HARTENERGY

Hydraulic Fracturing Techbook

2021

A supplement to

E&P Oil and Gas Investor

E&P Oil and Gas Investor

Hydraulic Fracturing
The 2021 Techbook

A supplement to E&P and Oil and Gas Investor

Hart Energy's Techbook Series

The 2021 Hydraulic Fracturing Techbook is the 21st in a series of techbooks in which Hart Energy provides comprehensive coverage of effective and emerging technologies in the oil and gas industry. Each techbook includes a market overview, a sample of key technology providers, case studies of field applications and exclusive analysis of industry trends relative to specific technologies. To learn more about E&P technology trends, visit HartEnergy.com/EP.

Celebrating the 10th Anniversary of the Hydraulic Fracturing Techbook!

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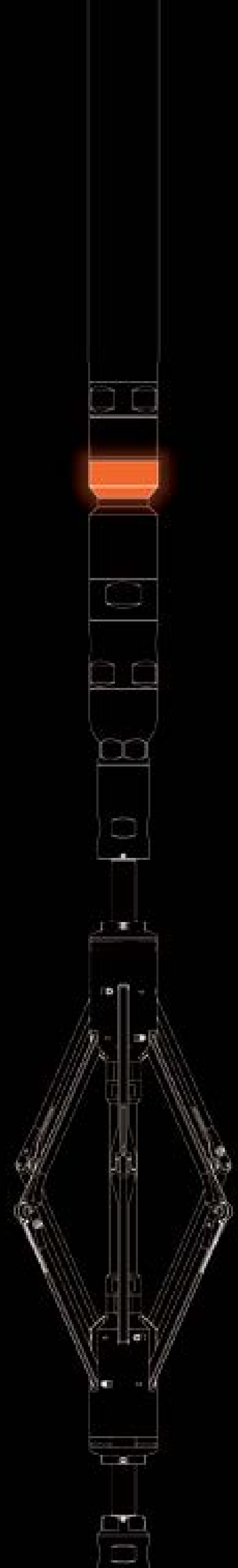
About the cover: With oil prices stabilizing and activity continuing a steady climb, optimism for unconventional development is high. Part of that optimism stems from the increased efficiency gains in hydraulic fracturing, which is making unconventional development more profitable and productive. Chevron is among the Permian Basin operators looking to increase production, targeting 1 MMbbl/d by 2025. (Source: Chevron)



(Source: Vladimir Melnikov/Shutterstock.com)

US Shale Digs In, Positions for 3.0 a Year After Historic Oil Price Crash

Unconventional development is on stronger footing on M&A and efficiency gains as outlook recovers.

By Alisa Lukash and Manash Goswami, Rystad Energy

As benchmark Nymex WTI futures hover around $70/bbl—a year after the historic oil price crash that led to negative settlements in a first for the industry—a renewed sense of optimism is slowly but surely sweeping through the U.S. unconventional sector.

After multiple bankruptcies, thousands of job losses and operations plans were abandoned, onshore producers have relatively firmer footing today than they perhaps had going into the downturn on the back of a consolidation spree, aimed at bolstering drilling efficiencies, adding scale and lowering administrative costs, positioning the industry for a stable 2022. While the market crash battered the global oil industry, the U.S. onshore industry was particularly hit hard given its practice of staying beyond its means, which resulted in producers piling up debt that they struggled to service once the prices plunged as cash flows got squeezed.

Capital markets, both equity and debt, shut their doors as the industry's credit worthiness worsened, particularly as the demand growth outlook for oil was unclear. But with OPEC, in an alliance with some of the other major exporters stepping in to regulate supplies, prompt approvals of vaccines to tackle COVID-19 and their subsequent rapid rollout, at least across the developed nations, have stabilized the global oil consumption outlook. That has helped return the market to balance and put a firm floor on oil prices.

U.S. onshore producers continued to stick with their pledge to cap spending, focus on debt repayment and balance their budgets. The combination of stronger prices and a stable demand outlook is again prompting investors to warm up to the sector, allowing shale operators to tap markets again and gain access to the ample liquidity available from trillions of dollars in stimulus, at rock-bottom interest rates given the Federal Reserve's accommodative monetary policy.

While the overall macro fundamentals seem sound, U.S. shale, much like the broader global oil and gas sector, must reckon with a race to cut greenhouse-gas emissions. Shareholder activism and a court ruling turned May 26, 2021, into a landmark day for the oil and gas industry. This showed that supermajors and independents alike needed to accelerate their pace of transition and pay heed to growing calls from society to take quicker action to switch to cleaner sources of energy.

While investor pressure on Exxon Mobil and Chevron and a court order on Shell dominated the day, the message was wide and clear for the broader sector that it is moving slowly on this subject. The G7 Summit wrapped up in mid-June with pledges from the leaders of some of the world's most powerful nations to proactively tackle climate change in yet another example of just how core this theme has become in global decision-making.

Gaining access to capital

Shale operators are raising more capital in 2021 than in the previous two years, and numbers are on target to match the 2018 shale boom—about $31 billion. So far producers have raised just under $15 billion, with March the most active month with almost $5 billion added in debt and equity (Figure 1).

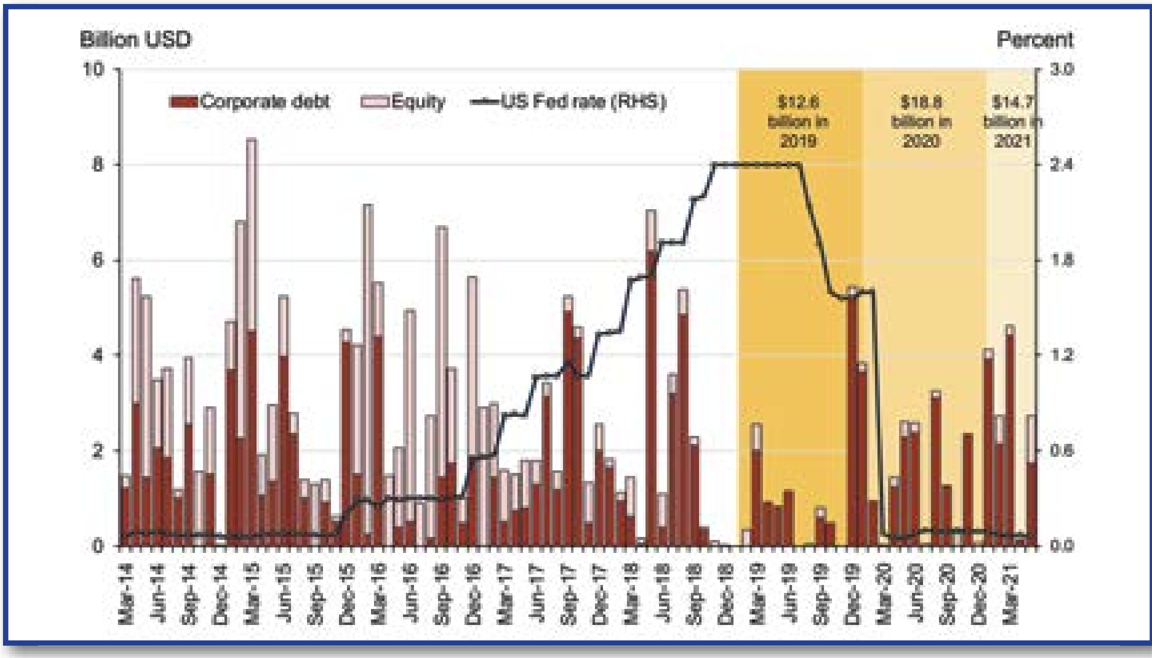


FIGURE 1. Public capital issuance in the U.S. E&P sector is categorized by debt and equity. (Source: Rystad Energy research and analysis May 2021)

Rystad Energy expects the overall amount to surpass $16 billion by the mid-year mark. In a departure from previous years, most of the raised capital so far in 2021 is not earmarked for actual drilling but rather for other financing activities, including deal financing. The surge in financing activity stands in sharp contrast to 2019, when borrowing fell to an all-time low. At the time, banks and other lenders were concerned the shale industry might not be able to service its existing debt, which was already weighing down balance sheets as sliding oil prices eroded cash flows well before COVID-19 came along. Many large players saw their credit ratings slashed or put under review.

A Rystad Energy peer group reported a new historical peak in free cash flows (FCFs) in the history of U.S. shale of positive $4.1 billion followed by $2.5 billion in fourth-quarter 2020.

Recent results showed operators had another financially strong quarter despite seasonally higher first-half 2021 spending, but oil output fell due to extreme weather in some regions. Analyzing producers' spending plans shows that many efficiencies achieved in 2020 rolled into 2021, allowing companies to step into 2022 with a strong inventory.

So far only a few operators have reported flat or increases in costs per foot, as most continue to make continuous efficiency gains and expect structurally lower drilling and completion costs per foot. In general, operators are planning flat output and spending for 2021 versus 2020, with guidance staying at the same level as previously communicated in February.

Rystad Energy's analysis covers a peer group of the top 39 public U.S. shale oil producers, excluding majors, gas companies and Anadarko. Due to mergers and bankruptcy filings, the group shrunk to 35 operators in fourth-quarter 2019 and to 28 in third-quarter 2020. The current peer group of 21 operators accounts for 40% of the expected 2021 U.S. shale oil output. The previous quarter's numbers are adjusted to exclude acquired companies by majors and operators, which were delisted.

The first quarter of 2021 showed $3.3 billion in underspending by shale producers when looking at capex compared to cash from operations (Figure 2). Even though overall capex is higher quarter over quarter, operators managed to keep spending below $5 billion for the peer group in first-quarter 2021 (compared to $3.5 billion in fourth-quarter 2020) while drastically increasing cash from operating activities to $8.3 billion—in line with the pre-COVID-19 level. The number of operators that balanced their spending in first-quarter 2021 reached 80%, which is only 10% below the previous reporting. The spread reached $3.3 billion—an all-time high. The reinvestment ratio (capex/CFO) stayed relatively flat over the last three quarters at about 60%, in comparison to the historical average of 140%, showing a significant moment for the industry as operators are transitioning to self-financing.

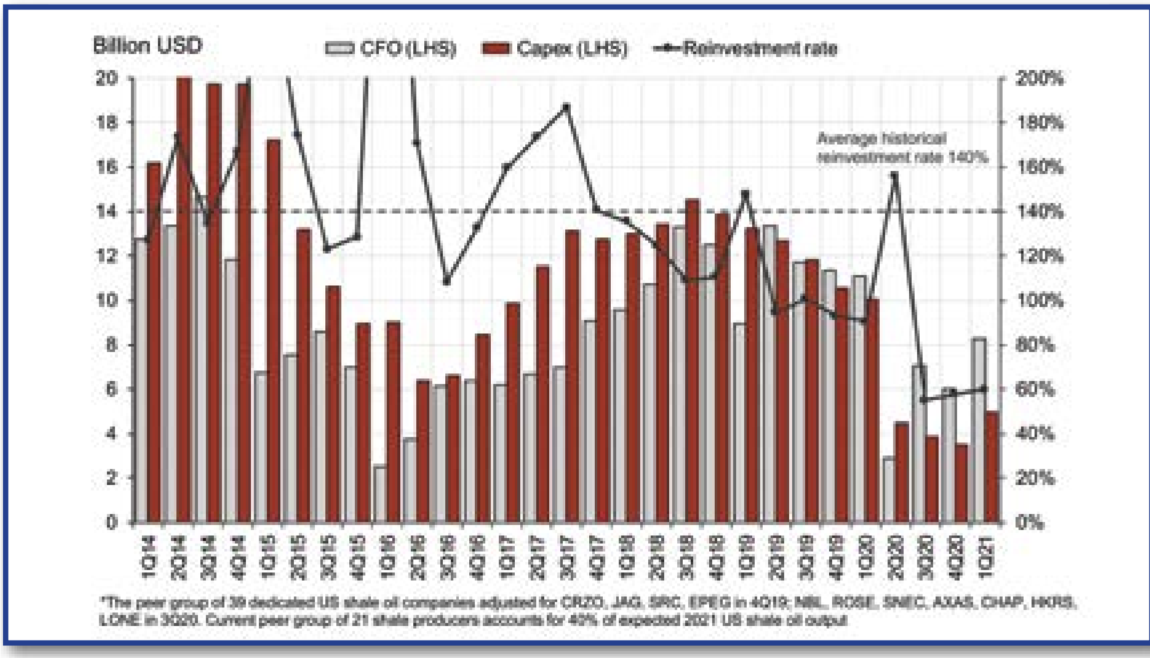


FIGURE 2. Quarterly CFO* is compared to capex for public U.S. shale oil producers. (Source: Company reporting, Rystad Energy research and analysis)

The combined net income for U.S. shale oil producers in the first quarter amounted to $1.6 billion compared with a loss of $2.1 billion loss the fourth quarter of 2020 and a loss of almost $6 billion in third-quarter 2020, while EBITDA recovered to $12 billion—a level that hasn't been reached since second-quarter 2014, from $6.6 billion in the previous quarter (Figure 3).

On average, operators' EBITDA increased by more than 80% in first-quarter 2021 compared to the quarter before while the Nymex strip recovered by $15/bbl.

Drive toward M&A

Shifting focus to the outlook for M&A activity, the U.S. onshore shale industry ramped up consolidation in 2019 and 2020 as producers faced a challenging cash flow environment where reduced corporate acquisition premiums had seemingly become a new norm (Figure 4).

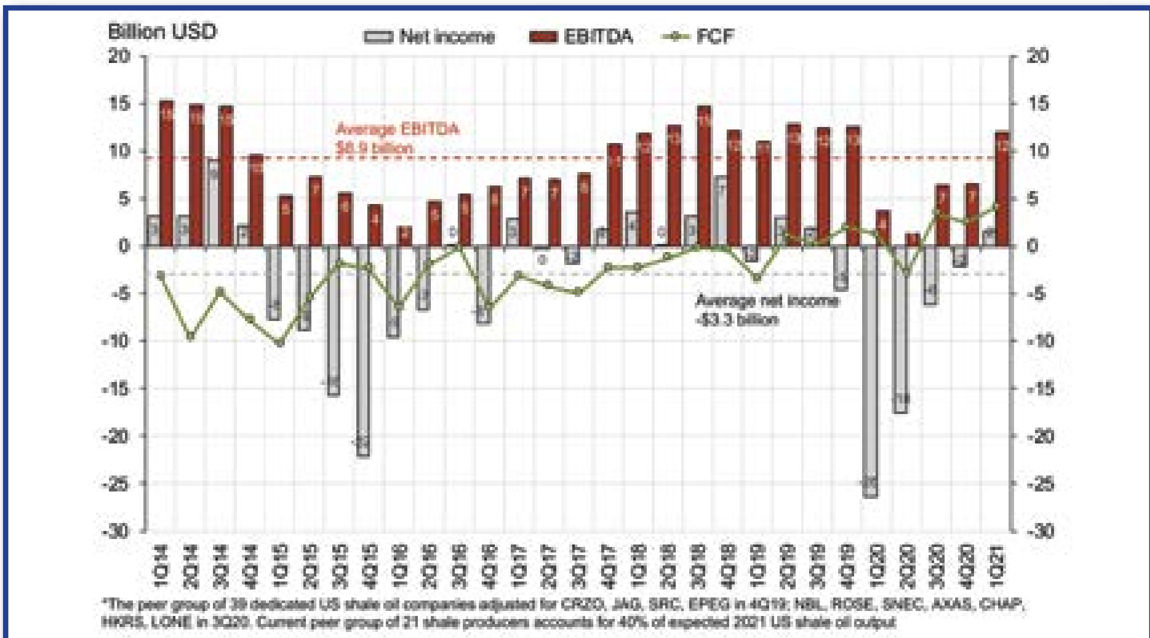


FIGURE 3. Quarterly earnings and cash flow are depicted for public U.S. shale oil producers. (Source: Company reporting, Rystad Energy research and analysis)

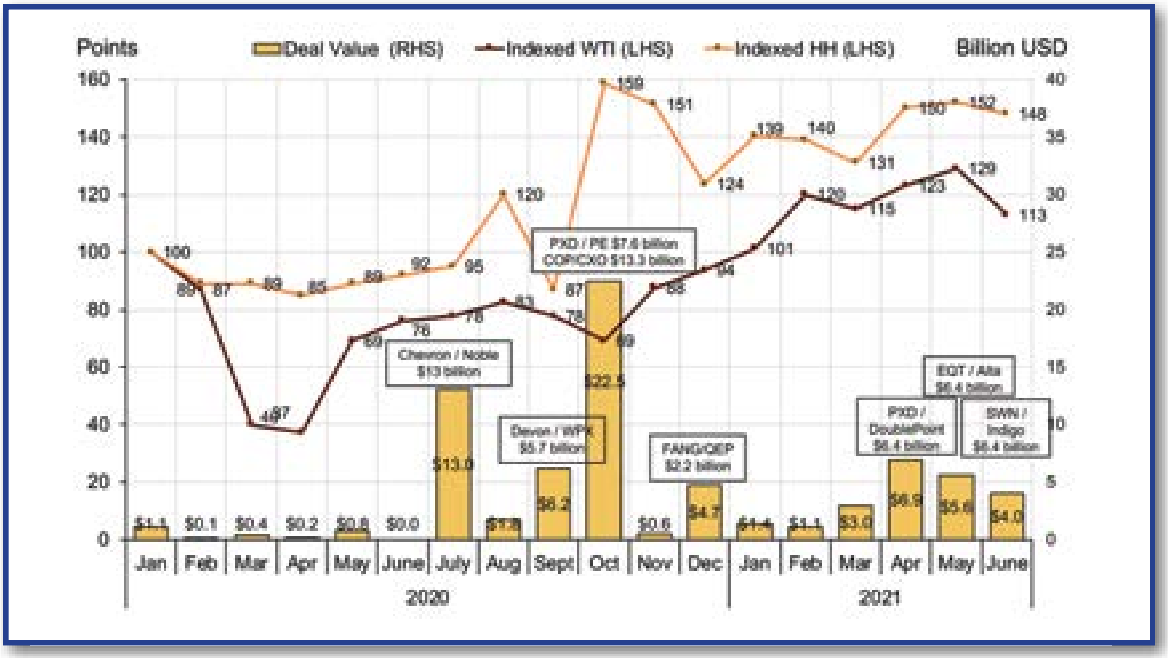


FIGURE 4. U.S. onshore M&A activity is compared to indexed WTI and Henry Hub. (Source: Rystad Energy Research and Analysis)

A sharp fall in acreage prices aided the drive, while investor interest for combined entities revived as efficiencies improved amid a continued reduction in costs. In part driven by that philosophy, M&A in the onshore industry reached a record high in second-half 2020, recovering sharply from the dramatic slowdown in the second quarter as the rapid spread of COVID-19 created a period of massive uncertainty, pushing both potential buyers and sellers to the sidelines.

So far in 2021, there has been an increase in transactional activity, especially in the second quarter, with independent operators going for private operators in the Permian and Appalachia as well as some acreage deals across the U.S. This is in contrast with 2019, when most of the transactions were small premium deals between play-focused operators, and with 2020, when supermajors acquired large shale operators. By acquiring a neighboring player, operators are typically able to increase their existing acreage position, realizing operational synergies and growing output at a reduced cost.

The largest financial push for consolidation comes from a significant acreage price reduction, as WTI plunged, while the overall equity investor sentiment for pure upstream producers had dropped. Rystad Energy reports a decline of more than 70% in average acreage prices across the U.S., from $17,000 per acre in 2018 to $5,000 per acre in 2020. In 2021 there has been a slight increase in the average shale net present value to $7,100 per acre, mainly driven by an improved WTI price forecast of $53.50 for the next five years.

Record breakevens

Several years ago, some tight oil industry players had projected that a continuous learning curve and structural cost improvements would ultimately bring half-cycle PV10 breakevens for new projects down to levels competitive with infill drilling opportunities in the Middle East. While that is hardly achievable at an industrywide level, there may be significant acreage positions exhibiting half-cycle PV10 breakeven prices in the range of $20-$35/bbl for recent well vintages.

Breakeven prices are ultimately a function of well costs and well productivity. Given that the former is at record lows while the latter is reaching new record highs almost every quarter, the breakeven price range is the lowest in the industry's history. When calculating the WTI half-cycle breakeven price, G&A overheads are also considered—another area where significant improvements have been made in recent years.

Figure 5 shows U.S. tight oil's 50 most commercial acreage positions based on second-half 2019-2020 well vintages, with acreage positions with at least 30 wells during the period considered. The left portion of the chart is dominated by the different parts of the Delaware Basin, with significant contributions from the Midland North and East sub-basins closer to the middle of the chart. Yet it


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FIGURE 5.
The top 50 tight oil acreage positions by PV10 half-cycle WTI breakevens*. (Source: Rystad Energy ShaleWellCube)

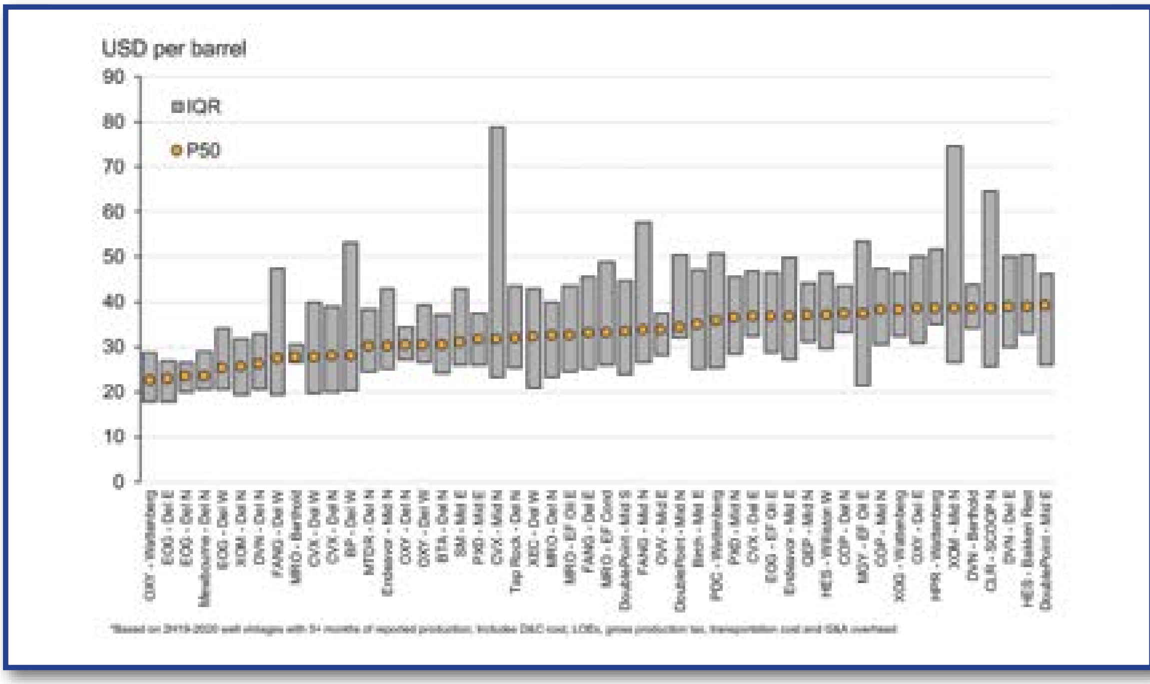
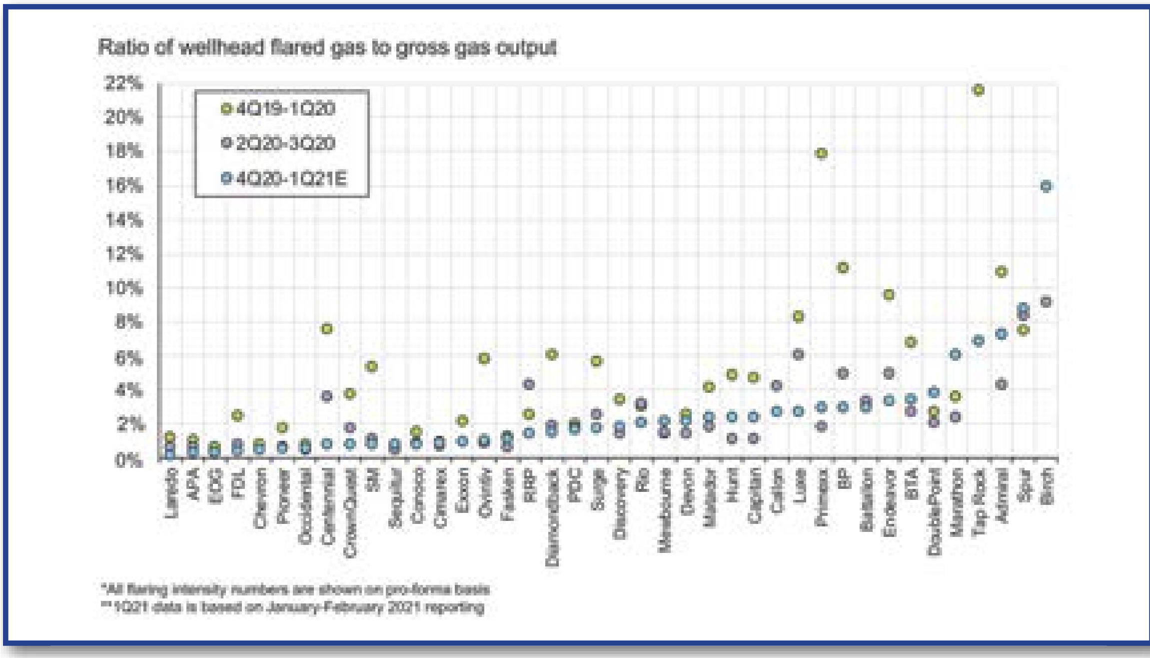


FIGURE 6.
Permian flaring intensity is displayed by operator and period of time. (Source: Rystad Energy US E&P Emission Dashboard May2021)



should be noted that nearly all major oil basins are able to contribute at least one acreage position to this group of assets with ultralow breakevens and with significant remaining inventory.

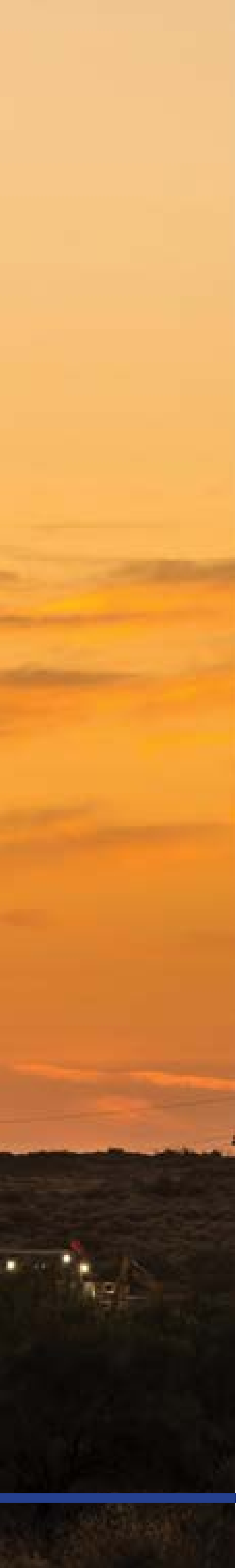
With the maturation of base production in 2020, it is also the first time in history when these half-cycle PV10 breakeven prices for new projects are just slightly lower than the corporate level breakeven needed to support maintenance capex, which is generally in the $30-$40/bbl range for 2021.

Flaring trends

The latest data support Rystad Energy's conclusion that operators continue to fuel structural declines in gas flaring despite the recovery in fracturing activity, with January U.S. onshore levels down to an average of 430 MMcf/d—lower than the crash-induced 490 MMcf/d last May. And even accounting for seasonal variations in activity, the latest range hovers at about 400 MMcf/d to 600 MMcf/d, more than half of 2018-2019 levels, thanks to operational improvements in the Permian and Bakken.

Specifically, the Permian has made notable strides (Figure 6), with wellhead gas flaring down sequentially across all sub-basins, save for a minor 2 MMcf/d increase in Delaware North, New Mexico. Flaring intensity also experienced structural declines, with basinwide intensity now set to average 1.4% in first-quarter 2021. Flaring intensity reduction has generally been championed by public operators like EOG through thoughtful capital programs and operational investments. Although, private operators have by and large prioritized growth at all costs. The group contributed to 55% of all wellhead gas flaring, despite only accounting for 25% of the basin's gross gas supply last year. Private operators that achieved continuous flaring intensity improvements included Crownquest, Surge Energy and Endeavor, while EOG, Occidental and Chevron continue to lead improvements among public independents. ■

(Source: kusjunianto/ Shutterstock.com)



Shale Producers Talk Development Plans, ESG and Completion Designs

Leaders from Devon, Pioneer, Chevron and ConocoPhillips discuss the latest in unconventional development and how recent acquisitions have enabled greater efficiencies.

By Brian Walzel, Senior Editor

For much of the past decade, small, medium and large operators across North America have fine-tuned their hydraulic fracturing operations to develop more and more hydrocarbons while working to improve their efficiencies and, thus, their economics.

Unconventional development has undergone constant and consistent evolution since its emergence, peaking with the Shale Boom and cratering with the price collapse and demand destruction last year. Now operators are in a cash-first mindset, having moved on from production growth at all costs. These trends are occurring during a time when ESG efforts have taken priority. Indeed, this is not the shale industry of old, or not even of recency.

Hart Energy was joined by leaders of four major shale operators who shared their thoughts on the latest completion designs, what their operational plans are for the basins in which they operate and how recent acquisitions by each have enabled greater efficiencies and improved operations.

For this exclusive roundtable discussion, Hart Energy spoke with Gerry Torres, vice president of Permian completions with Pioneer Natural Resources; Rich Downey, vice president of drilling and completions with Devon Energy; Jeff Gustavson, vice president of the Midcontinent Business Unit with Chevron; and Eric Davis, global completions chief with ConocoPhillips.

Hart Energy: What are your development plans over the next year or so for your North American unconventional operations?

Torres: We're going to average between 22 and 24 rigs in the Permian Basin this year, with an average of one rig in the Delaware. Our frac fleet counts can average between seven and nine frac crews in 2021. Now, with the acquisition of Double Point, we currently are at 26 drilling rigs and nine frac fleets. But if we moderate the Double Point growth, we expect to be in the rig and in fleet count that

Oppostite page: Devon Energy has projected to produce 290,000 bbl/d and has allocated $1.8 billion in upstream capital for the year. (Source: Devon Energy)

> "Our continuous acreage and top tier acreage, coupled with our highly efficient operations, allow Pioneer to have one of the lowest industry breakeven costs somewhere in the low or the high $20 per barrel."
>
> —Gerry Torres, *Pioneer Natural Resources*

I talked about in the ranges of 22 to 24 and nine to seven frac fleets. We expect to place anywhere between 470 wells to 510 wells on production, with an average of four wells per pad and somewhere in the lateral length of just greater than 10,000 feet. We plan to grow 5% annually. So we're still working the numbers as we moderate the Double Point activity, but we expect roughly zero to 5% growth in terms of barrels of oil.

Downey: We have been adamant that our goal is to stay very disciplined in the market today. We're currently averaging nearly 290,000 barrels a day, and our goal is to maintain the level of capital required to keep production volumes consistent. This year our spend is about $1.9 billion, which will be spread throughout the different basins, but most of our capex will be spent in the Delaware Basin within the Permian.

Companywide we have 16 rigs operating: 13 in the Delaware, two in the Stack and one in the Williston.

In the Delaware, we've got five rigs in the North (New Mexico) and eight in the South (Texas). North and South Delaware came together as a result of our merger with WPX in January this year. The WPX legacy acreage is south of the state line, including the Monument Draw area, and the Devon legacy acreage is in the North Delaware into New Mexico. The really great thing about the merger, and this just doesn't happen very often, is that we've taken the activity plans of the two individual companies and pulled them together without reducing activity levels. Now, with more than 400,000 acres across the Delaware Basin, we're seeing a lot of savings due to operational synergies that have occurred due to the merger.

We have two rigs running in the Stack in Oklahoma and just picked up a frac fleet in early June.

In the North, we've got the Powder River in Wyoming and the Williston in North Dakota. We completed wells earlier in the year and recently picked up a rig in the Powder Basin. We also have a rig coming back to Williston at the beginning of 2022.

And then we have the Eagle Ford, which is a 50:50 joint venture with BPX. BPX does the drilling and completion, and we handle the production of all the activity there.

Gustavson: Over the last year, our strategy shifted to one of maintaining existing production and focusing on the highest returns while preserving longer-term value. We cut our capital in the Permian to provide the capital flexibility needed to respond to the market conditions. In the near term, we're focused on maintaining that capital discipline. We are currently operating five rigs and two completion crews with a similar net rig count on the non-operated side. We have a strong position and growing free cash flow. In terms of getting back to the 1 MMboe/d trajectory, we intend to continue investing in the Permian, but we're going to do it at the right time. The resources remain, but we have a lot of flexibility and will build that activity level back up when it makes sense.

Hart Energy: Can you explain your well economics and how you find those economics favorable for development?

Torres: Pioneer has over a million net acres in the heart of the Permian Basin, and it's one of the world's most economic shale plays. Our continuous acreage and top tier acreage, coupled with our highly efficient operations, allow Pioneer to have one of the lowest industry breakeven costs somewhere in the high $20 per barrel.

Downey: From a drilling and completion perspective, we focus more on the well costs and efficiencies of the operations, but of course it all comes back to the rate of return and net present value of the development. By bringing WPX and Devon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Pioneer expects to produce up to 366,000 bbl/d this year in the Permian Basin. (Source: Pioneer Natural Resources)

together, two companies that were extremely successful in terms of well cost and production performance separately, we are seeing a lot of synergies from best practices. Both companies had done a lot of technical work to understand well spacing and communication between wells, and now that we've come together, we continue to see improvements.

Our frac design and casing design vary depending on our location, and for good reason, we mixed up legacy management and engineering teams to identify the best practices and opportunities.

Gustavson: Chevron's Midcontinent Business Unit has a very large and attractive portfolio of acreage and development opportunities, with over 75% in low or no royalty acreage. We are focused on developing areas with the most competitive unit costs.

Hart Energy: How is your company implementing some of its ESG/carbon reduction goals into its hydraulic fracturing operations, and what have been the results of those efforts?

Torres: Pioneer is focused on ESG improvement and carbon reduction in all facets of its operations, but within completions, in addition to the carbon reduction efforts, a highly efficient operation, and reducing idle times, we have conducted a bottoms-up evaluation of all the next-gen frac fleet technology on the market. And we've actually trialed some of these technologies to get a better understanding on the impact on the overall carbon footprint. We will continue to evaluate these new technologies related to electrification, dual-fuel and alternative power generation for these frac fleets, along with the ancillary fracking equipment.

Downey: Operationally, we are focused on reducing the carbon footprint from both the completions and drilling sides. Diesel-based frac equipment is being replaced by dual-fuel and electric-driven equipment. Currently we are upgrading our fleets to Tier 4 dual-fuel equipment, which has greater than 70% gas substitution rates.

On the drilling side, we have transitioned to running our rigs off the electric grid. In addition to reducing carbon emissions by not using diesel generators, the electric-driven rigs are substantially quieter and so improve our ability to communicate on site, which helps improve overall safety.

Additionally, we are using recycled water everywhere that we can, especially in the Delaware Basin


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where we aim to use 90% non-freshwater. By having so much acreage in the Delaware, we can build out the infrastructure to support the use of recycled water while also reducing water disposal costs.

Gustavson: We started introducing Tier 4 DGB [dynamic gas blending] frac fleets, consisting of 18 to 24 pumps, in Q1 of 2020. Currently we have two frac fleets running that are primarily Tier 4 DGB pumps. We plan on future fleets having this same technology. We have been able to reduce diesel usage over 40% per well and have reduced CO_2 emissions over 15% compared to using straight diesel. We are also looking at e-frac technology, working with our business partners on the right solution.

Davis: We are implementing different systems to reduce emissions in our frac operations and have been for many years. This isn't anything new for us. We first applied dual-fuel technology in both the Bakken and in Canada upward of 10 years ago. The technology was used as natural gas, and diesel prices fluctuated and fleets were available. Over the years, the focus has been primarily on natural gas/dual-fuel power generation and pumping systems and, more recently, Tier IV diesel fleets.

Now the market has shifted again, and we are trying to focus specifically on emissions as much as possible when fleets are available, but there isn't enough new equipment to cost effectively meet the demand. We have efforts ongoing applying dual-fuel fleets as well as proposals for fully electric fleets. We try to use them when they make sense, when they're available and as much as we can. Additionally, we have $80 million budgeted in 2021 that teams can apply for and spend on projects that are specifically focused on ESG to help defray the costs.

Hart Energy: What can you tell us about your completion designs, such as lateral lengths, sand/proppant loading, stage spacing, etc.?

Torres: With 1 million net acres, we have different development strategies, so we do have quite a bit different designs, but in general, our completion designs are approximately 50 barrels per foot and roughly 1,800 to 2,000 pounds per foot of in-basin proppant. And as far as our stage lengths, we optimize both for performance and cost.

ConocoPhillips operates about 1,600 new well drills in the Eagle Ford. (Source: ConocoPhillips)

"We've evaluated simul-fracs but have not implemented the technique at this time, as we have gained more efficiencies by the way we place our frac jobs. Everything we're doing with multi-well pads, we really haven't seen the value there yet with simul-fracs."

—Rich Downey, *Devon Energy*

Downey: We've talked about sealed wellbore pressure monitoring, a technology patented by Devon before the merger, and since we've come together, it has been applied in the Delaware South and the Williston, which had previously been legacy WPX positions. That technology is helping us understand frac placement, communication/interference between wells and well spacing.

We've also performed a lot of fiber monitoring, both permanent and dip in, which has really helped us understand the clustering and the placement of the frac job.

Devon had experience drilling three-mile laterals in Delaware North while WPX had experience drilling three-mile laterals in Williston. The experience and knowledge brought together has accelerated the implementation of three-mile laterals in additional areas and is another example of how we're learning from each other and getting better as one team.

Gustavson: Our completions designs continue to advance as we leverage learnings and advanced technologies, ultimately delivering on both our higher returns and lower carbon targets.

Davis: We're not that different from other operators in the sense that over time our well spacing, stacking, lateral lengths, cluster spacing and stimulation intensity have gotten more aggressive.

In many of our fields, lateral lengths are dictated as much by the leases as it is what we want to do from a development standpoint. For example, in our Eagle Ford play, our average lateral length is about 7,500 feet, but that's because we have some leases that allow us to drill 10,000-foot laterals to 11,000-foot laterals. Other leases only allow us to drill 5,000- to 6,000-foot laterals. So, depending on how many leases we're drilling that allow 10,000 to 11,000 versus 5,000 to 6,000 [feet], it moves that average yearly lateral length in the Eagle Ford up and down over time. If we happen to be in an area where we are drilling up 5,000-, 6,000-foot leases, then our numbers look like they're going down, but it's actually just a result of where we invest.

And it's similar in the Permian, except we do have some leases where we could drill upward of 15,000 feet. There, it's a mix between some 10,000- and some 5,000- and some 12,000-foot laterals.

The two places where we actually are more consistent is in our Bakken and in our Montney plays, where we average 10,000 feet and 7,500 feet. We have shown over the years that the longer the lateral, the lower our cost of supply and development efficiency is better. So we try to maximize length wherever we can.

On stage spacing and frac intensity, like the rest of the industry, we've seen a slight pullback over the last year and a half. For many years ConocoPhillips, like the whole industry, has been trying to get tighter and tighter in terms of spacing, tighter on cluster spacing and more clusters per stage. And now, like the rest of the industry, we have pulled back a little bit.

Instead of being in the 3,000 to 3,500 pounds per foot [of proppant] range, we're now getting more in line across the board around 2,500 pounds per foot. That's kind of a general average of our Big Four plays.

Individual fields can be above or below that. Similarly, we've pulled back on cluster spacing where we've been as low as a couple feet spacing in some fields, but now have moved back up to 7-30-foot spacing in other fields. We don't feel like there's one answer that fits all because the permeabilities in each one of these unconventional plays are different. That dictates different well spacing and cluster spacing based on the permeability. As the permeability gets higher, then the wider the spacing can be.

Hart Energy: Has your company implemented simul-fracs into its operations? If so, what has been the result?

Torres: We've been very happy. We've seen encouraging results. In our simul-frac trial, we completed four pads in Q1. We'll continue to trial simul-fracs throughout the rest of 2021. And as a matter of fact, we're currently evaluating the operational and logistical components for a more comprehensive simul-frac deployment for the future. That allows us to stimulate two wellbores and wireline two wellbores at the same time—so really four operations at the same time. By doing that it reduces our completion days, and it also helps with our overall cost of completing these wells. We expect those costs to be reduced as well.

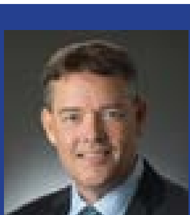
Downey: We've evaluated simul-fracs but have not implemented the technique at this time as we have gained more efficiencies by the way we place our frac jobs. Everything we're doing with multi-well pads, we really haven't seen the value there yet with simul-fracs.

With monoline being utilized throughout our operations, the frac efficiency of switching wells between stages has been greatly improved. This monoline is working fantastic for us. With the utilization of monoline, shutdown time between frac stages is minimized and we're back to fracking typically in less than 15 minutes.

Gustavson: Yes, all our fracs are planned to be stimulated using simul-frac. We have been able to treat two wells simultaneously at a lower rate, which corresponds to lower frictional pressure ultimately allowing us to use less friction reduction chemicals. Additionally, in areas that have a high-fracture gradient prior to simul-frac, we had to use 15K pressure control equipment (which costs more) during the stimulation. By adopting simul-frac, we have been able to stimulate wells in these areas using 10K pressure control equipment. Overall, we have been able to realize an average of 8% reduction in well costs and a 30% cycle time improvement.

Our wells can also be drilled with a smaller casing design since there is less friction pressure in the system due to simul-frac rates being lower than traditional frac pumping rates. Our business partner also benefits from the lower treating pressures seen with simul-frac since they do not have to replace valves/seats in the fluid ends as often as they would with higher treating pressures.

Davis: Yes, absolutely. We began systematically implementing in 2020 where it makes sense and where it is physically possible. We have deployed on new multipads and a few times on infill pads with multiple wells. However, we don't deploy everywhere. When you infill and/or you have a single well, then you can't twin-frac or simul-frac. So utilization of the technique depends on what our development focus is at the time and which areas within our portfolio we are concentrating investment. In 2021, 35% of our wells will use the twin frac technique. From a performance standpoint, on average, we're realizing savings of about $200,000 per well and seeing cycle time improvements of 40%, which means we're getting our wells online one to two weeks earlier depending on the lateral length. We expect our use of this technology to increase in 2022. Those stats are driven by the fact that we went from pumping on the order of 15 to 16 hours per day with single zipper ops to the low 20s hours per day with twin-frac. When you can pump that much more per day or in that many more wells in time, it has a significant effect on all your overall cost structure.



"Chevron keeps a pulse on the market for inorganic growth opportunities when we feel the value is there. We continue to focus on capital discipline and new assets needed to compete for capital with an existing strong portfolio."

—Jeff Gustavson, *Chevron*

> "We have $80 million budgeted in 2021 that teams can apply for and spend on projects that are specifically focused on ESG to help defray the costs."
>
> —Eric Davis, *ConocoPhillips*

Hart Energy: What role does natural gas play in your development plans now and in the future, particularly considering the growing role gas is likely to play in the near and long term?

Torres: Pioneer's asset base in the Permian is predominantly oil development. Although we do produce large quantities of associated gas in our production stream. With our marketing strategy, we do continue to move gas to California and the Gulf Coast. We are doing our part to help meet the world's demand for low-cost, low-emission energy.

Downey: Natural gas is an opportunity and a challenge for us. We primarily focus on oil, so the natural gas is associated gas. Our goal is to focus more on Bone Springs and Upper Wolfcamp, which are going to give us the higher oil content. At some point in the future, if gas prices continue strengthening, we'll have the opportunity to move downhole and pick up some of those additional zones.

Gustavson: Demand is growing and, ultimately, it takes all kinds to deliver the energy the world needs. While natural gas prices have recovered considerably, our focus on development is on higher return oil production. Natural gas does play a key role in our business, as we've converted our drilling and completions operations to use dual-fuel (diesel and natural gas, or even electricity).

Hart Energy: How do you approach M&A in the current environment the industry is in?

Torres: Both Parsley and Double Point were a natural strategic fit for Pioneer. They had contiguous acreage and Tier 1 acreage that was directly offsetting our Pioneer acreage. In addition to that, these transactions provide double-digit accretion to the cash flow per share benefitting our corporate metrics. Our focus now is on the seamless integration for Parsley and Double Point, making sure we fully achieve our combined annual target of approximately $525 million [in synergies] by the end of the year.

Generally, consolidations have been positive for the industry. Many quality name, strong balance sheets have been involved in M&A in one form or another [for] some higher leveraged companies that need to pay down their debt and improve their balance sheets.

Downey: Thoughtfully. The team is working extremely hard to make sure that we know what's out there and determine what may be a good fit for us moving forward. We're generating strong free cash flow right now and are focused on strengthening our balance sheet and returning value to shareholders, so we're not going to do just any merger or acquisition just for the sake of doing it. If an opportunity complements us and additional synergies can be gained, we will look at it very hard.

Gustavson: Although we don't need to complete an acquisition, Chevron keeps a pulse on the market for inorganic growth opportunities when we feel the value is there. We continue to focus on capital discipline and new assets needed to compete for capital with an existing strong portfolio.

Hart Energy: What types of synergies has your company adopted in M&A?

Torres: We expect to realize around $525 million combined annual synergy from the acquisition of Parsley and Double Point—$275 million of that is from G&A and interest savings and the remaining $250 million is from operational synergies of both of which are capital and LOE [lease operating expense]. So some of the synergies that we're already leveraging is our economies of scale to benefit our supply chain, our increased completion efficiencies through the use of simul-frac, blocking up acreage for wider implementation of extended-lateral length up to about 15,000 feet, and lastly, connecting our water infrastructure and shared production facilities.

Downey: We've recognized synergies by integrating teams and collocating them like moving former WPX employees to Oklahoma City. As our activity levels were not reduced due to the merger, we felt that it was important to pull the teams together and focus on best practices moving forward.

The companies complemented each other well, and we've seen synergies with the integration of our technologies and platforms. And I mentioned before that we're seeing a lot of synergies in operations, especially in the Delaware Basin where we're really focused on growth.

Gustavson: We're very happy with how the Noble Energy acquisition turned out, having now two quarters where we've been integrated, seeing everything we said—the free cash flow accretion, the returns accretion, earnings accretion. The synergies have exceeded initial expectations with savings in operating expenses, exploration, debt and third-party expenses. We're very pleased with the talent we've gained from the Noble employees that joined our team, and we're all learning from each other. We will use the best practices from both companies and continue to leverage our advantaged dataset built from our NOJV [nonoperated joint venture] work. Bringing in the Noble Midstream assets has also brought tremendous value on the experience and asset side as well, with full integration well underway.

Hart Energy: How do you balance generating cash flow with growing production?

Torres: Pioneer remains committed to our investment framework, which returns substantial cash to our shareholders and variable dividend with long-term oil growth of approximately 5% annually. And any excess cash generated as a result of higher oil prices will directly benefit our shareholders via our variable dividends as it's outlined by our investment framework.

Gustavson: Production is ultimately an outcome. We're starting in a strong position, and the flexible nature of these assets allows us to manage it with our shareholder's best interest in mind. We did achieve positive free cash flow last year in a much lower price market and expect to generate over $3 billion in free cash flow by 2025. ■

Chevron holds about 2.2 million net acres in the Permian Basin, with plans to accelerate production to 1 MMbbl/d by 2025. (Source: Chevron)

Powering Through

Pressure pumpers that survived a rough 2020 are in recovery mode, some say, as conditions improve with a continued efficiency drive toward a lower carbon world.

Velda Addison, Senior Editor

Despite oil market ups and downs, one target is a constant on the radar for U.S. pressure pumpers—improved efficiency.

Still recuperating from one of the worst years in the oil industry's history, activity has picked up across major shale plays, and oilfield service (OFS) companies are concentrating efforts on what they can control, not knowing what curveballs an unexpected merger of two E&P players, investor mandates or new market entrant could bring their way.

Many are powering through by focusing on next-generation technologies, increasing the efficiency of operations and completing more wells with less horsepower with sights on lowering emissions. Trends such as simultaneous hydraulic fracturing (simul-frac)—a process in which two horizontal shale wells are stimulated at the same time with one pressure pumping fleet to cut time and save money—are gaining traction. Pressure pumpers are also helping fulfill sustainability needs

As ESG initiatives continue to gain traction in the industry, NOV partnered with a client to conduct successful field tests of the Ideal eFrac system throughout 2021. (Source: NOV) with equipment that runs on natural gas or powered via the grid.

Hopes are that economics will continue to improve, following a dismal 2020 rocked by a global pandemic that dried up demand, extreme oil price volatility and the short-lived OPEC+ collapse that pushed WTI deep into negative territory.

For insights on how the pressure pumping sector is faring, these experts shared their thoughts with Hart Energy:

- Scott Toler, vice president of pressure pumping and cementing group, NOV
- Michael Segura, vice president of production enhancement, Halliburton
- Shawn Stasiuk, strategic business manager of production enhancement, Halliburton
- Eric Holley, senior product manager, Halliburton
- Nebojsa Knezevik, cementing bulk plant manager, Halliburton
- Sam Sledge, president, ProPetro
- David Schorlemer, CFO, ProPetro
- Shelby Fietz, vice president of business development, sales and marketing, ProPetro

Hart Energy: How would you characterize the state of the pressure pumping sector today, and how do you see this evolving over the next six to 12 months?

NOV: Recovering—for myriad reasons, 2020 was simply a year of survival for most OFS companies and those OEMs [original equipment manufacturers] that support the industry. While I would not classify 2021 as a rebound year, it is certainly showing signs of improvement as more fleets get back to pumping. But activity alone does not make a healthy market. We still need to see an improvement in pricing, which we won't see until there is a closer balance between supply and demand on the service side. Consolidation has played and will continue to play a part in accelerating the rate of recovery, but new entrants to the market—which we are hearing news of—could unfold that goodwill quickly.

ProPetro: Pressure pumping activity is up, but current economics are still unsustainable. For companies like ours to continue to invest in our people and our equipment, we need activity to remain steady to give us an opportunity to work with our customers to improve economics and enable reinvestment.

Halliburton: Efficiency is still the name of the game, and as an industry we remain focused on finding smarter, more efficient ways to increase pumping hours per day while extending maintenance intervals. Electric fracturing [e-frac], which offers lower emissions and diesel consumption as well as increased pump performance, continues to gain market penetration. However, as the industry strives to achieve that next level of efficiency and performance in surface and subsurface execution, we are beginning to see an emergence in automation being applied for process control and completion optimization.

Hart Energy: What is the forecast for frac spreads for 2021 and 2022, given operators' focus on shareholder returns instead of volume growth? Which basins do you anticipate activity increasing or decreasing?

NOV: My crystal ball says 'insert number here.' The reality is there is so much at play that it is really difficult to predict where the market will go with any certainty. All indications are that global economics and pandemic recovery will continue to push oil demand in the right direction, and global politics should support a continued recovery in North America. However, as compared to previous downturns, the momentum of this current recovery cycle has been subdued by the investor community's desire to see oil and gas companies post positive cash flow as opposed to positive production growth. After a dreadful 2020, I know the oil and gas food chain is anxious to get busy again, but I think the slower recovery will ultimately be beneficial to the industry with the potential for flattening out the up-and-down cycles of the past 15 years. Of course, private E&Ps are still a wildcard as ESG and returns are not necessarily big drivers.

ProPetro: We are currently only focused on the Permian and expect activity to remain flat the rest of the year with an opportunity to step up slightly going into 2022, assuming frac economics improve. We are only expecting Permian production to grow in the low single digits compared to 2019, if at all.

Halliburton: As an industry, we have adjusted to the new norm, and we are exercising capital discipline and watching cash flow. With a focus on generating returns for shareholders and new efficiency gains being realized with simul-frac operations, we see a potential for a moderate spread count increase of between 210 and 250 in 2022. As far as basins, I think we will continue to see Texas plays dominate the market with continued focus in the Permian and renewed focus on the Haynesville.

Hart Energy: Do you see more consolidation among pressure pumpers in the sector's immediate future? What does increased consolidation among operators mean for pressure pumpers?

NOV: Consolidation on the oilfield service side can bring a certain amount of leverage that can lead to pricing recovery, but crafting a deal in a recovering market burdened with depressed balance sheets, limited access to capital and potentially abused equipment takes some skill. I think we've seen some good examples in recent history where cash wasn't the driving factor, so there are a few decent models out there to build off of. However, ultimately, I don't see that many deals happening this year—let's say one or two before we see 2021 close out. For these deals to be really successful, the industry needs to see the questionable cold-stacked equipment in these deals hit the scrapyard; otherwise, assets reentering the market defeats the purpose of consolidation.

Seems like we're hearing about E&P consolidations every week right now with both big and small companies looking to combine. I think these consolidations make some pressure pumpers nervous. Most of the time, the drive to consolidate is to combine production and eliminate overhead redundancies, which ultimately should increase profitability and potentially make the transition to higher service rates for pressure pumpers a little more bearable one would hope. I think the nervous aspect of these transactions has to do with what side of the transaction your E&P is on. This is still a relationship business, and with a reduced number of potential customers and potential elimination of a longstanding relationship, your active spread count could flip pretty quick.

In addition, as private operators become consumed by public operators, we see the risk that the growth plans of a private can be swung to a maintenance plan in an acquisition as the focus on investor returns remains a cornerstone for public E&Ps, thereby reducing the near-term potential requirement for pressure pumping spreads. We all try to make our best plans based on what we know, and an acquisition of your best customer can change everything.

Hart Energy: Considering heightened focus on emissions reduction and a lower carbon future, how are you lowering the emissions profile of fleets?

ProPetro: The push to lower emissions by our customers and our sector will drive investment toward next-generation equipment that will help us achieve a lower emissions profile. The speed at which this will happen will depend on the financial attractiveness of those investments.

Halliburton says its Zeus electric pumping unit is capable of achieving sustained activity at 5,000 hhp. (Source: Halliburton)

Halliburton: Halliburton recognized the potential to use electricity rather than diesel, and we have been preparing for the market conditions to arrive that allow us to offer this premium alternative to traditional diesel-powered fracturing units.

Earlier this year, Halliburton introduced its all-electric frac site to reduce fuel costs and significantly lower overall emissions compared with other fracturing operations. This all-electric location, featuring the new Zeus electric fracturing pumping unit, can be powered multiple ways, including the grid, natural gas reciprocating engines or with low-emission turbines.

The Zeus pump is the industry's first pumping unit capable of achieving sustained activity at 5,000 hhp [hydraulic horsepower]. With its electric-based powertrain, the Zeus pumping unit delivers 40% higher performance than conventional pumps.

Hart Energy: What role do you believe e-fracs will play as more companies target lower emissions?

NOV: At NOV, we believe that the future of the frac industry won't be dominated by one particular horsepower technology, but rather a mix of technologies based on certain regions and circumstances. We definitely feel e-frac will be one of those leading technologies and have invested in considerable R&D efforts to understand how to optimize the product for the application.

From an emissions standpoint, our industry is currently focused on a conversion from diesel energy to cleaner burning natural gas. Dual-fuel systems and direct drive turbine technologies capitalize on burning natural gas at a varying degree of emissions reduction based on their specific application. E-frac technology sets itself apart in the fact that its power generation requirement can come from a variety of different sources that can be customized to the application to optimize emissions reduction, whether it be in the form of a single turbine-powered generator, multiple turbine-powered generators, multiple natural gas recip generators or the premier of them all, highline power. I think this versatility means we haven't yet realized just how far e-frac can go with regard to emissions reduction, which is exciting to think about. It certainly cements e-frac as the leading technology in this realm.

ProPetro: They will play a role, although limited until economics and infrastructure improve to enable deployment of more fleets like this.

Halliburton: E-frac is a premium offering that will play an increasingly important role as it's the quickest way to reduce emissions on location and achieve higher performance. While we would like to see more companies move to a grid-powered solution or blended power, which we see as the future for our industry, there is no way to predict how quickly the market may shift to e-frac.

Hart Energy: The completions space is continually evolving in the oil industry. What trends have emerged in the last year or two, and how has your company adapted?

NOV: Big Data is a buzz phrase we've heard a lot in the past few years and rightly so—data will be a driving factor in our industry for years to come. We've all seen how the development of cloud computing and the ease of storage of terabytes have given us access to a wealth of data. But data isn't knowledge, so our Intervention and Stimulation Equipment group formed an Advanced Analytics, Controls and Digital group to tackle the immense task of converting data into useful information for both OFS companies and E&Ps.

NOV's Max MT maintenance software system offers real-time visualization of maintenance-related data by using notifications for asset condition and performance, providing the customer with data to make critical operational decisions. (Source: NOV)

With the release of our GoConnect and Max Platform, we're laying the groundwork for a progressive approach to converting data into value for our customers. We're seeing some of our first green shoots now with algorithms that are capable of predicting a number of performance-related characteristics that address issues that have plagued the industry for years. As this digital learning continues, we will have unprecedented opportunities to refine and potentially revamp pressure pumping operations.

ProPetro: Simul-frac has driven incremental efficiencies with conventional equipment. We see this as an opportunity for large customers

NOV's Ideal eFrac fleet reduces emissions and increases power density while maintaining the redundancy that efficient frac operations require. (Source: NOV)

to leverage their scale with increasingly large projects. Dual-fuel equipment represents a stepping stone to achieve emissions reductions with equipment that is still similar to legacy solutions. Electric fleets are a middle- to long-term adaptation that will take some time to develop into a viable replacement for the equipment in use today.

Halliburton: Trends toward lower emissions and completion optimization have emerged. With capital efficiency and emissions top of mind for both service companies and operators, many oil and gas companies are looking to make the investment in electric.

Early this year, Halliburton successfully ran the first electric fracturing operation off grid power. This low-carbon approach to fracturing enables operators to reduce their diesel fuel cost to zero.

Although there has been an increased focus on efficiency over the last 10 years, many operators continue to struggle with fracture performance due to having limited visibility and control over how fractures interact with the rock. Operators want to know design effectiveness, prevent frac hits, increase stage lengths and achieve job consistency—all of which deliver better production at lower cost. Because of this, we are beginning to see an increase in the adoption of real-time measurements and fracture automation.

To help operators on their journey to real-time completion optimization, Halliburton introduced the SmartFleet intelligent fracturing system, which lets you see, measure and control how you land your fracs. To date, SmartFleet has helped operators improve cluster uniformity up to 30%, increase stage lengths and control frac hits. With this type of intelligent automation, operators have realized up to a 25% reduction in completion costs and ultimately an uplift in production up to 20%.

Hart Energy: What technologies do you see gaining traction in the coming months/years?

ProPetro: Simul-frac may gain traction with operators interested in maximizing completion efficiencies. The typical customer profile for simul-frac requires very large and sophisticated planning capabilities. Anything that will allow us to lower our emissions profile will gain traction because of the customer appetite for such improvements.

NOV: We've kept a watchful eye on simul-frac and the pace of adoption. With a constant drive by our industry to reduce the cost to first oil, we think simul-frac will see significant adoption over the next few years. It's not without its cons; higher pumping rates mean more horsepower needed on location, which can press the limits of current pad sizes. Growing the size of the pad obviously means more costs, something that we're all trying to cut out. Technologies like our Ideal eFrac System offering increased power density with 5,000-hp pump units and a dual blender design that feeds dual manifold systems—all of which compress the overall footprint of the spread—should be obvious choices as this technology continues to gain momentum.

Halliburton: We believe the next frontier for stimulation is intelligent fracturing. Intelligent fracturing is the ability to connect real-time measurements, artificial intelligence and automation in a way that provides operators with newfound control that drives efficiency at the surface and optimization in the subsurface. Fracture automation is not new. What is new is the intelligence and measurements SmartFleet applies so that operators can make stage-level decisions to optimize their completions in real time.

We also realize a critical component to adopting intelligent fracturing at scale is having instant visibility and access to real-time subsurface measurements that are both actionable and affordable. Today, fiber-optic fracture monitoring provides valuable insights that help operators understand and validate fracture performance. However, for many operators, the historical cost and complexity of incorporating fiber at scale is simply not economically feasible. In an effort to provide low-cost, risk-free fiber solutions that operators can use routinely in every well, Halliburton has engineered out cost and complexity of fiber-optic fracture monitoring. ExpressFiber disposable fiber cable is the newest addition to our scalable fiber portfolio. It provides a direct measurement of well interference at a price point lower than tracers and complicated pressure analysis and is installed in offset wells in 45 minutes with zero impact to operations.

Hart Energy: What have you found that customers are willing to pay more for?

ProPetro: Not much at this point, although we believe next-generation equipment will eventually garner better economics and/or contractual terms. Today, the market is hyper competitive, and pressure pumping pricing still reflects that.

NOV: In the current market environment, we see OFS companies spending their dollars on reducing maintenance cost, improving efficiency and improving their ESG footprint. Of the three, ESG has the biggest impact on their checkbook as technologies that are focused on reducing emissions come at a premium to the basic equipment needed to complete a well. What's interesting is that this premium hasn't necessarily translated into a premium on the service contract with E&Ps. Certainly, it can be the tiebreaker in a decision to award a contract, or may even be a prerequisite, but until we see a balancing of the supply/demand relationship in the OFS side of the business, the premium value can only be measured in utilization.

Halliburton: Today there are premium ESG technologies that the market is willing to pay for. Although it may not be in every operator's fracturing arsenal today, those who are pioneering a more

ProPetro is committed to lowering emissions, having announced in 2021 an investment in Tier IV Dynamic Gas Blending dual gas equipment and conversions. (Source: James Durbin/ The Oilfield Photographer Inc.)

Unlike standard task automation, Halliburton says the SmartFleet system enables real-time completion optimization by combining live subsurface measurements and intelligent automation that responds to the rock. SmartFleet allows operators to respond to fracture behavior, while providing real-time visualization and control over fracture outcomes across every stage. (Source: Halliburton)

intelligent way of fracturing appear willing to pay for the intelligent automation and real-time measurements that get them there.

Hart Energy: Where are your technology innovation efforts focused? Are operators seeking any particular solutions that pressure pumpers in general haven't been able to meet yet?

ProPetro: Lowering emissions, increasing efficiency and lowering costs. Both pressure pumpers and E&P customers are interested in leveraging next-generation technology; however, we haven't seen the broad adoption that might be expected. Implementing this next-generation technology to reduce emissions requires significant coordination and commitment between service provider and customer, which has governed the pace of adoption up to this point.

NOV: NOV is focused on the process of fracturing as a whole, not just considering the incremental changes but also the step changes. Understanding the perception of value has shifted from not just the monetary cost of creation of a well, but to include how the wells are created. This means leveraging innovative and technical solutions that may look different than the frac operations of the past.

In terms of goals for operators, we are seeing a continued push toward automation and standardization. Due to the wide variability in well completions and the human factor, E&Ps are seeking tools to help allow them to drive down cost and increase production. This is a challenge in a highly evolving market. Automation is continually discussed as a destination technology for the frac industry.

Halliburton: Delivering high-performing, electric fracturing solutions is a key focus area for our technology roadmap, as is intelligent fracturing. Operators are seeking the technology and insights to produce more with less, but automation alone isn't the answer. Having real-time measurements and intelligent systems that automatically respond to them is how the industry will reach that next level of optimization and efficiency.

The SmartFleet intelligent fracturing system is more than just pump automation. It's where automation and completion optimization converge—allowing operators to see and control fracture placement and stage lengths, while controlling costs and improving production. It may be new territory today, but just as subsurface measurements revolutionized directional drilling and real-time decision-making, intelligent fracturing will do the same for shale completions.

Hart Energy: What opportunities do you see for growth in the pressure pumping market?

ProPetro: Next-generation equipment, but we hesitate to define that as growth as it will happen in tandem with significant attrition. We see growth as increased ability to meet customer needs through our historically high level of execution and service quality, but not necessarily incremental scale or product lines. Although our team is continually vetting various opportunities to drive value creation.

NOV: From an OEM standpoint, our opportunity to grow in the current pressure pumping market is dependent upon our ability to innovate and bring new products and technologies to the market in an expedient manner. Pressure pumping is not expected to have a meteoric rise in demand over the next few years, but we have seen how quickly technologies can take hold and displace existing technologies under the right conditions. We need to continue to listen to our customers and our customer's customers in order to identify where we can make a difference in the food chain by using our extensive knowledge and resources to disrupt the status quo. I think the market we see in five years will have a much different look than what we see today. ■

Catching up on FDIs

The industry continues its work on identifying and understanding fracture-driven interactions.

By Brian Walzel, Senior Editor

In the journey to better understand the relationship between parent and child wells, or primary and infill wells, and the effects of interactions between the two, various thoughts and ideas exist from a variety of industry experts. Since the issue of fracture-driven interactions (FDIs) first arose around 2014, the oil and gas industry has recognized the importance of both understanding and, in most cases, limiting those interactions.

While FDIs were the topic du jour by 2018, the COVID-19 pandemic, OPEC+ price war and subsequent drop in oil prices and financial belt-tightening have shifted the industry's focus. Well interactions were less of a priority when few companies were drilling wells.

However, the issue didn't just simply go away. The unconventional development industry is still searching for answers and solutions as well as a firm understanding of FDIs. From better well spacing designs to fluid tracing to pressure monitoring to fracture diagnostics, a wide array of well designs and technologies are being applied to understand and alleviate negative impacts of FDIs.

"As is typical in our industry, when observations are made like this, people buckle down and try to figure out what is going [on], and they have with the concept of fracture-drive interactions," said Peter Duncan, president and CEO of MicroSeismic, a provider of real-time reservoir analysis. "Those interactions can range anywhere from a temporary loss of production to a permanent loss of production to the child well not performing as well as the parent well right up to the loss of the wellbore."

Understanding the challenges

Darcy Partners, an oil and gas technology analyst and consulting firm, hosted a webinar in February that focused on FDIs and primary and infill

well design challenges. In a subsequent interview with Hart Energy, Jack Blears, Darcy's head of E&P technology research, said the virtual conference had more than 400 attendees, and many of those attendees stated that their primary challenge for addressing FDIs was in the modeling phase.

"We took some survey data and we had over 130 responses, and the first question we asked was 'What's the biggest challenge with parent/child modeling for your organization?'" Blears said. "And the top three things out of the list of about 10 potential options were [about] the accuracy of the models themselves."

The other top challenges noted by Blears were workflow complexities, such as the number of softwares and disciplines in the modeling process, and the ability to gain actionable insights.

"Regarding accuracy, it's no secret these systems are highly complex," Blears said. "They are multiscale physics, non-linear physics, and all of these models we are building require a lot of different input parameters that are just inherently uncertain because the systems that we care about, they're a mile underneath the earth."

He explained that tasks such as estimating frac length, frac height, permeability and leak-off has to be performed indirectly.

"There is some good progress on what we can measure through fiber optics," he said. "But for the most part, what we see in our data here is that given a parent/child study is involving four to five wells, so when you multiply that by the number of parameters that are required, there's just a lot of uncertainty, a lot of unknowns. That's really one of the biggest challenges around the accuracy as well as just the fundamental lack of knowing what these fracture systems actually look like."

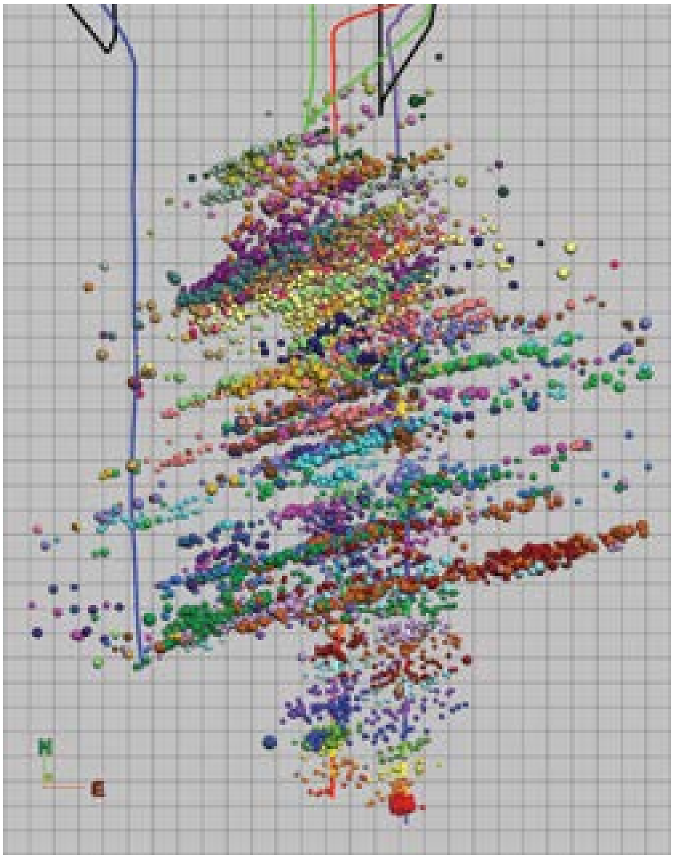
Blears explained that the inability to achieve actionable insights on modeling data stems from "not being ahead of the bit," meaning that a lot of the modeling work, especially in physics-based modeling, is done on a look-back basis.

"So you drill a few wells and you take a couple of weeks to months to analyze and try to tease out a relationship between why a given fracture treatment design resulted in a given outcome versus understanding on an upcoming well pad for how we use this model to predict the behavior and use it as a tool to really guide our completion design," he said. "That's where the industry wants to go."

Real-time monitoring

A number of industry consultants and technology providers see that such post-mortem, post-frac analysis, while still valuable, essentially comes too late when trying to mitigate the negative impacts of FDIs before they can occur. Technologies and methods that allow operators to make on-the-spot decisions on their frac jobs are a solution to FDIs that many, including industry consultant Ali Daneshy, favor.

Operators and service providers have been working for more than a decade to understand well interference and how to mitigate the effects of fracture-driven interactions. (Source: michaelrousphotography/Shutterstock.com)



This map view depicts results of microseismic monitoring of the treatment of the two easternmost wells (purple and red) in the presence of an earlier well (blue) that is on production. Note how the treatment of the new wells changes drastically when the predominant fracture strike direction aligns with the older well. This is a prime example of frac-driven interaction between adjacent wells. Grid size is 100 m by 100 m. (Source: Pan American Energy S.L. and MicroSeismic Inc.)

In 2010 Daneshy was contracted by Canadian producer Penn West to analyze post-frac data, and it was then that Daneshy first identified pressure changes in primary wells during infill well frac jobs. Since then, he has been working with and through various companies and associations to find solutions to FDIs. One solution Daneshy favors is real-time pressure analysis.

"One of the things the industry has known for a long time is that these horizontal wells are very unforgiving," he said. "Once you drill the well, doing any kind of remedial work is often not possible or very expensive. If you drill a well and get suboptimal production, you really don't have a chance to go back and spend a bunch of money to improve it."

Daneshy said that dynamic gave rise to massive—and largely uniform—frac designs.

"Because we cannot go back and correct our errors, the industry decided that if we are going to make a mistake, let's do it toward making a bigger job," he said. "As a result, they repeat the same frac schedule. If you have a well with 50 stages, you repeat the same fracture 50 times."

What Daneshy discovered was that by using the frac data, operators could decide when each stage reached its optimum usefulness.

"And when you get to that point, you stop it and go to the next one," he said. "As you are observing what is happening in the primary well [in terms of pressure changes], you are observing that in real time. If you reach a point where you think it's going to cause damage, you stop it. It is no problem at all to look at that pressure in real time as that job [on the infill well] is in progress."

Daneshy has also been a voice for the positive impacts FDIs can offer. He said that perhaps the most significant positive effect is achieving a better understanding of the individual fractures.

"As I started to dig in to this issue, I started to realize that this technology could revolutionize oil and gas productions," he said. "If you record these pressures in real time based on the level of interaction, you can get a very good picture of the relative position of the two fractures in the two wells. And based on that level of interaction, you can decide when you have done enough."

He said the data from real-time pressure monitoring can provide valuable information on the different frac signatures.

"This is giving you an indication of the length of the different fractures, each of the different fractures in the (primary well) and infill wells," Daneshy said.

Subsurface diagnostics

Real-time frac job analysis can be applied to more than just pressure monitoring. Deep Imaging, a subsurface imaging and frac diagnostics company, announced its acquisition of ESG Solutions in May. According to a press release, the combined company offers a suite of technologies that includes advanced diagnostic tools that track and measure frac fluid placement from the surface and away from the pad.

"Our technology really helps you constrain the X and the Y, where your fluid and proppant go during the frac," said David Moore, president and CEO of Deep Imaging. "But we really needed a Z component to our product. So we went out and acquired ESG. We really liked ESG because they took on the same thought process that we did."

He said that thought process included continued investments in velocity models and data processing that leads to actionable insights.

"They have real time, and we're going to be helping them by iterating it to an even better real-time product on their borehole seismic," Moore said.

Chief Development Officer Josh Ulla explained more as to the benefits of real-time monitoring as compared to post-frac evaluation.

"Post-mortems are useful to start cultivating the 'why?'" he said. "Why did we have that frac hit? But you need to have the 'what' as well. You need to know what has happened. If you're driving a car and you're about to hit a wall, you'd love to know what's happening so you can hit the brakes and avoid those obstacles."

Moore added that the operational tool helps you immediately identify a runaway frac stage toward a parent well or adjacent well.

"It's an evolution of technology," he said. "If you can stop it before it happens, you would, because it's an evolution of technology. We have been on fracs where there has been a frac hit, it a hit a parent well, and that parent well was only a 5,000-psi well, and they pressurized it to 4,500 [to] 4,800 psi. At that point, you've got to shut the frac down for 12 to 14 hours. So that alone, operationally you've wasted $100,000 and people's time."

MicroSeismic's Duncan noted that his business has recently started to see an uptick in activity.

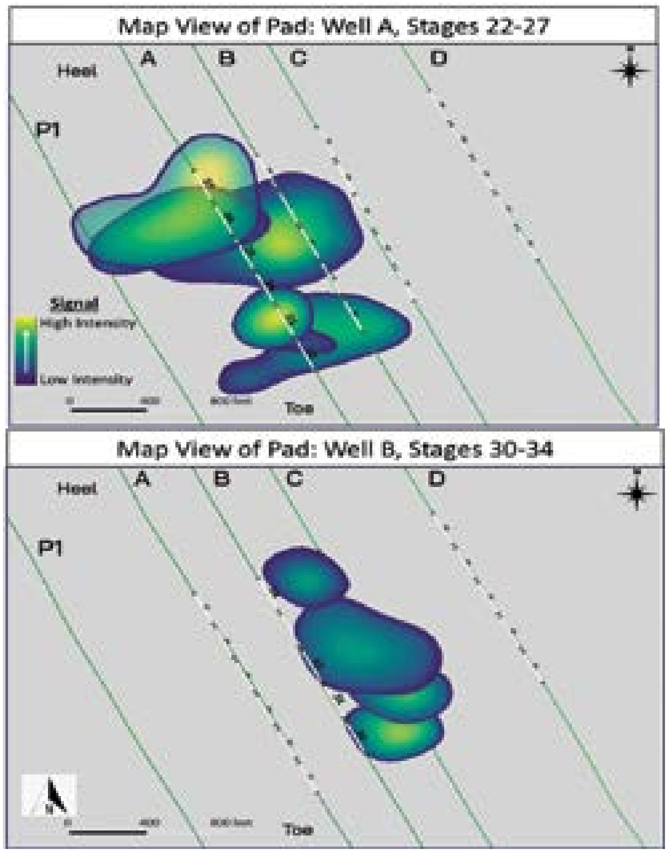
"Five or six years ago, the majority of our practice was driven toward people wanting to understand the stimulated reservoir volume that was being created," he said. "Now, probably 50% of my practice is being driven by people wanting to be aware of fracture-driven interactions, and specifically being concerned in places like the Eagle Ford [and] specifically being concerned about wellbores being constricted or sheared off by the reactivation of previously existing faults and fractures."

MicroSeismic's technology monitors the fracturing of rock through the proxy of the microseismic events that occur.

"We can locate those microseismic events around the stimulated wellbore," Duncan said. "We can locate them in time so we can see them change dynamically and how they move away from the wellbore. We can also tell whether the movement on these fractures when they stimulate the well are dip-slip or strike-slip, or more or less horizontal."

Trends he has identified include more emphasis on protecting the wellbore rather than protecting production.

"Some of our monitoring in the past was driven by trying to minimize fracture-driven interactions that would affect production volumes," Duncan said. "I see less emphasis on that now and more emphasis on monitoring fracture-driven interactions and detecting those prior to there being any negative emphasis on the mechanical integrity of well."



An Eagle Ford operator wanted to understand the effect sequencing had on parent/child interaction. By fracking the nearest child well first, they successfully created a buffer for B, C and D. The cost of creating that buffer was high interaction between well A and the parent well. (Source: Deep Imaging)

> "You drill a few wells and you take a couple of weeks to months to analyze and try to tease out a relationship between why a given fracture treatment design result in a given outcome versus understanding on an upcoming well pad for how we use this model to predict the behavior and use it as a tool to really guide our completion design. That's where the industry wants to go."
>
> —Jack Blears, *Darcy Partners*

Well spacing trends

In addition to the myriad technologies available to limit and understand FDIs, operators are still trying to determine which well spacing patterns can both optimize production while also mitigating risk factors. And not just well spacing—completion designs, well economics and the age of a play are all factors producers are considering when trying to better understand FDIs.

"If there is a risk of interference in the oil production, if you space the wells too tightly, that doesn't necessarily mean that upspacing is always going to lead to better productivity because it really also depends on the rock and on the completion and on a whole lot of different factors," said Amanda Richardson, senior research analyst with Wood Mackenzie. "So it's not as clear cut of a trend as you might expect between productivity and spacing. It's just a risk that needs to be mitigated basically.

Wood Mackenzie recently compiled a report studying well spacing and productivity in the Permian and Eagle Ford basins. The study looked at well densities in both plays compared to basin maturity, the effect of co-completions on wells, and single-well economics versus full section development economics. Wood Mackenzie found that multi-bench developments are more common in the Permian Basin's Wolfcamp development, which likely contributes to wider spacing on average than in the Eagle Ford.

"In the Eagle Ford, they are using much tighter well spacing, around 330 ft on average versus in the Wolfcamp [where] it's 600 to 800 ft," Richardson

A variety of technologies and solutions ranging from real-time pressure monitoring to reservoir analysis have been applied to help mitigate the negative effects of FDIs. (Source: Mike Irvin/ Shutterstock.com) said. "In the Wolfcamp you see multi-bench developments a lot more often. Those are staggered between the two benches, where as in the Eagle Ford, you see more of that. Also it's just much more drilled out and there's not as much room. So operators are getting the most value out of the acreages they have by fitting those wells in."

According to Wood Mackenzie, the average horizontal spacing in the Wolfcamp in Reeves, Loving and Lea counties was about 1,300 ft in 2014. Since then, that spacing distance has declined to between 800 ft and 1,000 ft. In the Eagle Ford, well spacing distances have only varied slightly, particularly in the Hawkville and Maverick condensate plays where wells have typically been spaced about 600 ft apart. In the Edwards Condensate and Karnes Trough—the two most productive Eagle Ford subplays—average horizontal spacings have declined slightly from about 500 ft in 2014 to about 300 ft in 2020.

"[Well spacing in the Eagle Ford] really hasn't changed a lot in the past three years," Richardson said. "Prior to that, there was more downspacing, but in recent years when you look at it on an average level at the subplays, it's been fairly consistent."

However, despite the plateauing of well spacing, particularly in the Eagle Ford, Wood Mackenzie found those efforts haven't necessarily led to production increases.

"The performance hasn't shown a corresponding uptick though, and that's where it's hard to parse out the multivariate aspect of all of this and how impact spacing alone has," said Ryan Duman, principal analyst of Lower 48 upstream with Wood Mackenzie.

He provided an example of the Midland Wolfcamp, where production related to well spacing has remained "about flat."

"I think the key question that is asked as operators theoretically continue to upspace [is] do you see performance follow, or is it one where they just mitigated some of that risk of performance rolling over like we've seen in the Eagle Ford and portions of the Delaware Basin?" he said.

Wood Mackenzie analyzed the impact co-completions along with upspacing might have on well performance and determined that while tightly spaced wells performed better if they were co-completed, they still underperformed more widely spaced wells on average.

According to Wood Mackenzie, in the Midland Wolfcamp, co-completed wells with wide spacing (defined as 660 ft or more) produced at about 35 boe/ft after 36 months on production, similar to wide-spaced wells that were not co-completed. However, tightly spaced wells that were not co-completed saw production fall to less than 30 boe/ft. Co-completed tightly spaced wells performed only slightly better, just over 30 boe/ft.

Over the years, there have been a variety of efforts and technologies emerge to help alleviate FDIs, some with more success than others. Proppant tracing and real-time pressure monitoring have each proven beneficial to varying degrees, but well spacing remains an inexact science.

"We're years down the line, and there's no simple solution or agreed upon solution that folks can employ," Duman said. "Generally, spacing is going to mitigate that risk or tailor completion design or other things to impact performance. It's dependent on individual operators and what rock they're actually trying to exploit, which can make it challenging to try to do more of the basinwide or very wide macro analysis.

> "As is typical in our industry, when observations are made like this, people buckle down and try to figure out what is going on and what they have with the concept of fracture-driven interactions."
>
> —Peter Duncan, *MicroSeismic*

In an analysis of Karnes Trough P50 type curves, Wood Mackenzie found that wells spaced 330 ft to 660 ft apart would be expected to recover about 10% more barrels per foot than wells spaced less than 165 ft apart. Widely spaced wells recovered about 44 boe/ft in the Karnes Trough, while tightly spaced wells recovered about 39 boe/ft.

"If you look at sections, levels, NPV [net present value] or payback or whatever metric of choice, as you start to move wider, say six wells per section, you start sacrificing the amount of resource you're going to develop and the overall value starts to decline again," Duman said. "So it's trying to balance that sweet spot of how much resource overall you can develop while accepting that individual well performance isn't necessarily going to be the best that it possibly can be." ■

(Source: Billion Photos/Shutterstock.com)

Are ESG-driven Green Technologies the Future of Fracking?

As ESG gains momentum, the pressure for sustainable production is pushing upstream companies to adopt new technologies for cleaner fracturing operations.

By Faiza Rizvi, Associate Editor

From investor calls to annual reports, ESG is the talk of the town for both operators and service companies facing immense pressure to lower the carbon footprint of their operations, and clearly, fracking is no exception. Upstream companies are increasingly focusing on adopting an ESG-conscious approach to fracking operations amid constant scrutiny of the impact of hydraulic fracturing on the environment and climate change.

"The genie is out of the bottle for climate change," Jonathan Rogers, CEO of Locus Bio-Energy Solutions, told Hart Energy, adding that there is immense pressure on oil producers from both the Biden administration and investors to adhere to ESG standards in oil production. "Oil and gas isn't going away, but we've got to adopt a step change in the way we produce it and especially focus on how we maximize our ESG efficiency," he said.

More oil, less carbon

The focus on sustainable production has intensified the need to invest in cleaner technologies as companies continue designing and implementing new solutions to minimize the carbon footprint of the fracturing business.

Locus Bio-Energy has developed SUSTAIN technology, which maximizes ESG compliance in hydraulic fracturing by reducing the need for new drilling, Rogers explained. SUSTAIN minimizes the use of chemical additives, using less water, reducing the carbon footprint of operations and providing treatments with low toxicity that are safe and environmentally friendly.

Additionally, it has enabled several operators in the Bakken and Permian to maximize IP and extend the total life cycle of the well to improve profitability. The process involves pumping the biosurfactant with water into wells targeting cracks in the rock formed when the oil is extracted by fracking, therefore reducing the attraction between rock and oil to recover more crude.

Not just that, biosurfactants are 100% naturally produced and have many advantages over traditional, hydrocarbon-based surfactants, including extremely low toxicity, high activity at elevated temperatures and low critical micelle concentrations that require as little as 1/50th the dosage rate.

"The technology isn't just a great lab idea … we're getting real results from operators who want more from existing wells so they don't have to frac as much," Rogers said. "We've got some great case studies in the Bakken and Permian, where we've been able to inject biosurfactants to mobilize a significant amount of oil from wells toward the plateau of their lifetime with lower capex and lower carbon footprint."

To reduce the carbon footprint and meet ESG goals, Rogers stressed the need to eliminate the number of fracs, in addition to focusing on increasing frac efficiency.

"If you take a Bone Spring well in the Permian, it starts at a great rate, say 1,000 barrels per day, but just after a year, it's down to 100 barrels per day,"

A Locus Bio-Energy chemist studies the unique multifunctionality of biosurfactants, including their ability to lower surface tension and improve wettability better than other oilfield chemistries. (Source: Locus Bio-Energy Solutions)

he said. "By the time you are three to four years in, you are down to 20 to 25 barrels per day. Our goal should be to change that production lifetime, obviously the number of fracs, but also improving the efficiency of each frac. If you come to ESG, the statistics are clear on why we should focus on reducing the number of fracs."

Rogers said a typical 55-stage frac requires at least 20 diesel frac trucks and about 110,000 gallons of diesel. In addition, he said water and cement need to be shipped to the frac—all of which added together is equivalent to 1,100 tons of CO_2 produced.

Locus Bio-Energy's biosurfactant treatments are 100% biodegradable and HSE-friendly, helping operators meet their ESG goals. (Source: Locus Bio-Energy Solutions)

Rogers also discussed a recent case study in the Permian Basin to evaluate the performance of Locus Bio-Energy Solutions' ESG-friendly SUSTAIN biosurfactant treatments compared to other industry frac surfactants.

Two unconventional horizontal wells with more than 50 stages in the Wolfcamp C Formation were treated with SUSTAIN. Cumulative oil produced was evaluated after 30 days and compared to historical fracs on identical adjacent wells. Within one month after the SUSTAIN treatment, both wells showed improved production and three times ROI at less than one-third of the dosage rate.

Well 1 produced about 6,300 more barrels of oil in the first 23 days after the start of production compared to the historical frac using microemulsion nano fluids. Well 2 produced more than 6,500 more barrels of oil than the nanofluids and 12,000 more barrels compared to another frac surfactant in the first 23 days.

The study confirmed that the SUSTAIN treatments enable operators to produce more oil than traditional fracking methods in the same amount of time and at a fraction of the dosage rate and cost.

Putting the best fleet forward

Chris Wright, CEO of Liberty Oilfield Services, said the company has been an early mover on ESG with the largest low-emission fleet on the market. He added that in its second year of operation, Liberty built one of the industry's first dual-fuel frac fleets, allowing substitution of clean-burning natural gas for diesel on location.

"Being in Colorado, the culture of our company has always made us focus on how we can improve the economics of oil and gas production and at the same time lower the impacts on the communities we operate in," Wright said.

Additionally, Liberty became a well-known name in the industry when it debuted its Quiet Fleet in 2016. These low-noise frac fleets gained popularity with operators that have fracking operations on surface locations adjacent to residential neighborhoods or other highly populated areas.

"We wanted to figure out a way to make frac fleets much quieter," Wright said. "A frac fleet is roughly the same horsepower as a 747 jet engine, which is loud. So we put in a two-year effort to figure out a sound suppression technology and ultimately developed the Quiet Fleet so that from 500 ft away—which was the minimum distance you could permit drilling

The Quiet Fleet dramatically reduces noise emissions during hydraulic fracturing operations. (Source: Liberty Oilfield Services)

a well location to an occupied residence—a frac fleet would sound just like background noise."

Wright also talked about another low-emission frac fleet that is in the works.

"The industry has been hearing a bit about Liberty's new frac fleet called digiFrac, which we've been working on for three years already," he said. "The digiFrac fleet will be the lowest-emission frac fleet industrywide with 20% lower greenhouse emissions, which is lower than the best-in-market."

To further reduce emissions, the fleet will not be driven by Tier IV dual fuel (dynamic gas blending), Wright noted.

"Instead the digiFrac fleet will be driven by natural gas reciprocating engines because [they] are turbocharged when the air is hotter so you would have a different combustion mix, resulting in higher thermal efficiency with lesser methane needed to be burned and dramatically lower methane slip," he said.

Wright noted that Liberty has also developed a power system for digiFrac that has a significant amount of battery storage to ensure smoother operations of the gas reciprocating engines that can draw battery power when demand for power spikes up during fracturing.

In addition, Wright applauded the industry's progress in addressing methane emissions.

"I think the industry has made tremendous progress in the area of ESG over the last 40 years," he said, adding that Liberty has had a strong focus on emissions, making sure no fluids leak out and touch groundwater, reducing NO_X and SO_2 emissions. "The pollutants from fracking have become lower, and gas emissions are starting to get meaningfully lower as well."

Wright added, "Operating with a lower environmental impact, making sure locations are as clean when we leave as they were when we had arrived—all this is in the DNA of the oil and gas industry already. What's new today is the investor focus on ESG stuff … today, there is a microscope looking closely at what we do. Liberty welcomes that, and I think most of our industry welcomes that."

Tackling the 2 Es: e-frac and ESG

"I think ESG is here and it's here to stay," said Ryan Supak, sales director with NOV. "For us, there are two major impacts. The first one is the investor focus on ESG, which has sent investors looking to place their dollars in other industries, including renewables, making it harder to acquire funding. Contradictorily, this leads to slower adoption of greener technologies due to lack of access to capital, which is the reverse of what the ESG community is looking for."

He continued, "The second impact is the development of these same greener technologies. For us, we have to consider how we participate in everything from dual-fuel and direct turbine drive frac units to all-electric fleets."

Supak also noted that one of the challenges that operators face in complying with ESG is maintaining well development costs while balancing new technologies.

"There is a large amount of idle frac equipment available with historically low service rates," he said. "At the same time, operators prefer the use of new technologies, which service companies have to charge a premium rate to acquire the equipment. How much you decide to invest in the environmental and social facets while maintaining the return on capital will define the next generation of well completions."

Supak noted that NOV's Ideal e-frac fleet has been designed with ESG compliance in mind. The system can run off a variety of power options that include natural gas gensets, battery systems and even grid power, all of which offer improved emissions profiles as compared to conventional frac.

In addition, the Ideal e-frac fleet's increased power density with 5,000-hp electric-driven pumps reduces the number of pump units needed on location. According to NOV, a smaller fleet size means less equipment to transport, resulting in up to 42% less roadway traffic, further reducing carbon emissions. The system is also neighborhood-friendly,

featuring significantly reduced sound pressure at the well site.

NOV's Ideal e-frac pump has been successfully operating in the field for more than 600 hours, providing improved reliability and consistent performance. During this time, the pump has worked alongside 15 to 20 conventional 2,500-hp hydraulic fracturing pumps, handling jobs that include simul-frac, slipstream and traditional operation.

On a job in the Eagle Ford, the Ideal e-frac pump was on the dirty side of a slipstream operation, and the pump averaged 3.8 times more flow than its conventional counterparts while pumping 4.7 times the sand and completing 98% of all stages at an average of 3,663 hp.

On a Permian Basin simul-frac job, the Ideal pump was tasked to carry 18% of all flow to the well. The pump was able to pump 44% more volume through a valve per valve change compared to the conventional pumps. With this heavy workload, which was the pump's first field trial, it represents the advantage that high horsepower contributes to field production and service life.

The NOV Ideal pump was sent to the field fully equipped with NOV's GoConnect system, which allows operators to track key Ideal pump metrics from anywhere in the world. This level of monitoring allows NOV to analyze data and predict service intervals. As the pump was working in the Permian Basin, NOV engineers were able to advise onsite service personnel of the pump's key performance indicators while providing assurance the pump was performing as intended. GoConnect provides the opportunity to remotely track and troubleshoot the Ideal pump while in service, providing quick explanations for abnormal performance and a clear path forward to the return to operation.

As the cost of services rise, time saved rigging in and rigging out equipment becomes more important. The NOV Ideal pump was specifically designed to be rigged in and out quickly, utilizing local connections and cabling. While in the Permian Basin, the pump was 100% electrically rigged into the well site before the conventional dual-fuel units were complete.

'Ticks many ESG boxes'

Tracy Turner, CEO of CP Energy Services, agreed that companies are increasingly adopting sustainability and ESG practices, which are now becoming a standard part of annual reports.

CP Energy Services offers a cost-effective technology that ensures ESG compliance, Turner explained. The Sand Commander is a four-phase separator that captures and removes 99% of harmful gases and provides ecofriendly completions, improves well completion economics and enhanced safety.

So what happens to the gas that is not flared?

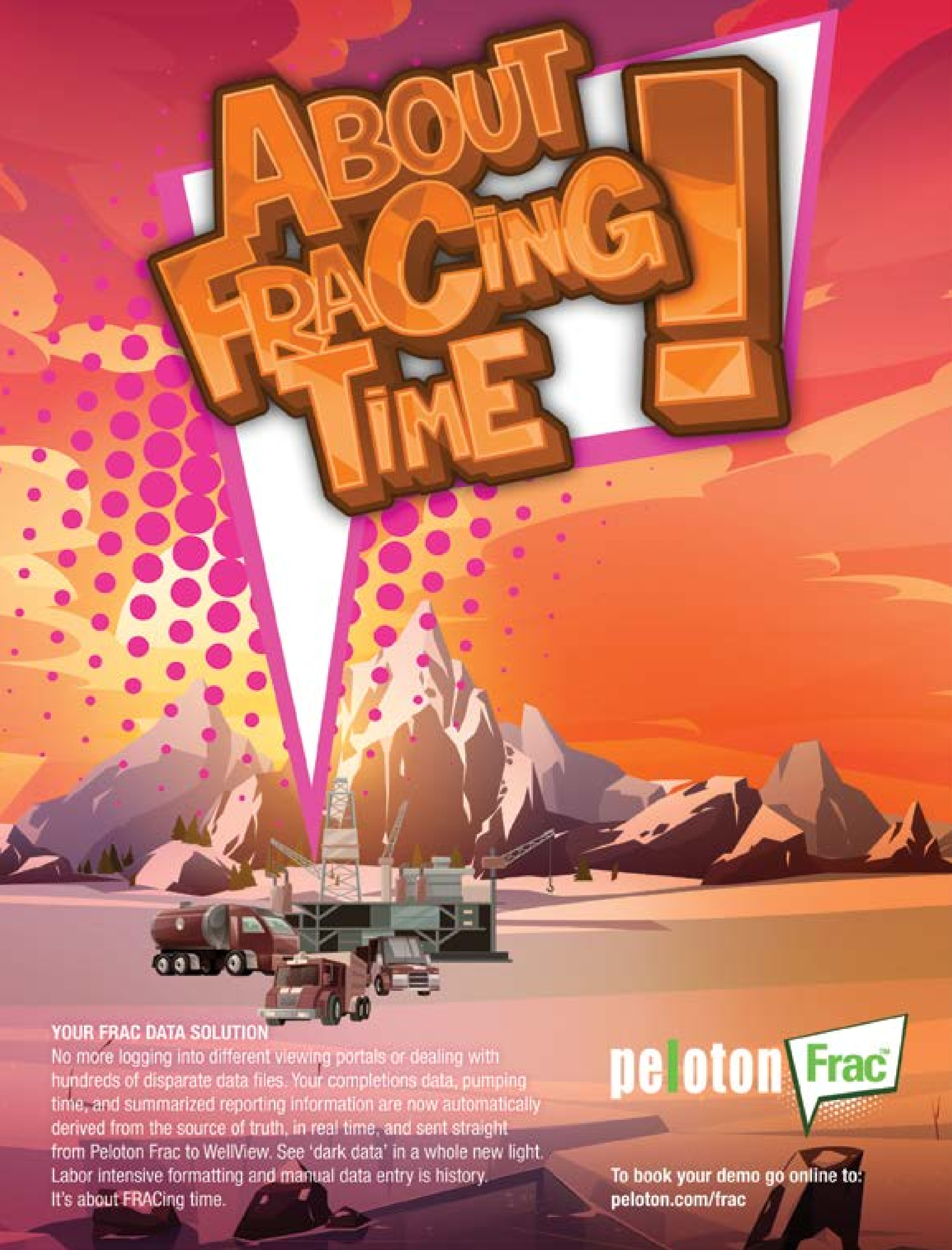
"We use the gas captured to drive a field gas generator that then charges a battery pack, or it can go from generator to anything electrically driven on the location," Turner said. "The other thing we have successfully been doing is that in natural gas basins ... we take the gas during drill-out and send it directly to the sales line. Not only are operators making money on drill-outs, but they are also earning carbon credits, which ticks many ESG boxes."

The Sand Commander also offers a water filtration system that provides an ESG solution for the sand, gas, oil and water components of a well completion, Turner explained.

"Given that our system continuously circulates water, it self-cleans the water, and we have a solution that can treat the water such that it can be reused immediately right on location," he said.

Turner said the water treatment feature offers a major ESG benefit to oil producers because it helps conserve water by reusing it for other fracs and drill-out operations, reduces equipment footprint and trucking costs, streamlines operations and improves safety. ■

The Sand Commander offers an ESG-friendly solution including gas capture, sand extraction and water filtration. (Source: CP Energy Services)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Water Management Joins the Digitalization Dance

Industry experts share their insights on the latest tech innovations in the areas of water reuse, disposal, hauling, evaporation, seismicity and more.

By Mary Holcomb, Associate Editor

Large volumes of water are being generated from oil and gas operations, and experts predict those volumes will continue to increase. The majority of the water is utilized for underground injection, but an overabundance of wastewater has called for new management practices.

Industry experts explored new and improved opportunities to manage the disposal and reuse of wastewater at Hart Energy's Virtual Water Management Conference held in May. The following sections provide a glimpse of some of the show's highlights. To watch the free conference on demand, visit hartenergyconferences.com/water-management-conference.

Remote ops

SitePro LLC's cloud-based software platform provides real-time access into the sector's vast fluid networks. The software suite is designed for automation as it aims to enhance an operator's return on investment through scale, reduced costs and gained efficiencies, according to SitePro Co-CEO David Bateman.

"It's a new technology with an advanced SCADA system that ties analytics and transactions all into one system," Bateman said. "Traditional SCADA systems focus on the field and engineering aspects, but we built SitePro to scale through the entire company."

A key differentiator of the technology, he noted, is that it has simplified most historic processes for automation, making it more malleable and customizable to an operator's needs.

"Historically, PLC [programmable logic controller] programming and ladder logic would take days or weeks," he said. "But we have it set up where those actions are preprogrammed in to add tanks, pumps, valves or change logic with just a few clicks."

As a full-spectrum service, the data visualization tool provides reports and analytics that can be leveraged differently from leadership teams to engineers.

"On the executive level, we see it used very effectively for things like [monitoring] volumes, collecting information about customers, seeing who is using the facilities and how often, and what type of water is coming in," he said.

On the opposite end, engineers can use the information to tailor system capacity, optimize system throughput, reduce energy consumption and monitor emissions, and set up other safety protocols.

The company's ticket management platform Site Ticket is reconciling issues in the field at saltwater disposal (SWD) and freshwater kiosks, where truckers and operators typically sign in. The digital ticketing platform integrates with almost every big accounting system, providing a streamlined billing process from the field.

Operators have seen a 70% to 80% reduction in field services labor and a 60% to 80% reduction in back-office ticketing at disposal wells and freshwater stations, according to Bateman.

Among the company's other remote operation technologies is SiteWatch, a camera surveillance application that links to a facility's alarm system to deter potential theft and reduce HSE events. With live feed and motion capture, mobile risk alerts give actionable information to better secure assets and comply with federal security regulations.

"We're seeing a massive adoption of camera solutions in the water midstream space," he said. "There are a lot more people wanting to have internal command centers, and cameras are a key part of having a virtual view of the field."

The surveillance system works in conjunction with automated facility management platform Site Control. This feature utilizes advanced edge computing to offer real-time tracking and feedback, which enables operators to immediately review data to make informed operational decisions.

SiteChemical is the latest addition to the suite, which helps optimize chemical usage by monitoring flow rates, volumes and composition. It automatically adjusts dosing to treat based on target concentrations.

Together, the suite of tools aggregates streamed data from Internet of Things sensors and controllers at facilities, pumps, valves and wellheads, forging a better line of communication between water companies and their assets.

Water hauling automation

Chorus Logistics, a W Energy software company, has designed fully automated technology to mitigate the growing costs carriers face from water production. The mobile application, TollTagger, guides drivers through every step of the transportation process, including non-driving steps such as loading and unloading. It improves speed and accuracy of data collection from the field and even functions with spotty cellular service.

"Our average customer has been able to cut water hauling and disposition costs by $0.30 per barrel," Chorus CEO Jeff O'Block said.

He said Chorus achieves this reduction by leveraging a cloud-based system, which completely eliminates back office and collections.

"When you're using our system, it does all the back office and billing for midstream companies and producers," he said. "The mobile application that carriers use does all the paperwork, so there isn't any invoicing or reconciliation process."

As the drivers are using the mobile application, the technology is able to capture the trucking, pipeline and injection costs. When the trip is completed, an automatic calculation of the drivers pay is processed, making payment reconciliation easier.

"This is a big win for the trucking companies because they don't need back-office resources for billing, so midstream companies and producers can pay on a daily basis based on the performance the system draws up," O'Block said.

In addition, an automation system is used for dispatching carriers to water collection sites.

"We time it so there is no demurrage, and the app allows us to communicate with the carriers in real time," he said. "We capture all the trucking, pipeline and injection costs in real time through our geo-fencing mobile app. It feeds the data up to our cloud server, and all the invoices are created."

By automating the mundane tasks, Chorus takes on the responsibility of forging the contractual obligations between producers and carriers. O'Block said working exclusively with a carrier guarantees accurate invoices and significantly improves cash flow for both parties.

Evaporation: a new horizon

The handling of post-production wastewater is at the center of the water woes troubling operators. The continued use of disposal wells as the primary solution has overpressurized capacity, especially in the Permian's San Andreas and Ellenburger formations, according to Hydrozonix President Mark Patton.

> The handling of post-production wastewater is at the center of the water woes troubling operators.

The increase in wastewater injection has caused an uptick in seismic events and prompted the Railroad Commission of Texas to develop a seismic review process for injection wells near a recorded earthquake.

"We've noticed increased permit times—especially in the Delaware Basin—because of seismicity issues," Patton said. "There is the potential for additional capacity restrictions because we're seeing rules being written that if there is a seismic event, without defining how big it is, that will allow [regulators] to go back in a restrict permit capacity or even deny a permit."

He said the problem now is that operators have turned to recycling to repurpose all the wastewater as completion fluid. But, Patton argued, recycling has not been solidified as an improved and adequate method for water management.


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The HYDROFLARE system burns gas that would normally be flared to evaporate flowback and produced water so it does not have to be hauled away for disposal. Solids left behind by the evaporated water are collected and conveyed to easily moved receptacles. (Source: Hydrozonix)

The reason, he explained, is because recycling depends heavily on the consistency of completion activity, which moves with the average oil price.

"The way that we recycle and reuse produced water in the oil field is by using it as a completion fluid and that activity is lower today than it was before," Patton said. "So operators aren't going to invest in a permanent recycling facility when there are inconsistencies in their completions programs."

With recycling becoming a stressed avenue, Patton saw a need for improved evaporation methods. He said adding a third leg to produced water management programs "adds a bit more stability."

Hydrozonix has released its flare-gas emissions control device HYDROFLARE. This technology evaporates the produced water that oil and gas companies generate in the fracking process by using it as a scrubbing agent to scrub flare gas and reduce emissions.

The company has also incorporated its ozone wind scrubbing technology into the system, providing more than a 90% reduction in NO_X.

However, most companies' flare gas and produced water are not at the same location. So Hydrozonix developed a new fully automated surface evaporation system.

"We found that you can model the salt drift and there is a function of humidity, wind speed and the velocity at the nozzle head that shows how far you're spraying the water in the air," Patton said. "We developed a control system and did a complete redesign on the nozzle configuration so we're not spraying the water as high. We lose some of the operation efficiency, but we're reducing the amount of drift significantly."

He said surface evaporation is typically a nonstarter for most operators because of salt drift. By spraying water in the air to evaporate it, this creates a salt dust that spreads all over the surrounding area.

"Our new system eliminates that risk," Patton said. "We think programs like this are what we're going to need to add a third leg to produced water management because it needs a way to alleviate the inconsistency problems in recycling and the threats to capacity and disposal wells."

Additionally, the company still develops improved recycling methods like its automated oxidation system HYDRO$_3$CIDE. The system treats produced and flowback water by producing ozone gas, which kills bacteria without leaving harmful residual chemicals in the water. With HYDRO$_3$CIDE, the company successfully launched a fully unmanned recycle facility in the Permian Basin. According to Patton, adopting the system dropped the operator's recycling fees from \$0.20-\$0.25/bbl to under \$0.10/bbl.

Furthermore, the system creates a green and sustainable alternative to liquid chemical programs. And as ESG continues to gain popularity, the company wants to remain intentional about developing carbon-conscious technologies and solutions.

"One thing we've learned through ozone treatment is that the introduction of gas into water can have a friction reduction benefit as well," he said. "Our latest patent application is to use CO_2 instead of the residual gas that comes from treatment. Using CO_2 as a friction reduction agent provides both carbon capture and carbon utilization in the same step."

Water recycling, reuse and sharing

The heightened discussion around reuse options in the oil and gas industry has operators seeking treatment practices that can maintain well performance and preserve costs while satisfying growing ESG concerns.

Recycling has been the treatment method that has gained equal interest among majors, large independents and small operators. Operators are looking to leverage this technique to better three major areas: well performance, well cost and service price, and corporate initiatives and ESG solutions, according to Select Energy Services COO Michael Skarke.

WaterOne automated pumps help improve safety by reducing the risk of pressure spikes while also increasing fuel efficiency. (Source: Select Energy Services)

Despite being produced-water agnostic, Select has developed a high-, mid- and low-spec treatment system to meet an array of spec criteria—what Skarke considered the first step to preparing wastewater for recycling.

"The high-spec solution is very tight specs on total oil and grease and total suspended solids," he said. "We use an oil/water separation, an aggressive oxidizer and filtration flocculants for a chemical and mechanical separation."

On the other end, the low-spec system is significantly minimized in each of those processes. When the water criteria are established for recycling, he said matching the fluid with water is the next major part of the equation.

"This means selecting the right water, treatment and chemistry for the well," Skarke said. "This is really difficult to do and a challenge for the industry because of water quality issues like brackish and produced water blends and different characterizations of the produced water by depth and formation."

He said most completion chemistry is developed on a pre-fracturing basis. But once the frac starts, the water quality is likely to radically change.

"When that change occurs, making changes on the fly to the completion chemistry is costly and creates suboptimal performance," Skarke said.

WaterONE automation tackles frac chemistry compatibility and volumetric complications between produced and frac water. It crafts proprietary automation algorithms that improve labor efficiency and increase safety on location.

"Automation allows you to optimize performance and react quickly to real-time events," he added.

The technology is scalable across multiple projects allowing operators to make broad assessments of water assets in real time. The technique has proven successful in the Permian where the highest volumes of produced water are located. The Permian has half the frac crews, half the rigs and 75% of the drilling and completions spending. Skarke explained that the regulations in the basin allow for water recycling, and as a result, it is the fastest growing market.

In February, Select commenced construction on the first produced water recycling facility project serving the core of the Midland Basin in both Martin and Midland counties. Leveraging the automation system, the facility supports the recycling of roughly 50,000 bbl/d of water from multiple Permian operators. It also provides 2 MMbbl of recycled water storage capacity.

"Water sharing between operators will be critical to water management and recycling," Skarke said. "This facility takes water from up to three to four operators and distributes that water back out to each individual operator, allowing them to maximize produced water reuse, minimize disposal and utilize more fresh and brackish water."

He predicted identical facilities will be put in place because "this is what the market needs." Additionally, these recycling practices are environmentally and economically beneficial, Skarke said.

"We're all in this ESG game together, and we're all trying to figure out what it looks like," he said. "We're focused on being a partner as well as a solution for the operator in terms of guiding them through their ESG objectives, and we're really doing that through our automation."

As the Permian remains the largest produced water and frac market, Select plans to develop additional bio-control and recycling technologies

to prepare source water to go downhole on the fly or tie flowback water back into frac supply for reuse.

De-risking seismicity

Increased seismic activity in the Permian has crystallized concerns for the fate of the water management sector.

"This has become a huge concern across stakeholders in the Permian Basin," said Kelly Bennett, B3 Insight co-founder and CEO. "Seismicity will be a major factor shaping water management over the next few years, and that will have pretty big implications for oil and gas."

Information from the region points to a relationship between fluid injection and increased seismicity, where the event is triggered by increased pore pressure from water injection. This has led both Texas and New Mexico to fast track regulatory policies to mitigate induced seismicity, causing a direct negative impact on disposal.

B3 Insight research showed that seismic events greater than a 2.0 magnitude boomed in recent years across the Midland and Delaware basins.

"There are more of them in new places today than there were three years ago," Bennett said. "When we look at the growth rate of these in both the Delaware and Midland basins, the cumulative number of events are growing exponentially."

The data showed a 15% to 20% decline in approved capacity for shallow disposal wells in the Delaware Basin, beginning in 2019. Similarly, approval for 100,000 bbl/d of capacity for deep disposal wells by the Railroad Commission of Texas was last granted in May and June 2020.

The decrease in permits, he noted, is the result of expanded policies including a revamped grading scale, stricter data submission requirements and the addition of a 10-mile radius restriction around disposal wells within areas of concern.

Bennett predicted the impact of regulatory action will see even smaller wells be required to reach ideal production levels, more remote locations for new capacity to extend the distance from production, urban areas and critical infrastructure, and predicted the erosion of economies of scale.

"In an industry that really relies on economies of scale, getting less capacity for the same amount of money has a potentially disruptive impact on water management economics moving forward," Bennett said.

As a result, there has been an increase in the adoption of seismic monitoring and earthquake response plans. Moreover, stakeholders are conjuring new tactics like submitting smaller capacity requests to adapt to the new norms.

"The developers of new capacity are often taking on significantly more upfront risks on their permits," he added. "Some are drilling and testing their wells prior to placing surface infrastructure and before knowing the capacity of the well that they've invested in."

By default, Bennett said others are agreeing to special operating conditions like seismic monitoring and "they are just calling that the cost of doing business in water management."

"But, this doesn't change the fact that this is a pretty hard nut to crack," he added. "There are great consortiums tackling this issue head on, but stakeholders, E&Ps, midstream and water management companies often lack the capabilities because it takes more than data or a fancy technical model."

Oilfield water intelligence provider Sourcewater Inc. has launched its geoscience platform, WaterMap GEO, to aid in de-risking seismicity.

The software utilizes satellite data to draft basemaps of water pipelines, frac ponds, reserve pits and well pads, geologic fault lines, seismicity and disposal formations, as well as injection intervals.

"We are seeing the level of seismic activity rocket, and this has become a serious issue much too fast for everyone in the industry to have a grip on it," said Sourcewater Founder and CEO Josh Adler. "So we're trying to play a frontline role and help companies make good decisions about the level of risks that are acceptable."

The analytical tool, Adler said, gives insight on who is producing water, where that water is being produced and what producers are doing with that water. By providing critical information like a region's geologic fault lines, operators can completely avoid induced seismicity.

So far, the system has mapped more than 2,000 fault lines across the Permian Basin.

He said both operators and disposal companies should be intentional about SWD design and placement because it has a huge impact on capital costs.

"You want to make the best decisions where you can like placing shallower wells or disposals, so there isn't as much drilling costs," Adler said. "But you want to be safe and effective about not going into an overpressurized formation where there will be seismic events or you could potentially run out of disposal capacity a few years into operations." ■


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Latest Innovations in Hydraulic Fracturing

This special section highlights more than a dozen of the latest hydraulic fracturing technologies and services and how these tools aim to address operator challenges.

Compiled by Ariana Hurtado, Senior Managing Editor, Publications

Merger enables next evolution of frac understanding

A company can now observe more aspects of the frac while the well is being fractured. By deploying the right fit of technology from electromagnetics, microseismic, tilt and fiber, Deep Imaging/ESG Solutions enable the next evolution of frac understanding to better treat the reservoir and start offering the returns on investment investors demand from acreage. The time has come that we start partnering as an industry, and the Deep Imaging/ESG Solutions merger is the first step in getting the most returns from onshore rocks.

Deep Imaging's fluid placement is overlaid on ESG Solution's microseismic response in the real-time viewer. (Source: Deep Imaging/ESG Solutions)

A novel approach to directional drilling

As unconventional oil plays rise in prominence, directional drilling is only becoming more challenging. In light of this, Enteq Upstream is bringing an alternative type of rotary steerable system (RSS) to the market with its SABER tool. The concept, initially developed by Shell and re-engineered by Enteq Upstream, overcomes the challenges of traditional RSS design to achieve greater reliability and lower operational costs, essential for those wishing to remain financially competitive in a low-price environment. The sleek, mechanically simple design offers greater reliability and a lower tortuosity borehole while delivering fine-control through true at-bit steering. This is because, rather than the pads and plates of traditional RSS design, the SABER tool steers using an internally directed pressure differential system. Not only is this mechanically simpler, it offers the advantage of a collar and smooth external design with minimal matching, all of which contributes to greater reliability, uptime and cost efficiency.

This technology was licensed exclusively from Shell in September 2019 after many years of research, testing and field testing. (Source: Enteq Upstream)

On-the-fly resin coating controls proppant flowback and enhances conductivity

Hexion's PropCure on-the-fly curable resin coating allows users to enhance hydraulic fracturing proppant on location. The coating is a two-part system that is combined with a simple static mixer then added directly to the blender tub using standard liquid additive pumps. Once in the fracture, the on-the-fly resin-coated proppant provides all the same benefits of traditional curable proppants like grain-to-grain bonding and helps keep proppant in the fractures to prevent flowback and equipment damage. Additionally, it has a tailored surface chemistry that alters the relative permeability of the proppant pack. Even at a low concentration, it can improve conductivity and reduce or eliminate the need for additional surfactants. The product is effective at bottomhole temperatures of 105 F to 350 F. A Bakken operator stated that the PropCure coating resolved its sand flowback issues while increasing oil production 25% in the first 180 days over offset wells on the same pad.

Biosurfactants meet sustainability and production goals in hydraulic fracturing

Increasing ESG and financial pressures are intensifying the need for sustainable chemistries that safely improve performance. SUSTAIN biosurfactants, an economically feasible green technology developed by Locus Bio-Energy Solutions, boosts performance and helps to achieve increased ESG standards when compared to traditional surfactants. SUSTAIN has unique properties that allow it to replace and outperform traditional frac surfactants at a fraction of the dosage rate and cost. Recent case studies in the Permian comparing SUSTAIN to leading microemulsion nano fluids demonstrated significantly increased production volumes and faster peak oil on flowback, with one-third of the dosage rate and impressive returns on investment.

Locus BE chemists develop biosurfactants with unique multifunctional properties for hydraulic fracturing, which allow them to mobilize more oil than traditional surfactants. (Source: Locus Bio-Energy Solutions)

HVFRs achieve ESG goals without compromising hydrocarbon production

In today's shale fracturing market, the industry is pushing the boundaries in several areas. Maximizing reservoir drainage with longer laterals is the target for many operators, and carrying more proppant in the fracturing fluid is necessary for success. Sustainable operations and ESG goals are becoming increasingly important to the industry and using less freshwater for hydraulic fracturing can have a major impact. How can friction reducer (FR) chemicals manufacturers support operators with these objectives? Newpark has launched its Transition range of brine-tolerant high-viscosity friction reducers (HVFR), which provide both viscosity and elasticity for efficient proppant transport and distribution within created fractures in laterals exceeding 21,000 ft. They maximize regain conductivity of the fractures as they are engineered to be self-breaking. The Transition products also function efficiently in high concentrations of extreme brines enabling customers to meet their production and ESG goals using one technology.

The Newpark approach is to evaluate potential fracture conductivity damage of all its FRs and HVFRs and design mitigation solutions as appropriate. (Source: Newpark)

ESG-friendly remote power generation unit

As the oil and gas industry targets new ways to deliver reliable remote and emergency power while reducing emissions, a new technology has been released called DuraPax. This power solution from NRG Technologies delivers 3.6 MW of continuous duty power per unit, while fully complying with EPA Clean Air Act standards. No additional exhaust stacks or catalysts are required. The power unit's nitrogen oxide emissions are 40 to 50 times cleaner than blended fuel systems. At full load, it is 75% lower than EPA CO_2 emission requirements. DuraPax brings continuous run times as high as 750 hours before preventive maintenance is due. Versatility is further enhanced by a low 60-psi to 100-psi gas supply requirement versus 535-psi turbine demands. The company recently field-tested the DuraPax technology alongside its DuraStim electric fracturing pump in the Permian where the mobile unit surpassed strict emission standards despite severe heat and varying power loads.

Featuring a modular design, the DuraPax remote power generation unit provides scalable power for oil and gas field applications and virtually anywhere remote power is needed. (Source: NRG Technologies)

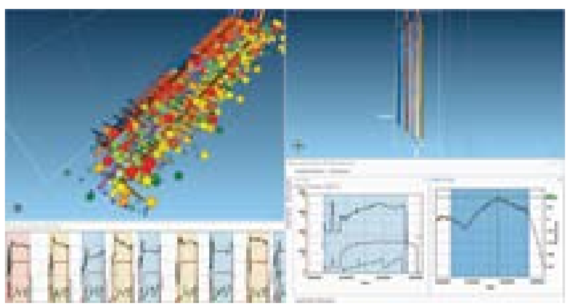
Next generation in completions data integration

Peloton Frac is a universally compatible, real-time completions data visualization and storage tool for operators and pressure pumpers. The application ensures all treatment data are accessible and interactive in a standard, structured format during and after the job. WellView is the source of record for well data. Frac is a critical, complex dataset within the well life cycle. Peloton has developed a next-generation integration between Frac and WellView. This integration eliminates manual input and file transfer (Excel, WITSML) and saves time, allowing field personnel to focus on safe supervision of operations instead of data entry. Combining Frac and WellView data provides rich metadata versus summaries seen with most third parties. Data are passed at the event/sub-stage level, and logic thresholds drive time reporting with enhanced accuracy over manual stage indication. Peloton Frac allows users to get the data their organization needs for timely reporting and to see what they may have been missing—from the source of truth, directly from the data van.

WellView is a complete well information management system for well planning, drilling, completion, testing and workovers. (Source: Peloton)

Holistic unconventional field development

Integrating completion data, including pressure, fiber optics, microseismic and tracer, has been an elusive, although vital, concept for holistic unconventional development. With data files usually loaded into and transferred between many software programs, an asset team faces months of rigorous analysis work that prevent knowing the lessons learned for the next pad. Looking at these data from a holistic view optimizes completion designs. Reveal Energy Services' ORCHID completions interpretation platform, the industry's only software to integrate all data sources, allows an asset team to collaborate with files that have been time-synchronized and quality controlled. The diagnostics process is streamlined into hours from months. With ORCHID, a Permian Basin operator saved $500,000 by eliminating a workover based on an arduous analysis using legacy software tools.



ORCHID, a desktop completions interpretation platform purpose-built for integrated diagnostics analysis, is designed to reduce costs, effort and resources to empower profitable development decisions 80% faster. (Source: Reveal Energy Services)

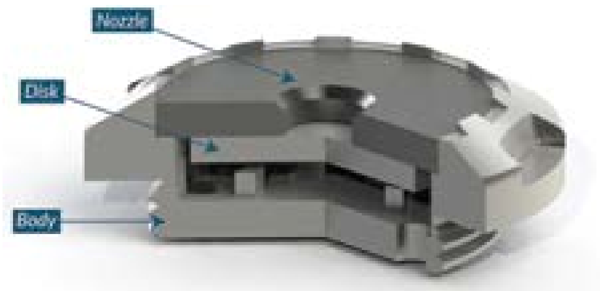
Mobile field tickets and asset management software for fracturing services

In any market, service providers for hydraulic fracturing have to manage critical resources efficiently at every step of value creation (e.g., employee hours and safety records, equipment movement and operating time, fleet maintenance and repairs, and chemicals and consumables usage). By using RigER mobile field tickets connected to an asset management module asset manager, a company can track its fleet by serial numbers, while frac crews can lead and update jobs daily and transfer the revenue data to the office for faster invoicing through one software—no more disparate forms, apps or spreadsheets. The flexibility of RigER makes oilfield service and rentals simple to manage from the first client call to the final invoice (e.g., client quote and rental agreement, service call/request, job schedule, field operations, rental fleet management, oilfield jobs calendar, field tickets, asset management and performance analysis).

RigER allows users to schedule timely service, quickly dispatch jobs, invoice clients faster and receive accurate reports. (Source: RigER)

Leveraging flow control technology to increase reservoir recovery

Tendeka's ReFlow Control advanced completion system leverages flow control technology to further enhance cyclic gas injection EOR in horizontal wells. ReFlow Control deploys a combination of the company's FloSure autonomous inflow control devices (AICDs) and FloCheck injection valves. The valves are designed to control flow in opposite directions, meaning that both gas injection and gas/oil production can be managed. Deployed in a well segmented into multiple compartments, the FloCheck injection valves balance the distribution of gas injection along the length of the wellbore. Simultaneously, the FloSure AICDs autonomously allow oil production but restrict the premature production of gas once the wells are at the production stage. ReFlow Control can improve cyclic gas injection EOR recovery efficiency by as much as 200% while minimizing gas injection costs and optimizing soak period resulting in increased return on investment.



The FloSure AICD is designed to increase oil production over the life of the field. (Source: Tendeka)

Achieving ESG targets with automation

ECOstart is a fully autonomous fleet idle management system that is designed to reduce emissions while saving time and money. Powered by Universal Pressure Pumping's nCOMMAND platform, the ECOstart system automatically con-

ECOstart continuously monitors the entire fleet to ensure all engines are ready for action whether it is the dead of a Northeast winter or the heat of a West Texas summer. (Source: Universal Pressure Pumping) trols the starting and stopping of all frac pump engines on location, eliminating wasteful engine idle time during hydraulic fracturing operations. Three key objectives are achieved: limiting idle time reduces diesel fuel consumption, lowers emissions and reduces maintenance costs. Tractors on location are replaced with the centralized starter skid, significantly reducing the overall footprint. ECOstart is compatible with all diesel engine manufacturer variants: Tier II, Tier IV and dual fuel. Autonomously adapting to changing ambient air temperatures, ECOstart continuously monitors the entire fleet to ensure all engines are ready for action whether it is the dead of a Northeast winter or the heat of a West Texas summer. Leveraging Universal's PTEN+ platform, users can measure the idle reduction performance and overall emissions reduction score.

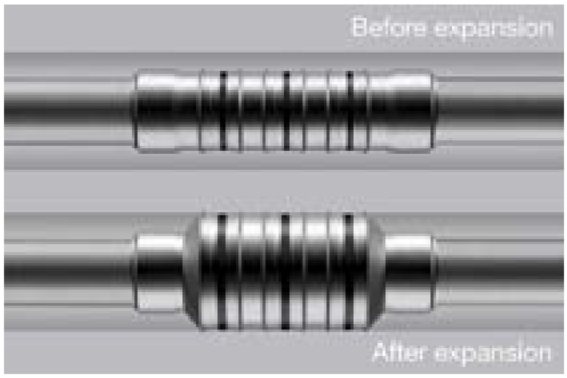
Actionable drilling and completions insights driven by enterprise AI

Saving time, finding efficiencies, optimizing processes and reducing costs are ultimate goals for any company. To meet these goals, operators are turning to machine learning and automation to help drive results. Well Data Labs offers artificial intelligence (AI)-enabled reporting, benchmarking, real-time alerting and optimization tools, and deep diagnostic studies that are helping operators increase efficiencies, create repeatable workflows, and reduce costs and risk. Leveraging its AI automation, Well Data Labs helps operators plan, manage and optimize their drilling and completion activity. The company has worked with numerous North and South American operators to provide sealed wellbore pressure monitoring reports and fracture diagnostics to study well spacing and completion design. The platform can also identify and alert operators in real time on events like pressure changes that may indicate casing failure and fracture-driven interactions. With the company's pad efficiency reporting, operators can drive well/pad profitability by minimizing swap time and nonproductive time while also optimizing material usage.

Well Data Labs simplifies multiple, complex data sources into actionable, easy-to-understand, real-time insights. (Source: Well Data Labs)

Metal expandable packer technology can prevent sustained casing pressure

Combining metal expandable packer technology with cementing offers a reliable, safe and more effective solution for life-of-well sealing in hydraulically fractured wells. When used to supplement current cementing practices in open hole, MEP technology can prevent issues with sustained casing pressure before, during and after hydraulic fracturing operations. Also known as bradenhead pressure, sustained casing pressure can lead to challenges with wellhead emissions, casing deformation and even curtail production. Welltec has developed a full-bore Light Packer for the hydraulic fracturing market that can be seamlessly incorporated into existing well construction programs. A Welltec Light Packer is rotatable, self-centralizing and does not trap pressure like conventional external casing packer technology. This type of metal expandable packer technology is unique in its ability to seal and conform to exact borehole geometry, and it is achieved by applying surface pressure to the casing bore after the wiper plug is landed post cement. ■



The Welltec Light Packer rapidly expands via controlled surface pressure. (Source: Welltec)

Editor's note: *The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.*

Academia and Industry Embrace Nuance in Fracturing

Moving to subtle understanding of fissures and proppant.

By Gregory DL Morris, Contributing Editor

Pictured above: At Colorado School of Mines, students and faculty are advancing the frontiers of knowledge in areas such as mineral exploration and subsurface characterization, renewable energy sources and technology, advanced water treatment, robotics and high-performance computing. (Source: Colorado School of Mines)

Oil and gas developers are learning the power of persuasion. Since the initial commercial success of unconventional development, the sophisticated subtlety of seismic data interpretation and fine control of directional drilling have been in sharp contrast to the brute force of breaking rocks: heavy horsepower driving huge volumes of water carrying massive loads of proppant.

Recently, prompted by the needs of profitability, efficiency and stewardship, producers and the drillers they hire are rediscovering that pounding proppant into the pay zone is not a goal in itself, but merely a means to the end of getting hydrocarbons to the surface. Basic and applied research in academia and in the field are establishing that in many cases coaxing the resource out of the rock can be faster, easier and less expensive than crashing it out.

University research

There has been extensive work done on fracture propagation, proppant transport and lodgment, and fluid recipes. The swing to some subtlety even extents to new generations of wellhead power.

"The main purpose of our work is to understand how to maximize the surface area in the fracture so there is more contact with the wellbore," said Chandra S. Rai, Miller Chair and professor of petroleum and geological engineering with University of Oklahoma Mewbourne College of Earth and Energy. "That means studying things from the hydraulic fracturing process itself to proppant behavior. We take rock recovered from drilling or from outcrops and put it into the stressed condition as it would undergo during fracturing."

Those experiments last for several months. Over the course of the research, some intriguing findings have already been made. Notably, some of the decline curve for a well is not just a matter of tapping out the pressure.

"There are a lot of things happening that are reflected in the decline curve," Rai said. "The type of proppant, size and quality are part of the curve. The better we understand the other factors, the better we can address productivity of the well."

As one example of the multiple variables involved, "even ceramic spheres have their downside as proppants," he said. "They are very strong, no doubt, they won't break. But they are subject to embedment and to chemical degradation."

Most broadly, Rai advocates a holistic approach.

"As wells are going deeper and deeper, they are taking larger and larger compressors. But we have come up with some methods where you don't need so much horsepower."

—Chandra S. Rai, *University of Oklahoma Mewbourne College of Earth and Energy*

"We can take some [rock] samples from the well, hydraulically fracture them and look at them under the scanning electron microscope and say that if you pump differently you could get better results," Rai said. "As wells are going deeper and deeper, they are taking larger and larger compressors. But we have come up with some methods where you don't need so much horsepower."

This is as much a business revelation as it is a technical one. Since the commercialization of hydraulic fracturing, the basic approach can be captured in the pop culture expression "Hulk smash!"

"These days we are just bulldozing down hole," Rai said. "People want to use maximum horsepower, maximum amounts of water [and] maximum sand loading. All that takes bigger compressors that cost more money. Maybe for all that you just get one large fracture. But what you really want is a dense network of small fractures that remain open. It's not about maximum power or load; it's about maximum surface area of the source reservoir rock exposed to the bore so it can be drained."

To monitor those experiments, Rai's program uses acoustic sensing.

"We can map the sound just as can be done for microseismic surveys," he said. "The focus, as I said, is to learn the effects of lithology, fluid properties and pumping protocol to optimize surface area and productivity of the frac."

One particular area of focus is proppant behavior.

"Several things can happen," Rai explained. "That can range from degradation to embedment, all of which can affect conductivity. Proppant is put in place to hold the fracture open, but the proppant itself affects fluid flow. There can also be silica diogenesis or other chemical reactions."

The decision about what type of proppant often involves balancing how robust the grains or spheres are versus how much they cost. But the toughness of the proppant is only one factor.

"There can be instances where the rock closes around the proppant or the proppant becomes imbedded," Rai said. "That is just as detrimental as if the proppant gets crushed."

From crosslink to HVFR

Oilfield services companies are also transferring knowledge. Having sold its onshore hydraulic fracturing business in North America to Liberty Oilfield Services in January, Schlumberger is now focused on taking its expertise to unconventional development in other parts of the world, notably Argentina, Saudi Arabia, the United Arab Emirates (UAE) and China.

"Geologically, the Vaca Muerta Formation in Argentina has some similarities to the Eagle Ford, but under higher tectonic stress," said Pedro Artola, Schlumberger's stimulation technology adviser for the Western Hemisphere. "That means that the pressures are higher than in North America. We are pumping at 11,000 to 12,000 psi. That also means that the selection of friction reducer is fundamental. Early jobs used crosslink gel, but that has been replaced with high-viscosity friction reducers [HVFR] for better proppant transport."

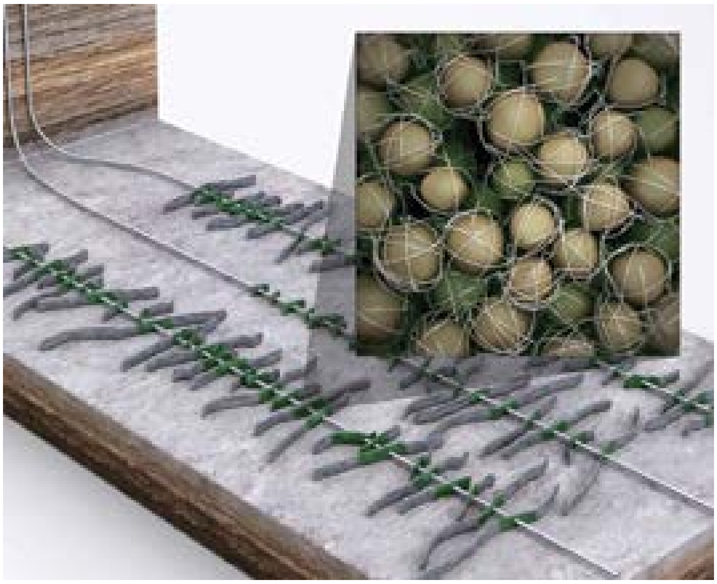
That is effective even at salinity levels of 300,000 ppm, Artola said. Laterals in the Vaca Muerta are often about 8,500 ft, so shorter than is common in the U.S., with 45 to 50 stages, which is a bit denser than in the U.S.

"Proppant selection is a similar story to the U.S.," Artola added. "Ceramics were considered early, but we have moved away from that. We are now using mostly in-basin sand, mostly 100 mesh and 30/70."

Some operators are experimenting with high-intensity completions.

"They are placing 2,800 to 3,000 pounds per foot in stages of 180 feet, even 150 feet," he said. "That means 24 [million] to 25 million pounds per well as compared to the average in North America of 15 [million] to 16 million pounds."

In the Eastern Hemisphere, "the most action is in the Middle East and China," said Philippe Enkababian, Schlumberger's stimulation technology adviser for the Middle East and Africa. "Both regions have



PropNET proppant flowback control technology maintains proppant pack integrity and conductivity after hydraulic fracturing in any reservoir environment. This enables aggressive cleanup, faster well turnaround, lower flowback costs and reduced time to commercial production. (Source: Schlumberger)

capitalized on the work done in North America and Argentina. The tectonic regimes are highly compressive with strike-slip faulting. That makes proppant characteristics and placement very important."

In the Middle East, the primary targets are Jurassic carbonaceous shales.

"Saudi Arabia is in full development," Enkababian said. "The UAE wells are still in the appraisal stage. They tend to be deeper and hotter."

The evolution of chemistry is similar to what took place in the Western Hemisphere.

"By 2017 Saudi Arabia was pumping mostly slickwater," Enkababian said. "In 2018 and '19 there was a gradual shift to HVFRs. In the UAE the conversion was just last year."

Enkababian noted that in Saudi Arabia laterals tend to be only 5,000 ft to 7,000 ft lateral length, while the variability in China is wider at 6,000 ft to 11,000 ft.

"In China it is common to frac 30 to 40 stages, with proppant loads of 2,000 to 2,500 pounds per foot of 100 mesh and 40/70 ceramic," he said. "Chemistry is a mix of crosslink, slickwater and HVFR."

He explained that because of the higher compressive forces in the rock, most in-basin sand still needs some ceramics near the wellbore to cope with the closure stress.

"In the early days, it was common to use full ceramic, and in the basins under appraisal, and most jobs still use approximately 80% ceramic," he said. "There is a gradual reduction in the use of ceramic proppant in the Eastern Hemisphere. The shift to in-basin sand in those regions has given improved economics with no meaningful reduction in production."

Worldwide the shift to in-basin sand and less water is part of an overall effort to reduce cost and environmental impact.

"Water availability and cost are not too much of a challenge in most regions," Artola said, "but there are some savings and environmental improvement. In Argentina some clients are considering implementing a partial closed-loop reusing produced water blended with fresh. We can use flowback water, produced water, brackish water and, in some cases, even seawater."

Where to land the laterals

As the industry rethinks the need for ever-greater horsepower, it is also reconsidering the desirability of ever-greater later lengths.

"The state-of-the art is two- to three-mile laterals," said Jennifer Miskimins, head of the Petroleum Engineering Department at Colorado School of Mines (CSM). "That is driven by land use as well as economics. Long laterals from the same vertical well can save in capital costs. The wine-rack technique for spacing has become standard even though researchers and industry are still trying to determine the balance between optimized drainage and interference in every basin. Some operators are ahead [on spacing optimization]; some operators think they are ahead."

A more elusive challenge is where to land the laterals within the pay zone.

"Across plays, and especially in the Wolfcamp and Eagle Ford, researchers and industry are trying to understand where and how many laterals to drill," Miskimins said.

An important part of making those determinations is downhole metrics, notably the diagnostic fracture injection test, which is done at the toe of the bore.

"It helps to determine the stress profile of the entire well," she said. "That is an important pretreatment diagnostic for permeability—where are the easy molecules to access?"

Another useful diagnostic, Miskimins mentioned, is sealed wellbore pressure monitoring that Devon patented a few years ago. The technique can help determine spacing and clustering.

"It is just a wellbore in the center of the wine rack," Miskimins explained, "just a piece of pipe being used as a pressure gauge. As the other wells around are fractured, the changes in pressure are recorded and help determine pumping action and how far the fractures are propagating."

The concept is relatively simple; the patented parts are the processing and analyzing of the data.

More broadly, Miskimins said fiber-optic sensors and data analytics are being used more widely.

"There is just so much data coming out of the well," she added. "Visualization of what is going on downhole and across the play is growing fast. There is much more sophistication in the stimulation world."

One of Miskimins's areas of concentration is proppant transportation using both data from fieldwork and computational fluid dynamics.

"If you are pumping 40/70 sand, we have found that in the bore and in the frac, the sand will segregate itself. Just as you see in a riverbed with high flow rates, there will be differentiated settlement of dust, gravel and boulders. Even if the sand is well sieved, the particles of different size and shape will separate top to bottom."

In terms of proppant, transportation is very much affected by viscosity. In many formations the preferred weight is a step higher than slickwater, but not quite a gel, Miskimins said.

"Ceramic beads are always better in terms of their durability, but what people are pumping depends as much on economics as on characteristics," she said.

The same applies to sand. Local sand is usually cheap, and pits have been opened in or near most major basins. Still, "Ottawa [Wisconsin] sand is some of the best," according to Miskimins.

Miskimins is also studying how the perforations in the pipe are eroded, which can affect well performance.

At present downhole sensing can differentiate gas from liquid, but the Holy Grail remains discerning oil from water.

"At present, there is not enough difference in density for sensors to detect," Miskimins said.

Drilling and completing successes

Beyond the laboratory bench, CSM collaborates extensively with the industry but also has its own field research facilities. Notably, a former silver mine.

"We have drilled holes through the mine and lined them with instruments and fiber optics," Miskimins said. "We can measure stress and temperature, among other readings. For temperature we can measure the gradient of 0.1 F every 20 feet for the wellbore length. We can measure strain in the rock."

For all the advances in frac operations, Miskimins said frac performance has remained steady.

"We can detect stresses out thousands of feet from the bore, but in terms of actual drainage from the rock we are still lucky to get 50 feet of effective wellbore," she said. "We also know that the fractures grow farther than we drain from."

So even after decades of successful unconventional development, there is still plenty of progress to be made in simply cracking the rock and getting the hydrocarbons out of the cracks.

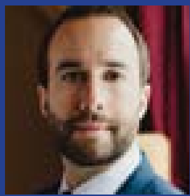
Colorado School of Mines researchers were recently awarded $6.3 million by the U.S. Department of Energy to develop and demonstrate a potentially transformative system to harness and distribute geothermal energy. (Source: Colorado School of Mines)

"Overall, industry has gotten very good at drilling and completing wells," she said. "Times that used to be measured in weeks are now measured in days. What we are still trying to improve is efficiency. We can drill fast and frac fast. We are trying to be sure that the fracs are actually doing what we want them to do."

North America is where unconventional development was invented, and the region remains on the leading edge.

Proppants and produced water

"The two basins in Canada where the industry is pushing the edge of frac design are the Duvernay and the Montney," said Dustin Domres, leader of fracture optimization for the Canadian division of Calfrac. "Typical pressures are 60 to 70 megapascals, with 80 MPa as an upper limit. Proppant loads have been tested up to 6.5 metric tonnes per meter. Fluid volumes vary greatly from region to region. In



"The two basins in Canada where the industry is pushing the edge of frac design are the Duvernay and the Montney."

—Dustin Domres, *Calfrac*

Canada and in the U.S., most jobs have been pumping slickwater, with a huge uptake of HVFRs."

Robert Sharpless, manager of divisional engineers for the U.S. division of Calfrac added that in the U.S., across the major basins, pressures run from 8,000 psi to 12,000 psi, with proppant loads of 1,000 to 2,000 lbs/ft of completed interval.

One important factor in frac design, Sharpless added, is the degree to which an operator decides to use produced water.

"The chemistry can be a challenge. In the Permian and the Marcellus, many operators use produced water, but the ratio varies greatly, from 100% to zero," he said. "That can mean total dissolved solids of anything up to 250,000 ppm."

He noted that the relatively high use of produced water in the northeastern U.S. means that cationic friction reducers are commonly used. Operators provide expected water characteristics at the time of a bid, but before the job is pumped, samples of actual field water are taken to qualify the planned chemistry. By applying tailored chemistry, the choice of an optimal friction reducer can provide the opportunity for increased placement efficiencies, job design modifications and improved operational execution resulting in a reduced environmental footprint.

As much as possible, Calfrac uses dry friction reducers with emulsions or slurried friction reducers. Most of their completion programs in Canada and a few in Argentina have moved in that direction. By transporting bulk dry friction reducers, they have reduced their round trips by almost 60%. The company expects dry friction reducers to possibly become more common for them in the U.S. soon.

Moving into the jet age

Not all of the reconsiderations in fracturing technology are completely new. Over the decades, drillers have experimented with topside power, including turbines and electric motors. There has been a consolidation around conventional diesels with some gains recently in electric power, but that too is being reevaluated. It is all part of a longer-term view to efficiency and effectiveness over the life of the well, including refracs, not just big IP rates.

"We have had over 15,000 unconventional wells drilled in the state," said Vamegh Raouli, department chair and Continental Resources Distinguished Professor of petroleum engineering at the University of North Dakota (UND). "The technology is very much advanced. In the longer laterals 30 stages is common, and in some cases we have seen as many as 60 stages."

As producers and drillers have pushed downspacing, communication or interference between wells, what Raouli calls "frac hits," is a growing problem.

"The goal is not necessarily to increase stages but to maximize efficiency and minimize effort and expense," he explained. "There is also a challenge to determine whether to refrac or not, and if so, when and where. That is a focus of our effort. We have a few Ph.D. students working on refrac research, especially on the potential benefits of refracturing. There are lots of theories on that, but we want to know what is actually going on."

In particular, the research is digging into the direction of the refrac.

"Ideally, you want to go different from the original frac," Raouli said. "The questions are whether the rock is capable of being fracked that way, and if so, how to do it."

The research is being supported by state funding.

"In North Dakota, we have the unique property of having shale oil with its challenges as compared to shale gas to study," he said. "The North Dakota Industrial Commission supports our program, which has close to 80 Ph.D. students. That may be the largest in the country, at least in the top three. The Energy and Environmental Research Center at UND is another great benefit to our students and our program."

E-frac fleets and turbine-driven pumps

To achieve optimal fracturing treatments, one of the main inputs is horsepower at the wellhead, which is where BJ Energy Solutions is leading a renaissance in natural gas fired turbines. While turbine engines have inherent operational benefits, the company made a virtue of necessity when it replaced its fleet.

"We have a rich legacy dating to 1872," said Warren Zemlak, BJ's president and CEO. "When we reemerged as an independent company in 2017, we faced a large, aging diesel-powered fleet. There was a lot of talk at the time about electric frac fleets. We did a lot of work studying cost, operational simplicity, emissions, energy balance, fluid handling, reliability and settled on direct-drive turbines."

The emphasis, Zemlak said, is on the mobility and modular design, maximizing efficiency, and minimizing cost and environmental impact. There is also an acknowledgement that in some formations a subtler approach to fracturing may be more productive than simply hammering horsepower into the well.

"With diesel-powered fleets, you are often limited to the relationship between an engine and transmission," Zemlak said. "Electric- and turbine-driven pumps have a linear relationship, so you can optimize the power efficiency between the available power and number of pumps resulting in a smaller footprint. We have also incorporated proprietary digital controls."

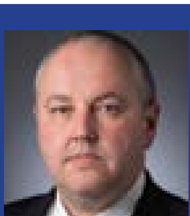
Realistic physics

More advanced power at the wellhead is being matched with more powerful analysis of what is happening in the bore.

"Our focus has been on drilling and completions data as well as pressure monitoring and fuel usage," said Jessica Iriarte, manager of the data science team with Well Data Labs. "But there is so much data available, we have been expanding into tying those to emissions tracking as well. We also have a partnership with Devon Energy for analyzing well interactions by monitoring sealed wellbores."

Having structured industry data from different sources allows Well Data Labs to compare many aspects of well performance against industry trends or against design parameters. Not surprisingly, a great deal of analysis and modeling is directed to maximizing production while preventing communication between wells. That ranges from cluster efficiency to fracture treatment design including fuel efficiencies.

"One of our models can predict communication between wells in real time," Iriarte said. "We can notify a client when there is a frac in one well that causes a pressure response in another. We are working on understanding what causes those. It's not so much about getting as much fluid and proppant as possible into the well but doing it in a cost-effective, environmentally friendly and safe way."



"Electric- and turbine-driven pumps have a linear relationship, so you can optimize the power efficiency between the available power and number of pumps resulting in a smaller footprint."

—Warren Zemlak, *BJ Energy Solutions*

Beyond the turbine engine itself, "all the remaining mechanical components are similar to traditional equipment," he said. "You don't have to retool the pumps or retrain the workforce. Turbine reliability allows the team in the field to focus on job execution."

Noting that the concept of direct-drive turbines is not new and acknowledging that the history of the system is checkered, Zemlak stressed that the new generation of turbine power has more than 10,000 hours of operation in the Haynesville, "one of the harshest environments."

He added, "These are proven engines with very long lives. They will outlast the pumps."

Big Data can also yield insights above ground.

"We can analyze rig states, activity and events and focus on efficiencies," Iriarte said. "Then we can compare crew to crew, rig to rig, and generate real-time diagnostics alerts. That way the operator can make changes to improve and sustain their operational efficiency."

Modeling and simulation analysis

Ahmad Ghassemi, professor of rock mechanics and McCasland Chair in the Mewbourne School of Petroleum and Geological Engineering at the

"One of our models can predict communication between wells in real time. We can notify a client when there is a frac in one well that causes a pressure response in another."

—Jessica Iriarte, *Well Data Labs*

University of Oklahoma, leads a program on experimental work as well as modeling and simulation analysis.

"The emphasis is on effective stimulation mechanisms," he said. "More connected cracks in the formation means more surface area exposed to the wellbore. We want to know how they form, when and where. That will allow for design optimization and pumping protocols."

The recent attention to interference among proximate wells is one particular area of emphasis and a reminder of the adage that the model is only as good as the premise.

"Most people believe in a single frac, and most models take that route," Ghassemi explained. "But core and communication among wells indicates more complex modeling is necessary. A lot of models take a lot of short cuts. They are heavily tied to the original conceptual thrust. The physics need to be realistic."

Another area of emphasis is micro-seismicity in stimulation, in contrast to induced seismicity from reinjection of produced water. Ghassemi's program is examining how microseismicity relates to increasing the permeability of formations.

The output of all the research is a better understanding of well spacing, infill drilling, and the timing and approach to refracs.

"Modeling is very useful, especially for timing of refracs, not just on spacing," he said.

And giving a nod to a less carbon-intensive future, Ghassemi's program extends its expertise into geothermal development.

"That is getting a lot of traction lately," he said. "It's really many of the same issues as oil and gas drilling, just deeper and at much higher temperatures." ■

A number of graduates from the Mewbourne School of Petroleum and Geological Engineering (MPGE) programs have become CEOs of major oil and gas companies, and seven MPGE alumni have served as president of the Society of Petroleum Engineers. (Source: University of Oklahoma)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