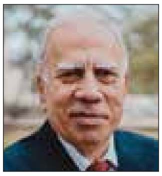
"Halliburton's early involvement in the development of hydraulic fracturing methods, materials and equipment is an important part of our legacy."

JEFF MILLER, chairman, president and CEO, Halliburton

The Beginnings

As far back as the 1860s, oil and gas wildcatters occasionally used explosives for fracturing. The first patent for an "oil well torpedo" was filed in 1865 shortly before the conclusion of the Civil War, but the use of explosives with nitroglycerin and other materials was not sufficient. The hydraulic portion of the equation was missing.

Stanolind engineering partners



“Once you create one fracture, you have to isolate it to create another fracture. So, there was an extra cost, and extra technology coming from a service company. All of that caused reluctance to use it. The technology now is so much better.”

MOHAMED SOLIMAN, professor of petroleum and engineering, University of Houston

Floyd Farris and Joseph B. Clark are generally credited with developing the idea for hydraulic fracturing, a concept they introduced in 1946.

Their early experiments pumped gelled gasoline—essentially napalm—into wells at high pressures to crack the rock. Much smaller volumes of sand and other materials propped the cracks open. Of course, the early experiments were focused on conventional vertical wells and vertical fracs.

Early in the process, Stanolind secretly approached the Halliburton Oil Well Cementing Co., then commonly known as Howco, to develop the well stimulation process that would eventually become fracking. They partnered together for the first experimental fracture treatment in 1947 in the Hugoton Field in Kansas to produce natural gas from limestone from the Klegger #1 well, which was drilled to 2,400 ft.

Mohamed Soliman, a University of Houston endowed professor of petroleum engineering and former Halliburton chief reservoir engineer, literally wrote the books on fracking, including “Fracturing Horizontal Wells.” He also co-wrote a chronology of fracking milestones with B.W. McDaniel of Halliburton.

Soliman noted in his book that the first test well initially was considered a bust.

“At first, the treatment seemed to have failed; however, as there was disagreement as to the need to add a chemical breaker to the 1,000 gal of gelled gasoline carrying approximately 100 lbm of quartz sand, none was added. After approximately a week and some injection of fluid with a breaker chemical, the gel apparently had thinned sufficiently to allow the start of gas production, and they ultimately saw a moderately successful stimulation result.”

Other more successful test wells followed. At the end of 1948, Stanolind won a patent, and Halliburton

A Halliburton frac team sits idle in the foreground as a coil using operation takes place in the distance on Noble Energy's Wells Ranch operation in Weld County, Colo., in 2013.

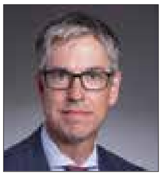
received a three-year exclusive license to commercialize the hydraulic fracturing process, named "Hydrafrac."

The first commercial frac job came on March 17, 1949, from Alma, Okla., in the Velma Field in Stephens County. This, by no coincidence, was just a few miles from Halliburton's home in nearby Duncan.

A second commercial well was immediately fracked in Archer County, Texas, about 100 miles south of Duncan.

The first Oklahoma well was 4,882 ft deep and was fractured with a single pump and about 150 lbm of sand.

"At that point, there was no such thing as a frac pump. We begged, borrowed, cheated or stole from the cementing group to do that initial job," said Shawn Stasiuk, Halliburton vice president of production enhancement. "We were using a steam-powered pump back then. It was around 75 hp. It was really small and was more proof of concept. They were pumping at 3.5 bbl/min. We used oil or gelled kerosene as the base fluid back then. Obviously, pretty volatile stuff."



"We talk about speed of change in the business, but the speed of change from 1949 to the early 1960s was just a crazy amount of change. They were moving at light speed at that point in terms of the amount of innovation that was happening in the industry."

SHAWN STASIUK, vice president of production enhancement, Halliburton

"Today, there would be a lot of HSE concerns with those sorts of things," Hunter added.

The men on site were mostly wearing business suits, some smoking cigarettes.

"It was a little bit of a different time period," Stasiuk said with a laugh.

The first Oklahoma frac cost about $900, and the first Texas frac was $1,000. That equates to roughly $25,000 combined today.

"It quickly showed that, yes, this technology works. It's viable, and the production uptick is fantastic," Stasiuk said. "And, from there, it really kickstarted the industry. Halliburton is super proud to be a part of that first job. From there,

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things just accelerated as we go through the decades."

Fabulous '50s and '60s

Stanolind and Halliburton teamed up to complete more than 300 frac jobs during the following 12 months. The next year saw about 1,000 jobs, and then the final year of the exclusivity agreement added roughly 3,000 more.

"You could see the acceleration of the technology," Hunter said, as production gains triggered faster adoption.

But fracking really took off after the exclusivity deal ended and other players joined the fray.

As Soliman wrote, the year 1953 also saw a significant leap forward when water and gelling agents replaced napalm and other petroleum products in the injection process.

From the time of the first commercial frac in 1949 to the mid-1950s, U.S. crude production rose from 5 MMbbl/d to 7 MMbbl/d and eventually reached a then-record high of 10 MMbbl by late 1970. Hydraulic fracturing was just one component of the boom, but a key role player.

During 1953, the frac job count averaged about 2,300 per month, with other pumping service companies such as Dowell (later Dowell Schlumberger), the Western Co. and Cardinal Chemical among the top participants, according to Soliman.

At the time, jobs featured only 1,500-4,000 gal of injected fluid and

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Halliburton crew members review Sensori fracture monitoring data.

Hydraulic fracturing had evolved to use more pumps (twin HT-400 pumping units), horsepower and overall equipments and materials by 1963 as the industry continued to grow.

HALLIBURTON

just 0.5 lbm of proppant per gallon, typically at rates of up to 4 bbl/min.

According to Soliman, 1955 proved to be an early peak year for hydraulic fracturing with almost 45,000 frac jobs recorded, and treatment sizes averaging 7,000 gal. They mostly used a thin crude oil to begin the fracture growth, and a more viscous crude to carry proppant.

Still, fracturing remained quite rudimentary by today's standards, and that led to the emergence of the "pump whisperers."

"Every piece of equipment, pumping equipment, blending equipment, had at least an operator stationed on the equipment. Even until the early '80s, we had people that would literally sit on top of a driveline or a pump, and they developed a sense of feel and hearing that, if something went wrong with the pump, they could tell you pretty close to what was wrong with it just from the experience and the vibration," Hunter said.

"We called them the pump whisperers. But it took a tremendous amount of manpower to run spreads that way. And it was dangerous. Today, we'd call it the red zone," Hunter said. "Back then, you'd see those guys sitting just happily up on top of a pump, and they may be pumping 12,000 psi [pounds per square inch] while smoking a cigarette, no safety glasses. That's just how the oilfield was. It hadn't matured into the safety-oriented environment that we have today."

Going into the late 1950s and the early '60s, the technologies evolved, Stasiuk said. The companies went from pumping 3.5 bbl/min to more than 20 bbl/min.

"What they also realized was the more volume they put in the ground, the more volume they would produce," Stasiuk said. "Everyone was looking for, oddly enough, horsepower density, just like they're looking for that today."

That shift necessitated more specialized hydraulic fracturing gear, including more advanced frac pumps, which grew from 75 hp to more than 1,200 hp, and two or three pumping units on a site by 1963. By 1964, more than 400,000 Hydrafrac treatments had been pumped as most oilfield operators accepted the process, according to Soliman. By the late 1960s, Pan American Petroleum, formerly Stanolind, was leading high-injection fracs in Oklahoma with close to 250,000 pounds of proppant. That's a sizable jump in scale, although it pales to the several million pounds of proppant in most shale wells today, according to Soliman.

Stanolind was renamed Pan

American before becoming Amoco, named after Indiana Standard's American Oil Co. subsidiary. BP would merge with Amoco in 1998.

A National Petroleum Council study titled "Impact of New Technology on the Petroleum Industry 1946-1966" cited the two most significant technology advancements as water injection, or flooding, and hydraulic fracturing.

By the mid-1960s, hydraulic fracturing had spread internationally and offshore. The first hydraulic fracturing of an offshore U.K. well occurred in the North Sea West Sole well, east of the Humber estuary.

"We talk about speed of change in the business, but the speed of change from 1949 to the early 1960s was just a crazy amount of change," Stasiuk said. "They were moving at light speed at that point in terms of the amount of innovation that was happening in the industry."

Technology Comes Into Focus

As OPEC flexed its muscle with embargoes, U.S. production faltered, and the so-called peak oil discussions escalated.

But the waning U.S. oilfield activity also allowed for greater focus on technological evolution.

The reality is that well into the 1970s, oilfield operators still understood relatively little about the rocks, perforating and other downhole conditions. The focus was on drilling technologies. Core studies were few with respect to fracturing stimulation.

"The '70s and even the '80s were filled with high-tech chemistry, heavy-gel systems and things that for unconventional wells would just kill the reservoir," Hunter said. "That was one of the hurdles."

Eventually, fracking became more analytical and scientific and, therefore, more useful.

The Gas Research Institute (GRI), founded in 1976, started contributing substantially to hydraulic fracturing research. In the late 1970s, Amoco fracking pioneers Ken Nolte and Mike Smith, among others, set out to study and better understand observed pressures during hydraulic fracturing treatments. At the annual Society of Petroleum Engineers convention in 1979, Nolte and Smith presented their conclusions in landmark papers, setting the basis for the fracturing net pressure analysis and its concepts.

In the late 1970s and especially during the 1980s, the industry saw the proliferation of large fracturing treatments placing more than 1 MMlb of sand in single-stage treatments into low-permeability formations, mostly gas-bearing sands, according to Soliman.

But the focus was still on vertical, conventional wells. The first horizontal well was drilled in 1921, but horizontal wells were not common until the 1980s and, even then, they were not combined with hydraulic fracturing.

George Mitchell, the "father of fracking," began experimenting with shale fracking at Mitchell Energy in the 1980s with the goal of cracking the code on shale gas. It took until the late 1990s and early 2000s to truly solve.

In the 1990s, Chesapeake Energy founders Aubrey

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"Fracking really took the U.S. market back to the place it is today as the largest producer of hydrocarbons in the world. And it's probably only going higher, at least a little bit higher, from here as we continue to unleash American energy superiority."

JAMES WEST, senior managing director, Evercore ISI

McClendon and Tom Ward pushed ahead with more modern fracking techniques in the Austin Chalk, but achieving success took time.

Soliman said he and others at Halliburton and elsewhere believed in the combination of horizontal drilling and fracking back in the 1980s, but the best techniques and shale formations were still unclear. He made his first presentation on the topic in 1987.

"I think one of the problems was it was coming from a service company when we started," Soliman said. "The pushback was, 'You are coming from a service company, and you guys are just trying to make money.'

"Once you create one fracture, you have to isolate it to create another fracture. So, there was an extra cost, and extra technology coming from a service company. All of that caused reluctance to use it," Soliman said. "The technology now is so much better. You can create so many fractures. At the time, we were creating every fracture by itself and going to four to six fractures. So, it's expensive."

It took a producer to convince others.

"I give Mitchell Energy credit that they decided to apply it and see what happens," Soliman said.

Digitalization and the Onset of the Shale Boom

It may seem rudimentary now, but the pivot away from the slide rule and the adoption of handheld calculators to the oil patch in the 1980s proved greatly beneficial for efficiency.

Then came personal computers, digitalization and the development of microseismic technologies.

The shale boom wasn't just the combination of intensive hydraulic fracturing and horizontal drilling, but also the additions of digital tools that improved seismic interpretation, said James West, senior managing director at Evercore ISI.

"We had to get better with seismic to understand where the reservoir was," West said.

But that wouldn't be enough. Drilling technologies also needed to improve to extract the best value from the reservoir, West said.

"We had to develop directional drilling tools that were better able to get into the reservoir to drill down and drill over and into the reservoir and had a diagonal or a curvature that could get us into that reservoir," he said. "And then we had to test and evaluate where we should be fracking in that reservoir."

Mitchell Energy did the first horizontal completion in the Barnett Shale in 1992, but it was not economic, nor did it utilize large, multistage fracking.

It would take Mitchell several more years to develop the slickwater fracking that would herald the beginning of the shale boom. As Soliman put it, success finally came when engineers decided to mimic the way water fracs were most successful in the Cotton Valley Sands of East Texas, which used massive volumes of water and high injection rates.

Mitchell Energy was sold in 2001 to Devon Energy, which further developed the combination of intensive fracking and horizontal drilling in the Barnett.

The shale boom, of course, would then spread throughout the country with land grabs in the Bakken, Marcellus and Haynesville plays before the tight oil boom was triggered with the Eagle Ford and the Permian Basin, now by far the most active basin.

From 1949 to the early 2000s, fracking really focused on "one or two stages of fractures and then not much else," West said.

"When George Mitchell and his crowd started to experiment with shale reservoirs, which had to be fracked, and could be fracked in multiple areas in multiple zones, that led to what we now have as the shale revolution," West said. "First, it was natural gas, and it's now become more associated with oil. We're doing 40 or 50 stages of fractures and pumping millions of pounds of sand into reservoirs and lots and lots of water and fluids into the same reservoirs.

George Mitchell

"Fracking really took the U.S. market back to the place it is today as the largest producer of hydrocarbons in the world. And it's probably only going higher, at least a little bit higher, from here as we continue to unleash American energy superiority."

Continuing to Evolve

The shale boom still seems relatively new, but it has evolved remarkably

Devon Energy operations in Rawlins, Wyo., in the Green River Basin, 2021. George Mitchell, the "father of fracking," began experimenting with shale fracking at Mitchell Energy in the 1980s. Two decades later, Mitchell's methods led to a revolution that returned the U.S. to the top of the global hydrocarbon market. Mitchell Energy was sold to Devon Energy in 2001.

DEVON ENERGY

since the early shale years of the Barnett more than two decades ago.

"The scale has just gone up dramatically," said Marshall Adkins. "There's a gazillion evolutions along the way that I don't think people really understand."

Forty years ago, he said, a frac job might represent 10%-20% of the total well cost. Now, the fracking costs typically are two-thirds of the cost of the well. "The importance and cost of the completion and frac job has gone up massively compared to other costs related to drilling and producing oil and gas."

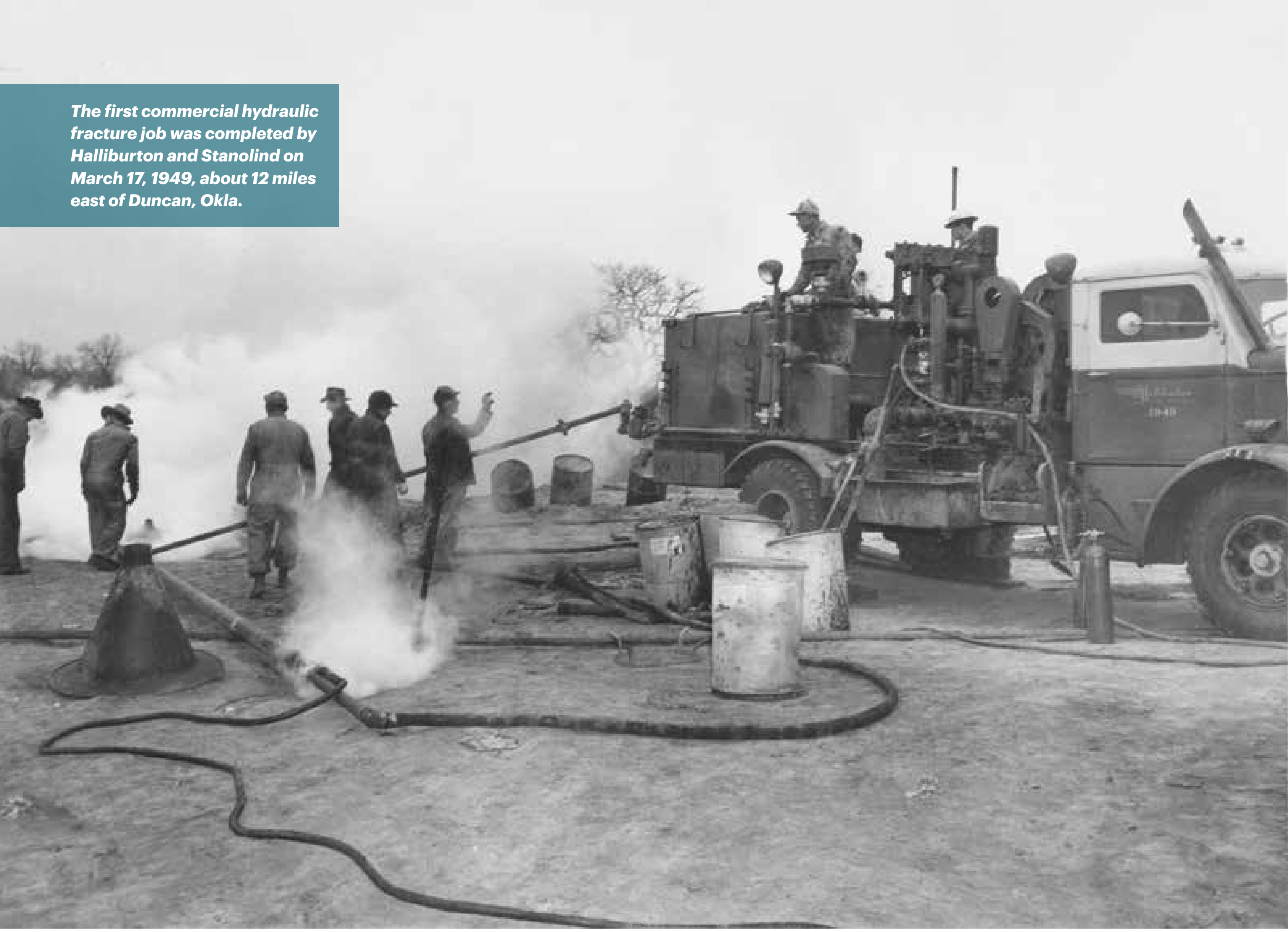
Horizontal laterals grew to 1,000 feet or so, then to 1 mile, 2 miles and now even 4-mile laterals are common that include horseshoe shapes and other modifications. The industry moved from zipper fracs to simul-fracs to, now, trimul-fracs to complete as many wells as efficiently as possible.

Proppants have changed, as well. For a while, the industry used higher-cost ceramics, then switched to white sand, and then realized it could make do with plain in-basin sand.

Everything is exponentially more efficient, Hunter explained, "Back 35 years ago, the frac crew would leave the field camp at 3 a.m. They'd go out to location, rig up, you'd run until the late morning or early afternoon, tear down and, by the end of the day before sunset, everything was gone. That's how fracturing was and continued for a decade or two. But today, the equipment hardly goes back to the yard. Multiple shifts rotate, and we pump around the clock. It's totally different out on location than it was when I joined."

A single well can require 25 million gallons of fluid and 25 million pounds of proppant, he said, in some cases requiring 40,000 hp. "It's really like a factory that exists on location that pumps 24 hours a day. That's what everyone's goal is. It doesn't shut down, and it stays there for long periods of time."

Stasiuk elaborated: "If we look at what a frac spread is today versus what it looked like even in 2019, it's entirely different. It is crazy to see just how fast the industry is changing right now. With electrification, you've got spreads running off power lines that no one would've believed back in the day was even a potential thing. You've got a ton of automation going into the equipment now. We just pumped our first fully autonomous frac job, which is a pretty crazy thing to see. That speed of change right now in the fracking industry is just something we've never seen before."



The first commercial hydraulic fracture job was completed by Halliburton and Stanolind on March 17, 1949, about 12 miles east of Duncan, Okla.

HALLIBURTON

Everything will continue to become more autonomous, more compact and modular, more electrified and more efficient, Stasiuk said, noting that more progress can still be made on lateral footage completed per day.

James West said he also anticipates better understanding and efficiencies to come for reservoir characterization.

"With understanding where to put the fractures, we're probably in the fifth or sixth inning. We're not fully there yet. The reservoirs are all different. We're not quite sure why they change like they do," West said. "So, we do too many stages of fractures, and some of those fractures don't work. So, we're wasting a little bit of money on those fractures. I think there's still some optimizations that can happen there."

> "Good design work looks obvious in the end. It's not easy to get there. And a lot of people might say, 'Well, I could have done that.' But it's not easy to see out the windshield; it's easy to see in the rearview mirror. I think the shale development is exactly that."
>
> **TIM HUNTER,** chief technical advisor with production enhancement, Halliburton

Maybe 75 years is a long time to achieve this level of progress, but innovative ideas and economics and technological advancements all need to combine to bring things to reality. This is the natural evolution of technology.

Hunter illustrated this fact with something a mentor once told him, "Good design work looks obvious in the end. It's not easy to get there. And a lot of people might say, 'Well, I could have done that.' But it's not easy to see out the windshield; it's easy to see in the rearview mirror.

"I think the shale development is exactly that." E&P

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Tracking Equipment Condition to Prevent Failures

A novel direct-drive system and remote pump monitoring capability boost efficiencies from inside and out.

PAUL WISEMAN | CONTRIBUTING EDITOR

Zipper fracs, simul-fracs, trimul-fracs and e-fracs are all terms that reflect the increasing pressure for speed, efficiency and environmental responsibility in completion procedures. Finding ways to simplify and enhance operations continues to be a motivator for a number of companies, including Liberty Energy and NexTier Completion Solutions, which recently became part of Patterson-UTI.

For Liberty, e-fracs were a positive step, but the company realized that to deliver real energy and location efficiency, modifications would need to be made. Meanwhile, NexTier was focusing on improving pump monitoring to reduce costly downtime by predicting and preventing most failures before they happen.

Taking Performance to the Next Level

Liberty Energy's new digiPrime system drives frac pumps directly from an ultra-efficient, natural gas-powered engine which, in a recent field test, saved roughly $20 million in fuel costs per year per frac fleet. Moving to a natural gas-powered engine might seem like a simple solution, but making the transition required the company to overcome significant engineering challenges.

Pivoting from diesel and its associated cost and greenhouse gas emissions to power frac pumps was one thing for Liberty's president and incoming CEO, Ron Gusek. But doing it with e-fracs, which involve using natural gas to generate electricity, then turning that electricity back into mechanical power in electric frac pumps, while a good first step, still seemed roundabout and drill-pad-space greedy.

Connecting piston-based natural gas engines directly to frac pumps would boost efficiency by reducing the energy loss inherent in changing gas from one form to another. So, direct-drive would minimize fuel use and shrink the frac equipment's drillsite footprint by reducing power generation needs. Yet making the prime mover, an MTU 16V 4000 16-cylinder, natural gas engine, drive a pump directly instead of a generator required some creative engineering.

Unlike a vehicle engine, a standard wellsite generator drive motor has no throttle because a generator needs consistent speed to provide constant power levels. It is designed to run at 1,500 or 1,800 rpm exclusively. Because of this, if the controller detects any load change, it could shut the engine down.

Directly driving a pump does involve shifting gears on the transmission as the pump's load changes.

"That causes the engine a real challenge," Gusek said. "When you change gears, you're asking the engine to do more work, but the rpms aren't allowed to drop. The (engine controlling) computer's not prepared for that change when it comes. It's not delivering enough fuel to the engine, so the rpms would fall out of the acceptable range and the engine would stall or shut down."

Smoothing out the load change was the key. "We effectively had to fool it into being prepared for more horsepower," he said. This way, the controlling computer would deliver enough fuel and oxygen to accommodate the load change without shutting down the engine.

The Liberty solution, called digiPrime, takes advantage of the fact that the MTU 16V 4000's drive shaft connects the pump at its back and includes a small generator under the cooling system at the front.

Some careful load coordination makes this work.

Controlling the generator's load has the effect of managing the engine's total load. About 20 seconds before shifting gears, the exact amount of the increase in horsepower is known to the system. At that point, Gusek explained, "We have the generator start to put incremental load on the engine. We can add an extra 200-300 horsepower of load requirement there. We can do that over 10 or 15 or 20 seconds so the engine is now very comfortably settled into this next step. Then we can shift gears, and at that very instant, we can turn off the generator. So, the engine sees a very gradual increase in load, and it settles in at this new place."

Efficiencies extend throughout the process. According to Gusek, the engine itself is among the industry's most fuel-thrifty, checking in at 44% heat efficiency—significantly more than a standard gasoline engine's mid-30s level. Being direct drive, it also eliminates the energy loss inherent in going from mechanical to electrical and back again, which is the case with standard e-fracs systems.

NEXTIER

Data collected from NexTier's Insight program when anomalies occur allow the company to identify areas that might need to be reengineered for greater durability.

Smaller Footprint

Older units were limited to 2,000-2,500 hp on a trailer, but this one reaches 3,000 hp, Gusek said. "It's basically a two-for-one swap in term of the amount of horsepower we can get on a single trailer." This reduces the amount of equipment space required on site.

Replacing older Tier 4 engines, which use 25% diesel and 75% natural gas, with an engine that uses 100% natural gas might lead to the assumption that eliminating diesel would increase natural gas use. But Gusek reports that, due to its extremely high efficiency, the engine actually uses less natural gas.

Saving Time and Energy

The digiPrime units have only been in the field since early 2024, so there is no data yet on yearly energy cost savings. However, based on estimated figures using 2023 prices for diesel and natural gas, Gusek estimates that a fleet using 100% digiPrime could save around $20 million versus the older mixed-fuel e-frac fleets.

Eliminating diesel should also extend run time between overhauls.

Gusek said diesels require overhauls about every 25,000 hours, and he estimates that the natural gas-only unit could more than double that run time, creating further cost savings. Without performance data, however, "It's way too early for us to tell," he said.

Boosting Runtime

Deep and continuous digital monitoring of a motor's condition—engine rpm, engine temperature, oil temperature, transmission pressure—makes it possible to identify conditions that are likely to presage a failure. Armed with that knowledge, NexTier's team gets ahead of most issues, rightly timing preventive maintenance and creating a smooth path to orderly servicing and replacement.

The NexTier monitoring system, known as Insights, has significantly extended equipment run times and virtually eliminated failures, according to director of digital operations Kevin Sutton.

The monitoring system consists of wireline, power solutions and other pieces of equipment. By comparing current pump conditions to its extensive historical database, the system boils down alerts to a red, amber and green (RAG) system. Sutton calls it "our biggest tool" in avoiding failures.

Green means all systems are go. A change to amber would occur, for example, if a normal operating level

NEXTIER

Comparing current conditions to an extensive historical database allows NexTier's alarm system to designate alerts as green (no issues), amber (less than ideal, but not an emergency) or red (out of specs, action required).

of 100-150 rpm was slightly exceeded but not in a dangerous range. A rate of 150-170 rpm is not ideal, Sutton said, "but is not going to be incredibly detrimental to the component. That's what we call our amber area." Should the level exceed 170 rpm, the alert moves to red. "That's where we recognize that there's going to be potential damage to the component if it continues," he explained.

NexTier technicians oversee the tool 24/7 from a remote monitoring center. Depending on the issue, the repair team might remove a pump and replace a part or a fluid. Before the pump is returned to service, it is tested to make sure the performance issue was appropriately resolved. Pre-reinstallation verification assures that repairing one component did not create an unintended consequence elsewhere and that the original repair was performed correctly.

Repair testing also extends to larger jobs in which the pump is taken to the shop for major repairs or an overhaul. In-shop digital testing ensures the repairs were made, the pump was properly reassembled and all is in good order before the pump goes back to the field.

It's About (Run) Time

Continuous monitoring allows anomalies to be identified and addressed before performance or safety becomes an issue.

"If we want to pump, let's say, for 1,000 hours, and we notice something looks a little bit odd or different or not normal, we can say, 'Let's pull that pump out, let's do a couple of preventive maintenance steps on it,' and only be offline for about an hour or so," Sutton said.

Accumulated knowledge also informs proper preventive maintenance (PM) schedules, which Sutton said is "the truly ideal situation, keeping ahead of all maintenance before any failures occur." Once PM intervals are set, they are continually compared to RAG alerts. If certain components are regularly failing, it may be time to update the schedule, he said.

The data also informs equipment design, allowing the company to identify areas that might need to be re-engineered for greater durability.

Continuous monitoring has already proven its value in the field, Sutton said. "With the development of this Insights program, we've seen a 110% increase in engine life cycles. Power end life cycles have gone up 125% and transmissions, which seem to be the toughest, have gone up 65%." E&P

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A Novel EOR Process Could Save Shale from a Dry Future

A new solution looks to remedy the problem of production declines.

JAXON CAINES | TECHNOLOGY REPORTER

The objective in unconventional developments is to produce as much shale oil and gas as possible from a reservoir. But, even with the most advanced EOR solutions, a large percentage remains in the ground. According to a report by the U.S. Department of Energy's Office of Fossil Energy and Carbon Management, "Even under the best of circumstances, primary, secondary, and tertiary (enhanced) techniques can ultimately lead to recovery of 30 to 60 percent of the original oil in place," which leaves a lot of hydrocarbons unproduced.

Operators are looking for ways to extract more oil and gas from producing wells, but they need evidence that new technologies can outperform traditional EOR solutions.

Shale Ingenuity's SuperEOR, which has been field-tested with positive results, could be one answer to the recovery conundrum. Similar to huff-and-puff injection, this solution involves injecting a solvent into the reservoir, which expands into a gas to drive oil out of the rock.

Robert Downey, CEO of Shale Ingenuity, explained the technology to *E&P*. "What we use is a liquid hydrocarbon solvent solution that you pump into a shale formation," Downey said. "When you pump [the solvent] into the formation, it becomes miscible in the oil at low pressure of around 7 or 8 PSI and the formation heats it up. But, the minute you open that well to flow, that solvent wants to explode into a gas and push that oil very explosively out of the rock and up the wellbore."

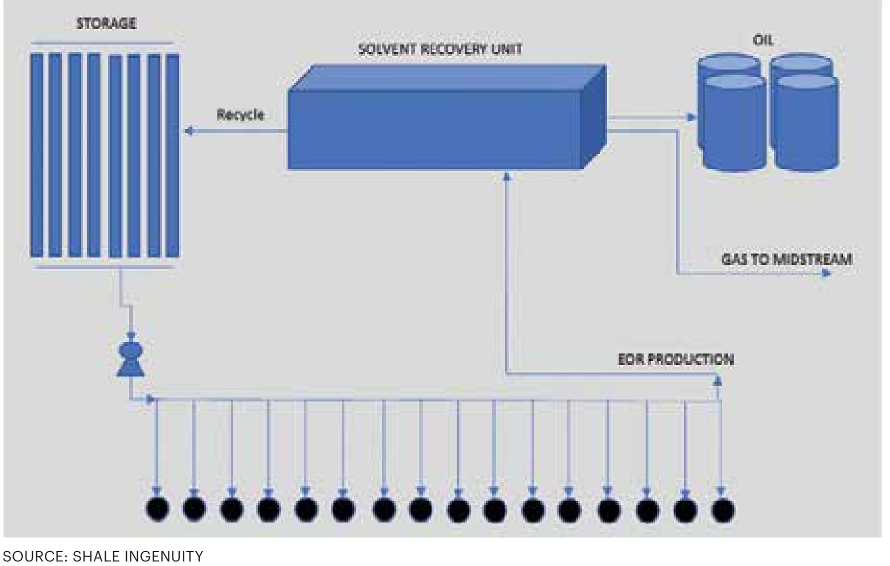
SuperEOR offers higher recovery rates and reduces production costs by about 50% compared to primary recovery methods, Downey said.

"Obviously, there are a lot of depleted shale wells out there now, and people are looking for a way to make this work. But, using natural gas or CO_2 just doesn't work very well, even without having all the fracturing issues," Downey said.

SuperEOR works at lower bottomhole pressures than natural gas or CO_2 because the solvent is miscible in the formation oil at much lower pressure. Because it has much greater viscosity, it is also much less likely to move into fractures in offset wells.

The recovered solvent, which is gathered by a special solvent recovery unit, significantly improves oil recovery. According to Downey, the company's proprietary solvent not only improves production up to 500% more than traditional methods, but also can be recovered from the rock and reused.

SuperEORTM Project Process Schematic

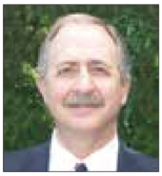


SOURCE: SHALE INGENUITY

The SuperEOR solvent can be recovered from rock and reused, making this process more sustainable than other EOR methods.

How It Works

"The big problem when injecting natural gas into these shales is that you get to a certain bottom of pressure and the natural fractures that are in the shale start opening up," Downey said. "Then the gas wants to move into the shale fractures and bypass the matrix. It doesn't go into the matrix and become miscible in the oil, so you end up pushing the gas to an offset well,



"Cyclic stimulation will work on vertical wells, horizontal wells, conventional wells, unconventional wells, oil, gas, low perm, high perm, old wells and new wells. It's about 20% to 50% of the cost of a typical frac job."

ROBERT DOWNEY, CEO, Shale Ingenuity

and you don't get good oil recovery."

Shale Ingenuity's solution works differently. "We don't have that problem because, when you inject the liquid and you don't have to go to this high bottomhole pressure, you don't activate those fractures," he explained. "The liquid goes right into the shale oil in the formation and then you flush it back out."

This closed-loop system minimizes environmental impact and has the potential to cut greenhouse gas emissions from oil production by up to 75%, Downey said.

"At the surface, your production goes to the tanks, your gas goes to your gas gathering line, the solvent gets stored as a liquid on the surface, and then you reinject it with a triplex pump. It's all closed loop; so the environmental impact is much lower," Downey said. "In fact, you could even take your solvent recovery unit and do some additional things on there to further reduce the already limited air emissions."

As project size increases, efficiency improves. Similar to a gas processing plant, a large-scale operation is highly scalable. The cost per 1,000 cf decreases substantially as plant size grows.

The cost of using SuperEOR in oil production is approximately $17/bbl, making it much less expensive than other EOR methods, Downey said. "Historically, the high cost per barrel and challenges related to gas containment have hindered the success of natural gas and CO_2 huff-and-puff, shale oil EOR projects."

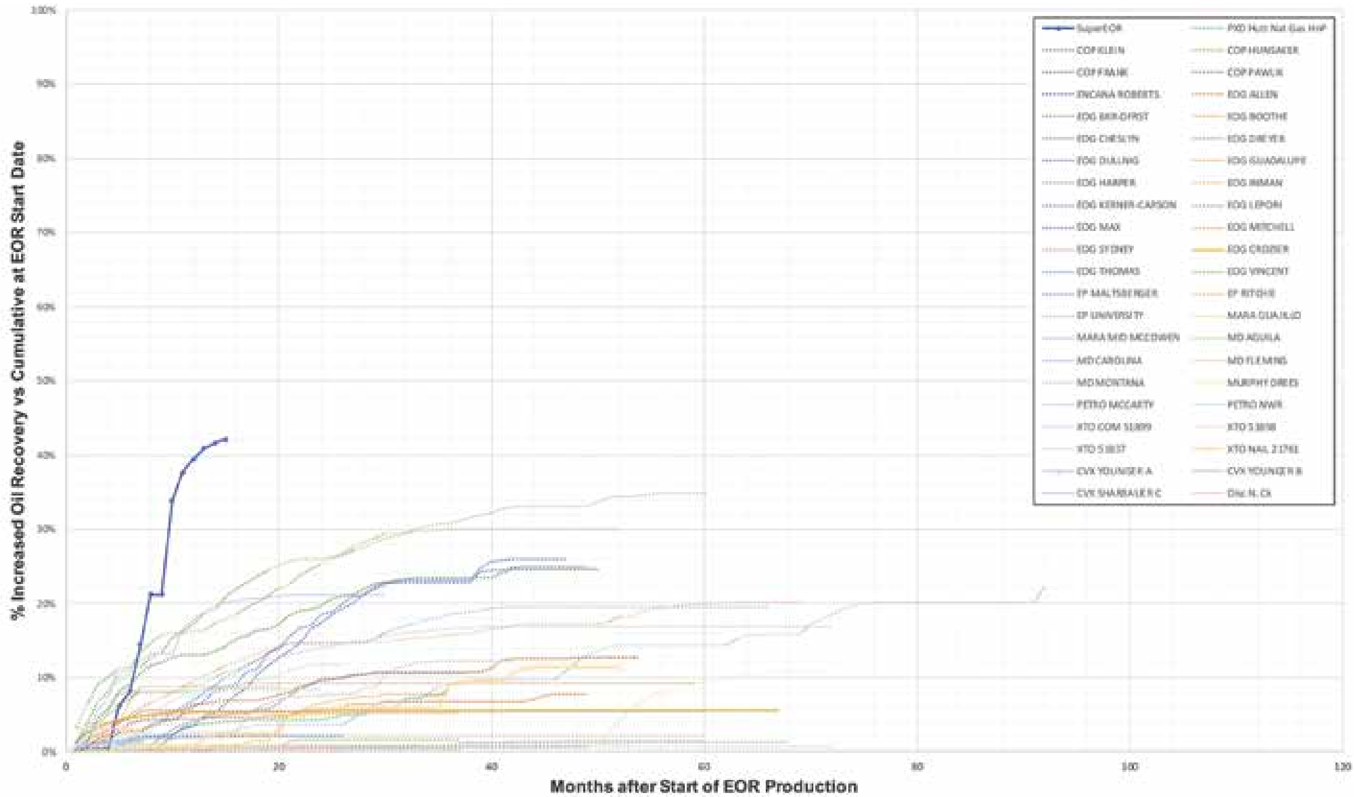
"If you wanted to do a project of 60 wells, the economics for that are going to be better than a project with 10 wells," Downey told *E&P*. Operators might break even on a 10-well project after six or seven months. But, with a 60-well project using SuperEOR, "you're looking at a return on investment of seven to 10 times your money and payouts in six to seven months," he said.

Putting the Solution to the Test

The new technology has been modeled and tested across various shale plays, including the Utica and Eagle Ford shales, and the Powder River Basin.

A field test in the Eagle Ford demonstrated the efficacy of the solution. According to Downey, using the proprietary

Normalized EOR Oil Recovery, SuperEOR vs All Texas Shale Oil Nat Gas HnP Projects



SOURCE: SHALE INGENUITY

This graph shows a comparison between the results of a SuperEOR project in the Eagle Ford and all other natural gas huff-and-puff EOR projects in Texas.

solvent enabled a 44% increase in oil recovery and a rise in production from 13 bbl/d to 390 bbl/d in only 10 months. The closest results achieved using traditional recovery methods Downey found was a program for EOG Resources that achieved 35% recovery, but only after five years. Other EOR solutions were unable to reach even that threshold, he said.

Variations on a Theme

Shale Ingenuity also developed a technology called UltraEOR that incorporates a technique called Cycle Stim, which uses cyclic hydraulic fracturing to create numerous small shear fractures in the wellbore. This process increases the surface area available for solvent contact, and Downey said he expects this solution to double the oil recovery rates achieved by the earlier product. Although not yet field tested, the technique has the potential to increase oil recovery by 1,000%, Downey said

The solution is both versatile and cost effective, Downey explained: "Cyclic stimulation will work on vertical wells, horizontal wells, conventional wells, unconventional wells, oil, gas, low perm, high perm, old wells and new wells. It's about 20% to 50% of the cost of a typical frac job."

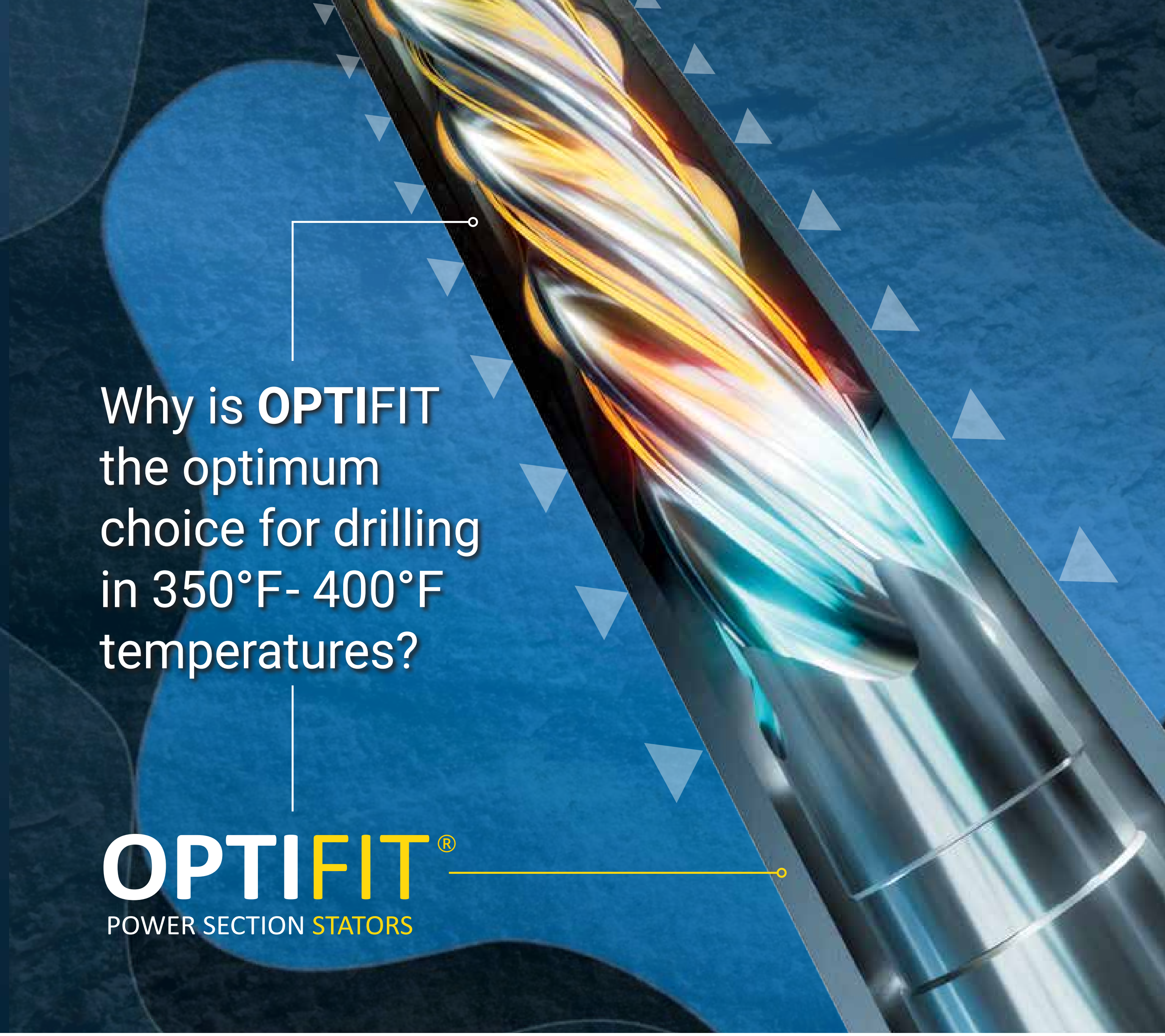
The process uses less fluid and sand, requires no chemicals, and needs fewer people on location to deploy it, Downey said.

The industry has been slow to adopt Cycle Stim due to its complexity and the preference for traditional fracking methods, Downey said, but he is optimistic that the technique's lower cost and reduced environmental footprint will be compelling reasons to test it in the field. He believes the results will lead to widespread use.

Drivers for Change

As the oil and gas industry grapples with the realities of diminishing shale reserves, the emergence of innovative technologies could significantly impact recovery and economics. Advanced extraction methods like these not only promise to rejuvenate aging wells, but also offer a more sustainable and cost-effective solution for enhancing production. Although industry inertia may slow widespread adoption in the near term, the potential benefits—ranging from significant increases in oil recovery to substantial environmental improvements—are drivers for change.

E&P



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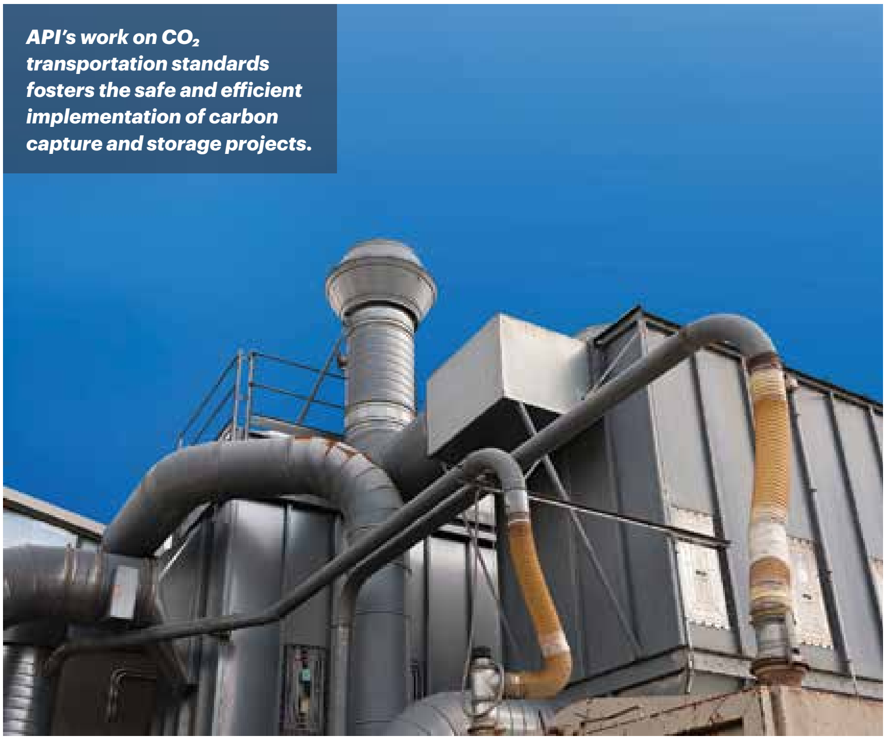
Navigating a Path to Lower Carbon Industry Operations

API has published nearly 100 standards addressing environmental performance and emissions reduction.

ANCHAL LIDDAR | SENIOR VICE PRESIDENT OF GLOBAL INDUSTRY SERVICES, API

The global energy landscape is undergoing a rapid transformation, driven by the competing challenges of meeting rising energy demand, keeping energy affordable and addressing climate change. At API, we are pursuing a balanced approach that leverages both conventional energy sources and innovative, lower carbon technologies. It is a comprehensive strategy that achieves both goals without compromising American energy security.

It is a complex challenge, but we are well suited for the task. Our member companies are leaders in both conventional energy production as well as in developing innovative, lower carbon solutions. Together, we are committed to navigating a path toward lower carbon operations, deploying a multi-pronged approach that incorporates standards development, collaboration and cutting-edge research.



API's work on CO_2 transportation standards fosters the safe and efficient implementation of carbon capture and storage projects.

SHUTTERSTOCK

Standards Driving Low-Carbon Operations

Central to this multi-pronged approach is developing and continuously updating industry standards that support lower carbon technologies that are both safe and efficient. For more than a century, API's collection of 800-plus voluntary consensus standards have been the foundation of industry operations around the world, a legacy whose focus evolves to meet the changing needs and expectations of industry and the public.

This includes a significant focus on improving environmental performance and reducing greenhouse-gas (GHG) emissions, for which API has published nearly 100 standards. In the past three years, API has published nearly 60 standards directly contributing to reductions in GHG emissions during resource extraction and energy transportation, which help to combat climate change.

As we work toward a lower carbon future, these standards are continuously reviewed and updated—not just by API, but by a diverse pool of stakeholders—to address the specific challenges presented by emerging technologies.

Key initiatives that are being developed to drive the responsible adoption of lower carbon technologies include:

- **CO_2 Transportation Pipelines:** This recommended practice is under development and will establish guidelines for the design, construction, operation and maintenance of CO_2 pipelines used for carbon capture and storage (CCS) projects. This will enhance safety and reliability as CO_2 is transported to storage sites.

- **Offshore Wind Safety and Environmental Management Systems (RP 75W):** Leveraging API's expertise in offshore oil and natural gas operations, this standard will provide a framework for establishing safety and environmental management systems for offshore wind farms, promoting responsible renewable energy development.

- **Hydrogen Infrastructure Standards (API 5L & Spec 6D):** Recognizing the potential of hydrogen as a clean energy carrier, API is revising standards for pipelines and piping valves (API 5L & Spec 6D) to address the specific requirements of hydrogen service.

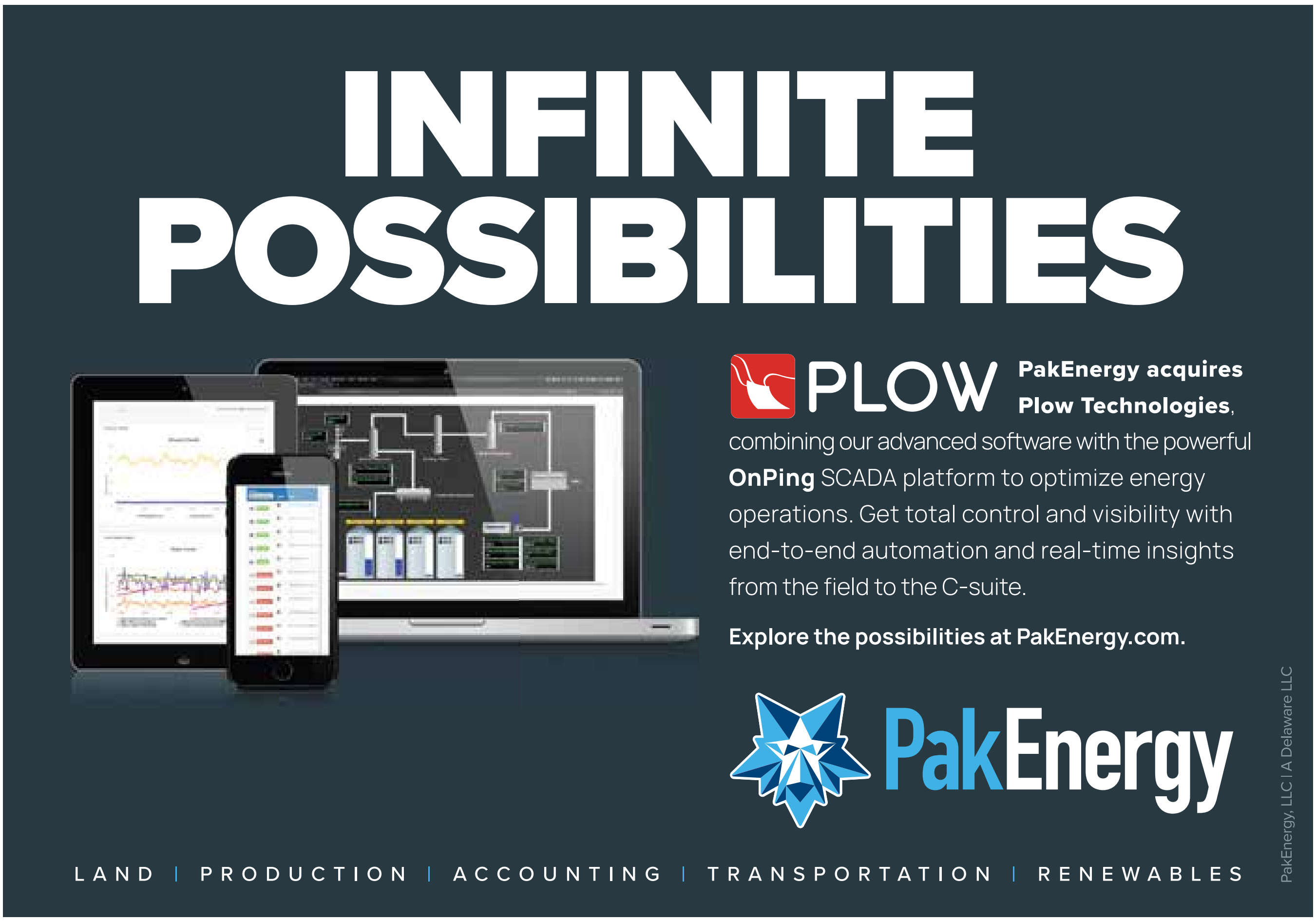
Collaborative Innovation for a Sustainable Future

Collaboration is essential for achieving meaningful progress on the energy transition without compromising energy security. API engages stakeholders across the industry (producers, refiners, pipeline operators and service companies) and government to develop standards that reflect the latest knowledge and recommended practices.

Recent standards also seek input from a broader range of stakeholders, including the general public and tribal communities. For instance, RP 1185, "Pipeline Public Engagement," fosters meaningful, two-way dialogue and cooperation with the public. This inclusive approach helps identify knowledge gaps while promoting the effective allocation of resources, without duplicating efforts.

Research that Promotes New Technologies

As industries across every sector of the economy look to reduce their emissions, there is a growing recognition that new technologies are urgently needed to meet these commitments. Fortunately, the list of promising emerging technologies gets longer by the day, and many of them involve capabilities and skill sets that directly overlap with the core competencies of the oil and gas industry. For that reason, API supports innovation that promotes technologies with significant emissions reduction potential, including:



▶ **CCS**

CCS technology is widely recognized as a necessary component of deep decarbonization, especially as it pertains to decarbonizing hard-to-abate sectors and industrial processes. Often, these vital sectors—steel, cement and other industrial operations—generate significant emissions but require high heat that cannot be generated by traditional renewable energy sources. CCS technology provides a pathway for emissions reductions by capturing carbon emissions from industrial processes, transporting them to secure geological formations and storing them permanently underground.

The oil and gas industry is the longstanding leader in the development and deployment of CCS technologies, largely via its use in EOR. The industry is thus well positioned to lead in the deployment of CCS across multiple other applications and use. API supports policies that incentivize CCS projects, such as the 45Q tax credit, and works with government agencies to develop regulations that facilitate its deployment. Additionally, API's work on CO_2 transportation standards fosters the safe and efficient implementation of CCS projects.

▶ **Hydrogen**

Hydrogen is an incredibly versatile molecule and fuel source, with a myriad of potential applications across multiple sectors. There are also multiple pathways for producing hydrogen, further expanding interest in its future role as a major component of the energy system.

Expanding the hydrogen economy is key to accelerating reductions in carbon emissions, particularly in industrial sectors that are difficult to decarbonize. As with CCS, the oil and gas industry has deep expertise and experience in producing and transporting hydrogen due to its longstanding use in refining operations. The industry is thus poised to be a leader in expanding hydrogen markets, both in the U.S. and around the world.

API advocates for technology-neutral policies that support clean hydrogen development from all available sources (including low-methane intensity natural gas) and is revising standards (API 5L & Spec 6D) to facilitate the safe and reliable transmission of hydrogen. It also engages with the government to support any hydrogen production-related tax credits that support market growth and decarbonize hard-to-abate sectors without driving up emissions in the production of hydrogen itself.

▶ **Offshore Wind**

Offshore wind is a rapidly growing renewable energy source that can complement oil and gas production in a lower carbon energy mix. State and national decarbonization strategies lean heavily on the widespread deployment of offshore wind. However, the projects are of a massive scale, and involve significant technical and engineering complexity.

The oil and gas industry has immense experience in offshore operations, which can be applied to offshore wind. API is developing the RP 75W standard for offshore wind safety and environmental management systems, another way it supports the development of sustainable energy.

▶ **Methane Emissions Reduction and Flaring Efficiency**

Methane is another GHG that is the focus of emissions reductions. While the oil and gas industry is far from the only source of methane emissions, the last decade has seen a concerted effort by operators across the energy value chain to reduce their methane footprint. Beyond individual company commitments, a new suite of significant regulations is poised to further accelerate emissions reductions in the U.S. and other major supply regions.

API develops targeted standards and best practices to minimize methane emissions from oil and natural gas operations, including reducing routine flaring. A flare-management program developed by The Environmental Partnership has helped reduce flare volumes and flare intensity—both important in shrinking the industry's carbon footprint.

▶ **Carbon Footprinting**

API supports the development of standardized methodologies to enhance environmental performance and sustainability within the lubricants industry. It recently published Technical Report (TR) 1533, "Lubricants Life Cycle Assessment and Carbon Footprint," which defines an approach for life-cycle assessment (LCA) and carbon footprint (CFP) of lubricants and specialty products, providing customers with reliable sustainability metrics.

Toward a More Sustainable Future

As the world addresses the dual challenges of securing reliable energy and promoting environmental stewardship, API is demonstrating the effectiveness of standards development, collaboration and research in forging a path toward lower carbon operations.

API remains committed to working with industry stakeholders, government entities and the American public to drive innovation and advocate for policies that strengthen our energy supply and help build a lower carbon future. E&P

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2025 CONFERENCE ONLY BROCHURE

Extending ESP Service Life with Permanent Magnets and Improved Gas Handling

New contra-helical pump systems are designed to reduce gas locking.

PAUL WISEMAN | CONTRIBUTING EDITOR

In the shale era, electric submersible pumps (ESPs) have become the workhorse of the beginning phase of a well, which is its most productive. New types of ESPs using highly efficient permanent magnet motors (PMMs) are gaining acceptance for their ability to boost production along a shale well's production decline curve.

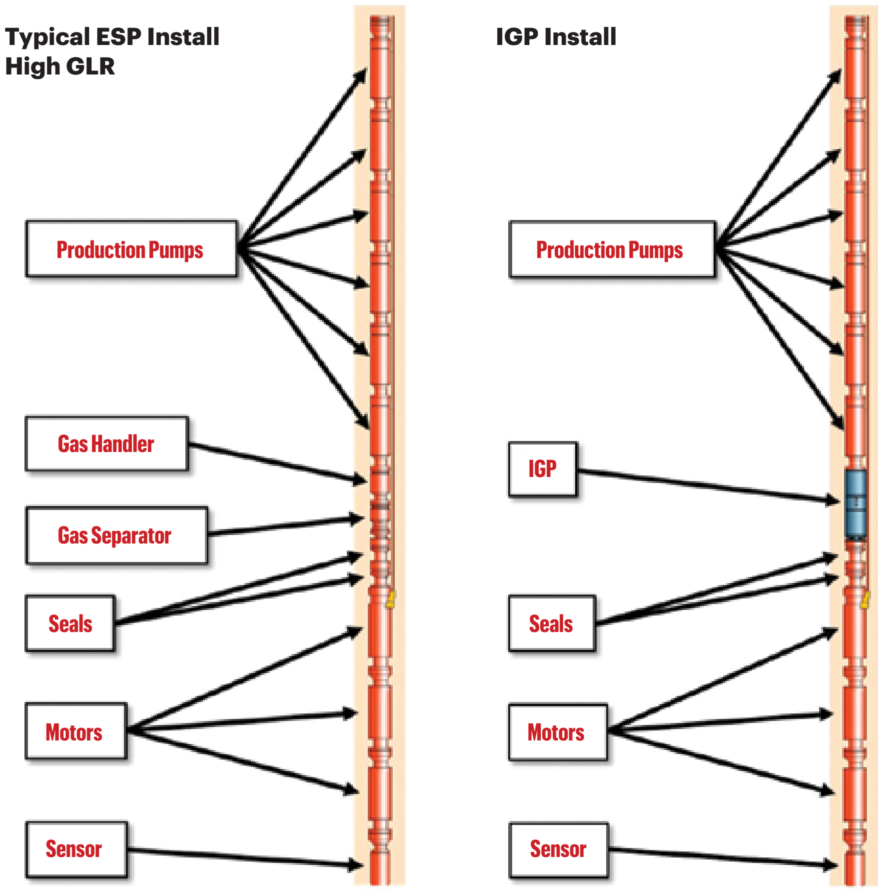
As wells age and production drops, gas production rises, creating gas-locking issues. These are being addressed by contra-helical pump systems designed to reduce gas locking. Baker Hughes and Extract Production, an NOV company, are advancing the industry in these and other areas.

PMM Energy Savings, Efficiencies Make Them a Viable Option

For almost a decade, developers have known that powering ESPs with PMMs instead of traditional induction motors (IMs) can cut power consumption and reduce the size of equipment inserted downhole. Early-day drawbacks included the shorter run life of PMMs and safety concerns due to the possibility of generating electrical charges when not running. So, PMMs remained under the radar while developers who saw their potential continued to improve them.

In the last few months, PMMs have become a hot commodity, said Dana Meadows, Baker Hughes' artificial lift portfolio director. In 2023, the company's PMM, branded as Magnefficient, accounted for only 3% of Baker Hughes-installed ESPs. This year, PMM installations have ballooned to 11% of ESP installations, and that number is growing.

Integrated Gas Processor Installation vs. Typical Installation

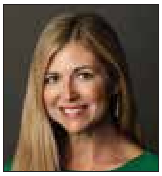


SOURCE: EXTRACT PRODUCTION

Extract's integrated gas processor is installed right below the production pumps (right graphic) in place of the gas handler and gas separator (left graphic).

Three Reasons for Sudden Growth

There are multiple drivers for this increase, Meadows said, including improved safety devices, concerns about power grid overloads and the need to extend the economic life of producing wells. Baker Hughes has spent the last three years developing a complete system involving PMMs, the E2000 ESP and variable speed drives.



Dana Meadows

Because the magnets are permanent, they require less electricity to run. Officially, Baker Hughes says power savings are in the 10%-15% range, although some clients have seen cost reductions of up to 26%. This results in a lower operating cost for the well and more barrels of oil produced per day, Meadows said.

For many operators, PMM energy efficiency is as much about reducing loads on the already strained power grid and boosting ESG scores as it is about saving dollars. Power company fees for running new lines can run into the tens of thousands of dollars and involve weeks of delays. By replacing IMs with PMMs, producers often can add more wells without incurring major infrastructure costs, Meadows noted, pointing out that the reduced power demand can also increase daily production.

"One operator said the power savings is great, but they're able to get more out of the well per horsepower than they were able to out of IM because they previously had been maxed out on the power grid," she said.

PMMs also enhance safety because the same permanent magnets that reduce power requirements can generate current of their own when an installed pump is shut off, allowing the crude oil above it to flow back into the hole. Unrestrained, that flow can cause torque to be transferred from motor to pump, or vice versa, in both clockwise and counterclockwise directions in some instances.

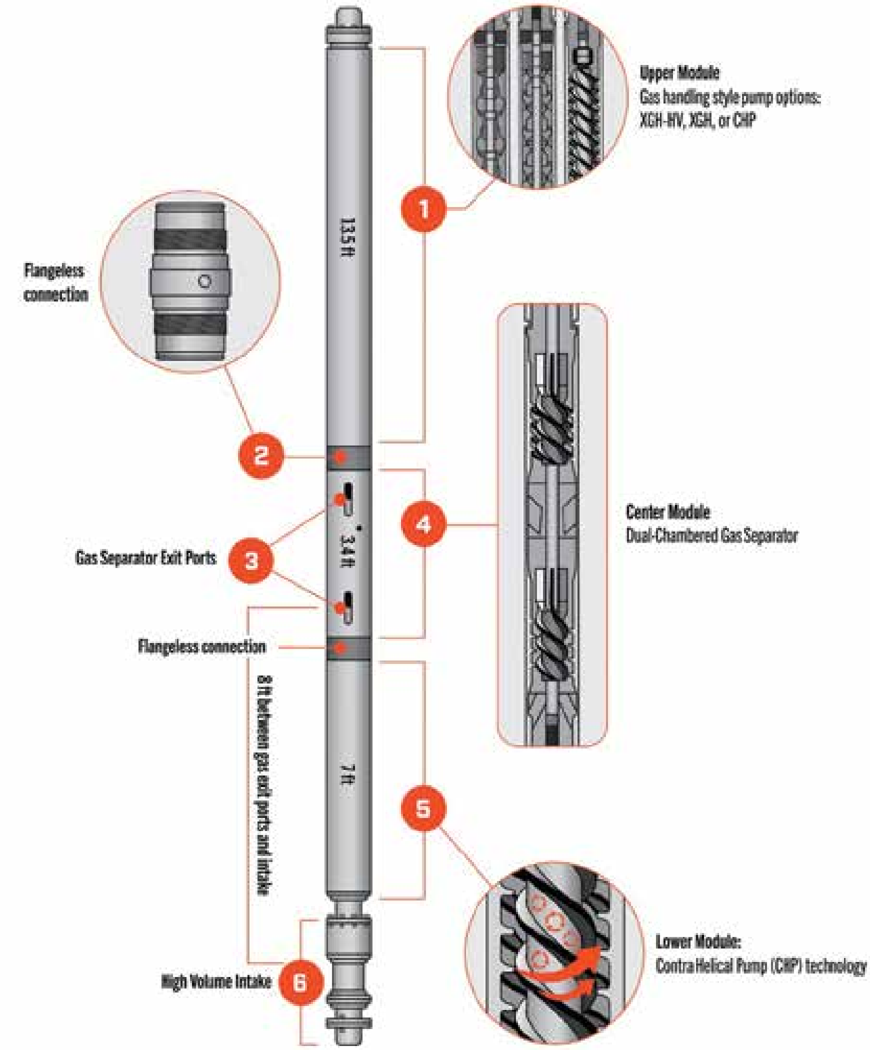
"If the motor is not restrained and you spin the shaft, that generates electricity because of the permanent magnets," Meadows said. "That can create a hazard if someone is operating at the surface or handling the cable."

To prevent the reverse spin, Baker Hughes developed a mechanical device that requires no wireline to operate it or a pin to pull when the pump is installed. It is designed with two clutches, one that allows the torque to transfer from the motor to the ESP in only one direction. It can free spin in operating mode, but it cannot rotate in reverse, which eliminates the action that can generate a dangerous power surge.

Meadows stressed that the company still urges operators to continue implementing existing safety measures as a fail-safe.

Simpler installation compared to older-model pump assemblies is

Integrated Gas Processor



SOURCE: EXTRACT PRODUCTION

In a downhole assembly, the three-module IGP is installed right before the pump. It can reduce gas locking by up to 50%.

another attractive factor, she noted. With the older Flex ER, three pumps were required per well. The E2000 system requires only two pumps, which cuts 26 ft from the string.

The motors also are more compact, with PMMs coming in at 27-28 ft instead of the IM's 52 ft. With this total length reduction of around 50 ft, installation and service become more manageable.

Meadows said producers appreciate the advantages. "With a shorter, lighter system, they said they were able to get closer to the production zone than they were originally able to," she said.

Longer life for the PMM comes in two forms. The first is advances in rotor and stator durability, which enable the PMMs to run longer. The E2000 and its wider efficient production range stretches from 3,100 bbl/d to 100 bbl/d. Because most ESPs only operate efficiently down to 300 bbl/d, the new system significantly pushes back difficult and costly decisions on next-step lift systems. This has the additional effect of extending a well's profitable life.

Integrated Gas Processor Reduces ESP Gas Locking

It is no secret that shale wells produce prolifically on ESPs for about the first year of life. Then, gas production rises to the point that the ESPs begin to lock up and must be continually stopped and restarted. All of this reduces pump uptime and production rates—and the starting and stopping creates electrical jolts that can shorten pump life. This is costly both in dollars and in lost production during downtime.

Traditional gas handlers and separators help, but they become less efficient as gas-to-liquids (GTL) ratios rise through the production life of the well. This results in higher gas void fractions (GVFs), the percentage of free gas versus gas that remains in the liquid, all of which create problems for ESPs.

To overcome this, Extract Production introduced its Integrated Gas Processor (IGP), designed to seamlessly replace gas handlers and separators. It uses a pair of contra-helical pumps to reduce the amount of free gas flowing through the ESP.

According to the company, in one application, the IGP boosted oil production by 153% and gas production by 224%, and reduced the GLR by 14% and pump intake pressure (PIP) by 11%. The IGP also has been shown to reduce gas locking by up to 50%.

How It Works

In a downhole assembly, the three-module IGP is installed immediately before the pump in place of the traditional gas handling equipment.

Extract's engineering director, James Rhys-Davies, said, from the bottom up, the IGP starts with a high-volume intake where the mixed-phase oil and gas enters. "The first module is the contra-helical pump stage that helps homogenize the fluid. Next is the dual-chambered separator module that separates the gas from the liquid, sending the gas into a casing flowing annulus and the liquid into the ESP," he said.

The third stage offers three options for compressing the remaining gas.

"We try to separate as much of the gas into the annulus as possible, but there's always going to be a little gas left over in the liquid stream. So, when we separate the gas into the annulus and it goes up the casing and out into a casing flowline, any remaining gas in the liquid goes up through the tubing string, where it is separated at the surface," he explained

This assembly separates the intake ports from the separator ports, Rhys-Davies said. "We think that's helping to eliminate or reduce the recirculation. On a normal gas separator, that's about a 1- or 2-foot separation, but we've got about 8 feet of separation, and that helps to let the gas go up the way and not to come back in."

When to Lift and Separate

Gas separators of any sort are rarely installed in a new well, said Extract's Chris Osborne, vice president of the artificial lift product line. "There's usually little gas to worry about for the first six to 12 months, and the IGP's flow rate is limited to 4,000 bbl/d, so it could slow down a prolific well's initial production."

Chris Osborne

When the IGP is installed at the start, he noted, it usually is in Midcontinent wells. "They're not as prolific, and don't hang on as long as Permian Basin wells," he said. In those cases, including IGP at the beginning eliminates the need for a workover to install it later.

Osborne added that, due to the tendency toward high sand content in early production in Permian wells, most producers do not want to rush the installation of any extra equipment that could be damaged by sand.

In the Field

A recent installation, in which Extract replaced a competitor's 3000 pumps and gas separators with the IGP and Extract 3000 pumps, yielded some significant results. Due to increased pump uptime and improved gas separation, the producer saw oil production rise by 153%, gas by 224% and water by 316%. The GLR dropped by 14%, and the PIP was reduced by 11%, showing that the pump operated more efficiently.

With the significant decline curves in older unconventional wells, numbers like these translate into significant improvements in profitability. E&P

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Harnessing the Power of Digital for Gas Lift Optimization

Innovative technology improves production from unconventional wells.

RAKESH RAI, VINEET CHAWLA, ROMAN MOLOTKOV AND EDUARDO MARIN | WEATHERFORD

Gas lift accounts for nearly half of the unconventional well production in the Permian Basin; however, optimizing high-producing, gas-lift wells remains a significant challenge due to the complexity of field conditions, evolving operational requirements and increasing economic pressures. With the number of gas-lift applications rapidly expanding, companies that want to better manage opex are focusing on technologies that enable effective gas-lift optimization.

Unlocking Gas Lift with Pad or Centralized Compression Optimization

In the current conservative investment environment, reduced drilling and completion rates have shifted the focus of operators in the Permian Basin to enhancing returns by driving production growth through the optimization of artificial lift capex and opex.

The rising cost of electrical-submersible pump (ESP) operations, combined with the rapid decline in reservoir pressures, is compelling operators to explore more cost-effective and sustainable artificial lift methods like gas lift. Pipeline infrastructure improvements and low-cost gas availability are allowing Permian operators to accelerate the transition from high-cost ESP lift to lower-cost gas-lift operations, improving production over the lifecycle of the well.

As the number of wells being managed grows, gas-lift issues can go undiagnosed without complete data and a rigorous analysis of well performance using a digital twin. The result is inefficient lift operations. In the absence of traditional well performance analysis and optimization of lift gas allocation, systems frequently underperform in production and lift cost reduction.

Optimizing and troubleshooting gas-lift systems is essential to maintaining lower operating costs, but achieving optimization is challenging because of the complex interplay among lift operations, surface network dynamics and reservoir characteristics.

Selecting the right automation in the field and implementing appropriate enterprise production optimization platforms enables industry-standard workflows that incorporate best practices, leading to reduced costs and increased profitability.

Gas Lift Completion, Facilities, Operations

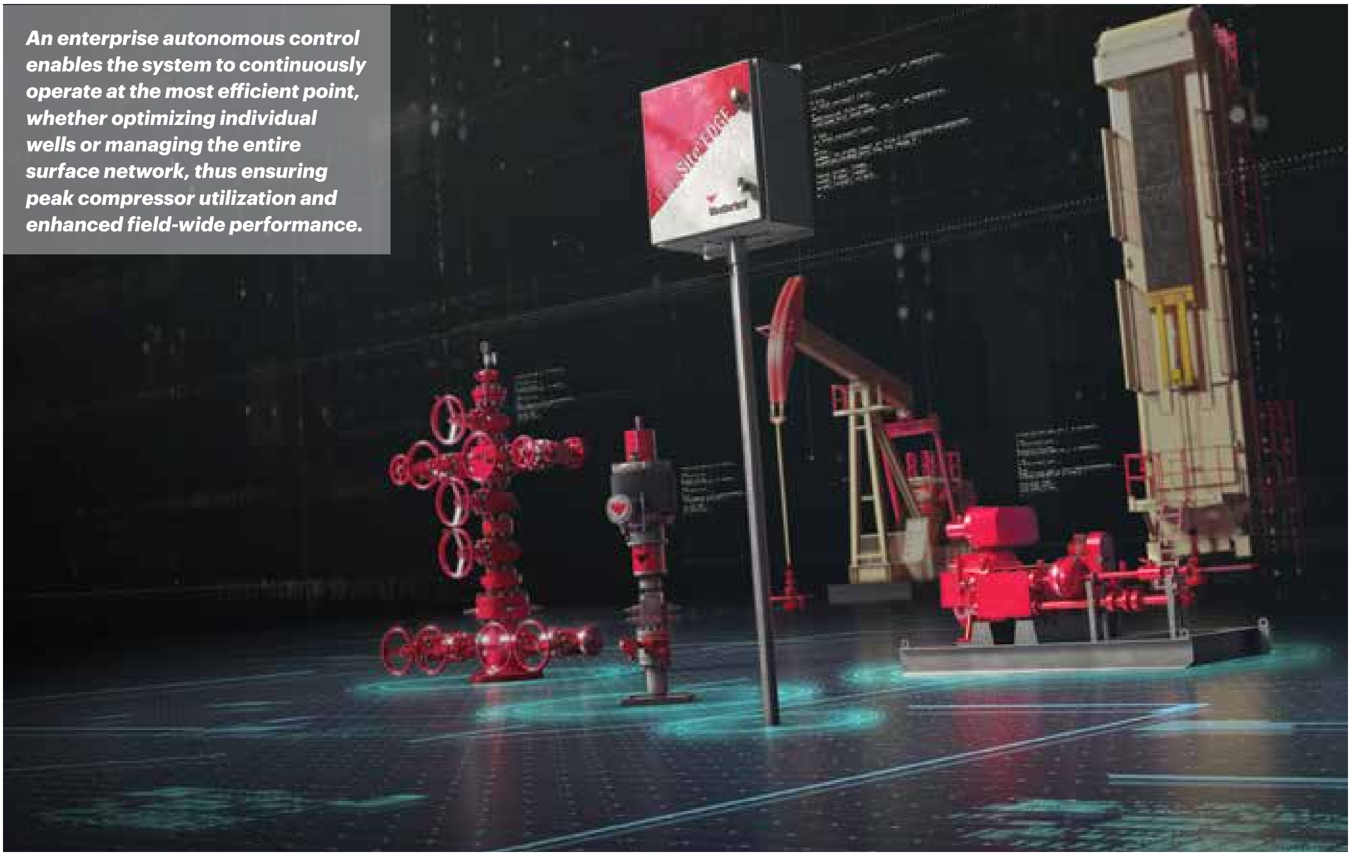
Permian wells present a wide array of challenges, ranging from highly inefficient lift to centralized facility management, to pad allocation optimization, gas buyback limitations and pipeline restrictions. Resolving these issues requires different levels of digitization and automation. Whether through closed-loop or open-loop systems, effectively optimizing surface networks—properly balancing gas-injection rates with production needs across a field's network—is vital to achieving maximum production efficiency while managing wastage and operational costs. The need for precise control and real-time adjustments has never been more pressing.

Although efficiency is vital to economics in unconventional developments, safety remains the top priority, particularly as the scale and complexity of gas-lift operations increase. Ensuring effective systems management with minimal risk to personnel and infrastructure requires robust monitoring and control systems that can anticipate and mitigate potential hazards.

Production Optimization

Production optimization maximizes asset value by improving operating efficiency and lowering costs. Production targets are set for each well, and resources, such as the available gas lift, power, etc., are allocated among the wells. The process applies various techniques for monitoring, analyzing and improving the performance of reservoirs, wells and surface facilities.

Data is critical to the process, but as more field sensors and monitoring devices become digitized, the volume of data increases. While some of this data is invaluable for making informed decisions, the challenge lies in efficiently processing and analyzing field information to avoid overload and ensure that actionable insights are derived. Choosing the right digital foundation makes it possible to streamline data



An enterprise autonomous control enables the system to continuously operate at the most efficient point, whether optimizing individual wells or managing the entire surface network, thus ensuring peak compressor utilization and enhanced field-wide performance.

WEATHERFORD

management to facilitate analysis and improving decision-making.

The Weatherford ForeSite production optimization platform automates daily operational and engineering tasks and provides operational intelligence for faster decision-making. The platform delivers production optimization by improving efficiency, maximizing uptime, achieving carbon neutrality and enhancing production.

Improving Efficiency

Workflow automation is essential to simplifying the gas-lift optimization process, ensuring that optimization engineers can seamlessly integrate physics-based models with real-time operational data. With automated workflows, every time a new well completion is added to the completions database, i.e., system of record, the corresponding physics model is automatically generated and fine-tuned to match the specific conditions of the well. This process is archived by importing well tests directly from bulk separators or multiphase flow meters along with key well data from the surface and downhole sensors.

Out-of-box automated workflows include well-test validation, daily well analysis, virtual flow metering, production allocation and automated well-model creation from completion system of record. This process eliminates the need for manual intervention, allowing engineers to focus on higher-value tasks.

Self-tuned models are a game changer in this context as they continuously adapt to reservoir and production conditions, ensuring wells operate at peak efficiency. By leveraging automation, these models not only streamline the optimization process, but also identify opportunities for improved performance, allowing operators to maximize production and reduce opex in a dynamic field environment. This approach ensures that optimization is proactive and continuous to drive field-wide efficiency gains.

An automated process significantly enhances the quality and integrity of corporate systems and data sources. By quickly identifying data that fails to meet validation standards, the system ensures that only accurate and reliable information flows through the operational ecosystem. This proactive approach strengthens data governance and allows organizations to maintain optimal data quality across their systems, ultimately enhancing operational efficiency, minimizing risk, and fostering continuous optimization for greater organizational agility and value creation.

According to an SPE paper

presented at the 2016 ADIPEC conference, 80%-90% of engineering time required to analyze the well is eliminated, improving efficiency and enabling operators to scale up field development while reducing per-well management costs.

Maximizing Uptime

Autonomous control ensures maximum uptime can be maintained on each well by identifying production issues, analyzing the root-causes, evaluating mitigation strategies and deploying changes in supervised or unsupervised mode. Autonomous control enables seamless integration with both closed-loop and open-loop optimization for centralized and pad compressors. It eliminates well loading, maintains optimal flowing bottomhole pressure (FBHP), and dynamically adjusts gas injection rates for enhanced performance. The customized logics, configured with autonomous control, help operators overcome operating challenges and achieve optimal lift operations throughout the lift operation.

Though autonomous control can be achieved at the edge or at enterprise, it is important to recognize that edge device deployment might not be economically viable for every well due to cost or technological complexity considerations. While wells with rapidly changing flow conditions that require real-time adjustments and wells with communication challenges are perfect candidates, for wells and assets with high-speed connectivity, autonomous control at the enterprise provides an alternate solution without additional edge investments at each well.

Enterprise-level autonomous control can implement low to medium frequency optimization across the broader field. A hybrid approach that combines edge with enterprise autonomous control to leverage edge capabilities where necessary and enterprise control for broader operations, has proven highly effective in achieving full-field autonomous control. This ensures a cost-efficient, comprehensive optimization strategy that maximizes production potential while managing operational expenses across the entire asset.

An enterprise autonomous control enables the system to continuously operate at the most efficient point, whether optimizing individual wells or managing the entire surface network, thus ensuring peak compressor utilization and enhanced field-wide performance. Unlike traditional "black box" systems, the autonomous control logics can be configured and adapted to the unique conditions of the field. This adaptability ensures that site-specific parameters are embedded within the optimization process, providing operators with a transparent, flexible and highly efficient control framework that drives both operational excellence and continuous value creation.

Achieving Carbon Neutrality

ForeSite enables remote operations for a well or facilities. For gas-lift operations, this means the set points to control lift-gas injection or production chokes, line pressure (high pressure versus low pressure) management and gas buyback management can be performed remotely, reducing the carbon footprint to manage production operation. Additionally, determining optimal lift point for a well and managing compression facilities either at a pad level or at a central compression plant ensures minimization of energy footprint, i.e., carbon emissions, for lift operations.

The ForeSite production optimization platform was deployed in the Delaware Basin, targeting 88 gas-lift wells with an average daily production of 55 bbl/d. A digital twin was built for all wells based on completion and operations information and connected to the real-time data of the well and facilities through the SCADA platform. The data, along with validated well-test and real-time data points, was used to perform nodal-analysis models, providing a comprehensive representation of each well's subsurface operating conditions.

Downhole gauges were strategically installed in two wells to validate the accuracy of the models and ensure reliable performance predictions based on multiphase flow correlations. Additionally, multiple pressure and temperature surveys were conducted to gather essential data for multiphase-correlation calibration and refinement. Through this rigorous validation process, the platform demonstrated its ability to accurately predict well behavior and identify optimization opportunities.

After model validation, 27 wells were selected for optimization. By leveraging the platform's advanced analytics and optimization algorithms, these wells achieved an average uplift of approximately 210 bbl/d, translating to an estimated increase of 61,000 bbl over a 2.5-year period, a value of over $3 million.

A summary of key performance indicators (KPI) delivered included:

- **Increased production:** The wells equipped with the production optimization platform saw a 25% increase in production compared to baseline operations. This was achieved through the system's continuous optimization of gas injection rates, which ensured that each well operated at its peak performance level.

- **Reduced opex:** By optimizing gas usage and reducing unnecessary operational activities, the deployment also led to a significant reduction in operational

As the oil field becomes more and more digitized, the volume of data collected and monitored increases. Choosing the right digital foundation streamlines data management to facilitate analysis and improve decision-making.

SHUTTERSTOCK

expenditures. This cost saving was attributed primarily to the decreased need for manual interventions and the efficient use of resources.

- **Greater reliability:** Automated alerts for inaccurate well tests help identify issues that might have gone unnoticed using traditional methods. This proactive approach to detecting data quality problems ensured reliable and accurate well performance analysis.
- **Less manual data entry:** Creating an automated well model from a centralized data source reduced the need for manual data entry and improved data consistency across the organization.

Surface Network Optimization

Surface network optimization is a crucial tool for managing closed-loop gas-lift systems, particularly when dealing with the complex challenge of lift-gas allocation. In centralized compression systems, where gas is compressed and reinjected into multiple wells, lift gas must be distributed optimally to maximize production and minimize energy consumption. Effectively managing lift-gas allocation can improve well performance, reduce energy consumption and minimize equipment wear. This leads to increased production and lower operating costs.

The production optimization platform module allows operators to achieve this by modeling the entire surface network, including pipelines, separators and manifolds. The platform integrates with reservoir models to deliver a true reservoir to export point optimization. By analyzing multiphase flow, pressure drops and other relevant parameters, the module identifies bottlenecks and inefficiencies that can hinder production. These insights enable more informed decisions about lift-gas allocation to ensure gas is directed to wells where it can have the greatest impact.

For example, if the module identifies a pipeline that is experiencing excessive pressure drop due to corrosion or scaling, lift-gas allocation can be adjusted to reduce flow through the compromised line to prevent further damage. Similarly, if a separator is operating inefficiently due to poor design or maintenance, the module can identify alternative routes for gas flow and optimize lift-gas distribution accordingly.

Autonomous Control

On a field in the Anadarko Basin, a

Conventional oil production in West Texas

SHUTTERSTOCK

major natural gas production area, gas-lift wells were being optimized manually, which was inefficient and time-consuming. A field technician was tasked with adjusting compressor rpm and wellhead choke to control the gas-injection rate and bottomhole pressure. This process was slow and often required recalibration. Converting to automated controls that could dynamically adjust well conditions and reduce gas usage would improve efficiency and reduce buyback gas costs.

Enabling unsupervised autonomous control following autonomous control logic customization, the system maintained flowing bottomhole pressure by adjusting the choke to control lift-gas injection for a specified flowing bottomhole pressure setpoint and adjusting the production stream to achieve a stable operation by minimizing tubing-head pressure fluctuations.

A summary of KPIs delivered included a 25% reduction in buyback gas and a 70% reduction in operator visits.

Harnessing Successful Outcomes

By leveraging high-frequency data, instantaneous alarms and fully automated control logic integrated in a single platform, this strategy provides a sustainable and profitable solution for different lift types. After overcoming the challenges of scaling to full-field production optimization, advanced workflows are now in place to ensure optimal flow rates, extend equipment service life and efficiently allocate gas lift.

With more than 12 successful deployments across North America, these methods have proven their effectiveness and can be adapted for different lift types in global applications.

Capturing Value Through Automation

Gas-injection optimization represents a significant opportunity for improving production efficiency and reducing costs. The ForeSite production optimization platform has proven to be a powerful tool in achieving these goals, delivering tangible results in both production enhancement and cost savings. As the digital transformation continues to reshape the industry, the adoption of technologies like this will be essential for maintaining a competitive advantage and ensuring long-term sustainability. E&P

Breaking New Ground

Microseismic technology proved its value in unconventional wells, and new applications could enable monitoring of sequestered CO_2 and facilitate geothermal energy extraction.

JAXON CAINES | TECHNOLOGY REPORTER

When Peter Duncan shared his decision to launch MicroSeismic in early 2003, the response was, admittedly, unenthusiastic.

The CEO and founder recalls his peers asking him, "Are you crazy? What is microseismic monitoring? Is there a business?"

People had never heard of it, yet Duncan was determined to redefine how the oil and gas industry approached subsurface monitoring, turning what was once a niche academic concept into a commercial powerhouse.

In the early days, most practitioners believed that capturing microseismic events required geophones placed downhole, close to the source of seismic activity. But Duncan took a new approach.

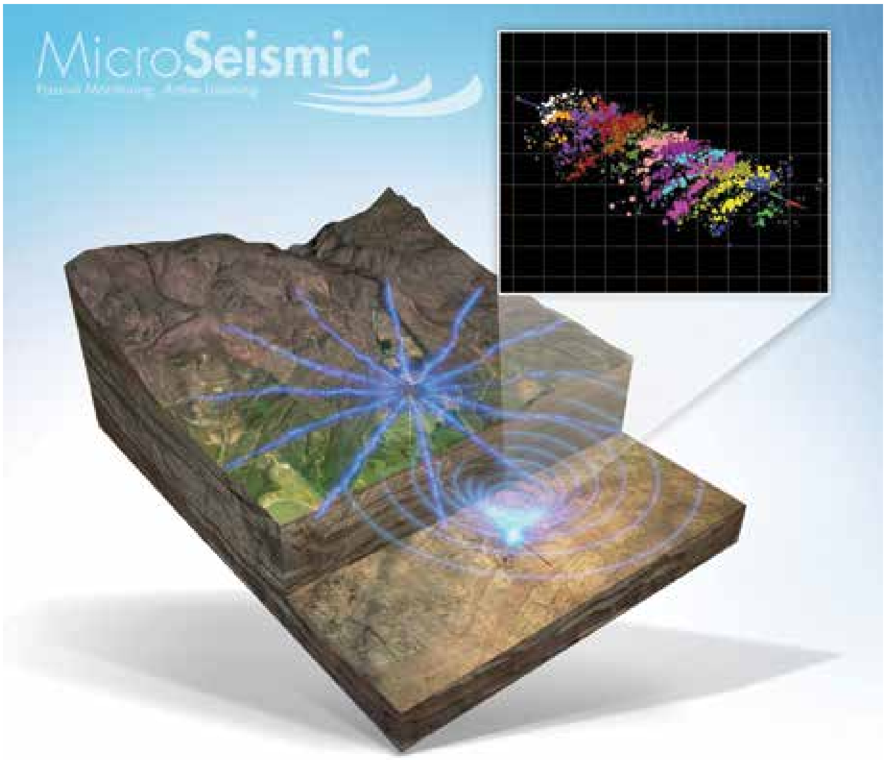
"You don't need to drill down; you can place geophones on the surface and still hear those events," he said. "In the past, they put their geophones—just single geophones—on the surface of the earth, and they listened and they didn't hear anything. The signals were too small."

Duncan and MicroSeismic decided to scatter multiple geophones across the surface and use "the power of the stack" to overcome the signal-to-noise problem and produce clearer data. He likened this to using a dish microphone at a football game—where gathering sounds from afar can yield clearer results than placing a microphone close to the source.

While initially laughed off by his peers, Duncan's method allowed the company to provide a valuable service and spearhead the

MICROSEISMIC

MicroSeismic scatters multiple geophones across the surface using "the power of the stack" to overcome the signal-to-noise problem and produce clearer data.



SOURCE: MICROSEISMIC

MicroSeismic's BuriedArray data acquisition deploys a permanent array of MicroSeismic-designed geophone strings installed in the near surface to monitor an area of more than 500 sq miles.

"We're going to predict the hydrocarbons, and we're going to use an extrapolation and say, 'Well, if you keep fracking for another half-hour, you're going to get this much more hydrocarbons.'"

PETER DUNCAN,
founder and CEO,
MicroSeismic

microseismic industry, although he does not like to take credit for that.

Bringing the Downhole Picture Into Focus

The better visibility created by the added geophones allowed MicroSeismic to create a clearer picture of downhole operations, Duncan said. By recognizing the focal mechanisms of microseismic events—how rocks slip past each other—his team enhanced data accuracy, allowing for better interpretation of fracking results, no longer having to use the old-fashioned "dots in a box" display.

"We can actually put in a little planar element where the size of the planar element is proportional to the magnitude that we see and where we can tell whether the event moved like this or like that. And so, now we've got a much better geologic picture of how the frac looked," he said.

This development transformed microseismic data into detailed discrete fracture networks and laid the groundwork for FracRx, a real-time monitoring system that helps engineers make decisions during fracking operations.

"We started to use that [data] to monitor in real time. We're going to predict the hydrocarbons, and we're going to use an extrapolation and say, 'Well, if you keep fracking for another half-hour, you're going to get this much more hydrocarbons,'" Duncan said.

"We're going to help you make efficient decisions about not how to frac—someone else is deciding where to drill the well—but we're going to help you make more efficient decisions about when you complete that well, how long you should pump, how much you should pump into it, and more."

This capability became even more critical as the industry faced challenges, especially during the COVID-19 pandemic, which saw a dramatic decrease in operational capacity.

As the company adapted to new challenges, it also explored additional markets. One significant development involved CO_2 sequestration, aiming to monitor carbon stored underground to ensure safety and prevent leaks.

"The DOE (Department of Energy) sent out a general notice that they're looking for ways to monitor carbon when it's been sequestered to make sure that it's not causing earthquakes, and to make sure that the carbon is staying in the reservoir where you put it. And we said, 'Well, we think we could hear little earthquakes that are the precursors to big earthquakes. We think we could hear if it starts to leak out of the reservoir.' We'd actually done this once," Duncan said.

This led to the advent of the CO_2SeQure suite of technologies, which includes the BuriedArray system, which is similar to a high-tech security system for CO_2

A FracStar monitoring truck set up to monitor data collected in the field.

MICROSEISMIC

storage, Duncan said.

The BuriedArray system is a network of underground sensors that continuously monitors CO_2 storage, keeping track of CO_2 movement, detecting small seismic events and sending data to a central processing facility.

Before CO_2 injection starts, the array measures baseline seismic activity. During injection, it monitors for seismic events that could indicate caprock issues or regional fault slippage, using a "stoplight system" to alert operators if certain critical levels are exceeded.

MicroSeismic also is venturing into the advanced geothermal business. This initiative brings the company's technologies full circle, as the process is based on the original FracRx solution, Duncan said.

"In places like California, hot rocks are close to the surface. You can drill in and circulate water through the rocks to heat the water and then harvest the heat for electricity," he said. Geothermal systems take the process into a different realm. "What enhanced geothermal systems are all about is drilling down into the deep basement rocks that are very hot to make supercritical steam and be able to bring more energy up to the surface so that it becomes more commercial."

Duncan sees potential for enhanced geothermal systems (EGS) to reshape the energy landscape. By applying lessons learned from fracking, he believes technologies such as distributed acoustic sensing (DAS) can facilitate more effective geothermal energy extraction.

DAS, also known as Distributed Fiber Optic Sensing, is an innovative technology that uses lasers to detect sound in real time along an optical fiber cable. Connecting a DAS unit to one end of a standard optical fiber transforms the fiber into thousands of vibration sensors or microphones spread over many kilometers. This setup requires no additional electronics or hardware, making it a highly efficient way to monitor sound and vibrations over large distances.

MicroSeismic is currently working with Australian company Terra15 to offer a DAS-based microseismic solution to enhance the company's monitoring capabilities.

"DAS is a technology that I'm hopeful will come to bear to be able to get higher-resolution signals than we can get with geophones. But, as a general application, it's not there yet," Duncan said. "There are limitations on what the DAS can do, and we're still working on that. But, I'm hopeful that will be something that replaces our conventional geophone." E&P

What Chevron's Anchor Breakthrough Means to the GoM's Future

WoodMac weighs in on the 20k production outlook.

PAUL WISEMAN | CONTRIBUTING EDITOR

On Aug. 12, Chevron announced first oil from its Anchor project in the Gulf of Mexico. It was the first production from any of the region's super high-pressure formations, at 20,000 lbs psi. Heralded as a breakthrough, the company announced that its new technology would release 2 Bbbl of GoM oil that had been unreachable with older technology.

How will that 2 Bbbl in production happen? How long before 20,000 psi production ramps up, and what will it look like in 2030? It's likely that other related technologies will play a part, as BP and others are also working to reach those plays. Chevron and Wood Mackenzie provide some insight into how this may play out.

CHEVRON

Anchor deepwater project

Chevron's Ideas

Anchor is a joint project between operator Chevron (62.86%) and TotalEnergies (37.14%), located in the Green Canyon area about 140 miles off the Louisiana coast. Chevron reports that the Anchor semi-submersible floating production unit (FPU)'s design capacity is 75,000 gross bbl/d of oil and 28 million gross cu ft/d of natural gas. The overall development will include seven subsea wells.

Estimated total recoverable resources from the field may be as much as 440 MMboe. Once production ramps up, Chevron expects Anchor to produce more than 75,000 boe/d for 30 years. And because the Anchor FPU is all-electric, Chevron says its production will be among the lowest-carbon intensity in the world.

Anchor is Chevron's sixth operated GoM facility. The company expects its total production in the region, operated and non-operated, to reach 300,000 boe/d by 2026. Chevron is among the largest GoM leaseholders, with 393 leases as of the second quarter, having added almost 100 leases in lease sales 259 and 261.

Engulfed in Change

WoodMac is tracking several other 20,000 boe/d projects that are underway in Paleogene formations. They include:

Blackstone Energy Partners' Beacon: The Shenandoah project was first sanctioned in 2021. In 2026, Beacon expects first oil from Monument to tie into Shenandoah. Both are about 160 miles off the Louisiana coast.

Shell Offshore's Sparta: Sparta was sanctioned in December 2023 and is expecting first oil in 2028. A Shell release says it (51% operator) and Equinor Gulf of Mexico (49%) expect Sparta to reach peak production of about 90,000 boe/d at some point. Estimated discoverable resources are 244 MMboe. It will be Shell's 15th deepwater host in the GoM.

BP's Kaskida: The project expects first oil in 2029. Wood Mackenzie looks for BP to sanction Tiber in 2025, with first oil in 2030. Wood Mackenzie looks for BP to start drilling Tiber two to three years before first production. BP is 100% owner of both blocks.

Kaskida is in the Keathley Canyon block 292, 250 miles

▸ CLOSER LOOK

CHEVRON ANCHOR SPECS

Location: U.S. Gulf of Mexico, 140 miles offshore Louisiana

Water depth: 5,000 ft

Reservoir depth: 30,000-34,000 ft

Maximum reservoir temperature: 250 F (121 C)

FPU height: 25 stories

FPU topsides area: 42,080 sq ft

Seawater displaced: 70,000 mt

Production life: up to 30 years

First oil: 2024

Peak production: up to 75,000 net bbl/d

Total production: up to 440 MMbbl net over 30 years

SOURCE: CHEVRON

CHEVRON

The Anchor development will consist of seven subsea wells tied to the semi-submersible floating production unit in the Green Canyon area.

up to 440MM
estimated barrels of recoverable oil-equivalent

20K
pounds per square inch rated at wellhead

34K
approximate feet from water surface to reservoir

75K
net barrels of oil production per day design capacity

southeast of New Orleans. BP estimates recoverable resources at around 275 MMbbl of oil equivalent from the initial phase. Additional wells could be drilled in future phases.

Tiber is also in Keathley Canyon, in block 102, 250 miles southeast of Houston and 300 miles southwest of New Orleans. BP has yet to estimate this field's total recoverable resources.

Economics and Technology

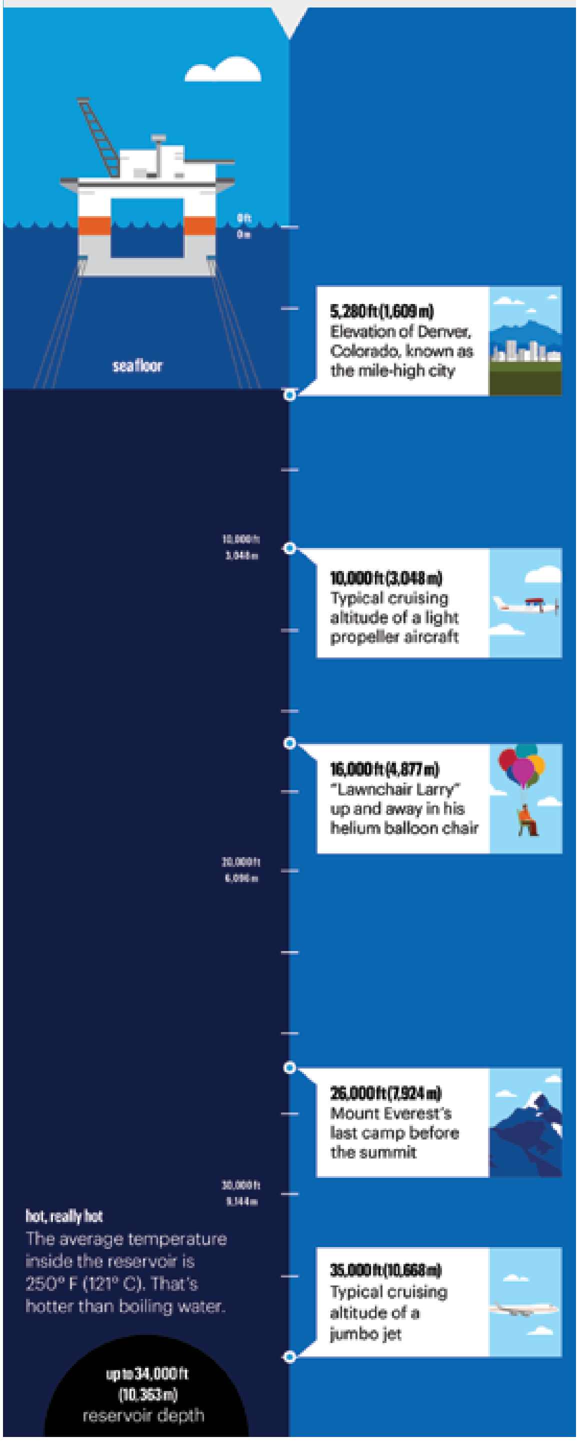
The amount of economically recoverable resources in any area depends on technology and pricing. Technology is usually steady in its advance, but prices may vary widely depending on geopolitics, economic health of various countries and other unforeseen factors, like the COVID pandemic.

For Wood Mackenzie, the 2 Bbbl is based on current technology, but the impetus for further improvement is based on rising expenses as much as market prices for oil. Rising daily rig rates will push companies to focus their advances in drilling and completions technology on improving efficiencies to reduce operational costs, the analysts said.

Operators in Paleogene GoM projects have been economizing by using multi-zone completions, artificial lift and waterflooding, much

Going Deep to Help Meet Energy Demand

Oil and gas production from Chevron's Anchor floating production unit began in 2024. Anchor operates in water depths of more than 6 miles. Here is how the reservoir depth compares to above-the-surface heights.



SOURCE: CHEVRON

as is done on land, WoodMac said, and Anchor is among those designed with future waterflooding in mind.

Average breakeven prices for the fields—Shenandoah, Monument, Tiber, Kaskida and Sparta—is estimated at about $37/bbl, said Wood Mackenzie. A significant price drop could endanger new projects, but those that are already in progress would likely continue.

Most development is likely to be infrastructure-led exploration to take advantage of existing pipelines. But, Wood Mackenzie noted, improved imaging could uncover future high-impact prospects in what it called "more frontier areas" of the Paleogene play.

Based on already-discovered fields of this size and those which Wood Mackenzie expects to reach that level, production could reach 130,000 boe/d in 2025 and more than double to 300,000 boe/d by 2030.

Court Ruling Could Muddy the Waters

In August, a federal judge in Maryland ruled that a key 2020 National Marine Fisheries Service (NMFS) environmental review of Gulf of Mexico oil and gas operations, known as a biological opinion or BiOp, violated the Endangered Species Act. Saying that the NMFS "underestimated the risk and harms of oil spills to protected species," it vacated that BiOp, effective Dec 20.

Without intervention from a higher court or Congress, Wood MacKenzie senior research analyst Miles Sasser said, "Once the ruling goes into effect, operators must decide whether to proceed with exploration and development activity in the GoM at their own risk or suspend operations until a new review is issued."

The previous ruling had provided E&Ps with a framework for operating under leases and permits they had been issued. As long as they abided by that BiOp, operators were free to move forward without risk of fines or sanctions for incidental harm to endangered species under the Endangered Species Act.

Further, the BiOp serves as a blanket review of activity, streamlining the permitting process and lessening the burden on government agencies, Sasser explained

Lacking an active BiOp, he said that regulators would need to evaluate each permit on a case-by-case basis that could create a massive backlog, effectively shutting down the permitting process.

While all Gulf operators should keep their eyes glued to the case's progress, Sasser sees "companies with large pre-production projects or phased developments as the most at risk given the high up-front capital that has already been invested—certainly 20K falls into this bucket."

As concerning as this is, Sasser believes there are several possible off ramps as the December date approaches. Most likely, "a stay by an appeals court allowing permitting to continue while the legal challenges play out. The revised BiOp from NMFS is already in the works and expected early in 2025, but it is likely that a new BiOp will face its own legal challenges." E&P

Getting Laser Focused on Emissions Reduction

Technology helps companies meet new guidelines with expanding methane detection network.

VELDA ADDISON | SENIOR EDITOR, ENERGY TRANSITION

Concerns about methane emissions are not new to the oil and gas industry, but a change in the U.S. Environmental Protection Agency's (EPA) Methane Emissions Reduction Program has companies making adjustments to how they manage them.

Methane is the main component of natural gas. Colorless and odorless, methane is a contributor to global warming and is a known precursor gas to ground-level ozone, which can be harmful to humans in high concentrations. When leaked into the atmosphere, methane causes environmental damage. It also can damage a company's bottom line by cutting into potential profit from natural gas sales and introducing costs from fines associated with the methane tax recently put in place.

The EPA has set standards to lower emissions from high-emitting equipment, mandated monitoring of methane leaks from well sites and compressor stations, and directed companies to eliminate routine flaring of natural gas produced by new oil wells. New regulations also require companies to switch to zero-emitting technologies and discontinue the use of natural gas-powered pneumatic controllers.

The methane tax requires oil and gas facilities that emit more than 25,000 metric tons (mt) of CO_2e per year to pay hundreds of dollars for each metric ton of methane released into the atmosphere. The tax took effect in 2024, with first payments due on March 31, 2025. Companies will pay $900/mt for reported methane emissions in 2024. The tax increases to $1,200/mt in 2025 and to $1,500/mt from 2026 onward.

"When you have this quantitative time-continuous information, people understand what is actually important in the field and start to adjust their practices."

GREG RIEKER, co-founder and CTO, LongPath Technologies

Faced with progressively stringent requirements, companies are seeking technologies that make compliance easier. LongPath Technologies is one of the industry players providing solutions.

Breaking New Ground

Methane monitoring in the oil and gas sector typically is conducted with aerial imaging or by using optical gas imaging cameras. LongPath's technology continuously identifies and quantifies methane emissions at lower detection levels than conventional methods, according to the DOE's Loan Programs Office (LPO).

Unlike traditional monitoring methods, the technology uses lasers to accurately identify molecules in the air and then alerts operators to leaks as small as 0.06 kg/hr. It was developed with the University of Colorado and the National Institutes of Standards and Technology, supported by the U.S. Department of Energy's (DOE) Advanced Research Projects Agency–Energy and other DOE grants.

According to Greg Rieker, co-founder and CTO at LongPath Technologies, the technology works in much the same way as a cell phone network. "You subscribe to the cell phone network and then you get the data," he said. "That's exactly how LongPath works. We put out the nodes, we monitor the surrounding area, and then we feed that data back to the customers in real time so that if something happens, they're aware of it very quickly."

The Colorado-based company's network includes 50- to 70-feet-tall towers, which the company maintains and monitors. Each tower is equipped with transceivers that send out laser beams traveling up to a mile and a half. Covering about 10 sq miles, each node is capable of monitoring greenhouse gas emissions for dozens of facilities, such as production and compression facilities, delivering data in real time via dashboards and customized alerts to field personnel.

Growing the Network

LongPath has networks in the

LONGPATH TECHNOLOGIES

LongPath Technologies provides an emissions network that continuously monitors methane emissions across oil and gas supply chains in real time. Its technology features towers equipped with laser transceivers that send out laser beams to detect emissions.

Permian, Denver-Julesburg, Piceance and Anadarko basins, and the Eagle Ford and Bakken shale plays. It hopes to expand into California and elsewhere as it continues building out its network. In October, LongPath secured a $162.4 million loan guarantee from the LPO to help finance expansion of the company's monitoring network. This financing will support the deployment and installation of more than 1,000 remote monitoring towers, with up to 24,000 sq miles of coverage.

The goal is to have certain companies anchor a network built out in a region, which will allow LongPath to provide continuous monitoring to more companies in the area, Rieker said.

The network could prevent methane emissions equivalent to at least 6 million tons of CO_2 annually, which equates to removing 1.3 million gasoline-powered vehicles from roadways, according to the LPO.

"What's nice about that approach is it's sort of a win-win-win," Rieker said. "We can get the network in the area, then everybody that is covered by that network benefits from using it."

Lasers in Action

The company records up to 40 or 50 readings per day on each facility in the 1,000 sq miles of monitoring infrastructure already in place.

"From the moment a reading is made to when the data makes it to the customer is 10 minutes or less," Rieker said. "It's getting faster as we get better and better with our systems. So, you're looking at leak detection on the order of minutes to hours rather than days or weeks or months."

The system is already paying off, Rieker said, pointing to an instance when continuous monitoring caught a sporadic leak at a facility.

"This was emission that would have

been hard for them to catch because it was just happening during a short period of time," he said. "It turned out to be a pressure regulator that was in the wrong spot."

In another instance, the monitoring technology caught an emission that showed the natural gas production had dropped off by about one-third, he said, noting a dump valve was the culprit.

"Because methane/natural gas is a colorless, mostly odorless gas, it's hard to really understand how much is actually coming out," Rieker said. "So, when you have this quantitative time-continuous information, people understand what is actually important in the field and start to adjust their practices."

LONGPATH TECHNOLOGIES

LongPath plans to build more real-time methane monitoring stations in oil and gas basins with backing from the U.S. Department of Energy's Loan Programs Office.

Adding to the Toolkit

Jonah Energy, a privately held oil and gas company based in Colorado, has an extensive emissions-detection toolkit that contains optical gas imaging cameras, among other tools. According to Howard Dieter, vice president of environmental, health and safety, the company uses drone-based methane sensors that quantify emissions across its assets, uses meters connected to pneumatic control devices to measure emissions, and schedules periodic aircraft-based perimeter flights.

Jonah Energy conducts monthly inspections of its facilities, quantifying the types and locations of any leaks so the team can fix them. "We can compare the emissions we expect to see to those measurements and determine whether or not we're accurately representing the emissions," he said. "It gives us some kind of a top-down check."

The company first deployed LongPath's technology in late 2023 with 10 locations. That has since grown to 21 locations out of about 100, Dieter said.

Having the technology on site has enabled faster, more targeted responses to conditions that are not normal operating emissions, he said, noting that it also enables insight into temporal variability across the field.

"When I'm doing measurement, I can easily go out and say, OK, this measurement is within the range of emissions I would expect to see from this facility, and that range of emissions is in line with the permit that we have to operate that facility."

Paul Ulrich, vice president of government and regulatory affairs for Jonah Energy, said he has witnessed a remarkable voluntary response from operators and technology providers to reduce emissions in ways never conceived 10 to 15 years ago.

"That, to me, has been a very positive development. We're at a point now where we can deploy and test new technology as much as we want based on how many providers are out there," Ulrich said. "LongPath in particular is pushing the envelope to help us meet the challenge."

Looking Ahead

The DOE loan will go toward building up LongPath's networks to make coverage available for companies across regions, Rieker said.

"From an oil and gas perspective, we see so much opportunity for increased production because losses in general from the system … might be bigger than operators can imagine. So, there's a real gain in efficiency for operations that's there," he explained.

Though LongPath is focused on oil and gas sites, the technology could be used in other industries that need to track methane emissions, Rieker said. The possibilities include monitoring emissions from landfills or even tracking methane levels from wetlands as temperatures rise.

"Every day we get a call from somebody that says, 'hey, do you think it could work for this?' And more often than not, we have to say no," Rieker said. "But that's just because we're growing … [and] we're really focused right now on this oil and gas market. But we would love to set this up in the future." E&P

Delivering Dividends Through Digital Technology

Increasing automation is creating a step change across the oil and gas life cycle.

JAMES BRADY, EUGENIA SOROTOKIN AND MATTHIAS GATZEN | BAKER HUGHES

From the subsurface to the production field, the conversation in upstream oil and gas has been dominated by digitalization and the potential for technologies like artificial intelligence (AI) and machine learning (ML) to deliver greater efficiency, consistency and performance improvement through automation.

But talking about the promise of technology is a far cry from achieving it.

Even though advanced solutions have the potential to transform the industry, implementation has not been rapid or uniform. Some companies are just beginning to experiment with these technologies, while others are incorporating them in day-to-day operations.

One reason for the inconsistency in adoption is that integrating advanced technologies requires a shift in thinking from mechanical to digital terms. And changing a mindset is challenging.

In some ways, this is the same sort of adjustment that took place in the 1990s when the industry began gathering sensor data from equipment for vibration analysis and condition monitoring. Analyzing performance data provided the insight required to move from planned maintenance to an early form of predictive maintenance. The value of being able to predict and plan rather than react produced tangible results. Now, there is broad acceptance that using performance data for more informed decision-making delivers efficiencies that cannot be achieved any other way.

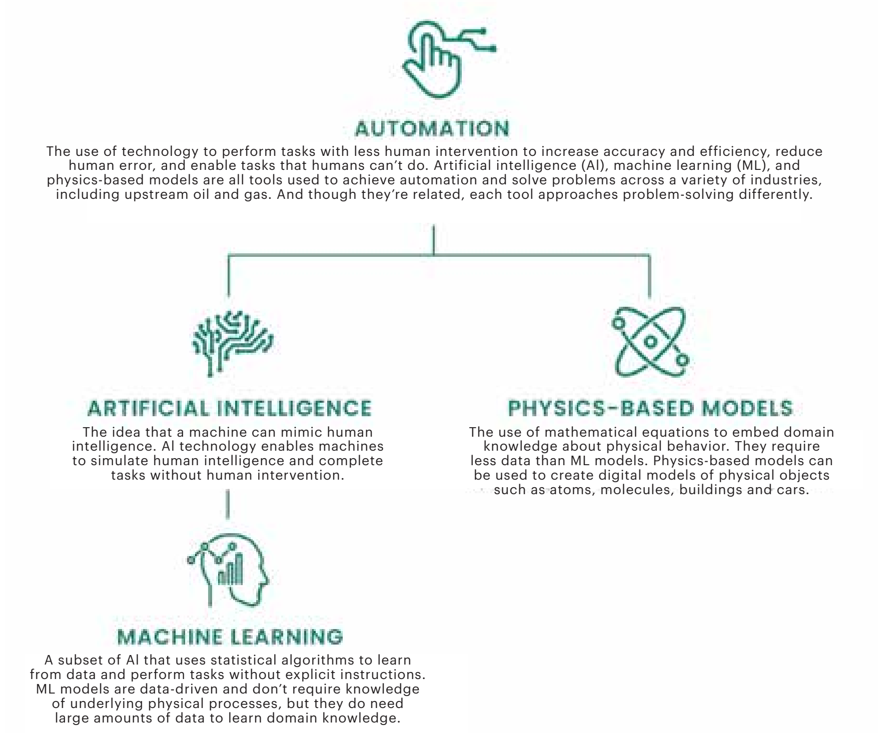
Understanding the Lexicon

Advanced technologies hold immense promise, but to extract value from these solutions, it is critical to understand how they work.

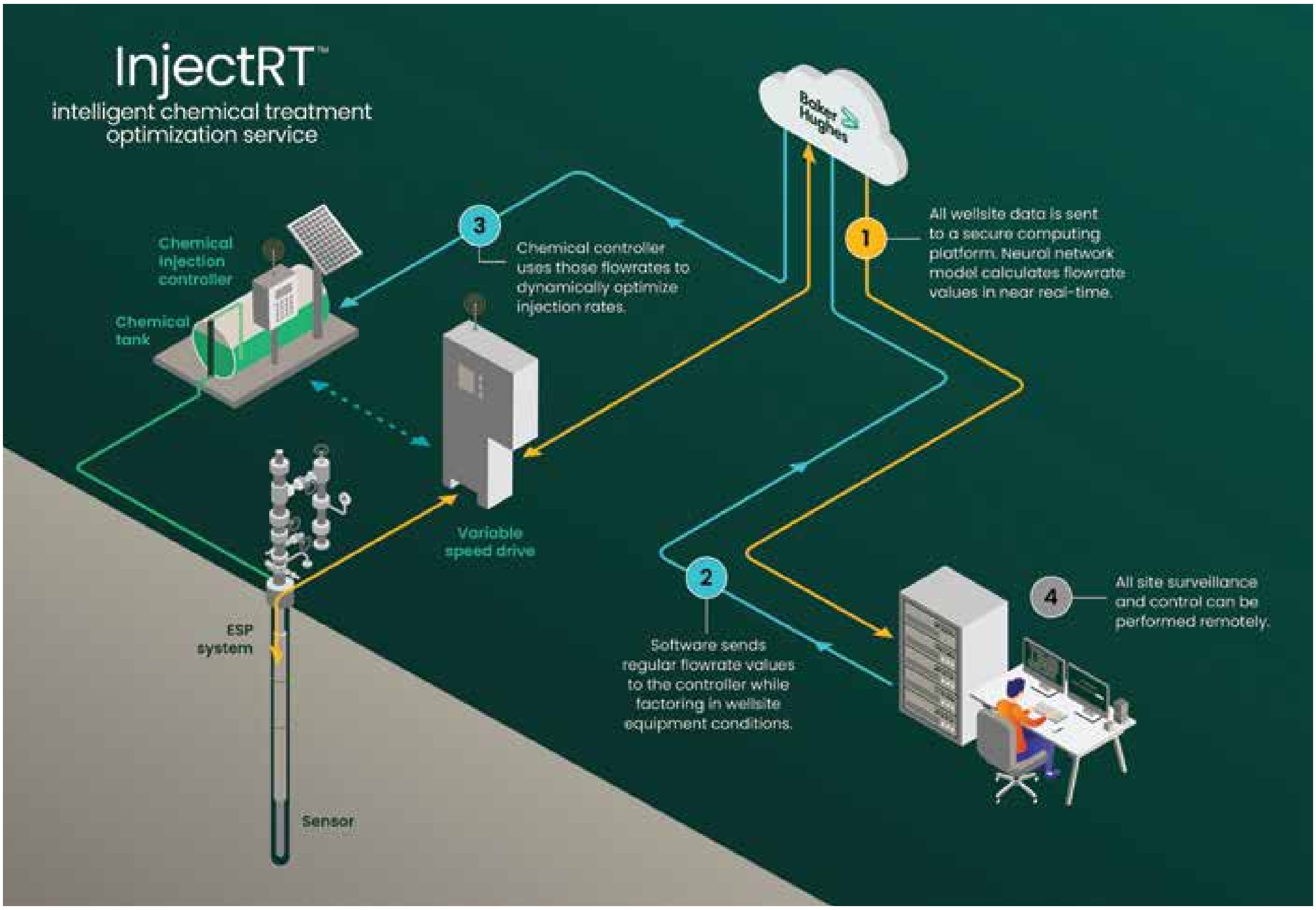
According to the results of a recent industry survey, there is confusion about what “digitalization” actually means. The fact that there are multiple definitions for digitalization makes it difficult to have a productive conversation about how it can be applied to deliver value. Agreeing on—and understanding—the terminology is a prerequisite for broadly applying digital solutions and measuring their value in terms of operational improvement.

A nearly ubiquitous digital technology is AI. AI systems are designed to perform tasks that historically have relied on human intelligence, such as understanding natural language, recognizing patterns and making decisions. AI systems can learn, reason to some degree and, in conjunction with a

Defining the Terms



SOURCE: BAKER HUGHES



SOURCE: BAKER HUGHES

control system, act autonomously. Such AI systems are used in oil and gas operations to improve well planning, detect hazards like high levels of gas, identify equipment anomalies and optimize drilling operations

ML is a subset of AI in which data-driven models use statistical algorithms to learn and perform tasks without explicit instructions. This technology is used broadly in oil and gas operations. ML models examine data to recognize patterns that can be used, for example, for process optimization or identifying equipment wear and predicting potential failure conditions.

Although ML models are similar to physics-based models in that they use historical and real-time data, physics-based models function differently. They use underlying knowledge to create digital models of physical objects from small hydrocarbon molecules to multiphase flow, to equipment aging and degradation in harsh environments, to large, complex subsea installations.

Physics-based models are critical components for creating digital twins, which replicate a physical object, process or system. Constructed using all the data available, a digital twin combines real-time data, simulation capabilities and predictive analytics to transform data into actionable insights that can be applied to operations. Because a digital twin uses both historical and operational data, it is a valuable tool in the design and planning stages of a project as well as during operations.

Collectively, these technologies are enablers for automation, which allows tasks to be carried out with less human intervention or with no human intervention at all.

Drivers for Automation

There are many reasons for automating operations, but they all boil down to one thing—value.

For decades, the oil and gas industry has struggled to contend with a shortage of skilled workers and increasingly relies on technology to help fill in the gaps as experienced, older workers retire. Automating processes allows novice crews to work at a much higher skill level, carrying out routine functions and delivering consistent results. For veteran oilfield workers, automating these functions streamlines operations, which allows them to avoid repetitive tasks and focus instead on higher-value or more complex aspects of their jobs.

Automation also makes it possible to deploy smaller onsite crews, which has a number of operational benefits.

Smaller crews mean fewer trips are required to get workers to and from the field, and fewer vehicles generate less emissions. This creates a pathway for reducing CO_2e from well construction operations and precipitates a reduction in CO_2e from every barrel of oil produced by the asset. And when automated functions are electrified, there is an even greater reduction in the environmental impact of day-to-day operations.

Automation is also revolutionizing safety, which is directly related to productivity in oil and gas operations. Automation is a way to prioritize safety by reducing the number of people required on site and consequently reducing the opportunities for injuries, incidents and accidents.

The biggest value driver, however, is that automation increases productivity. Once a process is automated, it can be optimized, which allows more value to be extracted from existing assets.

Today, automation—often embedding technologies like AI, ML and physics-based models—is changing the face of oil and gas operations, delivering on promises to drill faster and farther with better accuracy and ultimately, produce more hydrocarbons at a lower cost.

Overcoming Obstacles

Repetitive tasks that follow a set of pre-defined rules and instructions are best suited to automation, which is why refineries are increasingly implementing automated processes. From transporting materials and products within the facility to emissions monitoring to process control, automation is delivering efficiencies that lead to enhanced productivity and improved safety.

Although automation has proven its value in downstream operations, the upstream segment of the oil and gas industry has not yet experienced scaling of this technology.

Hesitation is due as much to misgivings about the applicability of the technology in complex and varied operating environments as it is about safety. In an industry characterized by complex processes in harsh operating conditions, assuring safety is critical. The hesitation to automate is often driven by the ambiguity of the input data. In subsurface applications, the data that would be used to automate in a control loop could be uncertain or incomplete.

The biggest barrier to adoption, however, is overcoming doubts that automation can deliver enough value that it is worth changing the way work is done today.

Fortunately, as more functions are successfully automated and positive outcomes demonstrate reliability, trust is building among stakeholders, and automation is gradually proliferating.

Discrete processes are being automated in nearly every type of energy industry activity, and these successes prove that automation has the potential to deliver value in every step of the field development life cycle.

Powering Insights

Intelligent tools provide data-driven insights that enable better decision-making in well planning operations.

For some organizations, implementing a digital twin is a fairly new undertaking, but for Baker Hughes, it is already an integral part of developing a drilling plan. Well designs are improved through extensive iterative modeling with a digital twin that uses the best available data to produce an optimal well plan.

To ensure a well is drilled within planned parameters, the digital twin runs simulations for the entire drilling program, taking into account formation properties, temperatures, pressures, flow rates, wellbore trajectory, casing and completion design to identify the best possible scenario. This reduces the likelihood of encountering unexpected issues that could compromise a successful project and allows the plan to be continually optimized for efficiency.

Digital twins are also leveraged during real-time operations. Instead of the model being fed with simulated data, real-time data allows the model to continuously update, resulting in a system that is geared toward finding the optimum setpoints for well construction, which can be used as inputs for autonomous operations.

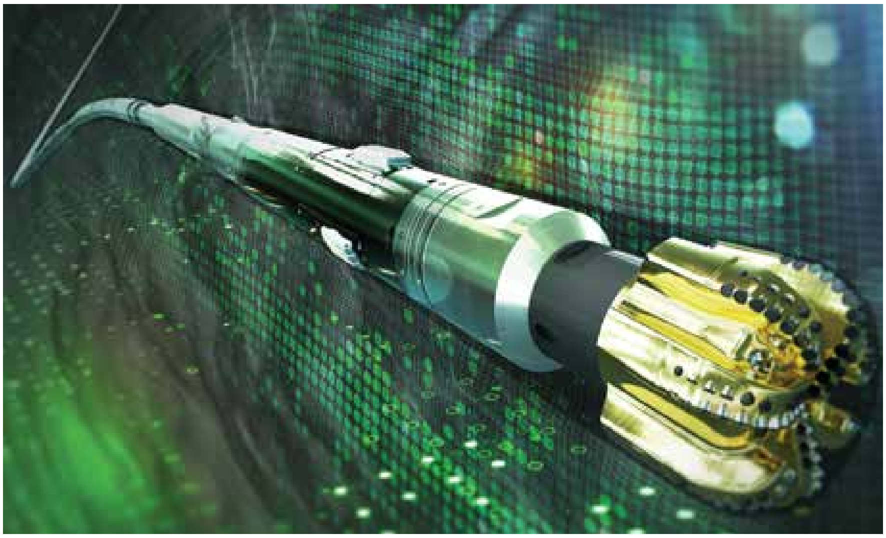
Achieving autonomous operations requires a digital well construction platform that enables holistic operations management. This is where a platform like Corva's—a Houston-based company that delivers cloud-based well construction digital solutions—comes into play.

In addition to enabling visualization at the rig, asset or fleet level, Corva's digital platform includes more than 100 applications that allow process optimization throughout the well construction process.

Moving from Data to Drilling

Data is foundational to performance improvement, but collecting accurate data is just the first step on the road to automation. Data is used in three primary ways that enable increasingly sophisticated operational control.

The first is descriptive, which in simple terms is collecting and reporting performance data. Descriptive data is static, and experts must evaluate it and determine if action should be taken, for example, to adjust the power level on a piece of equipment or change the frequency with which a task is executed. If there



SOURCE: BAKER HUGHES

The AutoTrak Curve Pro rotary steerable system combines azimuthal hold, inclination hold, new electronics and firmware to automatically correct the well's trajectory to reduce tortuosity, torque and drag.

is no human intervention, nothing changes operationally.

Predictive models apply descriptive information to provide a forward look at operations based on historic and real-time performance data. In this case, the system not only examines current conditions but also forecasts future ones such as when a piece of equipment will need to be replaced.

Prescriptive modeling uses historical and performance data to assess, analyze and take action independently. For example, the system can change the choke on an engine or limit the number of times a valve opens and closes to reduce wear. In this instance, the system detects an issue, performs an analysis, determines the best action to take and then executes that action to alter the outcome.

Before the industry is ready to accept the outputs of a prescriptive model and trust in its ability to automate operations, there must be evidence that proves descriptive and predictive automations are possible.

Earning Trust

Based on more than 100 years of drilling experience, the Baker Hughes i-Trak drilling automation service demonstrates real-time wellbore placement can be automated to improve accuracy and efficiency.

The system is a paired hardware-software service that allows the execution of automated well placement. Data from downhole tools, rigs and third-party sensors are sent to the edge automation server, which hosts time-critical applications that cannot be executed in the cloud. The server executes microservices that automate the steps of the well construction process, sending commands to the rig control system to enable full closed-loop automation.

The server is the mastermind of automated operations and coordinates decentralized functions managed from the cloud as well as functions executed directly within downhole electronics, such as automated steering. Through the Baker Hughes IoT platform the system is connected bidirectionally to a remote operations center that is staffed by a team of experts for 24/7 oversight.

The i-Trak system can be deployed in multiple modes that allow operators to approach projects with different levels of automation. The first level is "shadow mode," in which the system creates a well trajectory based on real-time data and proprietary algorithms. The crew assesses each suggestion before applying those that are deemed appropriate using traditional geosteering technology.

The next level of application, "advisory mode," permits the automated solution to be performed by i-Trak's reservoir navigation system (RNS) once the driller approves the action. At this stage, the driller is overseeing operations but not manually intervening.

The most advanced level is full automation, in which the RNS detects and analyzes downhole conditions and physically changes the well trajectory for optimal penetration in the best part of the reservoir.

This capability was put to the test by Equinor in Norway's offshore Johan Sverdrup field. Using deep-reading resistivity inversions, i-Trak generated navigation proposals that were translated into steering commands and automatically transmitted to the bottomhole assembly for implementation downhole. This enabled precise placement of a high-quality wellbore an average of 1 m from the reservoir roof with minimal dogleg severity (1.3-degree/30 m average). Approximately 70% of the reservoir footage was drilled with automated directional drilling technology, resulting in a smooth completion run drilled 17% under budget.

Automating Optimization

While the primary goal of the RNS is to keep the well in the most productive part of the reservoir, real-time drilling data also can be used to make other decisions to improve operations. For example, it is possible to autonomously monitor drilling fluid and predict the fluid composition required for the next operational step to achieve the best outcomes.

Drilling data also can be used for drill bit optimization. Analysis of downhole and operational data indicates how effectively the bit is penetrating the formation and provides insights that allow suboptimal performance to be identified. This information can be used to determine how changes in the bit design could improve ROP. With drilling performance data in hand, it is possible to quickly customize cutter placement on the drill bit for a specific application. In short, better data enables better bits.

Automating Production

In an industry increasingly focused on efficiency, it is important to reflect that the shortest cycle barrel is not delivered by drilling new wells; it is delivered by optimizing producing wells that are underperforming. By that logic, production automation should be ahead of drilling automation, but the reality is that it lags behind.

Production is a complex conglomerate of equipment, operational and reservoir variables that continuously change over a longer period of time. Each field also presents a different set of challenges. From well-specific parameters, such as an optimized chemical treatment and carefully selected downhole equipment, to field-level constraints, such as fluid-handling capacity and power quality, each project has a unique combination of variables that interplays in the production process.

Most ambiguous is the movement of liquids and gas between the wells, where it cannot be observed or measured. Field or reservoir drainage is ultimately about the recovery of hydrocarbon liquids or gases present in the field through the mechanism of the wells.

In addition, there is significantly less capital investment from operators in this segment. While the value is high, the execution is complex. Most investments are opex, which factor directly into the cost per barrel of production.

The goal is to minimize this expense while optimizing economic recovery. For fields or wells producing over decades without a concerted effort over time to collect and preserve this measured data, less can be inferred about what factors impacted historical production.

To effectively orchestrate these disparate components in a cohesive way, there must be seamless coordination across the entire system. The solution must account for the distinctive characteristics of each field and provide a scalable way to deploy automation.

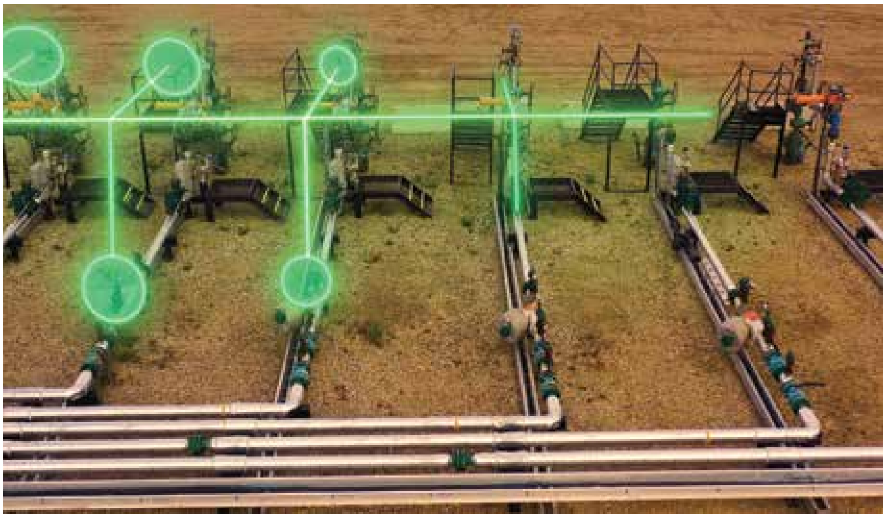
In recent years, companies have been preparing for this future by focusing on data management, aggregation and visualization. Moving forward, they are building on that foundation to gain efficiencies through increased automation.

Implementing production technology requires a cohesive orchestration layer—a single pane of glass experience to manage the complexity of the field. This experience is supported by:

- Advanced analytics capabilities to deliver insights;
- The ability to easily integrate core operating data, often located in disparate systems;
- Secure connectivity to real-time operating data, required for everything from alarming to feeding analytics;
- Smart hardware to enable reliable and effective operations; and
- Domain expertise and a solutions-focused approach.

It sounds like a tall order, but solutions being deployed today are proving that it is not mission impossible.

Baker Hughes is applying AI to deliver advanced analytics for electric submersible pumps (ESPs) using its proprietary Leucipa production automation technology. The analytics applied to ESP performance leverages sophisticated ML models to detect potential failure conditions, such as sanding or scale. Building the ML model began with gathering historical data for training. In this case, the company's 24/7 artificial lift monitoring team supported the training process by providing



SOURCE: BAKER HUGHES

Baker Hughes is applying AI to deliver advanced analytics for electric submersible pumps using its proprietary Leucipa production automation technology.

SOURCE: BAKER HUGHES

The CENefficient ESP system combines Baker Hughes' high-efficiency pumps, serviceless seals, permanent magnet motors and variable speed drives.

specialized knowledge of critical condition trends.

Leucipa's ESP AI software analyzes data from the equipment, identifies indicators that failures are likely to occur and provides warnings so adjustments can be made to the pumps.

In addition, an ensemble model integrates multiple failure conditions into a predictive framework that issues alerts and suggests steps that can be taken to prevent failures. This solution has accurately detected more than 3,000 critical conditions in one operator's field in the span of 30 days.

But the intent of this technology is not to provide failure prediction but to provide optimization recommendations utilizing AI-based failure prediction coupled with physics-based modeling.

Physics models are important as both standalone engines and as a companion to ML. For example, physics models can create synthetic data for ML models when actual data is missing.

One example of analytics-driven, closed-loop automation is the recent deployment of a solution designed to autonomously optimize chemical dosing based on real-time insights gathered from an ESP.

Control and telemetry data are sent to the cloud, where a physics-based model leverages a neural network to calculate key parameters like flow rates. Those values are sent to a chemical injection controller that uses flow volume to calibrate the amount of chemical to dispense downhole and then ensures that the precise volume is injected. This process demonstrates how analytics can be connected to smart hardware to drive closed-loop automation.

Applying this solution inhibited scale and optimized chemical treatments in real time. The operator monitored field operations to capture metrics demonstrating that automation decreased power consumption and reduced emissions. Over a 90-day period, this solution delivered 29,000 incremental barrels of production per day across the customer's wells.

On the Horizon

Oilfield automation is continuously evolving, and existing solutions clearly show that automation is becoming an increasingly integral part of reservoir assessment, well planning, drilling and production.

Applied automation is already delivering gains in productivity. Strong results to date, coupled with the continuing pressure to get more value from existing assets, will be a strong driver for expanding and extending this technology. Ongoing investment in R&D will fund a pipeline for developing next-generation algorithms, methodologies and technologies that will improve today's automated processes and facilitate even more automated functions.

The advent of generative AI will allow access to more information, further improving the certainty required to automate. At some level, generative AI pulls together validated data from many sources, especially previously unstructured reports and supporting data, to improve confidence. Advances in artificial reasoning will allow simple, rule-based systems to become more powerful at scale. These advances in reasoning also will deal with much more complex scenarios that humans deal with today.

Improvement in automation requires trust; however, the uncertainty in which the E&P sector operates can slow down the process of building that trust. This can be accelerated by leveraging change management practices as a part of adopting new solutions.

API is already planning for this future, forming committees to address the challenges ahead and charging them with developing a pathway for standardization. Intelligent systems could soon be connected to every rig and every well, managed through a single interface to achieve even greater efficiencies and increased production while improving worker safety and enhancing environmental stewardship.

A future characterized by highly autonomous operations and end-to-end improvement is not far beyond the horizon. E&P

Understanding the Impact of AI and Machine Learning on Operations

Advanced digital technologies are irrevocably changing the oil and gas industry.

JAXON CAINES | TECHNOLOGY REPORTER

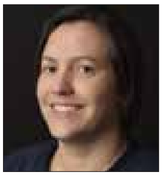
Although the oil and gas industry is unlikely to be the first thing that comes to mind when the subject of AI comes up, the fact is that AI, particularly in the form of machine learning (ML), has been integral to operations for more than a decade.

According to Karen Czachorowski, IT and data delivery lead at Aker BP, ML is essential to operations because of the value it delivers. "Machine learning models can predict the most productive drilling sites, optimize drilling paths and monitor reservoir performance in real time, enhancing extraction efficiency and reducing environmental impact," she explained.

ML plays a vital role in the energy industry, and new technologies continue to change the playing field. Evidence of this is the fact that generative AI is gaining ground.

"Generative AI can revolutionize the oil and gas industry by enabling more accurate reservoir modeling and seismic interpretation, enhancing offshore operations, improving predictive maintenance and on-demand maintenance and optimizing supply chains and logistics, thus increasing efficiency and reducing costs across the entire value chain," Czachorowski said.

The increasing desire for and growing implementation of generative AI in the oil and gas industry has been spurred by two fundamental problems, according to Czachorowski: supply chain bottlenecks and quality in execution. In her view, these issues are derailing many new projects aimed at meeting energy security needs and facilitating the energy transition, pushing them over budget or behind schedule and, in some cases, diminishing returns.



"Without digital transformation utilizing industrial data and AI, we are not set up for success. Therefore, the need to reinvent the execution of industrial capital projects is immediate and urgent."

KAREN CZACHOROWSKI, IT and data delivery lead, Aker BP

"Without digital transformation utilizing industrial data and AI, we are not set up for success. Therefore, the need to reinvent the execution of industrial capital projects is immediate and urgent," she said.

Applying AI to Operations

In oil and gas operations, AI models can use data from sensors and machinery to reduce downtime and maintenance costs by predicting equipment failures. This predictive capability ensures continuous operations and extends the service life of expensive equipment. Additionally, AI can analyze historical and real-time data to identify inefficiencies and recommend adjustments, potentially delivering higher output and lower operational costs, enhancing efficiency and improving productivity.

"I can tell you that your ability to predict failure of equipment accurately and resolve that failure before it happens has millions and millions of dollars of impact in terms of lost downtime," Jason Schern, CTO of Cognite, told *E&P*. "The repair costs if something actually fails and goes down is orders of magnitude greater than if you can just provide preventative maintenance to prevent it from going down."

Czachorowski explained how Aker BP has begun implementing generative AI in its operations, partnering with Cognite to develop the Cognite AI DocParser, an AI agent that automates attribute extraction for material master registration to significantly reduce manual processes.

Based on Aker BP's initial tests, the DocParser can handle 67% of the equipment material master tasks, leading to considerable cost savings, better data quality and fewer duplicate items without making any changes to the AI model itself. Although human verification of the agent's work is still part of the process, Czachorowski described the results as "impressive" and said she

Examples of Contextualization Pipelines

Uncontextualized data	Machine learning	Rules engine	SME validation
	Time series / Assets	55 rules identified	99.9% matched

Starting point

Time series not matched to be asset hierarchy

Identified rules

55 rules generated

91.6% time series matched

0.6% conflicts (time series mapped by more than one auto-generated rule)

Rules reviewed

Customer domain expert rule validation

40 rules kept (some modified)

5 new rules created

99.9% matched

0.1% conflicts

Without proper contextualization, data that is gathered is useless

SOURCE: COGNITE

sees the potential for great savings using this tool.

"It's probably not an exaggeration to say that the impact of machine learning in the oil and gas industry has been multiple percentage points to the top line and the bottom line of companies around the world," Schern said. "And it's why they spend so much time working on it."

Understanding the Challenges

While the adoption of AI can address several key challenges in the oil and gas sector, offering solutions that enhance efficiency and transform the industry's operations and decision-making processes, there are still barriers, with the main issue being the many types of data that must be collected and interpreted.

Industrial data is often varied and messy, and different data sources rarely match up perfectly. This mismatch creates a challenge for using AI effectively. For both ML and generative AI, inconsistency makes the data more difficult to work with, said Schern.

"In the case of machine learning, you need good clean data along with labels and relevant features," Schern explained. "If I have data that's coming from a pressure gauge, I need labels that tell me at a certain point if something is occurring somewhere else... Being able to combine those things is what gives you really rich data for building machine learning models, which is going to make predictions more accurate."

Another barrier is the lack of people within the industry who know how to properly apply ML and generative AI tools to capture the greatest advantage. Finding experts with advanced skills and specific industry knowledge can be challenging and expensive, particularly in an environment in which many businesses are competing for the same talent.

Change management is another impediment to adoption. Organizations often resist adopting new technologies, especially in areas where technology is not widely used. People can be skeptical about new technology if they do not fully understand it. Providing training to help workers understand and use the technology can speed up the innovation process.

"Embracing AI is not just about

"It's probably not an exaggeration to say that the impact of machine learning in the oil and gas industry has been multiple percentage points to the top line and the bottom line of companies around the world. And it's why they spend so much time working on it."

JASON SCHERN, CTO, Cognite

technology; it is about transforming how we operate and unlock value from our data," Czachorowski said. "A successful system comprises people, processes, data, tools and their interactions. Ensuring these elements work together in alignment is crucial and remains an ongoing challenge."

Thankfully, said Schern, a new wave of professionals with the necessary skill set is entering the industry.

"The next generation is super familiar with this type of technology and usage in their daily life," he said. "They're the most prepared generation to be able to take advantage of large language models in their daily work."

As new workers enter the industry, finding a way to facilitate knowledge transfer from experienced employees to newcomers is critically important. Large language models (LLMs) are helping to address this concern by quickly providing important information when asked the right questions. According to Schern, an operator in Japan has adopted a few of Cognite's AI solutions to fast-track learning for less-experienced workers.

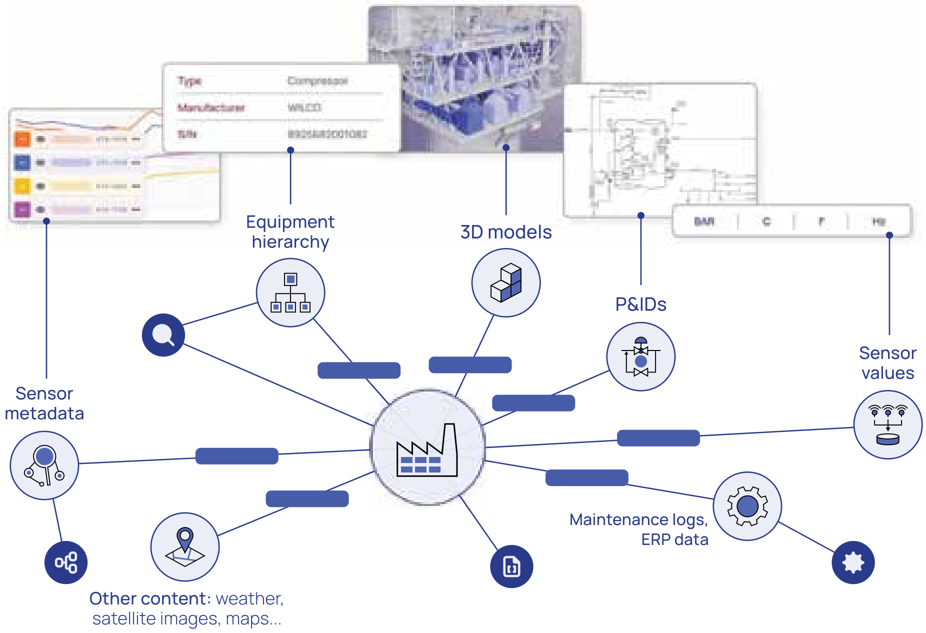
Digital Technologies Shape the Future of Energy

Despite the barriers to implementing this technology, it is clear that AI can enhance hydrocarbon exploration and extraction.

These technologies can analyze vast amounts of data from sensors and monitoring systems installed on offshore rigs and platforms, detecting patterns and anomalies that indicate potential issues. Today, AI-powered analytics and predictive modeling are empowering offshore facilities with real-time, actionable intelligence, leading to safer, more efficient and cost-effective operations.

"Integrating AI into daily processes is reshaping our work by driving efficiencies, reducing costs,

Everything in Alignment



SOURCE: COGNITE

To apply generative AI in industrial environments, the ability to prompt large language models with operational context is critical.

enhancing safety, and enabling more informed decision-making, thereby transforming traditional operations and creating new opportunities for growth and innovation," Czachorowski said.

Making AI an integral part of operations—as is the case in geological data interpretation—empowers the energy industry to achieve greater automation, optimize processes in real time and respond swiftly to changing market conditions, ultimately driving growth and improving economics.

As AI agents become more prevalent in day-to-day activities, Schern believes more improvements in efficiency will reveal themselves in the workforce.

"I fully expect that at some point in the future, compute cost and tooling will improve to the point that companies, if they have contextualized data, are going to be able to fine tune and train their own LLMs that will just know their data," he said. "When you can do that, it reduces the burden of having to provide information along with your question."

Because of the interpretive ability of LLMs, companies will begin to see better, well formulated answers to their questions about operations, Schern said.

"At some point, will the reasoning engine of large language models join up with the predictive capabilities of machine learning? It's a distinct likelihood sometime in the future," he said.

With the oil and gas industry embracing the power of ML and AI, it is clear that this advanced technology is redefining operations. Although the road ahead is not without challenges, ongoing integration of advanced technologies will continue to deliver benefits, and as AI tools become more sophisticated and widespread, they will provide new opportunities for innovation and growth. E&P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The Continuous Journey of Drilling Automation

Incremental improvements lead to significant advancements.

CHUCK WRIGHT | NOV

Drilling is a complex interaction of machinery and humans that has radically changed over more than a century in the oil field, and automation has been part of the long, continuous effort of process improvement.

While giant technological improvements make the headlines, continuous small steps generate sustainable change and ultimately lead to significant progress. In general, product development, especially industry-changing innovations, can be seen as a never-ending struggle for process improvement and optimization.

NOV has been at the forefront of this automation journey, introducing the NOVOS reflexive drilling system in 2015 and using it as the steppingstone toward further process autonomy. The ATOM RTX technology platform, which incorporates mechanization and the use of robotic systems on the rig floor as well as process control systems, was a natural next step in the automation transformation of traditional drilling rig processes and operations.

Interconnected technologies work together synergistically to achieve three fundamental objectives of drilling automation: remove danger, improve performance and efficiency, and enhance awareness of the process.

Efficiency gains from drilling processes have limits but offer the crucial advantages of consistency, safety and speed.

NOV

The NOVOS reflexive drilling system has delivered consistent efficiency improvements on land and offshore rigs worldwide.

Equipment Automation

A continuous drive to remove people from the red zone of the drill floor has succeeded to varying degrees over the last few decades. Although some manual processes remain because they are tough to replace, the industry agrees that much more can be done, including offshore, where most of the success has come so far.

By eliminating the variability associated with human operators due to experience and skill level—and influenced by fatigue and weather conditions—the precise and repeatable execution of tasks enables more reliable and consistent drilling outcomes, and reduces downtime and delays.

The ATOM RTX system is the mechanization link between process automation and the execution of drill floor tasks, which include making and breaking connections, as well as racking and tailing pipe on the rig floor and at height on the racking board.

Work continues to push mechanization into bottomhole assembly (BHA) handling, safety valves and casing tailing, the processes and physical tasks that constitute a well program. Developed technologies that are essentially designed to complement each other can be further combined to improve performance.

The current robotic system is intended to be developed and adapted to future tasks. The end of the robot, the end effector, is designed such that it can be configured to new requirements, which is crucial. Even though many processes are well-defined in well construction today, they lack the benefit of advanced digital process automation controls and mechanization. This represents a new design paradigm that could considerably change the way things are done in the field, potentially keeping personnel completely clear of dangerous environments.

Process Automation

The first benefit of automated processes, consistency, was evident early in the development of the NOVOS platform and architecture. Seemingly simple rig tasks and processes, traditionally requiring manual procedures and training, ultimately proved amenable to advancements in optimization.

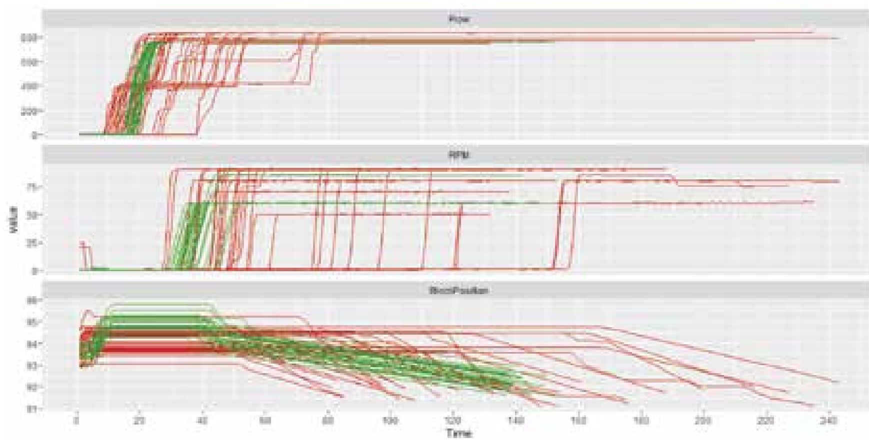
A specific example is stump height in setting slips. Small variations in height create after-action effects. For instance, increasing or decreasing the stump height relative to the "last time" means the iron roughneck needs to change the approach height to break the connection. This requires more time—at least several seconds. The exact timeframe depends on the stump height variance. These seconds add up when completing wells with a large amount of pipe and then tripping several times.

The advantages of consistency extend to activities such as pump ramping and BHA rotation. Some drillers are proficient in consistently executing ramp-ups and rpm changes, but variance still exists

NOV

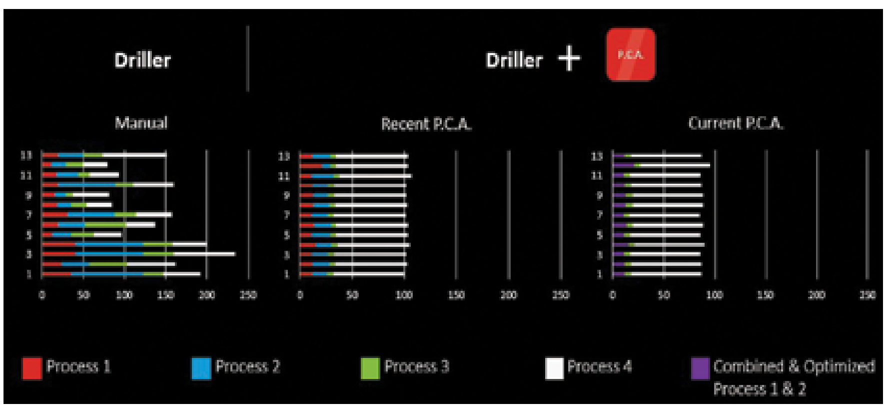
The ATOM RTX robotic system performs tasks including doping, guiding when stabbing, tailing, stand building and mud containment with a high degree of precision and repeatability.

How NOVOS Works



SOURCE: NOV

The green lines are the early NOVOS field testing repeatability of step tasks flow-RPM-block position for connections.



SOURCE: NOV

A field example demonstrates optimization of various processes through NOVOS process control automation.

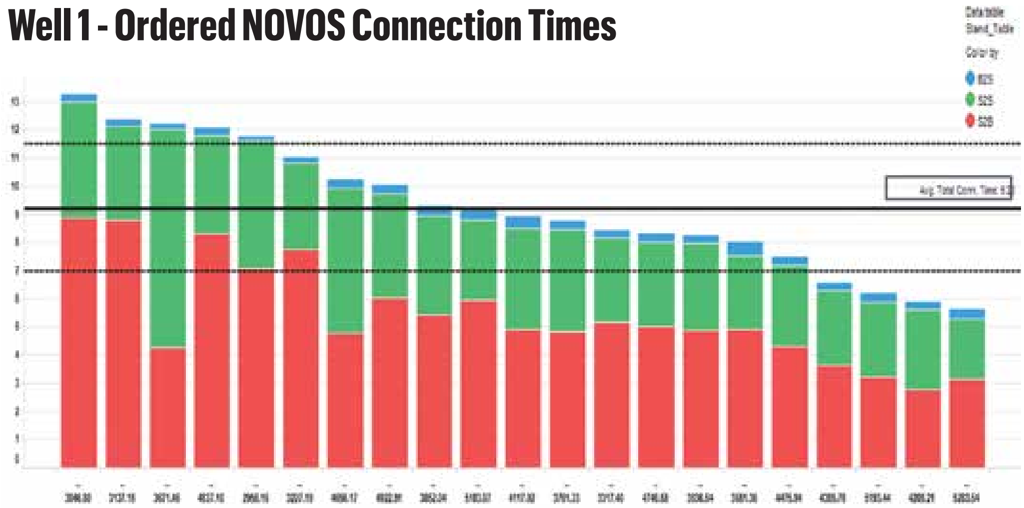
because of operator attention span, distractions, mental and physical fatigue, and other factors. Machines do not suffer from those faults and can execute ramp-ups flawlessly on each cycle.

Variance exists in any system regardless of how precise it is, but the process control system architecture has been proved to improve efficiency. It is the control of total variance that generally defines a system as colloquially "better."

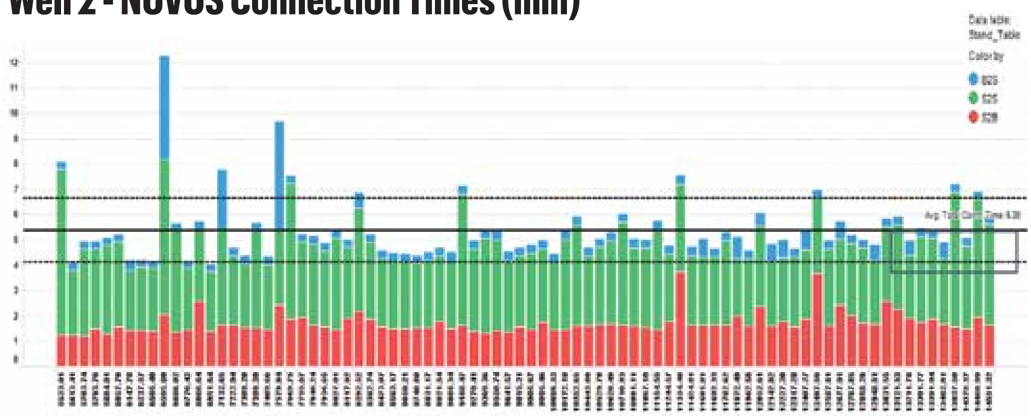
Another aspect of pure time savings in individual steps is the optimization achieved by combining steps with process control automation. The design of a process automation control system allows individual steps to be reviewed and optimized into a more streamlined flow.

Process optimization improves the sequencing of complex systems. As demonstrated with process control automation, coupling process automation with advanced mechanization presents an opportunity to combine manual steps into a more streamlined and optimized operation.

Well 1 - Ordered NOVOS Connection Times



Well 2 - NOVOS Connection Times (min)



SOURCE: NOV

In the Appalachia well program, applying process automation control optimized connection times from one run to the next.

Field Performance Demonstrates Value

Effective performance of process control has been proved from South America to Norway, Thailand to Canada, and from Pennsylvania and West Texas to Alaska, Abu Dhabi and the Gulf of Mexico in both offshore and onshore drilling environments.

Automation advancements have delivered 40% to 67% improvements in drilling and tripping performance across crews and platforms within the same field. While comparing one field to another is challenging due to the differences and the specialized requirements of each reservoir, the underlying truth remains the same. Bringing process automation and mechanization into the same space, along with advanced analytics, combines to deliver consistent results showcasing that an orchestrated approach to technology not only leads to further improvements but also ensures sustained performance. This approach enhances efficiency and leads to safer and more informed decisions in the well programs through better data.

The application of the NOVOS reflexive drilling system in Appalachia shows a distinct improvement in the average connection time as well as consistency throughout the well program. Having consistent results means that the process stages become more predictable inside the well program. This consistency can be the continued improvement of logistics and logistics scheduling, which are also important aspects of well construction.

Drilling rigs employing the NOVOS architecture and proactive support structure have set weight-to-weight (W2W) and slip-to-slip

(S2S) connection records in fields worldwide. A drillship offshore Guyana set a record W2W average of approximately 7.86 minutes, while a semisubmersible in the North Sea obtained a record W2W average of approximately 3.41 minutes. On Alaska's North Slope, this technology delivered the fastest W2W time of 11.16 minutes on an intermediate section of their well program.

Drilling Automation Processes and Autonomy

There are many "wants" in the development of drilling automation processes and autonomy: better control, more stable operation, less vibration, continuous improvement, accurate placement, repeated performance and higher reliability. The list is long and seemingly endless. While some drillers today can consistently deliver on many of these wants, skill sets vary for drillers across a fleet of rigs, and driller fatigue—which leads to suboptimal performance—is a real concern.

Influencing factors like these prevent repeatability and consistency, but machines excel at repeatability and can continually monitor parameters. General alarm systems exemplify this capability and represent one of the simpler ways automated "watching" has been employed over the last few decades.

The drilling system, however, is both human and machine. Increasingly complex drilling systems require constant input from industry professionals to maintain performance standards. Process control automation and autonomy are complementary to crewed operations.

Moving toward autonomy does not mean humans are excluded from decision-making. Instead, humans become empowered to make better decisions. One of the main drivers of process automation is to reduce the operator burden borne in great part by the driller and to improve repeatability and consistency.

The ultimate goal is to provide an interconnect for the numerous systems that provide everything from advisory information to multiple levels of control such that they operate synergistically. The industry is still struggling to determine exactly what that interconnection will look like, but it seems evident that AI systems, which currently play a role, will continue to be essential on the path to automation and mechanization.

Systems that monitor incoming operational data in real time still do not fully utilize the potential of direct bilateral communication with the process control system and automated operations. Well execution must move beyond manually transferring information and files and become a two-way hub of communication. A fully integrated process control system, connected with the mechanization of processes to aid in detailed data collection, is essential for achieving this standard of well construction.

Rig Design Optimization

Dominant design is the engineering principle that a certain design maintains dominance in an industry or space but, at some point, becomes challenged by a new design. An example is the robot vacuum, which no longer resembles the dominant design of traditional vacuum cleaners.

As automation process control and mechanization of physical drilling processes continue, a new opportunity emerges to challenge the status quo of rig design. This presents a chance to uniquely transform the system and enhance the optimal layout.

Fully Autonomous Rig Operations

Fully autonomous drilling is seemingly a world away. However, there was also a time when automated pipe handling and the capability to create deep lateral reach wells seemed far-fetched.

Drilling technology continues to move operationally toward total autonomy. In early 2023, NOV removed the driller's cabin from the Prime 1 test rig at its Springett Technology Center to develop all the ancillary systems needed to support that function. The ATOM RTX system was the steppingstone that truly enabled the driller's cabin to be removed.

It is important to recognize that the technological gains of autonomy are not exclusive to drilling processes. Other well construction processes, such as casing, cementing and completion can also benefit from continued development, and the scope of automation can include field development beyond well construction.

Challenges

Major barriers to process automation and autonomy include the rising cost of finding a solution and the challenge of bringing a concept to market. Market conditions often preclude wide-scale adoption. While the desire exists at every level of the industry to move forward, the volatile nature of the oil and gas industry has not been especially conducive to finding the necessary partners to fully develop every aspect of the process automation system.

The Road Ahead

The next technological leap in automation technology involves continuous small steps that build on previous successes. The building blocks of performance and process optimization are in place, as is the ability to sustain improvements despite changes in industry personnel and required skill sets. Successes will continue to grow as the synergy between process control and mechanization technology matures. E&P

Innovative Insulation: The Future of Thermal Management

Silicone-based, spray-on coating simplifies application and improves protection for assets and workers.

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Downstream industry assets often operate at temperatures exceeding 1,200 F (650 C). Today, the standard practice for managing and controlling heat is to use mechanical insulation, such as mineral wool or calcium silicate, and metal jacketing on heated tanks, piping and related equipment. Insulation improves energy retention and ensures workers are protected from hot surfaces.

While mechanical insulation addresses the issues of retaining energy and protecting workers, all these systems have drawbacks. Traditional systems are cumbersome to install because they require significant scaffolding for large applications, precise cutting for complex geometries and proper sealing to prevent water ingress.

The industry needs a better solution, one that provides the necessary protections but is easier to install.

Traditional Insulation System Challenges

Mechanical insulation systems require a primer coat on the substrate, fitting the insulation, and securing a jacketing layer to protect against damage and water ingress. Over time, rainwater or washdowns can seep under the jacketing and saturate the insulation, which leads to reduced thermal insulation capacity and creates an environment prone to corrosion under insulation (CUI). Heavy saturation can cause the insulation to shift or collapse, compromising its effectiveness.

Conventional spray-applied coatings, primarily waterborne acrylic or epoxy-based coatings, are limited in temperature resistance—serving equipment operating at 350 F (177 C) or lower—and often require multiple layers to achieve the desired thickness for optimal protection. These limitations restrict the use of conventional coatings and result in long application times. The need for multiple layers can lead to extensive schedule additions and potential intercoat issues due to weather, especially when the coatings are applied to large structures such as storage tanks.

Both mechanical insulation and conventional spray-on insulations face significant challenges in preventing CUI. Mechanical insulation can trap moisture, leading to high corrosion levels, while spray-on insulation coatings still require a primer to protect the steel substrate.

CUI can result in costly maintenance, repairs, shutdowns and even catastrophic failures. For instance, in 2001, corrosion led to a rupture in a pipe carrying flammable gas in the U.K. that resulted in an explosion and fire. It is clear that effective corrosion prevention is necessary to avoid incidents like this and that there is a need for a better solution.

A robust spray-on insulation is the answer.

The Future of Insulation

Recent developments have led to the creation of a new silicone-based, spray-on insulation coating that is not only effective but easy to apply. This innovative solution can be applied at high film builds, withstand a broader temperature range than conventional spray-applied coatings and mitigate corrosion in atmospheric and immersion conditions. The new hydrophobic spray-on insulation coating uses silicone technology with thermally insulative fillers.

Before the new insulation coating was introduced in the field, it underwent multiple tests, including those that assessed application robustness, thermal properties, corrosion resistance and water permeability, to validate its performance.

Thermal testing shows that the coating endures continuous and cyclic temperatures reaching as high as 500 F (260 C), surpassing the 350 F (177 C) upper limit associated with conventional insulation coatings.

Apart from withstanding temperature extremes, field applications and lab tests confirm the silicone-based coating's low thermal conductivity. This property allows the coating to significantly reduce surface temperatures and minimize heat loss, even at high temperatures, providing energy efficiency and safe-to-touch surfaces. A single coat is enough to provide safe-to-touch surface temperatures per American Society for Testing and Materials (ASTM) standards.

Improved CUI Mitigation

Another advantage of applying the new hydrophobic coating is that it resists water absorption better than many fibrous insulation materials. It absorbs less than 3% water when submerged after 72 hours, compared to much higher absorption rates in mineral wool. The fact that there is less moisture means increased insulation performance for greater operational efficiency.

Application properties were evaluated using a range of equipment, including high-volume, low-pressure conventional spray and texture spray with diaphragm or low-pressure transfer pumps. Conditions ranged from 40 F (4.4 C) to 300 F (149 C), with 20% to 95% relative humidity. The coating could be applied easily with conventional spray equipment, reaching dry-to-touch in a few hours or less at 77 F (25 C) and were hard enough to walk on the next day, allowing for the quick application of a second coat if needed.

Thermal heat resistance was evaluated using the ASTM D2485 method B, assessing the coating for degradation, delamination, cracking and loss of adhesion. The coating demonstrated less than 5% mass loss after 100 hours of dry heat exposure to 500 F (260 C) and could withstand cyclic temperatures up to 600 F (316 C) without visual degradation. Cryogenic testing showed resistance to temperatures from -321 F to 500 F (-196 C to +260 C) without delamination, blistering, rusting or cracking.

The coating's water permeability and corrosion resistance were internally tested through the anti-corrosion performance requirements of the International Organization for Standardization (ISO) 12944-6 C5H corrosion performance, ISO 9227 salt spray and ISO 6270-1 water condensation tests. The coating demonstrated excellent corrosion resistance even under harsh conditions.

Innovative Insulation Impact in the Field

An integrated energy company recently applied the new silicone-based spray-on insulation coating, PPG PITT-THERM 909, to one of its storage tanks. The company initially faced significant challenges with traditional mechanical insulation systems, including high maintenance costs, frequent CUI and energy inefficiency. The application of the new insulation solution went smoothly, and now the company is measuring the spray-on insulation coating's effects on energy efficiency, surface temperature and CUI mitigation.

The new silicone-based spray-on insulation coating offers significant advancements in thermal management not only for storage tank protection but for other assets in the petrochemical and energy industries. It addresses the limitations of traditional insulation methods, providing faster application, greater durability and superior protection for workers and assets. The coating's ability to withstand a wide range of temperatures and reliably mitigate CUI makes it an optimal choice for petrochemical and energy assets operating in demanding environments. E&P

Extended Reality Provides Options in Training, Collaboration

Virtual, augmented and mixed reality tools promote safety and efficiency.

PAUL WISEMAN | CONTRIBUTING EDITOR

Much is made about AI and machine learning in oil and gas operations, but rising up behind these is another technology that is being used to boost efficiency and safety, and reduce the carbon footprint of operations. Extended reality (XR) is the umbrella term for virtual reality (VR), augmented reality (AR) and mixed reality (MR). All three involve immersive technologies that combine the physical and virtual worlds, and three companies—Chevron, Baker Hughes and Argis Solutions—are capitalizing on XR to improve training, remote collaboration and mapping, among other functions.

"I love to look back and see where we started and where we're going—and just imagine what's possible."

KEVIN HAVARD, XR immersive technologies, Chevron

Chevron Uses XR In Safety and Human Experience

The extensive benefits of XR for safety and human experience are what drives Chevron's Kevin Havard to get up in the morning.

Havard, the company's product owner for XR immersive technologies, says, "I love to look back and see where we started and where we're going—and just imagine what's possible. How can we make things better and safer for our Chevron employees and contractors in the field?" Having worked in the field himself, Havard noted, "I know what it's like to work in the more dangerous areas."

Chevron's journey into XR began in 2018 with its adoption of the Microsoft HoloLens, a headset that operates as a fully self-contained holographic computer. The company combined that with Dynamics 365, Microsoft's suite of cloud-based business applications.

"Remote Assist, for example, enables remote experts to work with users in the field to help troubleshoot issues across the world," he said, adding that virtual reality and mixed reality are not the same. With VR, "You're in a fully immersive experience," Havard said. "When we think of mixed reality, you're taking a little bit of that virtual overlay into the real world."

With AR, the same overlay principle is applied on a tablet or cell phone instead of an immersive holographic headset.

▶ HOW IS IT USED?

Chevron uses XR primarily for 3D design, remote collaboration and training/retraining.

▶ VIRTUAL DESIGN

The company's 3D design review process connects offices worldwide. "We can incorporate subject matter experts from different business units, asset classes and functions access, and validate different phases in planning and design, construction, and operations for a variety of projects," Havard said.

For example, as Chevron worked on expanding its Gulf of Mexico Jack St. Malo field, the project's engineers were able to holographically project 3D models of the design in a conference room. This way, the planners could examine issues such as clearance, safety issues and other design data before fabricating any equipment, while also saving a number of costly trips on site.

CHEVRON

Chevron includes extended reality (XR) in training—for safety—and in virtual meetings to save travel and reduce the company's carbon footprint.

▶ DISTANCE COLLABORATION

A simple monitor allows distant collaboration, but XR takes things a step further, Havard noted, because the surround-type headset gives the feeling of actually being there. "When you're fully immersed in virtual reality, you don't have any distractions," such as checking a cell phone for email.

▶ VIRTUAL TRAINING

"Virtual reality immersive simulated training provides step-by-step guidance and immediate feedback," he said. High-risk tasks like chemical injections and related work can be done in a virtual, safe space for trainees, "protecting the environment and themselves." Pigging, lockout/tagout and other training can be started in a virtual environment, then continued in a training facility.

Havard stressed that employees still get one-to-one field training after getting the VR-based head start, allowing them to complete training more safely and with greater awareness and knowledge retention than by starting off in the field. "It really helps enhance the overall human-centric approach in the way we work," he added.

This option also allows cross-functional learning and virtual visits to distant Chevron offices for upskilling and familiarization. In all travel-related options, Havard stressed the company's focus on reducing carbon emissions and boosting efficiencies as key components.

Implementing and using XR is getting easier as the company expands its technology. According to Havard, most XR services are now cloud-based. "We can do high-fidelity modeling and streaming while still managing to keep the headset untethered. It's a completely wireless experience for most of our users."

Argis' AR Mapping Tracks Buried Assets

Argis CEO and founder Brady Hustad came into the geographic information systems (GIS) space in the 1990s, when most of his clients were in oil and gas or municipalities. After seeing AR demonstrated on a mobile device, he asked the developers, "Are you going to take this technology outside?" When they answered, "No, we're never going outside," Hustad saw his opportunity. He built his first version of mapping AR over one weekend.

After patenting his version of AR and going through a series of business transactions, he formed Argis in 2016. The name is a combination of AR and GIS. His founding system was called Lens.

Now Argis is releasing an enhanced product called Z-Focus, built on top of Esri (Environmental Systems Research Institute) software, which Hustad called "the premier spatial GIS software in the industry." He described Z-Focus as, "an advanced visualization reporting tool."

In the oil and gas sector, both upstream and midstream companies have significant underground assets that transport everything from produced water to raw products to refined substances, all of which can cause some type of damage if the pipeline is accidentally ruptured.

ARGIS SOLUTIONS

Z-Focus's AR mapping overlays hidden assets on a traditional map. This gives service crews accurate information for repairs or for planning routes of new lines.

Looking at what he called a "flat map" gives important data about what is on the surface. "Z-Focus takes that map and makes it a 3D visualization," Hustad said. "You're getting your pipes, your wellheads, your gauges, your equipment. Z-Focus puts it in place in the real world. It allows you to interact with your data by clicking on it to see its information, such as the last time it was maintained. Even when it's under the ground, you can see it attached to the real world with good accuracy."

Details like this allow field personnel to clearly picture where assets are, as well as other infrastructure or hazards they might need to avoid.

Z-Focus also adds value on the rare occasion when an asset is not where it was expected to be or if the surface landscape has changed.

"Z-Focus helps communicate and helps reduce the number of costly extra trips," he said. For example, a crew might return from the field without completing the assigned work—at a cost of thousands of dollars. The supervisor might ask, "Why didn't you do the work?" And

"Plug [augmented reality] and [virtual reality] into AI, and the next three years are going to be exciting in terms of the learning technology space, in reducing the likelihood of hazards."

MARTIN DUTHIE, training delivery leader, Baker Hughes

the answer could be, "The pipes weren't where you said they'd be" or "Somebody built an unauthorized retaining wall over the pipe's path." The new site conditions can be updated in Z-Focus so future interaction with the pipes can go smoothly.

The key benefit of the software lies in preventing costly mistakes. Sending a truck and a crew out to address a problem in the field costs thousands of dollars, so any amount of time saved in locating assets more than pays for the software's cost, Hustad said.

In truth, things run smoothly about 95% of the time, he said. But when a single wasted trip can cost $2,500 in equipment and wages, saving two or three incidents per year helps the bottom line, Hustad said, noting, "The product costs $15 (per month) and two minutes."

In field trials, Z-Focus has worked well for clients so far, he said.

The benefits captured from XR to date are significant, and advances in technology will soon deliver even greater capabilities with broader applications. First movers like Chevron, Baker Hughes and Argis will no doubt find more ways to leverage this technology over time, and with continued evidence that demonstrates how XR improves worker safety, enables better decisions, and reduces costs, others will soon follow their lead.

Combining VR with Hands-On Training

While AR/VR/XR have been in some level of use for about 10 years, virtual-everything came to the forefront during the pandemic in 2020, said Baker Hughes' Martin Duthie, the company's training delivery leader, based in Aberdeen, Scotland.

Employee safety is a driving force for VR in Duthie's view. "We want them to leave work the same way they come. Many of our field personnel are in dangerous environments, so improved safety is part of our risk management strategy."

Because mistakes can be deadly in the real world, there is value in having trainees preview certain situations virtually. "You have that safe benefit of understanding what went wrong, to see and understand it, so you don't make the same mistakes when you go into the field," he said.

Some of the most complex technical tasks cannot be replicated in a virtual environment, particularly certain tasks involving artificial lift, wireline, and coiled tubing. VR does not create a work environment as hot as the Permian Basin or as cold as the North Sea, and it is not going to simulate the weight or resistance of a tool or piece of equipment. For that reason, Duthie said, "Training is a blended approach at our two training centers—one in Dubai and one near Houston." Combining classroom with virtual and in-the-field training completes the picture, Duthie explained.

"When you go out into the field, by that point you should be competent and comfortable in your knowledge." Next steps include ongoing observation and assessments. "We have a very thorough examination and assessment techniques before an individual can be deemed competent," Duthie said.

Baker Hughes also uses VR for cross-training. "Someone may be in completions and perhaps they have an opportunity to go into the well construction segments, and being able to demonstrate these scenarios on VR, they get more comfortable," he explained.

Beyond VR applications in dangerous and technical positions, Duthie said, the technology also benefits executives. "We can train our executive leadership with virtual reality headsets and have them in an uncomfortable situation."

VR can place an executive in a simulated face-to-face encounter with a virtual avatar, where they must make decisions in what seems like real time. In this scenario, the avatar is actually a seasoned coach wearing a headset, "but the trainee can't see them. You're immersed in that world," Duthie explained. The coach observes the trainee's reactions during the training session and offers suggestions for alternative responses that could change the tenor of the encounter.

Duthie is adamant that VR training has the advantage over just a computer screen or "Death by PowerPoint." Employees are noticeably more comfortable and competent when VR training is part of the mix, he said.

Current VR technology is limited to larger companies because of its expense, but Duthie is excited about its future. "Plug AR and VR into AI, and the next three years are going to be exciting in terms of the learning technology space, in reducing the likelihood of hazards."

Remote collaboration between onshore and offshore personnel using VR will save trips to distant platforms while solving issues more quickly, he said. "If for any reason a field engineer comes up with a problem, onshore or offshore, they have the ability to use a headset with smart glasses, or even their mobile phone and have the subject matter expert walk them through the task, to see what issues they're facing." E&P

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