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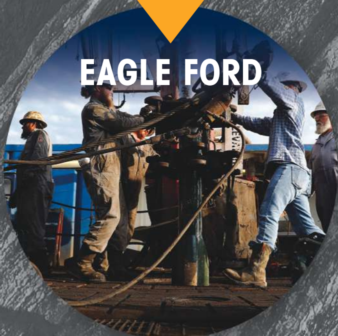
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From the Editors

2019 UNCONVENTIONAL YEARBOOK

HARTENERGY

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2019

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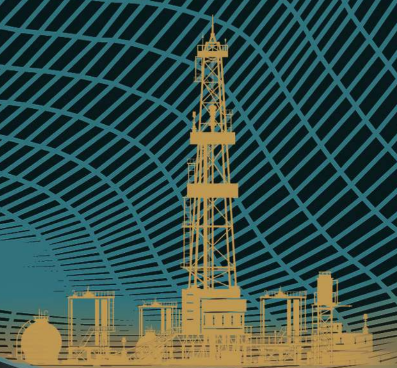
December	*E&P* Special Issue – Unconventional Yearbook



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ONLINE CONTENT **DECEMBER 2018**

ACTIVITY HIGHLIGHTS

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Woodford Producer Flows 19.8 MMcf/d of Gas

A Woodford discovery by Continental Resources Inc. was tested flowing 19.8 MMcf/d of gas and 4,190 bbl/d of water. Located in Section 28-4n-6w in Grady County, Okla., the Bovine 1-28-33-34XH well is producing from an acidized and fractured zone between 15,912 ft and 26,226 ft.

Arsenal Receives Permits for Marcellus Tests in W.Va.

Arsenal Resources LLC has received permits to drill three Marcellus Shale tests in an unnamed field in Cove Dist., Nestorville 7.5 Quad in Barbour County, W.Va. One of the wells, 204 Howdershelt BCH, has a projected depth of 16,112 ft, with a true vertical depth of 7,594 ft.

Goodrich Completes Two Haynesville Shale Wells

Goodrich Petroleum Corp. has tested two extended-lateral Haynesville Shale wells in Red River Parish, La. The Thorn Lake Field wells were drilled from offsetting surface locations in irregular Section 11-14s-11w and both bottomed about 2 miles to the south in Section 23.

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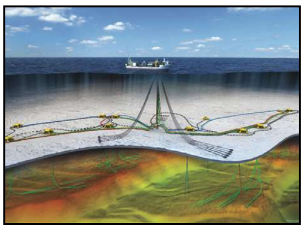


Norway, Newfoundland and Labrador Keep Arctic Exploration Alive

By Velda Addison, Senior Editor, Digital News Group

Projects like the Equinor-operated Johan Castberg and Bay du Nord developments highlight the Arctic region's potential.

Oil Industry Moves beyond Digital Hype to Add Value

By Velda Addison, Senior Editor, Digital News Group

Chesapeake Energy Corp., Baker Hughes, a GE company, and VAKT share thoughts on digital technology and how it is transforming the industry.

CEOs have Appetite for New Technology

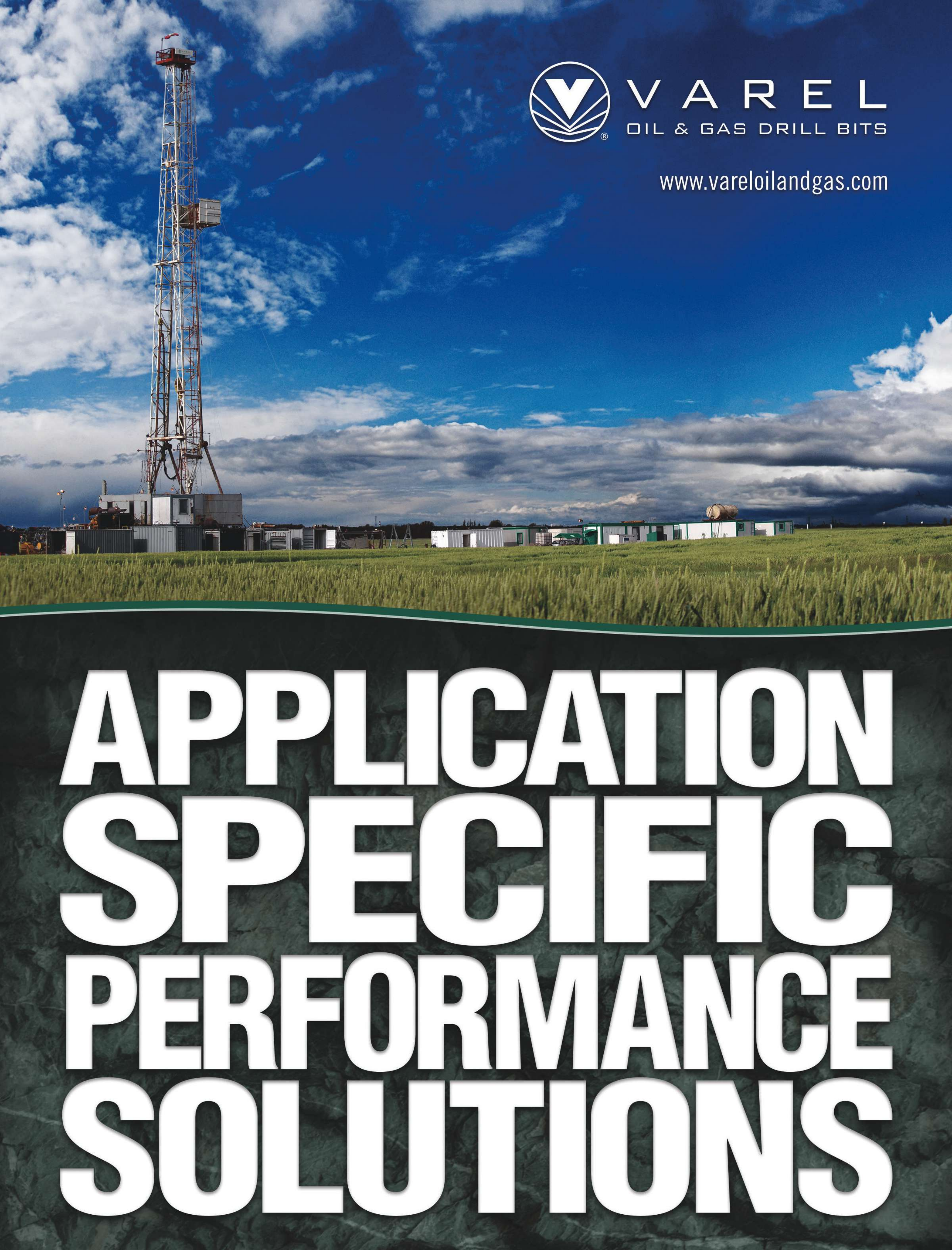
By Mary Holcomb, Assistant Editor, Digital News Group

CEOs are aware of the benefits of new technology such as artificial intelligence, but many say their companies are unprepared for disruption.

Analysts: More Spending Needed to Meet Future Oil, Gas Demand

By Velda Addison, Senior Editor, Digital News Group

Annual development spending by upstream oil and gas companies needs to rise to about $600 billion through the next decade, analysts say.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New Year Ahead Brings Adaptation

A little of this mixed with a little of that creates a stronger future.

Birds do it. Bees do it. Flowers do it. Even car manufacturers do it. How else would the world get the recently discovered Burket's warbler, the Africanized honeybee, the Stargazer Lily or the Toyota Prius? Hybridization, the process of combining a variety of elements to create a new element, is nature's way of responding to the "what if" question.

For the *E&P* editorial team, that question came disguised not as a "what if" but as a "how can we deliver compelling content and insights on the year ahead to our readers faster?" Naturally, our discussion turned to the December issue, then to the annual *Unconventional Yearbook*, and voila!

You, dear reader, hold in your hands the answer. In this first-of-its-kind hybrid issue, we have combined the compelling content for which Hart Energy's playbooks are known with the insightful commentary by the *E&P* editorial team to create the 2019 Unconventional Yearbook issue.

On the pages that follow, you will find in-depth coverage featuring the top five unconventional U.S. regions: the Permian Basin, Eagle Ford, Bakken/Niobrara, Midcontinent and Marcellus/Utica.

Reuters reported that U.S. crude oil output from seven major shale basins was expected to hit a record of 7.94 MMbbl/d in December, according to a monthly government forecast released on Nov. 13.

The total oil output from the basins was expected to rise 113,000 bbl/d, driven largely by increases in the Permian Basin of Texas and New Mexico, where output was forecast to climb by 63,000 bbl/d to about 3.7 MMbbl/d in December, the U.S. Energy Information Administration said.

U.S. natural gas production, meanwhile, was projected to increase to a record 75.1 Bcf/d in December. That would be up more than 1 Bcf/d over the November forecast and would be the 11th monthly increase in a row. Output was just 63.9 Bcf/d a year ago in December 2017.

Production from these plays has pushed the U.S. to the top as the leader in global oil production.

Expert editors and contributors provide the most important facts and figures on the economics as well as technology trends, logistics, environmental concerns and key player activity in this comprehensive and unique issue of *E&P*.

In addition, this hybrid approach will continue into the new year with four issues planned to take a similar approach.

In March an expanded *Water Management Techbook* will land in your mailbox. In addition to best practices and technology trends for the unconventional market space, we'll dive into the offshore sector and how operators are handling produced water challenges and more. The May issue will feature the *Offshore Technology Yearbook*, delivering comprehensive coverage of the global offshore market, including exploration, drilling and production trends.

The *Permian Basin Playbook* will publish in the October issue with a thorough review and analysis of topics concerning operators, service companies and more in the region. The December 2019 issue will deliver a 20/20 focus on the decade ahead for shale players in the *2020 Unconventional Yearbook*.

Our analysis didn't end once the decision was made to go with four hybrid issues in the new year. We also looked at other areas within the magazine that could use a fresh approach.

Take, for example, our cover stories. In addition to our traditional lineup of exploration, drilling, completions and production technologies, we've added frack sand and logistics, deepwater advances and downhole tools. Each are topics with the potential to grow exponentially in the year ahead. E&P

Jennifer

Apache's Raymond Plank Passes Away

'It's not about what we get; it's about how we get it and how we use it,' Plank once said.

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Raymond Plank, the founder and former chairman of Apache Corp., passed away on Nov. 9 while at his beloved ranch, Ucross, outside Sheridan, Wyo. He was 96.

An avid reader to the end, growth and learning were two words that cropped up again and again when we last talked with Plank in 2012 upon publication of his memoir, "A Small Difference." He had a remarkable career that spanned more than 50 years.

"For the many of us at Apache who knew him, and the many more whose lives he touched, we remember Raymond as a visionary leader and a strong, passionate and caring man. His leadership, courage, generosity and integrity are central to the core values he instilled at Apache, and they continue to guide us today. We send our deepest condolences to the Plank family," said Apache CEO and President John J. Christmann IV in a statement.

(Source: Apache Corp.)

Raymond Plank
1922-2018

Born in 1922 and raised in Minneapolis, Plank was a bomber pilot in the Pacific during World War II before returning to the U.S. Three of the B-24s he piloted barely made it back and never flew again, relegated to being a source of parts.

Exiting Yale in 1946 with a bachelor of arts degree, majoring in international relations, he formed a small bookkeeping, tax and accounting firm in Minneapolis. It was transformed when he started managing oil and gas investment partnerships at the request of some clients. He and two friends, Truman Anderson and Chuck Arnao, formed Apache Corp. in 1954 with $250,000. Today its market cap is $13.6 billion.

In 1956 Apache offered its first oil and gas investment program and was an industry leader in that until it dropped annual drilling program sales in 1986. Apache went public in May 1969.

Plank built the company beyond his wildest dreams, with a series of savvy acquisitions and drilling throughout the U.S. The company made a splash with some of the biggest acquisitions from the majors in the 1990s, obtaining mega-independent status and gaining superior positions in Australia, Canada and Egypt. Its market cap reached $50 billion by 2008, his last full year as chairman. He retired in January 2009.

Plank received much recognition throughout the years and served on numerous civic, charitable and industry boards. He was honored as CEO of the Year three times by the Wall Street Transcript.

He was called irascible, frank and a force of nature. He was always interesting. But service to others was a cornerstone of his life, following the advice he received from his father at age 10, to make "a very small difference on behalf of others."

His dreams for growth, corporate and personal, always led to hands-on philanthropy. Among the many charitable causes he created, Apache built 203 one-room schools to educate young girls throughout Egypt, and Apache also endowed the Fund for Teachers, which has supported more than 5,000 U.S. teachers with stipends and sabbaticals.

"It's not about what we get; it's about how we get it and how we use it," he wrote. "It isn't what we inherit or pursue; it's about whether and how we elect to grow. Lifetime learning is so important. If I weren't learning I wouldn't be around, because it's my mind which allows me to still get around," he told *Oil and Gas Investor* in 2012. E&P

Leslie

Horizontal History

Horizontal drilling was an overnight success 85 years in the making.

By Richard Mason, Chief Technical Director

You've heard the conventional wisdom that success has a thousand parents while failure is an orphan. That thought comes to mind after reviewing crowd-sourced observations about the evolution of horizontal drilling on discussion threads for the Society of Petroleum Engineers.

One can view the innovation simply in terms of the horizontal drilling process that dates back to the 1930s or holistically in terms of support technologies, such as packers for zonal isolation, that extend more than 100 years ago. Today horizontal drilling implies precisely targeted wellbores, slickwater plug-and-perf completions, high proppant volume and hydraulic horsepower to generate drainage from multiple stages.

- **Horizontal drilling now represents more than 80% of the U.S. land rig count.**
- **Multiple smaller iterations converged to create today's all-purpose drilling solution.**

The story that unfolds is international in scope with iterations in Russia in the late 1930s and targeted laterals in the Mediterranean's Rospo Mare Field via Elf Aquitaine (now Total) in the early 1980s. There were evolutionary stops along the way offshore in the North Sea and onshore in Latin America and Canada during the 1980s and 1990s.

Iterations include long, medium and short radius curves to go horizontal with the domestic industry now focused on medium radius curves to turn the wellbore from vertical to horizontal.

Credit the Russians with early use of downhole motors as a key technology, which evolved from submersible pumps to which the Russians attached a turbine-powered drillbit. Later, evolution of the PDC drillbit provided the ability to survive hostile downhole conditions and to drill faster.

Turning horizontal was one thing. Initially, whipstocks solved the problem, followed by jointed downhole tools, which were later supplanted by cleverly designed articulated bottomhole assemblies (BHAs).

But steering a BHA in a targeted manner was another thing altogether. Credit MWD technology dating back to the late 1970s that provided the ability to communicate downhole data to the surface and almost simultaneously LWD, which included tough logging conditions of the curve and lateral in the Permian Basin's Spraberry Formation in 1985. LWD enabled surface operators to see the downhole environment.

Finally, there are business model variations that hastened technological innovation. While the multinational majors were instrumental in basic research and early field experiments, especially offshore, many innovations that moved the industry forward came through smaller companies with an experimental attitude. The Austin Chalk was developed primarily, but not exclusively, by firms such as Amoco (now BP), Sun (later Oryx) as well as Burlington Resources (now ConocoPhillips) in the late 1980s.

Consortia, some with government funding, enabled the industry to advance the process through trial and error under the observation and guidance of subject matter experts a decade faster than would have been the case with single large companies.

Where are we today? Iterations find directional drillers using algorithms to automate the geosteering process and create straighter wellbores. Completing wells successfully presented its own technological challenge, but pump-down methodology, drillable plugs and self-dissolving materials are reducing costs and expanding productivity in tight formation reservoirs.

One also can credit top drives and the ability to rotate the drillstring along with modern fluids and improvement in cementing. Extended-reach laterals now exceed 20,000 ft and total measured well depth approaches 30,000 ft in select circumstances.

No need to ignore history to repeat it. Rather, new history will be made through refinements that move the technology forward. E&P

Seismic Data Enable Productive Wells

Despite a general lack of seismic in shale wells, it can have a profound effect on productivity.

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The Permian Basin has gotten so much ink lately that it might seem like poking a hole anywhere will result in a barnburner well. But that's not actually true. Sometimes seismic can actually make a difference between a great well and a dud.

That was the message delivered by David Paddock of WesternGeco at a recent Geophysical Society of Houston luncheon. While WesternGeco is no longer actively engaged in seismic acquisition, it still prides itself on processing and interpreting seismic data. Paddock outlined two projects in the Delaware Basin where seismic made a difference.

"The industry tries to pigeonhole us early in the life of the asset," he said. "They want to use us for structure [and] for landing these wells. But really, we use seismic over and over again."

He added that this recent work includes characterizing stress, the rock and natural fractures. "That really gets you into the realm of the completion design, and once you get the wells under production, you start to understand what the production drivers are and utilize those learnings. You keep going back to seismic throughout the life of the asset," he said.

"This is the cool stuff you can do with seismic."

—David Paddock, WesternGeco

According to Paddock, 72% of the wells in the Wolfcamp are economic. But WesternGeco geophysicists were challenged with determining why 28% of the wells weren't.

The company chose 22 wells based on multiple sources of data. Based on its estimates, only 10 of the wells in the study area were economic. "It's actually a bit of a train wreck," he said.

While the study checked for silicaceous rock, even the best rock had only 7% porosity. Some of these wells had a very small ROP. The seismic showed that the reservoir was not consistent across the entire area despite previous models.

"You can't just frack your way to success," he said. "You need hydrocarbon-filled porosity for this to work."

Some of his examples showed wells where either the operating company didn't believe in using seismic or a company had a rig on location and had to drill up its acreage before seismic was available. These wells often missed their targets.

Paddock said most companies working in this area are drilling up the Wolfcamp A Formation and will soon be turning their attention to the Wolfcamp B. "You can actually start to do some exploration here, which as a geophysicist I find exciting," he said, adding that current data indicate the quality of the shale. For instance, the more silica that is involved, the more porosity is likely to exist.

Water is another issue. Faulting in the region can bring in water not only from the Pennsylvanian and Mississippian formations but also from the shallower Delaware Formation. "If you drill too close to these faults, it will be an issue," he said. Fine-tuning the fault attributes has helped the company in the North Sea and is likely to be useful in the Permian Basin as well.

"This is the cool stuff you can do with seismic," he added. "The dirty little secret of 3-D mechanical earth modeling is that you have a pretty good idea of your tectonic stresses. You know what the stiffness is.

"You can go into your mechanical earth model and dial up and down the 'stickiness' until it matches the model. We think that you can predict induced seismicity using seismic data as your primary measurement." E&P

Rhonda

The Other Shales

E&P companies are quietly at work proving up the next generation of unconventional plays.

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Read more commentary at
EPmag.com

It is easy to get caught up in the staggering Permian Basin oil production numbers or bewildered by the Beast of the East's (Marcellus) breathtaking rates of gas production. Midcontinent operators are "scooping and stacking" impressive well returns, the Eagle Ford appears to be on an ascent trajectory to soar once more, and the Bakken is getting back to rockin' and rollin.'

The advancements in technology necessary to make each play successful did not happen overnight. It was a steady progression of trying new approaches, tweaking as needed and repeating until the right solution was found to make a well produce at economic rates.

That same process is underway in unconventional resource plays across the globe. Take, for example, the recent announcement by Total S.A. and Abu Dhabi National Oil Co. (ADNOC) to launch an exploration program in the Ruwais Diyab unconventional gas concession block. The French major was granted a 40% stake, with ADNOC retaining the remaining 60%, according to a press release. The concession allows for two exploration and appraisal phases for a period of up to seven years, followed by a 40-year development and production period.

> Success will require a little time, a little luck and a whole lotta perseverance.

"The Diyab play has the potential to be a high-impact play ranking alongside the most prolific North American shale gas plays and is an excellent addition to our exploration portfolio," Total Chairman and CEO Patrick Pouyanné said in the release.

Cuadrilla Resources has inched closer to its final goal of producing shale gas from the U.K.'s Bowland Shale. The company announced in November that it had begun to see natural gas flow to the surface from its shale exploration well at its Preston New Road site. The gas returned to surface, along with water being recycled from the shale rock, after hydraulic fracturing a small section of the shale surrounding the first horizontal exploration well, according to a press release.

"The volumes of gas returning to surface at this stage are small. However, considering that we are only at the very start of fracturing operations and, given operating constraints, have not yet been able to inject as much sand into the shale as we had planned, this is a good early indication of the gas potential that we have long talked about," Cuadrilla CEO Francis Egan said in the press release. Next steps are to fully test flow rates from two exploration wells near the end of 2018 and into the new year following the completion of hydraulic fracturing operations, which began in mid-October, according to the company.

Here in the U.S., it was news coming out of the Tuscaloosa Marine Shale (TMS) that caught my eye as Perth-based Australis Oil & Gas announced that it had begun a six-well drilling campaign in its acreage near Gillsburg, Miss. The Nabors B14 drilling rig has been contracted to drill a minimum of six wells for the company with a provision to extend. According to an investor presentation in October, the first four wells will be drilled proximal to the company's Lawson 25-13H well, which has produced more than 300,000 bbl of oil in its first 24 months. First production for the Bergold 29H and Stewart 30H wells are planned for late February/early March 2019.

As with everything, success in Ruwais Diyab, the Bowland and the TMS will require a little time, a little luck and a whole lotta perseverance. E&P

Jennifer

Industry Looks to Stay Ahead of Environmental Issues

New attitudes and innovations work to combat air and water quality concerns.

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Read more commentary at EPmag.com

The studies are plentiful and wide ranging. The oil and gas industry is acutely aware of the environmental challenges associated with unconventional production. Many basins are seeing increased levels of air toxins, and wastewater injection has caused seismicity issues in Oklahoma and some in the Permian Basin.

However, despite many prevailing notions, the industry is not sticking its collective head into the same ground into which it drills. A closer look into the science community's observations of these environmental issues reveals a wealth of useful information oil and gas companies are leveraging to mitigate the impacts of hydraulic fracturing. For example, Stanford geophysics professor Mark Zoback has performed groundbreaking work in identifying areas in the Permian Basin where seismicity issues could arise from wastewater injection.

"Operators who are applying for a permit for an injection well now know to request information on the closest fault, how far they are from the basement [and] they ask to see what the stress fields are," said Laura Capper, president and CEO of EnergyMakers Advisory Group. "There is a heightened awareness of understanding those contributing factors."

Companies are touting new systems and processes that make significant impacts on the environment.

The Oklahoma Corporation Commission is being proactive in its efforts to avert future seismic activities in the Arbuckle Formation by issuing a new directive designed at "keeping future volume increases in check."

In addition, companies like Equinor and BP have made no secret about their designs to reduce greenhouse-gas emissions in their operations. Exxon Mobil has touted the need for carbon capture efforts, and Occidental Petroleum is fully employed in carbon capture practices in the Permian.

At oil and gas conferences and exhibitions across the U.S., companies are touting new systems and processes—systems such as electric fracturing fleets and zero-leak valves—that make significant impacts on the environment.

Meanwhile, organizations like the South Texas Energy & Economic Roundtable (STEER) serve as a bridge between the oil and gas industry—in STEER's case, in the Eagle Ford—government agencies and the public.

STEER Interim President Chris Ashcraft said the organization provides emission data from Eagle Ford operations to the Alamo Area Council of Governments so the council can accurately build emissions models and identify how best to improve regional air quality.

Ashcraft said one example of the work operators have embraced in recent years has been a concerted effort to reduce flaring.

"Flaring was a huge issue early on in the Eagle Ford," he said. "But there's been a focus on putting infrastructure and pipelines in place to reduce the amount of flaring and ways to utilize flared gas."

Ashcraft said when new environmental regulations are issued, operators often work ahead and work quickly to adapt to the new mandates.

"When they see regulations coming, they'll work to push it through the right way," he said. "To the point where ultimately those environmental impacts are mitigated, and because they view those efforts as having a social license to operate." E&P

The future is bright for activity in the Permian Basin as development accelerates in the region. (Source: Shell)

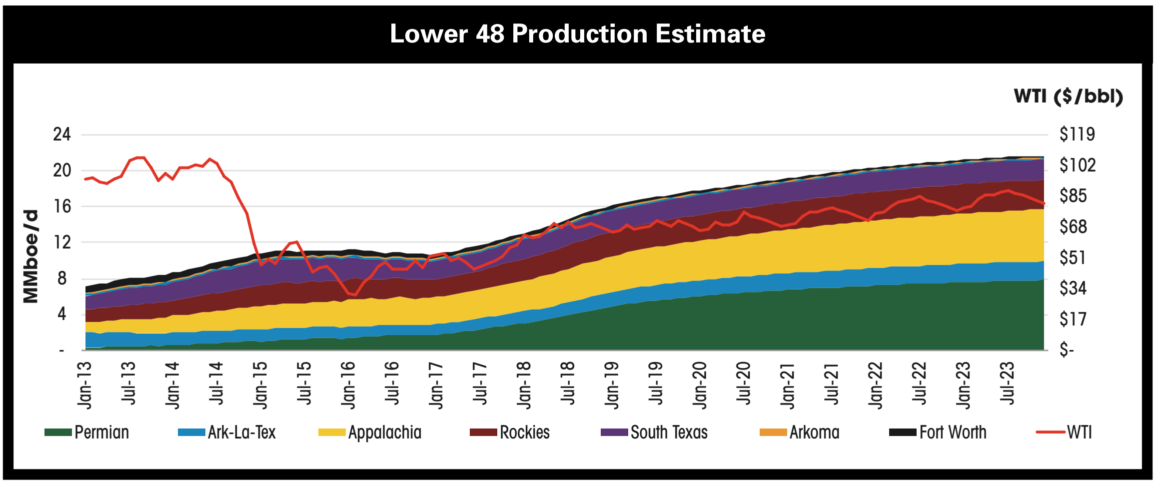
2019 Outlook Shaped by Evolving Themes

By **Stephen G. Beck**, Senior Director, Upstream, Stratas Advisors

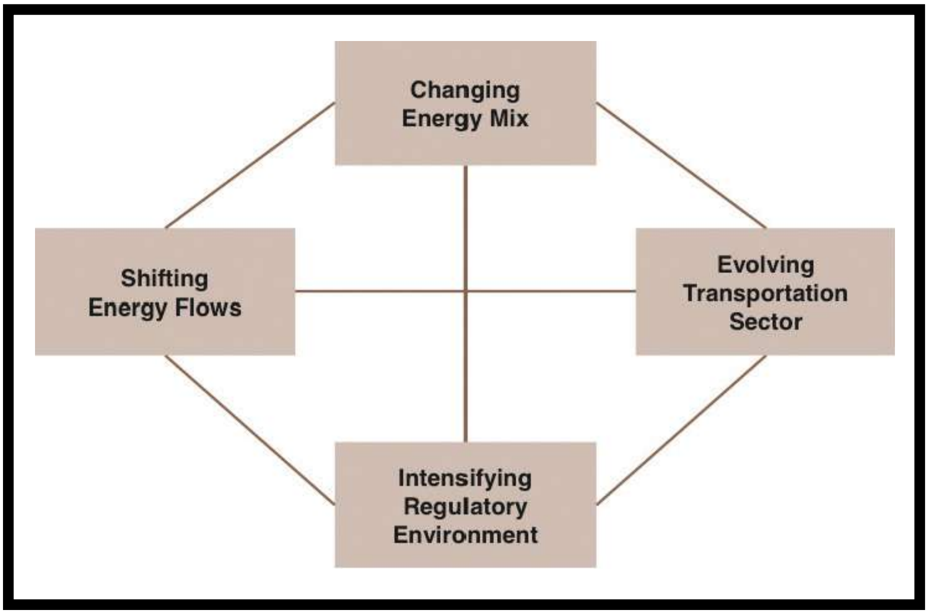
Familiar trends will continue to resonate in the new year as Shale 2.0 becomes another year older.

The 2019 outlook for shale remains dynamic on many levels. Operators and oilfield service companies continue to push the limits of technology and business processes, enhancing their chances of meeting investor expectations and extending the miracle of shale both geographically and temporally. During the past 12 months, companies broadened the application of longer laterals and high-intensity fractures, unlocking additional potential in places like the Permian, Powder River and Anadarko basins. However, companies did not stop with changes in the field. Instead, companies increasingly cast attention on their business processes, looking for opportunities to drive out costs. The combination of these collective efforts is a key driver behind changes in the 2019 forecast.

Shale and tight resource production is estimated to average 20.5 MMboe/d in 2019, an increase of 2.9 MMboe/d versus 2018 estimates. At the resource level, the Permian Basin remains king. Current 2019 estimates for the Wolfcamp, Bone Spring and related reservoirs have production averaging 5.9 MMboe/d. Breaking this down, the Delaware sub-basin Wolfcamp contributes 50%, the Midland sub-basin Wolfcamp contributes 32% and the Bone Spring contributes 18%. The Alpine High is commingled with the Delaware sub-basin Wolfcamp. This may change in the next year given the ramping activity and Apache's commitment to the play. In the Midland sub-basin, the Wolfcamp reigns supreme with 1.9 MMboe/d of production. Outside the Permian, expect the Anadarko and Powder River basins to notch growth of 0.22 MMboe/d and 0.04 MMboe/d, respectively. Elsewhere, look for the Appalachia plays to post gains of 0.57 MMboe/d (3.4 Bcf/d), driven in part from increased flows to the west and northwest and to the south. In summary, the plays with the greatest December 2019 versus December 2018 year-on-year growth are the Delaware-Wolfcamp at 0.76 MMboe/d (35%), the



Stratas Advisors' shale and tight resource production outlook represents the Lower 48 from 2013 to 2023. (Source: Stratas Advisors)



Stratas Advisors' four themes that impact energy help shaped its U.S. production outlook. (Source: Stratas Advisors)

Scoop at 0.11 MMboe/d (32%) and the Stack at 0.13 MMboe/d (29%).

Four themes shaped Stratas Advisors' views on U.S. production in 2018: a changing energy mix, shifting energy flows, an intensifying regulatory environment and an evolving transportation sector. These themes weigh on the company's views individually and collectively in varying degrees depending on the time horizon and the level of intensity anticipated from each theme.

At this juncture, a review of the Stratas themes and the role of each in the forecast will clarify the 2019 outlook.

Changing energy mix

The subject of a changing energy mix is multifaceted. Beginning with the obvious, liquids production from shale and tight resources is light and very light (field condensate).

At Stratas, production streams by grade and country of origin are tracked. In recent years, increases in unconventional resource production have been met by reductions in other areas like Venezuela. Using Venezuela as a case study, it is quickly seen that there are two dimensions presented by this change—the first is geographical and the second is crude quality. While the shift from South America to North America is not that great of a deal, the shift from heavy sour crude to light sweet and ultralight grades can be much more impactful. Sophisticated refineries, such as those in the U.S., are specifically designed to handle heavier crudes. This is not to say they are unable to handle light feedstock, just that the economics can vary. Suffice it to say that changes in mix introduce complexity to an already complex system.

Shifting energy flows

Staying with the Venezuela case study, it is easy to see that crude shipments are shifting about as a result of the shifting energy mix. However, this is but the tip of the iceberg with respect to energy flows. To put things in perspective, the U.S. is a top global producer. More to the point, production increases in shale have been outstripping changes in domestic demand, leading to increased exports and decreased imports from OPEC members and others. Looking to the horizon, it seems reasonable to project rising exports in the coming years. Projects connecting the Permian Basin and other productive areas to export terminals will serve to support longer-term development across North America. This is not novel but worth repeating nonetheless: Good long-term visibility is a critical success factor for all segments of the value chain. Long-term visibility in upstream hinges on having sound understandings of the resource geology, effective engineering and comparative economics.

Intensifying regulatory environment

Try as it might, the industry's ability to foretell the future is far from perfect. That reality allows the introduction of the third theme—an intensifying regulatory environment. Some are likely to challenge the notion of intensifying regulations. After all, regulations appear to be loosening at the U.S. Environmental Protection Agency, and the current administration appears friendly to the industry.

However, battle lines have been redrawn. Industry opponents have retrenched back to state and local jurisdictions. Colorado's Proposition 112,

defeated in the November midterms, was a proposal that could have severely impacted oil and gas activities across the state. In the most austere interpretation of Prop 112, every square mile of Colorado could have been subjected to scrutiny. Regardless of the proposition's outcome, companies in Colorado are feeling regulatory intensity.

Elsewhere, the ongoing sagas of the Dune Sagebrush Lizard in the Permian Basin and the sage grouse continue. In the case of the lizards, one study after another continues to hamper some efforts. Add to that the policies and restrictions arising from climate change and the swirling efforts by groups in California, the Pacific Northwest and elsewhere, and a case can be made for a tightening regulatory environment.

Evolving transportation sector

Stratas' last theme, an evolving transportation sector, speaks to both the near and long term. In the near term, industrial transportation is transitioning in real time. Changes to emissions on the open seas are leading mariners to consider early retirements of vessels versus installation of scrubbers. With new vessels, options for propulsion now include low-sulfur diesel, LNG and more. In passenger cars, marketing of electric vehicles appears on the rise. Clearly, more options will be introduced down the road.

Looking ahead

With this canvas, consider the road ahead for operators, service companies and investors in shale. In short, 2019 will resemble 2018 in that growth and financial discipline chatter will be common themes around shale water coolers, and risk and uncertainty will dominate international affairs. Familiar trends will continue to resonate in the new year as Shale 2.0 becomes another year older.

It is with this backdrop that modestly higher average prices are expected to support slightly higher spending in 2019. West Texas Intermediate (WTI) prices are expected to average $68.71/bbl in 2019, up from $67.03/bbl in 2018. Meanwhile, natural gas is expected to average $3.30/Mcf, up from just over $3. These prices lend support to a double-digit increase in capital spending versus 2018.

Spending levels throughout the year are projected to remain relatively stable with about half going to the Permian Basin. Most Permian spending will land in the Wolfcamp formations, with slightly more of the Wolfcamp spending finding a home in the Delaware sub-basin. More generally, unconventional resources will gobble up more than 90% of total 2019 spending. Even though 2019 spending is projected higher compared to 2018, rising net cash generation and persistent financial discipline will sustain improving financial metrics for the industry.

Despite higher overall spending and increased efforts to convert drilled but uncompleted wells to producer status, the ROP growth is expected to slow in 2019. Several factors will contribute to the slowing growth rate. First, a number of critical bottlenecks, including infrastructure constraints, have stymied upstream progress in recent years. While a number of infrastructure projects are on schedule to alleviate some bottlenecks, other factors, including acute labor shortages, will continue to aggravate upstream efforts in 2019.

Regardless of the obstacle, shalers have proven their mettle, delivering both economic results and production growth. While 2019 promises to deliver more growth, companies are no longer content with growth for growth's sake. Instead, whether by choice or circumstance, companies increasingly are changing to meet today and tomorrow's energy needs.

Production estimates

The year-on-year production for December 2019 is estimated at 0.7 MMbbl/d, down from an estimated 1.4 MMbbl/d in 2018. The all-important shale oil segment is projected to finish 2019 at about 8.2 MMbbl/d, an increase of about 1 MMbbl/d over December 2018. Permian shales are poised for growth of about 0.9 MMbbl/d of growth and represent a little more than half of total shale production in the U.S. In other shales, the Midcontinent and Rockies also are expected to add to growth.

Moving on to Lower 48 natural gas, increases in shale gas will be partly offset by declining conventional volumes. Wellhead volumes from shale resources are expected to rise by about 8 Bcf/d versus December 2018. During this same period, conventional production will likely contract by about

2 Bcf/d, leading to net growth of approximately 6 Bcf/d. Compared to 2018, this represents about a 50% reduction in modeled growth.

In spite of multiple challenges in recent years, oil and gas companies have persevered, remaining competitive when some counted them out. Persistently low prices forced shalers to create new models and solutions. Backward integration, once the provenance of large integrated companies, is now found across independents. Operators scoped out costs, identified opportunities for reductions and delivered savings.

Many insiders and observers alike refer to modern well designs as Shale 2.0. However, a detailed review of wells across major shales reveals that progress has been more evolutionary than revolutionary. Lateral lengths increased progressively over many years. Just how did the transition take shape? From the beginning of the shale era back in the mid-2000s when lateral lengths averaged a little more than 2,000 ft, companies pushed the limits of technology by extending the path by another 500 ft or so. Every few years, those early efforts paid off and a new standard was ushered in. Today, companies are largely looking to drill 1.5-mile to 2-mile horizontal section lengths, or 7,500 ft to 10,000 ft. While longer laterals have been drilled, the optimal length on modern completion designs fall in this range.

Much has been written on reduced cluster spacing, shorter stage intervals and increased stage counts. Suffice it to say that progression in completions also has been evolutionary in nature. Companies try new approaches, make adjustments, try and try again until they find something that works. This is a core part of the DNA of shale companies—master scientists with proven track records, backed by investors willing to take risks. The net result is a shale industry ready, able and willing to compete on the world stage. E&P

Horses walk along a hill near a rig site in the Bakken Shale. (Source: Marathon Oil)

Maintaining the Stride, Staying Ahead

By **Ariana Hurtado**, Associate Managing Editor

Each of these 40 companies is one of the largest producers and/or one of the most active operators in a major U.S. shale play.

The U.S. Energy Information Administration (EIA) estimated that in 2017 about 4.67 MMbbl/d of crude oil was produced directly from tight oil resources in the U.S. "This was equal to about 50% of total U.S. crude oil production in 2017," according to the EIA's website. In addition, the EIA estimated that in 2017 about 16.86 Tcf of dry natural gas was produced from shale resources in the U.S., which was about 62% of total U.S. dry natural gas production that year.

The EIA later reported in November 2018 a total of 5,372 bbl/d of new well oil production and 42,042 Mcf/d of gas production in the Anadarko, Appalachia, Bakken, Eagle Ford, Haynesville, Niobrara and Permian regions.

Looking ahead, the EIA predicts that U.S. crude oil production will average 12.1 MMbbl/d in 2019, according to its November "Short-term Energy Outlook."

The Permian, Eagle Ford, Bakken/Niobrara, Marcellus-Utica and Midcontinent regions feature the most robust and soaring production numbers. In the following section, Hart Energy profiles some of the most active operators in these five unconventional U.S shale plays, highlighting their first-half 2018 results.

Editor's Note: *These profiles were written based on second-quarter 2018 reports. Updated profiles with third-quarter results will be available on* EPmag.com/epm-supplements.

Anadarko Petroleum Corp.

Anadarko's U.S. onshore operations are located in Colorado, Texas, Utah and Wyoming.

Anadarko advanced its first full pad development at the Silvertip-A location in Loving County, Texas, in the second quarter. (Source: Anadarko Petroleum Corp.)

The company's second-quarter 2018 sales volumes of oil, natural gas and NGL totaled 58 MMboe, or an average of 637,000 boe/d, according to Anadarko's second-quarter results news release.

In the Delaware Basin of West Texas, the company's oil production averaged 62,000 bbl/d of oil for the second quarter, which was an 88% increase over the second quarter of 2017.

During this quarter the company also announced a successful startup of the Reeves Regional Oil Treating Facility (ROTF) in May as well as a record number of wells turned to sales. The company also advanced its first full pad development at the Silvertip-A location in Loving County, Texas, where it completed 12 extended-reach lateral wells targeting multiple intervals in the Wolfcamp-A Formation. These wells were expected to begin producing in the second half of the year and will flow to the recently commissioned North Loving ROTF, according to the release.

In the Denver-Julesburg (D-J) Basin of northeast Colorado, Anadarko continues its horizontal drilling campaign featuring natural-gas-powered rigs and noise-reduction technology. During the second quarter, the D-J Basin averaged net production of 261,000 boe/d, the release stated.

Anadarko also is looking at other onshore opportunities in Wyoming's Powder River Basin, where the company said it has made about $100 million worth of leasehold acquisitions and amassed more than 300,000 acres for less than $2,500 per acre, according to Anadarko CEO Al Walker on an Aug. 1 earnings call. The company is focused on the Turner Formation, having already drilled wells in the play with rates exceeding 2,000 boe/d and oil cuts above 80%, according to Walker.

Antero Resources Corp.

Antero operates in the Marcellus and Utica shales. In the Marcellus Antero has more than 486,000 net acres of leasehold located in northern West Virginia and southwestern Pennsylvania, and the company is operating five drilling rigs in West Virginia, according to Antero's website.

During the second quarter of the year, Antero placed 25 horizontal Marcellus wells to sales and drilled 22 wells in the Marcellus with an average lateral length of 9,600 ft in approximately 12 total days from spud to final rig release on average, according to the company's second-quarter 2018 results report. Antero also set a state of West Virginia record for the longest lateral drilled to date at 15,100 ft during the second quarter.

As of Aug. 1, Antero expected to place 50 to 60 Marcellus wells to sales during the third quarter of the year, including the company's largest pad to date, a 14-well pad that commenced production in July, the report stated. Antero expected an average of four crews operating during the second half of the year, compared to six crews in the first half.

Antero has more than 137,000 net acres of leasehold in eastern Ohio in the Utica Shale, where the company operated one drilling rig during the first half of the year, according to its website.

Antero placed five horizontal Ohio Utica wells to sales during the second quarter and expected to place 15 wells to sales in the Utica during the third quarter, according to its second-quarter report. The company's five-year plan does include the resumption of drilling and completion activity in the Ohio Utica Shale in 2019.

As of Aug. 1, the company stated in the report that it "does not plan to operate any drilling rigs or completion crews during the remainder of 2018 as the second-half 2018 development plan shifts to liquids-rich locations in the Marcellus due to the continued strength in liquids pricing."

Apache Corp.

Apache's U.S. operations are in the Permian Basin, with more than 2.8 million gross acres, and in the Midcontinent/Gulf Coast region, which includes more than 1.8 million gross acres.

Apache reported year-end 2017 Permian production of 681 MMboe estimated proved reserves. In 2017 the Permian region averaged 16 rigs and drilled or participated in 215 wells, 158 of which were horizontal, with a 97% success rate, according to the company's website.

Apache stated it had "plans to continue an elevated level of activity in the Permian region during 2018, while continuing to balance capital investments between its larger development project at Alpine High and focused exploration and development programs on other core assets in its Permian region." During 2018 the company expected "to average approximately 14 drilling rigs, which includes six to seven rigs at Alpine High focused on a combination of retention, development and delineation drilling. Approximately $1.6 billion, or roughly two-thirds, of the company's 2018 capital upstream budget will be allocated to the Permian region."

Second-quarter 2018 Permian highlights included 89,928 bbl/d oil production, 134,621 bbl/d total liquids production and 201,832 boe/d.

The company's Midcontinent/Gulf Coast region includes primarily western Oklahoma, the Texas Panhandle and the Eagle Ford Shale in East Texas. Apache has more than 3,100 producing wells in the region.

Dusk illuminates an Apache drilling site at the Wildfire Field located near Midland, Texas. (Source: Apache Corp.)

"In 2018 Apache plans to run a targeted program, drilling additional wells in the Woodford-Scoop play. In addition, the region will continue its focus on high grading acreage and building its inventory of future drilling locations," the company stated on its website.

Second-quarter 2018 Midcontinent/Gulf Coast highlights included 11,492 bbl/d oil production, 25,542 bbl/d total liquids production and 48,147 boe/d.

BP

In the third quarter, BHP Billiton sold its onshore U.S. assets to BP. The $10.5 billion sale of BHP's interests in the Eagle Ford, Haynesville and Permian-Delaware oil and gas assets to BP America Production Co., a subsidiary of BP Plc, closed Oct. 31.

These acquired assets produce 190,000 boe/d, of which about 45% are liquid hydrocarbons, according to BP's website. BHP's "operated rig count remained unchanged at five, with two rigs at Eagle Ford, two rigs at Permian and one at Haynesville," according to BHP's third-quarter 2018 results report.

In Wyoming's Wamsutter Field, BP is the largest operator with about 2,000 wells. Moreover, the company "recently [as of Oct. 18] launched a separate pilot project in which it teamed up with a Silicon Valley firm and applied a mathematical model to optimize production at 180 onshore wells in Wyoming," according to BP's "U.S. Economic Impact Report 2018."

"This led to a 75% reduction in venting emissions events, a 20% increase in production and a 20% reduction in costs," the report stated. The company expected the project to expand to more than 2,000 onshore wells by the end of the year.

BP also operates about 800 oil and gas wells in the East Texas Basin and about 1,200 wells in the Texas Panhandle. The company has an interest in another 1,500 wells in the South Texas Eagle Ford Shale through its joint venture with Lewis Energy, according to information on BP's website.

In addition, BP is the largest operator in Colorado and operates 1,350 wells in the area.

The company also has about 2,600 operated and 5,100 nonoperated wells in the New Mexico portion of the San Juan Basin, and it brought five Mancos Shale horizontal wells online in New Mexico this year.

Cabot Oil & Gas Corp.

Cabot's E&P and development operations are focused in the Marcellus Shale in northeastern Pennsylvania, with about 172,000 net acres, primarily in Susquehanna County.

"Cabot's 2018 capital budget is approximately $950 million with approximately 84% of spending focused on the Marcellus Shale and up to $75 million of exploratory leasing/testing capital," the company stated on its website. "For the full year 2018, the company plans to drill approximately 85 net wells and complete 95 net wells."

As of Oct. 22, the company was operating three rigs and two completion crews in the Marcellus Shale. "Daily equivalent production for the six-month period ending June 30, 2018, was 1,890 MMcfe/d (99% natural gas)," according to Cabot's second-quarter 2018 results report. The company expected to place 37 net wells on production in the third quarter.

In addition, in February Cabot sold its operated and nonoperated Eagle Ford Shale assets to an affiliate of Venado Oil & Gas LLC for $765 million, according to a press release. The divestiture included about 74,500 net acres (about 65,100 operated and about 9,400 nonoperated) of Eagle Ford Shale leasehold primarily located in Frio and Atascosa counties in Texas.

Centennial Resource Development Inc.

Centennial Resource Development has about 80,100 net acres (100% operated) and 2,400 drilling locations (60% oil) in the Delaware Basin. The independent oil producer recently made a shift from one-well operations to multiwell pad developments and reported the following IP results in its second-quarter 2018 results report.

The Red Rock A Unit T09H well achieved a 30-day IP rate of 1,578 boe/d, with 1,143 bbl/d of oil. The Red Rock A Unit U04H well reported a 30-day IP rate of 1,268 boe/d, with 940 bbl/d of oil.

The CWI Long A U31H, B U40H and C U49H wells achieved 30-day IP rates of 2,158 boe/d (78% oil), 2,899 boe/d (78% oil) and 2,278 boe/d (78% oil), respectively. The three-well pad delivered an average 30-day oil IP rate of 194 bbl/d per 1,000 ft of lateral per well.

The Ninja 4-50 49 2H, 3H, 4H and 5H wells delivered an average 30-day IP rate of 1,878 boe/d (58% oil) per well. During its 60-day IP period, the pad produced more than 225,000 bbl of oil.

In addition, the Balmorhea State G 8H, H 9H and I 10H wells each began production at an average 30-day IP rate of 1,337 boe/d (77% oil) per well, or 166 bbl/d of oil per 1,000 ft of lateral per well.

Chesapeake Energy Corp.

Chesapeake Energy has operations in Louisiana, Ohio, Oklahoma, Pennsylvania, Texas and Wyoming. Chesapeake's average production for the second quarter was about 530,000 boe/d, compared to about 528,000 boe/d a year earlier, according to the company's second-quarter 2018 results report.

"The Powder River Basin in Wyoming is quickly establishing itself as the growth engine of the company, as recently demonstrated by a 78% increase in net production compared to the average fourth-quarter 2017 rate," the company stated in the report. "On July 22, 2018, total net production hit a new record of approximately 32,000 net boe per day (42% oil, 41% natural gas and 17% natural gas liquids), compared to an average fourth-quarter 2017 rate of 18,000 boe per day." The company expected Powder River Basin net production to reach about 38,000 boe/d by the end of the year and total net annual production to more than double in 2019.

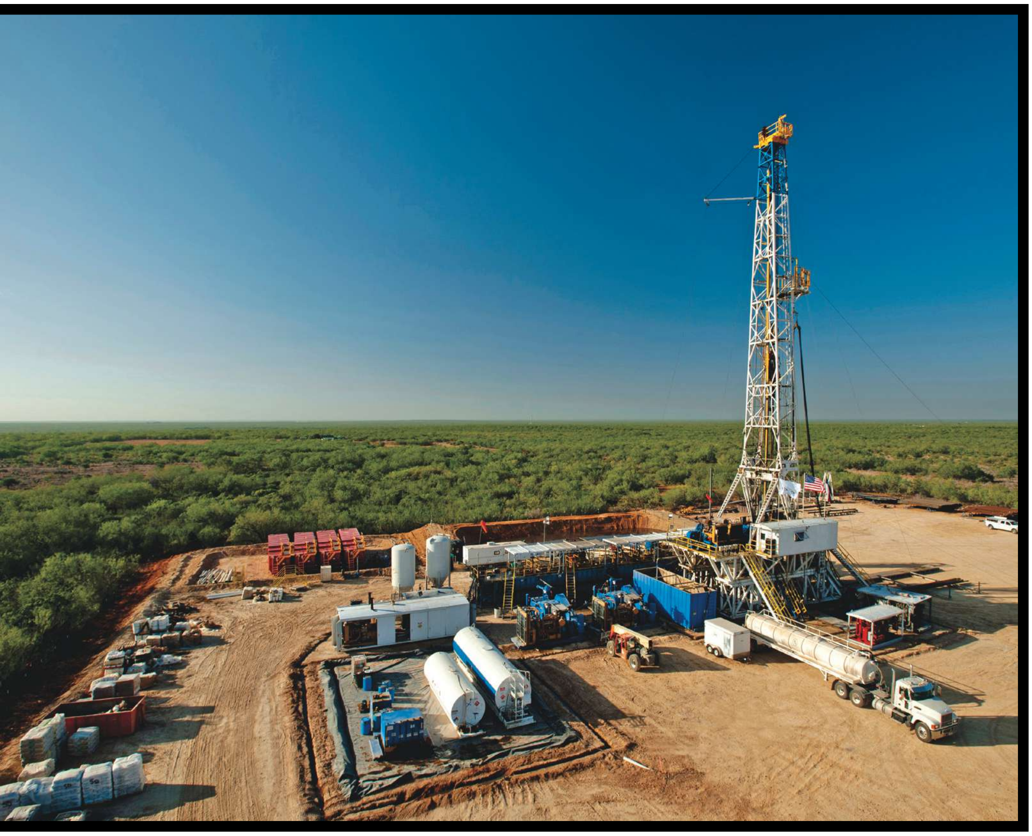
In the Eagle Ford Shale, Chesapeake was utilizing four rigs (as of Aug. 1). The company placed 48 wells on production during the second quarter and expected to place 38 wells on production during the third quarter and 47 wells during the fourth quarter, according to the report.

In the Marcellus Shale, the company has 400,000 acres and is one of the largest producers of natural gas in Pennsylvania, according to a company fact sheet. As of Aug. 1, Chesapeake was utilizing three rigs in the Marcellus and placed 10 wells on production during the second quarter. In addition, the company expected to place 14 wells on production during the third quarter and 18 wells during the fourth quarter, according to the company's second-quarter report.

In July "Chesapeake successfully drilled its longest lateral to date in the Lower Marcellus Shale at approximately 13,380 ft, only to be surpassed by an even longer planned lateral of approximately 14,500 ft currently being drilled," the report stated. "Both wells are expected to be placed on production before year-end 2018."

Chesapeake announced in July that it entered into an agreement to sell its interests in the Utica Shale for about $2 billion to Encino Acquisition Partners. The transaction was expected to close by the end of the year.

On Oct. 30, Chesapeake announced its intent to acquire WildHorse Resource Development Corp. The transaction is expected to close in the first half of 2019.



Chesapeake was utilizing four rigs in the Eagle Ford Shale as of Aug. 1. (Source: Chesapeake Energy)

Chevron

Chevron is one of the largest producers of oil and natural gas in the Permian Basin as well as one of the largest net acreage holders in the area with about 2.2 million net acres.

The company holds about 500,000 total acres in the Midland Basin and has about 1 million total acres in the Delaware Basin, according to a company fact sheet. The company reported production of 119,000 net bbl/d of crude oil, 383 MMcf/d of natural gas and 45,000 bbl/d of NGL in 2017.

"Production increases from shale and tight properties in the Permian Basin in Texas and New Mexico were partially offset by the impact of asset sales of 54,000 bbl/d," the company stated in its second-

quarter 2018 results report. "The net liquids component of oil-equivalent production in second-quarter 2018 increased 8% to 575,000 bbl/d, while net natural gas production decreased 5% to 980 MMcf/d."

Cimarex Energy Co.

Cimarex has operations in Texas, Oklahoma and New Mexico with focuses on the Midcontinent and Permian Basin. The company invested $1.28 billion for exploration and development activities in the Permian and Midcontinent regions in 2017 and expected to invest $1.6 billion to $1.7 billion in these areas during 2018, according to Cimarex's website.

In the Permian region, production averaged 121,744 boe/d, and oil volumes averaged 48,797 bbl/d, according to Cimarex's second-quarter 2018 results report. Cimarex completed 32 gross (13 net) wells in the Permian region during the second quarter, and there were 45 gross (32 net) wells waiting on completion as of June 30. Cimarex was operating 10 drilling rigs and five completion crews in the region as of Aug. 7.

In addition, Cimarex closed on the sale of assets in Ward County, Texas, on Aug. 31 for $544.5 million.

In the Midcontinent region, production averaged 88,864 boe/d for the second quarter, according to the report. Also during the second quarter, Cimarex completed 57 gross (10 net) wells in the region. At the end of the quarter, 96 gross (25 net) wells were waiting on completion. Cimarex was operating three drilling rigs and one completion crew in the region as of Aug. 7.

Moreover, the company expected overall third-quarter production volumes to average 206,000 boe/d to 215,000 boe/d with oil volumes estimated to average 61,500 bbl/d to 64,500 bbl/d, according to the report. The total 2018 production volumes are expected to average 214,000 boe/d to 221,000 boe/d with annual oil volumes estimated to average 66,000 bbl/d to 68,000 bbl/d.

CNX Resources Corp.

CNX Resources' operations are in the Appalachian Basin. In the second quarter, the company operated three horizontal rigs and deployed a fourth

CNX drills at the CNX MOR31 pad in Washington County, Pa. (Source: CNX Resources) in late June, and those horizontal rigs drilled 16 wells. CNX also utilized three fracturing crews to complete 18 wells, and it set a company record of completing 78,877 ft, or 394 stages, in May, according to the company's second-quarter 2018 results report.

Three Marcellus Shale wells were turned in-line in Washington County, Pa., in the second quarter, and CNX expected to turn in-line about 30 wells in the third quarter.

Marcellus Shale volumes, including liquids, in the second quarter were 64.7 Bcfe. In addition, water disposal costs improved during the second quarter, compared to the previous quarter, as the company reused more produced water for fractures, avoiding the need to send that water to disposal, the company stated in the report.

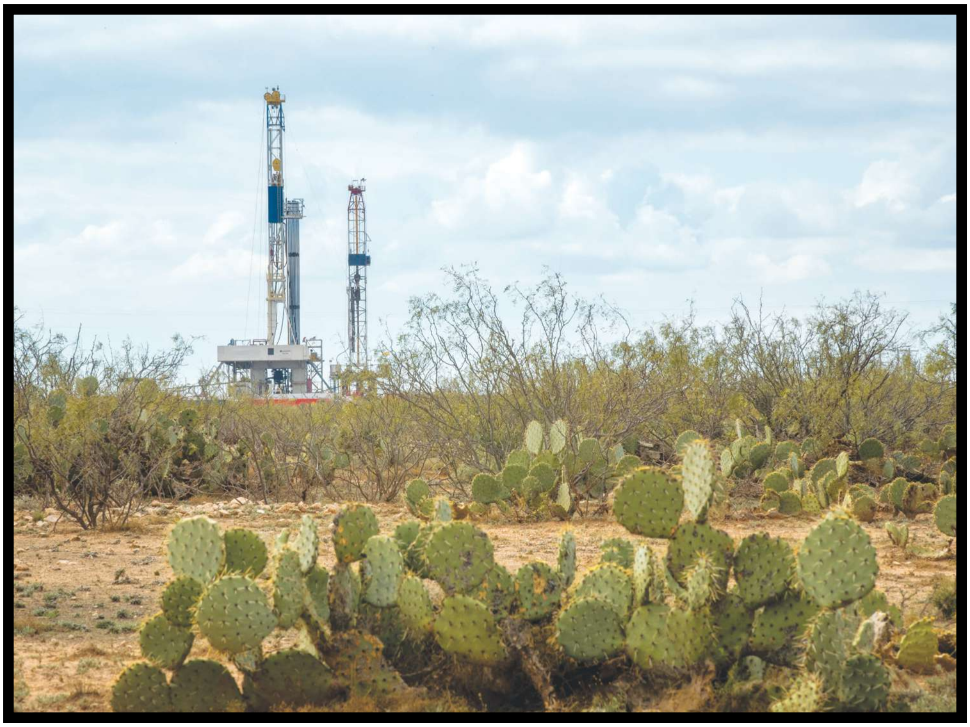
Utica Shale volumes, including liquids, in the second quarter were 42.6 Bcfe, approximately 209% higher than the 13.8 Bcfe the same period a year earlier, driven primarily from Monroe County, Ohio, volumes.

CNX Resources sold substantially all its Ohio Utica joint venture assets to Ascent Resources-Utica LLC on Aug. 31 for approximately $400 million, a press release stated.

Concho Resources

Concho operations are focused on the Permian Basin. The company reported production of 21 MMboe and 515 MMcf/d natural gas and averaged 21 rigs in the second quarter, according to Concho's second-quarter 2018 results report.

In July Concho acquired RSP Permian Inc., making Concho the largest unconventional shale producer in the Permian Basin, according to a company press release.



As of the second quarter, Concho had 21 rigs operating in the Permian Basin. (Source: Concho Resources)

In the Northern Delaware Basin, Concho added 16 wells with at least 60 days of production (as of the end of June). The average 30-day and 60-day peak rates for these wells were 1,987 boe/d (73% oil) and 1,859 boe/d (72% oil), respectively, according to the second-quarter report.

Drilling activity in this area is focused on large-scale development of the company's assets, with nine out of 16 rigs working on multiwell projects. "The largest project underway is the Dominator, which consists of 23 wells targeting five distinct landings within a single section. Concho is currently [as of Aug. 1] running six rigs on this project," the report stated.

In the Southern Delaware Basin, Concho added five wells with at least 60 days of production (as of the end June). The average 30-day and 60-day peak rates for these wells were 1,463 boe/d (80% oil) and 1,297 boe/d (80% oil), respectively, according to the report.

In the Midland Basin, Concho added 21 wells with at least 60 days of production (as of the end of June). The average 30-day and 60-day peak rates for these wells were 1,294 boe/d (86% oil) and 1,137 boe/d (86% oil), respectively, the report stated.

As of Aug. 1, Concho expected third-quarter production to average 280,000 boe/d to 285,000 boe/d (65% oil) and full-year 2018 production to average 260,000 boe/d to 263,000 boe/d (64% oil), according to the report.

ConocoPhillips

ConocoPhillips' onshore Lower 48 segment, which covers the Gulf Coast, Midcontinent and Rockies, holds 10.4 million net acres (mostly HBP). The company's major focus areas are the Eagle Ford, Bakken and Permian Basin.

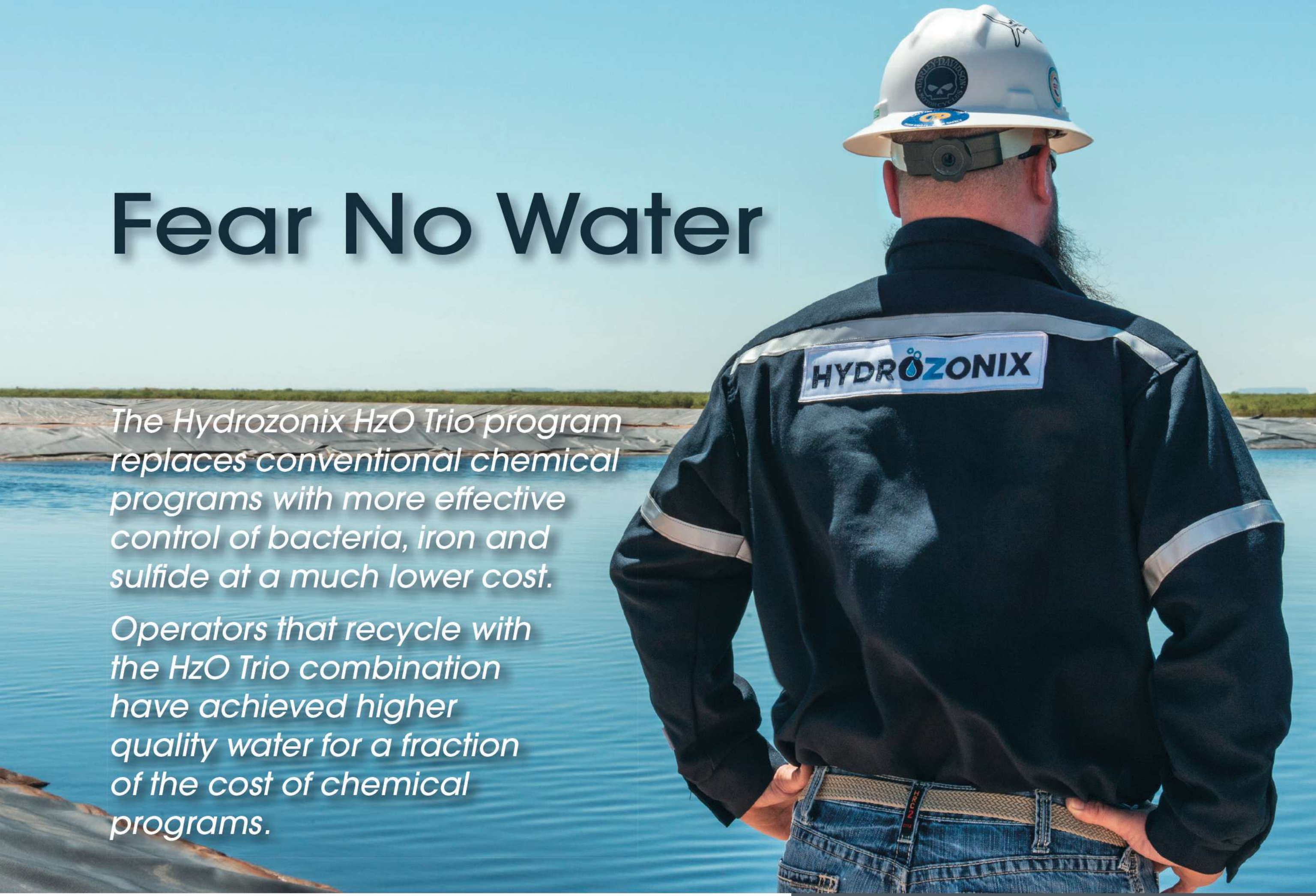
By year-end 2017, the company had completed asset sales for its San Juan Basin, Panhandle and Gomez assets, with a sale pending for its Howard Glasscock asset. In addition, the company reported year-end 2017 Lower 48 production of 322,000 boe/d (17% NGL, 28% natural gas and 55% crude oil) and 1.4 Bboe proved reserves, according to ConocoPhillips' Lower 48 fact sheet (released in March 2018).

According to the company's second-quarter 2018 results report, "year-over-year production from the Lower 48 Big 3 unconventional plays [Eagle Ford, Bakken and Permian Basin] grew by 37%" and "achieved a Big 3 production milestone of 300,000 boe/d significantly ahead of schedule."

In the Eagle Ford, the company reported year-end 2017 production of 133,000 boe/d, holding about 210,000 net leasehold and mineral acres, primarily in DeWitt, Karnes and Live Oak counties. The company had more than 1,000 total wells online by year-end 2017, according to the fact sheet.

ConocoPhillips also reported year-end 2017 production of 83,000 boe/d in the Midcontinent region. In the Permian Basin, the company holds about 1 million net acres and 2017 net production was 60,000 boe/d, the fact sheet stated. In the Anadarko Basin, the company holds about 290,000 net acres and 2017 net production was 13,000 boe/d.

In August 2018 ConocoPhillips entered into an agreement to sell its interests in the Barnett



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Shale to Lime Rock Resources for about $230 million, a press release stated. The transaction closed on Nov. 1.

In the Rockies region, which includes the Bakken, Wind River Basin, Uinta and Niobrara, the company reported year-end 2017 production of 82,000 boe/d.

The company holds about 98,000 net acres in the Niobrara play and 2017 net production averaged 3,000 boe/d. In addition, the company's Bakken development area comprises about 630,000 net acres and 2017 net production averaged 65,000 boe/d. The company had more than 694 operated wells online by year-end 2017, according to the fact sheet.

Continental Resources

Continental Resources' operations are in the Bakken and Scoop/Stack plays. The independent oil producer reported second-quarter 2018 production of 25.8 MMboe, or 284,059 boe/d. Total production for the second quarter included 157,116 bbl/d of oil and 761.7 MMcf/d of natural gas, according to the company's second-quarter 2018 results report.

In the Bakken the company expected to average five completion crews and six rigs in the second half of the year, ramping up to seven rigs by year-end 2018, the company stated in the report. The company also expected to complete about 125 additional Bakken wells with first production by the end of the year. Continental's Bakken production averaged 158,119 boe/d in the second quarter, and the company completed 35 gross (19 net) operated wells flowing at an average initial 24-hour rate of 2,282 boe/d.

Continental's second-quarter Scoop production averaged 64,786 boe/d, and the company completed 16 gross (13 net) operated wells with first production during the same quarter. The company's second-quarter Stack production was 51,722 boe/d, and it completed 26 gross (13 net) operated wells with first production during the same quarter. Continental is projected to average four completion crews and 18 rigs in Oklahoma in the second half of the year, ramping up to 19 rigs at year-end 2018, according to the report.

Devon Energy

Devon's operations focus on the Delaware Basin, Stack, Eagle Ford and Rockies with 4.3 million net acres and about 23,100 gross producing wells. The company reported 2017 net production of 543,000 boe/d (63% liquids) and reserves of 2.2 Bboe (54% liquids). In the second quarter of 2018, Devon reported total companywide production averaging 541,000 boe/d, according to the company's second-quarter 2018 results report.

In the Delaware Basin, where the company has 670,000 net acres, it reported 2017 net production of 56,000 boe/d and 184 MMboe reserves. Second-quarter 2018 total volumes in the Delaware Basin were 79,000 boe/d. "Growth in the Delaware was driven by prolific well productivity, where the top 10 wells in the quarter averaged initial 30-day rates of approximately 3,000 boe/d," the company stated in the report.

In August 2018 Devon announced it entered into a definitive agreement to sell 9,600 net acres of noncore Delaware Basin acreage in Ward and Reeves counties to Carrizo Oil & Gas for $215 million, according to a press release.

In the Stack, where the company has more than 600,000 net acres, it reported 2017 net production of 107,000 boe/d and 456 MMboe reserves.

In the Eagle Ford, the company reported 2017 net production of 62,000 boe/d and 60 MMboe reserves.

In the Rockies region, Devon reported 2017 net production of 17,000 boe/d and 30 MMboe reserves.

Diamondback Energy

Diamondback's operations are primarily focused on the Wolfcamp, Spraberry, Clearfork, Bone Spring and Cline formations in the Permian Basin.

Second-quarter production of 112,600 boe/d (73% oil) was up 10% over the first quarter and 46% year-over-year, according to the company's second-quarter 2018 results report. During the second quarter, Diamondback drilled 53 gross horizontal wells and turned 50 operated horizontal wells to production. Operated completions during the second quarter consisted of 29 Wolfcamp A wells, 18 Lower Spraberry wells and three Wolfcamp B wells.

Diamondback operated 11 drilling rigs and five dedicated fracturing spreads during the second quarter and expected to add its 12th and 13th operating rigs to development during the third quarter, the report stated. The company also expected to turn between 170 and 190 gross operated horizontal wells to production for full-year 2018.

In August Diamondback announced its intent to acquire Energen Corp. for about $9.2 billion, further increasing its presence in the Permian, a press release stated. The transaction was expected to close by the end of the year.

Additionally, Diamondback acquired Ajax Resources LLC for $900 million on Oct. 31. "The Ajax acquisition will bring Diamondback's total leasehold interests to approximately 230,000 net surface acres in the Permian Basin," a company press release stated.

Encana Corp.

Encana's core U.S. assets are in the Permian and Eagle Ford.

The company reported Permian production of 88,200 boe/d, including 55,200 bbl/d of oil, in the second quarter, and it stated that production was up 43% year-over-year with production of more than 90,000 boe/d, according to Encana's second-quarter 2018 result report.

The company also brought 11 net wells onto production in the Eagle Ford in the second quarter.

In October Encana's wholly owned subsidiary, Encana Oil & Gas (USA) Inc., announced its intent to sell its San Juan Basin assets in New Mexico for $480 million to DJR Energy LLC, a press release stated. The transaction was expected to close by the end of the year.

On Nov. 1, Encana announced its intent to acquire Newfield Exploration Co. for $5.5 billion. The transaction includes approximately 360,000 net acres in the Scoop/Stack in the Anadarko Basin and is expected to close in the first quarter of 2019, according to a press release.

EOG Resources Inc.

EOG Resources is one of the largest independent (non-integrated) crude oil and natural gas companies in the U.S. At year-end 2017, EOG's total estimated net proved reserves were 2,527 MMboe (52% crude oil and condensate, 20% NGL and 28% natural gas). About 97% of these reserves were located in the U.S., according to a company fact sheet released in March 2018.

In the Eagle Ford, EOG has 520,000 net acres and its inventory in this area stands at 2,300 net undrilled premium locations, according to EOG's second-quarter 2018 results report. The company completed 270 net wells since the last premium inventory assessment in 2017. EOG also continued delineation of the South Texas Austin Chalk, completing five wells in the second quarter of 2018.

In the Delaware Basin, EOG holds 416,000 net acres. "EOG has identified an additional 375 net undrilled premium locations in the Delaware Basin, raising the total to 4,815 locations and more than replacing the 250 locations drilled since the last

Encana's Hons & Hoffman liquids-processing facility, newly completed in the Eagle Ford, is the first facility the company fully built since acquiring the asset in 2014. (Source: Encana Corp.)

premium inventory assessment in 2017," the company stated in the report.

In addition, EOG's third largest asset, the Powder River Basin in Wyoming, consists of 400,000 net acres, and the company has identified more than 1,600 net premium drilling locations in the area, according to the report. EOG has identified 141,000 prospective net acres for the Mowry Shale, 89,000 prospective net acres in the Niobrara Shale and 169,000 prospective net acres in the Turner Formation. The company completed two Mowry wells and seven Turner wells in the second quarter.

In the Williston Basin in North Dakota, EOG drilled nine wells and began production from two wells in the second quarter, according to the report.

EOG also began production from eight wells in the Denver-Julesburg Basin during the second quarter.

EQT Corp.

EQT has approximately 3.6 million gross acres in the Appalachian Basin, including about 790,000 gross acres in the Marcellus play, more than 13,600 gross productive natural gas wells, 97 Tcfe of total resource potential and 13.5 Tcfe of proved reserves.

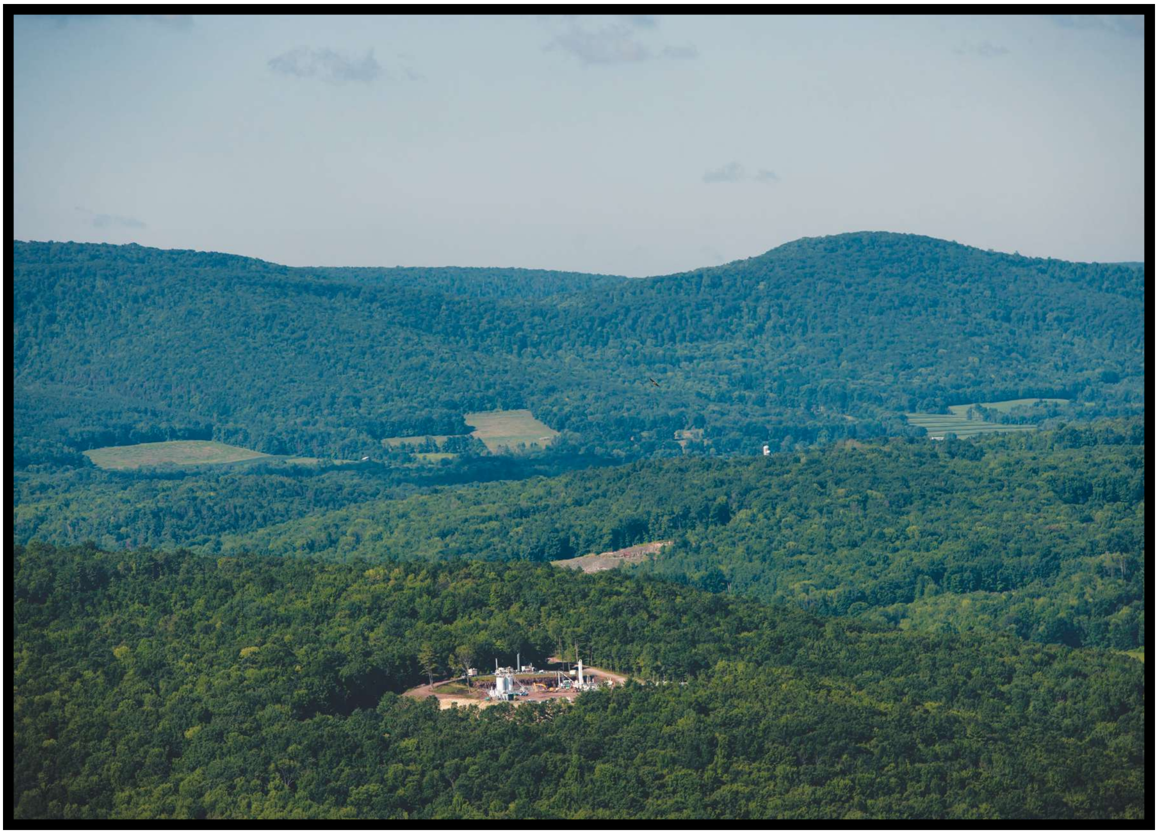
In June EQT sold its Permian assets for $64 million, according to the company's second-quarter 2018 results report. No other details were provided.

Equinor

Equinor has more than 2,200 onshore U.S. producing wells, and its U.S. operations are in the Bakken, Marcellus and Eagle Ford.

In the Marcellus Shale, Equinor has 344,000 net acres and is "evaluating the application of a number of new technologies within [its] operations," the company said on its website. Equinor is "assessing methods that aim to enhance recovery by enabling more effective completions optimization and well spacing."

Equinor is one of the largest producers in the Bakken area. The company has 249,000 net acres in the Bakken (as of 2015). In addition, "Equinor has reduced its flaring in the Bakken below 10%, surpassing current regulatory requirements," the company stated on its website.



Equinor's shale gas production carries on in the hills of Pennsylvania. (Photo by Helge Hansen, courtesy of Equinor)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In the Eagle Ford, the company has reduced the number of days it takes to safely drill a well from more than 50 days down to as few as 12. The company has 82,000 net acres in the Eagle Ford (as of 2015).

Exxon Mobil / XTO Energy Inc.

In its second-quarter 2018 report, Exxon Mobil reported that its Permian and Bakken production of 250,000 boe/d was up 30% in the second quarter compared to the same quarter last year.

In addition, XTO Energy, a subsidiary of Exxon Mobil, is one of the most active operators in the Permian Basin with 3.9 million acres in Texas. "Since 2014, we have grown our Permian portfolio to a high-quality resource base of almost 10 billion barrels today," the company stated on its website. "By 2025, we plan to increase our production in the basin to 600,000 barrels per day, representing a fivefold increase in our unconventional Permian production."

XTO Energy works in all the major U.S. shale plays. The company has 553,392 acres in Colorado, 662,000 acres in Arkansas, 776,000 acres in Kansas, 661,000 acres in Louisiana, 267,000 acres in Montana, 685,000 acres in New Mexico, 486,000 acres in North Dakota, 381,000 acres in Utah and 135,000 acres in Wyoming.

In Oklahoma the company holds 1.1 million acres and operates in 26 counties.

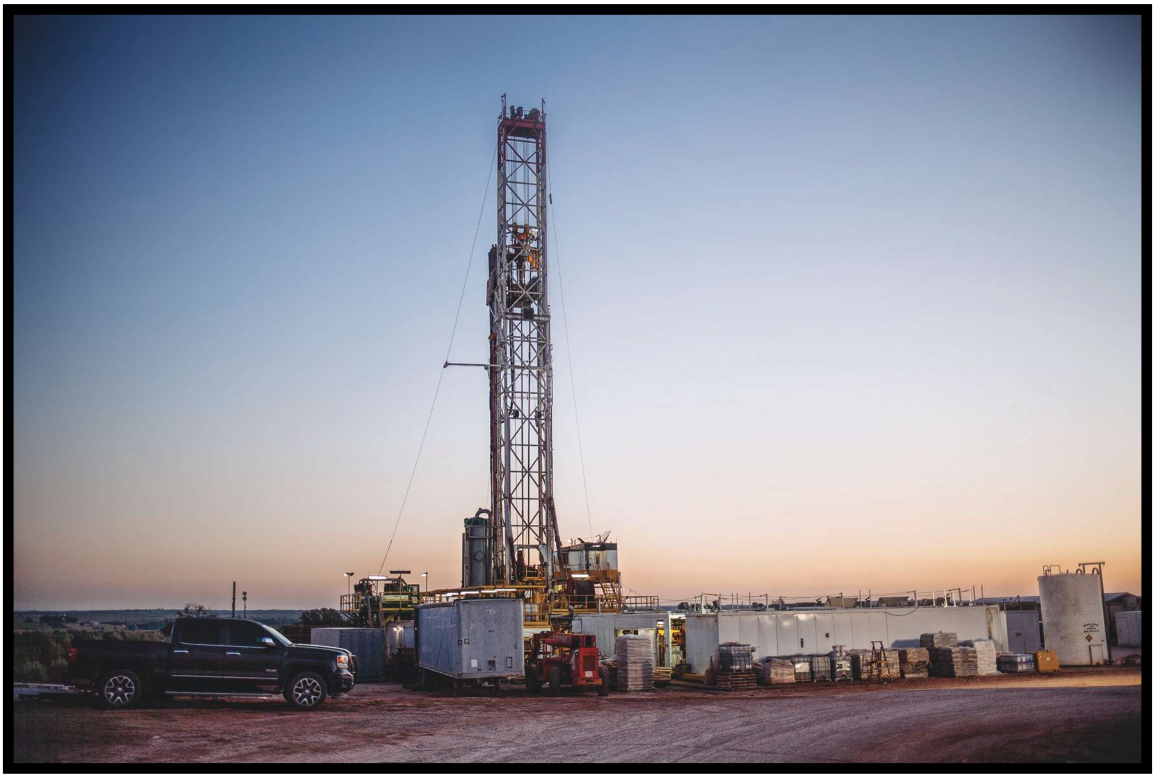
XTO Energy is also an active operator in the Marcellus and Utica shale formations in Pennsylvania, Ohio and West Virginia. The company has 534,000 acres in Pennsylvania, 56,000 acres in Ohio and 140,000 acres in West Virginia.

FourPoint Energy

FourPoint Energy is a private E&P company that operates in the Anadarko and Permian basins.

The company's 2 million gross acreage position in the Anadarko Basin is located in 13 counties in Oklahoma and Texas. FourPoint operates 5,646 producing wells and five rigs in the area and, as of Oct 25, reported gross production of 1.05 Bcfe/d, according to the company's website.

FourPoint recently entered the Permian Basin and is actively exploring opportunities for future development, according to the company. In June



FourPoint Energy's Extreme Rig 23 operates in western Oklahoma. (Photo by Jeff Martin, courtesy of FourPoint Energy)

Double Eagle Energy Holdings III LLC and Four-Point Energy announced the formation of a new company named DoublePoint Energy LLC, which will be a pure play Midland Basin company with more than 70,000 acres in the core areas of the oil-rich, multipay zones in Midland, Glasscock, Martin, Howard, Upton and Reagan counties in Texas, a press release stated.

Hess Corp.

Hess, the second largest producer in North Dakota, has 554,000 net acres in the Bakken with an average working interest of about 75%, and it reported net EUR of about 2 Bboe (as of Oct. 30).

Hess' operations take place in the Bakken in North Dakota. (Source: Hess)

Hess' 2018 Bakken E&P capex was set at about $900 million, and the company expected full-year 2018 Bakken production to be between 115,000 boe/d and 120,000 boe/d, according to the company's second-quarter 2018 results report. The company also expects production to increase to about 175,000 boe/d by 2021.

Second-quarter net production from the Bakken increased 6% to 114,000 boe/d from 108,000 boe/d in the year-ago quarter "due to ongoing drilling activity and improved well performance," the company stated in the report. Production in the second quarter was "impacted by weather-related downtime in June," and the company operated an average of four rigs in the second quarter, drilling 28 wells and bringing 27 new wells online. Hess added a fifth rig and expected to add a sixth rig early in the fourth quarter of the year.

Marathon Oil

Marathon Oil has U.S. operations in the Eagle Ford, Bakken, Scoop/Stack and Permian.

In the Eagle Ford, Marathon's production averaged 106,000 net boe/d in the second quarter, and it brought 39 gross company-operated wells to sales in the quarter with average 30-day IP rates of 1,880 boe/d (66% oil), according to Marathon's second-quarter 2018 results. The company expected 145 to 165 gross operated wells to sales by year-end 2018.

In the Bakken Shale, Marathon's production averaged 82,000 net boe/d in the second quarter. The company brought 21 gross company-operated wells to sales in the quarter, 12 of which were in the core Hector area with average 30-day IP rates of 2,285 boe/d (79% oil). According to the company, two Three Forks wells in West Myrmidon set new basin records. The company expected 60 to 80 gross operated wells to sales by year-end 2018.

In the Scoop/Stack plays, Marathon's Oklahoma production averaged 80,000 net boe/d in the second quarter, and the company expected 40 to 50 gross operated wells to sales by year-end 2018.

In the Permian Basin, the company's Northern Delaware production averaged 17,000 net boe/d in the second quarter. Marathon brought 13 gross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Marathon's net production averaged 82,000 boe/d in the Bakken Shale in the second quarter. (Source: Marathon Oil)

company-operated wells to sales in the Malaga area in Eddy County, N.M., a mix of development and appraisal wells with an average 30-day IP rate of 1,130 boe/d (61% oil), according to Marathon's second-quarter results. "Drilling efficiencies enabled us to reduce our rig count from five to four in the second quarter, without changing our full-year guidance of 50 to 55 gross operated wells to sales," the company said.

Additionally, in June Marathon executed an agreement with San Mateo for water gathering and disposal in Eddy County, which the company said will significantly reduce unit production costs.

Matador Resources Co.

Matador operates in the Delaware and Midland basins, Eagle Ford Shale and Haynesville Shale. The company reported second-quarter average production of 52,900 boe/d (56% oil), 29,700 bbl/d of oil and 139.2 MMcf/d of natural gas, according to the company's second-quarter 2018 results report. As of Aug. 1, Matador expected to complete and turn to sales 151 gross (74.1 net) operated and nonoperated wells this year.

The company's second-quarter average production in the Delaware Basin was 46,500 boe/d (59% oil), 27,400 bbl/d of oil and 114.6 MMcf/d of natural gas, the report stated. Matador completed 33 gross wells in the Delaware Basin in the second quarter.

From Jan. 1 through Aug. 1, Matador acquired or had under contract approximately 16,000 net leasehold and mineral acres in and around its existing acreage positions in the Delaware Basin, including approximately 3,400 net mineral acres, the report stated.

During the second quarter, Matador also divested about 400 net undeveloped acres of its Eagle Ford leasehold position in South Texas for total consideration of about $8 million, the report stated.

Newfield Exploration Co.

Newfield's U.S. operations are in the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota and the Uinta Basin of Utah.

Second-quarter net production for the company's U.S. assets was 186,700 boe/d (39% oil and 62% liquids). "Stronger than expected production

Newfield has commenced a program focused on row-drilling cube development to capture additional efficiencies in the company's Stack play. (Source: Newfield Exploration)

results were driven primarily by the Anadarko Basin, which averaged 131,100 boe/d (midpoint of guidance was 123,000 boe/d), an increase of 13% relative to the prior quarter and approximately 48% year-over-year," according to Newfield's second-quarter 2018 results report.

Second-quarter average net liquids production in the Anadarko Basin was more than 80,000 boe/d. The company's net crude oil production from the Anadarko Basin averaged more than 42,000 bbl/d of oil (up more than 40% year-over-year), the report stated.

The company also continues to advance its Sycamore, Caney, Osage, Resource Expansion (Score) initiative. According to the company, it saw recent positive drilling results in the Northwest Stack in northeast Dewey County, Okla., where the company holds about 24,000 net acres (more than 70% operated). By the end of the year, more than 80% of this position was expected to be HBP, according to the report.

In the Williston Basin, Newfield's net production in the second quarter averaged 21,000 boe/d.

On Nov. 1, Encana Corp. announced its intent to acquire Newfield Exploration Co. for $5.5 billion. The transaction includes approximately 360,000 net acres in the Scoop/Stack in the Anadarko Basin and is expected to close in the first quarter of 2019, according to a press release.

Noble Energy

Noble Energy's U.S. onshore operations are located in the Denver-Julesburg (D-J) Basin, Delaware Basin and Eagle Ford Shale. Total sales volumes from the company's U.S. onshore assets averaged 244,000 boe/d in the second quarter, and U.S. onshore oil volumes totaled a record 105,000 bbl/d of oil, according to the company's second-quarter 2018 results report. During the second quarter, Noble averaged nine operated drilling rigs (two D-J, six Delaware and one Eagle Ford) and six operated fracturing crews (three D-J and three Delaware).

In the D-J Basin, the company had 335,000 acres and reported production of 110,000 boe/d and total proved reserves of 484 MMboe at year-end 2017. Noble also drilled or participated in 138 gross wells that year and reported 6,226 gross productive wells at year-end 2017. The D-J Basin averaged 121,000 boe/d and brought 16 operated wells online in the second quarter of 2018.

In the Delaware Basin, the company had 117,000 acres, was running five rigs and reported total sales volumes of 38,000 boe/d in the fourth quarter of 2017. Noble had 238 MMboe total proved reserves as of year-end 2017. In the second quarter of 2018, sales volumes from the Delaware Basin totaled 47,000 boe/d and the company brought 23 operated wells online.

In the Eagle Ford Shale, the company had 33,000 net acres and reported production of 70,000 boe/d and 191 MMboe total proved reserves at year-end 2017. Noble also drilled or participated in 47 gross wells that year and reported 344 gross productive wells at year-end 2017. In the second quarter of 2018, sales volumes from the Eagle Ford totaled 76,000 boe/d and the company had brought online nine operated wells.

Oasis Petroleum Inc.

Oasis Petroleum primarily operates in the Williston and Delaware basins.

The company has about 506,000 net leasehold acres in the Williston Basin. "We are currently focused on exploiting what we have identified as significant resource potential from the Bakken and Three Forks formations, which are present across a substantial majority of our acreage," the company said on its website.

In June Oasis Petroleum sold an estimated 4,400 boe/d of net production and about 65,000 net acres of noncore assets in the Williston Basin for $283 million, a press release stated.

In the second quarter, the company produced 79,400 boe/d from its U.S. assets, representing an increase of 28% over the second quarter of 2017, according to Oasis Petroleum's second-quarter 2018 results report. The company expected third-quarter 2018 production to range between 85,000 and 88,000 boe/d, which accounts for divestitures that were expected to close during the third quarter.

In the second quarter, the company also completed and placed on production 37 gross (27.8 net) operated wells, including 35 gross (25.8 net) operated wells in the Williston Basin and two gross (two net) operated wells in the Delaware Basin, the report stated. The company expected to complete about 110 gross operated wells this year in the Williston Basin and six to eight gross operated wells in the Delaware Basin.

Occidental Petroleum Corp.

Occidental Petroleum's U.S. operations are focused in the Permian Basin. The E&P company is one of the largest operators and oil producers in the Permian, with nearly 2.5 million net acres and producing about 9% of the total oil in the basin.

Occidental manages operations in the Permian Basin through two businesses: Permian Resources, which consists of growth-oriented unconventional opportunities, and Permian EOR, which utilizes EOR techniques, such as CO_2 flooding and waterfloods.

In the second quarter, Permian Resources' average production volumes were 201,000 boe/d, and Permian EOR's were 153,000 boe/d, according to Occidental's second-quarter 2018 results report.

In addition, each year Occidental's Permian EOR business injects more than 950 Bcf of CO_2 into oil reservoirs in the Permian, making Occidental the largest injector of CO_2 for EOR in the Permian Basin, and among the largest globally, the company said on its website.

Parsley Energy

Parsley Energy operates in the Midland and Delaware basins.

The company's second-quarter 2018 net oil production increased 14% quarter-over-quarter and 57% year-over-year to 67,700 bbl/d of oil, and total net production averaged 107,800 boe/d, according to Parsley's second-quarter 2018 results report.

Parsley placed 45 gross (44 net) operated horizontal wells on production during the second quarter. "This higher-than-anticipated net well count was driven by operational efficiency gains and acreage trades that increased Parsley's average working interest," the company said in the report. "In light of these trends, the company is increasing the number of operated horizontal wells it expects to place on production in 2018 from 144 net wells to approximately 158 net wells. These additional net wells are not predicated on the addition of incremental rigs or completion crews."

During the second quarter, Parsley spudded 43 wells and placed 45 gross operated horizontal wells on production (37 in the Midland Basin and eight in the Delaware Basin). Parsley expected development activity to remain weighted to the Midland Basin for the remainder of the year, the report stated.

The company increased full-year 2018 net oil production guidance to between 68,000 bbl/d and 70,500 bbl/d of oil. According to the company, at the midpoint the updated range translates to estimated year-over-year growth of 54%.

PDC Energy

PDC Energy's focus is on the Core Wattenberg Field in the Denver-Julesburg (D-J) Basin in Colorado and the Delaware Basin in West Texas.

In the Wattenberg Field, the company has drilled 20 to 22 horizontal wells per 640-acre section. "The 2018 capital investment program is focused on the Kersey area, with some spuds in its Plains area, as well as turning in-line the 24 horizontal wells it acquired in the Prairie area," the company said on its website. PDC expected to run three drilling rigs in the D-J Basin this year.

In the Delaware Basin, the company has about 60,000 net acres in Reeves and Culberson counties, and it expected to run three drilling rigs this year. "The drilling in 2018 is focused primarily on drilling single Wolfcamp wells in the A or B benches to meet drilling obligations as well as a downspacing test in its Eastern area that will evaluate the equivalent of 12 wells per section in the Wolfcamp A and a well that will test the Wolfcamp C," the company said.

PDC reported second-quarter production of 9.4 MMboe, representing a year-over-year increase of 20% from Wattenberg and Delaware basin operations, according to the company's second-quarter 2018 results report. In addition, PDC reported second-quarter production of about 103,000 boe/d as well as oil production of about 3.9 MMbbl, which represented 42% of the company's total production.

Pioneer Natural Resources

Pioneer Natural Resources has operations in the Permian Basin and Eagle Ford Shale in Texas. However, the company is in the process of becoming a pure play Permian Basin operator by the end of the year.

Pioneer has 750,000 gross acres and is the largest acreage holder and producer in the Midland Basin with approximately 550,000 gross acres in the northern portion of the play and approximately 200,000 gross acres in the southern Wolfcamp joint venture area. The company reported second-quarter production of 274,000 boe/d in the Permian Basin and expects to place 250 to 275 wells on production this year, according to its second-quarter 2018 results report.

Pioneer's full-year 2018 updates included the company expecting its noncore asset divestiture process to be completed by the end of the year; closed sales of the West Panhandle field, Raton Basin and selected Eagle Ford acreage for $383 million; and progressing its divestiture of Eagle Ford and other South Texas assets, according to the report.

QEP Resources

QEP Resources operates in the Permian Basin and Williston Basin. The company reported year-end 2017 proved reserves of 684.7 MMboe and second-quarter 2018 production of 14.1 MMboe.

In the Permian Basin, QEP reported year-end 2017 proved reserves of 272.7 MMboe. Permian Basin net production averaged about 44,100 boe/d (91% liquids), and the company placed 37 gross operated horizontal wells on production during the second quarter, according to QEP's second-quarter 2018 results report. At the end of the quarter, the company had five operated rigs in the Permian, and it released one of its operated rigs during mid-July.

In the Williston Basin, the company reported year-end 2017 proved reserves of 146.9 MMboe. According to its second-quarter 2018 report, QEP is open to bids from potential buyers regarding the sale of all or a portion of its Williston Basin assets.

At the end of the second quarter, the company had no drilling rigs in the Williston Basin.

Range Resources

Range Resources has operations in the Appalachia region and in north Louisiana.

In the Appalachia region, the company has about 875,000 net acres and reported third-quarter 2018 net production of 1.98 Bcfe/d. This year Range directed about 85% of its capital budget toward Marcellus Shale development.

According to the company's third-quarter 2018 results report, "Range's net production for the third quarter of 2018 averaged 2,267 MMcfe per day, consisting of 1,530 MMcf per day of natural gas, 111,469 barrels per day of NGL and 11,314 barrels per day of condensate and oil. This makes Range one of the top 10 natural gas producers in the U.S. and a top three NGL producer amongst E&P companies."

Sanchez Energy

Sanchez Energy's operations are in the Eagle Ford and Tuscaloosa Marine Shale, where the company reported second-quarter production of 7.2 MMboe, or 79,516 boe/d, according to the company's second-quarter 2018 results report. Sanchez drilled 57 gross (33 net) wells and completed 41 gross (28 net) wells in the second quarter. As of June 30, Sanchez had 2,278 gross (918 net) producing wells with 73 gross wells in various stages of completion, according to the report.

As of year-end 2017, the company had 487,000 gross leasehold acres (about 285,000 net acres) and more than 8,000 gross (3,700 net) specifically identified drilling locations for potential future drill-

Shell has interests in 500,000 acres (260,000 net acres) in the Delaware Basin. (Source: Shell)

ing in the Eagle Ford. About 748 of these drilling locations represented proved undeveloped reserves, according to the company.

Shell

Shell has interest in 500,000 acres (260,000 net acres) in the Delaware Basin with focus on the Wolfcamp, Bone Springs and Avalon formations.

Shell has focused on de-risking its acreage in the Delaware Basin and has advanced several key areas, according to the company. Shell has more than 1,300 operated and nonoperated wells and six operated and eight nonoperated rigs (as of the third quarter) across Loving, Ward, Winkler and Reeves counties. The company accelerated development in the Permian with a plan to bring about 100 Shell operated new wells online this year. To do so, Shell focused on multiwell pad drilling and long lateral wells to improve efficiencies and reduce surface impacts, the company said.

In line with this acceleration in activity, Shell's production has increased from 25,000 boe/d in 2013 to more than 100,000 boe/d in 2018 (operated and nonoperated) and is expected to increase to more than 200,000 boe/d by 2020 (GES, post royalty). Most of the production is light tight oil.

Shell has made significant investments in the supporting gathering lines and central processing facilities (CPFs). It operates five CPFs and plans to develop additional facilities to match its production growth, the company said Oct. 29. The company also operates 11 saltwater disposal (SWD) surface facilities and 20 SWD injection wells. By the end of the year, it expected to have 14 SWD surface facilities and 24 SWD wells.

In early 2019 Shell will deploy the first integrated prototype of its iShale program in the Permian. The program leverages advances in automation, digitalization and advanced analytics to optimize field design and enhance well productivity.

SM Energy Co.

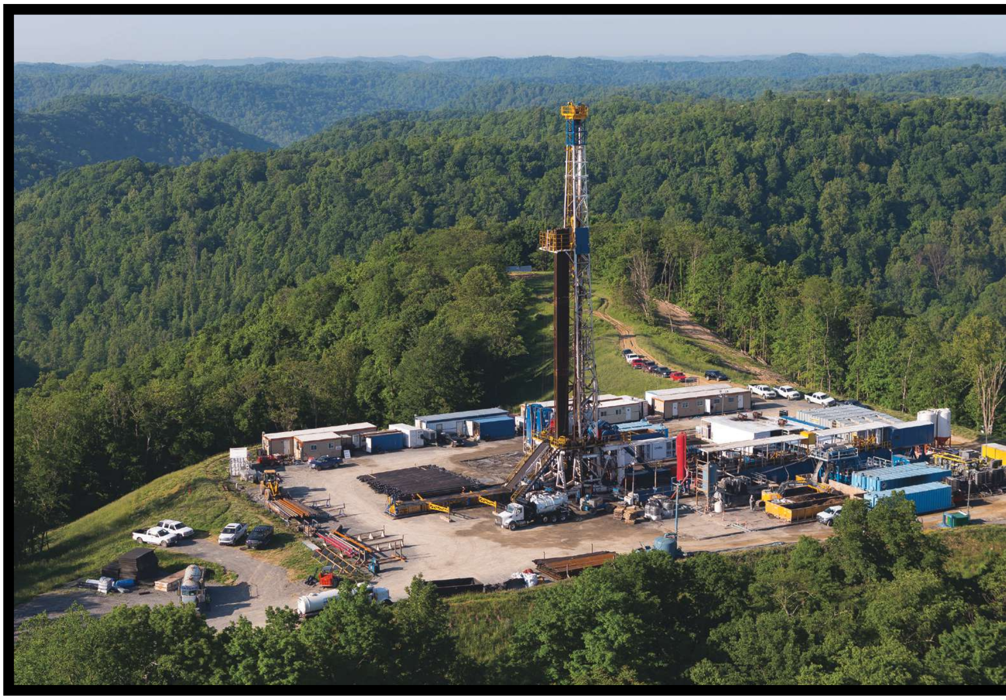
SM Energy's operations are in the Midland Basin and Eagle Ford Shale.

In the second quarter, the company reported production of 10.5 MMboe, or 115,000 boe/d, according to the company's second-quarter 2018 results report. As of February 2018, the company expected production growth of 135% from 2017 to 2019 in the Midland Basin. For full-year 2018, SM Energy expected production of 43.5 MMboe to 45 MMboe (an average of about 42% oil in the commodity mix), according to the report.

In the third quarter, SM Energy reported total production of 12 MMboe (130,200 boe/d), which comprised 42% oil in the commodity mix and 62% liquids, according to the company's third-quarter 2018 preview report. The company's third-quarter production was 64,800 boe/d in the Permian and 65,400 boe/d in the Eagle Ford.

Southwestern Energy Co.

Southwestern Energy (SWN), with more than 500,000 acres in the Marcellus Shale in the Appalachian Basin, produces natural gas, oil and NGL. For the first nine months of 2018, SWN produced 252



Southwestern Energy maintains an active drilling program for NGL-rich and oil-rich wells in West Virginia. (Source: Southwestern Energy Co.)

Bcfe and generated adjusted EBITDA of $1 billion, 21% above the period a year ago "due to an ongoing benefit from higher value natural gas liquids and oil production," the company said.

During the third quarter, SWN announced the sale of Fayetteville Shale E&P and midstream assets for $1.87 billion. The transaction was expected to close in early December.

Whiting Petroleum Corp.

Whiting Petroleum operates in the Rocky Mountain region, with its largest projects in the Bakken, Three Forks and Niobrara.

The company reported second-quarter production of 11.5 MMboe (84% crude oil/NGL), averaging 126,180 boe/d. The Bakken/Three Forks plays in the Williston Basin averaged 103,480 boe/d, and the Redtail Niobrara/Codell plays in the Denver-Julesburg Basin averaged 22,005 boe/d. During the second quarter, Whiting drilled 33 wells in the Williston Basin area and no wells in the Redtail area as well as put 22 wells on production in the Williston Basin and 16 wells on production at Redtail, according to the company's second-quarter 2018 results report.

Whiting also completed a $130 million acquisition of Williston Basin properties contiguous with the East Missouri Breaks and Hidden Bench areas, the report stated. The properties included 54,833 net acres and had production of 1,290 boe/d and estimated proved reserves of 26 MMboe (as of July 31).

In 2017 Whiting Petroleum drilled the 43-4TFH well in the Walleye prospect in North Dakota. (Source: Whiting Petroleum)

WildHorse Resource Development Corp.

WildHorse Resource Development (WRD) has 418,000 net acres in the Eagle Ford as well as operations in the Austin Chalk in East Texas.

In September WRD acquired 20,305 net acres in the Eagle Ford, Austin Chalk "and other intervals" with about 39 boe/d of net production, a press release stated.

The company increased its average production by 107% to 46,700 boe/d for the second quarter of the year compared to 22,600 boe/d for the second quarter of 2017, according to WRD's second-quarter 2018 results report. The company brought 28 gross (26.2 net) Eagle Ford wells online and completed five Eagle Ford refractures in the second quarter. Second-quarter net production consisted of about 33,400 bbl/d of oil, 6,000 boe/d of NGL and 43.5 MMcf/d of natural gas.

On Oct. 30, Chesapeake Energy announced its intent to acquire WildHorse. The transaction is expected to close in the first half of 2019, a press release stated.

WPX Energy

WPX Energy has 100,000 net acres in the Permian and 85,000 net acres in the Williston Basin.

The company reported second-quarter oil volumes of 80,800 bbl/d from its operations in the Delaware and Williston basins, according to its second-quarter 2018 results report.

During the second quarter, WPX's Delaware production averaged 74,400 boe/d, and the company had 20 wells with first sales in the basin. WPX completed 32 gross operated wells (29 net) in its two core basins during the second quarter of 2018 and participated in another seven gross (one net) nonoperated wells in the Delaware Basin, the report stated.

The company's Williston Basin production averaged 50.6 Mboe/d in the second quarter, and WPX completed 12 Williston wells during the quarter, evenly split between the Bakken and Three Forks formations.

The company expected full-year 2018 oil volumes of 78,000 bbl/d to 82,000 bbl/d, according to the report. E&P

Operators are bulking up on drillpipe and drilling rigs as laterals go longer. (Photo by Ricardo Merendoni, courtesy of *Oil and Gas Investor*)

Drilling Becomes Standardized While Completions Get Customized

By **Gregory DL Morris**, Contributing Editor

Rigs are consolidated at the high end while sand shifts back to quality.

Oilfield services look to 2019 with some firm trends in place. Rig operators are consolidating and standardizing their fleets with premium machines now that day rates are covering the cost of capital. Sand loads, pressures and lateral lengths are all still increasing, but the pace of acceleration is slowing. There is a renewed focus on quality, not just quantity. Even as drilling is standardized, each well is being customized or tuned. Service firms are sanguine about Big Data presenting the next important opportunity for gains in efficiency and productivity.

These FlexRig3s are located in western Oklahoma. (Source: Helmerich & Payne)

"In every downturn or correction, we look to the start of the recovery," said John Lindsay, president and CEO of Helmerich & Payne (H&P). "When things started to improve in 2006, we started building our FlexRig3s and 4s. We continued building about four rigs per month through three subsequent cycles from then through 2014, with the exception of the global recession. As a result, through the mini-cycles, the other drillers were losing share because it was the older rigs that were being laid down."

To underscore the point, Lindsay cited that H&P had a market share of 4% in 2001, 8% in 2008, 15% in 2014 and 21% in 2018. "Through the cycles we have been able to invest in capabilities. In October 2014 we had 300 rigs operating. By the summer of 2016, we had just 67 rigs turning to the right. That was tough, but it prepared the organization for growth. We put 127 rigs back to work in our fiscal 2017 [which began Oct. 1, 2016] and upgraded 91 rigs to super spec that year. In fiscal 2018 we were on pace to upgrade 48 to 50 rigs. For fiscal 2019 we have 12 more upgrades committed and a further 12 planned per quarter if demand holds," he said.

To be sure, rig counts are very different from what they were even 10 years ago. The fundamental changes in unconventional development, notably pad drilling, and the fundamental changes in rigs as drillers consolidate around larger and more capable designs have altered the relationship between rig counts and industry activity.

"In the year 2014, the industry had 1,800 to 1,900 rigs running, and we are down to about 1,000 to 1,050 today," Lindsay said. "In 2014 AC [alternating current] drive had about 40% of the market. Today that is 67% to 70%. And the replacement cycle continues. The consolidation of the industry at the higher-end rigs is a result of the longer and longer laterals as unconventional development evolves. As recently as 2015, the average lateral length we drilled was 6,000 ft. Today our average is 8,000 ft. We have even drilled some for clients at 10 ft, 12 ft and 15,000 ft. That adds complexity and demands on the rig."

This is not to say that rig counts are not important. It is more a matter of which rig is doing what. "The industry fleet is delivering more wells with longer laterals more quickly with a smaller fleet," Lindsay said. "For us, a big part of that is not just having an upgraded fleet but a uniform fleet. These are our rigs built to our specifications. We are effectively the original equipment manufacturer, and we also own a lot of the software."

That software element is important, Lindsay said. "With the emphasis on better well economics in longer laterals, producers are very attentive to enhancing the quality of the wellbore and the placement. That is especially true with infill drilling and tighter spacing. That is where our MOTIVE and MagVAR software come in," he said.

There are only about 250 legacy mechanical rigs and the silicon-controlled rectifier systems drilling horizontal wells, Lindsay estimated. "A lot of our competition has had to write off a big portion of their fleets. That was a big drive for us to build the modern rigs. When those went to work, we got 90% of our money back on the first contract," he said.

What counts as a big well or a big fracture also has changed and varies by basin. "We started to see the trends to longer laterals, heavier sand loads and higher pressures as early as 2012. The Eagle Ford shifted more quickly than others, and we had a presence of 80 or 90 rigs in that basin, so we had a front-row seat. It used to be that 5,000 psi was standard for pumps. Today that is 7,500 psi," he said.

That said, H&P has mostly kept to its knitting. "As our peers got into pressure pumping and other services, we stuck with what we do best. That has enabled us to reduce cycle times. Now [that] the new build cycle is over and the industry is into

The Super Triple 1200 is equipped with full pad walking capabilities and high-pressure circulating systems. (Source: Precision Drilling)

The Super Triple 1500 is equipped with full pad walking capabilities and high-pressure circulating systems. (Source: Precision Drilling)

the upgrade cycle, we will continue to gain share," Lindsay said.

Full-scale industrialization

The industry has evolved into "the full-scale industrialization of the drilling process," said Kevin Neveu, president and CEO of Precision Drilling, a land driller that is active in all shale plays across North America. "Pad style drilling and well standardization are driving today's exceptional performance. And that is not just speed; it is also the quality of the wellbore."

Neveu is very specific in his description of drilling as "industrial" in contrast to the term "manufacturing," which is commonly heard around the industry. "In manufacturing you control every variable of the process. You can see and touch the work piece in real time. But in drilling you never actually see the cutting tool or the work face and certainly not in real time. I much prefer the term 'industrialization.'"

He is also very specific about how the drilling process is being industrialized at the same time well completions are being customized. While the latter is often considered the result of advances in fluid chemistry and pressure pumping, Neveu believes the next level of advances will come from data analytics.

"We have already gotten through most of the gains we are going to get through mechanical process improvement," he stated. "We are now looking to the data side and have some work to do. Today, we can capture 20 gigabytes of well data per day, but it is difficult to sort through that much or even move those through a central hub. There is a huge opportunity in the data surrounding the wellbore process. We are just scratching the surface," he added without a hint of irony.

And while the top performance of the best rigs may be testing the physical limits of the process, not all rigs are at that level. "Only about half of the rigs running today are leading edge," said Neveu, and a "few of those are operating at optimum efficiency."

These modern rigs are making a remarkable difference. "In the Permian we are able to drill short-lateral wells in 12 days and long reaches in 20 days," Neveu said. "That is down from 65 to 78 days, a reduction factor of 60% to 75%. We believe the pace of improvement is flattening, but as we get better at interpreting data, we will be able to build the best well every time, eliminate inconsistencies and strive to eliminate downhole failures."

Specifically, he said Precision is focused on the elimination of human bias and variability. "It is a matter of interpreting what is happening at the drillbit in real time based on advanced analytics," Neveu said.

As 2018 winds down and he looked ahead to 2019, Neveu believes that business was "improving as activity levels for [Precision Drilling] are about 75% to 80% of where they were at the peak in 2014, while the industry is in the range of 50% to 60%. We have gained share."

Working out of the worst downturn

It is important to note that there is a lag between price cycles and drilling activity of six months to a year. Thus the low point for the price of oil was in the second quarter of 2015, and the low point for rig activity was in the second quarter of 2016. Many long-term newbuild contracts initiated in 2014 may have had several years of duration, some of those date back to November 2014, signed just weeks or even days before the OPEC actions precipitated the price collapse.

"The worst downturn I have ever experienced in a long career was 2015 and 2016," Neveu recalled. "That was the only time we had two years back to back where producers substantially reduced their capital expenditure [and] demand for our service essentially collapsed. The downcycle in the early '80s was long and protracted, and peak to trough may have even been greater, but it was over a longer time frame."

Through all recent cycles, there has not been a great deal of consolidation in the drilling sector. One reason has been the myriad rig types that make it difficult to integrate fleets. The availability of capital to finance a deal also has been rare. So the bid that Precision has made for Trinidad Drilling is a unique opportunity to "take us from No. 4 to a solid No. 3 in terms of market share in the U.S. The Trinidad AC rigs are a rare fit for compatibility rather than the start of a roll up as standardization of the rig fleet remains a strategic focus for Precision.

"The Trinidad board supports the deal, and we hope to close the deal by the end of 2018," Neveu said, "with an expanded fleet that would include about 170 similar high-performance, AC-drive pad-capable rigs."

"Generally, as prices improve so does activity, but that varies greatly by basin and from oil to gas," said Michael Henry, global operations manager for production enhancement at Halliburton. "There are some pipeline constraints in the Permian and also in the Northeast. That has forced operators to develop other parts of their holdings until the constrained areas can get additional transportation."

He also noted that there seems to be an increase in drilled but uncompleted wells (DUCs), but that may be temporary. "Operators are being more disciplined with their budgets as we get close to the end of the year," Henry said. "In previous cycles they may have just gone ahead and spent the money to complete, but today producers are keeping to the idea of the most production for the least money."

That sort of discipline also leads to flexibility. In the 2014-2016 downcycle, many producers accumulated DUCs because they had to. When the recovery started, everyone was happy to go DUC hunting. Having now established that completion does not have to come immediately after drilling, producers have that as a new option for deploying their development dollars and sticking to budgets. That not only keeps shareholders happy but allows tweaking of production to meet pricing and demand variations.

Deeper downhole data

Another manifestation of that separation between drilling and completion is that as drilling has become more like a manufacturing process, completion is trending toward customization.

There is no contraction between repeatability and custom tailoring, Henry said. "They are not mutually exclusive. A streamlined, integrated approach to more wells per pad is just efficient use of equipment and capital. Operators do want to know about well dynamics, placement of course, but also fracture modeling and potential impact on other bores," he said.

As one example, Henry noted that the cost of fiber-optic, in-bore diagnostics has become much more economical. "It's not quite mainstream yet, but it is becoming much more common," he said. The cost is not the only thing that has been brought down; processing times have been reduced as well.

What constitutes a big fracture is changing as well. It used to be that 10 by 10—10,000 ft deep and a 10,000-ft lateral—was considered a big well. "That is certainly not standard," Henry said, "but it's not considered very big or long as it used to be. We are seeing more sand and more stages [and] 500,000 to 600,000 pounds of sand per stage is still considered big. We have done some very big jobs with 1 million or 2 million pounds per stage, but those were unusual, high-intensity jobs for very specific formations."

As the pace of the recovery in domestic production accelerates, so do most of the characteristics of wells. "In the Midland Basin, laterals are moving rapidly toward 10,000 ft as a standard," said Dan Fu, director of technology at BJ Services. "Just last year the average lateral length was 8,000 ft. Today it is 9,500 ft. Half of the wells are longer than 2 miles."

He also observed that while wells are getting longer, rigs are drilling those wells in the same amount of time. If anything, spud-to-total-depth and spud-to-spud times are dropping on aggregate. Once the bore is finished, volumes of proppant used also are growing. "We have seen an increase of 30% to 40% in proppant loads," Fu said. "In 2014-15 the average was 1,500 pounds of proppant per foot; now that is up to 2,500 pounds per foot."

With all that increased size and performance, costs are actually lower. "In the past few years, the costs of drilling and completing have decreased by $5 to $10 per barrel," Fu said. "That is a result of a combination of factors. More wells are being completed faster and more efficiently, so the cost per barrel is going down."

That said, no tree grows to the sky. "As spud-to-TD [total depth] and spud-to-spud times are decreasing, and as we put more wells on a pad, we have to manage the wells and each bore carefully for possible interference," Fu said. "There is a growing industry concern about the parent-child relationship for each well on a pad. Well-to-well separations are down to 1,000 ft or even 800 ft. With current fracking techniques and pressures, fractures extend as much as 400 or even 500 ft from the bore."

Thinking and planning in 3-D

Thinking and planning in 3-D are starting to get as close as possible without the risk of communication. "There is a lot of experimentation," Fu said. "We have done hundreds or thousands of wells, so we don't take a lot of measurements now. The

focus is more on trying to optimize. Companies are understanding the resource better using advanced analytics. Data analytics is becoming very attractive from the cost point of view."

Fu added that producers and drillers are starting to think in terms of cubes, which is to say all three dimensions. "This is all very new, just over the horizon. People are starting to think in full 3-D on how to complete stacked pays at multiple depths and multiple directions with multiple bores at the same time."

> **"LEGACY EQUIPMENT IS JUST NOT UP TO TODAY'S JOBS.** Now that we have evolved to what amounts to a manufacturing process, the reliability of the equipment, in addition to its power and flexibility, is essential."
>
> *—Dan Fu, BJ Services*

BJ Services is an independent pressure pumping company that was created when CSL Capital Management and West Street Energy Partners (WSEP) acquired the North American land cementing and hydraulic fracturing businesses from Baker Hughes, a GE company (BHGE). CSL and WSEP have a 53.3% stake, and the combined companies of BHGE have 46.7%.

BJ Services organizes its R&D into three segments: chemistry, data and equipment. "We don't try to do everything in house," Fu said. "We work with chemical suppliers, data analysts and equipment companies. Our ThinFrac MP tunable chemistry incorporates several properties including proppant transport and precision breaking. We use that in about half our fleet and have seen improvements in cost to operators."

Vast new computing power at relatively low cost and high speed, so-called data mining or Big Data, has put new emphasis on public or industry data in addition to the proprietary data that a service company gets from each job.

"We are looking at public data as well as our own to help determine how different reservoirs respond," Fu said. "We are working with a small data company on simulations in lieu of running a tool into the well. That system, which we call SAVANT, is faster and there is less risk of a mechanical problem such as a tool getting snagged. We consider this reservoir characterization a differentiator for us."

One essential factor in faster drilling and completion is a modern high-horsepower flexible rig. "Legacy equipment is just not up to today's jobs," Fu said. "Now that we have evolved to what amounts to a manufacturing process, the reliability of the equipment, in addition to its power and flexibility, is essential."

Against the grains

Sand supply, especially from local sources, has gone from tight to almost oversupplied in just a few months. "In the Permian, as well as South and East Texas, most operators are willing to use local sand," Halliburton's Henry said. "It is too early to tell the long-term results as compared to using Northern white sand. There have not been any initial concerns, no short-term impacts that I know of. But [for] long-term [impacts], the jury is still out."

That sudden swing in sand supply from tight to loose is a microcosm of the logistics and service sector broadly. "It has certainly been a challenge for the industry to go from the slowdown to a fast ramp-up," Henry said. "We have certainly learned to operate more efficiently. Part of the acceleration is that information flows more quickly so people are making more quick decisions. Some service companies have been more successful than others in adapting to that pace."

While rigs have been consolidated to a largely standardized fleet of big, powerful and flexible models, the evolution of proppant has been one of diversification. "The industry has moved quickly from ceramics to sand," Fu said. "We are now seeing the evolution from primarily use of Northern white to in-basin sand. Northern white is still used, and I expect will continue to be. The percentage of in-basin sand is likely to grow to more than half."

While the mix continues to shift, loads are starting to settle into a range. "We have about reached a plateau in sand volume," Fu said. "Not too long ago we would use 30 [million] to 40 million pounds per job. Now that is 200 million and climbing, but not

climbing as fast." Specifically he was referring to BJ Services' new blender, which is able to handle more than 200 MMlb of sand without failure as compared to 30 MMlb to 40 MMlb in the previous design.

"Within that load, we are using a combination of very fine 100 mesh and coarser 40/70. We have heard of some experiments with 200 mesh, but that trend to finer grains has stopped," he said.

Mammoth Energy touches just about every basin across its service lines. "We see stable activity across the three main areas of the country: the Northeast, Appalachia and the Utica; the Scoop and Stack; and the Permian," said Don Crist, director of investor relations. "Things are up a bit in the Eagle Ford in the last three months [as of third-quarter 2018], but the biggest change has been in the Rockies. We have been getting a lot more inquiries from the Powder River Basin and the D-J [Denver-Julesburg]."

For all the attention that the Permian gets, Crist noted that it is actually a late adopter in terms of drilling and completion techniques. "The Marcellus-Utica, the Scoop and Stack, even the Haynesville and D-J have all been early adopters in the past," he said.

As an example, Crist said that "all the jobs we have done this year, we have used 100 mesh initially to sandblast the formation, then 40/70 behind that as proppant to hold the fractures open. This has shifted in recent years as historically 100% 40/70 was used. Operators are seeing the benefit of using 100 mesh to start fracks and open up the formations."

Mammoth has expanded two of its facilities over the past year or so. The mine at Taylor, Wis., was expanded from 700,000 tons/year to 1.75 MMtons/year. A new 300,000-tons/year dryer was installed in the Piranha facility and also in Wisconsin, increasing the capacity of that mine to 1.9 MMtons/year.

Quality over quantity

"We feel strongly that sand is specific to a need. Some operators have tried to use 100 mesh for completions, and long-term production is impacted when compared to using 40/70 as a propping agent. As a result, we have seen completions standardize with approximately 25% 100 mesh and 75% 40/70.

"While acknowledging the cost advantage of in-basin sand," Crist added, "Northern white will have a place in the market because it is simply a better sand."

Regardless of grain size, he noted that loading seems to be stabilizing around 3,000 lb/ft. That is substantially higher than the 1,000 lb/ft that was common just a few years ago.

Pressures remain variable, mostly by formation. "Here in Oklahoma, the Scoop is deeper and is a higher pressure formation," Crist said. "The Stack runs across several zones. In the northeast portion in Osage County, pumping is usually at about 6,000 psi. In the deepest part of the Scoop, it might be twice that. From an equipment standpoint, anything above 8,000 psi is high-pressure work."

Laterals are also variable. "About 6,500 ft to 7,500 ft is standard," Crist said. "[And] 10,000 ft is still big in most places, but in the Bakken we have been doing 10,000 ft for eight years. In the Permian we are seeing an average of about 7,000 ft with some wells getting longer toward 10,000 ft."

By the end of the year, specialty chemicals firm ChemTerra Innovation expects to have its greenfield chemical blending plant in service in West Texas. ChemTerra is playing both sides of the proppant business, supplying coatings that reduce dust and other lost material to rail cars of premium sand that are shipped from upper midwestern states and also supplying coatings for in-basin sand to improve its performance to compete with Northern white sand.

ChemTerra was created as a discrete operation within Trican Well Service at the end of 2017 to sustain the North American growth of its oilfield chemicals business even as the parent well service business consolidated to exclusively Canadian operations. ChemTerra also has developed surfactants to enhance oil recovery, part of its larger portfolio of oilfield chemicals for hydraulic fracturing, well stimulation and cementing. The company manufactures some of its own coatings and chemicals and also contracts some manufacturing to toll blending companies.

"We are still a new company just establishing our place in the industry," said Natasha Kostenuk, ChemTerra's general manager, "but we have been very well received and [are] looking [for-nanoActiv® HRT

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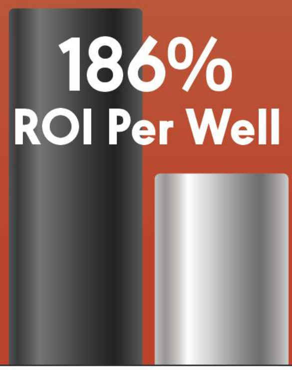

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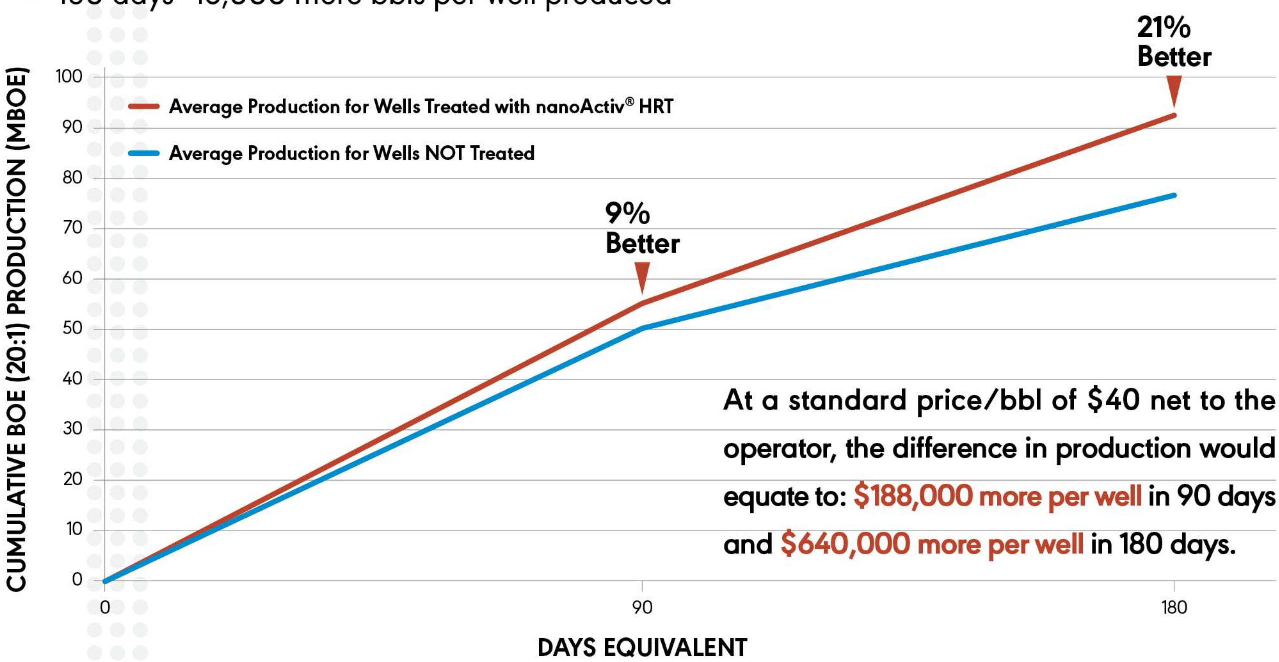

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*Weighted difference in average BOE (20:1) cumulative production. nanoActiv® HRT treatment vs. offsets (2017-2018). New well frac'd completions located in the Midland and Delaware Basins. Data was limited to direct offsets with reasonable data quality as reported to Texas RRC.

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nanoActiv® HRT is made in the U.S.A. by Nissan Chemical America Corporation in Houston, Texas. · · 1731 ward] to a strong 2019." She added that business in Canada has been a little tough lately with all the pipeline controversies and export constraints, so the company has been focusing its chemicals growth in the U.S. where production and exports are booming.

"We rolled out the proppant coatings in Canada through Trican," said Bill O'Neil, ChemTerra's R&D director, "and now the push has been in the U.S. Business is very different on the other side of the border. Within that overall growth has been the major shift to local sand in the Southwest. The quality is very questionable for in-basin sand, but the focus has been on cost rather than performance."

About three-quarters of the delivered cost of Northern white sand to West Texas is transportation. That cost, plus the challenges of supply as demand boomed, led to the focus on local sand. "We are already starting to hear about problems with fines washing out valves during flowback," O'Neil said. "We have seen samples that are unwashed and unsieved."

Local sand is "a cheap and quick solution," O'Neil added. "Some operators might not be bothered, until they start to see damage to equipment on flowback." The overall approach for the coatings is in three areas: dust control, consolidation to prevent loss to flowback and improved crush strength.

Going with the flow

Water will continue to be an area of focus, added Halliburton's Henry. "Sometimes it is top of mind, sometimes a little lower, but never not a factor. The driving factor is cost, both to procure water and to dispose of it. Fracturing is about flowback. Wherever possible, operators will use produced water. Of course that changes the chemistry so it becomes a challenge for each well to check compatibility with both the characteristics of the water and of the formation. That gets back to the customization idea. When using produced water, the most important thing is to pay attention to the source," he said.

Water remains variable, not so much with the basin per se, but more with the amount of activity in the local area, explained BJ Services' Fu. Lots of activity in the immediate vicinity means more demands on water sources and also more produced water, so the strong tendency is to use what is most readily available and less expensive. "Producers are definitely favoring use of produced water," Fu said. "That is a trend in every single basin. We are even starting to see this in the project requirements."

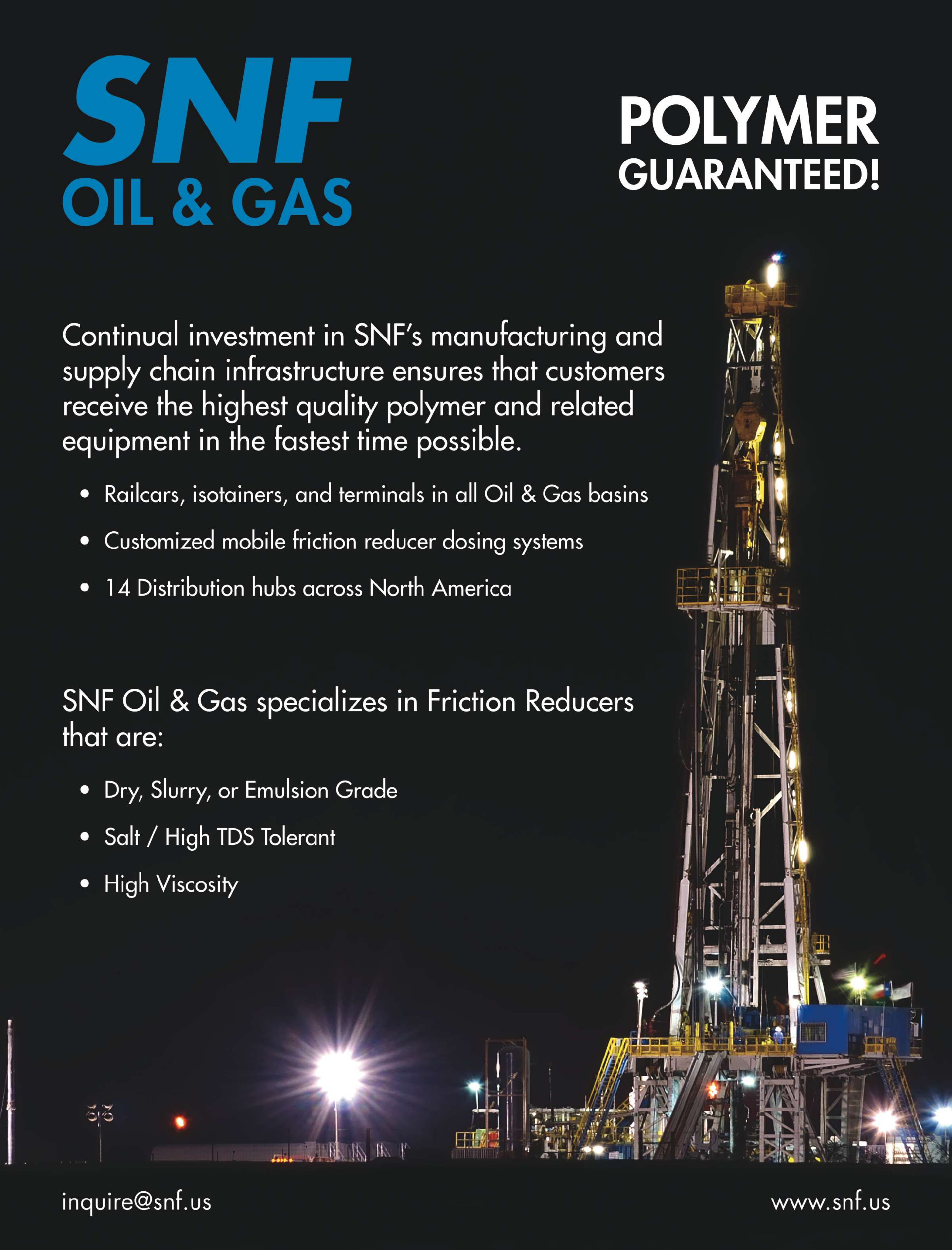
Fu stressed that decisions on water should not be made in a vacuum. "In general, cations in produced water can reduce the efficiency of regular friction reducers by 70% to 80%. We use specialty friction reducers to address that. It all comes down to economics. There are lots of options for producers from water sources to chemicals to equipment and techniques. Fracturing fluids are indeed truly tunable. It all comes down to costs on how much to tune," he said.

Trends in chemistry seem to mirror trends in sand. "As a chemical company, we see people pushing more and more to produced water," Kostenuk said. And that makes for highly variable water characteristics, "but with all the pressures on costs, there is also pressure on chemistry. There is a general trend when costs are under pressure for people to water down the chemicals. But there is a need to maintain quality and performance."

One example of that is an additive that enhances oil recovery from the start. "EOR is usually considered secondary or tertiary recovery," O'Neil said, "but we have published papers and received patents for chemistry that turns frack water into the equivalent of a waterflood."

Across the industry in aggregate, O'Neil estimated that water use is about 50:50 fresh to recycled. "The trend is definitely going more to recycled, but even in a closed system there is some loss that has to be replaced. Canada is still using mostly freshwater, but even that is starting to change," he said.

Getting that water and sand downhole is also in flux. "We are hitting the point where pressure pumping is tipping into oversupply. The pumpers have built up their horsepower, perhaps too much. They are seeing the same price pressure as we are seeing in chemicals. The sector never fully recovered from the big recession, and now we are back to pricing pressure," he said. E&P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Technology Rules in the Oil Patch

By **Hart Energy Staff**

Know these—viscosity, velocity and proppant size—and you have the advantage.

"You have to know the rock and be able to innovate quickly," Phil Webb, COO of Surge Energy America, told attendees at Hart Energy's Executive Oil Conference on Nov. 7.

"The tools to steer wells are incredible today, and now the effort is to accurately quantify the subsurface volume," said Allen Gilmer, co-founder and executive chairman of Drillinginfo Inc. The goal, said members of the event's "positive sum production" roundtable, is to wrest as many barrels of oil equivalent per day as possible per dollar invested.

The conference kicked off with a focus on the Permian, which for supermajor Shell Oil Co., is home, sweet home.

Shell views shales as a complement to its vast international and deepwater portfolio, according to Gretchen Watkins, the company's executive vice president for upstream unconventionals. Shell plans to grow its Permian production from the current average of 120,000 boe/d today to 200,000 boe/d by 2020.

"Reducing flaring is critical for the industry's social license to operate," Watkins said, adding that economic production also was key. She said Shell has stopped installing flare stacks on its new well pads in the Permian.

Another discussion concluded that the Permian is primed for a coming wave of consolidation. Panelists included Mike Marziani, executive vice president and CFO for Tall City Exploration III LLC; James Walter, Co-CEO of Colgate Energy LLC; and Chris Atherton, president of EnergyNet.

The panelists examined pricey tracts of land in the basin. Bids on the U.S. Bureau of Land Management's 50,000 acres in New Mexico totaled $972 million. That's partly because the acres are in the prolific Delaware Basin and partly because the tracts are longer. Prices for side-by-side parcels swung from $300 to $2,500 per acre based on the ability to accommodate 2-mile laterals.

Very large firms will be able to swallow a percentage of leaseholds with a low cost of capital, with the result that the big get much bigger, panelists said. As these companies consolidate, they will shed noncore assets down the chain.

For the smaller companies, the story is a bit different. Panelists said it is likely that small to midsized Permian E&P companies can expect stock-heavy offers and a pittance of cash these days.

The importance of the basin was underscored by Reed Olmstead, director of North American onshore research and business development for IHS Markit. The dramatic growth in U.S. crude oil supply—1.3 MMbbl/d in 2018 alone—is propelled by strong Permian Basin production.

As takeaway constraints are relieved, Olmstead believes U.S. crude supply will grow another 1.5 MMbbl/d in 2019, but pipeline bottlenecks will likely keep Midland and Cushing, Okla., hub differentials wide well into next year, with no easing expected until 2020, he said.

The entrance of global operators into the Permian will change the activity profile of the play, said members of the takeaway roundtable. That is because programs executed by multinationals tend to be stable and less sensitive to volatile oil prices.

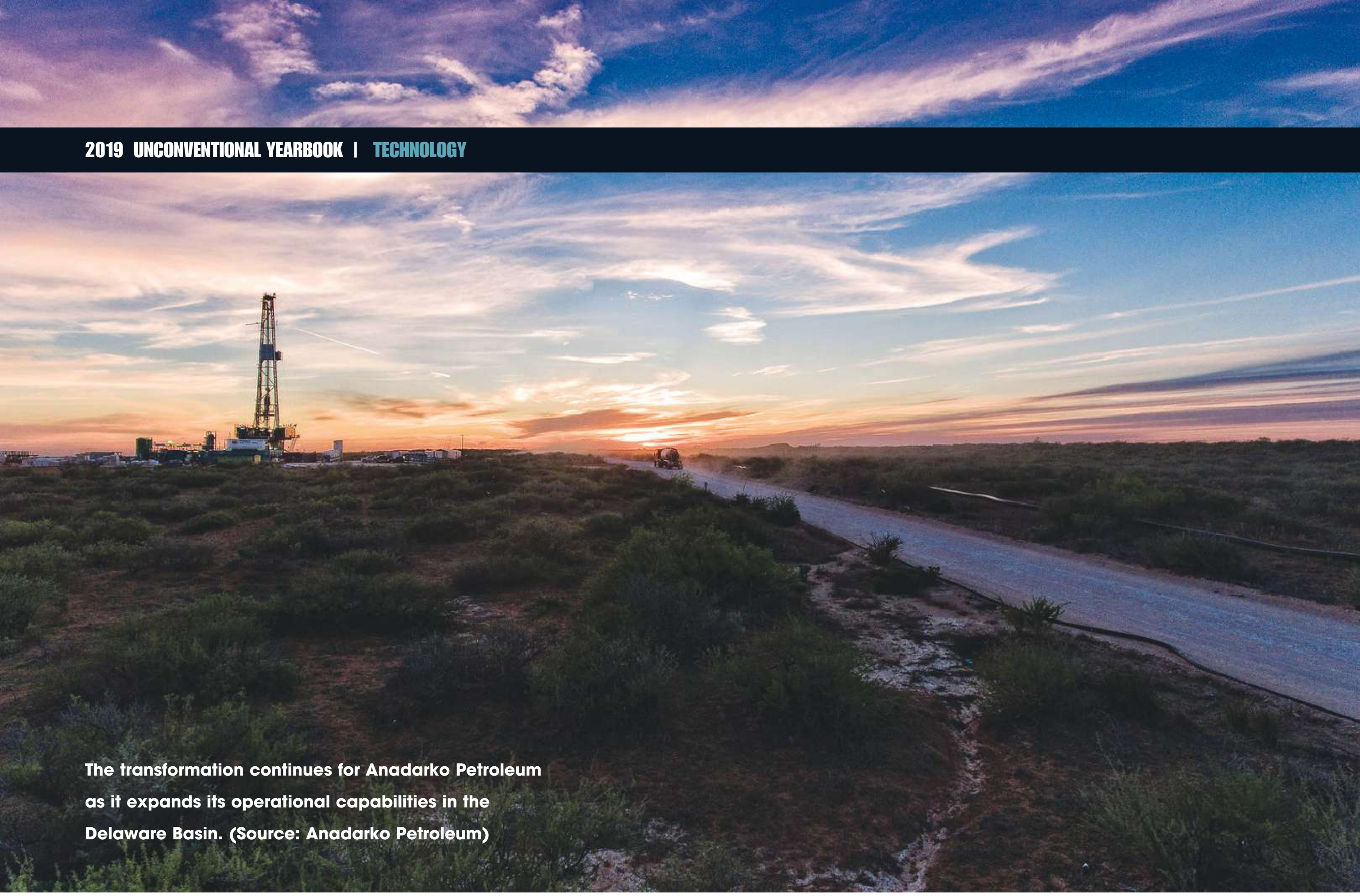
Steve Pruett, president and CEO of Elevation Resources LLC, said there are lots of incentives for companies to delay completions at the moment, but this is just a pause. At this point, he sees uncertainties aboveground outweighing those below the ground.

One issue to be reckoned with: water.

"We plan for water as much as we plan for oil," said Carrie Endorf, vice president for reservoir engineering and planning at Parsley Energy.

But once those issues are resolved, those massive volumes of Permian crude need a destination, said Joel Fry, principal at Tailwater Capital.

"It has to be exported, and we need the infrastructure and the market destinations for Permian Basin crude," he said. "It's a global issue." E&P



The transformation continues for Anadarko Petroleum as it expands its operational capabilities in the Delaware Basin. (Source: Anadarko Petroleum)

Transformation Continues for Delaware Basin Operator

By **Jennifer Presley**, Executive Editor

Dual-basin independent E&P company is ready for 2019.

In much the same way that the shale revolution transformed the oil and gas markets, so too has it transformed the way E&P companies conduct business. This transformation process is one that Anadarko Petroleum fully embraced, according to Chad McAllaster, vice president of Delaware Basin development for the company.

"Several years ago, Anadarko made the strategic decision to transform our U.S. onshore business by divesting nearly all of our natural-gas-leveraged assets as they simply could not compete for capital allegation within our portfolio," McAllaster said before a packed crowd at Hart Energy's Executive Oil Conference in early November in Midland, Texas. "The result is a simplified and high-graded onshore portfolio, with scalable infrastructure advantage positions and two of the best U.S. onshore oil basins."

In addition to the 400,000 net acres it holds in the Denver-Julesburg (D-J) Basin, holding more than 2 Bboe of recoverable resources, Anadarko has 600,000 gross acres of stacked pay in the Delaware Basin. That acreage contains an estimated

4 Bboe of recoverable resources, with an estimated breakeven cost at $20 to $30/bbl.

"We've invested nearly $2.5 billion between the D-J Basin and the Delaware Basin. We're running 12 drilling rigs and nine completion crews between these two positions," he said. "We're going to deliver an excess of 70% oil growth in the Delaware and more than 15% oil growth in the D-J. The returns on these investments are extremely attractive, as we have more than 6 Bboe net stacked resources and decades of inventory before us."

Anadarko delivered record production in the Delaware Basin, according to its third-quarter 2018 operations report, with a total sales volume of 120,000 boe/d and oil sales volumes averaging 70,000 bbl/d of oil. This represents a 13% increase from the previous quarter and an 83% increase from the third quarter of 2017. The company turned 50 wells to sales during the third quarter.

"Given the extensive footprint in the Delaware Basin, we continue to advance numerous foundational components of Anadarko. For example, we enabled long-lateral development through trades and swaps of over 35,000 acres to ensure operational efficiencies, we secured an in-basin sand supply and run 100% of our completions off of in-basin sand," he said.

The company continues to delineate the entire stratigraphic column as well as collect rock, fluid and pressure data across its anchorage position, he added.

"We're building infrastructure to facilitate our growth, including gas processing, oil treating and water disposal capacity," he said.

That infrastructure buildout included the placement of the company's second regional oil treating facility (ROTF) into service in Loving County, Texas, adding oil processing capacity of 60,000 bbl/d of oil.

"With both the Loving and Reeves ROTFs now ramping production, Anadarko has successfully increased nameplate oil processing capacity by 120,000 bbl/d of oil in 2018 and is in the final stages of installing more than 850 miles of associated pipelines," according to the company's third-quarter 2018 operations report.

"Our tankless production facilities [the ROTFs] are the catalyst for producing our wells in their optimal state and establishing the foundation of our future growth," McAllaster said. "These ROTFs are a best practice we brought down from our D-J Basin operations."

According to McAllaster, pressurized fluids straight from the wellsite are delivered to regional treating facilities, thereby eliminating the storage tanks and the associative equipment.

"It helps us lower operating costs as we eliminate trucking and the associated emissions," he said. "We see this as the responsible way to operate as we think about the size and scale of our asset and the years of growth that we're capable of delivering."

McAllaster explained that through the production constraints and the infrastructure buildout period, the company continued to improve its well practices.

"We hold our targeting practices and our completion design practices such that we are seeing year-over-year improvement in results. We changed our completion design practices back in late 2016 as we moved to what we consider a generation one to gen two frack consisting largely of 2,500 pounds of sand per foot and 55 barrels of water per foot," he said.

The company also is actively testing the interaction of well spacing in its completion designs. In its Silvertip-A campaign, completions operations on 12 extended-lateral wells focusing on four Wolfcamp A targets and one Third Bone Spring target were finished. Early results of the five wells connected to permanent facilities and flowing to the Loving ROTF are encouraging, he said.

The transformation continues for the company as it continues to gather more information about the Delaware Basin. In addition to participating in the joint U.S. Department of Energy/Gas Technology Institute study on hydraulic fracturing, the company is seeing promising returns from its Oredigger spacing test. The campaign features nine wells with five target areas in the Third Bone Spring and Wolfcamp formations.

"We're so excited about our developments in the Delaware Basin," McAllaster said. "With over 4 billion barrels of oil resources to develop and with our critical infrastructure backbone now in place, we're set to deliver." E&P

Increases in lateral length and proppant intensity are driving extreme demand for frack sand. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)

Sand, Water Logistics Shift into High Gear

By **Jennifer Presley**, Executive Editor

Shale logistics teams prepare for increased pace in 2019.

Other than water, there is very little in the world more boring than sand. Yet, both have captured the attention of the oil and gas industry for their role as crucial ingredients in the drilling and completion of a shale well.

Sustained oil and gas production combined with an escalating increase in lateral length and proppant intensity is driving "extreme" demand for frack sand, according to an IHS Markit report released in August. The current market value for frack sand exceeds $4 billion in 2018 and will reach nearly $6 billion by 2023. By comparison, the market value for frack sand in 2016 was $1.3 billion, according to the "IHS Markit ProppantIQ 2Q2018 Analysis" report.

On the water front, a Duke University study published in August found that the amount of water used per well for hydraulic fracturing surged by up to 770% between 2011 and 2016 in all major U.S. shale gas and oil production regions. In addition, the study showed that the volume of brine-laden wastewater that hydraulically fractured oil and gas wells generated during their first year of production also increased by up to 1,440% during the same period.

"If this rapid intensification continues, fracking's water footprint could grow by up to fiftyfold in some regions by the year 2030—raising concerns about its sustainability, particularly in arid or semi-arid regions in western states or other areas where groundwater supplies are stressed or limited," the report stated.

The multiyear effort to meet the industry's sand and water demands has its challenges, like sourcing and transporting adequate supplies without busting the budget or severely impacting operations. Many of the solutions to these challenges will continue to be stretched thin in 2019 as shale operators push for higher production returns and to capitalize on increased takeaway capacities made possible by new pipelines.

Sand market outlook

Over the past few years, the laws of supply and demand have gotten a real workout in all industrial sectors. For the oil and gas industry, global energy demand is a key driver. Global energy consumption is projected to grow by an additional 17% between 2016 and 2025 from 13.3 billion tonnes of oil equivalent (Btoe) to 15.5 Btoe, according to a presentation delivered by Todd Bush, vice president of commercial and principal for Energent, a Westwood Global Energy Group, at the Petroleum Connection's 7th Annual Frac Sand Supply & Logistics Conference held in October in San Antonio.

"What it really indicates for us is that there's a growing need for energy—not just crude but natural gas, LNG and, for the U.S. specifically, export capability," Bush said. "We were excited to see what that does [and] how that balance comes into the market because it is still something that is new for the market. Everyone is still trying to get their arms around what it means. We're seeing growth, getting close to 1 million barrels per day there in export capabilities. It is an exciting area to watch, especially as we move into 2019."

In looking for growth opportunities, Bush noted that it is interesting to see how not only the Permian Basin adjusted to lower-per-barrel oil prices but how other shale plays, like the Bakken, Eagle Ford and Niobrara, have adapted and matured.

Part of that maturation process includes the buildout of infrastructure and takeaway capacity. For the Permian Basin, more than 6,000 miles of new trunk lines are planned or under construction to carry crude, natural gas and NGL to the Gulf Coast, according to Bush. It is a natural leap to question how the capacity constraints have impacted well completions.

"We're anticipating the DUC [drilled but uncompleted] inventory to build and increase even more," he said. "We've seen about a 30% increase in the DUC backlog year-over-year and we're anticipating this to grow, especially for the D-J [Denver-Julesburg] Basin, with a majority of the DUCs in the Permian."

The total DUC well count for October was 8,545, according to the U.S. Energy Information Administration Drilling Productivity Report issued in November. Of that, the Permian Basin has 3,866 DUC wells and the Eagle Ford has 1,571.

More than $1.4 billion in Permian completions spend was pushed to 2020, according to Bush, with about 380 completions being deferred, adding to the DUC inventory there.

"We're watching the uncompleted backlog to see how operators actually bring that backlog down over time," he said. "For example, we've seen a couple of large operators in the Delaware Basin complete wells that were drilled three years ago. We're seeing more wells being completed that were drilled."

Regional constraints like pipeline capacity could easily create an oversupply of sand, according to Svetlana Doh, oil and gas analyst for GlobalData.

"Rapidly growing sand demand in the Permian is raising questions on whether there will be enough supply of proppant available. It is estimated that the total sand consumption in the Permian will reach more than 77 billion pounds this year," she said in a press release. "The demand growth is mainly due to the increased wells lateral length and larger amount of proppant injected per well, which grew by more than 70% in the last three years."

Doh noted that the share of locally produced sand is expected to grow to more than 40%, increasing the competition to the white sand supply from the upper Midwest to the Permian.

"In fact, there were at least five sand mines opened in the Permian by Hi-Crush, Black Mountain Sand and U.S. Silica in 2018 with a proppant supply of 35 billion pounds per year. Many more mines are expected to be opened soon, which will likely solve the basin's sand shortage problem over the near future," she said in the release.

"However the ample local sand sources can easily translate into an excess supply whenever drilling activity reduces its pace due to the logistic bottlenecks in the Permian Basin," Doh said. "If this is persistent, sand prices will fall, benefiting operators that do not face any pipeline restrictions."

Ryan Carbrey, senior vice president of shale research for Rystad Energy, also presented at the Frac Sand Supply & Logistics Conference. He sees the DUC count continuing to increase in the Permian Basin until the third quarter of 2019 when he expects "completion activity to really pick up as people expect to put oil in the pipeline in the fourth quarter, with other plays not showing an increase in DUCs except for maybe the Midcon."

According to Carbrey, there are three things that impact frack sand demand: number of wells drilled, the lateral feet per well and proppant per foot.

"All three of those increased at roughly the same time, causing an exponential increase in overall frack sand demand. We are not expecting all of those increases at the same rates going forward. However, we are projecting well counts and proppant per foot to increase moderately," he said.

As for frack sand supply, Carbrey noted the major shift to in-basin sand in 2017.

"Almost no one was talking about in-basin sands in 2014," he said. "Starting in 2017, we started hearing about the in-basin sands and the Permian, and the same phenomena that happened in the Permian has occurred in other places."

Sand expansion

Those other places include South Texas, Oklahoma and the Rockies.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The D-J and Powder River basins are set to see the opening of at least two frack sand mines in 2019. (Source: f11photo/ *Shutterstock.com*)

In U.S. Silica's third-quarter 2018 earnings call, CEO Bryan Shinn noted the addition of local sand projects in other basins with varying degrees of market acceptance.

"We believe that as much as 12 million to 14 million tons of new capacity could eventually come online outside the Permian, mostly in South Texas and the Midcon," he said. "We do, however, expect that many of our customers will continue to want to pump Northern white sand in these basins as well as other geographies such as the Bakken, the Rockies and the Northeast."

The incremental local capacity will continue to apply pressure to the Northern white sand sales volumes, with high cost Northern white mines facing closure as more local mines come online, he added.

"We've seen more than 12 million tons per year of idle capacity," he said. "We believe that another 10 million to 15 million tons of nonlocal capacity may come offline in the next few quarters."

According to Shinn, less than one-third of U.S. Silica's contribution margin came from Northern white sales, and the company expects to triple its Permian capacity by the end of the first quarter of 2019 with its sand mine ramp-ups in Crane and Lamesa.

Another dynamic at play in the frack sand market is, according to Shinn, the many E&P companies choosing to directly source its sand to assure supply and reduce completion costs.

"It is a disruptive change as these customers are more focused on product quality, supplier safety and reliability as well as delivered cost. They are also more likely to sign longer-term contracts—those that are aligned with their long-term drilling plans as evidenced by our recently announced 15-year sand supply contract with Pioneer Natural Resources," he said.

The self-sourcing trend also is delivering value in unexpected ways. For example, WildHorse Resource Development announced at the beginning of the year its plans to build an infield sand facility to support its Eagle Ford operations. First slated to come online in the first quarter of 2019, the company announced that first sand loadings were expected as early as November 2018, with full-capacity operations to begin at the end of the month. The 727-acre facility holds about 85 MMtons of 100 mesh and 40/70 mesh sand, providing a more than 40-year supply of sand, according to the company.

In October Chesapeake Energy announced its intent to acquire WildHorse for $3.9 billion. The infield sand facility, while not factoring directly into the decision to purchase, is certainly considered a perk.

Jason M. Pigott, executive vice president of operations and technical services for Chesapeake, said in its third-quarter 2018 earnings call that while sand is not necessarily the company's core business,


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it does provide the company with advantages that could create operational synergies fairly quickly.

The sand mine is an "excellent asset to have," said Doug Lawler, president and CEO for Chesapeake. "So completing [the project] out and it being operational gives us a lot of flexibility. We're looking to capture value and create synergies across the portfolio, and the sand mine will be fully utilized and optimized to capture that value."

For its operations in the Marcellus Shale and Powder River Basin, Chesapeake announced in November that it signed a new, long-term agreement for the in-basin purchase of Northern white sand from Hi-Crush Partners, according to a press release. The company will use one PropStream container crew and related logistics with the option to expand based on demand.

"We are excited to reach an agreement to provide services to meet Chesapeake's demand for Northern white frack sand and associated proppant logistics needs," said Robert E. Rasmus, chairman and CEO of Hi-Crush, in the release. "We believe this agreement affirms the value of our 'Mine. Move. Manage.' operating strategy as well as the ongoing demand for Northern white frack sand, the strength of our logistics network and our success in increasingly partnering with producer customers."

Analysts with Simmons Energy projected in a recent oil services report that the effective capacity in the Eagle Ford will near about 8 MMtons to 9 MMtons by the second quarter of 2019 (nameplate of 13 MMtons) compared with demand of about 14 MMtons. Additionally, the analysts believe mines from outside the Eagle Ford region will continue to sell sand into the basin for the better part of 2019.

In addition to its three mines in the Permian Basin with mining capacity of 13 million annual tons, Black Mountain Sand has two mines in the Eagle Ford and plans for one in the Midcontinent. The company is planning to open mines in the Powder River Basin and D-J Basin in 2019 with an estimated annual capacity of 2 MMtons and 4 MMtons, respectively, according to Rhett Bennett, CEO of Black Mountain Sand. Bennett, a panelist on an in-basin sand discussion held at the Frac Sand Supply & Logistics Conference, said the company has looked into bringing sand online in the Bakken and Appalachia. "Finding the right deposits is a challenge, and the jury is still out on finding a deposit that is commercially viable to mine that's of sufficient quality," he said. "But we're looking."

With three Texas-based sand mines, Vista Proppants and Logistics announced the development of a 1- to 1.5-MMtons/year sand mine northeast of Fay, Okla., to serve customers primarily operating in the Midcontinent region's Scoop and Stack oil and gas plays, according to a press release. The 1,150-acre mine site has ready access to water, electricity and natural gas and will begin construction following permit approval.

"Our development of an in-basin mine in the underserved Scoop and Stack plays is the next step in Vista's long-term strategy to provide customers a broader-based, truly differentiated mine-to-wellhead solution for their frack sand needs," Vista CEO Gary Humphreys said in the press release. "We plan on producing both 100 mesh and 40/70 products with solid crush and other characteristics designed to best serve the growing need for in-basin sourced frack sand."

Kristin Smith, CFO for Vista Proppants and Logistics, also a Frac Sand Supply & Logistics Conference panelist, noted in her remarks that as a vertically integrated business, Vista is able to deliver sand at the lowest cost.

"Our value proposition is getting sand from the mine all the way to the wellhead," she said. "Having access to sand in the Permian Basin is no longer a differentiator. Our competitive advantage is our logistics network. We started in trucking in 2004; we know the challenges of the trucking market very well. We went into transloading in 2007 and then, of course, mining in 2011. We are able to control our costs and to be a low-cost provider by owning that full supply chain of assets and have the deep organizational knowledge in all aspects of that supply chain. It's helped us be successful and to allow us to deliver the sand to our customers on time and at a low cost."

Water, water everywhere

In addition to a sand supply challenge, the increased rate of drilling and the increase in lateral length footage has further elevated the chal-

Top: Drilling and completing a well requires water—lots of it, and storage pits provide a means for containment in the Permian Basin. (Photo by Ricardo Merendoni, courtesy of *Oil and Gas Investor*)

Bottom: The process of getting sand and water supplies the "last mile" to the well site will continue to rely on heavy trucks in the new year. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)

lenge of effectively managing oilfield water needs. While locating and procuring ample supplies of water remains a challenge for some operators, disposal of produced water remains a challenge for others.

According to its U.S. Water Management market segment report, Spears & Associates stated that the demand for water management services associated with the acquisition, transport, transfer, storage, flowback, treatment and disposal of water increased 44% in 2017 to $18.9 billion in response to increased horizontal drilling activity, increased per-well fracturing job size and increased recycling/treatment activity.

In Bluefield Research's "Water for Hydraulic Fracturing: Market Size, Trends & Forecasts, 2018-2027" data insights report, it stated that water management spending for hydraulic fracturing services is expected to total $161 billion over the next decade. In terms of volumes, Bluefield's analysts estimated that more than 2.2 Bbbl were consumed in 2017 by the hydraulic fracturing industry, producing about 660 MMbbl of contaminated water for disposal and of that about 14% were treated and reused.

Several key water trends touching on water sourcing, recycling and disposal in the Permian Basin were highlighted during Hart Energy's Executive Oil Conference (EOC) Water Forum in Midland, Texas. The water management services market is one that has experienced exponential growth in recent years, with its evolution tracking the region's production growth.

"Water has been a part of the oil business forever," said Bill Zartler, CEO of Solaris Water Midstream, in his remarks at the conference. "It is just changing in magnitude of demand on the supply side for hydraulic fracturing and the size of the wells we're producing today."

For example, in 2005 oil production ranged between 800,000 bbl/d and 950,000 bbl/d, with a primarily vertical rig count and about 80,000 bbl to 100,000 bbl of water per month being disposed at a saltwater disposal (SWD) facility. Water delivery at the time was heavily focused on trucking as pipelines were not considered economical at the time due to limited centralized gathering facilities, according to Cory Hall, president and CEO of Aqua Terra Water Management.

"Horizontal shale activity kicks off in 2011, with frack sizes averaging nine stages using 10,000 barrels of water per stage, with lateral lengths ranging between 3,900 ft and 5,280 ft," Hall said. "Permian

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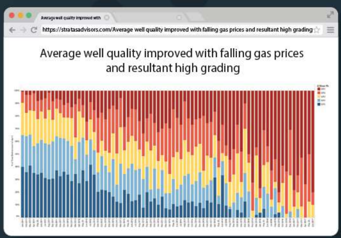

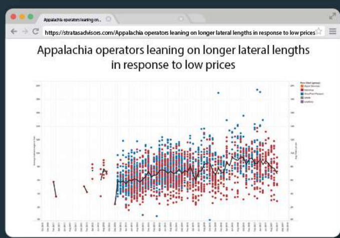

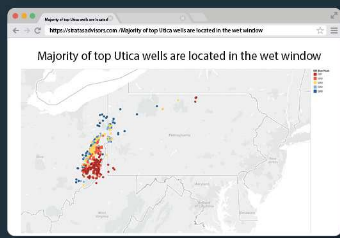

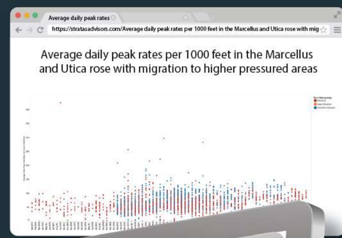

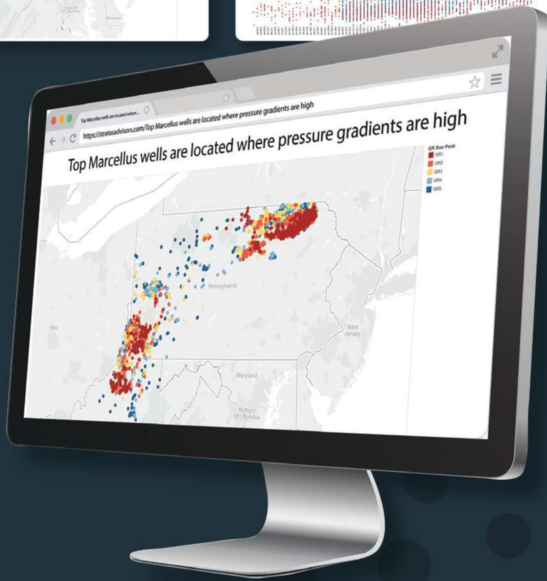

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Basin production surpassed 1 million barrels of oil per day that year."

At this time, trucking was still the primary delivery method, as water infrastructure development was in its infancy and SWD facilities were seeing water disposal rates up over 2005, with 150,000 to 250,000 bbl per month, he noted.

Just as drilling and completion techniques and technologies evolved, so too did the industry's response to water management.

"In 2018 we focused on pipeline deliveries," Hall said. "They're safer, more reliable and more economical. Having multiple disposal facilities tied together helps eliminate downtime and better manage volumes."

Disposal water volumes in 2018 averaged between 400,000 bbl to more than 1 MMbbl of water per month, he said, adding that the estimated production for the month of November was expected to surpass 3.5 MMbbl/d.

"Frack sizes average 25 to 35 stages per well using 10,000 barrels of water per stage for 1-mile long laterals," he said. "Two-mile long laterals are seeing 50 to 70 stages per well, with each stage receiving 10,000 barrels of water per stage. Effectively, every well today is receiving 250,000 to 700,000 barrels of water to just frack the wells."

However, increased disposal volumes will likely create future water management issues, according to Mark Patton, president of Hydrozonix.

"We're going to see challenges in the practice of disposal by injection," Patton said. "You're either going to start transporting water farther away to [dispose in] zones where you do not have capacity issues or formations pressuring up. Or you're going to have to look at other options, including water reuse programs and evaporation. It has to be a part of your overall water management program."

The growth of the water midstream market will continue long into the future, according to Zartler.

"This market is evolving pretty massively and it will continue to evolve," Zartler said. "It's a very large market and it's not going to be done by one or two companies. It will evolve like the hydrocarbon mainstream. There's a large number of consolidated midstream companies that didn't exist in 1992. They all exist today because it's more efficient. It's a better service to the industry and helps make our business better."

According to Mark Houser, CEO of University Lands, the push toward consolidation of operations and water infrastructure is one that will require cooperation among operators and service companies.

"We think that water management is going to consolidate similar to the mainstream business, and we're working with operators to help that happen," he told EOC Water Forum attendees. "We're going after three, maybe more, areas of consolidation—the Delaware Basin, the Southern Midland and Northern Midland basins. The main thing is going to be getting cooperation between all the operators, which have been building their own networks.

"At one point, there were no Kinder Morgans or Enterprises. In some ways, I think it is even more predictable because of not just the frack water demand but also the produced water supply. In my mind, it gives you a very predictable stream." E&P

The use of freshwater resources is being gradually phased out as more operators look to reuse produced water for well completions. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)


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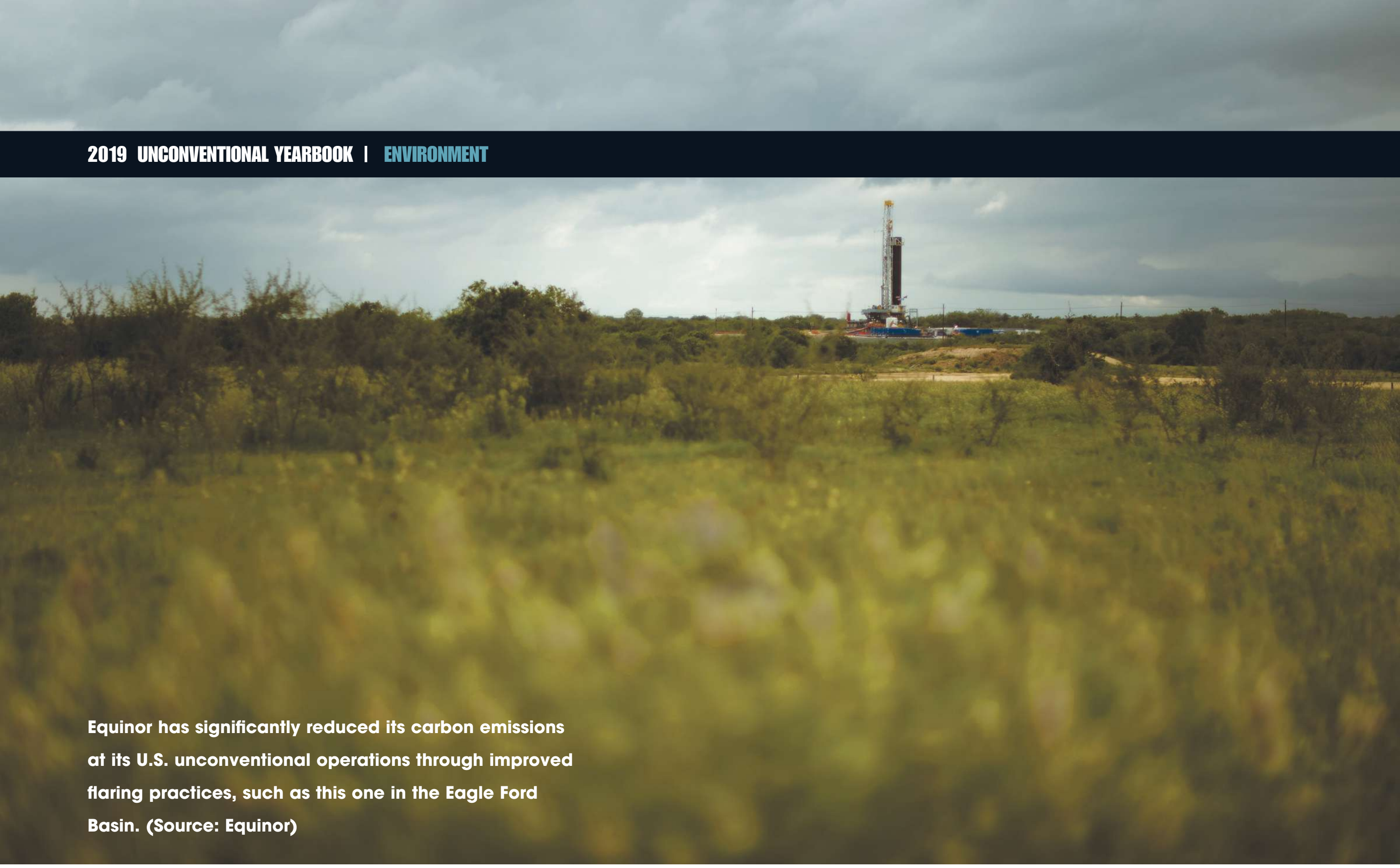


Equinor has significantly reduced its carbon emissions at its U.S. unconventional operations through improved flaring practices, such as this one in the Eagle Ford Basin. (Source: Equinor)

Keeping an Eye on the Environment

By **Brian Walzel**, Associate Editor, Production Technologies

Operators and service companies discover innovative solutions to environmental concerns.

Energy companies are faced with myriad challenges when working to produce oil and gas. The costs to do so are in the millions of dollars, the environments in which they work are often harsh and unforgiving, and hydrocarbon reservoirs are complex and difficult to navigate and understand. Additionally, companies must do all of these things safely and go to lengths to ensure their workers, as is commonly explained, go home in the same shape they went to work.

Although each of those issues is critically important to an oil company's operations, so too are their efforts to operate in an environmentally responsible way. As the shale revolution matures, along with it has emerged a better understanding of the environmental issues associated with unconventional oil and gas production. A wide variety of scientific studies during the past decade have revealed that unconventional oil and gas production is responsible for poor air quality in places like the Bakken and earthquakes in Oklahoma—a result of injecting wastewater into disposal wells. Most recently, the U.S. Occupational Safety and Health Administration (OSHA) has enacted new mandates instructing oil companies to better control respirable silica dust at fracturing pads.

Addressing these issues has become a priority for many oil and gas companies as they work to overcome adverse perceptions of their own industry.

As oil companies work to find the best solutions for cutting down on greenhouse-gas (GHG) emissions and avoiding seismicity issues, federal and state regulators continue to work to find the right balance between environmentally responsible operations and overly onerous and costly restrictions.

The U.S. Environmental Protection Agency (EPA) is studying current wastewater disposal restrictions, announcing in October a plan to work with industry stakeholders and communities to reevaluate details of the Clean Water Act that deal with produced water management. The EPA is looking to potentially loosen restrictions on the discharge of produced water.

In addition to wastewater management regulations, the EPA also is considering easing fugitive emissions monitoring. The EPA announced in October that it is proposing changing monitoring requirements for "non-low production well sites" to once per year, for "low production well sites" to once every other year and to eliminate the requirement for monitoring "all major production and processing equipment" once it is removed from a well site "such that it becomes a wellhead-only site."

The EPA disclosed that such actions between 2019 and 2025 would result in an increase of 100,000 short tons of methane emissions, 24,000 more tons of volatile organic compounds emissions and 890 more tons of hazardous air pollutant emissions than under current monitoring guidelines. The EPA also reported that the new mandates would result in industry cost savings during the same period of $43 million.

Emissions management

Following a series of recent studies that have identified elevated levels of GHG emissions in regions of unconventional oil and gas production, both operators and service companies are adopting practices that are proving to reduce emissions while also saving on expenses.

One of those practices is carbon capture, utilization and storage (CCUS) in which operators capture and store CO_2 to eventually sell to other industries or oil and gas companies or use themselves for EOR methods. Occidental Petroleum utilizes CCUS in its Permian Basin EOR operations and is developing two monitoring, reporting and verification (MRV) plans for its CO_2 EOR fields in the Permian Basin at the Denver Unit in Texas and in Hobbs, N.M. According to Occidental, the plans provide a framework for quantifying the amount of CO_2 permanently sequestered in the geology of the reservoir.

The company reported that during the first year of the MRV plans, Occidental sequestered more than 59 Bcf of CO_2.

Equinor also has made strides to lessen its CO_2 emissions in its North American unconventional operations. Max Medina, subsurface manager for global unconventionals at Equinor, said the company reduced its CO_2 emissions by 65% from 2014 to 2017 by improving its flaring operations.

"Our mission as a company is to go down to 8 kilos of CO_2 emissions per barrel, and we're certainly on a trend to get there in our U.S. operations," he said.

Medina added that Equinor is in the early stages of implementing carbon capture practices for its unconventional operations, and field tests could take place in 2019. He said Equinor is utilizing best practices the company has learned from similar carbon capture operations in Norway and is working to scale those practices for onshore U.S.

"Here, the challenge is we don't have the scale or the single place to install a facility that we have in Norway," he said. "We find we need more modular capture facilities. How we make that work on a modular basis where we can spread carbon capture around our basins is our challenge."

Operators venturing into CCUS operations will find a regulatory environment encouraging them to do so. In February Congress approved legislation that increases the tax credit for carbon capture and storage projects. The 45Q tax credit, introduced in 2017 as the FUTURE Act, is a performance-based tax credit on eligible carbon capture projects.

According to the Great Plains Institute, the requirements for the credit include safely storing CO_2 in geologic formations or putting it to beneficial use

Evolution Well Services' electric fracturing fleet results in a smaller footprint on the pad site along with reduced CO_2 emissions and fuel cost savings. (Source: Evolution Well Services)

in products then claiming the credit, such as EOR. The value of the tax credit depends on the type of CO_2 storage. Companies storing CO_2 for EOR receive a credit of $35/ton, while $50/ton is available to companies storing CO_2 in geologic formations.

Speaking at the Society of Petroleum Engineers Annual Technical Conference and Exhibition in September, Wayne Rowe, Schlumberger's carbon services project manager, said previous tax credit levels were not enough to encourage many companies to implement CCUS operations. The previous iteration of the 45Q tax credit allotted $10/ton for EOR operations.

"There really wasn't much of a driving force for an oil company to take advantage of this," he said.

Rowe said the credit increase, however, will likely spur interest and investment in CCUS operations in the U.S. The Great Plains Institute also reported that the changes to the credit would provide certainty for investors knowing that the credit will be available once a project begins operations.

"This increased financial certainty should catalyze investment in projects by helping to close the remaining cost barrier to deployment of carbon capture technology, reducing the commercial risk for early adopters and driving down costs over time through innovation as more and more experience is gained through the development, financing, construction and operation of carbon capture projects," reported the Great Plains Institute in March.

Modern frack fleet

In addition to CCUS projects, electric fracturing fleets are emerging as an option for operators to both cut down on emissions at the well site and save on costs. In June CNX Resources announced a three-year agreement with Evolution Well Services for a 56,000-hp, 100% electric fracturing fleet. According to CNX Resources, adopting an electric fracturing fleet will save the company 95% on fuel costs while allowing the company to operate "well below" the EPA's Tier 4 emission standard.

Andrea Passman, senior vice president for engineering and operations at CNX Resources, said that in addition to the improved cost savings and emissions Evolution Well Services' electric fracturing fleet offers, CNX Resources discovered such operations result in a much smaller machinery and worker footprint at the well site.

"The footprint of the Evolution frack crew is about one-third of that of a normal crew because the skids they bring the pumps in, there are fewer of them," she said. "Normally, a regular job to get the horsepower that we would need would take 20-plus trucks. Now we're talking about eight."

Passman added that while a conventional fracturing crew would likely amount to 15 to 20 workers, Evolution Well Services' electric fracturing crew totals 10 to 12 people.

"And most of them are actually not on the equipment on site because it is all run from a single location," she said. "It is very modern."

Carrie Murtland, vice president of technology and marketing at Evolution Well Services, explained that the company's technology utilizes a turbine generator package to power pumping activities where electricity is distributed from the turbine generator to the process equipment, including the pump trailers, which contain more than twice the horsepower of conventional fracturing pump trailers.

Murtland said Evolution Well Services' power packages emit roughly 1% of the carbon emitted by conventional diesel engines. In addition, many of the dangers inherent with traditional diesel fueling operations at the well site are eliminated by the system.

"Eliminating diesel engines from pumping operations prevents the need for 'hot fueling' during pumping operations, which is a well-known hazard linked to many wellsite location fires during conventional fracturing operations," she said.

Murtland added that based on an operation pumping an approximate 300 hours per month, operators could save between $1 million and $1.5 million per month in fuel savings by reducing diesel fuel consumption by up to 95%.

"Additionally, this technology fits very well with pressure pumping activities in sensitive areas due to the reduced noise level—85 dB versus 115 dB—and requires a much smaller operational footprint," she said.

Evolution Well Services' fleets have so far been deployed in the Utica/Marcellus, Permian, Eagle Ford and Scoop/Stack. Murtland said operators in the Permian Basin have shown increased interest in electric fracturing fleets as a result of takeaway constraints leaving operators looking for a productive use for their natural gas. Basins in the Northeast feature infield gas that is relatively high pressure, which Murtland said eliminates the need for compression and often is sufficiently dry as to be burned without necessitating the extra step of stripping out liquids.

"Our fleet is less than half the size of our conventional peers and works well on hillside pads of the region," she said. "We have completed some wells on pads where conventional fleets simply would not fit; oftentimes we hear of pads being made to fit drilling rigs, but not necessarily frack fleets. This technology fixes that."

Green innovations

Meanwhile, in an effort to provide the industry with cheaper and cleaner fuel, Frac Shack International Inc. has developed a combined diesel and natural gas distribution unit for bifuel hydraulic fracturing spreads. Frac Shack's bifuel unit has 14 natural gas lines and 14 diesel lines and is compatible with CNG, LNG pipeline gas or field gas.

"Distributing both diesel and cleaner-burning natural gas to the pumpers helps [operators] offset their diesel consumption, which saves them money and also helps reduce the environmental impact in regard to diesel emissions," said Dave Lamberton, sales and marketing manager for Frac Shack. "So the frack spread is burning cleaner-burning fuels, it's running more efficiently, operators are saving fuel costs and they're helping reduce emissions in the environment."

Across a variety of fronts, money is being invested and studies continue to be conducted to assuage any negative effects hydraulic fracturing has on the environment. Among those efforts is the Oil and Gas Climate Initiative (OGCI), a voluntary CEO-led consortium comprised of BP, Chevron, Eni, Equinor, Exxon Mobil, Shell, Occidental and more.

The OGCI has established a $1 billion investment fund for technologies that help lower the carbon footprint of the energy and industrial sectors. Portions of those funds are provided to companies selected by the OGCI to develop systems and tools to meet the OGCI's goals. Among those to receive funding has been Clarke Valve, which designs and manufactures control valves.

According to the company, Clarke valves are the only valves in the world to achieve American Petroleum Institute (API) 641 certification for low fugitive emission performance. API 641 applies to stem seal materials and requires allowable leakage of 100 ppm by volume. In June 2017 Clarke Valve delivered its first shipment of its Shutter Valves, a valve system that virtually eliminates fugitive methane emissions, to an operator in the Denver-Julesburg Basin.

In other efforts, the Independent Energy Standards Corp. (IES) developed its TrustWell Responsible Gas Program. The TrustWell program offers a rating, similar to LEED ratings for buildings, for natural gas wells based on a variety of factors, including emissions, leaks and spills, well integrity, water sourcing and more. The program is designed to connect potential buyers of natural gas to sellers whose product earns the TrustWell certification.

In September the IES announced the first transaction of a "responsible natural gas product" in the history of the oil and gas industry using the TrustWell Ratings certification system. According to the IES, New Jersey Natural Gas has contracted with Southwestern Energy to secure certified natural gas for commercial use.

Managing wastewater

In the wake of the unconventional revolution, operators have been charged with managing the sheer volumes of wastewater that are produced along with oil and natural gas. According to the Colorado School of Mines, about 21 Bbbl of produced water—more than twice the amount of water that flows over Niagara Falls every day—is generated each year in the U.S. from the country's approximately 900,000 wells. To manage that much water is costly. According to an Approach Resources report, as much as $5/bbl, or up to $1.5 million per well, is attributed to water sourcing and disposal in the Midland Basin.

In addition to the financial burden vast amounts of wastewater places on operators, produced water management also brings with it inherit environmental challenges. Wastewater injection practices, particularly in Oklahoma, have resulted in elevated occurrences of earthquakes. The Oklahoma Geological Survey reports that between 2013 and 2017 there were 2,519 earthquakes with measured magnitudes of 3.0 and above.

However, during that time, researchers and state officials said they mostly identified the causes of induced seismicity and put into place measures and restrictions on wastewater injection practices, which have drastically reduced the number and severity of earthquakes in Oklahoma.

"Research has pointed us toward injection volumes, specifically in the Arbuckle Formation," said Michael Teague, secretary of Oklahoma's Energy and Environment Department. "The high volumes [of injected produced water] in that formation were essentially the root cause for the bulk of the induced seismicity that we were seeing."

Frac Shack's bifuel system leverages a combination of diesel fuel and natural gas, which helps pumpers offset diesel fuel consumption and costs. (Source: Frac Shack International)

In response, the Oklahoma Corporation Commission (OCC) enacted restrictions on injection volumes, and the restrictions have mostly worked. Teague said from 2015, when the number of earthquakes in Oklahoma reached a peak of 903, through 2018, there has been more than an 86% reduction in seismic events measured at 3.0 and above.

With a better understanding of what caused induced seismicity in Oklahoma, the OCC is now looking to limit growth in future disposal rates in the Arbuckle Formation. In February the OCC issued a directive to evaluate those disposal rates.

"The continued drop in earthquakes, as well as new data and input from the Oklahoma Geological Survey, have caused a change in our orientation from focusing on current disposal volumes within the AOI [areas of interest] to looking ahead to try to ensure there isn't a sudden, surprise jump in those disposal volumes," Tim Baker, director of the Oklahoma Oil and Gas Conservation Division (OGCD), stated in a press release issued earlier this year.

According to the OGCD, the directive includes not only those Arbuckle disposal wells within the AOI already restricted in volume, but also the few potentially high-volume disposal wells that previously were not under a volume reduction directive because there has been no seismicity in their area.

While the problem behind induced seismicity has so far been attributed to high-volume injection rates, there are some indicators that longer-term injection and even production from older formations have caused regional earthquakes. A report recently issued by EnergyMakers Advisory Group included a holistic assessment of 15 risk factors and mitigation strategies for disposal and EOR wells.

"Our understanding of seismicity is continuing to increase, and the field is probably more complicated than meets the eye," said Laura Capper, president and CEO of EnergyMakers Advisory Group. "While we're continuing to understand why it's happening, we're also finding out understanding of contributing causes is more complicated than we thought. The long-term effects of cumulative injection can play a role in some areas, and in others, the long-term effects of production, which might result in gradual settling, or subsidence, have also been associated with seismicity."

During the course of a recent study, Capper and her team evaluated every disposal well in the U.S. along with the corresponding publicly available datasets with the goal of identifying any general trends in seismicity issues. Those findings revealed that a key factor correlating with induced seismic activity in Oklahoma is reservoir pressure.

"Our research indicates that while high volumes of water can be a significant contributing factor, it's not always a high-pressure problem," Capper said. "I believe it is as much of an underpressure problem that can occur when you're injecting produced water at high rates in more shallow aquifers, if that shallow (or moderate) aquifer has a lot of low-pressure formations beneath it. The existence of those low-pressure intervals beneath it can facilitate the pressure transfer down to the basement. That can cause a seismic event. That's a very simplistic explanation of why Oklahoma has so much seismicity—because it's got this monster underpressured formation going beneath practically the whole state."

Capper reasoned that dynamic is why the Permian Basin, which is notoriously overpressured, experiences fewer seismic events.

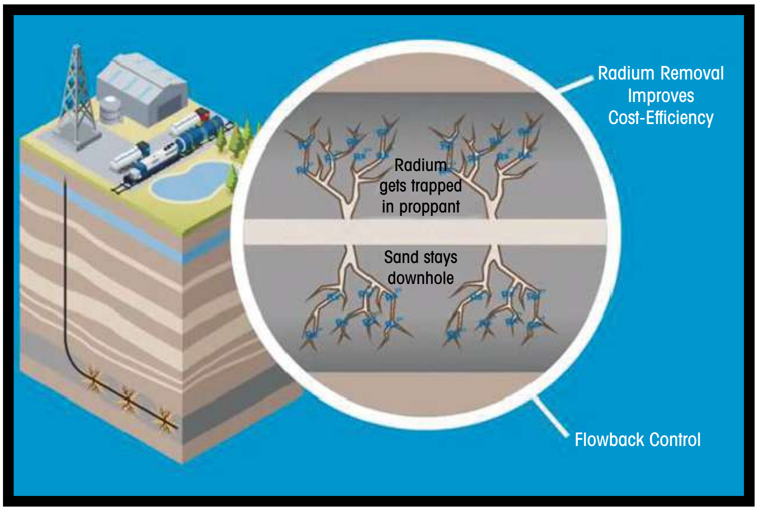
"In at least some regions, there's a lot more correlation between seismicity and relatively underpressured areas than overpressured areas," she said.

Permian Basin seismicity trends

Meanwhile, in the Permian Basin, water management is becoming a growing issue, primarily from a production and cost perspective. As production rises in North America's most prolific basin, so too does the amount of produced water. While some operators such as Apache Corp. and Approach Resources have implemented produced water recycling systems, many still are using legacy injection wells to dispose of record amounts of wastewater.

Capper explained such operators may soon need to consider other options, including recycling.

"Because [disposal wells] in some areas show signs of diminished capacity, operators are going to have to work harder to find places to dispose of their water," she said. "They might not be able to inject it back into that same well they've been using for 20 years. They may need to find a disposal well with a more receptive formation."



Dow Chemical Co.'s VORARAD system reduces radium quantities in produced water prior to injection in disposal wells. (Source: Dow Chemical Co.)

If operators do look for new locations to dispose of produced water, they'll have more resources available to them to inject that water safely as to avoid any seismicity issues in the Permian. Earlier this year Jens-Erik Lund Snee and Mark Zoback, geophysics professors at Stanford University, developed a detailed stress map of the Permian Basin. The study, published in February in the journal "The Leading Edge," featured a map of the entire Permian Basin region and identified areas of the basin that could be susceptible to earthquakes from wastewater injection. As the study reported, seismicity issues in the Permian have been concentrated near Pecos, Texas, around the Dagger Draw Field in New Mexico and near the Cogdell Field in Snyder, Texas.

The map developed by Snee and Zoback identified faults striking east-west in the northern Delaware Basin and much of the Central Basin Platform that would be most likely to slip as a result of injection. In the southern portion of the Delaware Basin, faults striking northwest-southwest are most likely to slip, according to the study.

"Knowing the orientations of faults that are unlikely to slip at any given fluid-pressure perturbation can be of great value because it provides operators with practical options for injection sites," the report stated.

Reducing produced water hazards

Not only are companies increasingly aware of how much produced water they inject and where they inject it, but also of the chemical makeup of what is being injected into underground reservoirs. According to the EPA, radioactivity levels in produced water from unconventional drilling "can be significant and the volumes large."

Among the wide array of systems designed to improve the quality of produced water is Dow Chemical Co.'s VORARAD downhole radium sequestration technology.

According to Dow, radium is problematic because it is soluble in water and can travel to the surface in flowback and produced water. Radium decays further into radon gas, which can cause inhalation hazards if exposed. According to the company, because dissolved radium can become concentrated in scale, suspended and precipitated solids when the wastewater is stored, transported or treated, high levels of radioactivity can result.

VORARAD fuses proppant particles together, preventing them from traveling to the surface, which can cause pipe and pump blockage and decrease near-wellbore productivity. The technology works to sequester downhole radioactive isotopes from rising to the surface in produced water.

"As operators continue to develop more sustainable water usage practices for hydraulic fracturing, VORARAD helps alleviate current environmental concerns, fundamentally reducing radium levels in produced water with all of the consequent benefits," said Juan Carlos Medina, marketing manager for Dow. "These include a reduced radioactive footprint throughout the entire water recycling process and reducing transportation of hazardous materials through towns and cities as they are moved from wells to authorized disposal facilities."

RCS regulations

Addressing concerns over air and water environmental issues is only part of the challenge for operators and service providers in maintaining their social license to operate. Ensuring the health and safety of oilfield workers is the priority, and modern hydraulic fracturing operations pose new challenges. One of those challenges is associated with the vast amounts of fine-grained sand used to fracture wells. Recent studies by the U.S. National Institute for Occupational Safety and Health (NIOSH) and OSHA have shown that wellsite workers might

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In addition to consulting and monitoring services for silica dust control at well sites, AIRIS Wellsite Services also offers dust collection systems, which help reduce exposure to RCS. (Source: AIRIS Wellsite Services)

be exposed to dust with high levels of respirable crystalline silica (RCS) during hydraulic fracturing.

According to OSHA, RCS is the portion of crystalline silica that is small enough to enter the gas-exchange regions of the lungs if inhaled. During the course of the research, NIOSH found that sand mover and blender operations and workers downwind of these operations, especially hot loading, had the highest silica exposure.

In response, in June OSHA enacted a new standard for permissible exposure limits (PEL) for industry workers. The new PEL limits worker exposures to 50 micrograms of RCS per cubic meter of air averaged over an eight-hour day.

"Unlike something like a fire or smoke where you can easily see the hazard, RCS is the size of human hair; you can't see it," said Rob Heiberger, operations manager for AIRIS Wellsite Services. "The guys on location don't realize something that small can be hazardous to their health."

AIRIS Wellsite Services provides silica dust control consulting services and custom engineering controls as well as its Dust Vacuum 4 dust collection system. Heiberger said AIRIS Wellsite Services helps companies ensure they are compliant with the new OSHA standards on allowable PEL.

"Everyone seems to know that they have to do something at this point," he said. "Some don't know what to do, some know what to do and are actually doing it, and then there are some who don't know what they are supposed to be doing. They know they are supposed to be doing something but are completely unsure of what."

In a recent white paper issued by Hi-Crush, Jeffery Johnson, the company's environmental compliance director, wrote that it may no longer be feasible for companies to continue to rely on pneumatic operations for handling sand at well sites.

"New work practice and engineering controls are likely necessary to reduce the dust and silica generated to safe and compliant levels," Johnson wrote. "Implementation of controls will be required, and providers and operators may struggle with the increased cost and efficiencies potentially lost by implementing such controls."

Hi-Crush's PropStream last-mile system integrates a variety of aspects in frack sand supply management. The system also reduces dust generation and decreases worker exposure to dust and RCS. Johnson wrote that the system is self-contained and delivers sand to the blender hopper with a minimal release of dust as the sand enters the hopper.

"Use of pneumatics for material handling and transfer is completely eliminated, as sand is contained in transportable containers, gravity fed onto an enclosed conveyor and conveyed into the hopper," he wrote.

Companies like Occidental Petroleum, Equinor and CNX Resources are rapidly taking steps to meet evolving regulatory requirements and be good stewards of the industry by retaining their social license to operate. Meanwhile, service providers like AIRIS Wellsite Services, Evolution Well Services, Frac Shack and Hi-Crush continue to innovate and stay ahead of the curve by offering modern solutions to modern challenges.

As Equinor's Medina said, for companies to remain at the forefront of environmental awareness and worker safety, the work must go beyond simply being aware of the issues.

"It's not just monitoring," he said. "You need to be committed to act and spend the money to solve the problems." E&P

The drilling rebound in 2018 was pronounced and sustained. (Source: huyangshu/ *Shutterstock.com*)

2018 Is a Year for the Record Books

By **Stephen G. Beck**, Senior Director, Upstream, Stratas Advisors

Take a look in the rearview mirror before previewing the year ahead.

In the previous *Unconventional Yearbook*, Stratas Advisors presented 2018 growth estimates of 18% for U.S. unconventional resources, calling for average production of 16.6 MMboe/d for the year. With 2017 and 2018 largely in the books, it is safe to say that 2018 production is likely to average 17 to 17.5 MMboe/d, approximately 4% above the company's estimate from last year.

So what did Stratas get right and where did things go astray? For starters, the Permian came on stronger than expected. A quick look at last year's yearbook forecast confirms Stratas' call for 3.7 MMboe/d, translating to 1.2 MMboe/d of growth from unconventional resources in the Permian. Comparing the estimate to the 1.6 MMboe/d growth (as of Nov. 13) shows a greater than 30% upside surprise. Additionally, the Bakken accounts for another 0.2 MMboe/d of unexpected upside. Combined, the Permian and Bakken account for almost 90% of the surprise.

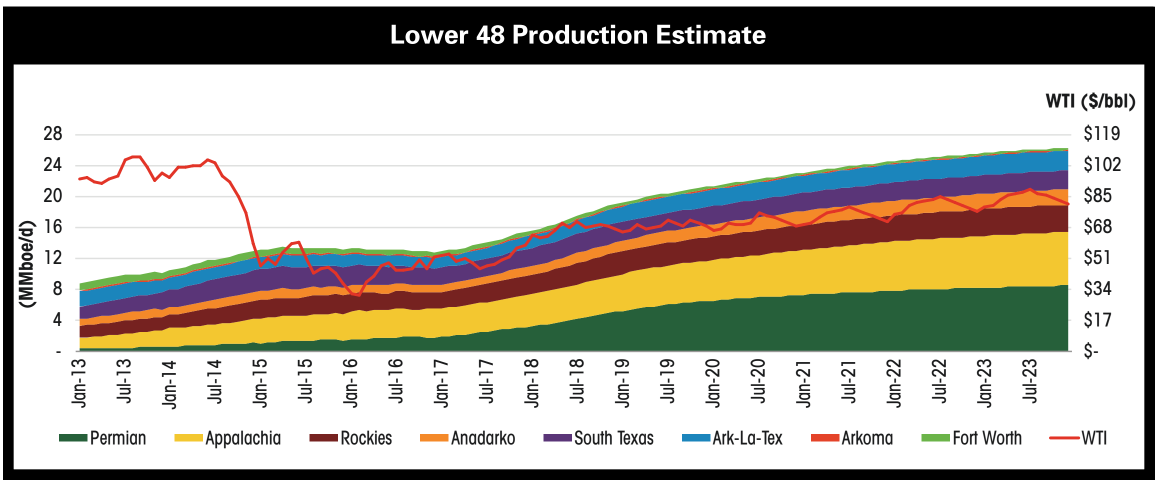
Notably, the Wolfcamp in the Delaware sub-basin is the key resource behind the Permian's remarkable growth. Other surprises in 2018 worthy of mention include the Scoop play, which is surging faster than expected on the back of the Springer Shale, and the Powder River Basin, driven by strength from multiple horizons including the Turner, Sussex, Mowry and Niobrara, among others.

Looking through the windshield

With 2018's review behind us, Stratas turned its attention to the outlook for 2019. Hydrocarbon production from unconventional resources is forecast to average 20.3 MMboe/d in 2019, up 17% from the 17.3 MMboe/d in 2018. Liquids represents approximately 38% of the barrels of oil equivalent in 2019.

Splitting apart liquids from wellhead gas, changes in the growth rate in Permian oil production become pronounced in the near future. Key factors leading to the slowdown in Permian growth is a flat rig count, a rising "maintenance mountain" and lingering constraints, both infrastructure and other. In 2019 the Permian rig count is expected to remain rangebound at ±50 versus the current count of nearly 500.

The biggest headwind facing Permian growth, and by default U.S. production growth, is slowing growth in field activity. In mid-2016 there were



Hydrocarbon production from unconventional resources is forecast to average 20.3 MMboe/d in 2019, up 17% from the 17.3 MMboe/d in 2018. (Source: Stratas Advisors)

about 130 rigs drilling for shale in the Permian. A year later, the number more than doubled to about 330 rigs. In mid-2018 an additional 110 rigs were added, raising the count to about 440. Clearly, the rate of growth in the number of shale rigs in the Permian is already slowing. At mid-2019, this count will rise by another 20 rigs, plus or minus, thus averaging close to 460 units. Beyond 2019, Permian rig counts will continue growing, albeit more moderately. Prospects for moderating rig additions coupled with persistent challenges to capture greater capital efficiency will be key factors behind slowing production growth.

Slowing growth will manifest through increasing challenges at replacing production declines, previously noted as the maintenance mountain. In the Permian the slowing growth in the number of operating rigs foretells of a rising maintenance challenge. Two factors figure prominently in this challenge: 1) high initial decline rates in young wells will lead to substantial replacement needs in the near term, and 2) slowing numbers of new wells added will extract a greater price in terms of production replacement from each new well added.

Analyzing production

Stratas' framework for analyzing production components lays a foundation for explaining the productive nature of oil and gas resources. Production is apportioned to "base" and "new source" components. Base components represent the stock of wells that were already flowing hydrocarbons at the end of the year prior to the year being observed. New source components represent the stock of wells added in the year being observed. The more wells introduced in the last 12 months, the younger the average age in the stock of wells. The relative youthfulness of the stock of wells is a huge factor on average production declines in a play.

Base wells, without intervention, are always in decline. In the age of shale, declines are far greater in the early years of a well's productive life. Typical first-year declines in shale wells are well above 50%, while subsequent declines are notably less than first-year figures. Extrapolating this to rigs, as goes the rig count, so goes the average youthfulness of the wells (with some caveats, of course). First, remember that a lag between drilling and first production of five months or more is common. It is important to recognize that the specifics surrounding inflection points and trends with respect to youthfulness varies accordingly.

New source production fulfills two vital roles. New wells replenish spent production capacity, refilling the productive tank from losses arising from declining production. New wells also are the primary source for growth. Analysts often view these two elements as "maintenance" and "growth" components. Analysts pay particular attention to the volumes needed to keep production flat with the prior year's exit rate.

Consider the Permian, specifically now that the essence of play youthfulness has been covered. Slowing growth in rig counts coupled with drilling increasing numbers of complex and sophisticated wells is expected to lead to an inflection point in the number of new Permian shale wells added by the early 2020s. When this occurs, the full weight of the steep declines on Permian production will begin to show. Transitions like the one envisioned for the Permian in the early 2020s typically result in greater proportions of new source production being consumed by maintenance. Therefore, less production from new wells is available for growth.

Drilling, cutting costs

In the modern shale era, it is no longer good enough to report rising type wells and record 30-day peak rates. Contemporary investors are demanding responsible development and financial results. Initial efforts focused on capturing drilling efficiencies by reducing the number of days for getting wells down. Oftentimes, wellbore quality was sacrificed in the quest to report the best drill times ensued. Severe doglegs constrained completion options and well productivity suffered. Not long after, industry pros adjusted goals, emphasizing both speed and quality in drilling.

Persistently low prices led to more changes. For shale to compete with OPEC and other resources, costs had to come out. Drilling was low-hanging fruit. It wasn't long before drilling operations were optimized across the major shales. However, savings from drilling fell far short as drilling

represents less than half the cost of shale wells. Anxious operators knew they had to go after costs for completions.

Driving out costs in completions proved far more complex than drilling. It was one thing to identify proppant as a major cost factor in completing wells. It was a whole different thing to arrive at solutions. Most oil men will say there is no greater hit on profits than lost production time. Given this, risks were great for operators who contemplated using unproven sand in their wells. Sure, transportation costs were real. But so too is the cost of low production. Therefore, pilots tested the viability of various grades and sources of sand. Ultimately, in-basin sourcing of proppant proved successful.

In time, new business models emerged. Today, direct sourcing is more common among midsize and large independents on efforts to capture margins and squeeze out stranded costs. Direct sourcing demands a certain amount of sophistication, especially when the procurement of goods extends beyond proppant and completions alone. Backward integration appears to be today's holy grail. Those who successfully link engineering specifications, sourcing and financial administration stand to benefit.

Moving out to the pads, operators have been developing multiwell pads for years. However, early needs to hold acreage led to many pads with one or two wells on them. More recently, operators have been increasingly opting to wring out inefficiencies through zipper fracks. Zipper fracks reduce latent time during completions by leveraging completion equipment across two wells in sequenced fashion. In the world of cost savings on completions, the last man standing really is manpower. Headcounts have been cut dramatically on completion spreads. A few years ago, spreads were manned with 40 or so professionals. Today, fewer than 30 heads on a job is common. Automation and remote monitoring have been contributing factors supporting this effort.

Permian, a resource for the ages

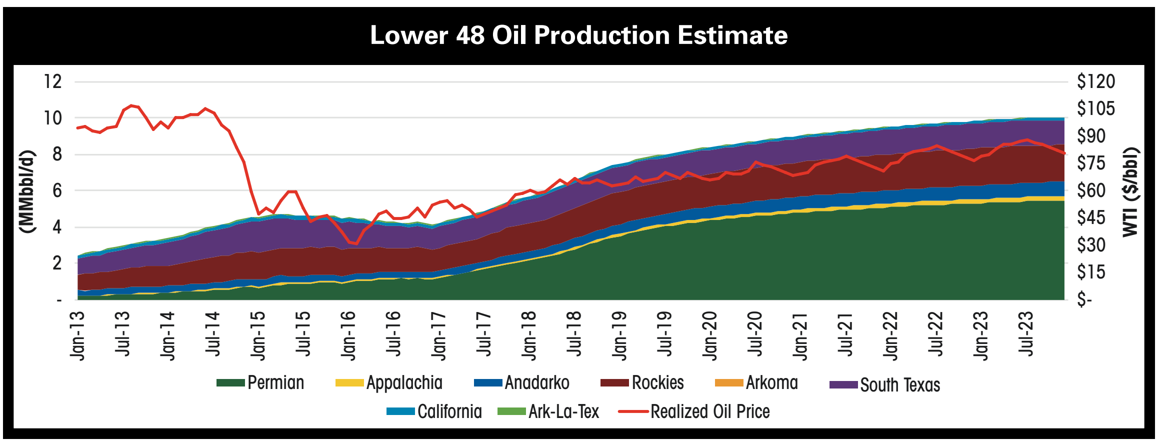
The short-term outlook for the Permian calls for oil production of 4.2 MMbbl/d by the end of the year, up from 3 MMbbl/d at year-end 2017. Production gains were stronger than originally forecast despite infrastructure and labor constraints. The stronger than expected growth was underpinned by a surging rig count. In 2018 the Permian shale rig count averaged about 430 units.

Looking to 2019, a moderating rig count in Permian shale will temper annual production growth and set the stage for even stronger headwinds for growth in 2020. Longer term, Permian production will follow a flatter growth trajectory as the Wolfcamp and Bone Spring mature.

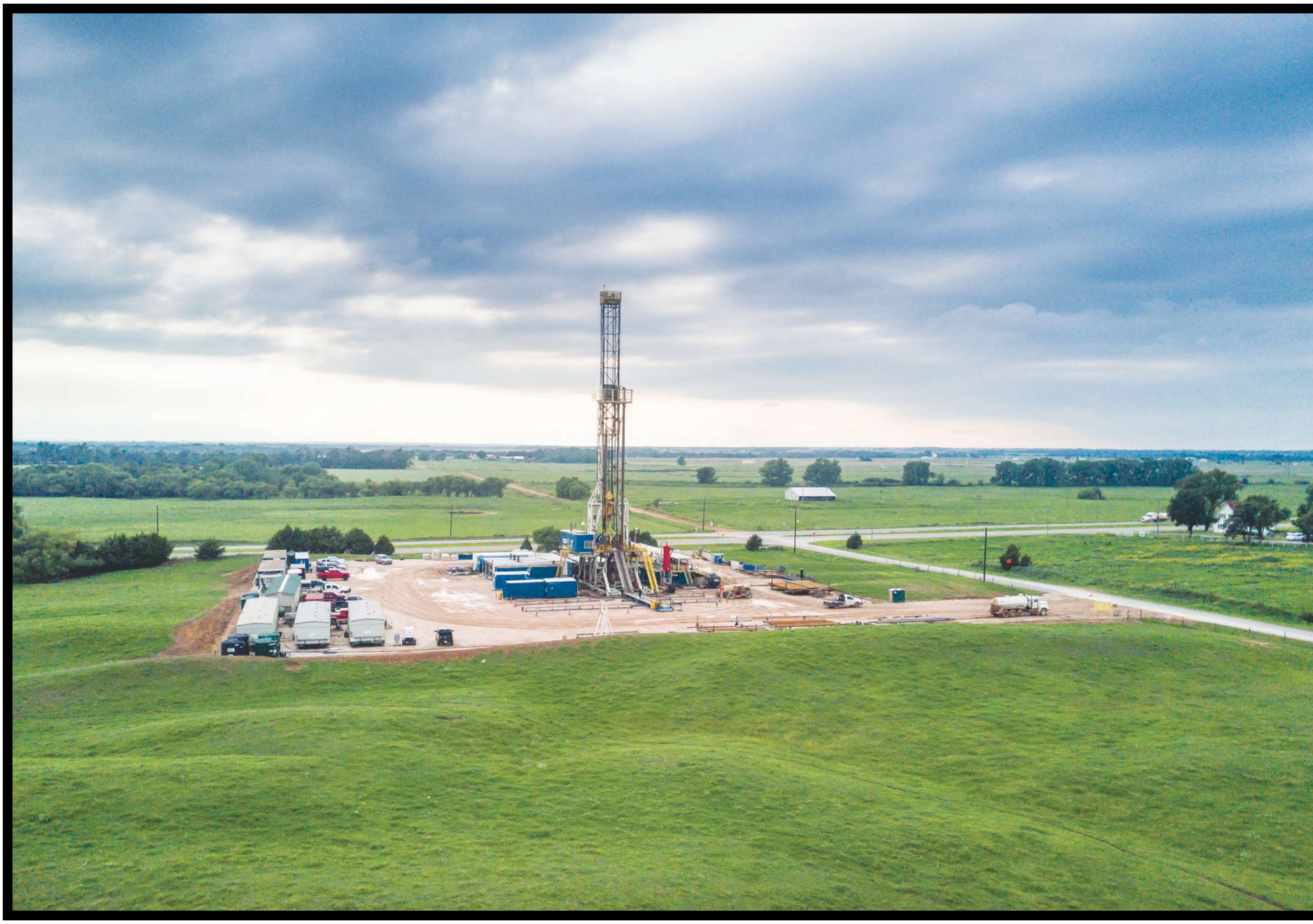
Breakeven economics in the Bone Spring and Wolfcamp remain supportive in spite of expectations of longer laterals and more intense completion designs. Top wells in the Wolfcamp have breakeven prices near $30/bbl West Texas Intermediate (WTI). On the opposite end of the spectrum, bottom performers remain uneconomic at recent prices.

Eagle Ford shows resilience

The Eagle Ford is on track to exit 2018 at 1.4 MMbbl/d of production, a little more than 100,000 bbl/d of growth versus 2017. Growth was driven



Permian production will follow a flatter growth trajectory as the Wolfcamp and Bone Spring mature. (Source: Stratas Advisors)



Rig counts in the Midcontinent have been climbing fast, according to Stratas Advisors. (Photo by Edward DeCroce, courtesy of *Oil and Gas Investor*)

by a stable and growing rig count. Looking ahead, 2019 rig counts are expected to climb modestly. In general, the Eagle Ford has entered midlife. Midlife plays are characterized by well-understood resource delineation, ample remaining inventories of undrilled locations and stable operations. The Eagle Ford is forecast to generate relatively stable production into the 2020s. The Eagle Ford generates solid economics and cash flow, which operators use to fund exploration projects both nearby and elsewhere. Portions of the Eagle Ford generate some of the best economics in shale.

Karnes and nearby counties continue to deliver. As the old saying goes, there is no substitute for good rock. Favorable gas-oil ratios and access to infrastructure support ongoing development in this area. Elsewhere in the play, operators have been shifting to extended-length laterals and more intense completions with higher proppant loadings. Extended-length laterals are more common in areas like Atascosa and Frio counties in Texas. The western reaches of the Eagle Ford remain liquids-challenged. Consequently, wells in this area have a greater risk of being uneconomic.

Bakken reborn

The Bakken found its footing this year as higher crude prices and solid operations bolstered operator confidence. Production this year entered into record territory in recent months. For December, production is expected to reach 1.3 MMbbl/d, up from 1.2 MMbbl/d at year-end 2017. Development has been strongest along the Missouri River, an area with higher gas content. Like the Eagle Ford, the Bakken is maturing further into midlife status.

Rig counts in the Bakken are projected to remain relatively stable and excess cash flow is expected to be deployed to areas like the Powder River Basin, the Midcontinent and other Rockies opportunities. Breakeven prices for the best Bakken wells are well below $40/bbl WTI, and a majority of wells have breakeven prices below $60. These economics, along with ample drilling inventories, will allow the play to attract capital for years to come.

Rockies

The Rockies appear to be ground zero in the energy-environmental battle being waged. Proposition 112 in Colorado, while defeated, raised the stakes in this battleground area. The recent decision by a judge to once again delay the Keystone Pipeline demonstrates the resiliency of challenges the industry faces in the region. Despite all this, momentum in the Niobrara grew stronger this year. In the Denver-Julesburg (D-J) Basin, oil production is forecast to reach 0.3 MMbbl/d in December, up about 60,000 bbl/d year-on-year. In the Powder River, gains were impressive as several operators made strides on stacked opportunities.

Economically, the region delivers competitive options. Breakeven prices for more than 75% of wells in the D-J Niobrara are below current prices. In the Powder River Niobrara, the same is true for a majority of wells.

Midcontinent

The Midcontinent remains largely a story of the Scoop and Stack. December 2018 production in the Scoop and Stack are estimated at 0.1 and 0.3 MMbbl/d, respectively. The leading development in 2018 is the Springer Shale, a subset of the Scoop. Rig counts have been climbing fast, driven largely by Continental Resources. Advertised type curves for the Springer Shale show great promise.

Economically, the Midcontinent has been a mixed bag. Plays like the Scoop and Stack have highly competitive performers. On the other hand, the Granite Wash, Mississippi Lime and the Arkoma Woodford have disappointed.

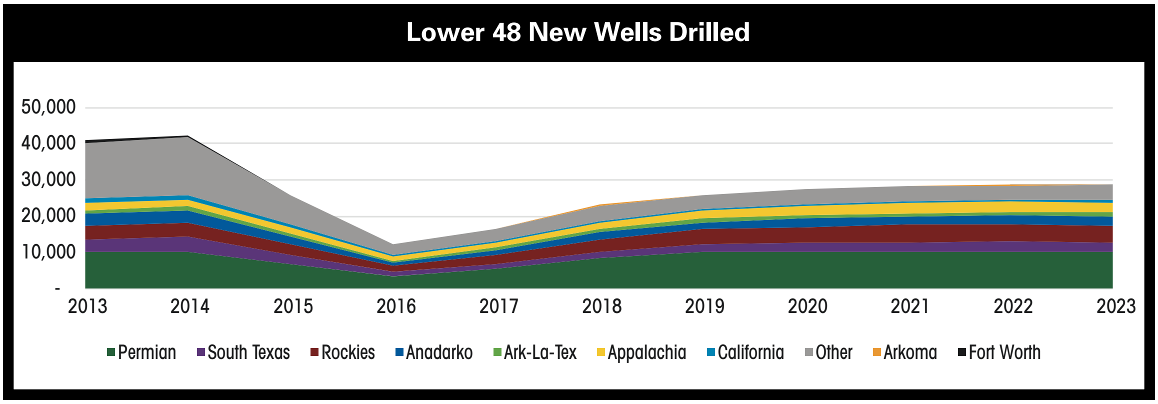
In general, complicated geology is largely to blame. High levels of natural fracturing combined with more complicated depositions make for serious challenges. The best breakeven prices in the Midcontinent are below $40/bbl for the top wells in the Scoop/Stack.

Appalachia and Haynesville go head to head

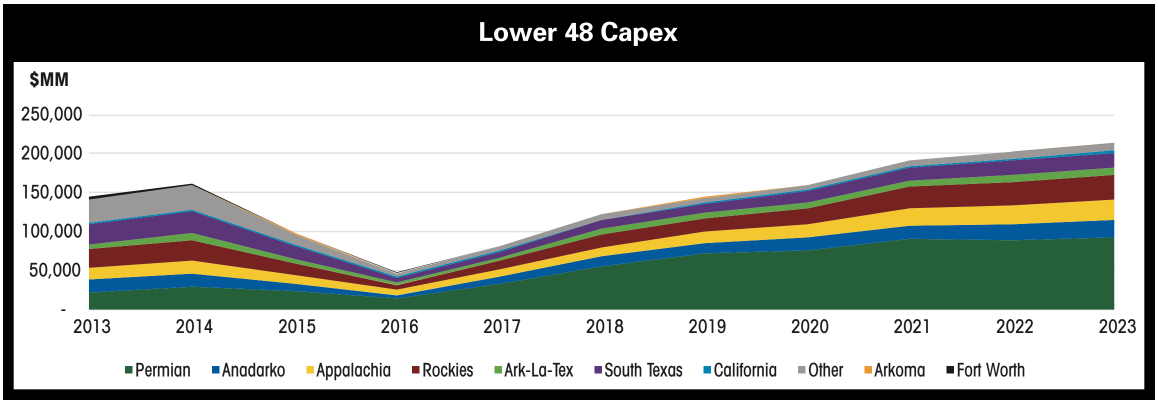
As prospects for LNG exports loom on the horizon, look for gas-on-gas competition between the Marcellus and Haynesville. The Marcellus will remain the tour de force in dry gas, while the Haynesville will ply the latest completion designs in an effort to capture share. Insulation from transportation risk and proximity to LNG export terminals are favorable for the Haynesville.

Breakeven prices are below $4/MMBtu, NYMEX for more than 75% of Marcellus wells. Top Haynesville wells have breakeven prices in the mid-$2/MMBtu range.

Both the Marcellus and Haynesville contend with increasing associated gas volumes from the Permian and other shale oil plays. Economics for associated gas will remain extremely competitive.



Stratas expects activity levels to remain relatively stable in the coming years as illustrated in this chart of well additions. (Source: Stratas Advisors)



Capital spending will remain on an upward sloping path, as the Permian powers overall spending in the U.S., driven in part by more complex and bigger wells. (Source: Stratas Advisors)

Peering through the kaleidoscope

The rebound in drilling from the trough was pronounced and sustained through 2018. The need for U.S. operators to remain competitive through the downcycle in prices led to draconian measures. Fortunately, survivors of this most recent downturn came out stronger. Unfortunately, the easy fixes are in. Drilling and completions are highly optimized, captive capital has been wrung out of business processes and lingering challenges for raising production remain. The key challenges are labor shortages, infrastructure and an intensifying regulatory environment. Therefore, look for activity levels to remain relatively stable in the coming years.

As highlighted in the overview of this issue, industry participants find themselves in the cross-currents of key themes—changing energy mix, shifting energy flows, intensifying regulatory environment and an evolving transportation sector. Of these themes, the first three are set to weigh heavily on the industry in the near term. The mix of energy is in flux.

The success of U.S. shale since the early 2000s has been critical to reshaping energy around the globe. This is true for both crude and natural gas. The U.S. is fully entrenched as an energy powerhouse for both liquids and gas. In liquids, rising production has led to rising exports, which is reshaping global trade flows. Prospects look strong for ongoing growth in liquids production, particularly from the Permian. That said, production growth will come at a slower pace.

Two maturing shale oil plays, the Bakken and Eagle Ford, have more fully transitioned to harvest mode. To be clear, the outlook for these plays remains bright. Established operators in both plays control large portions of the capital deployed to them. A modicum of capital discipline is almost ensured.

In natural gas, the Marcellus will continue to reign supreme in shale gas plays, followed by the Haynesville. Power sector demand and rising LNG exports remain the drivers of growth for gas in the mid- to long-term outlooks.

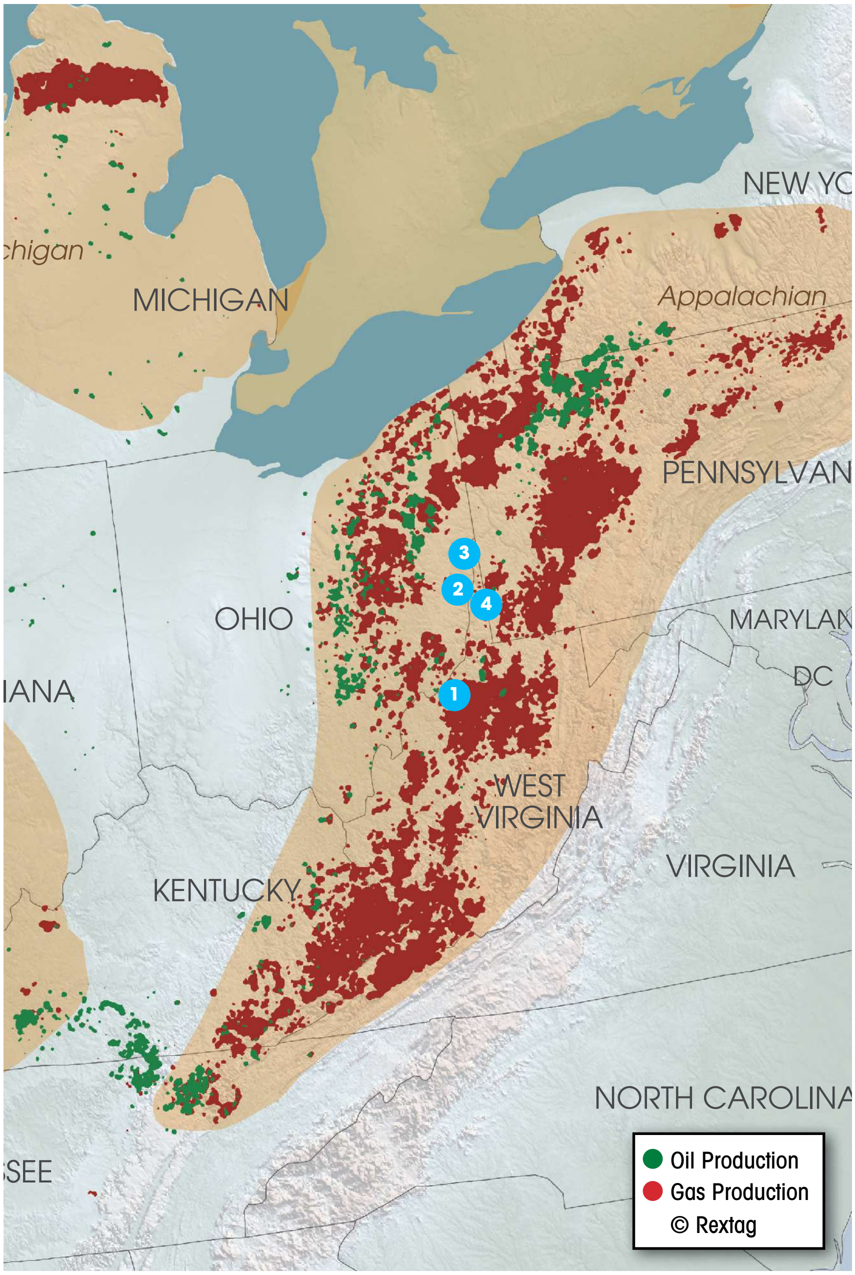
Looking deeper into 2019, infrastructure will remain a topic. Projects in multiple basins have become entangled in regulatory approval processes within the states impacted. Stratas anticipates most of the entangled projects will get sorted out within the next year. Progress on infrastructure in the Permian and Appalachia is expected to positively affect flows in late-2019. Elsewhere, transportation is less of an issue.

Spending on the upswing

While operators have learned to embrace their newfound passion for living largely within cash flow, capital spending will remain on an upward sloping path as the Permian powers overall higher spending in the U.S., driven in part by more complex and bigger wells. The estimates in the capex chart are based on current technology and cost escalations based on recent observations. Additional cost pressures could arise in select industry segments (i.e., labor and trucking) as constrained resources get bid up.

Good thing for the industry that this comes when commodity prices also are projected to trend higher. To be sure, regardless of the price environment, energy investors are likely to insist on transparent, returns-based exploration and development programs. The days of drilling for growths sake are over, at least for now. E&P

MARCELLUS-UTICA



1 Antero Resources Corp. has been issued permits for three Shiloh-Wick Field-Marcellus Shale ventures in Tyler County, W.Va. The permitted wells will be drilled from a drillpad on a 317-acre lease in Centerville District, Middlebourne 7.5 Quad. The Heintzman Unit 1H well has a planned depth of 17,800 ft and will be drilled to the south. The Heintzman Unit 2H well has a planned depth of 17,500 ft and will be drilled to the southeast. The Heintzman Unit 3H well has a planned depth of 17,400 ft and will be drilled to the east-southeast. Nearby production in the Shiloh-Wick Field is at an Antero Utica producer, Rymer Unit 4HD. It was completed in 2016 flowing 20 MMcf/d of gas.

2 Ascent Resources LLC has received permits for four Utica Shale-Colerain Field wells in Jefferson County, Ohio. The wells will be drilled from a drillpad in Section 34, Mount Pleasant Township. The Ruth E MTP 2H well has a planned depth of 22,000 ft, and the Ruth E MTP 4H well has a planned depth of 22,000 ft. The Ruth E MTP 6H well has a planned depth of 22,500 ft, and the Ruth E MTP 8H well has a planned depth of 23,000 ft.

3 Ascent Resources LLC is underway at two Jewett Consolidated Field wells in Jefferson County, Ohio. The Utica Shell wells are on a 378-acre lease in Section 18-8n 3w. The Geno E SMF JF 5H well has a planned depth of 24,300 ft and will be drilled to the northwest. The offsetting Geno W SMF JF 1H well has a planned depth of 26,000 ft, and it will be drilled to the north. Nearby production is at an American Energy Partners completion in Section 27 in the Dillonvale 7.5 Quad at the Smithfield A 1H-27 well. The Smithfield pad discovery was drilled to 18,525 ft (9,631 ft true vertical depth), and it was tested flowing 18.1 MMcf/d of gas.

4 Southwestern Energy Co. has received permits to drill two Marcellus Shale tests from a drillpad in Ohio County, W.Va. The Roy Riggle OHI 6H well has a projected depth of 12,429 ft and a projected true vertical depth of 6,542 ft. It will be drilled to the northeast. The offsetting Roy Riggle OHI 206H well has a planned depth of 15,325 ft and a planned true vertical depth of 6,519 ft. It will be drilled to the southeast. The company also has received permits to drill Marcellus ventures in nearby Brooke County, W.Va., at the Worthley Brk 1H, Worthley 201H, Worthley Brk 210H and Worthley Brk 5H wells.

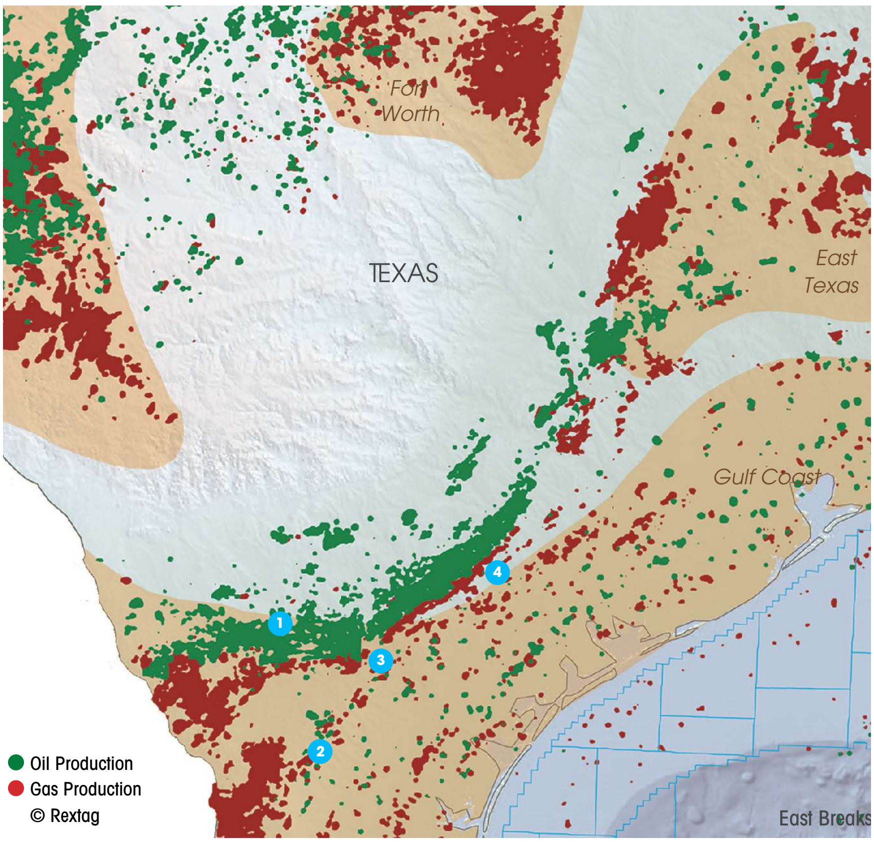
EAGLE FORD

1 Two Eagle Ford discoveries were announced by Freedom Production Inc. in the Dimmit County (RRC Dist. 1), Texas, portion of Briscoe Ranch Field. The Hovencamp Unit 1H well flowed 602 bbl of 45-degree-gravity crude, 2.022 MMcf of gas and 311 bbl of water per day through acid- and fracture-treated perforations at 6,633 ft to 13,809 ft. During testing on a 34/64-in. choke, the flowing tubing pressure was 395 psi. The horizontal producer was drilled to 13,957 ft (6,719 ft true vertical depth). The offsetting Hovencamp Unit 2H well produced 503 bbl of 43-degree-gravity crude, 1.41 MMcf of gas and 366 bbl of water per day. The 13,986-ft well has a true vertical depth of 6,699 ft, and production is from an acid- and fracture-treated zone at 6,655 ft to 13,835 ft. Gauged on a 34/64-in. choke, the flowing tubing pressure was 428 psi. The wells are on a 240.6-acre Southwest Texas lease in Section 20 in Block 1 in the H&GN RR Co Survey, A-1007. The parallel lateral wells bottomed about 1.5 miles to the southeast in Section 21 in Block 1 in the H&GN RR Co Survey, A-127.

2 Killam Oil Co. has tested a Wilcox gas well in Webb County (RRC Dist. 4), Texas. The Ortiz Ranch E 1 well flowed 1.294 MMcf of gas, 60 bbl of 42.7-degree-gravity crude and 198 bbl of water per day from Lobo (Wilcox) at 6,658 ft to 6,772 ft. The Umbrella North Field well is on a 40-acre South Texas lease in Section 23 in the Leonardo Sanches Survey, A-283. Gauged on a 48/64-in. choke, the flowing tubing pressure was 1,415 psi and the shut-in tubing pressure was 2,415 psi.

3 An Eagle Ford Shale well was announced by Lewis Petroleum Properties in Hawkville Field in La Salle County (RRC Dist. 1), Texas. The Cenizo 1H well flowed 6.799 MMcf of gas and 874 bbl of water per day from fracture-treated perforations at 11,838 ft to 18,039 ft. An 11,950-ft vertical pilot hole was horizontally drilled to 18,220 ft, and the true vertical depth was 11,450 ft. It is on a 5,030-acre Southwest Texas lease in the Seale & Morris & Seale Survey, A-664, and it bottomed about 1 mile to the north in HE&WT RR Co Survey, A-1285. Gauged on a 20/64-in. choke, the flowing casing pressure was 4,680 psi and shut-in casing pressure was 6,641 psi.

4 EOG Resources Inc. has completed two extended-lateral oil wells in the Atascosa County (RRC Dist. 1), Texas, portion of Eagleville Field. The wells are on a 2,189-acre Southwest Texas lease in Section 100 ½ in the Antonio Manchaca Survey, A-558, and it bottomed within 1 mile to the southeast in Section 1323 in the James F. Pittman Survey, A-680. According to IHS Markit, the Strawberry A 1H well flowed 2,548 bbl of 36-degree-gravity crude, 727,000 cf of gas and 4,076 bbl of water per day from acid- and fracture-treated perforations at 9,997 ft to 23,032 ft. The well was drilled to 23,100 ft (9,874 ft true vertical depth). It was tested on a 46/64-in. choke with a flowing tubing pressure of 1,148 psi. The offsetting and parallel Strawberry B 2H well was tested flowing 2,640 bbl of 36-degree-gravity crude, 723,000 cf of gas and 3,126 bbl of water per day. Production is from acid- and fracture-treated perforations at 9,697 ft to 22,967 ft. The 23,034-ft well has a true vertical depth of 9,919 ft. Gauged on a 44/64-in. choke, the flowing tubing pressure was 1,232 psi.



PERMIAN BASIN & MIDCONTINENT

1 Capitan Energy Inc. announced two horizontal Wolfcamp gas producers in the Delaware Basin in Culberson County (RRC Dist. 8), Texas. The Roxanne Fee 46 2H well flowed 5.501 MMcf of gas, 1,223 bbl of 49.8-degree-gravity condensate and 3,677 bbl of water per day. Production is from acid- and fracture-stimulated perforations at 9,745 ft to 14,286 ft. It is in Section 46 in Block 58 T2S in the T&P RR Co Survey, A-2362. The horizontal Ford West Field producer bottomed about 1 mile to the south at 14,502 ft (9,498 ft true vertical depth). Tested on a 36/64-in. choke, the flowing tubing pressure was 2,100 psi and was drilled about 3 miles to the southwest. The James Fee 6 2H well is in Section 5 in Block 112 in the PSL Survey, A-1573. It initially produced 4.869 MMcf of gas, 993 bbl of 49.7-degree-gravity condensate and 4,869 bbl of water per day. Production is from fracture-treated perforations at 9,775 ft to 17,875 ft. Drilled to 18,098 ft, the true vertical depth is 9,353 ft with a 1.5-mile lateral that bottomed to the north. Tested on a 42/64-in. choke, the flowing tubing pressure was 1,300 psi.

2 A horizontal Devonian gas discovery in Pecos County (RRC Dist. 8), Texas, is producing 8.307 MMcf of gas and 700 bbl of water per day. Teakwood Operating LLC's Alpine High Field venture, Texas American Syndicate 6 1H, is in the southern portion of the Delaware Basin. It is in Section 6 in Block 122 in the T&STL RR Co Survey, A-9142, and it was drilled to 20,630 ft (13,337 ft true vertical deoth). It bottomed within 2 miles to the northeast in Section 5. Production is from acid- and fracture-treated perforations at 17,345 ft to 20,452 ft. Gauged on a 1-in. choke, the flowing tubing pressure was 262 psi and the shut-in tubing pressure was 2,250 psi.

3 Novo Oil & Gas Texas LLC completed a horizontal Mississippian oil discovery in Ector County (RRC Dist. 7C), Texas. The Cowden 601H well produced 402 bbl of 43-degree-gravity crude, 302,000 cf of gas and 1,693 bbl of water per day from acid- and fracture-treated perforations at 10,890 ft to 15,109 ft. The wildcat was drilled to 15,550 ft and is in Section 6 in Block 43 T2S in the T&P RR Co Survey, A-584. A lateral well was drilled about 1 mile to the southeast to a true vertical depth of 10,667 ft. It was tested on a 25/64-in. choke, and the flowing tubing pressure was 525 psi.

4 Jones Energy Inc. completed a western Anadarko Basin horizontal well in Ochiltree County (RRC Dist. 10), Texas. The Malinda 745 2H well is in Section 664 in Block 43 in the H&TC Survey, A-601. It is producing from a fracture-stimulated, openhole zone in Marmaton at 7,797 ft to 12,757 ft. The well was tested flowing 501 bbl of 38-degree-gravity oil, 826,000 cf of gas and 1,152 bbl of water per day. Tested on a 64/64-in. choke, the shut-in tubing pressure was 625 psi and the flowing tubing pressure was 321 psi. The true vertical depth is 7,181 ft, and it bottomed 1 mile to the north in Section 745, A-244.

5 Continental Resources Inc. completed an Anadarko Basin-Meramec producer that flowed 32.8 MMcf of gas with 2,691 bbl of water per day and no reported condensate. According to IHS Markit, the discovery, 2-30-19XH Heckenberg, was drilled across two sections in Blaine County, Okla. It is in Section 30-13n-13w and was drilled to the north to 25,478 ft (14,871 ft true vertical depth). Tested on a 38/64-in. choke, the shut-in tubing pressure was 7,085 psi and the flowing tubing pressure was 5,835 psi. Production at the Stack play well is from acidized and fractured perforations between 15,338 ft and 25,284 ft.

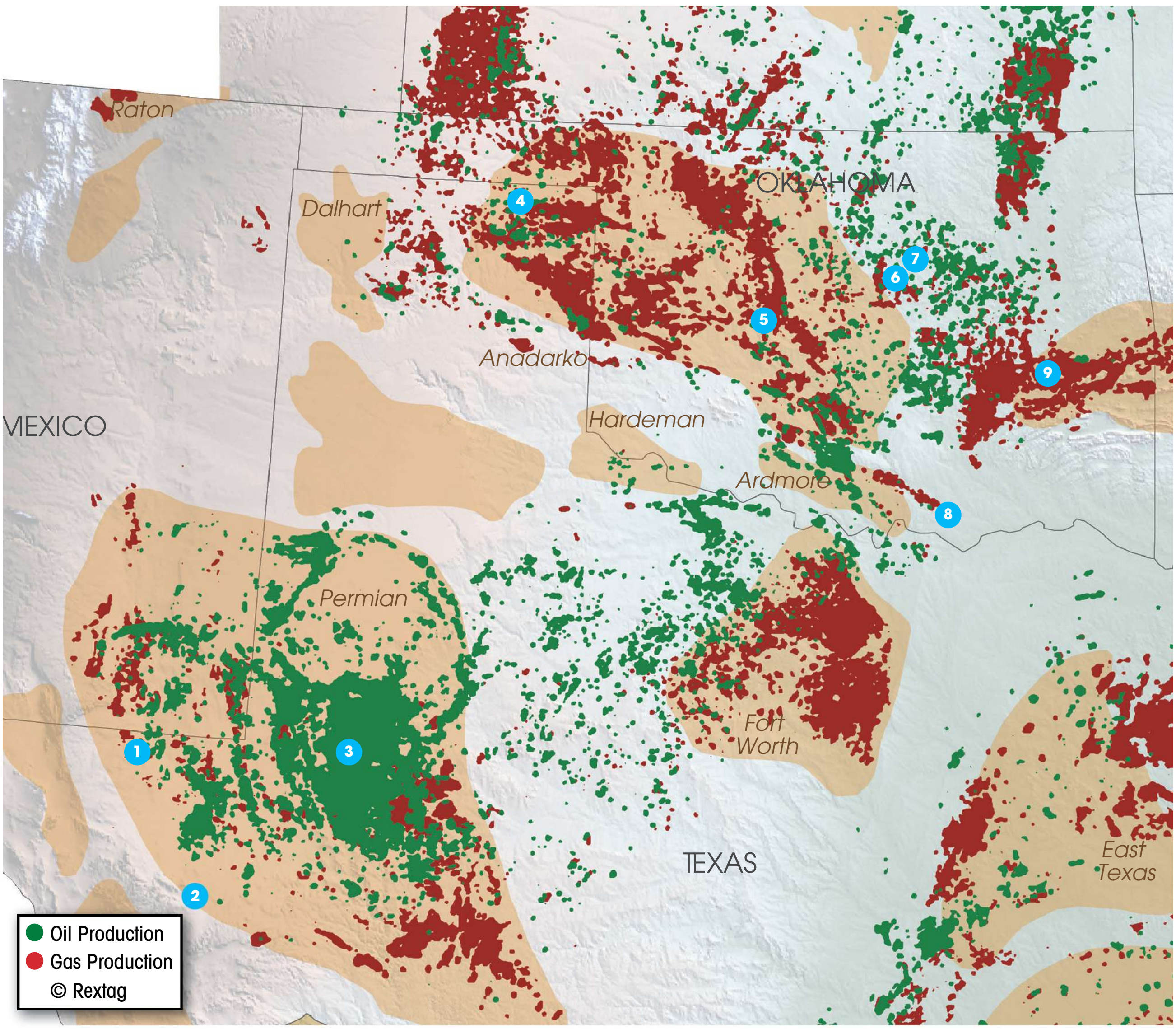
6 Chesapeake Operating Inc. completed three long-reach horizontal Oswego producers from a pad in Section 12-17n-7w of Kingfisher County, Okla. The GM 12-17-7 1HC well pumped 904 bbl of 43-degree-gravity oil, 926,000 cf of gas and 999 bbl of water per day. Production is from acidized and fractured perforations at 7,071 ft to 17,064 ft. It was drilled 2 miles north across Section 1-17n-7w to 17,233 ft (6,600 ft true vertical depth), and it bottomed in Section 36-18n-7w. About 20 ft east on the Sooner Trend pad, the GM 12-17-7 2HC well flowed 700 bbl of oil, 745,000 cf of gas and 1,126 bbl of water per day. It was drilled to 17,130 ft (6,588 ft true vertical depth) in a parallel lateral and bottomed in Section 36-18n-7w. It was acidized and fractured at 7,002 ft to 16,964 ft. The GM 12-17-7 3HC well is producing 330 bbl of oil, 283,000 cf of gas and 457 bbl of water per day. Drilled to 17,459 ft (6,581 ft true vertical depth), it bottomed in Section 36-18n-7w. Production is from perforations between 7,147 ft and 17,293 ft.

7 In Kingfisher County, Okla., Chesapeake Operating Inc. completed an extended-reach horizontal Pennsylvanian producer that was tested pumping 1,606 bbl of 39-degree-gravity oil, 1.6 MMcf of gas and 1,218 bbl of water per day. The Oswego producer, States 15-18-6 4HC, is in Section 15-18n-6w. Production is from an acidized and

fractured lateral at 6,775 ft to 16,657 ft. The well was drilled south to 16,735 ft (6,471 ft true vertical depth) and bottomed in Section 22-18n-6w. According to IHS Markit, the IP oil rate is the highest reported to date for the 127 horizontal Oswego producers in the county Rates for the other wells range from 2 bbl/d to 1,395 bbl/d with an average of 374 bbl/d.

8 XTO Energy Inc. has completed a horizontal Woodford producer in Love County, Okla. The Charles 1-23H14X well is in Section 23-7s-1e and was tested on a 26/64-in. choke flowing 1,123 bbl of 49-degree-gravity oil, 2.35 MMcf of gas and 3,473 bbl of water per day. Production is from a treated lateral at 15,225 ft to 24,654 ft. It was drilled to 24,817 ft (15,073 ft true vertical depth) and bottomed in Section 14-7s-1e.

9 IHS Markit announced that Unit Petroleum Co. recompleted a well in the Arkoma Basin's Panola Field as a Lower Atoka producer. The Hawthorne 3 is in Section 4-5n-20e in Latimer County, Okla. It produced 995,000 cf of gas and 67 bbl of water per day, and it was tested on a 64/64-in. choke with 95 psi of flowing tubing pressure. Production is from perforations at 12,330 ft to 12,382 ft, and additional details are not currently available. The company originally completed the 13,380-ft well in January 2008 flowing 2.82 MMcf/d of gas from untreated perforations in Basal Atoka (Spiro) at 13,186 ft to 13,197 ft. In March 2008 it was perforated and fractured in Basal Atoka at 13,131 ft to 13,197 ft and flowed 10.5 MMcf/d of gas with no water.



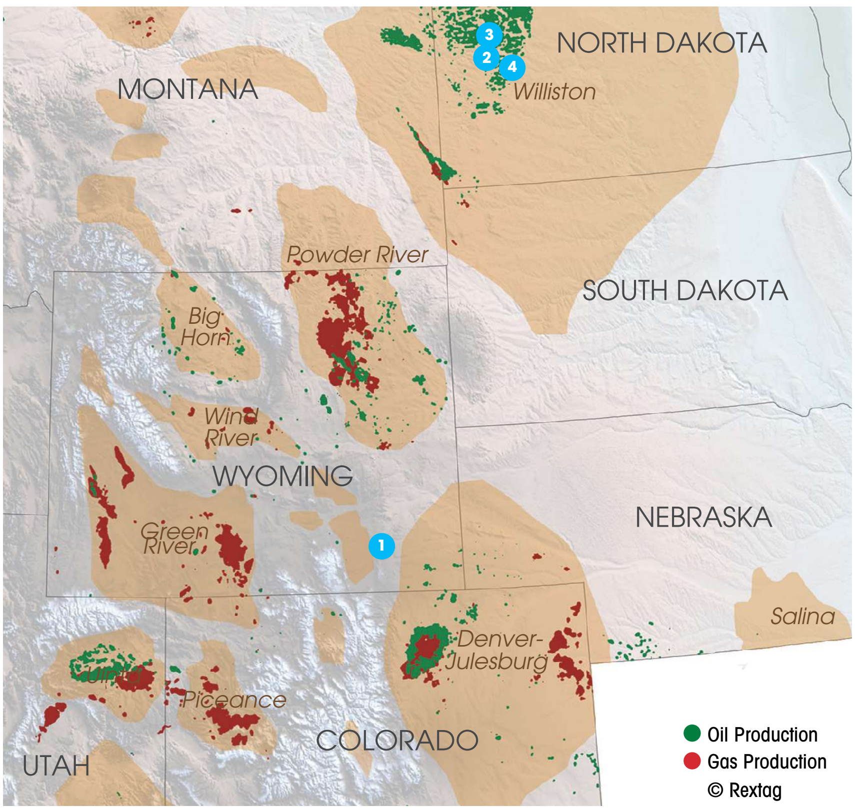
BAKKEN/NIOBRARA

1 EOG Resources Inc. completed three extended-reach horizontal Codell producers from a drillpad in the Denver-Julesburg Basin. The pad is in Section 26-14n-65w in Laramie County, Wyo., and all were tested on gas lift. The Big Sandy 542-2602H well initially flowed 1,231 bbl of oil, 901 Mcf of gas and 415 bbl of water per day. Production is from a horizontal Codell lateral well drilled to the southeast to 20,188 ft (8,620 ft true vertical depth) at a bottomhole location in Section 2-13n-65w. It was tested following 50-stage fracturing between 9,016 ft and 20,117 ft. The Big Sandy 543-2602H well produced 1,226 bbl of oil, 854 Mcf of gas and 498 bbl of water per day. It was tested after 53-stage fracturing between 9,223 ft and 20,989 ft in a Codell lateral well extending southeastward to 21,062 ft (8,614 ft true vertical depth) and bottomed in Section 2-13n-65w. The Big Sandy 544-2602H well initially flowed 1,018 bbl of oil, 730 Mcf of gas and 514 bbl of water per day. It was drilled southward to 19,796 ft and bottomed in 2-13n-65w at a true vertical depth of 8,629 ft. It was tested on a 64/64-in. choke following 48-stage fracturing between 9,074 ft and 19,725 ft.

2 According to IHS Markit, a Reunion Bay Field-Bakken discovery—the highest producing Bakken well to date—was announced by Marathon Oil Corp. The Whitebody-USA 14-23H well initially flowed 8,702 bbl of 41-degree-gravity oil, 10.023 MMcf of gas and 5,818 bbl of water per day. The extended-reach well is on the Fort Berthold Indian Reservation in Section 22-151-94w, McKenzie County, N.D. Production is from a horizontal Middle Bakken lateral extending from 11,017 ft eastward to 23,630 ft. It bottomed in Section 19-151n-93w under the Missouri River, and the true vertical depth is 10,706 ft. It was tested on a 64/64-in. choke following 57-stage fracturing between 11,114 ft and 23,499 ft with a flowing casing pressure of 2,150 psi.

3 Additional results were reported for a high-volume Middle Bakken well in McKenzie County, N.D., by Marathon Oil Corp. The Antelope Field completion, the Chauncey-USA 31-2H, is in Section 35-152n-94w and flowed 8,475 bbl of oil, 8.289 MMcf of gas and 4,492 bbl of water per day. Production is from a horizontal lateral well extending from 12,010 ft southeastward to 22,041 ft (10,711 ft true vertical depth) and bottomed in Section 11-151n-94w. It was tested on a 64/64-in. choke following 45-stage fracturing between 12,072 ft and 21,886 ft.

4 Marathon Oil Corp. announced results for two Three Forks wells in Bailey Field in Dunn County, N.D. The Olea 24-11TFH well flowed 6,573 bbl of 40-degree-gravity oil with 4.461 MMcf of gas and 8,491 bbl of water per day. Production is from a lateral well extending from 11,123 ft northward to 21,195 ft, and it bottomed in Section 2-146n-94w with a true vertical depth of 10,795 ft. It was tested on a 1-in. choke following 45-stage fracturing between 11,172 ft and 21,065 ft with a flowing casing pressure of 1,400 psi. From the same drillpad, the Sundby 24-11TFH well flowed 5,694 bbl of oil, 6.869 MMcf of gas and 6,497 bbl of water per day. Production is from a lateral well extending from 11,151 ft northward to 21,315 ft (10,793 ft true vertical depth) and bottomed in Section 2-146n-94w. Gauged on a 1-in. choke, after 45-stage fracturing between 11,200 ft and 21,180 ft, the flowing casing pressure was 1,800 psi. E&P



By Larry Prado, Activity Editor, Digital News Group, Hart Energy

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COMING NEXT MONTH

The January issue of ***E&P*** will focus on hydraulic fracturing. Other features will cover seismic processing and interpretation, directional drilling, plugs, produced water management, and subsea processing and monitoring. The unconventional report will focus on the Bakken, and the regional report will cover Norway. As always, while you're waiting for your next copy of ***E&P***, be sure to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER

The big five shale plays helped the U.S. surpass Saudi Arabia and Russia as the world's top producer of crude oil this year, according to the U.S. Energy Information Administration. *(Source: Permian and Eagle Ford photos by Tom Fox, Midcontinent and Bakken/ Niobrara photos by Edward DeCroce and Marcellus/Utica photo by Glenn Kulbako; all courtesy of* Oil and Gas Investor*)*

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The Importance of Pure Proppant

Quality control processes are key to keeping turbidities and silica exposure low.

By Scotti Bayman, Shale Support

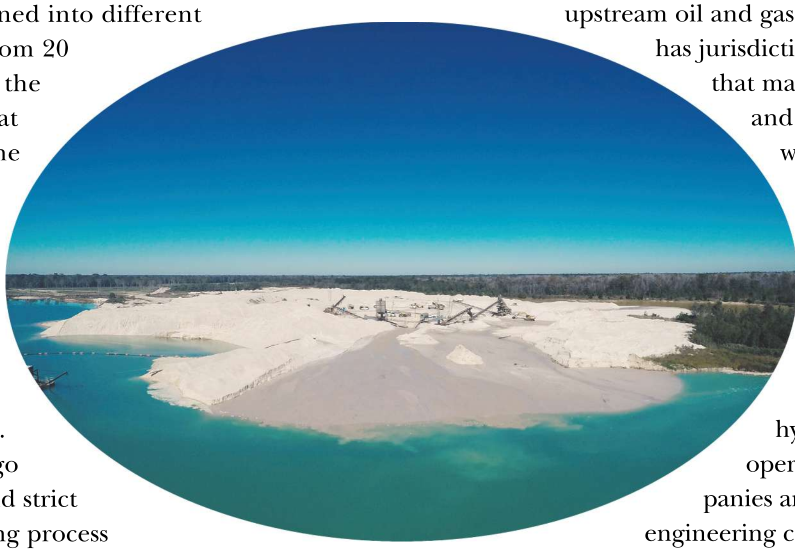
Turbidity is the measure of suspended particles, such as clay or sand, in distilled water, and it is one of many testing methods performed for American Petroleum Institute's (API) Recommended Practice 19C and the International Organization for Standardization's (ISO) 13503-2 proppant testing standards. Current API and ISO standards require turbidity to be 250 Formazin Turbidity Units (FTUs) or less. In essence, a lower turbidity means the sand is cleaner and has less dirt and silt attached to each particle.

While sand is screened into different mesh sizes ranging from 20 to 100 depending on the shale application, what remains constant is the need for proppant with low turbidity. This is better quality sand that maximizes operations while also being safer for employees and the environment.

Proppant needs to go through a rigorous and strict quality control cleaning process before it is suitable to be sold to customers. The washing process cleans sand, removing silt and clay content to reduce FTUs. Sand for fracturing use is typically placed in demineralized water for 30 minutes and then shaken by a wrist action shaker for an additional 30 seconds. The sand sits in a beaker of water for five minutes and then the suspended-particle sample is tested by a turbidity meter or spectrometer for FTUs.

Silicosis, a lung condition caused by inhaling too much silica over a long period of time, is a major concern and focus in the sand industry. Symptoms of silicosis can appear after years of exposure to silica dust, and symptoms often worsen over time as the lungs continue to scar. Both the U.S. Occupational Safety and Health Administration (OSHA) and the U.S. Mine Safety and Health Administration (MSHA) regulate silica dust exposure. The U.S. National Institute for Occupational Safety and Health (NIOSH) also studies and helps with regulation for silica dust exposure.

In addition, the NIOSH recommends that those entering a trade industry who may have contact with silica dust should receive medical examinations at least every three years. OSHA has jurisdiction over the safety and health of workers, including workers involved in upstream oil and gas operations. MSHA has jurisdiction over mine sites that manufacture sand for oil and gas operations. Sand with lower turbidity produces less dust and is the safest option for workers. High turbidity in sand directly correlates with high silica exposure during hydraulic fracturing operations. Service companies are required to put in engineering controls, such as a dust collection system, chemical dust suppressors or other systems, which add to the operating costs. The exposure to silica also affects the workers on site requiring mask filtration systems or limited work hours hindering operations, which also delays production and output.



Shale Support mines white fracture sand from its properties in Picayune, Miss. (Source: Abstract Media)

There is a tremendous demand in the energy industry for sand as rig counts continue to increase. As sand providers work to fulfill the growing needs of their customers, it is important to stick to quality control processes, ensuring the best products with the lowest turbidity are provided. E&P

CONTROLLED INTENSITY™

Pinpoint fracturing delivers aggressive infill completions one frac at a time, with less risk of well bashing.

Multistage Unlimited® pinpoint fracturing delivers more SRV with far less risk of frac hits and well bashing during infill field development, compared with plug-and-perf. You put fracs where you want them, and you control how much sand you pump into each one, preventing “super clusters” that can hurt production from offset wells. With repeatable frac placement from well to well plus recorded downhole pressure/temperature data, you can truly optimize stage count and spacing in a given formation with just a few wells.

More stages per well

NCS pinpoint fracturing is delivering more and more individual entry points per well and with far higher cluster efficiency than plug-and-perf. For example:

- 227 stages (Montney)
- 210 stages (Montney)
- 161 stages (STACK)
- 159 stages (STACK)
- 155 stages (Bakken)
- 147 stages (Permian)

More sand per well

More intensity means pumping more sand, and NCS Multistage pinpoint fracturing handles it:

- 18.2 million lb @1,870 lb/lateral ft (Montney)
- 17.5 million lb @2,190 lb/lateral ft (Montney)
- 15.0 million lb @1,711 lb/lateral ft (Duvernay)
- 14.2 million lb @1,973 lb/lateral ft (Permian)

Faster execution

NCS Multistage pinpoint completions are being executed faster than ever. Here’s why:

Higher rates. Technology and design advances have boosted Multistage Unlimited frac rates through the coiled tubing/casing annulus to nearly 80 bbl/min in 5.5-in. casing, far higher “per cluster” than plug-and-perf and more than enough to transport sand (>12 ppg) with slickwater.

Fewer coiled tubing trips. Almost 90% of NCS Multistage jobs are performed in a single coiled tubing trip. As many as 227 sleeves have been fracced without tripping out of the hole.

99+% sleeve success rate. More than 165,000 NCS sleeves have been installed, with the highest sleeve-shift success rate of any coiled-tubing completion system.

Learn more at ncsmultistage.com

NCS
MULTISTAGE

Predictable. Verifiable. Repeatable. Optimizable.

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