Hydraulic Fracturing Techbook

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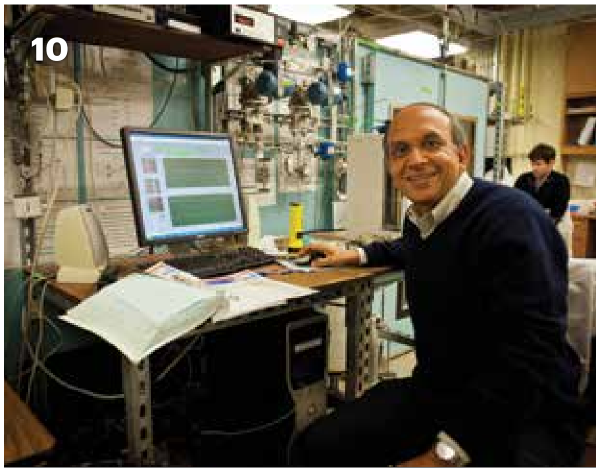
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Equipment Refresh, Retirement Suggest Tight Frac Market

Tier 4 dynamic gas blending and e-frac systems deliver fuel savings to capital discipline-conscious E&Ps.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Hydraulic fracturing companies are pursuing next-gen technologies and approaches like continuous pumping and remote fracturing to drop fuel costs and trim well drilling and completion time frames for their E&P customers.

Pressure on E&P companies for capital discipline, dividends and share buybacks translates into pressure on hydraulic fracturing companies through demand for faster, less-costly operations, Luke Smith, an analyst at Westwood Global Energy Group, told Hart Energy.

"A big driver for pressure pumpers, as far as adoption of technology and efficiency, is really coming from their clients, from the E&Ps, who are under pressure to return value to their shareholders," he said.

The E&P capital discipline narrative will likely be strong for the remainder of the year, and a lot of the efficiencies from the pumping companies will revolve around reducing costs for their clients, especially on the fuel consumption side, he said. Next-generation equipment like Tier 4 dynamic gas blending (DGB) engines and e-fracs can provide significant fuel savings compared to hydraulic fracturing units that run on diesel.

"Next-generation technology is really rolling out on a consistent basis," he said.

Much of this new technology involves replacing existing older-generation crews rather than increasing horsepower capacity. He also expects retirement of horsepower through the NexTier-Patterson UTI merger of near-equals. That combination will turn the resulting company into one of the leading pressure pumpers in terms of capacity, Smith said.

Halliburton has over 2.9 million hydraulic horsepower (hhp) capacity across the U.S. while the newly merged company will have about 2.6 million hhp capacity. He said the retirement of older units in the new company will likely drive up utilization and tighten the market further.

"That puts upward pressure on pricing," Smith said.

The NexTier-Patterson UTI combination raises the question of what might happen to the small hydraulic fracturing companies, especially as E&Ps continue their focus on capital discipline.

"They're not completely left out. There's Tier 4 DGB that they can invest in that doesn't require nearly the investment as an e-frac crew," he said.

"Overall, a lot of the E&Ps tend to like the things that reduce the amount of time."

LUKE SMITH, ANALYST, WESTWOOD GLOBAL ENERGY GROUP

Cannibalized for parts

The retirement of older units is not new. In 2020, Smith said he knew of companies idling half of their fleet with no intention of redeploying those units. Instead, they were cannibalizing them for parts, he said.

That resulted in a drop in horsepower in 2020 and 2021, but the industry has started building up capacity again, he noted. In first-quarter 2022, overall horsepower capacity was 14.3 million hhp. A year later, in first-quarter 2023, that number had grown to 15.2 million hhp capacity. In first-quarter 2024, that number is expected to reach 15.7 million hhp.

With Tier 4 DGB engines and e-frac units filling out fleets, Smith said, another factor for pressure pumpers to consider is being efficient with their time and equipment.

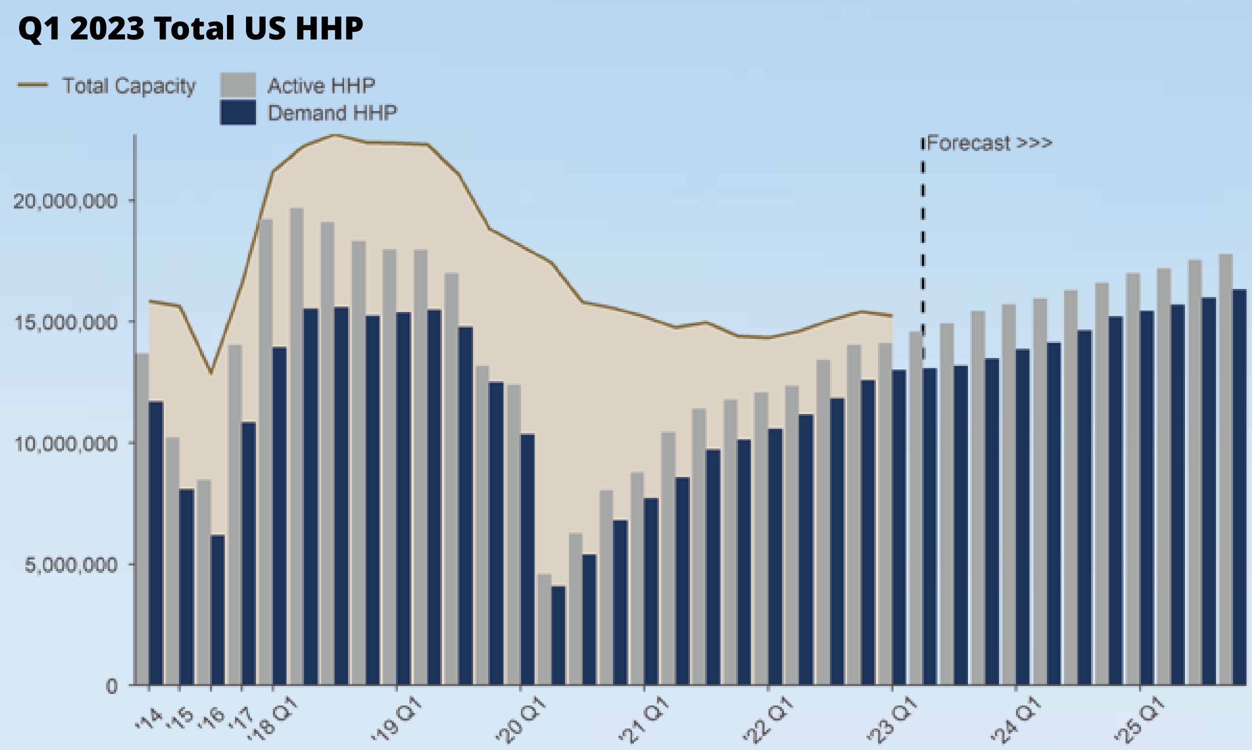
"Overall, a lot of the E&Ps tend to like the things that reduce the amount of time," Smith said. "What we've seen from some of the E&Ps is, they like on the earnings calls to mention how many extra days of production they're getting per quarter."

And as a result, pressure pumpers are doing things like continuous pumping and remote fracking to increase efficiency in operations.

"We're getting reports from E&Ps that they're seeing 24 hours, 36 hours of continuous pumping," he said, noting traditional crews might pump between 19 and 21 hours per day. "That's a big increase in efficiency."

Another efficiency gain in hydraulic fracturing comes from remote fracking, which is happening in the Permian Basin, he said.

"You have a pad corridor, and you can essentially frac



Source: Westwood Global Energy Group

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three of the pads with one crew remaining on a single pad," he said. "That way you do not have to break down the crew and then rig it up two times in order to frac all three pads."

Looking forward, Smith said leading pressure pumpers will need to be ready to meet demands associated with deeper targets.

"[E&Ps are] going after some of the gassier targets in the Permian, and that's in anticipation of LNG export capacity expansions that'll be coming online next year," he said.

Challenges associated with deeper targets may mean more wear on the equipment and the need to pump more proppant, which means larger crews and more hydraulic horsepower, along with access to sand and water infrastructure.

"For the leading edge pressure pumpers, it's about paying attention to those kinds of challenges," he said. ■

Shale Development Enters a New Era

Digitization, electrification and refined chemistry shape the future of hydraulic fracturing.

JUDY MURRAY, CONTRIBUTING EDITOR

Today's unconventional oil and gas developments bear scant resemblance to those of a decade ago, and experts designing new technologies say things will look even more different in the next few years.

That's because the focus of operators has shifted from maximizing production to maximizing shareholder distribution and reducing debt, said Ryan Duman, Wood Mackenzie's director of upstream research.

"That has shifted the focus to technologies that improve efficiency," he told Hart Energy.

Part of the reason stems from operators acquiring step-out acreage and adding to their inventories between 2016 and 2019.

"Now, they need to find the most efficient way to harvest what they already have, and that means doing more with less," Duman said.

For many companies, that has meant exploring ways to leverage automation software and AI to streamline operations.

"Using data captured in real time, 24/7, provides a clearer picture of operations, which leads to better decision-making," Duman said.

Operators are using operational data to fine-tune processes and are applying advanced analytics to real-time data, monitoring the performance of tools and equipment, and decreasing downtime through predictive maintenance.

"The market demand for ESG reporting is another driver that has made operators more bullish for technology like electric equipment, on-site gas turbines to generate electricity, no-bleed pneumatics and lower-emitting kits," he said, noting that reducing the environmental footprint of operations and improving economics are sometimes competing priorities.

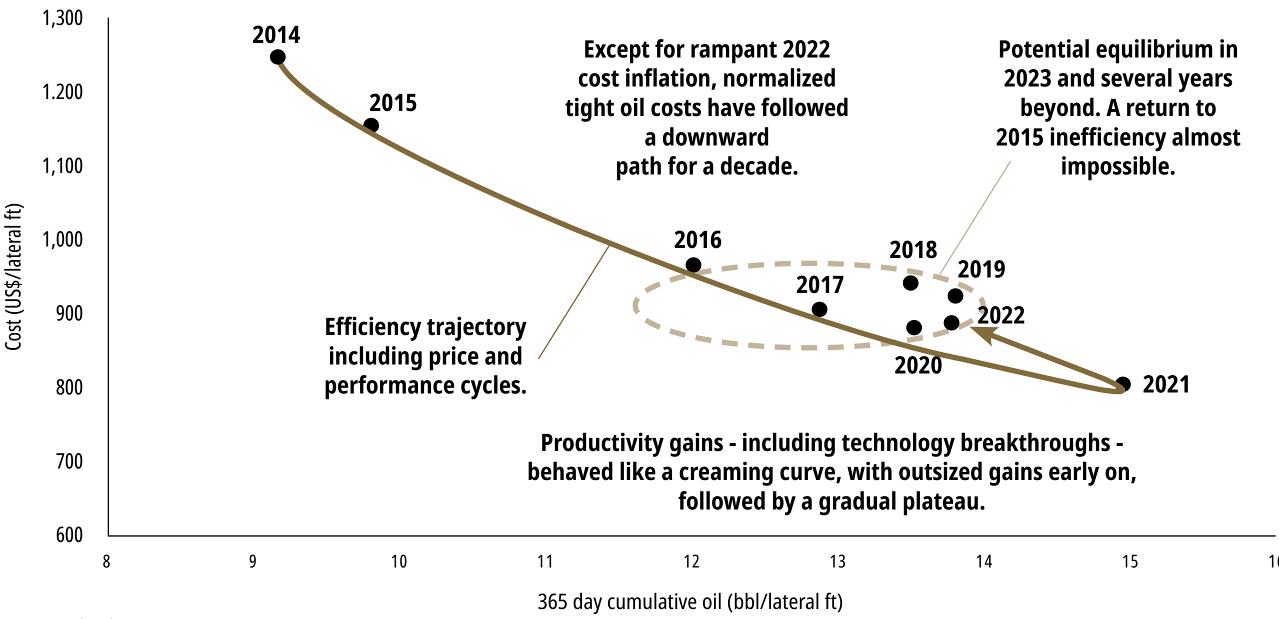
Despite the challenges, Duman said the industry overall has embraced ESG, and companies are making changes that allow them to market themselves attractively to investors.

"They are reducing methane and flaring, and the cost of the technologies that are helping them achieve those goals is more than offset with incremental revenue gains," he said.

Wood Mackenzie will continue to watch refracturing and enhanced oil recovery (EOR) technologies, which Duman believes are ripe for greater innovation.

"Because of the potential benefits associated with 45Q credits, there is going to be a push for CCUS [carbon capture, utilization and sequestration] development as well," he said. "This tends to make sense from a core compe-

Normalized costs versus oil well performance



Source: Wood Mackenzie

tency standpoint because companies can leverage in-house knowledge."

Electrification, alternative fuels and the value of automation

To Sam Sledge, CEO of ProPetro, the most dramatic change in the past couple of years is the transition from diesel to mostly natural gas as a primary fuel source.

"The transition away from diesel has been going on for three years, but right now, there is a massive recapitalization from a hard asset and financial standpoint going on in our space, and it might be one of the biggest changes at the well site," said Sledge, whose hydraulic fracturing company is 100% focused on the Permian Basin.

The primary reason for the transition is pure economics, he said.

"It is much less expensive to burn a molecule of natural gas than a molecule of diesel," Sledge said. That economic inducement is aligned with the environmental objective of lowering emissions. "If we want to talk about environmental sustainability, I think it is strongest when it runs parallel with economic incentives. We live in a free-market, capitalist country, and the goal of a company is to make money, but our goal as citizens and members of a community is to take care of the place where we live."

ProPetro

The Caterpillar engines used by ProPetro in the Permian Basin use dual-fuel engines that reduce emissions by burning diesel and natural gas at the same time.

The result?

"We are pushing harder and faster to the future, especially from an equipment standpoint," Sledge said. "The main part of that story is electrified equipment, which is mechanically simpler with fewer moving parts, allowing it to be operated precisely and accurately."

ProPetro planned to deploy its first electric fleet in early summer 2023, but the company already employs dual-fuel engines—technology pioneered by Caterpillar that enables the engine to burn diesel and natural gas at the same time.

"We think this is a bridge to more electrification," Sledge said. "This is possibly the only application in the world that consumes diesel and gas simultaneously."

Sledge expects many more innovations going forward.

"We are on a continuum, and we don't know where the end of the continuum is. There are so many smart people n the oil and gas sector that I think you're going to see a lot of amazing things happen over the next 10 to 20 years," he said.

Displacing diesel

Leen Weijers, Liberty Energy's vice president of engineering, shares Sledge's sentiments about economics continuing to drive innovation.

"Every company wants to add efficiencies to produce each barrel of oil more economically," said Weijers.

One of the ways Liberty is going about achieving that is by inventing and manufacturing operational equipment such as the Scorpion sand delivery system and the Mantis screwless sand delivery system, which moves sand directly into the blender tub.

"This equipment has enabled us to effectively pump local wet sand, which can be purchased at a lower cost than sand traditionally used for hydraulic fracturing operations," he said.

The company also is developing ways to manage fuel consumption and equipment performance. For example, the company's new digiFrac fleets enable diesel replacement with natural gas or CNG, both of which are much less expensive per energy unit.

"As we roll out digiFrac equipment, we now regularly break daily records for diesel displacement in the basins where we operate," Weijers said.

The company also has made moves to address the vulnerabilities associated with gas-only equipment by taking ownership of the natural gas/CNG delivery system through Liberty Power Innovations (LPI) to provide a reliable source of field gas (through mobile gas processing) or CNG to power its lower-emission solutions.

Underpinning the digiFrac and digiPrime fully electric frac system technology are Rolls-Royce gas reciprocating engines, which, according to Weijers, have the best thermal efficiencies of any engine available.

"Measuring performance in terms of hydraulic horsepower hours (hhp-hr) pumped for 70% daily pump efficiencies, gas reciprocating engines have about 45% lower emissions than Tier 4 diesel and are three times as clean as gas turbines," he said.

It's critical to improve operations incrementally, so Liberty focuses on putting new technologies to work as soon as it is practical.

"We are always looking for ways to cut emissions, reduce our footprint, minimize noise and curtail the number of trips to the work site to be a better neighbor in the areas where we work," Weijers said.

Liberty Energy

Liberty Energy's digiFrac pumps enable precise rate control and produce significantly lower emissions than Tier 4 diesel and gas turbine engines.

Liberty Energy is among the companies that have developed software that uses field data to increase efficiencies and ultimately improve the bottom line. Weijers described his company as "laser focused on reducing the barrel cost of production."

Liberty achieves this, in part, by leveraging its FracTrends database and performing statistical economics analysis using Fraconomics and fit-for-purpose calibrated modeling tools.

"We are helping to focus our industry on cost-effective ways to provide ever larger and denser fracture networks and to evaluate trade-offs, for example, between well density and fracture treatment size," he said.

Results over the last decade demonstrate that the company has helped lower well costs by 50% and enhanced well productivity to reduce the cost per barrel of oil produced by as much as 75%, Weijers said.

Electrifying the wellsite

Innovators at Halliburton are likewise well down the path of deploying electric fracturing equipment. By providing the same horsepower at the wellsite with half as much equipment, these innovations allow a company to reduce its carbon footprint, as well make strides in efficiency and reliability.

"We see about 30% faster transition times, which leads to more pumping hours," William Ruhle, Halliburton's strategic business manager, told Hart Energy. "That gives us 11% more hp-hr pumped per month than diesel, which is about equivalent to completing an extra seven wells per year per crew."

Removing the need for diesel has saved up to $2.5 million per month in diesel costs for zipper crews and reduces emissions by approximately 30%, Ruhle said. While there is a cost for electricity to run the equipment, it is considerably less

Halliburton

Halliburton's Zeus electric fracturing system can achieve up to 5,000 HHP per pumping unit without downtime during stage transitions.

Universal Pressure Pumping

Universal executes a frac job in the Utica shale.

than the cost of diesel.

On a project for Diamondback Energy in the Permian Basin, a Halliburton simul-frac crew achieved exceptional results using the company's Zeus electric fracturing system, which Ruhle said can achieve up to 5,000 hhp per pumping unit without downtime during stage transitions.

"By combining simul-frac operations with electric, Diamondback has realized completions savings of $50 a foot," he said.

Electrification is driving down costs and reducing emissions, but operators need to capture more efficiency gains, and that has led to expanded use of subsurface monitoring and using operational data gathered to optimize recovery.

"Digitization is embedded in everything we do and build; ML (machine learning) and AI aren't discrete solutions, they are embedded in processes and solutions," Ruhle said.

One example is the company's Octiv intelligent fracturing platform, which fully automates the fracturing process from a single system.

"Within that platform, we use technology such as AI and ML to predict equipment failures, identify anomalies, see how operations are running and respond automatically," he said. "Octiv automates up to 90% of the decisions made to control our surface equipment, and that leads to better reliability and consistency."

In North America, the system has completed thousands of stages using full-spread automation, controlling the fracturing process and executing condition-based protections that help prevent downtime across operations.

Capitalizing on data analysis and specialized chemistry

James Segars, director of solutions engineering at Universal Pressure Pumping, said his company is delivering value by analyzing data to optimize perforation efficiency.

"A huge amount of effort has gone into analyzing fracture geometry with regard to perforation design in the past few years," he said, noting that complex analysis goes far beyond simply creating the longest possible fracture. "We are targeting a high degree of recovery within the near-wellbore section to make the most of the wellbore spacing plan. From our standpoint, that is making the output more predictable, and that creates a positive impact on the economics of the program."

The company's solutions engineering team uses data to help operators with predictive analysis.

"We use output from laboratory testing to generate a hydraulics model to estimate pipe friction, which allows us to set expectations for surface treatment conditions. Ultimately, we can solve for the expected hydraulic horsepower hours and can generate a high-level assessment for cost and ESG consideration through fuel savings," he said.

Engineers also compare the predicted pressure to the actual pressure in end-of-stage variance reporting and examine the data to determine when there is a difference, and then share the findings with the operator to evaluate opportunities for improvement.

"We also know proppant delivery on a stage basis is critical to recovery as is controlling the volume of fluid we're injecting. In addition to managing differential pressure, we are looking at the volume of proppant used and identifying stages in which more or less fluid was pumped than expected. Many inefficiencies are rooted in variances between what was designed and what was delivered," Segars said. "Operators spend a lot of time and effort developing the fracture sequence, and they know what works best for their reservoir. Our job is to help them deploy that in a predictable and consistent manner."

Universal also is investing in developing tailored chemistries to help resolve challenges that routinely surface in the field. One of these is increased friction resulting from the use of higher salinity brines in place of fresh water, particularly in parts of New Mexico and Texas.

"Chemical technology is being improved upon daily to allow the use of as much brine as possible and to ensure produced water is reusable," said Joe Pinkhouse, Universal's chemistry domain champion.

Water is a valuable resource and is scarce in some areas where there is widespread drilling. Increasing the amount of fresh water that can be reused cuts down on water usage as well as treatment and disposal costs, he said.

The industry is trying to figure out whether the use of produced water is beneficial to the reservoirs, Pinkhouse said.

"Historically, the view overwhelmingly has been negative, but new research shows that the produced water—as long as it is used appropriately—has the ability to enhance the performance of the reservoir and perhaps eliminate some of the chemical needs."

Making headway with these initiatives depends on changing the perception of chemicals as commodities rather than specialty materials and assuming, for example, that one clay stabilizer is the same as another.

"That's simply not true," he said. "There is a lot of time and energy that goes into developing the chemistries, and we work with operators to ensure they are looking at data and comparing the products in a meaningful way."

Pioneering technology and the art of oilfield economics

Software advances continue to improve field operations and ResFrac, a company that provides computational subsurface modeling, is taking software to the next level.

COO Garrett Fowler explained how the solutions his company has developed address the issues that have arisen from erroneously applying "factory mode" development to oil and gas operations.

"Wells interact. Rock is variable. And there are nuances that differentiate individual wells and locations, so applying a single well design across a range of wells does not produce consistent results," he said.

What is known about the subsurface continues to expand.

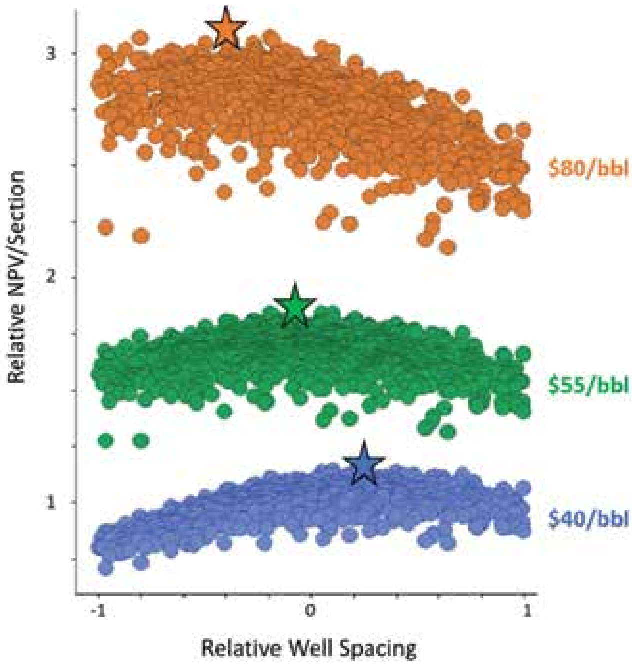
"Diagnostics today give us the ability to see into subsurface an order of magnitude better than 10 years ago," he said. "And applying first principles physics will unlock even better understanding."

Multiple things happen in the subsurface simultaneously, but the traditional methodology for subsurface modeling has been to segment activities and use separate pieces of software to calculate them independently from one another. Fowler said this is why modeling software has struggled to produce a truly cohesive picture of the subsurface.

"It is computationally and mathematically challenging to model all of the variables in one self-consistent, coherent set of equations where everything happens at once, but it is possible," he said.

ResFrac initiates this process with building a "why" model using first principle physics.

"Once we have a model that accurately describes how things are acting in the rock, we apply algorithms that use data analytical techniques," Fowler said. "Optimization algorithms run a variety of hypothetical simulations—moving a well 50 feet deeper, for example, or using twice as much fluid—to determine the best next step in the development process."



Source: ResFrac

Technology is allowing operators to build highly predictive models that enable prescriptive frac design and field planning. This image shows how NPV increases as the oil price goes up and that progressively closer well-spacings with higher commodity pricing delivers optimal NPV.

Fowler contends that this approach makes it possible to see the interaction of oil price and well spacing.

"The ideal distance between the existing wellbore and new wellbore depends on oil price because if you look at an internal rate of return, or net present value analysis, or other financial metrics, the degree of interference you tolerate is tied to the amount of revenue you can expect per barrel of oil," he said.

He believes the future of the industry is in prescriptive design that derives from enhanced understanding of the subsurface, where it is now possible to observe what is happening and explain why.

"The industry is mature enough to layer surface engineering, subsurface engineering and financial engineering to get a clearer picture of what should be done in a given situation," he said.

Building a computation framework for understanding these systems is crucial to establishing a foundation for extrapolating beyond hydrocarbons and examining how resources are extracted generally.

"That could lead to enabling extraction of other resources such as geothermal heat or exploiting the open pore space in the subsurface for carbon sequestration," Fowler said. "It becomes a matter of looking at what resources exist and what expertise we have as an industry to extract those resources." ■

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Extensive Tools for Frac Data Collection and Analysis Fuel Breakthroughs

Frac design, refrac liner testing and a waterless frac gun are among deep diagnostics in the queue.

PAUL WISEMAN, CONTRIBUTING EDITOR

With current shale well fracturing and production procedures stranding the vast majority of the well's oil, industry and academia are focusing extensive efforts to improve the process. Today's array of sensors and other data gathering devices are flooding researchers with rich troves of data that can help them improve frac procedures.

Among those with research advancements are petroleum departments at the University of Texas, Oklahoma State University, Colorado School of Mines and the University of Houston.

Tapered frac design

For the last decade, Mukul Sharma and associates at the Petroleum and Geosystems Engineering department at the University of Texas at Austin have researched the presence and the effects of induced, unpropped fractures in shale wells. In verifying their presence and identifying their causes, the goal has been to make a way to design frac clusters that properly engage the formation to maximize production. Sharma occupies the W.A. "Tex" Moncrief Jr. Centennial Endowed Chair in petroleum engineering at the university.

The result is a software package called Multifrac-3D, which models the process of hydraulic fracturing and flowback. The program tells frac designers how to get uniform fractures to drain more of the reservoir. This modeling has improved production by an estimated 30%-40% over fracs done without it, Sharma said.

As hydraulic fracturing of horizontal shale wells ramped up around 2010, limited knowledge of how frac networks propagated gave producers uneven production results across a field. Sharma showed that fracking didn't just create planar fractures. Often, fractures too small to receive proppant are created.

Sharma's team presented five pieces of evidence to demonstrate that this was happening in a 2015 SPE paper entitled "The Role of Induced, Un-Propped (IU) Fractures in Oil and Gas Wells." The five elements were: micro-seismic data, production history matching, tracer data, pressure communication between wells and calculations on the fate of the injected fracturing fluids.

"We've recently been studying what controls the geometry of the hydraulic fracture network in a naturally fractured reservoir," Sharma told Hart Energy. "The well completion, the number and clusters and the number of perforations in each cluster, as well as the pumping schedule, are things that we can control and have a major impact on the geometry of the fracture network. Of course, the natural fracture network and the heterogeneity in the reservoir have a big influence as well."

They observed that a geometric cluster design, in which all clusters contain the same number of perforations, often creates heel-dominated fractures. This can result in a loss of production from the other fractures. Adding more perforations to the toe, referred to as tapered completions, can provide more uniform proppant and fluid distribution.

Sharma's research provides a quantitative method to design the perforation clusters to provide the most uniform proppant and fluid placement in all clusters. The software has been extensively used in many applications, such as the growth of hydraulic fractures in naturally fractured rocks, geothermal wells and interference between parent-child wells.

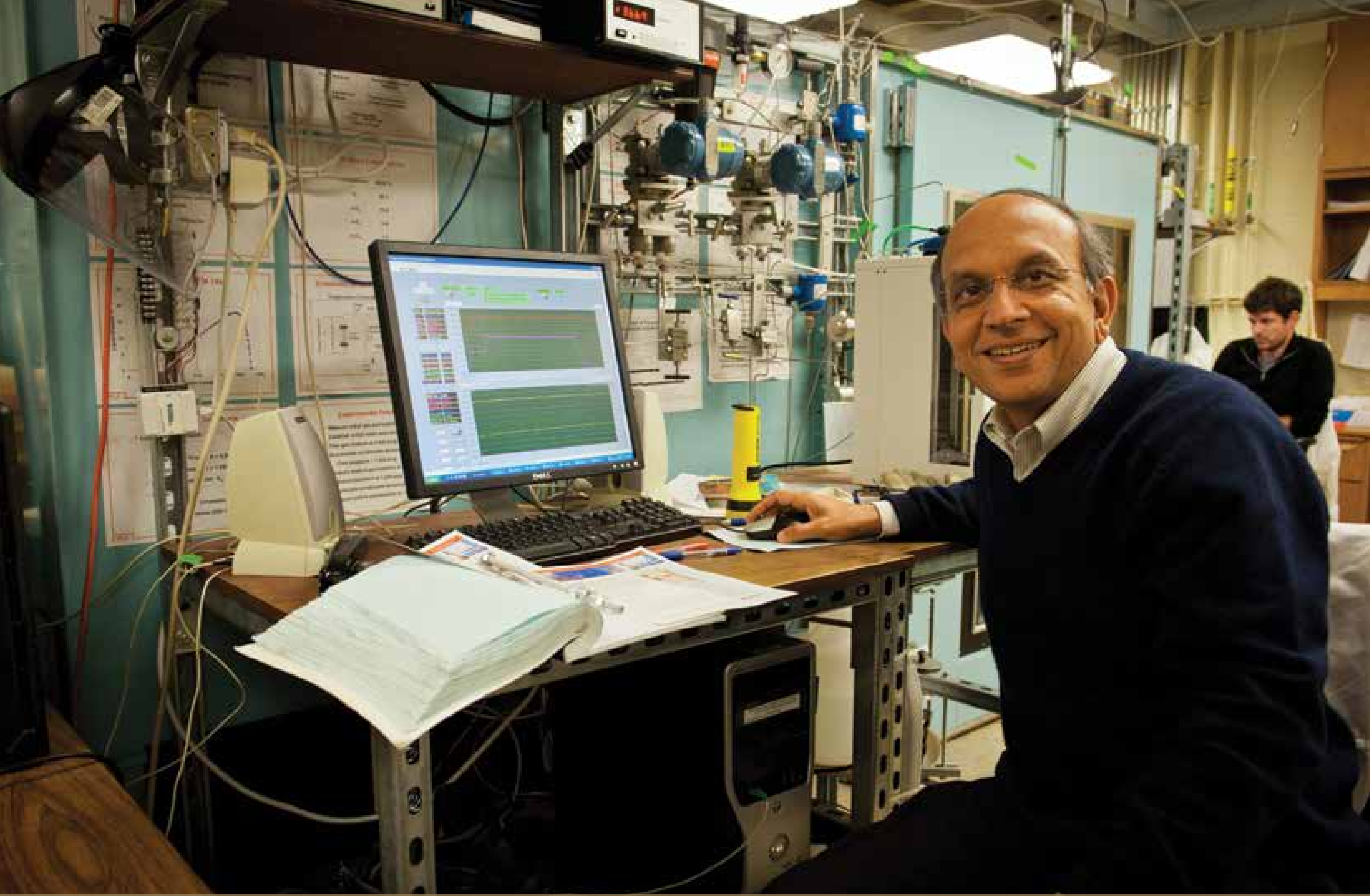
He said this software has been tested in several wells with success and stressed that the team continues to learn from field results to make further updates as needed.

Frac count and spacing optimization

Shale wells are notoriously stingy with their oil. To learn how to release more of that resource, petroleum engineering program professors at Oklahoma State University (OSU) use AI and machine learning (ML) in analyzing surface drilling and core test data to improve frac methods.

Early results show the potential to increase production by up to 50% over existing frac methods.

A U.S. Department of Energy (DOE) grant includes Continental Resources, which is the principal partner in the project; Lawrence Berkeley National Laboratory; the Oklahoma Geological Survey; and the University of Pittsburgh. They are nearing the end of the four-year, $19.9 million DOE project, with cost sharing from Continental Resources, aimed at evaluating shale formations in the Caney Shale, a potential petroleum resource in southwestern Oklahoma.



Mukul Sharma and his Petroleum and Geosystems Engineering team at the University of Texas at Austin have developed software known as Multifrac-3D, which models the process of hydraulic fracturing and flowback.

University of Texas at Austin

Geir Hareland, a professor and Continental Resources Chair in petroleum engineering at OSU, described the work as a field laboratory site.

Geir Hareland

"The objective was to core through this formation and do a variety of core testing and modeling, and to fracture one horizontal well about two miles long," he told Hart Energy.

The OSU frac team also includes Hunjoo Lee, assistant professor in the School of Chemical Engineering; Mohammed Al Dushaishi, Ward Fellow and an assistant professor in the petroleum engineering department; and other researchers.

During the process, they gathered extensive downhole data, analyzing each frac zone for rock hardness, ductility and other geomechanical properties. The research principles were then applied toward analyzing and improving frac designs in a variety of shale formations.

Three types of software were used for data analysis: Calgary, Alberta-based Rocsol Technologies' D-WOB (Downhole Weight on Bit), which uses surface measurements and wellbore friction drag models to calculate the downhole WOB on horizontal intervals; D-ROCK, also from Rocsol, which cost-effectively uses inverted Rate of Penetration (ROP) models and core correlations to create a detailed geomechanical and reservoir property log; and Halliburton's GOHFER frac modeling software.

Unsurprisingly, they learned that maximizing exposure to the producing zone boosted production. But the specific mechanics were less obvious. More fracs, closer together, over longer laterals and concentrating on the hardest and most brittle rock were the keys.

They also made new discoveries on staging parent-child wells, using something Hareland called "wine-racking." Alternating wells geared to produce higher and lower in the formation creates a kind of well cross-section waveform, he said, keeping larger distances between the wells and production from overlapping.

With about 18 months of production data in hand from the Caney horizontal well, the researchers have seen actual production match their pre-simulated model production in the formation.

Refracturing could also benefit from this research, said Hareland, because fracs done 10 years ago had fewer stages, but they were larger and spaced further apart. But shale's low permeability limits its oil's abil-

Colorado School of Mines

One refracturing method involves lining the existing casing before setting off the frac charges. But when the frac is done, the liner must maintain its position so the new fracs in the pipe line up with the fracs in the liner. These sections of old casing show the liner protruding out, at bottom right, from refractured sections ready for testing, in an operation overseen by the Colorado School of Mines.

ity to flow, so fracturing more stages with smaller fracs exposes the well to more production.

Keeping casing liners in place

As producers and investors look for more production, they also look for ways to lower costs and boost cash flow. To make that work, many producers look to refracturing wells that were first fractured in the early days of the shale revolution. Multistage wells are particular targets, as producers hope to reach producing zones that were missed or inadequately stimulated the first time.

One refrac method involves inserting an expandable casing liner into the existing casing. After sliding the liner into place, the installer expands the liner to fit by pulling a tool along its length. The liner's purpose is to keep the new frac from taking the path of least resistance through existing fissures without creating new ones. From there, the producer is starting anew because at that point, it is essentially a brand new well that has not been perforated, said Jennifer Miskimins, F.H. Mick Merelli/Cimarex Energy Distinguished Department Head Chair at the Colorado School of Mines. She is also the founder and current director of the Fracturing, Acidizing, Stimulation Technology (FAST) Consortium.

Jennifer Miskimins

Civitas Resources, an E&P operating in Colorado's Denver-Julesburg Basin, was using this kind of liner made by Mohawk, but wanted to be sure it performed as advertised, Miskimins said.

After installing the liner, the new frac would involve creating half-inch-diameter fracs using "piston-like forces, which could potentially move the liner that's sealed inside the casing," she said. If those forces shifted the liner by a half inch or more, that would cover up the corresponding fracture in the original casing, "destroying your refracking potential."

So Civitas asked the school to conduct as close to a real-world test as possible in order to find out.

At the school's Edgar Mine Testing Facility in Idaho Springs, Colo., the research team prepared both anchored and unanchored patch components in a pipe. One type of each was perforated with a full-size perforating gun, three shots in each section.

According to a paper published by the team, "Both the anchored and unanchored, perforated and unperforated, patch/casing sections were then push/pull-tested to determine friction factors and the impacts of the perforating on the patch/casing interface. These results were then incorporated into finite element method (FEM) modeling to determine the ability of the full-size, field-deployed patch to remain stationary and the impact such would have on perforation alignment during treatment conditions."

FEM modeling is a common method of mathematically solving engineering and math modeling equations.

The push/pull testing involved a lab machine that applied 50,000 psi of pressure to the lining, many times more than the normal frac pressures, Miskimins said.

As a result, "The takeaway was that these liners don't move," she told Hart Energy.

Formation structure analysis

The volume of water used in fracturing has surpassed 1 MMgal/well in tight shales, leading researchers to investigate alternative methods that don't require water. Pulsed power plasma stimulation (PPPS), which is already common for rock removal in mining operations, is gaining interest among academics. Researchers are seeking private funding to expand these efforts into oil and gas, especially in tight reservoirs and shale plays.

Mohamed Y. Soliman

But for the University of Houston's (UH) Mohamed Y. Soliman, a particular subset of the method shows great

At the University of Texas at Austin, researchers in the Petroleum and Geosystems Engineering department are testing how a geometric cluster design, in which all clusters contain the same number of perforations, works in a naturally fractured reservoir.

University of Texas at Austin

potential for analysis as well as for fracturing. As PPPS fractures the rock, it also emits an electromagnetic field in a process called electromagnetic wave propagation (EWP). Soliman, chairman of the Petroleum Engineering Department, was awarded the Society of Petroleum Engineers SPE Legends of Hydraulic Fracturing Award in spring 2023.

He and his UH team believe that tracking the EWP field's behavior as it navigates the rock could much more deeply and accurately analyze the character of the fracture and formation than current methods do. With that in mind, they want to design "a field tool that may be used for waterless stimulation for well format/fracture diagnostics and underground imaging," according to a paper Soliman published with colleagues at sciencedirect.com in November 2022.

Soliman compared PPPS to releasing the power of two double-A batteries all at once into an area of the formation.

"You have two capacitors, each of which stores 10 kilojoules (kj) of electricity. That's a small amount of energy when you release the energy slowly, as in a flashlight," he wrote. "But here, we are discharging those capacitors in 5-6 milliseconds."

By hitting the rock so hard, "It fractures the rock. When you do that, you also create an electromagnetic field that produces a shock wave, or EWP, which propagates through the rock," according to his research.

First step

The first step in testing their hypothesis involved creating a small physical model with which to compare actual results against computer models. If proven sufficiently accurate, the testing could be expanded into a field-scale trial.

Their lab test samples were concrete cylinders 9 inches in diameter and 12 inches long, with a bore tube down the center. Into those samples they discharged the 10 kj current and monitored its results. Soliman said, "We measured the electromagnetic field the shock wave produced, and we matched that experimentally and numerically."

Soliman and his team say their results validated the procedure and justified large-scale field research, for which they are currently seeking funding. They concluded that creating a PPPS-based stimulation tool would indeed be a cost-effective alternative to "current low-accuracy microseismic applications." ■

GoM's Lower Tertiary Drives Proppant Fracking Offshore

Whether the reservoir is a sandstone or carbonate, completing an offshore well is high-stakes and logistics-intensive, but technologies have helped drive down emissions associated with offshore hydraulic fracturing.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Proppants, the sandy heroes of the shale revolution, are rising in demand for offshore wells, particularly in the Gulf of Mexico's (GoM) Lower Tertiary Wilcox Trend.

The Lower Tertiary's reservoirs are sandstone, not the more common offshore carbonate reservoirs that require acid fracturing to maintain permeability. And the play is steadily gaining the attention of offshore operators.

Alexander Pirogov, senior fracturing engineer with Baker Hughes' global production enhancement product line team, said one of the chief trends he's observed is that offshore operators are increasingly starting to produce wells tapping the Lower Tertiary.

"They're going after these tighter, deeper, hotter formations, versus the old, established, maybe slightly shallower, unconsolidated formations they have been going after for decades," Pirogov told Hart Energy. "That means that we are shifting to a more complicated, more complex type of completion."

Because these tend to be larger jobs, he added, the offshore logistics become more complicated. That makes it more important than ever to plan from the perspective of fracturing, not just production.

"Previous wells would be drilled for production predominantly, and maybe have some sort of sand-control process in place," he said. "But now they're planning for a fracturing job targeting these lower permeability type of reservoirs."

That signals a shift to operators pre-planning wells with stimulation in mind, compared to past operations in which they largely only anticipated production, he said.

And they also are keeping in mind the potential for later workovers, he added.

Lower Tertiary formations require more exposure to the reservoirs, said Marty Usie, pressure pumping North America offshore service delivery technical manager at Baker Hughes. The longer fracture length requires more proppant and fluids, he said, but operators have to contend with higher pressure and temperatures in these formations.

"We're going to specialized fluid systems, specifically tailored with additives that address their reservoir needs, including surfactants and potential scale-inhibiting type of products during the completion," Usie said. "We're using high-end proppants, not sand, to maintain the fractures."

In one Lower Tertiary well in the Keathley Canyon area of the Gulf of Mexico, Pirogov said, Baker Hughes's *M/V Blue Tarpon* pumped 4.4 million pounds (MMlb) of KryptoSphere HD 25 proppant into a well to cover five stacked zones. This set a GoM record for the most proppant pumped into a single well.

"It's like a Formula One race. You know, you have that one shot, and you don't want to miss it."

PAUL HOSEIN, DIRECTOR OF STIMULATION AND RESERVOIR PERFORMANCE, SLB

In a second Keathley Canyon area well, the *M/V Blue Tarpon* pumped a GoM record amount of that same proppant—almost 1.1 MMlb—into a single zone of a three-zone well.

Usie said these types of jobs require much more logistics planning, including using multiple vessels to carry all the proppants and supplies.

Completing a multi-zone well in a single trip or multiple trips depends on how much proppant a vessel can carry. For multi-zone wells completed in a single trip, Usie noted, "You don't have the luxury of coming back into the dock."

"Usually, there's alternative supply vessels and in some cases, multiple stimulation vessels required to support the project and having to reload on location."

Fewer trips, fewer emissions

As Paul Hosein, SLB's director of stimulation and reservoir performance, pointed out, offshore is a high-stakes area.

Never have expenditures, carbon impact and emissions profiles mattered more, he said.

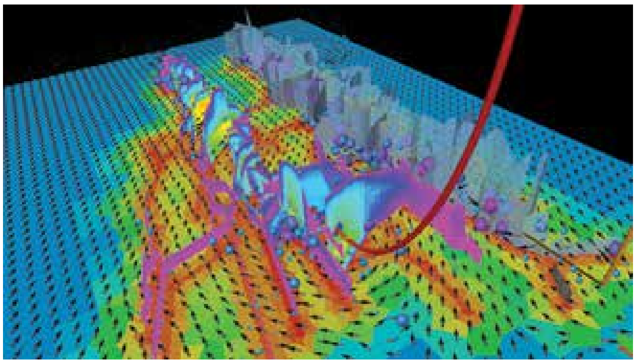
"You need to get it right the first time," he said. "The cost of failure is so high. On top of that, you generally don't want to go back to the well when you're finished."

Because offshore wells are increasingly deeper and more complex, that can mean more complicated completions requiring more materials—along with the right personnel and equipment—at the right time, Hosein said.

"From a fracture design perspective, typically you need

Baker Hughes

Baker Hughes' new Blue Orca stimulation vessel can carry 2.5 million lbm (1,134 tonnes) of sand or equivalent proppant, allowing it to perform multiple fracturing treatments without having to return to port to resupply.



SLB

SLB's Kinetix stimulation-to-production software has workflows that optimize hydraulic fracturing and acidizing in any reservoir and well environment.

to get deep reservoir penetration during fracturing," he said. "In general terms, the longer you get the fracture half-length, the better chances you have with long-term sustained production."

Getting such a fracture right requires a good design up front, he said.

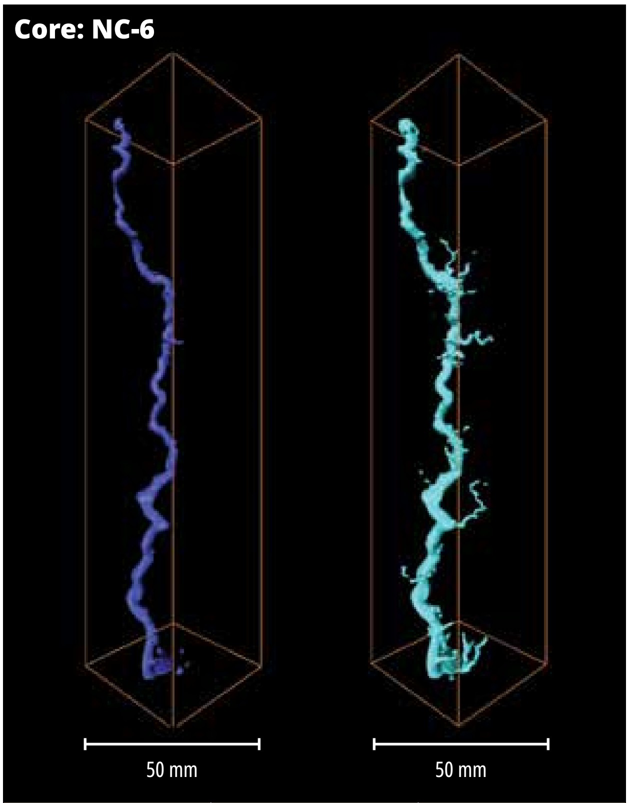
"It's like a Formula 1 race. You know you have that one shot, and you don't want to miss it," Hosein said.

SLB's Kinetix software makes it possible to plan the hydraulic fracture program based on mechanical properties of the reservoir using various fracture models. For acid fracturing, it allows simulation of frac fluids reactivity with the reservoir.

The software helps model offshore hydraulic fractures around the globe, including for some wells targeting a sandstone reservoir West of Shetland.

"By being able to accurately simulate with the reservoir data, the interaction of the fracture with the reservoir, and get it correctly placed, we've actually enabled this operator to change the economics of the whole operation," Hosein said.

SLB was involved from the beginning, he said, and is now helping the operator with the second and third phases of the development.



Fully Dissolved (Vol. %)	Partially Dissolved (Vol. %)	Total Affected Material (Vol. %)
0.98	0.77	1.75

Source: Halliburton

* Volume % calculated from a cropped volume

X-ray processed images of treated cores for plain 15% HCl acid (left) and X-Tend (right, at 15% HCl acid) with flow rate at 1, 3, 5 and 8 mL/minute, showing X-Tend allows deeper penetration of live acid into the formation.

Hosein noted that operators are concentrating on lowering their carbon footprint at every step of the well-construction process.

When working offshore, minimizing the amount of materials needed can minimize the number of vessel trips required to transport the materials, which drops costs and improves the emissions profile.

An offshore frac job may require more than 2,000 bbl of water. These operations typically used fresh water.

"That's hard to do," he said.

SLB's UltraMARINE seawater-base fracturing fluid solves that logistics challenge by making it possible to use seawater, instead of shipping in fresh water.

"You actually can pull seawater on the fly," Hosein said. "You can continuously mix from the ocean and mix it with your proppant."

As a result, operators do not worry about carting freshwater from shore, which burns a lot of fuel and generates a lot of emissions, he said.

"If you can actually use seawater for hydraulic fracturing, it

Source: Hart Energy

really does reduce your emissions impact," he said. "The largest part of the emissions of an offshore fracture job is not the job itself. It's the logistics of moving all the materials."

While proppant fracturing is growing offshore, it is still used less frequently than acid, which is a type of hydraulic fracturing that uses reactive fluids, Hosein said. This is because the types of rock typically stimulated offshore are more frequently carbonates than sandstones.

Opening up carbonates

Julio Vasquez, product manager for Halliburton's production solutions and production enhancement product service lines, said reactive fluids are typically intended for carbonate formations. For carbonates, HCl-based treatments are applied for matrix acidizing and acid fracturing, and reactive fluids eat away at—or etch away—the rock to create larger pathways for hydrocarbons to flow through back to the wellbore.

A little over 18 months ago, Halliburton commercialized X-Tend acid stimulation service, a low-viscosity, delayed-acting acid, for matrix and acid frac of carbonate formations offshore to allow deeper penetration of the live acid into the formation.

"It is very easy to prepare, and we can mix it on the fly or batch mix it," Vasquez said.

Since commercialization, X-Tend has been used on about 100 jobs globally, he said. It is used in carbonate formations up to 350 F, but can be taken to higher temperatures. Using X-Tend, he said, has resulted in oil production increases of between 2,000 bbl/d and 3,000 bbl/d.

World of water

Offshore water handling is particularly challenging, Vasquez said.

"Produced water has to be disposed of or reinjected back into the formation," he said. "You have a lot of restrictions with surface facilities handling water production."

WaterWeb, a technology Halliburton commercialized over a decade ago, selectively reduces permeability to water with minimal impact to hydrocarbon production, which means there is no need for mechanical isolation, he said.

However, while the WaterWeb polymer initially worked well in sandstone formations, it did not perform as well in calcite-rich formations, he said. Following some research and chemistry modification, he said, the product now works in both sandstone and carbonate formations.

In one carbonate application offshore Mexico, the water cut—the ratio of water produced compared to the total volume of liquids produced in a well—was 36%. After Halliburton pumped 370 bbl of WaterWeb into the well, the water cut dropped to 4% while oil production increased by 600 bbl/d, Halliburton said.

In a sandstone application producing from a multi-layered reservoir, water cut was reduced from 80% to 60%, and oil production increased by 300 bbl/d after deployment of WaterWeb.

While produced water is something that needs to be handled, water is needed for some operations. Halliburton's SeaQuest service makes it possible to use seawater instead of freshwater for fracture fluid or frac-packing operations.

"We don't have to go back to the port to get more freshwater," Vasquez said. "We're saving a lot of non-productive time, a lot of CO_2 emissions as well, while providing an optimum frac fluid rheology." ■

Clean the Frac Up

In an effort to boost sustainability, service providers are making conscious choices to use less diesel fuel.

JAXON CAINES, TECHNOLOGY REPORTER

The road to net zero can start at the wellhead, where technological advances are enabling a shift to natural gas for fueling hydraulic fracturing equipment—and cutting CO_2 emissions.

"Today, most frac pumps run on diesel. It's kind of the standard, but has a lot of CO_2 intensity," Kurt Harpold, strategic business manager for Halliburton, told Hart Energy. "So, one of the ways you can mitigate that or try to reduce your emissions is to burn more natural gas. You can burn more natural gas in a dual-fuel application where you're blending natural gas with diesel."

Halliburton has these capabilities with its Tier 4 dual-fuel systems. The system costs more, but offers an emissions profile 35% less than dual-fuel Tier 2 fuel systems. The dual-fuel systems pair easily with the company's Q10 X Fracture Pump, a positive displacement pump that takes low pressure water and creates high pressure water needed to fracture rock, he said.

Another way to reduce emissions is to "burn more natural gas in an electric application where you use natural gas to generate electricity for either turbines or gas [reciprocating] engines," Harpold said.

Halliburton's Zeus electric fracturing system allows pumping at higher rates while also lowering emissions profiles of the wellsite. The power-agnostic Zeus system offers a frac pump with no need for a diesel engine or transmission, allowing it to be more efficient on location, Christopher Atchley, product manager for Halliburton told Hart Energy.

Christopher Atchley

"The difference between what you see in a Zeus pump and what you have with the diesel pump, is that your diesel pump is going to be about 2,000 hydraulic horsepower, where the Zeus pump is 5,000 hydraulic horsepower," he said. "We can actually operate [Zeus] at 5,000 hydraulic horsepower, which we feel gives us an advantage in the market. It's more advanced than what we see with some of our competition."

The Zeus pump comes paired with Halliburton's newly designed large-bore, dual-manifold trailer that can deliver up to 230 bbl/min. Since it does not require diesel for fuel, its footprint is also 34% less than that of conventional frac fleets and is easier to maintain because there is no chance of a leak.

"When you think about what operators really want,

"When you think about what operators really want, the old adage is, 'cheaper, better, faster, pick two,' right? It's hard to have all three. Well, with our electric solution, operators want to lower the cost, they want greater performance and they want lower emissions. And electric is the answer."

KURT HARPOLD, STRATEGIC BUSINESS MANAGER, HALLIBURTON

the old adage is, 'cheaper, better, faster, pick two,' right? It's hard to have all three. Well, with our electric solution, operators want to lower the cost, they want greater performance and they want lower emissions. And electric is the answer," Harpold said.

E is for economics

Another cheaper, better, faster solution for hydraulic fracturing comes from Texas-based Catalyst Energy Services.

"One thing I do say about ESG in general is that it's missing an 'E.' And the first 'E' needs to be economics," Seth Moore, Catalyst Energy Services co-founder, COO and executive vice president, told Hart Energy. "People want an economic solution. They care about ESG, they've told the world that they care about ESG and this industry cares about ESG. But when you make the first 'E' economics and you're talking up to $18 million a year in savings, who wouldn't do that? Why would you not want to have this ESG solution that also produces real value for the system?"

Catalyst Energy Services' VortexPrime is designed to

The VortexPrime is an easily transportable, military-grade, natural gas-powered direct drive turbine

Catalyst Energy Services

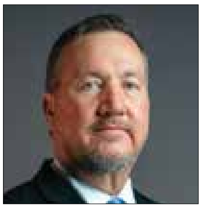
provide both. It is a compact, military-grade, natural gas-powered direct drive turbine. Each unit is easily transportable, self-contained and has its own turbine, drive train and pump. The fleet only requires six to eight pumps as opposed to a traditional frac fleet that might need 20 pumps.

Since VortexPrime requires no outside power source and has its own frac control software, the unit is able to go to location, rig in to the well via a manifold system, rig in water and fluid from the blender, and rig in fuel. From there the team runs a cable to the data van and completes the job.

"We frac by wire, kind of to steal the phrase 'fly by wire' from the air aviation industry," Moore said. "Everything we do is sensor controlled... you're dealing with this pretty impressive mechanical device, but it's all controlled electronically."

The fleet's control system was automated with operators in mind, Moore said. It has safety systems engineered into the technology to ensure that the system will not crash, including "pressure limiters, rate limiters, kick-outs and numerous vibration sensors."

While VortexPrime's invention was spurred by Catalyst Energy Services' desire to shrink some of the technology used for fracking, it also came with the added benefit of reduced emissions. The fleet is in the 95th percentile of waste stream reduction and Moore estimates that there



"One thing I do say about ESG in general is that it's missing an 'E.' And the first 'E' needs to be economics."

SETH MOORE, CO-FOUNDER, COO, AND EXECUTIVE VICE PRESIDENT, CATALYST ENERGY SERVICES

is a 40% reduction in CO_2 emissions when compared to a Tier 4 system. In a recent project, the fleet was able to save 658 metric tonnes of CO_2 emissions.

"If you could look at all the things you would want out of a frac unit or a frac fleet, VortexPrime checks all the boxes," said Moore.

Both Halliburton and Catalyst Energy Services have fully deployed their fracking technologies with the intent of bringing net zero goals within reach.

"I think that we'll continue to see that grow and we're to a point now where it's not just a cartoon in some LinkedIn post," Atchley said. "We're doing this on location every day." ■

Take Your Pick of Proppants

Advances in proppant technology give the hydraulic fracturing space the best of all worlds.

JAXON CAINES, TECHNOLOGY REPORTER

There might not be an industry that utilizes the "more than one way to skin a cat" adage better than oil and gas, especially when it comes to the proppants used to fracture reservoirs.

However, some ways are better—and cheaper—than others. Take the three proppants used in hydraulic fracturing: ceramics, resin-coated and natural sands.

Zigurds Vitols

"Ceramics are very good, but they cost 10 times greater than what we buy our natural sand for," Zigurds Vitols, president and CEO of Select Sands, told Hart Energy. "And when you measure the performance against the cost, we think that we have a more economical product to offer."

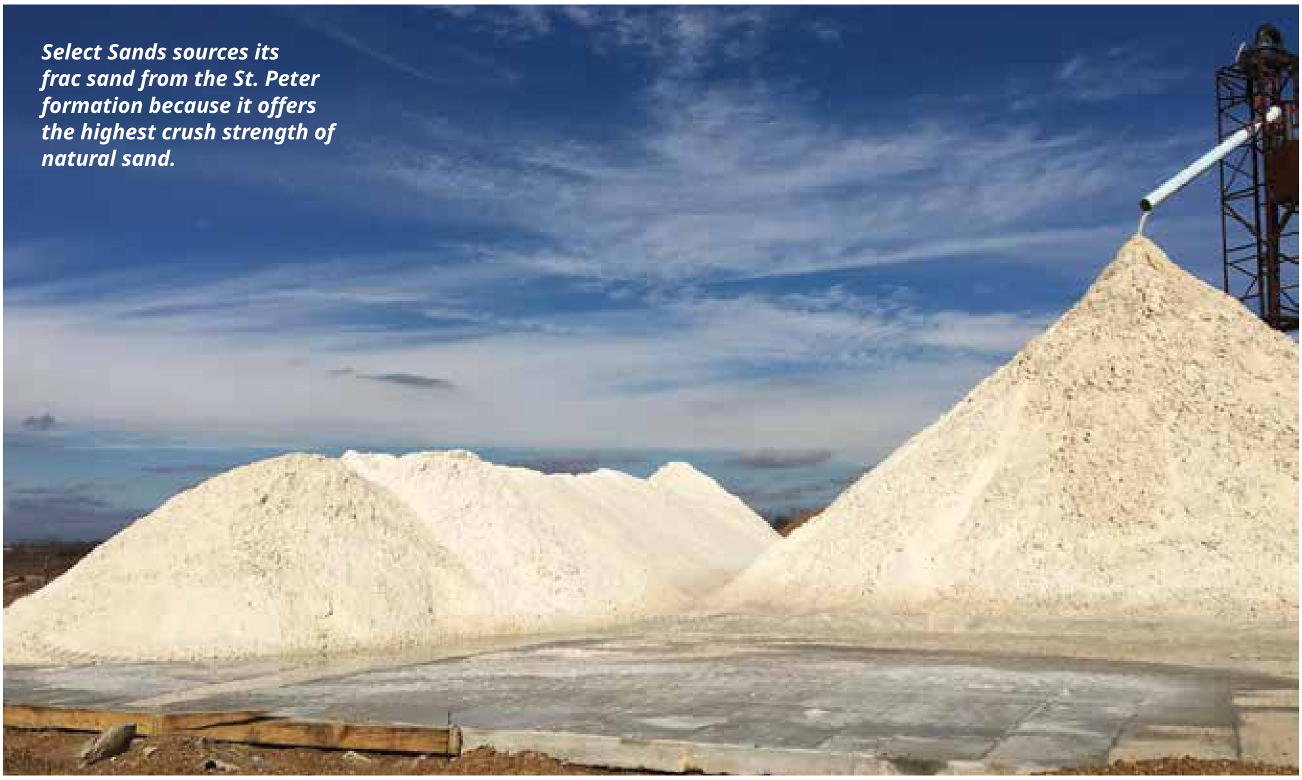
Select Sands is a Texas-based sand provider that mines northern white sand from the St. Peter formation, a sprawling sandstone formation that stretches north to south from Minnesota to Arkansas, and east to west from Illinois to Nebraska and South Dakota. This sand is the highest quality as defined by API and has the "highest crush strength you can get in natural sand," Vitols said. The sand is hard and spherical with little turbidity, making it the right specification to maximize recovery in a well, he said.

Turbidity is a measure of suspended particles, so a lower-turbidity sand is cleaner and has less dirt and silt attached to each particle.

The St. Peter formation is more conducive to fracking jobs in Colorado, Texas and Louisiana than the high turbidity in-basin sands, Vitols said. The in-basin sands are weaker and less spherical, preventing oil from moving easily. But there have been a number of advancements in chemicals and friction reducers that allow oil producers to still use in-basin sands, he said.

Unfortunately, in-basin sands still deteriorate quicker than white sands, which means engineers have to innovate.

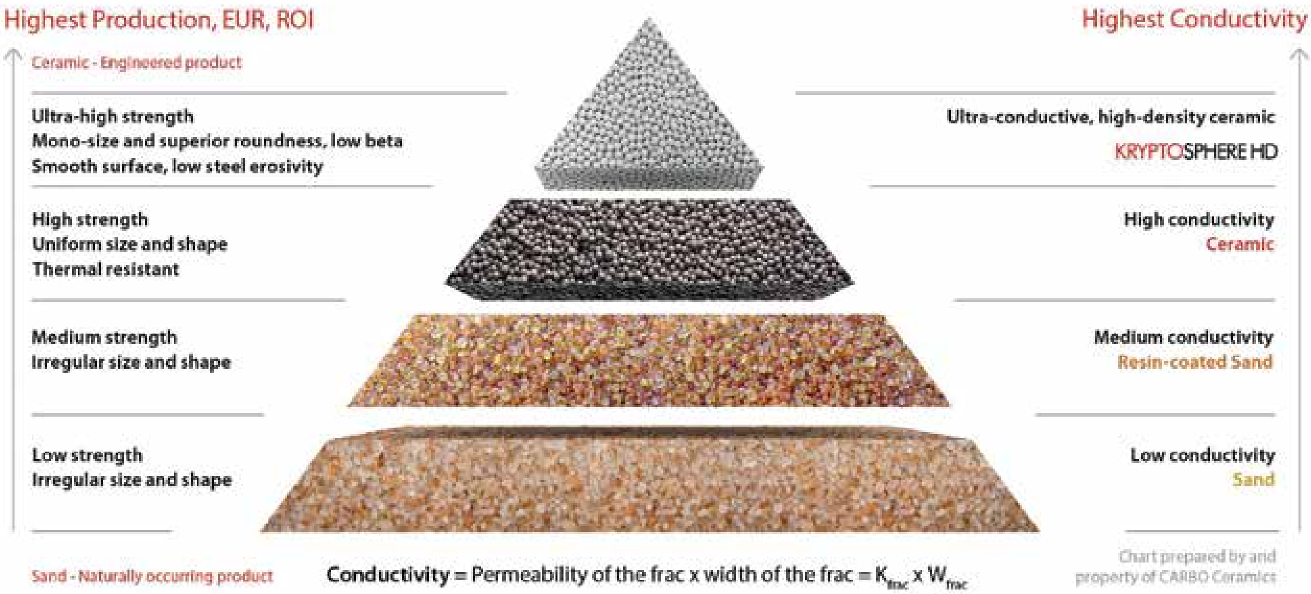
"When [in-basin sands] aren't as successful, the completion engineer will design a frac where some of the frac stages are with the white sand and some of the stages—where it's less critical—use in-basin sand," Vitols said. "So, we're seeing some frac stages being done with our sand and



Select Sands sources its frac sand from the St. Peter formation because it offers the highest crush strength of natural sand.

Shutterstock

Pinnacle of proppant



CARBO Ceramics

some in-basin sand in the same well. We're seeing some wells that exclusively use white sand, and some that don't use any white sand. So, there is a mix, but if you want to get extraction of your petroleum out of the frac, you use white sand."

Decisions, decisions

Decisions around proppant are some of the most important producers make when fracking a well.

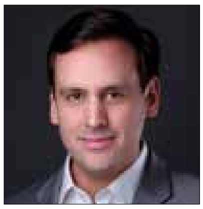
"Your choice in proppant is really what's going to dictate the long-term performance of the well," Josh Leasure, director of sales at CARBO, told Hart Energy. "If you're going to create a long-term well, ceramic proppant is your answer."

CARBO offers a wide variety of ceramic and resin-coated proppants. Among those products is the KRYPTOSPHERE, which Leasure calls "the pinnacle of proppant."

"The manufacturing process is what dictates how good [our] products are," he said. "We pride ourselves on the manufacturing process and how we're able to get rid of the weak points within those proppant grains."

Each proppant under CARBO's KRYPTO umbrella (KRYPTOSPHERE, KRYPTOAIR and others) is ultra-conductive and suitable for high closure stress environments. Each grain is the same shape and size, maximizing the flow of production through the fracs. Each offering from CARBO can also be modified to fit the specific needs of producers. Even the non-KRYPTO options have a higher thermal stability and conductivity than natural sands being used.

"We're not only providing the strength and the particle distribution the industry usually wants from the proppants. We add value to each grain and that value can be tailored to the issues or problems [operators] have," Max Nikolaev, senior vice president of sales at CARBO told Hart Energy. "So, if you are running the assets that have scale issues, we can address that. If you need tracers, we can address that. If you have issues with the flowback, we can address that and many, many, many other problems."



"If you're going to create a long-term well, ceramic proppant is your answer."

JOSH LEASURE, DIRECTOR OF SALES, CARBO

Ceramic proppants, such as the products CARBO creates, are mainly used for offshore fracking due to their expensive, yet highly effective nature. Because the volume of proppants is limited by how much will fit on a ship, producers want to get the most bang for their buck, said Brett Wilson, R&D manager at CARBO.

While natural frac sand is slightly less effective in its ability to maximize the flow of production from a fracked well, it is widely used onshore, as it is typically much easier to acquire than most ceramics. Natural sands are also cheaper than ceramics, allowing for more sand to be used when fracking a well. ■

Innovations Continue to Push the Limits of Efficiency

Next-generation fleets are poised to take center stage.

JUSTIN MAYORGA, RYSTAD ENERGY

Now well into the second half of 2023, the importance of hydraulic fracturing completion efficiencies remains the focal point for many service companies and operators, as both continue to be impacted by higher associated costs brought on by inflationary and activity-driven effects in 2022.

Against this backdrop, with many basins in the U.S. Lower 48 reaching maturity, some operators lacking premium acreage are now striving to enhance their strategies to overcome observed production degradation. Engineers in the U.S. shale industry have been motivated to explore operational improvements as a result of being confronted with both issues in a low commodity price environment. By doing so, operators are constantly pushing boundaries higher as lateral lengths and frac intensities continue to increase.

But it doesn't stop there—operators are now finding new means of further lowering their proppant and fuel cost with the adoption of next-generation fleets that are high in demand. We'll discuss these topics in depth while providing basin level examples.

Despite growing calls for energy transition, Rystad Energy firmly believes that U.S. shale production remains a crucial player in meeting global demand for hydrocarbons.

We'll first investigate completion efficiencies and analyze improvements brought on by the first half of 2023. As service pricing continues to be elevated, frac efficiencies remain a key method to offset some of these increases.

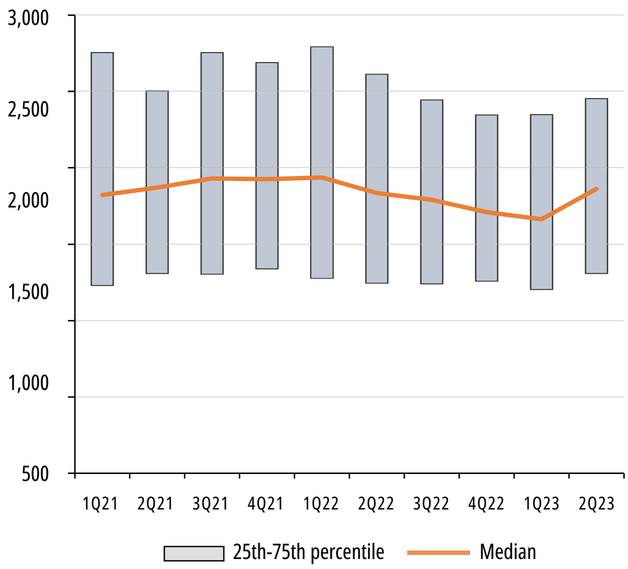
From an aggregated standpoint, stimulated lateral feet per day have decreased since first-quarter 2022 after hitting a high in fourth-quarter 2021. This seems counterintuitive to the story of increasing efficiencies, and this is why it's important to analyze other associated metrics to paint the full picture.

Lateral feet per day have been trending down; however, proppant pumped per day has continued to increase since first-quarter 2022. This essentially means that, despite completing wells at a slightly slower pace, operators have been able to displace larger amounts of proppant, which has resulted in an increase of 9% in proppant pumped per day compared to the prior year. Trends like this are observed in nearly every basin, where the Delaware Basin and Eagle Ford lead all others as proppant intensities continue to trend up despite being somewhat static for several quarters.

Because of this, the U.S. average proppant per well has continued to tick up as lateral lengths extend in various regions.

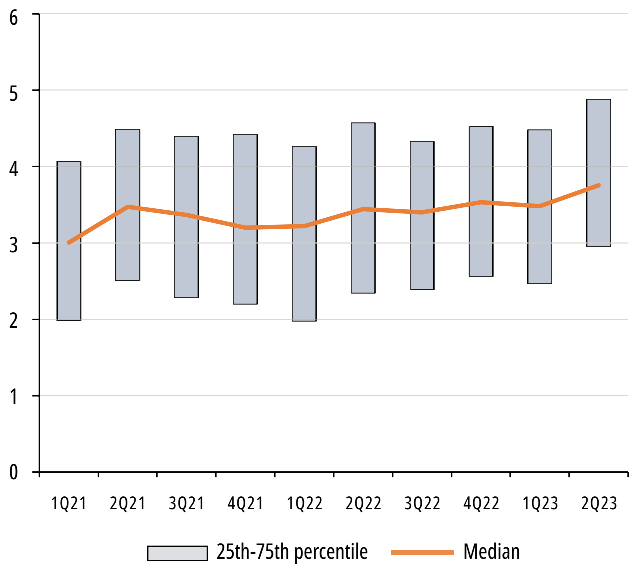
U.S. land hydraulic fracturing completion speed

Lateral feet stimulated per day

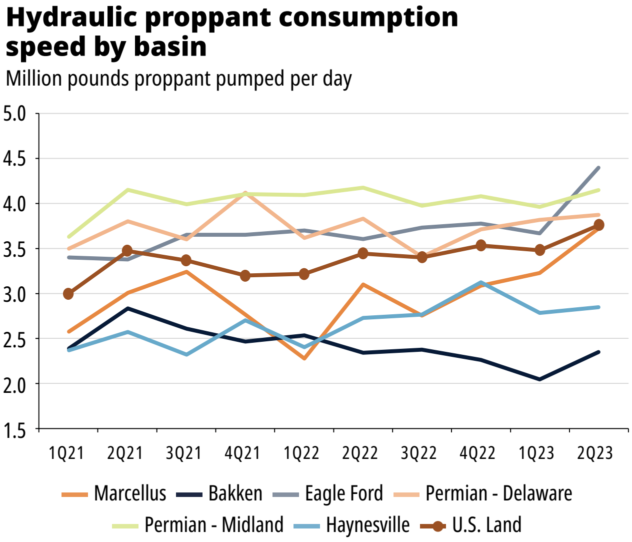


U.S. land hydraulic proppant consumption speed

Million pounds proppant pumped per day



All Charts Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis



For example, the average proppant mass per well within the Midland Basin has increased close to 24 million pounds per well, which was as low as 22 million pounds a year prior.

A handful of factors have allowed these types of gains, including, but not limited to, the reduction in time between well swaps, better maintenance programs and newer equipment. However, the main factor remains the adoption of simul-frac (also known as a double barrel and super zippers) activity. Many operators have been able to achieve superior metrics with this type of completion style.

Simul-frac refers to stimulating multiple wells at once with a single frac spread. For example, if you have a four-well pad, instead of fracturing one well while the wireline is perforating another, simul-fracturing will stimulate two wells while two wireline crews perforate another two. Some operators have taken this a step further and are now attempting to stimulate three wells at once, pushing the boundaries for completion speeds.

To date, Rystad Energy's data is suggesting 2023 simul-fracturing has led to an increase of approximately 84% compared to traditional zipper fracturing operations. It comes as no surprise that the Permian Basin is the key region where simul-fracturing operation adoption is the largest; however, operators in other basins have also engaged in this activity in 2023, including in the Eagle Ford and Denver-Julesburg Basin. It is important to note that this technique will not work for all. The primary users of logistical support and execution for large-scale projects are predominantly the larger public operators. To date, Rystad Energy estimates the adoption of simul-frac remains around 11% of all wells stimulated in second-quarter 2023.

It's becoming rather evident which operators are performing these types of operations when analyzing the top peer group within each basin. For example, taking the leading peer group based on the number of wells completed in 2023 within the Midland Basin, it's quite obvious that Pioneer Natural Resources and Ovintiv lead the pack; both are heavily engaged in these types of operations. These two operators have pushed over 6 million pounds or 3,000 short tons of proppant per day.

Among the peer group, consisting of both public majors and private operators, none have reached a daily production level of 5 million pounds or 2,500 short tons of proppant. At this rate, both Ovintiv and Pioneer, due to their heavy simul-frac activity, are seeing at least a 20% uplift compared to others within the peer group.

The Delaware Basin yields similar results with the top operators who heavily conduct these types of operations, such as EOG Resources and Occidental Petroleum, who remain the leaders in these metrics. This is important again because it comes down to cost and increasing the rate of return per well. During this period of high service pricing, despite premiums for additional horsepower for these types of operations, there's a notable amount of cost savings, depending on the contract agreed upon.

Simul-frac, however, is not the only indicator of how efficiencies have been increasing as traditional zipper frac operations continue to improve. This is tied to fleet size. Pressure pumpers continue to iterate that fleet size is increasing year over year, which is true to some extent. With extra pumps at hand, not only can faster rates be achieved, but redundancy for pump maintenance can also be increased.

This trend has not gone unnoticed by Rystad Energy's satellite detection, which has observed a slow increase in signal intensity. Since the pad coordinates are known, using satellites to detect hydraulic fracturing activity allows for accurate near real-time indications of when a crew arrives on location, thus eliminating reporting lag associated with frac focus filings.

Rystad Energy currently views the average fleet size to be around 55,000-60,000 hydraulic horsepower (hhp), depending on the location and the customer needs. Of course, this varies from basin to basin and the type of completion.

When it comes to technology, equipment continues to be the main advancement on the hydraulic fracturing front. Next-generation equipment or natural gas-capable fleets provide a strong value proposition as fuel displacement remains one of the most effective methods of well cost savings. In terms of emissions, these fleets have a positive impact as they use a cleaner fuel source.

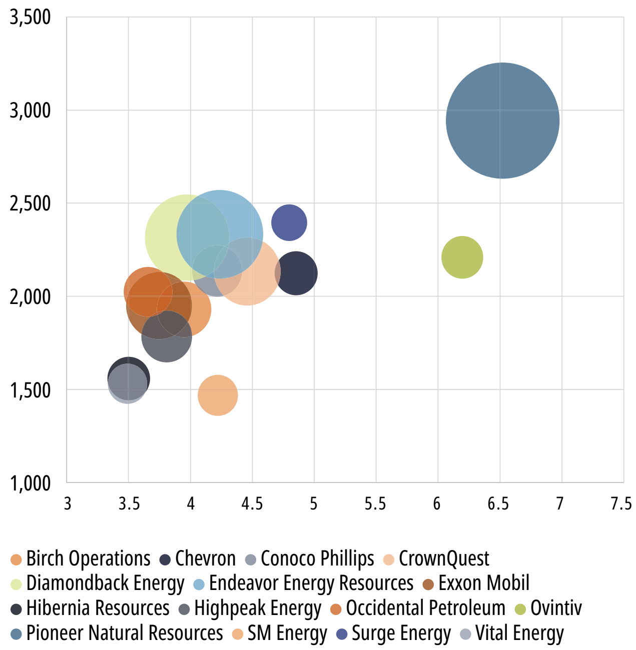
This leads to a reduction in their overall emission profile compared to conventional diesel fleets, provided they are optimized. The adoption of electric fleets remains high, with companies like Evolution Well Services leading the way alongside established oil field giants like Halliburton and ProFrac.

This trend is particularly evident as pure electric providers continue to show confidence in the sector. These electric pumps provide a cleaner method of performing stimulation operations and leave a smaller footprint due to the increased hhp associated with these pumps. A standard electric configuration holds approximately 5,000-7,000 hhp compared to 2,500 hhp on a legacy diesel pump.

Electric pumps boast more horsepower than legacy diesel equipment, but they also have the ability to burn field gas, eliminating the need for CNG, further reducing fuel cost for

Midland operator peer group efficiency metrics*

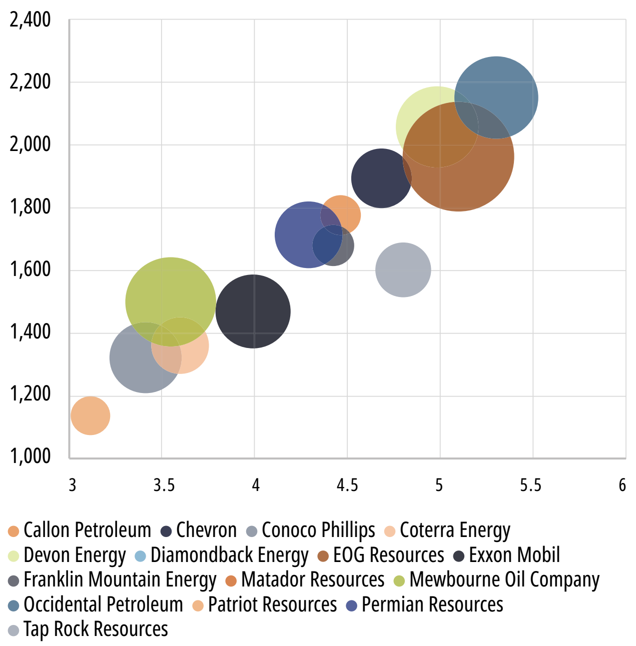
Feet per day (Y-axis) versus million pounds of proppant pumped per day (X-axis)



*Bubble size indicate number of wells and including only wells from January 2022 to YTD.

Delaware operator peer group efficiency metrics*

Feet per day (Y-axis) versus million pounds of proppant pumped per day (X-axis)



*Bubble size indicate number of wells and including only wells from January 2022 to YTD.

the end user. There are still various configurations on the electric power generation side, with some pressure pumpers opting for an agnostic approach. This typically involves a large modular turbine (34 MW) or natural gas reciprocal generator (genset); gensets are becoming more popular due to their reliability and ease of maintenance.

Other solutions have also been developed, including 100% natural gas fleet types that will be rolled out through 2023. Once such example is Liberty's DigiPrime fleet. While this remains in the early phases of deployment, the configuration eliminates the need for an offset power generation solution. It does this by having a natural gas engine mounted directly on the pump, packaging an all-in-one solution.

Rystad Energy currently refers to this type of pump as a mechanical direct drive. If this is successful, this could be a major disruptor in the next-generation fleet sector as it reduces the overall cost by eliminating offset power generation, which is a heavy barrier to entry for many. For example, a larger modular turbine could cost more thanthan $20 million per unit, while gensets could be as high as $10 million. BJ Energy Solutions has had its version of turbine direct drive units for some time now, which have been successful in harsh pumping environments such as the Haynesville.

While the U.S. shale patch continues to be dominated by diesel fleets, this is likely to shift toward natural gas fleets in the near future. Not only are newbuilds continuing to roll out the 100% natural gas side, but Tier 4 dynamic gas blending (DGB) or dual-fuel (DF) upgrades remain at a strong pace, with Caterpillar as a leader in the conversion sector. These types of pump configurations can achieve up to 85% diesel displacement if optimized. Several reports suggest that the accuracy rate in field conditions is around 60%.

Nonetheless, Caterpillar is continuously working on developing updates to enhance its performance. Because of the lower capital cost to upgrade, nearly every premier pressure pumper has now upgraded or has plans to upgrade legacy diesel fleets to be DGB or DF capable, with players such as NexTier leading others in this type of adoption. Due to both fleet types, Rystad Energy continues to estimate that natural gas fleets will soon take the market share by the end of 2023.

In the U.S. shale space, companies are still prioritizing cost reduction and speed when it comes to materials used for stimulations through 2023. While there hasn't been much change in this regard, the adoption of wet sand is becoming increasingly popular, particularly within the Permian Basin.

It's worth noting that even minimal conductivity is better than no conductivity at all. Because of this, operators are now sourcing proppant near their pads by constructing mobile mini-mines, which have been adopted throughout the Permian and Eagle Ford, led by Hi-Crush. Again, it is important to note that these are wet sand mines, or rather damp sand since the water content remains at approximately 5%.

The U.S. shale industry has continued to prove that it is willing to adapt quickly and do what is needed to improve its overall operations. Every year, we observe more and more innovations as the industry continues to shift and evolve, whether due to inflationary effects or the push toward ESG. As the industry continues to evolve, Rystad Energy will continue to monitor and benchmark as the fight for the top position continues to be an ongoing competition between operators and service companies alike. ■

Remote Completions Could Be Wave of the Future

Technology, trust and a track record could vault completions activities into remote workflows.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Are remote operations the future of hydraulic fracturing?

Operations like drilling wells and piloting ROVs can be done remotely, which suggests that completion activities could be, as well. The technology exists—or is close to ready—but it takes some trust, as well.

"I think a really big deal in the industry coming up is going to be these remote operating centers," ShearFRAC COO Tom Johnston told Hart Energy.

A geosteering expert can remotely monitor or operate multiple simultaneous well-drilling operations while directional drillers can also handle multiple wells, said Johnston, who has a geosteering background. It would just take a few people present on the drill site to keep an eye on things and handle maintenance of equipment.

"Then you go to the completion squad, and they're all just sitting out there, still doing it [in person]. That doesn't need to be," he said. "If we can do drilling remotely, we can do completing remotely, no problem at all."

On-site and off-site

One of the technologies necessary for remote operations—whether for drilling or completions—is automation. And AI is increasingly playing a role in automation.

ShearFRAC's FracBRAIN completions visualization platform takes pressure, proppant concentration, fluid and chemical rate measurements to calculate the simulated fracture surface area. Changes to rate and proppant change the fracture intensity and number of fractures in the reservoir, which influence completion effectiveness.

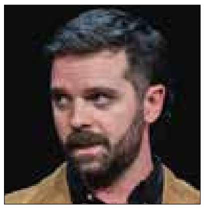
Johnston said FracBRAIN can help completions teams mitigate problems such as screening out, or restricted flow, as well as make incremental improvements on subsequent completions. FracBRAIN uses AI to accomplish this.

For an initial well on the pad, ShearFRAC's team will make sure the relevant data from FracBRAIN is available to experts in an on-site data van (which can currently handle an average of four wells at a time), as well as to off-site experts.

"We stay there three, four, five days for the initial pad and a couple of days for every pad beyond that," Johnston said.

That helps train the on-site team "to make sure they understand what they're looking at, what they need from us," he added.

ShearFRAC



"I think it's really powerful for us to be able to sit back and track those wells from somewhere else. It's much more efficient."

TOM JOHNSTON, COO, SHEARFRAC

Beyond that, "there's the feedback loop, and then it's all remote," he said.

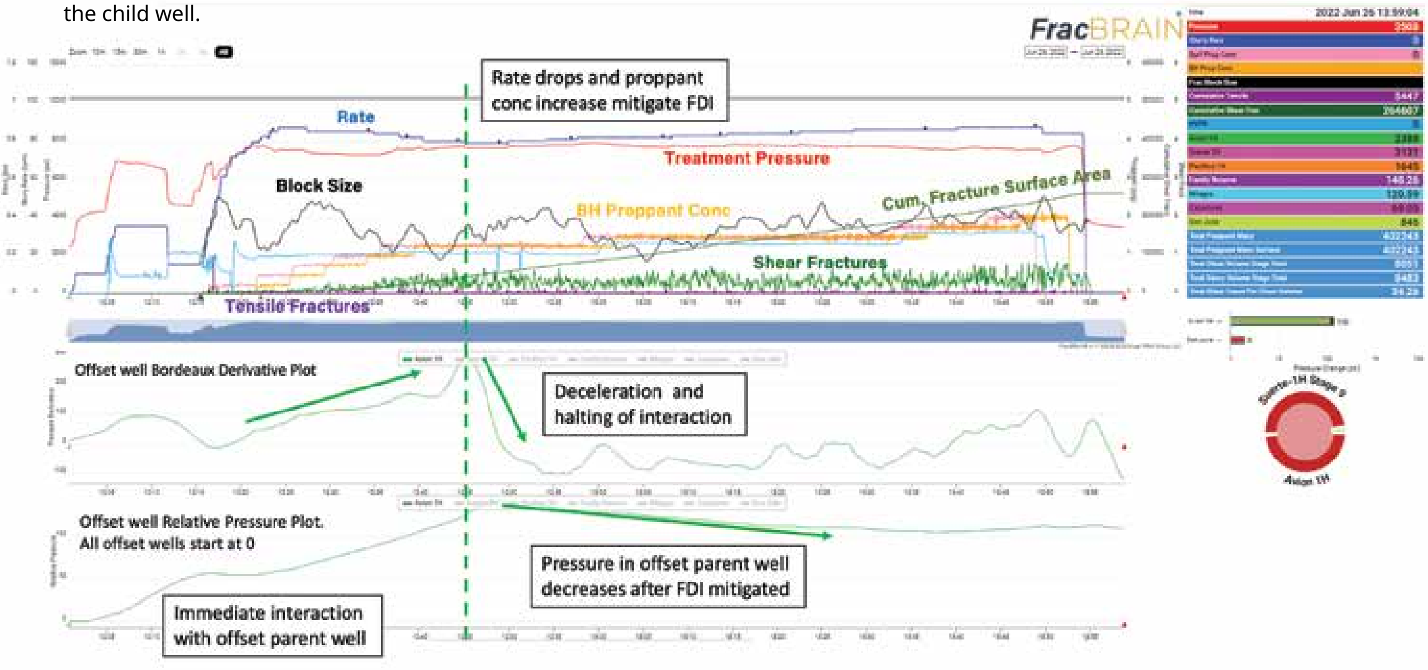
In Canadian completion applications, pump operators have access to the platform on site and consultants use it to work remotely with the pump operators, Johnston said. The approach creates "more efficiency per person so they can work several databases," he added.

Frac information is transmitted to the cloud, sometimes by Starlink, the broadband Internet linked by satellites operated by SpaceX.

"We need the internet. That's the computing power piece," he said. "Not only are we able to work on location with the people there, but because the display piece of our system is super lightweight, it'll grab the data from there, shoot it to the cloud, AWS [Amazon Web Services] will calculate everything, shoot it back to our website"

FracBRAIN and frac-driven interactions

Frac-driven interactions (FDIs) continue to occur instantly; however we learn to change rate and proppant concentration to plug up runaway fracture and continue stimulating rock near the child well.



Source: ShearFRAC

with about three seconds of delay. "That allows you to sit here and track and you're only three seconds behind what's going on location in those Texas wells. It's pretty awesome."

'Grow the grass'

Johnston said the company has calibrated measurements—which he said look like green grass on the FracBRAIN interface—using tracer data, microseismic and fiber optics with production data.

"If you're able to grow the grass higher, your wells are better," he said. "We've got a lot of evidence showing that the measurement is real, super non-invasive, super cheap. And then we get the production data at the end, as well. We're proving that whatever is happening here is correlating to production opportunity."

And while monitoring fracking operations, Sheari—FracBRAIN's AI assistant is a riff on Apple's AI assistant Siri—can recommend changes based on data in the pressure pattern, Johnston said.

But in the future, that could be automated. For example, Sheari's recommendation to increase the rate by 1 bbl/minute pings in the data van and a local expert checks operating values and figures out where that extra 1 bbl/minute will come from.

"There's no reason why it should have to go from a computer to him, from him to the screen to change it. Those pumps are already really smart," he said. "So, rather than the pump operator having to do it nowadays, they can just say one barrel and it will automatically balance them."

Trust issues

That kind of automation is possible, Johnston said. But the track record and trust aren't there yet.

"We need a little bit more experience" to ensure there are no safety issues, he said.

With automation, the consultant doesn't have to worry about risk mitigation and administration details. Instead, Johnston said, the consultant could focus on "just making that well as good as it could possibly be."

And that capability is close, he said. Some code has to be written, but that's the easy part, he added. The harder part is trust.

"It's the same conversation we're having around Tesla and automatic driving, right?" he asked. The hesitation relates to when things go wrong. "What happens, that one incident where that car is automatically driving, and someone's sleeping behind the wheel and runs over a dog. Whose fault is it? Tesla's fault? Is it the driver's fault? The dog's fault? That's the problem."

And Johnston believes the future with remote completions is close.

"I think it's really powerful for us to be able to sit back and track those wells from somewhere else. It's much more efficient," he said. "We're in conversations with the biggest company on how to make that work." ■

Encore of the Oil Patch

Underutilized to this point, refracking wells has proved itself effective in boosting oil recovery.

JAXON CAINES, TECHNOLOGY REPORTER

The goal of the oil and gas industry is to extract oil from the ground, transport and store it, and distribute it to the masses for consumption. This has been the status quo since the 1800s, yet it appears that many companies are leaving too much oil in the ground, and in turn money, on the table.

"We see a big discrepancy between the potential for refracs, with 36,000 wide coastal spacing candidates in the U.S. right now, and yet there's only a handful of refracs," Bob Barba, partner at Triple R Energy Partners, said during Hart Energy's Super DUG event. "Out of the 100 operators in Eagle Ford, 90% have not done refracs. And out of all the operators in the Permian, about 0%, as far as we can tell, have done it."

Despite the reluctance of many in the industry, Barba views refracs as the "real deal," specifically in the Eagle Ford play. And while companies might shy away from refracking basins as a result of operating in chalk or more brittle rock, that doesn't need to be a worry.

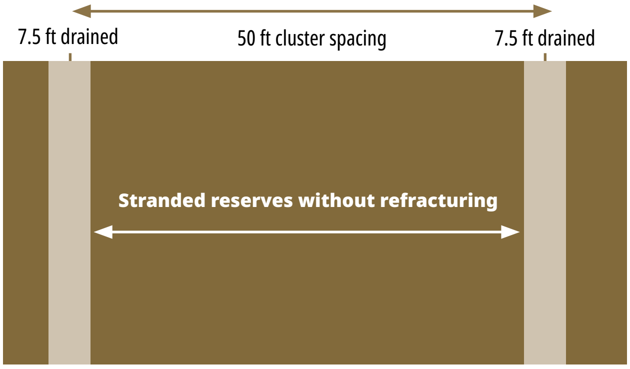
"As far as what I've seen, there hasn't been any reservoirs that haven't responded to [refracking]," said James Segars, vice president for solutions engineering at Universal Pressure Pumping. Segars has experience operating refracs in both shale and chalk basins, such as the Niobrara. He continued, "Obviously, some of them respond differently to the intensity of the fracture… but I would say at least from the overarching scenario, most [basins] should respond favorably."

However, just because most basins should respond favorably doesn't mean all of them will. And there are other concerns as well, including cost. Development costs are typically lower on newly drilled areas than they are on refracked reservoirs, Mark Pearson, president and CEO of Liberty Resources, told the audience.

"Go back three years ago, we were pretty happy if we're pumping 12 hours a day. Now we've got to be pumping 20 hours a day to really set benchmarks. Those efficiencies have really decreased the overall development cost of the place that we're currently in. I guess from my mind, it's kind of the balance between deployed capital," he said. "Do you go for the [somewhat] sure thing with the new D&C or do you look at the refrac opportunity?"

But despite his wariness around refracking, Pearson admits that it will likely soon become the norm. "I think as drilling inventory depletes, refrac is ultimately going to have to be where we go," he said.

Organic shale stranded reserves



Source: Bob Barba

Refracking aims to extract reserves left behind following traditional fracking operations and production.

One way to mitigate some of the concerns around refracking, Barba said, is to adopt a process called "protective refracking," which restores pore pressure in the parent well.

"There's huge potential for refraction and you'll see [refracs] work really well," Barba said. "We've got enough wells to know they work, and yet they're the most underutilized technology.

"Basically, it's a normal refrac, but what it does is restore the original core pressure in the parent well and gives you enough stress cage. That's why you want to do it at the same time, you don't want to do it a month before. You want to have that pressure there in real time so you've got that wall."

According to Barba, the biggest problem with unprotected child wells is the size of their depletion zones. Depletion zones are typically around 350 feet wide, but fracs can reach 1,000 feet. Walls in basins like the Eagle Ford are only three or four feet apart and "as soon as it sees that depleted zone, it's going to stop growing on the distal side" which is where the lost reserves are, Barba said.

To boost the perception of refracking throughout the industry, perhaps it just needs a rebrand. Pearson believes the term "recomplete" is more fitting of the newer, more refined process of recompleting a well, as opposed to the refracking of yesteryear, where oil and gas companies would "bullhead into the well using a chemical diverter and hope it was going to work."

Regardless, refracking has huge capability to change the energy industry, the more it's adopted. ■